From: Catharine Gilliam [cgilliam@NPCA.ORG]
Sent: May 16, 2008 16:13
To: vchec
Subject: NPCA Comments

Attachments: Dominion Air Board May 16 comments.pdf; Dark_Horizons_Report.pdf; GRSM.pdf; Hensley Report for NPCA.pdf
Cindy,

Attached are pdf's of the following documents:

- Comments from NPCA dated May 16, 2008
- Copy of NPCA report on National Parks and Coal-Fired Power Plants
- Copy of Fact Sheet on Great Smoky Mountains National Park and Coal -Fired Power Plants
- Copy of Hensley Energy Consulting Report

Thanks very much,
Catharine

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Photos courtesy of Air Resource Specialists, Inc.

Great Smoky Mountains National Park: Air Quality at Risk

Park highlights

- Great Smoky Mountains National Park, America's most visited national park encompassing more than 800 square miles of the Southern Appalachians in Tennessee and North Carolina, contains half of the remaining old-growth forest in the East, more than 2,000 miles of streams, and 850 miles of trails.
- The park supports an astonishing array of plant and animal life. Over 10,000 species have been documented in the park; scientists believe an additional 90,000 species may live there. Because of its great biodiversity, the park has been designated an International Biosphere Reserve.

Current air quality

- Great Smoky Mounatins National Park has the highest rates of nitrogen and sulfur pollution of any monitored location in North America, resulting in park rainfall that is 5 to 10 times more acidic than normal. Many trees in the park are dead or dying, and the water is too acidic to support some native fish.
- The park also suffers from among the highest levels of ozone (a lung-searing gas) in the Eastern U.S.; since 1990, ozone health limits have been exceeded on more than 300 days. High ozone pollution can cause visitors to experience breathing problems and asthma attacks.
- Average visibility in the park has been cut by about 40 percent in winter and 80 percent in summer, and sometimes less than one mile, meaning visitors may not even see surrounding mountains.

New coal-fired power plants

- Three new coal-fired power plants are under active development within 186 miles (300 km) of Great Smoky Mountains National Park, an area that already contains dozens of polluting coal-fired power plants, which are seriously polluting the park.
- Each year, these new plants would emit into the Smokies area air shed more than 16 million tons of carbon dioxide, 9,335 tons of sulfur dioxide, 5,604 tons of nitrogen oxides, and 560 pounds of toxic mercury. These pollutants will contribute to more hazy air, more unhealthy air days, greater stress to park trees, and increased mercury contamination of the park's streams.

National Park Service findings

- "[T]he real-world effect of [Duke Energy's coal-fired power plant] by itself would be severe impacts upon air quality and air quality related values at Great Smoky Mountains National Park."
- The Duke plant's "increase in mercury [pollution] coupled with the predicted increase in sulfur [pollution] could impact park resources, including threatened and endangered species."
- Dominion's Wise County, Va., coal-fired power plant "would have a significant impact" on sulfur dioxide pollution at Great Smoky Mountains National Park.
- "Dominion has not justified the need for [pollution limits] that are higher than [other comparable power plant projects]. Lower emission limits would result in less impact on park resources."

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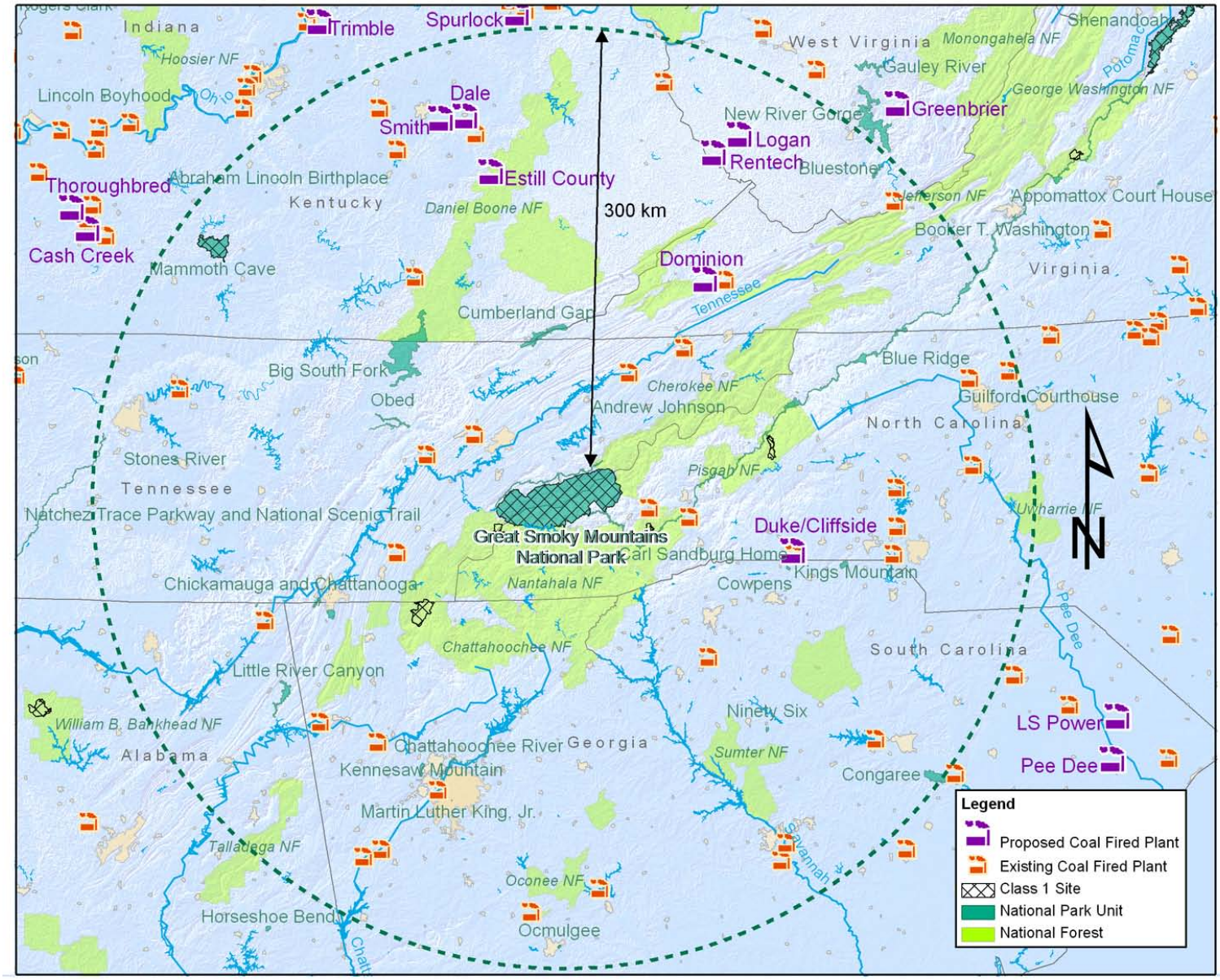

Great Smoky Mountains: Proposed Coal Fired Power Plants

0 50 100 200 Miles

0 75 150 300 Kilometers

Power plants that have received permits and not yet commenced construction or are in active permit process

Plant	Location	Owner	Size (MW)	Distance from Park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
Cliffside Power Plant	Rutherford County, NC	Duke Energy Carolinas	800 MW	130 km	9,608,567	4,126	2,407	463	Air permit issued January 2008
Virginia City Hybrid Energy Center	Wise County, VA	Virginia Electric & Power Co.- Dominion subsd.	668 MW	142 km	5,064,989	3,369	1,971	42	Draft air permit released January 2008
Spurlock Generating Station (unit 4)	Mason County, KY	East Kentucky Power Cooperative	300 MW	250km	1,864,267	1,840	1,226	55	Final air permit re-issued 4/08
Total New Pollution into Great Smoky Mountain National Park Area Airshed					**16,537,823**	**9,335**	**5,604**	**560**	

For more information contact: Bart Melton, 865.329.2424 ext. 24, bmelton@npca.org

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May 16, 2008

Dominion Virginia City Hybrid Energy Center
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Comments on Dominion's Coal-Fired Power Plant Proposed for Wise County, VA

National Parks Conservation Association ("NPCA") appreciates the opportunity to submit additional comments on the Prevention of Significant Deterioration ("PSD") and Maximum Achievable Control Technology ("MACT") permits for Dominion's proposed coal-fired power plant to be located in Wise County, VA. In making its final decisions on the proposed permits, we respectfully submit the following for your consideration:

- The Air Pollution Control Board ("Air Board") and Department of Environmental Quality ("DEQ") have the authority and obligation to protect public health, welfare and air quality related values in Class I areas in making permitting decisions. CAA §§160(1), *Id* at 160(2); *See also* Va Code §§ 10.1-1183, *Id* at 10.1-1307 E.1.
- The Air Board and DEQ are required to impose enforceable best available control technology ("BACT") emissions limitations for new sources of criteria pollutants. CAA §165(a)(4).
- The Air Board and DEQ are required to impose enforceable MACT emission limits for hazardous air pollutants, including mercury, from new coal-fired power plants. CAA §112(g)(B), *State of New Jersey v. U.S. Environmental Protection Agency*, D.C. Cir. Case No. 05-1097 (D.C. Cir. February 8, 2008).
- The Air Board and DEQ have the authority to consider alternative sources, alternative control technologies and the no build option in determining the outcome of a proposed permit. *See* CAA §165(a)(2).[1]

[1] *See In re Prairie State*, PSD Appeal 05-05, 12 E.A.D. __ (Aug. 24, 2006); BRIEF OF THE EPA OFFICE OF AIR AND RADIATION AND REGION V, *In re Prairie State*, PSD Appeal 05-05, 12 E.A.D. __ (EAB, Aug. 24, 2006); *In re Knauf Fiber Glass*, 8 E.A.D. 1212, (EAB 1999); *In re Hillman Power*, 10 E.A.D. 673, 692 (EAB 2002); *See In re EcoEléctrica*, LP, 7 E.A.D. 56, 74 (EAB 1997).

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We appreciate Dominion's effort to respond to questions posed by individual Air Board members. A number of responses, however, lend themselves to statutory obfuscation. The processes for determining BACT and MACT standards are straightforward and we offer the following to the Air Board and DEQ in efforts to identify the required analysis under the Clean Air Act permitting programs and the broad authority granted to the permitting agency in determining the enforceable pollution controls limits for emissions from a large new pollution source. As we have commented previously – as have other public interest organizations and the National Park Service – the draft permits do not comply with these requirements and we ask that the Air Pollution Control Board require the complete, required analysis and full compliance.

1. **Maximum Achievable Control Technology Analysis**

The Clean Air Act requires that coal-fired power plant permits include the most stringent level of pollution control achievable for each of the hazardous air pollutant ("HAP") it will emit. There are 189 HAPs listed under Section 112(b), 67 of which are routinely emitted by coal-fired power plants including mercury, arsenic, lead and formaldehyde. Each HAP is subject to the rigorous MACT analysis and determination process prior to construction. As reinstated by the D.C. Circuit in *New Jersey v. EPA*, coal-fired power plants are subject to MACT standards, and an emissions limit reflecting the "maximum degree of reductions achievable" for each listed pollutants. The MACT standard is much stricter than the BACT standard and should be expressed as an emissions rate, or mass per unit time basis, based on maximum capacity.

The air-permitting authority conducts a MACT analysis under CAA §112(g) for each HAP the new source will emit and includes the two principal analytical steps prior to determining the MACT standard:

- MACT "Floor" Standard: First, the permitting authority must determine the MACT emission limit which is "not less stringent than the emission limitation achieved in practice by the best controlled similar source" for each HAP that the source will emit. 40 CFR §63.41. This step determines the MACT "floor," or lowest level of emissions control.
    - The "similar source" is a "stationary source or process that has comparable emissions and is structurally similar in design and capacity to a… major source such that the source could be controlled using the same technology" 40 C.F.R. 63.41.
    - The emission limit for each HAP of the new source may not be lower than this level of emissions control, irrespective of cost, *See National Lime Association v. EPA*, 233 F.3d 625, 629 (D.C. Cir. 2000), and the need for design changes. *See Sierra Club v. EPA*, 479 F.3d at 882-83 (D.C. Cir. 2007).
    - The applicant must explain how it will comply with the "floor" level and the permitting authority must investigate all possible emission control options for so doing.

- MACT "Beyond-the-Floor" Standard: Second, the applicant and permitting authority must evaluate whether it is possible to achieve an even more stringent control level

for each HAP than determined to be the "floor", on a case-by-case basis, of similar operating facility's control technology and emission levels.

- The applicant must evidence how it will comply with the "beyond the floor" evaluation and the permitting authority must analyze whether the proposed source may achieve a level of emissions control "beyond-the-floor" or a "maximum degree of reduction." *See* 40 C.F.R. §63.43 (e)(xi).
- During this step, cost, "non air-quality health and environmental impacts and energy requirements associated with the emission reduction" may be taken into consideration. CAA §112(d)(2). *See also id* at 112(d)(3).
- This analysis must fully explore potential pollution control technology options as well as non-technology options for each HAP. See 40 C.F.R. 63.40 (defining control technology); *Cement Kiln Recycling Coal v. EPA, 255 F.3d 855, 863* (D.C. Cir. 2001).

2. Best Available Control Technology Analysis

The Clean Air Act requires any major new source subject to PSD conduct a BACT analysis and determination to ensure emissions limit are established for each criteria pollutants that reflect the "maximum degree of reduction" that may be achieved for controlling that pollutant. CAA 165 (a)(2), *Id* at 165(a)(4); 40 C.F.R. 52.21(b)(12). There are five recognized steps to the BACT analysis, which is a "top down" evaluation of all available control technologies. EPA's *Draft New Source Review Workshop Manual* (October 1990). Technologies are ranked in descending order of effectiveness with the "top," or strictest controls deemed the BACT unless such controls are technically infeasible. Where the "top" control is infeasible, the next most stringent control is evaluated. This evaluation continues down the ranking until an appropriate BACT is identified.

<u>The Five Main Steps in the BACT Analysis:</u>

1. *Identify available air pollution control technologies for each regulated emission from the emissions source, including fugitive units*
   - Air pollution controls include "production processes or available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques." 40 C.F.R. 52.21(b)(12).
2. *Eliminate technically infeasible options*
   - Technical feasibility demonstrations should be based on physical, chemical, and engineering principles. Options not technically feasible should be clearly documented and should establish that technical problems would preclude the successful use of the pollution control option.
3. ***Rank remaining control options by control effectiveness***
   - The applicant should provide information on a spectrum of alterative control technologies for each pollutant for each emission unit, which should include: emission reductions, expected emissions rate and energy, environmental and economic impacts.
4. ***Evaluate the most effective controls and document results, including a case-by-case consideration of energy, environmental, and economic impacts***

- The determination of energy, environmental and economic impacts are subjective, case-by-case assessments conducted by the permitting authority.

5. *Select the best available control technology*

Additional Concerns

Section 41 of the "Draft Dominion Operating Permit" fails to address the issue of Air Quality Related Values (AQRV's) in adjacent Class 1 Areas (as defined in the 1977 amendments to the Clean Air Act). NPCA is concerned that the existing language in Section 41 does not effectively limit SO emissions from the new Wise County facility. As written, Section 41 would allow the new Dominion facility to emit SO2 emissions beyond the limit defined in the permit. NPCA requests that the VA Air Board place an enforceable limit on Dominion's SO2 emissions at the proposed Wise County facility. An enforceable SO2 limit and application of the Best Available Control Technology at the source would improve SO2 emissions in the region, reduce sulfur deposition, and improve regional visibility.

NPCA requests that the Air Board confer with the National Park Service (NPS) Air Quality Staff during the next phase of review. National Park Service participation would be justified based on sulfur levels in headwater streams in the Great Smoky Mountains National Park (in North Carolina and Tennessee) and other visibility and deposition concerns detailed, and not yet answered, in prior submissions from the National Park Service Air Quality staff.

All previous comments and attachments filed in regards to the Dominion Virginia City Hybrid Energy Center air permits on behalf of NPCA are incorporated by reference. We hope that the Air Board and DEQ take into account the discussion above in arriving at any BACT or MACT determinations and reassert that the Air Board should not issue the final permits for VCHEC facility in the absence of substantial modifications to the draft permits.

Additional Submittals

- *Dark Horizons: 10 National Parks Most Threatened by Coal-Fired Power Plants*, NPCA Report released May 15, 2008
- *Fact Sheet on Great Smoky Mountains National Park*
- *Report Comparing Alternative Technologies for The Virginia City Hybrid Energy Center*, prepared for NPCA by Hensley Energy Consulting, LLC, March 2008

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Photo of Glen Canyon National Recreation Area courtesy of Michael Melford/National Geographic

Dark Horizons

10 National Parks Most Threatened by New Coal-Fired Power Plants

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Dark Horizons: Introduction

Already, one in three national park sites has air pollution levels that exceed health standards set by the U.S. Environmental Protection Agency (EPA). Most of the air pollution now marring the parks' scenic views, harming plants, and risking the health of wildlife and visitors, results from the burning of fossil fuels, especially by coal-fired power plants. Worse yet, more than 100 new coal-fired power plants are in various stages of planning and development across the country, putting national parks at risk.

Alarmingly, the Administration is responding to this growing threat to our national parks by seeking to weaken and rewrite the very laws that protect national park air quality. Over the objections of its own scientists, and those at the National Park Service, the EPA has proposed regulatory changes that will to make it easier to build new, polluting coal-fired power plants near national parks.

Americans expect and deserve clean air when they visit our national parks. Instead of weakening clean air protections for national parks such as Shenandoah, Great Basin, and Zion, the Administration should be working to ensure that America's national treasures are preserved for our children and grandchildren.

This report highlights the 10 national parks most at risk from air pollution from new coal-fired power plants, and calls for immediate and appropriate action to protect and preserve our national parks.

10 national parks most threatened by new coal-fired power plants, in alphabetical order:

- Badlands (South Dakota)
- Capitol Reef (Utah)
- Great Basin (Nevada)
- Great Smoky Mountains (Tennessee and North Carolina)
- Mammoth Cave (Kentucky)
- Mesa Verde (Colorado)
- Shenandoah (Virginia)
- Theodore Roosevelt (North Dakota)
- Wind Cave (South Dakota)
- Zion (Utah)

Fast Facts

- Of the 391 national park sites in the U.S. National Park System, **1 in 3** already suffers from the harmful effects of air pollution
- Nationwide, **more than 100** new coal-fired power plants are in various stages of planning and development
- **28** new coal-fired power plants are proposed for development within the air sheds of the ten national parks highlighted in this report

Dark Horizons: Executive Summary

National parks and historical sites provide Americans with some of the most memorable summer vacations anywhere – hiking high mountain trails, paddling down clear rivers, driving or biking scenic parkways. Unfortunately, the vacation season can also bring an unwelcome visitor to our national parks that spoils healthy outdoor fun – air pollution.

As detailed in this report, generations of families may suffer air pollution in our national parks if the Bush Administration succeeds in its plan to weaken park air protection laws. The Administration's plan would make it easier for coal-fired power plants and other big polluters to circumvent laws intended to keep the air in our national parks clean.

If we fail to stop this plan, our children and grandchildren will inherit national parks with sick and dying trees, parks with fish so laden with mercury that they are unsafe to eat, and parks where visitors cannot hike without risking an asthma attack. It's not too late to leave a cleaner and brighter national park legacy to tomorrow's families.

National parks already polluted

One in three of our national parks and historic sites have air pollution levels that exceed health standards set by the U.S. Environmental Protection Agency (EPA). Pollution levels usually spike in the summer months, just when our families seek out the parks.

Dirty air in a national park can be merely inconvenient, such as when visitors can't see more than a few miles due to sooty air. Or it can be dangerous and frightening, such as when a child has an asthma attack because of excessive levels of ozone pollution. Over the long term, air pollution can even damage and kill wildlife in the parks.

Most of the air pollution affecting the national parks results from the burning of fossil fuels, especially by coal-fired power plants. They account for an enormous amount of pollution that causes breathing problems, acid rain-damaged forests, smoggy skies, poisoned streams, and global warming. Some of the most remote national parks like Great Basin in Nevada have largely been spared dirty air until now. But as development and energy needs grow, they too are now vulnerable.

New power plants pose threat to national parks

Currently throughout the country, more than 100 new coal-fired power plants are in various stages of planning and development. In many cases, state and federal regulators are not requiring that these plants use the best pollution control technologies available today that could protect parks, wildlife, and other natural treasures from the most serious harm.

The Clean Air Act is supposed to prevent major polluters like coal plants from degrading park air quality. Under the Act, EPA and the National Park Service are empowered to prevent states from permitting new plants that would exceed park air pollution limits, cause unsightly haze, or harm park wildlife. Air quality experts from these agencies have raised the alarm about numerous coal plants that would degrade our national parks.

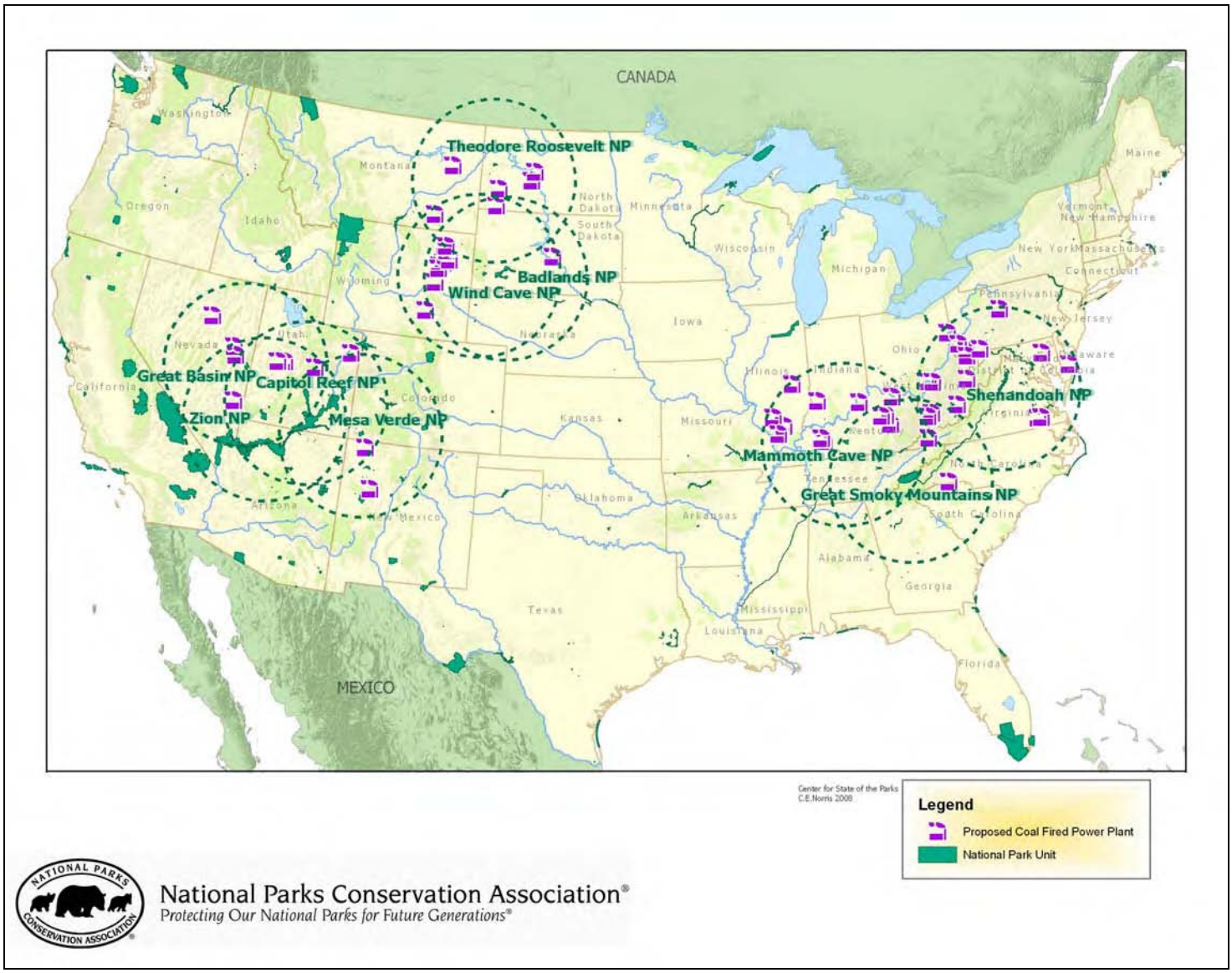
Plan to weaken park air laws

Alarmingly, the Administration is responding to this growing threat to park air quality by seeking to undermine the very laws that protect park air quality. The EPA has proposed regulatory changes that will make it easier to build new coal-fired power plants close to the national parks. The National Park Service has said that one of the changes sought by EPA "provides the lowest possible degree of protection" of air pollution limits designed to protect park air quality.

The Administration is now finalizing these changes in spite of the unanimous opposition of EPA's own regional offices, strong objections by the National Park Service, and an active Congressional investigation. For more information about these regulatory changes, see NPCA's fact sheet at www.npca.org/darkhorizons

Ten national parks most at risk from new coal-fired power plants

As this year's park vacation season gets underway, NPCA has highlighted ten national parks most threatened by pollution from proposed coal-fired power plants: Badlands (SD), Capitol Reef (Utah), Great Basin (NV), Great Smoky Mountains (Tenn., NC), Mammoth Cave (Ky.), Mesa Verde (Colo.), Shenandoah (Va.), Theodore Roosevelt (ND), Wind Cave (SD), and Zion (Utah).



Twenty-eight coal-fired power plants are proposed within the air sheds of these ten national parks. For the purpose of this report, the air shed is defined as a radius of 300 kilometers (186 miles) around each park. The National Park Service generally reviews all major new emissions sources within a 300-kilometer radius of a protected national park. All of the proposed coal-fired power plants documented in this report have undergone some level of review by the National Park Service, and all have been found to have some degree of adverse impact on national park air quality.

Each and every year, for at least 50 years, these 28 new coal-fired power plants would emit a combined total of 122 million tons of carbon dioxide, 79 thousand tons of sulfur dioxide, 52 thousand tons of nitrogen oxides, and 4 thousand pounds of toxic mercury into the air sheds of these ten national parks. These new coal-fired power plants will make the skies over our national parks hazy, will add dangerous chemicals to their soils and waters, and will make the air unhealthy for today's visitors, as well as for their children and grandchildren.

Americans should see these ten national parks now. If the Administration succeeds in weakening the parks' clean air laws, these parks could have hazier skies and unhealthier air in coming summers.

Bush Administration is risking its national park legacy

The Bush Administration has staked a significant part of its environmental legacy on its stewardship of our national parks. The Administration has steadfastly supported increased funding for the parks, and has proposed an ambitious National Park Centennial Initiative that would bring major new financial support to the National Park System by its 100th anniversary in 2016. NPCA applauds the Administration for these efforts on behalf of our national parks.

But even the best-funded national parks will not be the showplaces the Administration hopes to create if they suffer from unsightly haze, acid rain-damaged forests, unhealthy air, and mercury-poisoned streams. If the Administration hopes to secure a meaningful legacy for the parks, it must also help them achieve clear skies, healthy air, and thriving wildlife.

By seeking to weaken park air protection laws in its final year in office, the Administration risks obliterating its national parks legacy altogether. It's not too late for the Administration to stop this ill-conceived change to park air quality laws so that our children and grandchildren can enjoy national parks that are both well funded and on the path toward cleaner, healthier air.

Dark Horizons: Key Recommendations

For the current Administration: Enforce national park clean air laws, don't weaken them

The federal Clean Air Act prohibits major new pollution sources like power plants from harming national park air quality. The National Park Service is required by law to object when state agencies seek to permit power plants or other facilities that would damage parks. National Park Service air quality officials are doing their job, but state officials all too often ignore National Park Service findings and approve bad permits. The Administration has allowed the states to flaunt National Park Service authority. The Administration must enforce park air quality protection laws.

Unfortunately, the Administration is not simply refusing to enforce park air quality protections – it is also trying to weaken them. A proposed EPA rule would allow industries seeking to locate near protected national parks to circumvent pollution limits established by Congress to restore and maintain clean air. The proposed rule would change the way new air pollution is calculated, allowing for greater manipulation by industries seeking pollution permits, and would ultimately undermine strict pollution limits that are intended to keep park air from getting dirtier. Every EPA Regional Office in the country, as well as the National Park Service, has objected to this rulemaking, but the Administration shows no signs of backing away from weakening the law. For more information, see NPCA's technical information fact sheet, www.npca.org/darkhorizons.

OUTCOME: If the Administration enforced park clean air laws rather than trying to weaken them, all of the power plants featured in this report would either (a) be made to use more effective pollution control technology or use cleaner fuels, (b) be located further from the parks, or (c) not be built.

For the next Administration: Clean up older coal-fired power plants

Throughout the country hundreds of ancient coal-fired power plants operate without modern pollution control technology. Some are more than 50 years old and would not be unfamiliar to Thomas Edison, who built the first coal-fired electric power plant in 1882. Many of these plants inflict severe pollution damage on the national parks (for more information, see NPCA's 2006 report on air pollution in the parks *Turning Point*, www.npca.org/turningpoint). The federal Clean Air Act requires that these outdated plants install the best available retrofit technology or "BART" to reduce emissions to levels that protect the national parks from harm. Unfortunately, Bush Administration regulations issued in 2006 exempt hundreds of outdated power plants from upgrading their pollution controls.

The next Administration must require upgraded emissions control systems on every outdated power plant. The good news is that new laws are not needed. The next Administration can simply improve the flawed regulations issued by the Bush Administration to ensure that these ancient polluters reduce their harmful emissions as Congress intended.

OUTCOME: Cleaning up all of the outdated coal-fired power plants that harm national parks would dramatically improve the clarity of park scenic vistas, significantly reduce acid rain damage to parks, eliminate large amounts of toxic mercury contaminating park fish and animals, and provide healthier air for individuals and families seeking recreation in our parks.

For Congress: Reduce greenhouse gas emissions contributing to global warming

Coal-fired power plants are the largest source of greenhouse gas emissions contributing to global warming. Global warming is causing severe and potentially irreversible damage to our national parks. Glaciers are rapidly disappearing from Glacier National Park, and Joshua trees may no longer exist in Joshua Tree

National Park. The story of America from its earliest days, told in the historic forts and settlements of the Atlantic and Gulf coasts, may soon be obliterated by sea level rise and more powerful storms. Wildfires and pest infestations are on the rise in the West, decimating huge swaths of forestland in our national parks. Climate conditions in Alaska are changing so fast that some species that live in our parks, such as polar bears, may have no time to adapt to global warming, and may be forever lost. For more information on climate change and our national parks, see NPCA's 2007 report *Unnatural Disaster*, www.npca.org/globalwarming.

Many state governments, private companies and individuals are acting now to reduce greenhouse gas emissions, and Congress needs to do the same. Congress made an important down payment on reducing global warming pollution in the 2007 energy bill, which raised auto fuel economy standards and provided new support for renewable energy. As the next step, Congress should put in place a comprehensive system to reduce greenhouse gas emissions to safe levels and to help businesses, communities and parks adjust to climate changes already underway.

NPCA supports the America's Climate Security Act, S.2191, sponsored in chief by Senators Joe Lieberman (I-CT) and John Warner (R-VA). The bill, which passed the Senate Environment and Public Works Committee in late 2007, recognizes that climate change is an ever-increasing threat to America's natural resources. It reduces global warming pollution and provides funding to help the fish, wildlife, and plants of America's national parks adapt to and survive the effects of global warming.

OUTCOME: If Congress acts quickly to reduce U.S. greenhouse gas emissions to safe levels, and works with the Administration to ensure other nations follow suit, it may not be too late to avert the worst climate change impacts on our national parks. In addition, if Congress provides meaningful new funding to help fish and wildlife survive climate changes already underway, our national parks stand a better chance of retaining ecologically diverse and healthy ecosystems.

For state governments: Replace coal with energy efficiency and renewable energy

Throughout the country there are more than 100 proposed new coal-fired power plants under development. Many are within the air sheds of national parks. If all of these plants are built they will significantly increase air pollution and global warming, and cause irreversible damage to the national parks.

There are many alternatives to coal that can meet our growing energy demands without sacrificing our national parks, including solar, wind and geothermal energy. In many cases, new power plants are not needed at all. Enormous energy savings can be gained when states, electric utilities and electricity providers work with customers to use energy more efficiently. In addition, electricity-generation technologies available and in use today can allow coal to be used in ways that drastically reduce air pollutants and virtually eliminate greenhouse gas emissions. Before permitting any new coal plants, state regulators should examine these cleaner solutions to meeting their energy needs.

OUTCOME: If state regulators chose the cleanest options for new electricity generation not only would the air be cleaner, but also they will help create new opportunities for economic growth centered around clean energy industries within their states.

For individuals: Make smart energy choices

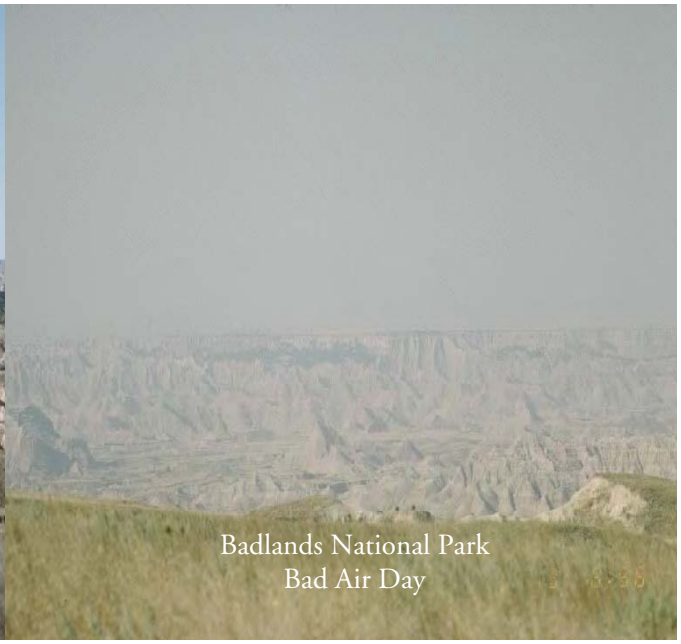
Americans rely on coal-fired power plants for more than half of our electricity. These plants generate the majority of pollution linked to acid rain, hazy skies, mercury-laden streams, breathing problems and global warming. Fortunately, many electricity providers are now offering consumers alternatives to coal power, including wind, solar, and geothermal energy.

At home, we can use electricity and gas more efficiently to help reduce fossil fuel emissions. EPA's Energy Star® program offers numerous examples of ways to save money on utilities and cut pollution at the same time. Visit www.energystar.gov to find out about high efficiency air conditioners, furnaces, and other home appliances.

If you are thinking of buying a new vehicle, EPA and the U.S. Department of Energy can help you choose one with low emissions and high gas mileage. Or, they can advise you how to operate your current vehicle more cleanly and efficiently. Check out their website at www.fueleconomy.gov.

Within the national parks, you can help cut pollution by riding shuttles, where available, instead of driving. Each park offers information to help you plan your trip. An alphabetical listing of all national park web pages is available at www.nps.gov/applications/parksearch/atoz.cfm.

OUTCOME: If all Americans made a few small changes in our lives, such as replacing old light bulbs with energy efficient ones, improving the efficiency of our home heating and cooling systems, driving less and recycling more, we could dramatically cut the need for new power plants and thus reduce the air pollution and greenhouse gas emissions that now harm our national parks.



Photos courtesy of Air Resource Specialists, Inc.

Badlands National Park: Air Quality at Risk

Park highlights

- Located in southwestern South Dakota, Badlands National Park consists of 244,000 acres of sharply eroded rocky buttes, pinnacles and spires, blended with the largest protected mixed grass prairie in the United States.
- Visitors can enjoy park trails with views of the White River Valley and unique Badlands rock formations.
- The park contains some of the world's richest fossil beds, dating 23 to 25 million years old.

Current air quality

- Although visitors should normally see 151 miles, haze in Badlands National Park has reduced the average view to 78 miles, and to 48 miles during the days with the worst haze pollution.
- Ozone and particle pollution account for most haze observed in the park on poor visibility days. These same pollutants can also cause breathing problems, asthma attacks and heart damage.
- Field surveys and controlled studies by the National Park Serivce show that ozone pollution damages some types of vegetation in the park.

New coal-fired power plants

- Six new coal-fired power plants are under active development within 186 miles (300 km) of Badlands National Park.
- Each year, these new plants would emit into the Badlands area air shed more than 17 million tons of carbon dioxide, 9,193 tons of sulfur dioxide, 7,843 tons of nitrogen oxides, and 1,501 pounds of toxic mercury. This new pollution will mean more hazy days, increased health risks to visitors, and more damage to park plants and animals.

National Park Service findings

- "Technical analysis shows that lower emissions [from WYGEN2] could now be achieved by converting the project to a [cleaner type of coal technology], and/or by improving the efficiencies of the chosen emission control technologies."

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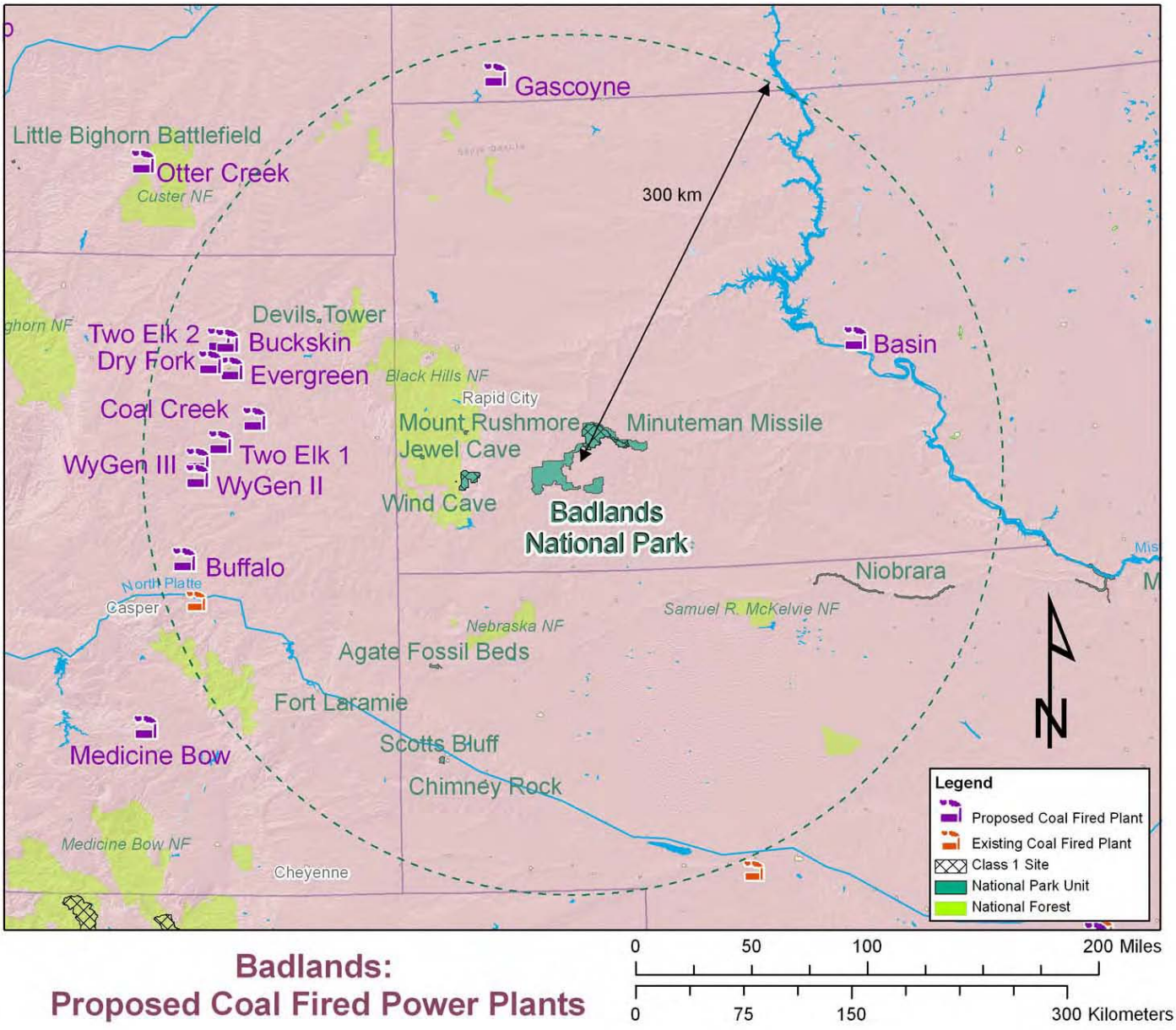

Badlands:
Proposed Coal Fired Power Plants

Power plants that have received permits and not yet commenced construction or are in active permit process

Plant	Location	Owner	Size (MW)	Distance from park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
Dry Fork Station	Campbell County, WY	Basin Electric Power Cooperative	385	220km	2,437,500	1,165	833	327	Final air permit issued October 2007
WYGEN 2	Campbell County, WY	Black Hills Corp.	100	213km	2,510,178	569	399	141	Final air permit issued July 2005
WYGEN 3	Campbell County, WY	Black Hills Corp.	100	213km	2,510,178	512	285	80	Final air permit issued February 2007
Two Elk Energy Park Unit 1	Campbell County, WY	North American Power Group	280	190km	2,112,500	1,711	1,167	***49***	Final air permit re-issued May 2003
Two Elk Energy Park Unit 2	Campbell County, WY	North American Power Group	750	190km	6,239,818	2,753	2,202	164	Application received September 2006
Gascoyne 500	Bowman County, ND	Westmoreland Power	***500***	260km	***3,250,000***	1524	2286	660	Draft air permit issued May 2007
Evergreen Coal Creek	Campbell County, WY	***Evergreen Energy Inc***	***XX***	195	***XX***	959	671	80	Application received November 2006
Total New Pollution into Badlands Area Airshed					**17,695,356**	**9,193**	**7,843**	**1501**	

For more information contact: Stephanie Kodish, 865.329.2424 ext. 28, skodish@npca.org

Photo courtesy of National Park Service

Capitol Reef National Park: Air Quality at Risk

Park highlights

- Located in Utah, Capitol Reef National Park was established to protect the grand and colorful geologic feature, the Waterpocket Fold, a nearly 100-mile long warp in the Earth's crust.
- The most scenic portion of the Fold, found near the Fremont River, is known as Capitol Reef: *capitol* for the white domes of Navajo sandstone that resemble building domes, and *reef* for the rocky cliffs which are a barrier to travel.
- The park's historic Fruita orchards are the largest within the National Park System, with 2,600 fruit and nut trees.

Current air quality

- Large pollution sources near Capitol Reef National Park include power plants, refineries, and lime kilns in Arizona and Nevada. Pollutants also travel greater distances to the park from sources throughout the Southwest.
- Visibility in the park is often impaired by haze caused by these facilities.
- Nitrogen and sulfur pollution in the park are above natural conditions. These pollutants damage American Indian artifacts, threaten local plants and animals, and put visitors' health at risk.

New coal-fired power plants

- Two new power coal-fired power plants are under active development within 186 miles (300 kilometers) of Capitol Reef National Park, in a region that already has five coal-fired power plants; three others are proposed just beyond that distance.
- Each year, these two plants would emit into the Capitol Reef area air shed more than 26 million tons of carbon dioxide, 8,821 tons of sulfur dioxide, 9,338 tons of nitrogen oxides, and 501 pounds of toxic mercury. As a result, there will be fewer clear days in the park, more damage to archaeological sites, and a higher health risk to park visitors.

National Park Service findings

- "We are concerned with the large increase in air pollution emissions in the area of the five Utah [national] parks from several recently proposed power plants. These five national parks have some of the most pristine air in the NPS system, and the NEVCO site is located upwind from the parks in this "clean air corridor."
- "…We remain concerned about potential cumulative impacts on visibility, especially at Capitol Reef NP."

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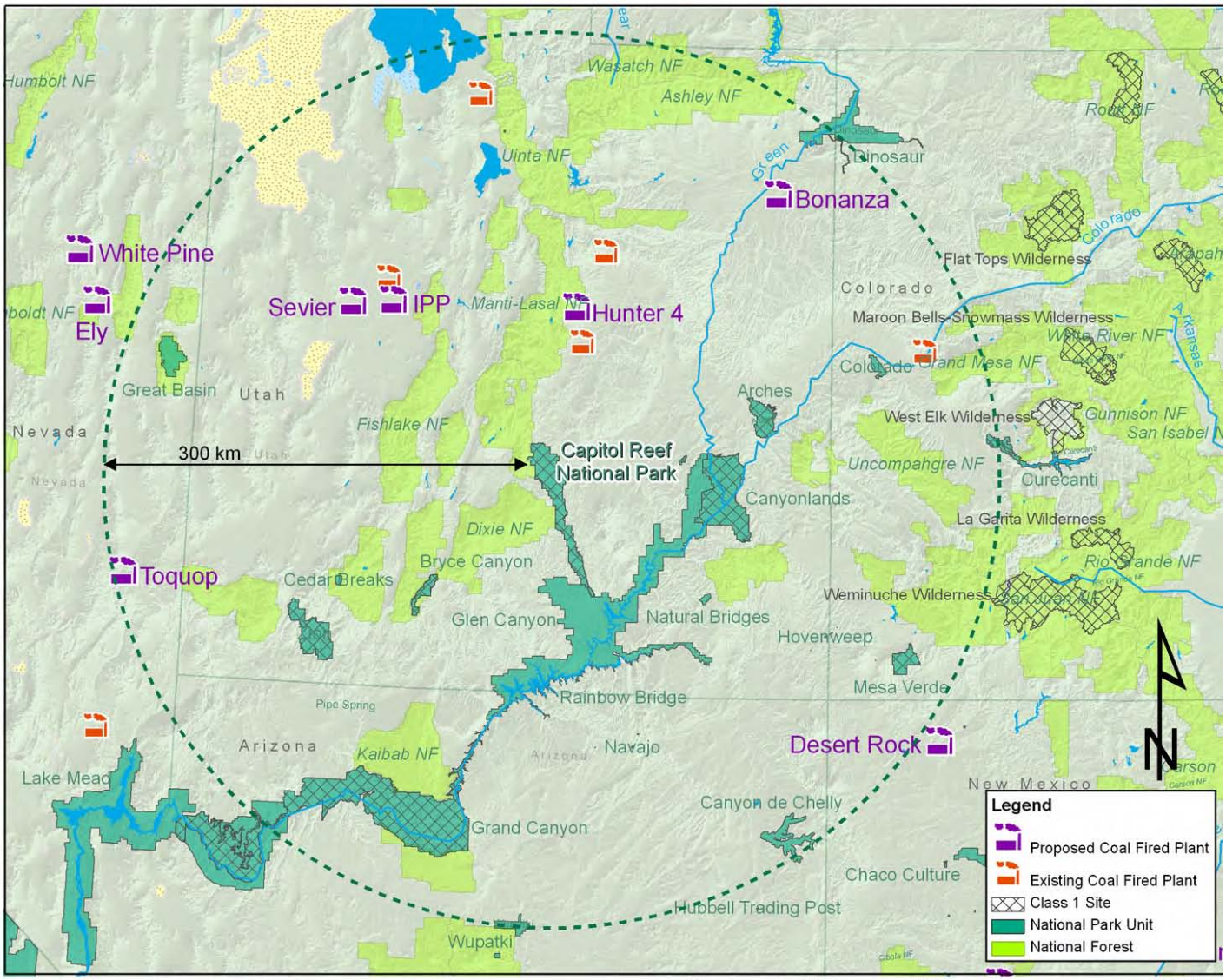

Capitol Reef: Proposed Coal Fired Power Plants

Plant	Location	Owner	Size (MW)	Distance from Park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
Sevier Power Company Project	Sevier County, Utah	Sevier Power Company - NEVCO Energy Company	270 MW	60 km	1,755,000	234	1,067	9	Final air permit issued October 2004
Intermountain Power Plant	Millard County, UT	Intermountain Power Agency	950 MW	149 km	9,922,200	3,568	2,775	83	Final air permit issued Oct. 2004
Toquop Energy Project	Lincoln County NV	Sithe Global Energy	750 MW	295 km	4,875,000	1,352	1,614	131	Draft permit issued in December 2007
Desert Rock Energy Project	San Juan County, NM	Sithe Global Energy/Dine Power Authority	1500 MW	240 km	8,921,928	3,319	3,325	263	Draft air permit issued in July 2006
Bonanza Power Plant	Uintah Co. UT	Deseret Power Electric Coop.	110 MW	250 km	715,000	348	557	15	Final permit August 2007
Total New Pollution into Capitol Reef National Park Area Airshed					**26,189,128**	**8,821**	**9,338**	**501**	

For more information contact: Karen Hevel-Mingo, 801.521.0785, khevel-mingo@npca.org

Photos courtesy of Air Resource Specialists, Inc.

Great Basin National Park: Air Quality at Risk

Park highlights

- Great Basin National Park in Nevada preserves over 77,000 acres of the Great Basin of the Western United States, a 200,000 square mile area. From the sagebrush at its base to the 13,063-foot summit of Wheeler Peak, the park includes streams, lakes, and numerous limestone caverns, including beautiful Lehman Caves.
- At Great Basin, hot desert valleys meet mountain ranges. Its diverse ecosystem, includes prickly pear cactus, sagebrush, aspen, fragile alpine wildflowers and ancient bristlecone pines, the world's oldest living things. Mountain lions, Clark's nutcrackers, snakes, and jackrabbits roam the park.

Current air quality

- Visibility in Great Basin National Park declines after periods of sustained northeasterly winds, when a brown-yellow haze appears in Snake Valley, obscuring the mountains east of the park.
- The National Park Service is closely monitoring visibility, nitrogen deposition and ozone in the park, all of which show signs of growing worse.

New coal-fired power plants

- Three large, new power coal-fired power plants are under active development within 186 miles (300 km) of Great Basin. This area already has four operating coal-fired power plants; two others operate just beyond that distance.
- Each year, these three new plants would emit into the Great Basin area air shed more than 46 million tons of carbon dioxide, 16,656 tons of sulfur dioxide, 15,494 tons of nitrogen oxides, and 800 pounds of toxic mercury. This new pollution will cause hazy skies to be the norm rather than the exception at Great Basin. They will also massively increase acidic pollution in the park, which over time will cause the abundance and diversity of fish, plants, and other wildlife to decline. Families will less often enjoy the dark night skies that reveal our Milky Way galaxy as rarely seen from populated areas.

National Park Service findings

- "The issuance of the permit proposed by the Ely Energy Center would compromise the [Great Basin National Park's] air quality, water quality and viewsheds and dark night skies."
- "The Park Service's analysis has found that the proposed levels of emissions [from Ely Energy Center] will result in a significant reduction in visibility at [Great Basin National Park] and to the surrounding area…Proposed sulfur, nitrogen and mercury [pollution] rates associated with the Ely Energy Center could potentially impact the pristine water quality of the park's lakes and streams as well as affecting the wildlife and fish dependent upon them."

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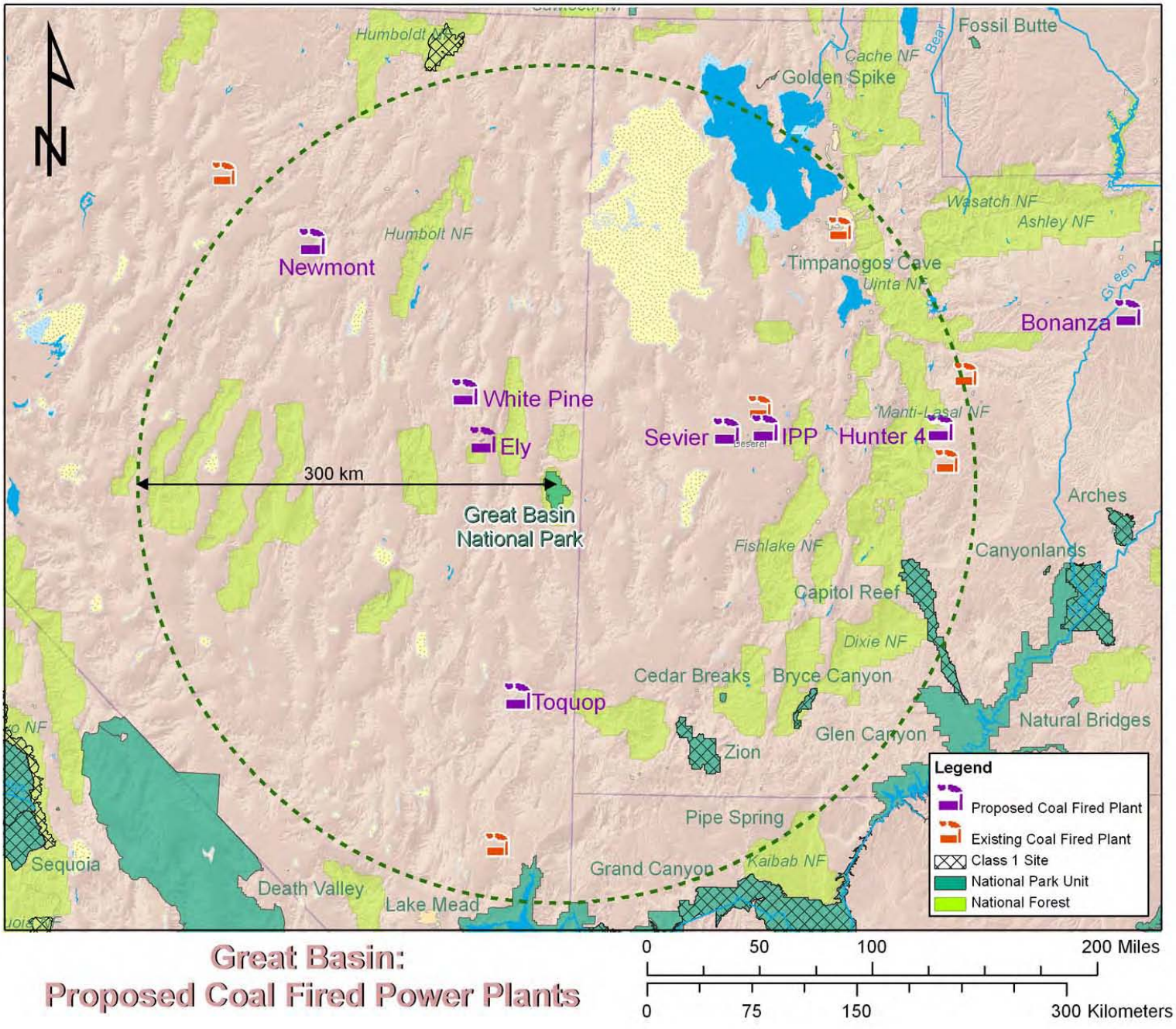

Great Basin: Proposed Coal Fired Power Plants

Power plants that have received permits and not yet commenced construction or are in active permit process

Plant	Location	Owner	Size (MW)	Distance from Park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
White Pine Energy Station Project	White Pine County, NV	White Pine Energy Assoc.-Dynegy/LS Power Assoc.	1,590 MW	85 km	12,600,000	6,071	4,814	279	Draft air permit issued in December 2006
Ely Energy Center	White Pine County, NV	Nevada Power Co. and Sierra Pacific Power Co.	1500 MW	60 km	16,000,000	4,853	4,628	263	Draft air permit issued Dec.2007
Newmont	Eureka County, NV	Newmont Mining Corporation	200 MW	270 km	1,224,791	578	596	35	Final air permit issued July 2007
Toquop Energy Project	Lincoln County NV	Sithe Global Energy	750 MW	210 km	4,875,000	1,352	1,614	131	Draft permit issued in December 2007
Sevier Power Co. Project	Sevier County, UT	Sevier Power Co NEVCO Energy Co	270 MW	190 km	1,755,000	234	1,067	9	Final air permit issued Oct. 2004
Intermountain Power Plant	Millard County, UT	Intermountain Power Agency	950 MW	150 km	9,922,200	3,568	2,775	83	Final air permit issued Oct. 2004
Total New Pollution into Great Basin & Zion Area Airshed					**46,376,991**	**16,656**	**15,494**	**800**	

For more information contact: Lynn Davis, 702.281.7380, ldavis@npca.org

Photos courtesy of Air Resource Specialists, Inc.

Great Smoky Mountains National Park: Air Quality at Risk

Park highlights

- Great Smoky Mountains National Park, America's most visited national park encompassing more than 800 square miles of the Southern Appalachians in Tennessee and North Carolina, contains half of the remaining old-growth forest in the East, more than 2,000 miles of streams, and 850 miles of trails.
- The park supports an astonishing array of plant and animal life. Over 10,000 species have been documented in the park; scientists believe an additional 90,000 species may live there. Because of its great biodiversity, the park has been designated an International Biosphere Reserve.

Current air quality

- Great Smoky Mounatins National Park has the highest rates of nitrogen and sulfur pollution of any monitored location in North America, resulting in park rainfall that is 5 to 10 times more acidic than normal. Many trees in the park are dead or dying, and the water is too acidic to support some native fish.
- The park also suffers from among the highest levels of ozone (a lung-searing gas) in the Eastern U.S.; since 1990, ozone health limits have been exceeded on more than 300 days. High ozone pollution can cause visitors to experience breathing problems and asthma attacks.
- Average visibility in the park has been cut by about 40 percent in winter and 80 percent in summer, and sometimes less than one mile, meaning visitors may not even see surrounding mountains.

New coal-fired power plants

- Three new coal-fired power plants are under active development within 186 miles (300 km) of Great Smoky Mountains National Park, an area that already contains dozens of polluting coal-fired power plants, which are seriously polluting the park.
- Each year, these new plants would emit into the Smokies area air shed more than 16 million tons of carbon dioxide, 9,335 tons of sulfur dioxide, 5,604 tons of nitrogen oxides, and 560 pounds of toxic mercury. These pollutants will contribute to more hazy air, more unhealthy air days, greater stress to park trees, and increased mercury contamination of the park's streams.

National Park Service findings

- "[T]he real-world effect of [Duke Energy's coal-fired power plant] by itself would be severe impacts upon air quality and air quality related values at Great Smoky Mountains National Park."
- The Duke plant's "increase in mercury [pollution] coupled with the predicted increase in sulfur [pollution] could impact park resources, including threatened and endangered species."
- Dominion's Wise County, Va., coal-fired power plant "would have a significant impact" on sulfur dioxide pollution at Great Smoky Mountains National Park.
- "Dominion has not justified the need for [pollution limits] that are higher than [other comparable power plant projects]. Lower emission limits would result in less impact on park resources."

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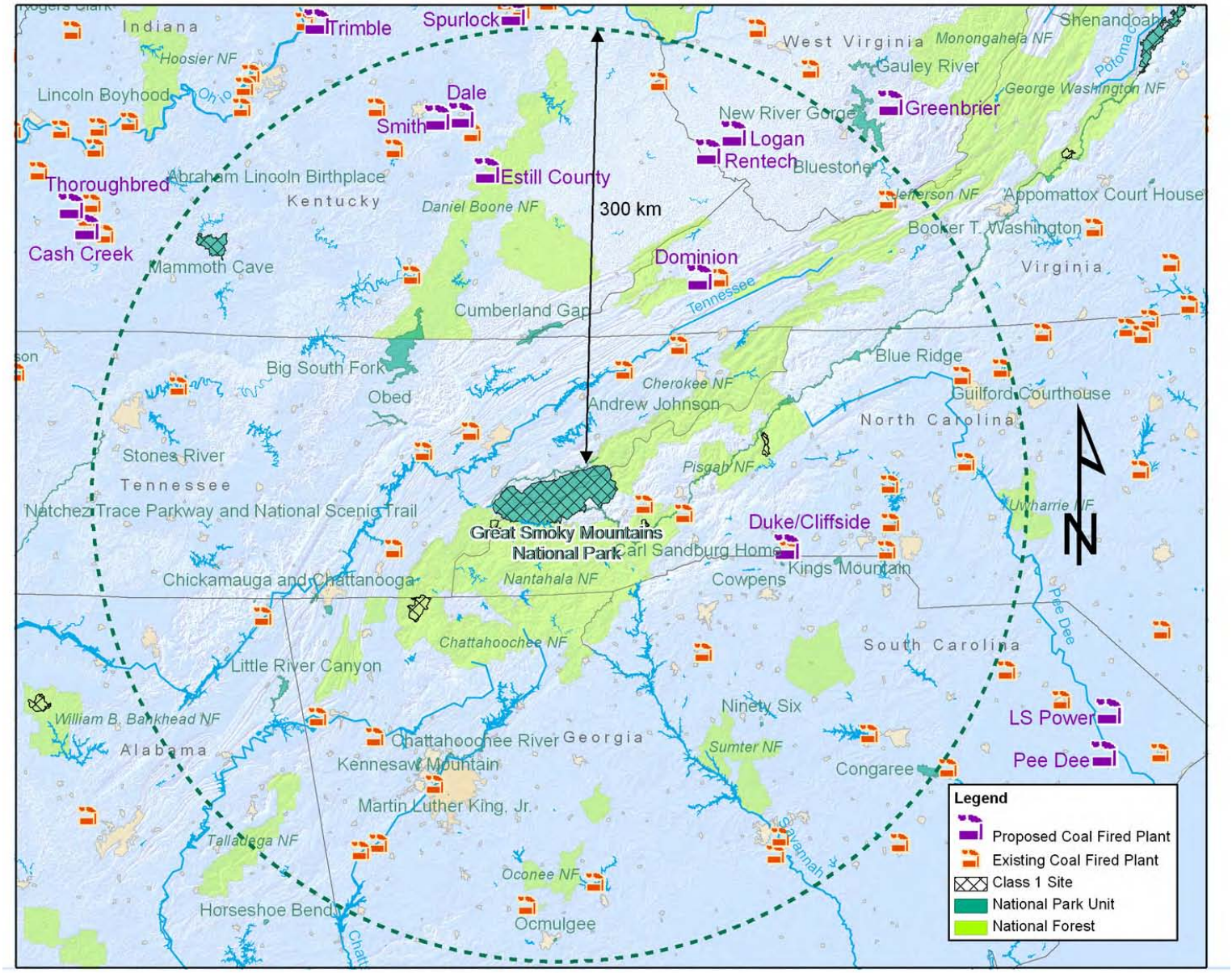

Great Smoky Mountains: Proposed Coal Fired Power Plants

0 50 100 200 Miles

0 75 150 300 Kilometers

Power plants that have received permits and not yet commenced construction or are in active permit process

Plant	Location	Owner	Size (MW)	Distance from Park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
Cliffside Power Plant	Rutherford County, NC	Duke Energy Carolinas	800 MW	130 km	9,608,567	4,126	2,407	463	Air permit issued January 2008
Virginia City Hybrid Energy Center	Wise County, VA	Virginia Electric & Power Co.- Dominion subsd.	668 MW	142 km	5,064,989	3,369	1,971	42	Draft air permit released January 2008
Spurlock Generating Station (unit 4)	Mason County, KY	East Kentucky Power Cooperative	300 MW	250km	1,864,267	1,840	1,226	55	Final air permit re-issued 4/08
Total New Pollution into Great Smoky Mountain National Park Area Airshed					**16,537,823**	**9,335**	**5,604**	**560**	

For more information contact: Bart Melton, 865.329.2424 ext. 24, bmelton@npca.org

Photos courtesy of Air Resource Specialists, Inc.

Mammoth Cave National Park: Air Quality at Risk

Park highlights

- Located in central Kentucky, Mammoth Cave National Park protects the world's longest known cave system, which includes five levels of subterranean rooms, narrow passageways, deep shafts, and underground rivers.
- The park, with more than 52,000 acres of land with rivers, rolling hills and scenic bluffs, is also home to 1,200 species of flowering plants, 84 species of trees, and 70 threatened or endangered species.

Current air quality

- One of the greatest threats to Mammoth Cave National Park is mercury contamination caused by emissions from coal-fired power plants. Nationwide, coal-fired power plants contribute to more than 40 percent of mercury emissions.
- Mercury is a potent neurotoxin that is passed up the food chain. The park's endangered Indiana bat has been found to have mercury at ten times the level considered safe for people.
- Ozone pollution in the park consistently exceed levels known to harm plants.
- The National Park Service says that hazy skies are a significant concern at the park.

New coal-fired power plants

- Three new coal-fired power plants are under active development within 186 miles (300 kilometers) of Mammoth Cave, an area that already contains roughly 40 operating coal-fired power plants.
- Each year, these new plants would emit into the Mammoth Cave area air shed more than 12 million tons of carbon dioxide, 14,724 tons of sulfur dioxide, 7,650 tons of nitrogen, and 606 pounds of toxic mercury, further endangering park wildlife and the health of park visitors.

National Park Service findings

- "[W]e believe that these proposed emissions [from Thoroughbred Generating Station] would have an adverse impact on visibility and could potentially affect federally listed threatened and endangered species at Mammoth Cave National Park...We ask that [Kentucky] not issue the final [air] permit until these technical issues are resolved and our concerns are adequately addressed."
- "We ask that [Thoroughbred Generating Station] consider stricter controls on their emissions so as to lessen the impacts at Mammoth Cave NP."

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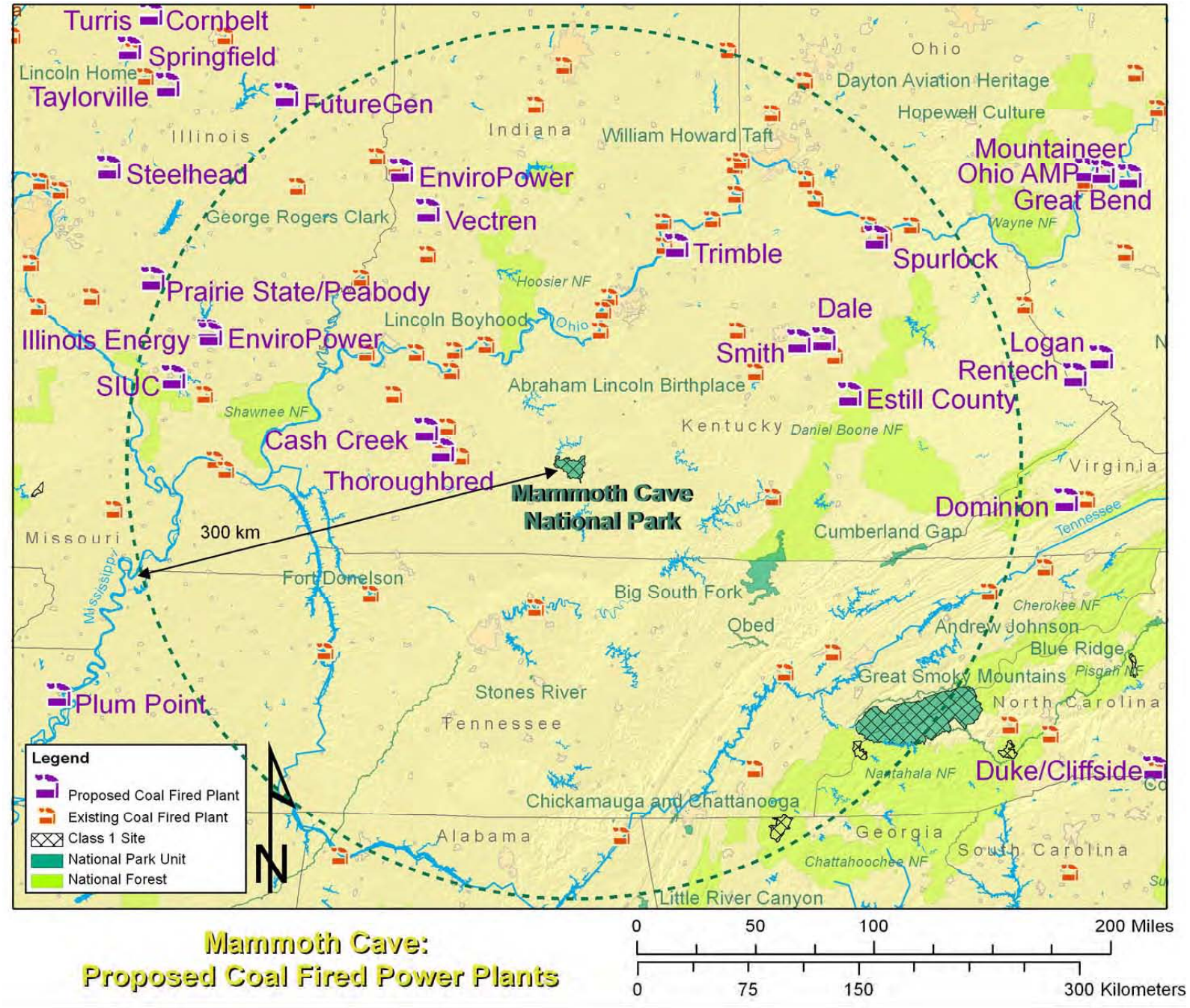
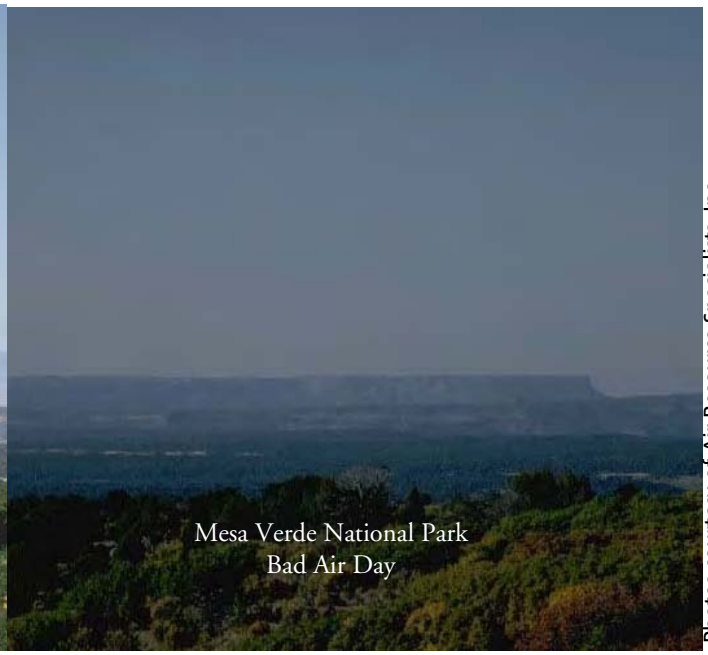


Mammoth Cave: Proposed Coal Fired Power Plants

Power plants that have received permits and not yet commenced construction or are in active permit process

Plant	Location	Owner	Size (MW)	Distance from Park	CO2 Tons/yr	SO2 Tons/yr	NOx Tons/yr	Hg lbsyr	Permit Status
Thoroughbred Generating Station	Muhlenberg County, KY	Peabody Energy	1500 MW	74 km	8,921,928	10,893	4,566	276	Final air permit issued May 2006
JK Smith Electric Generating Station (units 1&2)	Clark County, KY	East Kentucky Power Cooperative	556 MW	185 km	1,807,000	1,991	1,858	275	Permit application April 2008
Spurlock Generating Station – (unit 4)	Mason County, KY	East Kentucky Power Cooperative	300 MW	250km	1,864,267	1,840	1,226	55	Final air permit re-issued 4/08
Total New Pollution into Mammoth Cave Area Airshed					**12,593,195**	**14,724**	**7,650**	**606**	

For more information contact: Bart Melton, 865.329.2424 ext. 24, bmelton@npca.org



Photos courtesy of Air Resource Specialists, Inc.

Mesa Verde National Park: Air Quality at Risk

Park highlights

- Mesa Verde National Park offers a spectacular look into the lives of Ancestral Pueblo people who lived in the area for more than 700 years.
- Located in Colorado, the park protects over 4,000 known archaeological sites, including 600 cliff dwellings – some of the most notable and best preserved in the United States.
- Visitors may hike to mesa top sites and cliff dwelling overlooks or enjoy observing birds and wildlife, and cross-country skiing.

Current air quality

- Coal-fired power plants in New Mexico and Arizona are the largest sources of air pollutants, including sulfur dioxide and nitrogen oxides, in Mesa Verde National Park. These pollutants bring hazy skies to the park and harm the park's ancient Pueblo structures.
- National Park Service monitoring shows a trend of increasing ozone levels in the park in recent years, and rates nitrogen deposition as a significant concern. These pollutants can cause unhealthy air for visitors and harm park wildlife.
- Park visibility is degrading significantly on the worst visibility days.

New coal-fired power plants

- A huge, 1500-megawatt coal-fired power plant is under active development just 46 miles (75 km) from Mesa Verde National Park. Seven coal-fired power plants currently operate within 186 miles (300 km) of the park, while three others are proposed for just beyond that distance.
- Each year, this massive coal-fired power plant would emit into the Mesa Verde area air shed nearly 9 million tons of carbon dioxide, 3,319 tons of sulfur dioxide, 3,325 tons of nitrogen oxides, and 263 pounds of toxic mercury. This new coal plant would rapidly accelerate the decline of park air quality.

National Park Service findings

- "There are 27 units of the National Park System within 300 km of the proposed [Desert Rock] plant site; … the proposed project may lead to adverse impacts to [Mesa Verde and other parks] in the absence of conditions and measures designed to mitigate these impacts."

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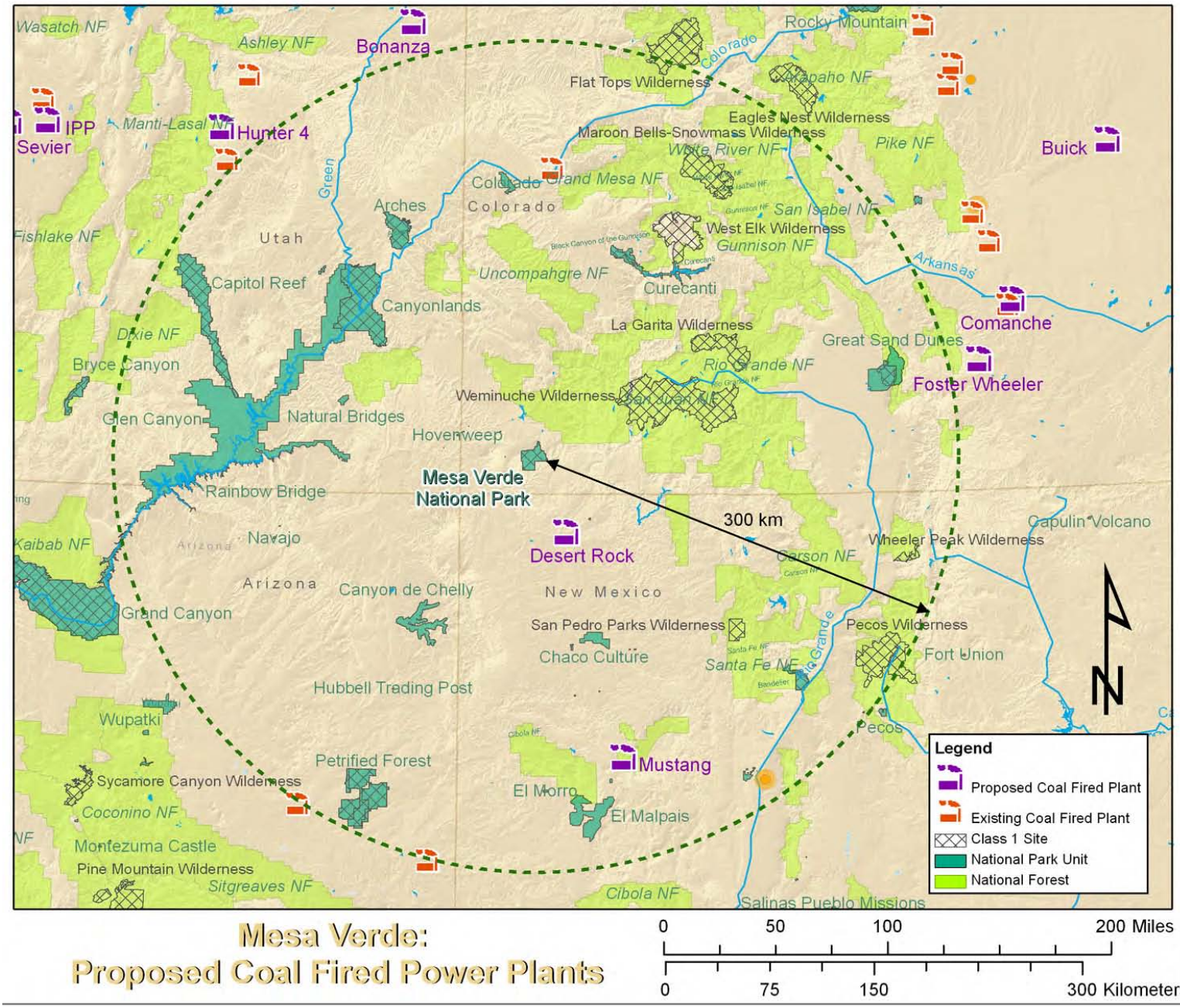
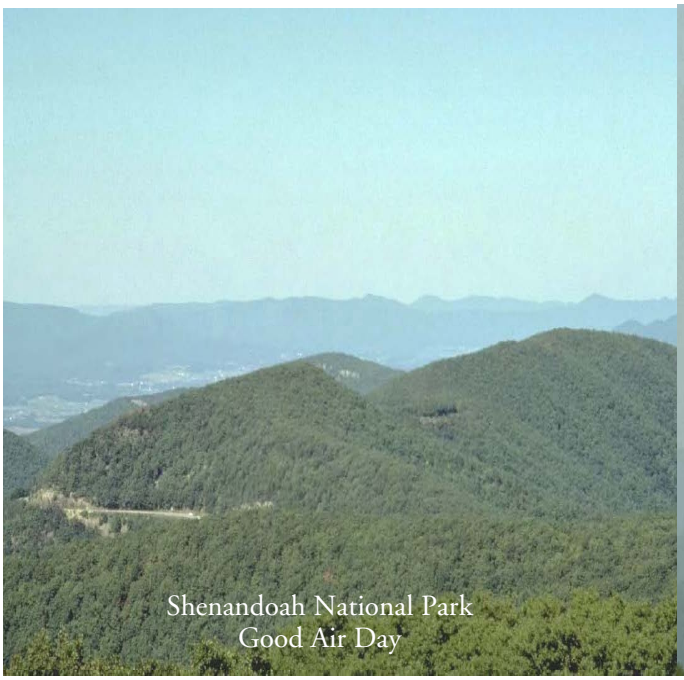


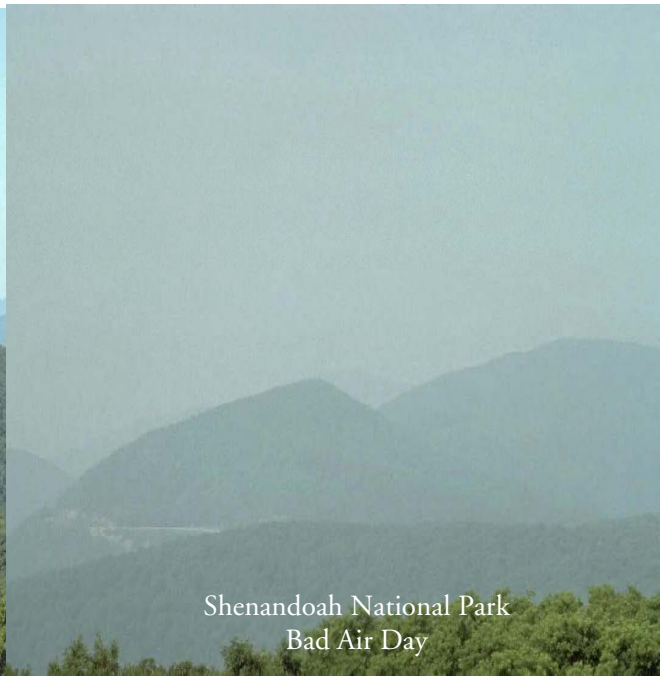
Power plants that have received permits and not yet commenced construction or are in active permit process

Plant	Location	Owner	Size (MW)	Distance from Park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
Desert Rock Energy Project	San Juan County, NM	Sithe Global Energy/Dine Power Authority	1500 MW	75 km	8,921,928	3,319	3,325	263	Draft air permit issued in July 2006

For more information contact: Karen Hevel-Mingo, 801.521.0785, khevel-mingo@npca.org



Shenandoah National Park
Good Air Day



Shenandoah National Park
Bad Air Day

Photos courtesy of Air Resource Specialists, Inc.

Shenandoah National Park: Air Quality at Risk

Park highlights

- Located within the Blue Ridge Mountains and containing headwaters of the Chesapeake Bay, Shenandoah National Park is heavily forested and is home to a large variety of wildlife and birds. In fact, this single park is believed to have more plant and animal species than now live in all of Europe.
- Close to large population centers in Maryland, Virginia, and Washington, DC, and with the 105-mile long Skyline Drive traversing its spine, the park is a major destination for hikers and bikers who escape the cities to enjoy more than 500 miles of trails, including 101 miles of the Appalachian Trail.

Current air quality

- Natural views of 100 miles now extend only 24 miles on average, and less than one mile on the most polluted days. Park visitors can no longer reliably see the Washington Monument, some 70 miles distant. Some visitors today may not even see the next mountain ridge.
- The number and diversity of native fish are declining due to air pollution making park streams more acidic.
- Ozone, a lung-searing gas, can exceed EPA health standards during summer months, exposing visitors to breathing problems, including asthma attacks.

New coal-fired power plants

- Eight new coal-fired power plants are under active development within 186 miles (300 kilometers) of Shenandoah National Park, an area that already contains dozens of operating coal plants.
- Each year these new plants would emit into the Shenandoah area air shed more than 28 million tons of carbon dioxide, 28,250 tons of sulfur dioxide, 13,617 tons of nitrogen oxides, and 576 pounds of toxic mercury. Park skies will be hazier, waters more polluted, and air unhealthier.

National Park Service findings

- Pollution from the Greene Energy coal-fired power plant will cause hazier skies at Shenandoah and will also harm fish and other aquatic life in the park.
- "The [Ohio] AMP project would significantly impact" pollution levels in Shenandoah National Park.

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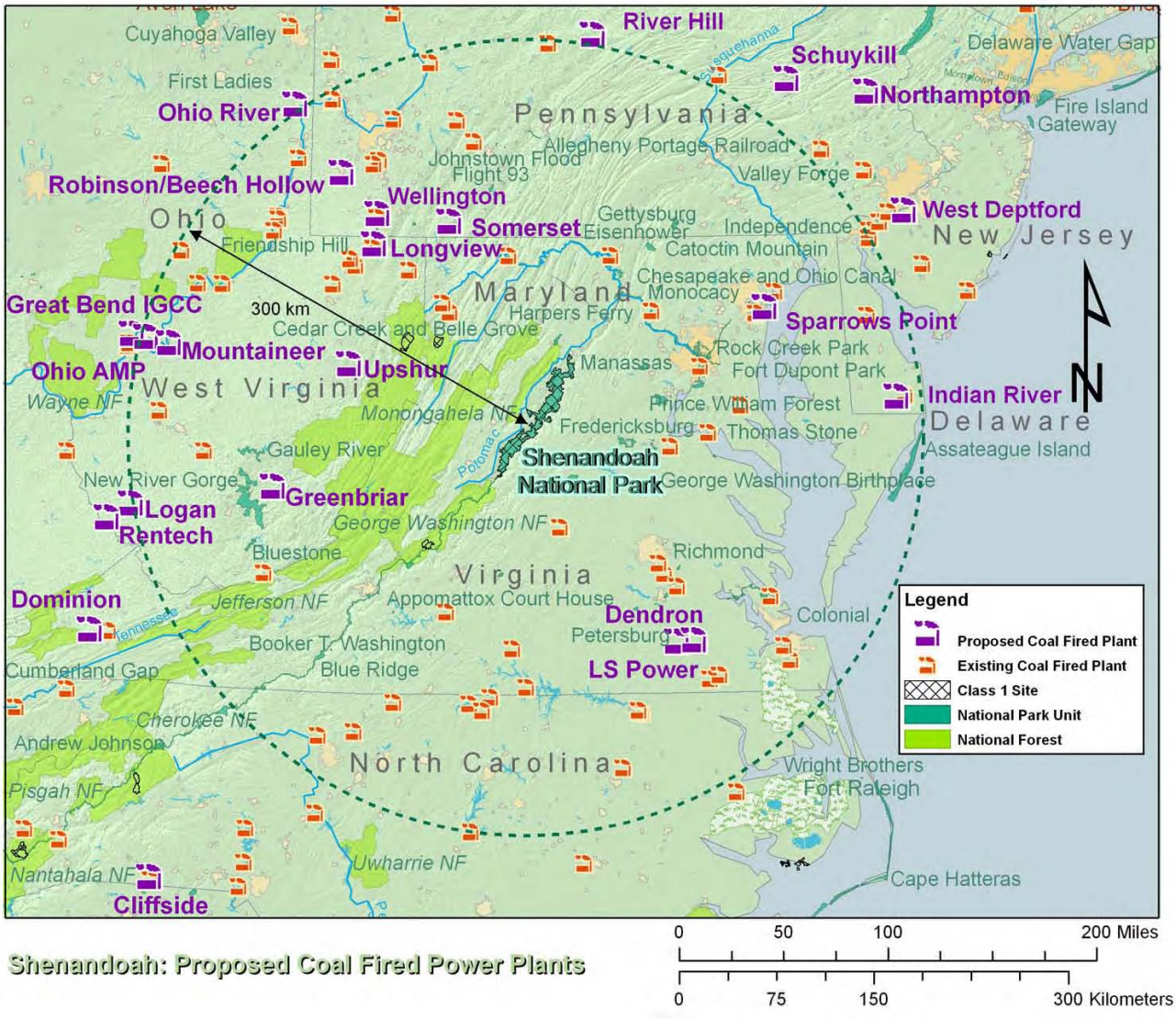

Shenandoah: Proposed Coal Fired Power Plants

Power plants that have received permits and not yet commenced construction or are in active permit process

Plant *= waste coal	Location	Owner	Size (MW)	Distance from Park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
Ohio American Municipal Power Generating Sta.	Meiggs County, OH	Ohio American Municipal Power	960	280km	7,300,000	6,820	3,194	172	Air permit issued February 2008
*Greene Energy Resource Recovery Project	Greene County, PA	Wellington Development	580	185 km	3,045,755	3,766	1,931	22	Air permit issued April 2005
* Somerset Power	Somerset, PA	Sithe Global Energy	300	140 km	1,950,000	2,146	924	27	Air permit application filed December 2007
* River Hill Power	Clearfield County, PA	River Hill Power Company Inc., Sithe Global Power Co, LLC	290	246 km	1,717,078	2,515	880	53	Air permit issued in July 2005
* Beech Hollow Waste Coal Plant	Washington County, PA	Robinson Power Company	250	240km	1,773,492	3,154	976	3	Air permit approved September 2006
Dendron	Sussex County, VA	Old Dominion Electric Cooperative	1500	200km	9,750,000	6,000	3,000	***~170***	Preapplication; ~Hg est. based on best in class.
Longview Power Plant	Monongalia County, WV	Longview Power, LLC, GenPower LLC	600	173 km	1,800,000	3,217	2,183	128	Air Permit issued March 2004
Western Greenbrier	Western Greenbrier County, WV	Western Greenbrier Co-Generation LLC.	85	180 km	948,029	632	529	1	Air permit issued in April 2006
Total New Pollution into Shenandoah Area Airshed					**28,284,354**	**28,250**	**13,617**	**576**	

For more information contact: Catharine Gilliam, 540.460.5105, cgilliam@npca.org

Photo courtesy of National Park Service

Theodore Roosevelt National Park: Air Quality at Risk

Park highlights

- One of the few islands of designated wilderness in the Northern Great Plains, Theodore Roosevelt National Park protects 70,447 acres of the colorful and ecologically rich Little Missouri River Badlands in western North Dakota.
- The park is home to a variety of prairie plants and animals, including bison, elk, and wild horses.
- 100 miles of trails in the park provide visitors with many opportunities for outdoor recreation.

Current air quality

- Theodore Roosevelt National Park is located in a rural area and now has relatively clean air.
- Even a little air pollution builds up over time, and park air quality suffers from the long-term cumulative effects of air pollution caused by oil and gas production and coal-fired power plants.

New coal-fired power plants

- A new coal-fired power plant is under active development only 56 miles (90 km) from Theodore Roosevelt National Park, while three others are proposed for construction just beyond 186 miles (300 km).
- Each year, this enormous new plant would emit in the park area air shed more than 3 million tons of carbon dioxide, 1,524 tons of sulfur dioxide, 2,286 tons of nitrogen oxides, and 660 pounds of toxic mercury. Because park air is now relatively clear, this new pollution will have a dramatic and noticeable impact on park visibility and will add significantly to long-term pollution damage.
- This new coal plant will emit massive amounts of toxic mercury into the park ecosystem, threatening fish and other park wildlife. By way of comparison, the eight coal-fired power plants under development near Shenandoah National Park will, combined, emit less mercury than the one new plant proposed near Theodore Roosevelt National Park.

National Park Service findings

- "Based on the available information, [NPS] ha[s] determined that emissions from the proposed [Gascoyne] facility could adversely impact visibility at Theodore Roosevelt NP."
- "[P]roposed emissions from the Gascoyne plant alone would result in perceptible [haze] at Theodore Roosevelt NP up to 19 days per year. We consider these impacts to visibility to be adverse because they would diminish the national significance of Theodore Roosevelt NP and potentially impair the quality of the visitor experience to that area."

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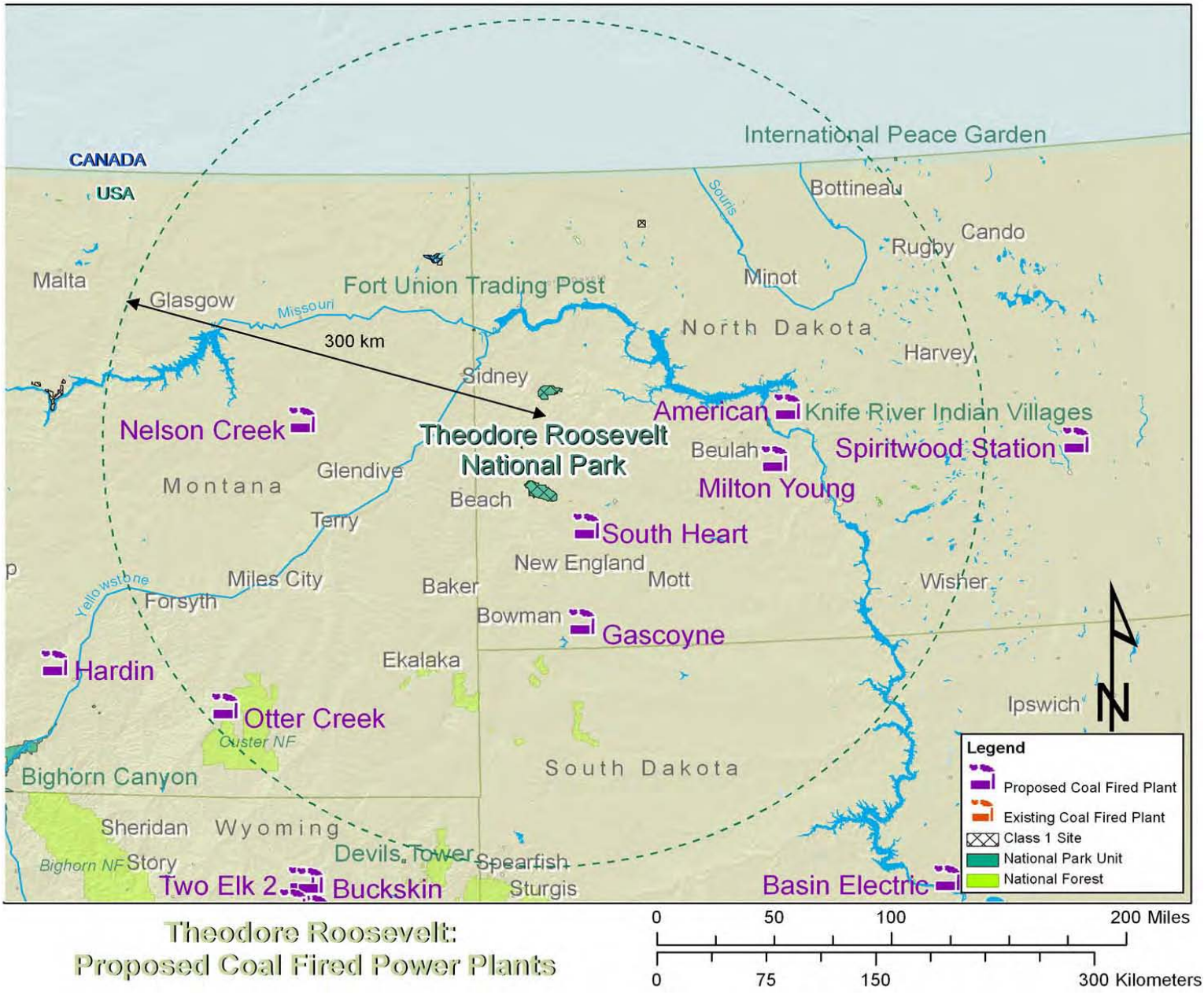

Theodore Roosevelt: Proposed Coal Fired Power Plants

Power plants that have received permits and not yet commenced construction or are in active permit process

Plant	Location	Owner	Size (MW)	Distance from Park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
Gascoyne Generating Station	Bowman County, ND	Westmoreland Power	500 MW	90KM	3,250,000	1,524	2,286	660	Draft Permit 5/29/07
Total New Pollution into Theodore Roosevelt National Park Area Airshed					3,250,000	1,524	2,286	660	

For more information contact: Stephanie Kodish, 865.329.2424, ext. 28, skodish@npca.org

Photo courtesy of National Park Service

Wind Cave National Park: Air Quality at Risk

Park highlights

- Located in the Black Hills region of South Dakota, the park protects one of the world's longest and most complex caves, with an amazing amount of the rare formations called boxwork.
- The park also protects over 28,000 acres of one of the few remaining mixed-grass prairies, as well as ponderosa pine forest, and native wildlife such as bison, elk, pronghorn, mule deer, coyotes, and prairie dogs.

Current air quality

- Wind Cave National Park is in a rural area with comparatively good air quality, but the park is nevertheless vulnerable to nearby and distant sources of air pollution.
- The National Park Service is carefully monitoring visibility in the park, which shows signs decline.

New coal-fired power plants

- Six new coal-fired power plants are under active development within 186 miles (300 km) of Wind Cave National Park.
- Each year, these new plants would emit into the Badlands area air shed more than 17 million tons of carbon dioxide, 9,193 tons of sulfur dioxide, 7,843 tons of nitrogen oxides, and 1,501 pounds of toxic mercury. With new pollution from these six plants, Wind Cave would no longer enjoy the distinction of having relatively clean and clear air.

National Park Service findings

- "... Dry Fork [power plant] may have the potential to adversely impact visibility in Wind Cave National Park by itself."
- "We are especially concerned about the cumulative impacts upon visibility from the extensive development in the Powder River basin and around Wind Cave NP."
- "Dry Fork's contribution to sulfur deposition in the park triggers management concern and warrants further consideration.... An increase in [sulfur deposition], in particular (as they are the largest contributor to visibility degradation), impairs the ability to observe landscapes, vegetative types, geologic patterns, and even wildlife, not only at great distances, but even in the range of even yards."

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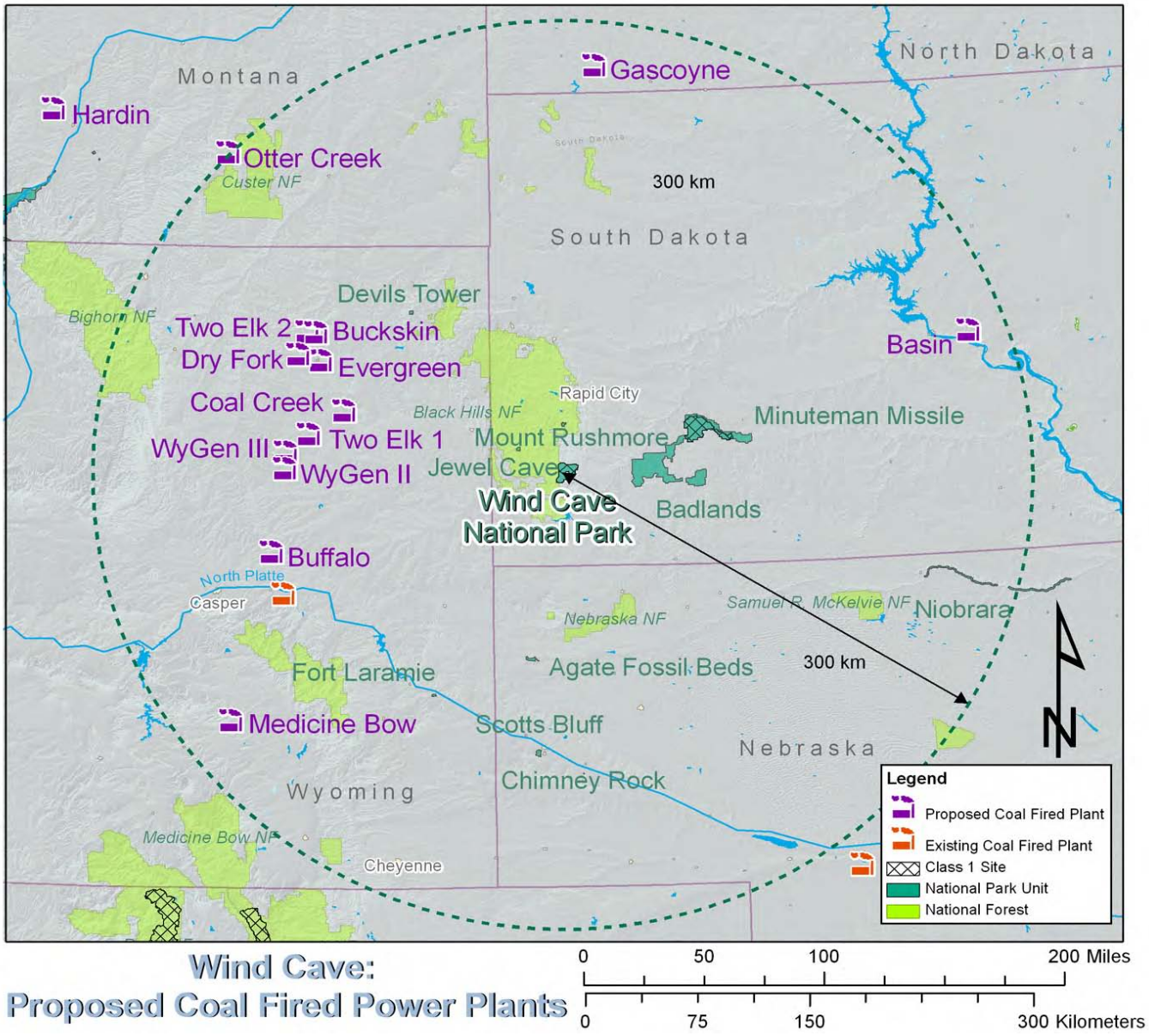

Power plants that have received permits and not yet commenced construction or are in active permit process

Plant	Location	Owner	Size (MW)	Distance from park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
Dry Fork Station	Campbell County, WY	Basin Electric Power Cooperative	385	180km	2,461,818	1,165	833	327	Final air permit issued October 2007
WYGEN 2	Campbell County, WY	Black Hills Corp.	100	168km	2,510,178	569	399	141	Final air permit issued July 2005
WYGEN 3	Campbell County, WY	Black Hills Corp.	100	168km	2,510,178	512	285	80	Final air permit issued February 2007
Two Elk Energy Park Unit 1	Campbell County, WY	North American Power Group	280	140km	2,112,500	1,711	1,167	***49***	Final air permit re-issued May 2003
Two Elk Energy Park Unit 2	Campbell County, WY	North American Power Group	750	140km	6,239,461	2,753	2,202	164	Application received September 2006
Gascoyne 500	Bowman County, ND	Westmoreland Power	***500***	280km	***3,250,000***	1524	2286	660	Draft air permit May 2007
Evergreen Coal Creek	Campbell County, WY	***Evergreen Energy Inc***	***XX***	143	***XX***	959	671	80	Application received November 2006
	Total New Pollution into Wind Cave Area Airshed				**17,695,356**	**9,193**	**7,843**	**1501**	

For more information contact: Stephanie Kodish, 865.329.2424 ext. 28, skodish@npca.org

Photo courtesy of National Park Service

Zion National Park: Air Quality at Risk

Park highlights

- Zion National Park preserves 229 square miles of sculptured canyons and soaring cliffs amidst the diverse wilderness occurring at the junction of the Colorado Plateau, Great Basin, and the Mojave Desert.
- Visitors can travel into the park along the Pa'rus Trail and explore other hiking, biking, horse, and walking trails.
- Many hikers travel along the bottom of canyons such as Timber Creek, Pine Creek, and Zion Canyon, or enjoy spectacular overlooks of the canyons from above.

Current air quality

- Hazy air, caused by fine particles of soot, is growing worse at Zion National Park.
- Several plant species that live in the park are known to be sensitive to ozone. National Park Service monitoring has found unhealthy ozone pollution and probable ozone injury to several plant species, including snowberry.
- Nearby sources of this pollution include power plants, refineries, and lime kilns.

New coal-fired power plants

- Three large, new coal-fired power plant projects are under active development within 186 miles (300 km) of Zion National Park, in a region that already has three operating coal-fired power plants; two other coal-fired power plants operate just beyond that distance.
- Each year these three new plants would emit into the Zion area air shed more than 44 million tons of carbon dioxide, 16,708 tons of sulfur dioxide, 14,898 tons of nitrogen oxides, and 765 pounds of toxic mercury. This new pollution will accelerate the worsening haze problem at Zion, add additional stress to rare plants in the park, and raise the risk that park visitors will experience asthma attacks or other breathing problems.

National Park Service findings

- "…we still have several unresolved issues regarding" air pollution impacts from White Pine Energy Station on Zion National Park, including whether pollution caps would be exceeded, whether visibility would be degraded, and whether the facility would use the best emissions controls. "We are also concerned about the cumulative impacts" of White Pine and other coal plants in Utah and Nevada.

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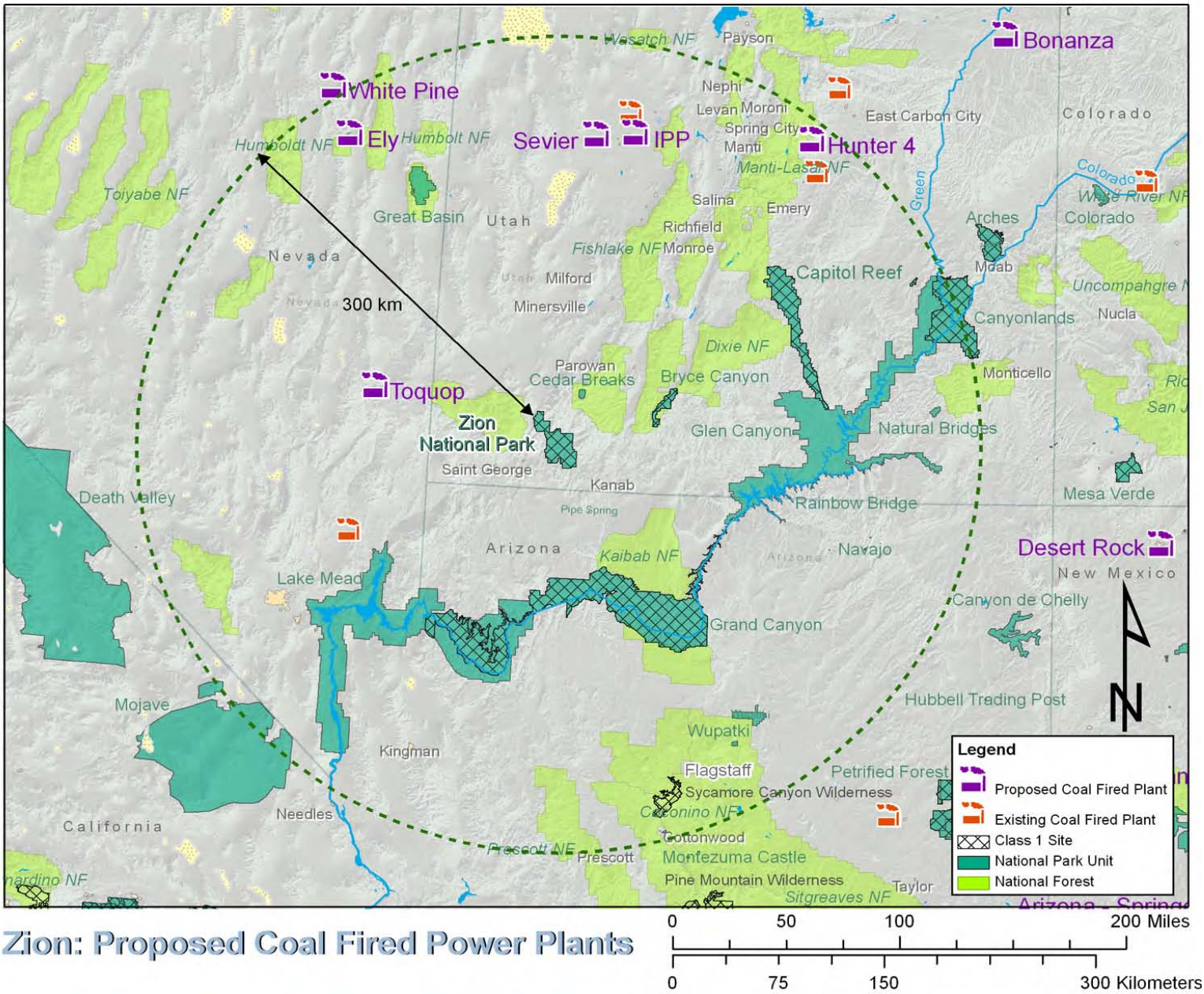

Zion: Proposed Coal Fired Power Plants

Power plants that have received permits and not yet commenced construction or are in active permit process

Plant	Location	Owner	Size (MW)	Distance from Park	CO2 tons/yr	SO2 tons/yr	NOx tons/yr	Hg lbs/yr	Permit Status
White Pine Energy Station Project	White Pine County, NV	White Pine Energy Assoc.- Dynegy/LS Power Assoc.	1,590 MW	283 km	12,600,000	6,071	4,814	279	Draft air permit issued in December 2006
Ely Energy Center	White Pine County, NV	Nevada Power Co. & Sierra Pacific Power	1500 MW	250 km	16,000,000	4,853	4,628	263	Draft Permit issued December 2007
Toquop Energy Project	Lincoln County NV near Toquop Indian Reserv.	Sithe Global Energy	750 MW	108 km from Zion	4,339,799	1,352	1,614	131	Draft permit issued in December 2007
Sevier Power Company Project	Sevier County, Utah	Sevier Power Co NEVCO Energy Co.	270 MW	190 km	1,755,000	234	1,067	9	Final air permit issued October 2004
Intermountain Power Plant	Millard County, UT	Intermountain Power Agency	950 MW	230 km	9,922,200	3,568	2,775	83	Final air permit issued Oct. 2004
		Total New Pollution into Great Basin & Zion Area Airshed			**44,616,999**	**16,078**	**14,898**	**765**	

For more information contact: Karen Hevel-Mingo, 801.521.0785, khevel-mingo@npca.org

Dark Horizons: Fact Sheet on Proposed EPA Rule

The U.S. Environmental Protection Agency (EPA) is attempting to weaken air quality protections for America's treasured national parks and wilderness areas. The proposed EPA rule described below would allow industries seeking to locate near these protected areas to circumvent pollution limits established by Congress to restore and maintain clean air. As a result, there could be more power plants emitting more air pollution into our national parks.

Clean Air Act protects air quality in America's national parks and wilderness areas

In 1977 Congress amended the Clean Air Act and designated certain national parks as class I areas, giving them the greatest level of protection under the Act. There are 158 class I areas, including 48 national parks, 21 Fish & Wildlife refuges, and 88 Forest Service wilderness areas.

To protect the air in class I areas, Congress created the prevention of significant deterioration or PSD program. PSD seeks to "preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special … natural, recreational, scenic or historic value." *Clean Air Act Sec. 160*.

Under PSD, Congress established limits (known as increments) on additional amounts of pollution in class I areas over baseline conditions that existed in 1977 when PSD was enacted. Increments are in place for emissions of sulfur dioxide, particulate matter, and nitrogen oxides. Because Congress sought to protect air quality not just from long-term pollution increases, but also from fluctuations and "spikes" that occur at certain times of year (e.g., peak summer energy use), it created both annual and short-term (3 and 24 hours) increments for these pollutants.

Because Congress wants class I areas to have the cleanest air in the country, these parks and wilderness areas have the smallest increments, or allowable amounts of new pollution. Most other areas of the country are class II areas, and their new pollution increments are about 4-20 times higher. By creating more "room" for new pollution in class II areas, the law seeks to steer new pollution sources away from class I areas.

A major new pollution source like a power plant may not locate near a class I area if it would increase pollution over the class I increments. The plant must do a study (known as an increment analysis) to show how much pollution is already in the class I area and how much additional pollution it will add.

In very limited circumstances, a new pollution source may be granted a variance allowing it to exceed class I increments if its emissions will not adversely impact air quality in the class I area.

EPA's proposed rule change will allow more air pollution in national parks and wilderness areas

The EPA is seeking to change the way increment analyses are conducted for class I areas. Four changes in particular will allow facilities seeking to locate near class I areas to manipulate the data to make it appear as if the air is cleaner than it actually is. These changes will open the door to new pollution in national parks and wilderness areas.

Proposed rule change hides a power plant's pollution spikes from regulators

Pollution levels in class I areas can vary significantly over the course of a day, week, month and year. For instance higher pollution can occur during daytime when more commercial activities take place, and during summer months, when power plants increase operations to meet air conditioning energy demand. Congress created short-term pollution increments to protect class I areas from these periods of higher emissions. The

EPA's proposed rule would undermine short-term increments by turning them into annual average pollution limits. A facility looking to locate near a class I area could average the hourly and daily emissions of all area pollution sources over the course of a year, thus hiding pollution spikes that can cause real harm in class I areas or even exceed the short-term increment limits. This is analogous to the police excusing a driver caught going 90 mph in a 55 mph zone because, over the course of a year, the driver's *average* speed did not exceed 55 mph. Having created a false picture of actual pollution levels in the class I area, the new facility could then claim the right to emit far more pollution than otherwise would be allowed.

Ignores major polluters in class I areas

Under current rules, a pollution source that has received a variance to exceed a class I increment will nonetheless still have its emissions counted when new sources are seeking to add pollution in the class I area. This makes sense because a variance source, by definition, is known to be a major contributor of pollution in the class I area. Under EPA's proposed rule, the emissions from any pollution source operating under a variance would not be included in an increment analysis. When calculating pollution levels in a class I area, a new facility could simply pretend that those sources don't exist. By ignoring these emissions, a new facility can claim there is more "room" for new pollution, thus degrading class I air quality to an even greater extent.

Allows phony pollution accounting

Under current rules, emissions from existing facilities that impact a class I area are established by looking at the most recent two years of operating data. The proposed rule allows actual emissions to be computed based on any time period that is claimed to be "more representative" of normal source operations. The alternative time period could even be two non-consecutive 12-month periods picked from anytime in the past. This opens the door to phony pollution accounting by new facilities that have a vested interest in producing the lowest possible pollution estimates for class I areas they are seeking to locate near.

Opens the door to 50 different standards

Air pollution does not respect state boundaries, and class I areas may be polluted by sources in many different states. It's therefore important that the methods for estimating class I pollution levels are the most accurate and are consistent from state to state. The EPA's proposal opens the door to 50 different standards for estimating class I pollution levels. Emissions "...shall be calculated based on information that, in the judgment of the reviewing authority, provides the most reliable, consistent and representative indication of the emissions from a unit or group of units in an increment consumption analysis..." Some states are likely to use methods that make the air in class I areas appear cleaner than it actually is, but EPA's rule provides no check against such practices.

Comments from EPA and National Park Service scientists on EPA proposed rule

The National Park Service and every EPA regional office in the country oppose the changes sought by EPA management because they concluded that park air quality would worsen.

- The proposed EPA methodology "provides the lowest possible degree of protection of short-term increments and it is usually the 24-hour increment that is the most critical" for protecting air quality. -- National Park Service

- "The protection of short term PSD increments cannot be assured using annual average emission rates." -- National Park Service

- "The argument, in the preamble, that it is unlikely that multiple sources will experience maximum emissions on the same dates is specious [and] ignores reality..." -- EPA Region 3

- "The exclusion [from the baseline of certain sources that have received variances] gives a permanent 'pass' to sources that happen to obtain a variance regardless of subsequent events [or that are] granted based upon error or mischief." -- EPA Region 3

- "The application of the concept of 'normal operations' to the PSD baseline concentration(s) does not appear appropriate as it makes PSD baseline concentration(s) up for interpretation by every applicant." -- EPA Region 4

- "…in the case where hotspots are due to single sources, the use of average short-term rates will likely underestimate expected actual short-term concentration increases." -- EPA Region 5

- "Dating back only to 2005, the EPA stated that use of annualized emission rates likely underestimates short-term impacts." -- EPA Region 7

- "…this proposal… would jeopardize protection of PSD increments and limit the public's ability to be involved contrary to the provisions of" the Clean Air Act. -- EPA Region 9

- "Because of this fundamental misunderstanding of the permit process and the lack of understanding of how variances work, this rulemaking misses the mark on the appropriate solution to the issue of increment consumption for sources with variances." -- EPA Region 10

Dark Horizons:
10 National Parks Most Threatened by New Coal-Fired Power Plants

May 2008

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Please visit www.npca.org/darkhorizons for more information and a PDF version of this report.

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Report Comparing Alternative Technologies for The Virginia City Hybrid Energy Center

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In the matter of the Application of Virginia Electric and Power Company for a PSD Air Permit before the Virginia Department of Air Quality

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1. INTRODUCTION

National Parks Conservation Association ("NPCA") retained Hensley Energy Consulting, LLC ("HEC") to prepare this report in connection with the application by Virginia Electric and Power Co. ("VEPCO") for a PSD air permit for the proposed Virginia City Hybrid Energy Center ("VCHEC"). HEC is an independent technology consulting firm specializing in clean power and energy technology. Its managing director, Dr. Douglas H. Cortez has over 35 years experience with a wide range of coal and petroleum processing technologies. Dr. Cortez's curriculum vita is attached as Exhibit DHC-1.

The report addresses the primary alternative technologies available to VEPCO for generating power from coal, principally Circulating Fluid Bed ("CFB") technology, Supercritical Pulverized Coal ("SCPC") technology, and Integrated Gasification Combined Cycle Technology ("IGCC"). The primary focus of this report is environmental performance, including climate change or greenhouse gas ("GHG") emissions. Other features of the technologies including fuel flexibility, water consumptions, solid waste, reliability and maturity of the technologies is discussed.

HEC is a technology consulting firm that relies upon publicly available information and the private experience of its managing director. Information and references cited in this report are from public sources and no third party confidential information available to HEC is disclosed. HEC believes the information presented in this report is from reliable sources but HEC cannot guarantee the accuracy of the information. HEC does not advocate any particular technology or project as such advocacy requires considering many important factors that are beyond the scope of this report.

2. COMPARISON OF IGCC, CFB and SCPC TECHNOLOGIES

Integrated Gasification Combined Cycle (IGCC)

IGCC technology can best be described as an environmentally superior process for generating power from coal. It accomplishes this by first converting coal to a clean burning fuel gas at high pressure in a gasification process. Gasification is the reaction of coal with steam in the absence of oxygen to produce "synthesis gas" or "syngas" which consists mostly of carbon monoxide and hydrogen. Pollutants in the coal, such as sulfur and nitrogen, are converted to acid gases and ammonia. Since the syngas is produced at high pressure (typically 500 to 1000 psi), the gas can be efficiently treated to remove virtually all of the impurities. The resultant "clean syngas" is burned in an efficient combined cycle plant which is integrated with the gasification step.

In addition to producing very low levels of regulated pollutants (i.e. SO_x, NO_x, particulates, mercury, VOCs), IGCC technology is uniquely suited to capture carbon dioxide (the major contributor to climate change and global warming). Since the clean syngas is produced at high pressure, it can be reacted with steam to chemically shift the carbon monoxide to hydrogen and carbon dioxide. The CO_2 can then be removed ("captured") and compressed for storage in underground geologic zones or used for enhanced oil recovery.

The technology for shifting synthesis gas to hydrogen and for capturing carbon dioxide in an IGCC plant is proven technology that is practiced today on a large scale in commercial hydrogen, ammonia and other petrochemical plants. A few IGCC plants operating in Europe today are capturing a portion of the carbon dioxide although none are sequestering the CO_2.

Supercritical Pulverized Coal (SCPC)

A supercritical pulverized coal (SCPC) power plant generates steam from pulverized coal in a conventional boiler and the steam is passed through a steam turbine generator set to generate electricity. SCPC plants achieve higher conversion efficiencies by generating steam at "supercritical" pressures. Under current definitions of BACT, recently constructed SCPC plant employ a wide range of pollution control equipment, including baghouses and precipitators to remove

particulate matter, selective catalytic reduction (SCR) to remove NOx, and wet limestone scrubbers to remove sulfur oxides. Over 25 SCPC plants have been constructed and are operating in the US today however not all of these plants include the full suite of environmental control technologies.

Circulating Fluid Bed Boiler

A circulating fluid bed boiler (CFB) power plant generates steam from pulverized coal in "fluid bed" into which limestone is injected to capture sulfur at lower combustion temperatures which also reduces the formation of NOx compounds. CFB boilers collect and recycle large quantities of ash to increase carbon burnout and increase plant efficiency. The nature of the combustion process in a CFB requires larger equipment with more solids handling than a conventional pulverized coal boiler which combusts the coal at higher temperatures in smaller volumes. Wet limestone scrubbing and SCR are not considered feasible for use with CFB technology today. In order to improve the SOx removal efficiency of CFB units processing high sulfur coals, dry lime scrubbing units have been added to some recently constructed CFB units. Selective Non-catalytic Reduction ("SNCR") is available to reduce NOx downstream of a CFB boiler. Similarly, catalytic reduction of carbon monoxide is not considered proven for CFB technology. The first CFB units were developed for smaller scale power generation applications (up to 100 Mw) and for burning high ash coals, coal waste, biomass and other lower grade solid fuels. In recent years, single CFB boilers as large as 250 Mw net have been constructed. CFB technology operating with super-critical steam conditions is not commercially available although super-critical CFB technology is under development. The proposed VCHEC CFB project is based on the largest available CFB technology (almost 300 Mw gross) with SNCR and dry lime scrubbing technology.

3. CARBON CAPTURE CAPABILITIES OF IGCC, CFB and SCPC TECHNOLOGIES

Post-combustion carbon capture technology (carbon dioxide removal) for SCPC and CFB technology is still under development. The technology that is closest to being considered commercial is amine scrubbing technology. This technology has been used in the natural gas processing and refining industries to remove acid gases (hydrogen sulfide and carbon dioxide) from high pressure gas streams that do not contain excess air or oxygen. However, specialized amine scrubbing systems that process clean flue gas from natural-gas-fired boilers and power plants have been demonstrated on a small scale. The technology has not been demonstrated on a large scale for coal-fired power plants. The low-pressure flue gas would need to be compressed at high power cost for these absorbers to operate efficiently. In addition, the flue gas would require additional treatment to remove residual sulfur oxides prior to being fed to the CO_2 scrubbers. Although these steps have been demonstrated at a small scale, significant scale-up of these steps would be required before the technology could be classified as commercially proven, much less commercially available.

In a recent report from U.S. EPA[1], the contractor (Nexant) surveyed the current state of the amine scrubbing technologies for large-scale PC power plants. The study concluded, "While the amine process is technically proven in small-scale commercial operations, the economics and scale-up issues associated with a 500 Mw or larger power plant are substantial." The EPA report also stated that, although the technology is being improved for natural gas applications, "...the development of similar systems for PC plants does not appear to be progressing very rapidly." Based a review of the public literature, there is a consensus that CO_2 scrubbing technology for SCPC plants carries significant cost penalties and performance risk that cannot be

[1] "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technology," EPA-430/R-06/006 (Jul. 2006) ("2006 EPA Report Comparing Gasification and PC Technologies"

projected at this time. Only after large scale demonstration plants are operating, can these risks be fully understood. Although a large coal IGCC plant with full carbon capture has not been constructed, numerous public and private studies have investigated the IGCC carbon capture option. There is a consensus in the literature that the technology for capturing CO_2 in an IGCC plant has been demonstrated in large scale petrochemical plants and is ready for deployment. The aforementioned EPA report stated: "The processes required to remove CO2 from an IGCC plant are commercial in other gasification applications."[1]

We are unaware of any reported study examining the application of post-combustion carbon capture technology to a CFB plant. However, since the flue gas stream to be treated will be similar to a SCPC plant, we do not see any major differences. Some developers of advanced amine scrubbing technology for PC coal boilers propose to integrate the scrubbing system with the coal boiler steam system to improve the energy efficiency of the total system. Similar integration features might be applied to a CFB plant. However, having reviewed the literature, we are not aware of any published information on integrating CFBs with amine scrubbing systems.

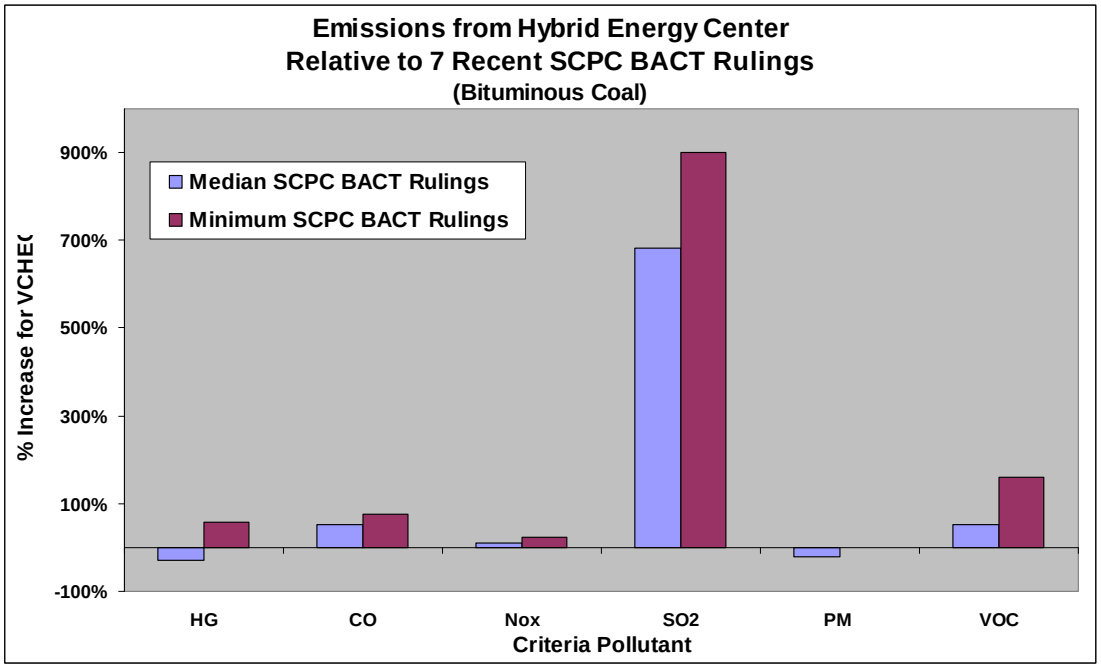
4. COMPARISON OF VCHEC EMISSIONS AND TYPICAL SCPC and IGCC PLANTS.

VEPCO has provided air emissions data in its PSD Permit. PSD permits have also been filed or issued for several large SCPC power plants in recent years. We have reviewed seven of the most recent SCPC plants that burn bituminous coals with medium to high sulfur content. (SCPC projects using low sulfur sub-bituminous coals are governed by different, but similar, set of BACT standards). Exhibit DC-2 summarizes the BACT determinations for these seven SCPC plants. EPA BACT methodology applies emission rates expressed in pounds of each criteria pollutant per

MMBtu of fuel fired to the boiler or combustion device. Since this report is addressing the relative environmental performance of SCPC, CFB and IGCC as power generation technologies, we have converted the BACT data in for each power plant to pounds of pollutant per useful unit of energy produced for sale, or net kilowatt-hours. Those data are also shown in Exhibit DC-2.

Figure 1 below shows graphically how the VEPCO CFB project compares to the seven SCPC plants listed in Exhibit DC-2.

Figure 1



VEPCO represents that the Hybrid Energy Center is a "clean coal" project. Figure 1 suggests that this may not be the case. With the exception of particulate matter, these data show that the VCHEC CFB project will produce substantially more pollution. Compared to the "best in class" SCPC projects, VCHEC will produce 7 to 10 times more SO2, and 50% to 150% more CO, VOC and mercury emissions. NOx emissions will be slightly higher than the SCPC that have been permitted.

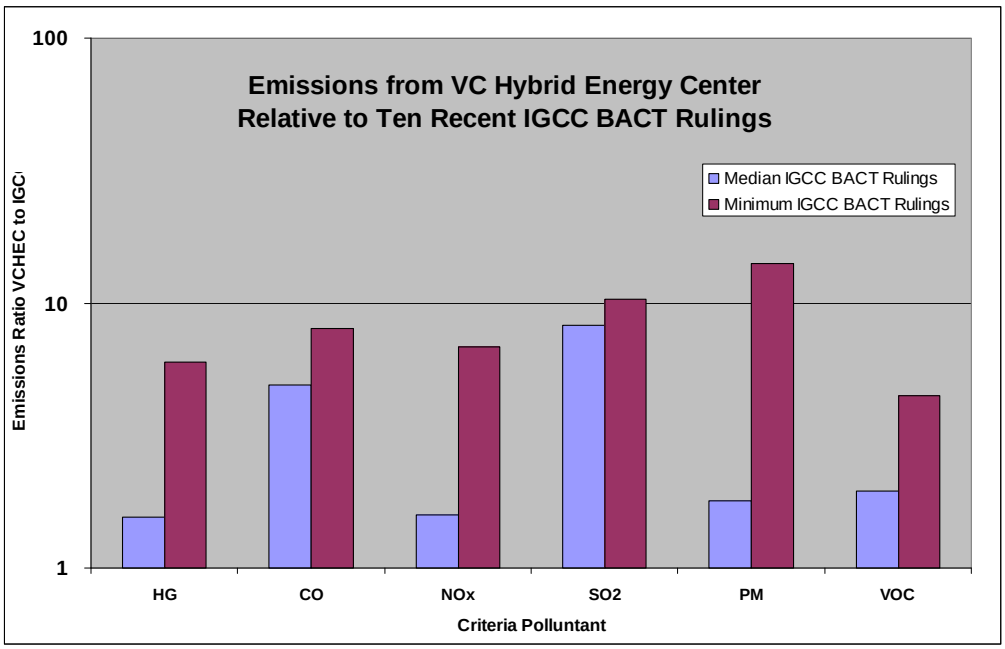
PSD permits have also been filed or issued for ten IGCC projects in recent years. Exhibit DC-3 summarizes the key data for criteria pollutants for those projects.

The data summarize the emission rates for criteria pollutants measured as normalized lb/MMBtu of fuel fed to the power plant. As with the SCPC data, we have estimated the same emission rates expressed in pounds per kwhr of useful power produced. (Note that in most cases, the emissions from start-up and shut-down periods and other ancillary sources are excluded. These other sources of emission are relatively small). Exhibit DC-3 also shows data for the two IGCC demonstration plants operating in the U.S.

The table in Exhibit DC-3 summarizes the median and minimum BACT determined rates for these IGCC projects. We have excluded the Wabash and Polk data from this analysis. Although these plants have emission rates generally below most PC coal plants, we believe it is a mistake to use these data to represent the state of the art IGCC technology. It would likewise be a mistake to compare the most recent SCPC data using the emission data from plants constructed 15 to 25 years ago. The Wabash and Polk IGCC plants were permitted in the early 1990's under different BACT rules and regulations. Therefore the most recent PSD permits represent the collective determination of permitting agencies and the technology suppliers of current emissions performance capabilities of IGCC and SCPC technology.

The data show that an IGCC plant will produce dramatically lower emissions than the proposed VCHEC CFB plant or a modern SCPC power plant. Figure 2 below shows graphically how the VCHEC CFB project compares to the ten IGCC plants. Since the differences are so large, we have plotted the ratio of VCEHC emissions to the median and minimum ("best in class") emission rates for the IGCC plants using a logarithmic scale.

Figure 2



The chart shows that compared to the best in class IGCC technology, the VEPCO CFB project will produce 5 to almost 15 times as much mercury, CO, NOx, PM and VOC emissions. These data show that IGCC, as evaluated by ten State EPA's will be the cleanest coal technology by a wide margin.

IGCC technology has the potential to achieve even better environmental performance. BACT methodology sets the emission rate after considering actual experience with the method of controlling each emission and the economics of achieving lower emissions. IGCC technology approved in the permits listed in Exhibit DC-3 is based on these conservative standards and the guarantees available from technology and equipment suppliers. Based on the practices of the refining and petrochemical industry, the gas processing technologies employed in a modern IGCC plant can be designed to achieve lower emissions. For example, in petrochemical plants where mercury traps have been used for years, the mercury in the clean product gas is virtually undetectable. Based on this experience, we would expect an IGCC

with mercury traps to release even less mercury than the best in class data in Figure 2 and Exhibit DC-3. Commercial gas cleaning technology also exists that could reduce SO2 emissions to near zero levels. However, the added cost of using this technology is not considered justified under today's BACT methodology.

The superior performance of IGCC technology over SCPC and CFB can be attributed to several factors. IGCC and CFB technology were developed for different applications. IGCC is best suited for higher Btu, lower ash coals, including bituminous coal, sub-bituminous coals, heavy oils and petroleum coke. An IGCC plant is very efficient at removing sulfur, so coal with any sulfur content can be easily processed in an IGCC plant. As discussed in Section 8, low ash bituminous coals appear to be available in Southwest Virginia. CFB technology is best suited for low Btu, very high ash coals, such as coal waste and lignites. With very high sulfur content coals, a CFB will produce higher SO2 emissions. As currently practiced, CFB technology has some limitations on use of air pollution control technology that is proven for PC boiler power plants. In its PSD application, VEPCO states that the following air pollution control technologies are not proven for CFB power plants: wet limestone scrubbing for SO_x reduction, selective catalytic reduction for NO_x reduction, and CO catalyst for carbon monoxide reduction. The inferior environmental performance of CFB technology is illustrated in summary of BACT determinations in Figures 1 and 2.

With IGCC technology, the systems used to reduce air emissions are each proven in IGCC and other commercial applications. More important, core IGCC subsystems can be engineered to improve environmental performance even after a plant is constructed. Retrofitting a CFB plant with wet limestone scrubbers, CO catalyst, and/or SCR units could be very expensive, provided the technology becomes available. Also, as illustrated below, the very large volumes of bottom and fly ash will create real challenges finding future markets for this waste material.

5. COMPARISON OF SOLID WASTE PRODUCTION FROM VCHEC AND TYPICAL IGCC PLANTS.

A typical bituminous coal IGCC project processes high BTU, washed coal at a heat rate of about 8900 Btu/kw-hr. The IGCC plant requires no limestone and produces only a non-hazardous slag that may be sold or disposed in a landfill. To illustrate the broad solids handling dimensions, we have prepared Table 1.

Using the data provided by VEPCO in its PSD application, the VCHEC CFB project will produce about 14 times the volume of waste solids (per Mw-hr of useful product) than a typical IGCC project. More important, the ash from a CFB plant is leachable and must be stored in managed landfills to prevent run off. An IGCC plant melts all of the ash in the coal and the slag product is non-hazardous. It may be sold as a construction material or stored in a less expensive landfill operation.

Table 1 also shows that the VCHEC project will also handle over twice the volume of solids to feed the plant (coal and limestone). The high volume of coal required to operate the CFB plant is due to its poorer efficiency, the use of high ash coal fuel, and use of air cooling. If low ash coal from the region were used, these volumes of coal transportation and ash handling would be reduced significantly. With IGCC technology, the amount of solid fuels and waste handling would be the lowest.

Table 1 - Comparison of Solids Handling Volumes - CFB vs IGCC

Source		VEPCO SW VA CFB PSD Application	IGCC Typical PJM Industry Reports
Plant Capacity	Mw	580	630
Coal Feed Rate	MMBtu/Hr	6,264	5,607
Coal Heating Value	Btu/lb	7,782	12,000
Plant Heat Rate	Btu (HHV)/kwhr	10,800	8,900
Plant Capacity Factor	%	90%	90%
Coal Use	tons/yr	3,173,052	1,841,900
Coal Use at 100% CF	coal at 100%	3,525,613	2,046,555
Coal Use at 100% CF	tons/yr	3,525,000	2,046,555
Limestone Use	limestone	350,000	-
Total Coal and LS	coal, limestone	3,875,000	2,046,555
Fly Ash Production	tons/yr	1,040,000	
Bed Ash Production	tons/yr	1,560,000	
Slag Production (10% a	tons/yr		204,656
Total Ash to Disposal	tons/yr	2,600,000	
Total Slag Production	tons/yr		204,656
Ash Product Rate	tons/mwh	0.512	0.037
Coal/LS Use Rate	tons/mwh	0.763	0.371

6. LOWEST COST OPTIONS FOR NEW COAL POWER GENERATION

Relative Cost of Electricity without Carbon Capture

Based on confidential information we received pursuant to the Virginia State Corporations Commission hearings, and recent estimates for SCPC and IGCC projects in the region, we prepared estimates of the cost of electricity (COE) from the VCHEC CFB project and a standard IGCC (630 Mw) and SCPC (800 Mw) power plant.. The rated capacity of a "standard" IGCC is approximate 630 Mw and fixed by the use of currently available state-of-the-art combustion turbines (Frame 7 class). The largest single boiler SCPC plant available today, with a single steam turbine, is approximately 800 Mw. Similarly, the VCHEC is based on using two of the largest

CFB boilers available today. The details of our study are confidential under SCC rules of confidentiality. However, our analysis indicated that the COE from the VEPCO CFB project will be meaningfully higher than an 800 Mw SCPC plant burning high BTU bituminous coal. When compared to a 630 Mw standard IGCC plant, the COE of the VCHEC is estimated to be about the same. From this study, it would not appear that the VCHEC CFB project is the least cost resource. Further information on this analysis is available in our non-confidential testimony before the VA SCC. [2]

Relative Cost of Electricity with Carbon Capture

When the impact of carbon capture equipment is included, the relative cost of electricity from SCPC, CFB and IGCC power plants changes dramatically. There have been many studies completed and more are underway on the costs of capturing carbon from conventional and IGCC power plants. In order to address this question, we developed the adjustment factors using several recently published independent studies. Table 2 below provides a summary this information:

[2] On behalf of the Southern Environmental Law Center, in the matter of the Application of Virginia Electric and Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate an Electric Generation Facility in Wise County, VA, before the Virginia State Corporation Commission, Case No. PUE-2007-00066

Table 2 - Changes for Carbon Capture (newly built)

Reference No. Exhibit DC-4		1	2	3	4	5	
		US DOE / Parsons	US. DOE NETL	US. DOE NETL	MIT	IECM	Average
Technology	Parameter	2002 Bit	2006 Bit	2007 Bit	2006 NA	2005 Bit	various Bit Coal
IGCC	Increase in COE	37.9%	33.8%	34.6%	27.1%	48.9%	36.5%
PC Coal	Increase in COE	66.2%	68.0%	81.4%	60.9%	139.6%	83.2%
IGCC	$/kw investment	47.8%	32.8%	36.0%	32.2%	36.8%	37.1%
PC Coal	$/kw investment	73.3%	74.8%	82.2%	60.9%	53.6%	69.0%
IGCC	Increase in heat rate	16.6%	24.2%	20.8%	23.1%	16.1%	20.1%
PC Coal	Increase in heat rate	40.3%	43.1%	43.7%	31.9%	62.1%	44.2%

These studies were chosen because they examined both technologies with and without carbon capture on a consistent basis. Even though there were technology differences and time and cost differences, the results are remarkably in agreement. For the study of the VCHEC plant, we used only the relative investment costs and heat rates to make the adjustments for carbon capture. All other assumptions remained the same. There are no studies that we are aware of on adding carbon capture to a CFB plant. However, we would expect the costs to be similar, as the technical differences in flue gas properties are small. Since the VCHEC CFB releases more CO_2 than a SCPC plant, the cost of carbon capture will likely be higher. For our study, we ignored this fact. Thus, our estimates are likely to understate the VCHEC costs of carbon capture.

The additional costs and performance penalties dramatically changes the projected cost of electricity. The details of our study are confidential under the SCC rules of confidentiality. However, our study shows that the IGCC option with carbon capture is projected to be the least cost resource. This result is consistent with the other studies that have been reported. The VCHEC CFB option becomes the highest cost resource among the three coal technology options. The significantly higher COE for VCHEC project with carbon capture is attributable to several factors, including

the high cost of adding CO_2 scrubbing and compression, the facility's poor heat rate, higher fixed operating costs and higher regulated return on shareholder equity requested by VEPCO.

There are a number of assumptions in our study that should be noted. The carbon capture data is based on applying amine scrubbing technology. This technology has not been applied to large scale coal plants but is believed by most experts to be the most advanced and commercially available technology for removing CO_2 from coal plant flue gases. There are other technologies that are under development that could reduce the cost of removing CO_2 from coal plant flue gases. The chilled ammonia and "oxy-fuels" technologies show credible promise for reducing the cost of carbon capture from PC boiler plants. However, those technologies are still in the research and demonstration phase and reliable data on performance and economics is not yet available.

Our study is also based on "newly built" cost estimates. The cost of retrofitting existing coal plants could be more expensive. Significant engineering efforts are now underway to better understand and optimize the cost of retrofitting carbon capture to conventional coal and IGCC plants. However, we would not expect the relative costs between IGCC and conventional coal to change when the retrofit option is better defined.

VEPCO claims that the VCHEC is designed to be "carbon capture compatible". The company justifies this statement on the fact that the plant plot plan contains space to add carbon capture equipment in the future. Other than identifying the plot space, VEPCO provides no other information on this feature of the plant.

In order to be truly carbon capture compatible, it would be necessary to develop a conceptual design of the carbon capture and CO_2 compression equipment and prepare an equipment arrangement drawing. This would require selecting a technology basis for this operation. Such a study would determine the changes in the design of the CFB plant that might be required to accommodate future addition of carbon capture equipment. The most effective carbon capture process requires

integrating the power plant steam system with the CO_2 scrubbing and stripping equipment. A phase one engineering study of the carbon capture system would identify the investments that would be needed to accommodate a future retrofit of the plant for carbon capture. Simply leaving plot area for a hypothetical carbon capture and compression plant does not make the plant carbon capture compatible. Based on my understanding of the term, we do not believe the current design of the VEPCO CFB plant is carbon capture compatible.

7. RELIABILITY OF SCPC, IGCC AND CFB TECHNOLOGIES

A major consideration in selecting a coal fired power generation technology is its long term reliability. Plant operating factors have a major impact on the cost of services for these capital intensive projects.

SCPC technology is a proven power generation technology. The North American Electric Reliability Council ("NERC") reports on actual coal boiler plant availabilities using several defined terms for availability.[3] One of the common measures of availability is Equivalent Availability Factor ("EAF") which measures the availability of the power plant after accounting for planned and unplanned outages including deratings due to partial outages. NERC reports the following EAF data for large coal power plants over 1000 MW:

Time Period	EAF
1982-2005	79.7%
1996-2005	81.9%
2001-2005	81.7%

The NERC data includes sub- and super-critical PC boiler plants with and without scrubbers, SCR and other contemporary environmental control equipment.

[3] See North American Reliability Council website: http://www.nerc.com/~gads/

The NERC data contains details for each type of boiler but this data is not available to the public. From the publicly available NERC data, we conclude that large coal PC plants average availability is in the 80% to 82% range.

In VEPCO's SCC filings, the company assumes that that the CFB plant would operate at 90% availability and capacity factor. There is little data available on availability of large CFB plants (over 500 Mw) in the public domain. The most recent, large CFB plant operating on waste coal is the Reliant project in Seward, Pennsylvania. Reliant reports the following information on their website[4]:

Average Capacity Factor for 18 months ending June, 2007

All Reliant Coal Plants, excluding Seward	82.2%
Reliant Seward CFB Plant	72.5%

These data suggest that Reliant's convention coal power plants have operating histories similar to the NERC averages. However, the data also show that their 550 Mw CFB unit has rarely achieved the level of availability that the conventional coal units have achieved. Since Seward is operating on only low cost waste coal, it seems unlikely that this low capacity factor is due to economic dispatch or curtailment. NERC most likely has individual power plant availability data, including CFB units. However, this data is not available to the public. Based on this limited amount of data, we would expect a very large CFB plant to perform no better than a SCPC power plant and possible with lower levels of reliability.

Reliability of newly designed IGCC plants is more difficult to determine. Critics of IGCC technology point to the performance of the Wabash and Polk IGCC

4 http://www.reliant.com/PublicLinkAction.do?i_chronicle_id=0901752280002001&language_code=en_US&i_full_format=jsp

demonstration plants as examples of reliability problems with IGCC technology. The operating history of these plants has been reported in detail in numerous DOE reports ending in about 2002-2003. Those reports explain in detail the sources of outages in the two demonstration plants. Although key components of the gasification sections of each IGCC plant had early problems with equipment design and performance, those problems have largely been addressed. Many of the outages of the Wabash and Polk plants were attributed to problems with conventional equipment outside of the gasification technology. For example, both plants have had on going problems with the air separation units and the combined cycle power units. Since 2002, there has been very little information available on the two US IGCC demonstration plants. The Wabash IGCC plant was acquired by Wabash Valley Power Cooperative two years ago. Recently, Wabash also acquired the combined cycle plant which a major cause of plant outages. We understand that since the combined cycle unit has been acquired and the entire plant has been operating as an integrated IGCC unit, that the performance has been outstanding. However, this detailed operating data is confidential. It can be made available to power companies that sign non-disclosure agreements and express a serious interest in IGCC technology.

Although they are designed to operate on asphalt, the large Italian IGCC projects demonstrate that complex, integrated, multiple train, IGCC plants can be operated reliably. A recent report by Foster Wheeler has provided availability data for these projects.[5] Foster Wheeler reports that the ISAB IGCC plant has achieved "excellent" results from the first year of commercial operations. Excluding the time the turbines operated on fuel oil, the facility achieved the following annual availabilities (i.e. syngas fuel only operations) during 2003 to 2005 of 86.5% to 96.3%. Foster Wheeler reports even better performance for the API Energia IGCC project. This plant achieved annual availability of 90% to 94% between 2004 and 2006.

[5] "IGCC Technologies: FWI Capabilities and Experience" Rosa M. Domenichini, Presentation to Great Plains Institute, October 8, 2007.

It is important to note that a significant investment in engineering of IGCC plants has been made in the past 2 to 4 years. Much of this information is not available to the public. Duke Energy, American Electric Power and other utilities have invested in the design, engineering and development of IGCC projects. Of relevance to the VEPCO VCHEC project is the efforts of Appalachian Power (AEP) to construct an IGCC in nearby West Virginia. Testimony of AEP Senior Vice President Michael Rencheck explained why AEP has selected IGCC technology for its long term reliable base load coal plant in West Virginia. Some of Mr. Recheck's testimony is summarized below:[6]

> *"We recognize that the IGCC technology has advantages, both environmental and economic, especially under potential C02 control scenarios, making it the logical choice for new baseload generation at the Mountaineer site. An IGCC plant using the newest, cleanest technology will initially cost more than conventional pulverized coal units, but we project that it will be the least-expensive option over the life of the plant. It's a decision for long-term success in an environmentally constrained world."*
>
> *"We conclude that deploying the IGCC technology on a commercial scale is both fiscally responsible and the right thing to do as a matter of public policy for AEP, for APCo, and for the States of Virginia and West Virginia."*
>
> *"At this time, there are no known commercial scale applications for carbon capture for a pulverized coal plant. When IGCC's environmental benefits are compared to that of conventional pulverized coal, IGCC clearly comes out ahead."*

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[6] Direct testimony of Michael W. Rencheck, On behalf of Appalachian Power Company before the Virginia SCC. Application of Appalachian Power Company For a Rate Adjustment Clause Pursuant to §56-585.1 A 6 of the Code of Virginia, Case No. PUE-2007-00068

These and other statements by AEP and APC in their testimony before the VA SCC are consistent with the studies and reports that we have cited and other statements in this report.

8. COAL QUALITY AND FUEL FLEXIBILITY

Both IGCC and CFB technologies are often described as "fuel flexible". VEPCO has stated that the VCHEC plant is fuel flexible.

IGCC technology can be designed to operate on a wide range of feed materials. As examples, the Wabash IGCC plant has operated on a range of 100% bituminous coals and 100% petroleum coke, the Mesaba IGCC project is designed to operate on a range of western sub-bituminous coals, Illinois bituminous coals and petroleum coke, and the Shell IGCC plant in Buggenum, Netherlands, operates on a range of imported coals and significant amounts of biomass. The predecessor to the Wabash IGCC facility, the Dow Chemical Placquemine LA IGCC plant processed over 1 million tons of sub-bituminous coal successfully. Dry feed commercial gasifiers, such as those offered by Shell, MHI, and Siemens, are all capable of processing low btu, high ash coals, wastes, biomass, and other difficult fuels. The Dakota Gasification plant in North Dakota has been processing high ash lignite for many years with great success. Don Shepherd with the National Park Service described these capabilities in his presentation to the Virginia Department of Environmental Quality.[7] Notwithstanding the technical ability of IGCC technology to handle a wide range of solid fuels, a fuel flexible IGCC plant requires specific design features that add to the cost of the facility. At the same time, a CFB power plant also requires added design features to process a wide range of solid fuels.

[7] "IGCC Briefing", Don Shepherd, National Park Service, Presented to the Virginia DEQ, January 25, 2008.

CFB technology is best suited for low value, high ash waste coals and biomass. The VCHEC plant is designed to operate primarily on high ash "run of mine" ("ROM") or unwashed coal (approximately 7780 Btu/lb, 44% ash). Although a CFB plant can be designed to run 100% waste coal, biomass or high ash coal, the plant must be designed for that purpose. The design of such a plant would add to the cost of the boiler, air pollution control equipment, utilities, off-sites and infrastructure. According to documents filed with the Virginia State Corporations Commission, VECPO has designed the VCHEC to burn up to 20% coal waste or up to 20% biomass or waste wood in blends with ROM coal. The VCHEC could be designed to process 50% or 100% very high ash coal waste, but VEPCO has chosen not to pay the premium in capital and operating costs to process more significant quantities of this waste material. Also, there appears to be no legal or regulatory requirement for VEPCO to process any coal waste or biomass. In addition, the proposed permit conditions limit the sulfur content of the coal fuels or blends. Therefore, it appears that the VCHEC could not be appropriately called a "fuel flexible" power plant and the statements made in the aforementioned Dominion letter to the DEQ do not appear to be supported by the facts.

VEPCO has not provided any information that would allow us to examine the impact of waste coal or biomass on environmental performance. VEPCO's PSD permit application states that processing ROM coal or blends of this coal with waste coal or biomass will meet the permit conditions limiting short term and annual emissions of criteria pollutants. VEPCO also states that if these conditions can not be met they will offset the higher emissions by purchasing offsets or shutting down other emission sources.

Based on similar CFB projects, we would expect the plant efficiency to decline when waste coal is blended with higher quality coal. If the waste coal is lower in sulfur content, the plant should be able to meet emissions limitations and BACT standards. However, the plant will produce more GHGs per kilowatt hour of output when burning coal waste. We would expect emissions of most criteria pollutants and GHGs to improve when burning small amounts of biomass blended with coal.

9. VIRGINIA COAL SUPPLY

VEPCO has stated in documents filed with the Virginia State Corporations Commission that the VCHEC uses CFB technology because there are limited supplies of low ash ROM coal or washed coal in Southwest Virginia and that Virginia's electric restructuring statutes require the use of ROM high ash coal and coal waste. VEPCO reinforced this position in a February 19, 2008 letter from Dominion to the Virginia DEQ[8], which states:

> *"…..…Va. Code § 56.585.1.A.6. finds such use of Virginia coal to be in the public interest. Thus consideration of alternatives to Virginia coal would be contrary to the General Assembly's clear intent. That leaves the question of fuel cleaning or coal washing. Such an alternative is also at odds with one of the goals of the project -- to consume waste coal so it does not pose an environmental risk. Waste coal is produced by fuel cleaning and preparation. It would be irrational to produce waste coal by fuel cleaning and then clean the waste coal. Moreover, there are no alternatives to CFB for burning waste coal. It would also be irrational to shun CFB technology that can eliminate the environmental risk of waste coal in favor of IGCC technology that would require greater amounts of coal washing resulting in still greater waste coal and its attendant risks."*

If one of the goals of the VCHEC is to process waste coal, VEPCO does not explain why the plant is designed to process only limited amounts of waste coal. ROM coal is not waste coal. It can be washed to create cleaner coal for use in conventional and IGCC power plants.

The enabling Virginia legislation (SB1416 and HB 3068) states:

> *"A utility may also apply a rate adjustment clause for recovery from customers of the costs of (i) a coal-fired generation facility that utilizes*

[8] Letter from Pamela Faggert, Vice President and Chief Environmental Officer, Dominion, to David Pryor, Director, Virginia Department of Environmental Quality, February 19, 2008.

Virginia coal and is located in the coalfield region of the Commonwealth, (ii) one or more other generation facilities, or (iii) one or more major unit modifications of generation facilities, to meet the utility's projected native load obligations. The utility may recover an enhanced rate of return on common equity associated with the type of project, which may include projects utilizing nuclear power, renewable technologies, carbon capture facilities, combined cycle combustion turbines, and conventional coal facilities."

Based on this language, it does not appear that the Virginia statute requires the use of biomass or coal waste to qualify for the enhanced rate of return. The primary requirement is the use of Virginia coal. Although the statute does not mention "clean coal" technology or IGCC, it does not preclude the use of advanced cleaner coal technologies.

VEPCO states in its filings with the Virginia SCC that higher quality bituminous coal may not available in the Southwest Virginia region. They suggest that only ROM, (unwashed coal) is available. Although unwashed coal will cost less than washed coal, the cost of processing high ash (40 to 50% ash) ROM coal in a CFB plant will add to the cost of electricity and would likely negate any cost advantages of using high ash coals. (Note: most waste coal CFB plants process 100% waste coal and have been financed with "solid waste" tax exempt bonds. This lower cost financing with lower cost fuel supply gives CFB technology an economic advantage over its alternatives. However, the VCHEC is not designed for 100% waste coal and would not qualify for solid waste financing.)

Most bituminous coals in the region are low ash or washed to reduce the ash and sulfur content. A report issued by the Virginia Department of Mines, Minerals and Energy[9] provides detailed data on about forty coal deposits in Southwest

[9] "Coal Sample Analyses from Southwest Virginia Coalfield", Virginia Division of Mineral Resources Publication 122, Virginia Department of Mines, Minerals and Energy, Division of Mineral Resources, Charlottesville, VA 1992

Virginia, the location of the proposed VCHEC plant. Although little data is provided on reserves and production, almost all of the coals described in this report are low ash, low sulfur coals. Many of the coals are high swelling index coals that might be valuable for metallurgical markets. These coals would require special washing to meet metallurgical specifications. Most Virginia coals listed in the report are high in pyritic and sulfate sulfur and appear to be well suited for coal washing to reduce sulfur and ash content. In fact, there are many coal washing plants in Virginia operating today. According to the U.S. Department of Labor, Mine Safety and Health Administration ("MSHA"), there are 46 coal preparation plants in Virginia[10]. 32 of these plants are operating today and 15 of them are in Wise County where the VEPCO VCHEC is to be located. Eight of the Wise Co. coal preparation plants have been constructed in the past 8 years. In a subsequent communication from the MSHA, they provided a list of existing coal preparation plants in Virginia and the daily average production of these coal processing plants.[11] These data show that the capacity of the Virginia fleet of coal prep plants is about 88,000 tons/day or 30 million tons per year. In it's response to Mr. Shepherd's presentation to the VA DEQ[12], VEPCO reports that Virginia coal production is about 30 mm tons per year. However, they also assert that an IGCC plant would run out of Virginia coal in 26 years.

In VEPCO's response to Shepherd, they provide Virginia reserves data from Virginia Tech (Westman) and an attached report from Miltech Energy. VEPCO appears to agree with Shepherd that the coal now being produced in Virginia from

[10] Letter from Ray McKinney, District Manager (Norton, VA), U.S. Department of Labor, Mine Safety and Health Administration to National Parks Conservation Association, February 28, 2008.

[11] Mine Access Database Datasheets from Ray McKinney, District Manager (Norton, VA), U.S. Department of Labor, Mine Safety and Health Administration to National Parks Conservation Association, March 10, 2008.

[12] Attachment 3 "Questions and Answers on Coal Quality and Availability", VEPCO response to Shepherd's presentation to the Virginia DEQ, undated.

both underground and surface mines ranges from about 11,800 to 12,900 btu/lb with ash content between about 9 to 17%. This data is consistent with the coal assays contained in the aforementioned Virginia DMR Report 122. These high Btu, low ash coals also appear to be processed coals and VEPCO seems to agree in its response to Shepherd.

VEPCO's sources indicate that the total reserves of Virginia coal vary from 273 million tons (recoverable reserves at producing mines) to 1349 million tons (mineable reserves). A 630 Mw IGCC plant will require about 1.8 million tons of coal (the high btu processed coal now being produced in Virginia is an excellent coal for an IGCC plant). Therefore, it appears that Virginia has adequate coal reserves for about 150 to over 700 years supply for a typical IGCC plant. In addition, the IGCC plant would consume only about 6% of the current supply of processed coal from coal preparation plants in Virginia.

VEPCO makes a unusual argument that the VCHEC plant will stimulate mining of ROM coal in Virginia. Since the CFB technology is best suited for high ash (40% or more), VEPCO reasons that the VCHEC project will stimulate production of this high ash coal. VEPCO does not provide any information on current production of the fuel it needs for at least 80% of the fuel requirements of the VCHEC project. In its response to Shepherd, it states that the VCHEC will require coal "not currently being mined in Virginia". VEPCO cites the Alpha Natural Resources deposits of an example of how ROM coal reserves will become economically recovered if the VCHEC project is constructed. VEPCO estimates that 20 million tons of Alpha's reserves would be proven if a market for ROM coal is created by VCHEC. Considering the high rate of consumption of ROM coal needed by VCHEC, the projected new reserves at Alpha would provide only a 6 year supply of coal to VCHEC. Over the 55 year projected life of the project, the VCHEC project will require about 175 mm tons of ROM coal. Developing a mine to produce this volume of ROM coal for a single customer will require third party investment in mine plant and reserves development. VEPCO has provided no information on why they believe the Virginia mining industry will make the required investment to provide this low

quality coal at a reasonable price for the life of the VCHEC project. However, the data appear to support Shepherd's position that the existing coal mining and processing industry in Virginia can supply the coal required to operate an IGCC plant for its life.

VEPCO also states that they may process limited amounts of coal waste from local washing plants or retrieve coal waste from existing waste piles. Since there are 15 coal washing plants now operating in Wise Co., it appears that significant volumes of coal waste are produced in the region. However, the VCHEC can process only limited amounts of waste coal and VEPCO does not appear committed to processing even small amounts of this material.

From our reading of the Virginia statutes and coal databases, it does not appear that a CFB technology based project using high ash ROM coal or coal waste is the only choice for a "clean coal" power plant using Virginia coals. An IGCC project would find a ready supply of suitable coal from existing Virginia coal producing facilities and would qualify for the enhanced rate of return as defined by Virginia statute. An IGCC facility would be a much "cleaner" plant, be carbon capture compatible and produce power for a lower price. Appalachian Power (AEP) appears to agree as they have applied to the Virginia SCC for a certificate to build an IGCC plant located in West Virginia with some power flowing to Virginia. On March 7, the West Virginia Public Service Commission approved APC's certificate of convenience and need for this IGCC project.

10. WATER USAGE

VEPCO states that there are limited supplies of water to operate a SCPC or IGCC plant with conventional wet cooling. To address this problem, VEPCO proposes to use dry or air cooling at the VCHEC. The use of dry cooling reduces plant efficiency and increases the emissions of criteria pollutants and GHG emissions

per unit of useful output. In the aforementioned testimony of AEP's Michael Rencheck, he discusses fuel flexibility and water usage of an IGCC plant. He stated:

> *"Finally, the IGCC process requires about one-third less water than a pulverized coal plant, generates less solid waste than a conventional coal plant; and enjoys greater fuel flexibility than conventional coal plants. IGCC plants can utilize a broad range of fuels, including coal from the North Appalachian and Central Appalachian basins, biomass and petcoke. Polygeneration options for IGCC technology can allow the facility to expand into future applications for coal use by producing feed stock for chemicals, fuels and other products. A typical pulverized coal plant cannot produce this option."*

A major report from the US Department of Energy examined the relative performance of IGCC and SCPC operating on bituminous coals[13]. The data of water usage in this report is consistent with the statements from AEP's Mr. Rencheck. In addition, it shows the dramatic impact on water consumption for a SCPC plant employing carbon capture technologies. Table 3 below contains our summary of the DOE reported data on raw water consumption for SCPC and IGCC technologies.

Table 3

Raw water, gal/mwhr	SCPC	IGCC	% change
no Carbon Capture	594	365	-39%
with Carbon Capture	1,336	501	-63%
% change	125%	37%	

The IGCC raw water consumption data are the average of the performance of three technologies (GE, ConocoPhillips and Shell). We normalized the data to show

[13] U.S. Department of Energy National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants, DOE/NETL-2007/1281, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report, May 2007, available at http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf.

the water consumption data in gallons per Mw-hour. The SCPC plant consumes more water than IGCC due to the high water needs of the wet scrubbing system. Without carbon capture the IGCC technologies consume about 39% less water.

When carbon capture is added to the SCPC plant, the water consumption rises 125%. However, carbon capture adds only 37% to the water use for the IGCC plants. The enormous increase in water demand for SCPC plant with carbon capture is due mostly to the large cooling loads required by the post-combustion CO_2 scrubbing system. When comparing IGCC with SCPC with carbon capture, the water use by the IGCC technology is 63% less.

Data is not available for the VCHEC CFB plant. However, the application of the same post-combustion scrubbing technology would have a similar effect. If water supply is limited in Southwest Virginia, then building an SCPC or CFB plant in that area would make these technologies even less "Carbon Capture Compatible" than an IGCC plant.

An SCPC plant in the same location as the VCHEC plant would require wet scrubbing and consume more water as stated above. However, an IGCC plant would require about one-third less water. If the water could not be supplied, then the IGCC plant could be air cooled using the same methods proposed by VEPCO. If carbon capture is added, then the IGCC plant would clearly have the lowest water consumption. Although we have not made the calculations, the IGCC plant with the use with dry cooling and carbon capture would be expected to be the lowest water consuming coal to de-carbonized coal to power plant possible.

11. GREENHOUSE GAS EMISSIONS

Numerous bills have been introduced in Congress proposing to limit the emissions of GHGs. Two of the leading bills are the Lieberman Warner bill and the Bingaman and Domenici bill. There is wide agreement that all major GHGs need to be included in any climate change gases, including carbon dioxide, methane and

nitrous oxide. There also appears to a broad consensus that climate change legislation is coming soon. However, the timing of when Congress will pass a bill and the President sign it is not known.

Greenhouse Gases (GHG) have been identified by the U.S. Environmental Protection Agency (EPA) and the Intergovernmental Panel on Climate Change (IPCC). Both organizations have established Global Warming Potential (GWP) factors for GHGs[14]. The three gases that are produced in the largest volumes from combustion of fossil fuels are carbon dioxide (CO_2), methane, and nitrous oxide (N_2O). EPA reports that N_2O has a GWP factor of 310, which means that one pound of N_2O emissions is equivalent to 310 lbs of CO_2 emissions.

A principal advantage of a CFB is the lower amount of fixation of nitrogen due to its lower operating temperature. However, it is widely understood that CFB boilers produce more N_2O than pulverized coal boilers. Formation of N_2O is favored at the lower temperature combustion conditions in a CFB. A PC boiler operates at much higher temperatures at which formation of nitrogen dioxide (NO_2) is favored. During the coal combustion process, fuel bound chemical nitrogen is a major source of nitrogen oxide gases, including NO_2 and N_2O. Nitrogen oxides are also formed from fixation of the nitrogen in the combustion air. A unique feature of a CFB is that the fuel bound nitrogen is preferentially converted to N_2O, a powerful climate change gas. NO_2 is not considered a climate change gas.

The gasification step in an IGCC plant operates at reducing conditions (absence of oxygen) under which no nitrogen oxides can be formed. All of the fuel bound nitrogen in the coal is converted to ammonia which is either sold as a chemical byproduct or converted back to harmless nitrogen. The combined cycle power block in an IGCC plant burns clean fuel gas with air. This process occurs at high temperatures at which no significant amount of N_2O is produced.

[14] http://www.epa.gov/nonco2/econ-inv/table.html

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories provides data for estimating N_2O emissions from various coal combustion technologies[15]. Table 2.6 in the Guidelines (Utility Source Emission Factors) recommends using an emission factor for N_2O of 61 kg/TJ for circulating fluid bed boilers compared to 0.5 to 1.3 kg/TJ for PC boilers.

IPCC recommends, in Table 1.4 in the IPCC Guidelines, a default CO_2 emission factor for bituminous coal fired PC Boilers of 94,600 kg/TJ[16]. Using these guidelines to estimate the impact of nitrous oxide emissions, the VCHEC CFB project is estimated to produce N_2O emission equal to 310 times 61 or 18,910 kg/TJ of GHG equivalent CO_2 emissions. This suggests that the VCHEC CFB project will produce about 20% more global warming gases than a similarly sized PC coal plant with the same heat rate. Since the CFB project operates on unwashed coal with air cooling, it's heat rate is 10,800 btu/kwhr (according to the VEPCO PSD application) compared to about 8,900 btu/kwhr for a typical supercritical PC plant or IGCC plant operating on washed coal. So the VEPCO CFB plant has a heat rate about 20% higher which means it processes 20% more coal fuel value to produce the same power as a SCPC plant. This suggests that the CO_2 emissions from the VEPCO CFB project will produce about 20% more CO_2 gases per unit of power output. If the CFB plant produces N_2O at the rate estimated by the IPCC Guidelines, the total GHG emissions per unit of power output (CO_2 and N_2O measured as equivalent units of CO_2) could be about 46% higher than a bituminous coal-fired SCPC or IGCC plant.

Although CO_2 and other GHGs such as N_2O are not currently regulated, such regulations are widely expected to be enacted soon and these regulations could have a large impact on the VEPCO CFB project. SCPC Boiler and CFB projects that will operate for 40 to 50 years will likely be impacted by a tax on GHGs or a cap and trade system that requires offsetting GHG emissions or installing equipment to

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[15] http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf

[16] *Id.*

mitigate the emission of such gases. As discussed elsewhere in this report, the cost of capturing carbon from a SCPC or CFB plant will be much more expensive than an IGCC plant. Since N_2O is a recognized GHG by the EPA and the IPCC, a CFB plant like the VCHEC will likely incur even higher costs to mitigate or offset N_2O emissions. In VEPCO's PSD application, the company claims to leave space to add carbon capture equipment in the future. VEPCO does not discuss N_2O emissions or whether the technology exists to mitigate N_2O emissions.

The limited amount of information we could find in the literature suggests that the CFB suppliers are aware of this problem and are working on staged combustion and boiler modifications to reduce N_2O emissions. However, we were unable to confirm if this technology is effective, commercially proven, or available with warranties on the same terms NO_x and SO_x are guaranteed. Based on this limited information, we would be concerned that building a CFB plant would take on unknown risks of CO_2 and N_2O regulations and control technologies in the future.

12. CONCLUSIONS

Based on the information contained in the documents filed by VEPCO with the VA DEQ and the VA SCC, and information from the literature cited in this report, we would offer the following conclusions:

- The VCHEC CFB project produces significantly more air emissions and solid waste and than alternative SCPC and IGCC technologies.
- Based on extensive BACT analysis and reviews of numerous recent IGCC and SCPC projects, IGCC technology produces significantly lower air and solid waste emissions than similarly sized SCPC plants.
- Based on published data for the VCHEC CFB project and alternative SCPC and IGCC technologies, the VCHEC project will produce significantly more greenhouse gases (CO_2 and N_2O) per kwhr of power. As a result, the cost of future carbon mitigation from the VCHEC CFB

project will be more expensive than for a SCPC plant and much more expensive than for an IGCC plant.

- An IGCC plant would produce electricity at a cost equal to or lower than VCHEC CFB project assuming reasonable levels of reliability (without consideration of carbon capture costs).
- If the cost of carbon capture is factored in and currently available commercial technology is considered, an IGCC plant will have a significantly lower cost of electricity than a CFB or SCPC power plant.
- Based on information from the Virginia Department of Mineral Resources, and data provided by VEPCO in the DEQ hearings, it appears that there numerous deposits of high quality, low ash coal deposits in Southwest Virginia which are suitable for feeding an IGCC power plant thus negating the need to use CFB technology for ROM coals. Data from the US Department of Labor Mine Safety and Health Administration indicates that there are numerous coal washing plants in the region that could supply lower ash and sulfur coal for IGCC facilities. This existing infrastructure could supply a typical IGCC plant for 150 years and much longer as proven reserves are developed to meet the demand of clean coal plants.
- There appears to no existing infrastructure to supply the ROM coal required by the VCHEC project and VEPCO has not provided a business case for why the required infrastructure will be developed by the mining industry. Waste coal appears to be available in the region. However, the proposed VCHEC project can process only limited amounts of this material.
- IGCC and CFB power plants can be designed for a wide range of fuel flexibility. However, it appears that the VCHEC plant is designed only for limited use of waste coals and biomass.

- An IGCC plant uses 33 to 39% less water than a SCPC plant. If dry cooling is used, the more efficient IGCC plant will use less water than the VCHEC plant. If carbon capture is required, then the IGCC plant will use dramatically less water than the CFB plant. Since the cost of carbon capture for VCHEC is prohibitive, the technology for reducing nitrous oxide emissions is not known, and supply of the large amount of water needed for this feature is problematic, it seems likely that VEPCO will forced to buy large amounts of GHG offsets when climate change regulations are enacted. VEPCO does not appear to have estimated these liabilities in its forecast of the revenue requirements for the VCHEC project.

In summary, the results of our research indicates that the VCHEC CFB plant, when compared to the IGCC alternative, does not appear to be a "clean coal" plant, does not appear to "carbon capture compatible", has limited fuel flexibility, may not have an assured source of ROM coal at a reasonable price, will use much more water if carbon capture equipment is required, and will likely have to purchase large amounts of GHG offsets in the future, and will likely have the highest life cycle cost of electricity of any of the alternatives available to VEPCO today.

EXHIBIT DHC-1

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Qualifications and Experience:

Dr. Douglas Cortez has over 35 years experience in the electric power, petroleum refining, chemical production, and synthetic fuels industries. During his career, he has focused on the clean fuels, clean power and alternative and synthetic fuels energy industries. He has held leadership positions in the fields of technology research and development, project development, project financing, and engineering and construction.

Hensley Energy Consulting LLC

In early 2006, he formed Hensley Energy Consulting LLC, an independent technology and management consulting company specializing in providing professional services to the clean energy and electric power industries and financial and government institutions. He is currently an advisor to the FutureGen Industrial Alliance, the Carson Hydrogen Power Project (BP Alternate Energy) and an advisor to Excelsior Energy (Mesaba IGCC). Other active clients include private equity funds, utilities, private developers of alternative energy projects and non-government organizations active in power plant siting proceedings.

Fluor Corporation

From 1984 to 2005, he was an executive with Fluor Corporation, the nation's largest publicly held engineering and construction company. At Fluor, he was Vice President, responsible for project development, project finance, and technology development serving a wide range of clients, including regulated utilities, independent power companies, coal mining, petroleum refining, and technology licensing companies. He contributed to the development and deployment of hundreds of power, cogeneration and clean coal and alternative energy projects, including coal, coke and heavy oil gasification projects, coal to liquids, substitute natural gas, integrated gasification combined cycle (IGCC) and coal to chemicals projects. His experience also includes carbon capture technologies for reducing the production of climate change gases.
In the power sector, he was active in developing, designing and financing a wide range of projects for regulated utility and independent power companies, including IGCC and conventional pulverized coal plants, complex refinery polygeneration plants, coal to chemicals and synthetic fuels facilities.

During his years with Fluor, he was active in technology evaluation, project development and finance in North America, Latin America, the Caribbean, Asia and Europe.

Tosco Corporation

From 1973 to 1983, he was an executive with Tosco Corporation (now part of ConocoPhillips). He was responsible for developing, financing and constructing cogeneration facilities at Tosco refineries and EOR fields, development of Tosco technologies for coal and petroleum coke utilization, development and licensing of Tosco's shale oil production, coal processing and petroleum refining related technologies. He was also a member of the management team that completed the acquisition of refining and marketing assets, as well as private and public oil and gas, coal and oil shale properties.

Other Experience

From 1969 to 1973, he was employed by an independent engineering consulting company that specialized in petroleum refining and geothermal energy production. During that period, he developed and constructed geothermal power plants, and petroleum refinery projects. He also consulted with the Plan Organization in Iran and

developed the 10 year expansion plan for the NIOC refining and products distribution system.

Employment History:

2006- Present	Managing Partner, Hensley Energy Consulting, LLC
1984 - 2005	Vice President, Fluor Enterprises
1973 - 1984	General Manager, Tosco Corporation
1970 – 1973	Project Manager, Ben Holt Company
1969 – 1970	Research Engineer, TRW Systems

Education:

ScD	Chemical Engineering, Massachusetts Institute of Technology
MS	Chemical Engineering, Massachusetts Institute of Technology
BS	Chemical Engineering, University of California, Berkeley

Industry Participation:

American Institute of Chemical Engineers
Gasification Technologies Council (Industry Representative, Workshop Speaker, Communications Committee)
Coal Utilization Research Council (Industry Representative)
FutureGen Industrial Alliance – Technical Advisory Committee

Recent Expert Testimony:

The following testimony addressed only technology and economic issues in coal power plant cases where gasification combined cycle technology is being considered. HEC does not advocate a public utility policy position.

1. On behalf of Wisconsin Energy, Public Service Commission of Wisconsin Docket No. 05-CE-130.
2. On behalf of Wisconsin Energy, Wisconsin Electric Power Permit 03-RV-166, Case No.IH-04-03, Wisconsin Division of Hearings and Appeals.
3. On behalf of Excelsior Energy, Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission, MPUC Docket No. E-6472-/M-05-1993, OAH Docket No. 12-2500-17260-2. (Phase 1 -2006)
4. On behalf of Environmental Defense, Southern Environmental Law Center, and Southern Alliance for Clean Energy, in the matter of Duke Power Co. LLC for approval

of an Electric Generation CPCN to construct two 800 Mw Coal Units for Cliffside Project, North Carolina Utilities Commission, Docket No. E-7, Sub. 790
5. On behalf of Clean Air Task Force And Indiana Wildlife Federation, in the matter of the Duke Energy Indiana for approval of Edwardsport IGCC project, before the Indiana Utility Regulatory Commission, Cause No. 43114.
6. On behalf of Environmental Defense, in the matter of Applications of TXU Generation Co. LP for State Air Quality Permits and PSD Permits, before the Texas State Office of Administrative Hearings, SOAH Docket No. 582-07-0614.
7. On behalf of Excelsior Energy, Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission, OAH Docket No. 4-2500-17260-2, MPUC Docket No. E-6472/M-05-1993, In the Matter of a Petition by Excelsior Inc. for Approval of a Power Purchase Agreement under Minn. Stat. § 216B.1694, Determination of Least Cost Technology and Establishment of a Clean Energy Technology Minimum Under Minn. Stat. § 216B.1693. (Exhibit DHC1, Phase 2 – 2007)
8. On behalf of the Southern Environmental Law Center, in the matter of the Application of Virginia Electric and Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate an Electric Generation Facility in Wise County, VA, before the Virginia State Corporation Commission, Case No. PUE-2007-00066

EXHIBIT DC-2

Summary of BACT Determinations for Recent Supercritical Pulverized Coal Power Plants using Bituminous Coals

Ref A	Utility or IPP	Plant Name	State	Capacity (MW)	PM (total) lb/MMBtu	PM (total) lb/Mwh	SO2 lb/MMBtu	SO2 lb/Mwh	Nox lb/MMBtu	Nox lb/Mwh	CO lb/MMBtu	CO lb/Mwh	VOC lb/MMBtu	VOC lb/Mwh	Hg lb/TBtu	Hg lb/Gwh
3	Louisville Gas & Electric Co.	Trimble County Generating Station	KY	750	0.018	0.167	0.018	0.167	0.080	0.740	0.100	0.926	0.0032	0.030	1.40	0.013
2	Thoroughbred Generating Company, LLC	Thoroughbred Generating Station	KY	1500	0.018	0.179	0.018	0.179	0.080	0.794	0.100	0.993	0.0072	0.071	3.21	0.032
8	Santee Cooper	Santee Cooper Generating Station	SC	1320	0.015	0.130	0.015	0.130	0.080	0.691	0.160	1.382	0.0024	0.021	3.60	0.031
5	Wisconsin Energy	Elm Road Generating	WI	1230	0.018	0.159	0.018	0.159	0.070	0.617	0.120	1.058	0.0035	0.031	1.12	0.010
1	Longview Power, LLC	Longview Power Station	WV	695	0.018	0.158	0.018	0.158	0.080	0.704	0.110	0.968	0.0040	0.035	2.65	0.023
4	Peabody Energy	Prairie State Energy Center	IL	1620	0.018	0.166	0.018	0.166	0.070	0.644	0.120	1.104	0.0040	0.037	NA	NA
7	Duke North Carolina	Cliffside	NC	800	0.018	0.177	0.018	0.177	0.070	0.687	0.120	1.178	0.0040	0.039	2.04	0.020
		Median Emission Rate			0.018	0.166	0.018	0.166	0.080	0.691	0.120	1.058	0.004	0.035	2.343	0.022
		Minimum Emission Rate			0.015	0.130	0.015	0.130	0.070	0.617	0.100	0.926	0.002	0.021	1.120	0.010
6	Dominion VP CFB	SW VA Hybrid Energy Center	VA	585	0.012	0.13	0.12	1.30	0.07	0.76	0.15	1.62	0.0050	0.054	1.45	0.016
		% VCHEC to Median SCPC			-33%	-22%	567%	683%	-13%	9%	25%	53%	25%	53%	-38%	-28%
		% VCHEC to Min SCPC			-20%	0%	700%	900%	0%	23%	50%	75%	108%	161%	29%	58%

1 Permit to Construct an Electrical Power Generation Plant , West Virginia Department of Environmental Protection, Permit No. R14-0024, March 1, 2004.

Title V Air Quality Permit , Commmonwealth of Kentucky, Dept of Environmental Protection, Permit No. V-02-001 (Rev. 1), December 6, 2002.

2 http://www.air.ky.gov/permitting/Thoroughbred+Generating+Station+Company+LLC.htm, DEQ Data: http://www.air.ky.gov/permitting/Louisville+Gas+and+Electric+Co.htm

3 Website: www.epa.gov/ttn/catc/dir1/natlcoal.xls , U.S. Environmental Protection Agency, Technology Transfer Network, August 10, 2004.

4 Construction Permit - PSD Approval , Illinois Environmental Protection Agency, Application No. 01100065, January 14, 2005.

5 Air Pollution Control Construction Permit , State of Wisconsin, Department of Natural Resources, Permit No. 03-RV-166, January 14, 2004, HR from Draft EIS 2003

6 PSD Permit Application for the Proposed Virginia City Hybrid Energy Center in Southwestern Virginia June 2006 Updated August 10, 2007, Virginia Dept of Environmental Quality

7 http://daq.state.nc.us/permits/psd/cliffside.shtml

8 PSD Application Santee Cooper Pee Dee South Carolina Vol 1 May 2006

A Emission Rates per KwHr computed by HEC using published system performance data

EXHIBIT DHC-3

Summary of BACT Determinations for Recent IGCC Coal Power Plants using Bituminous Coals

Ref	Note F	Power Project Name	State	Status	Coal Type	Technology	MW	HG lb/Tbtu	HG lb/Gwh	CO lb/MMBtu	CO lb/Mwh	NOx lb/MMBtu	NOx lb/Mwh	SO2 lb/MMBtu	SO2 lb/Mwh	PM lb/MMBtu	PM lb/Mwh	VOC lb/MMBtu	VOC lb/Mwh
1	A	Wabash River	IN	Operating, On-Line 1995	Illinois	E-Gas	262			0.036		0.087		0.080		0.005		0.001	
1		Polk Power Station	FL	Operating, On-Line 1996	Eastern Bit	GE Energy	260			0.045		0.101		0.170		0.008		0.001	
1		Kentucky Pioneer	KY	Permit Issued 2003	Eastern Bit	E-Gas	540			0.026	0.212	0.059	0.482	0.026	0.212	0.009	0.074	0.004	0.033
1		We Energies - IGCC	WI	Permit Issued 2004	Eastern Bit	GE Energy	600	0.56	0.00	**0.024**	**0.201**	0.059	0.495	0.023	0.193	0.008	0.067	0.003	0.025
1		Steelhead Energy Center	IL	Permit Filed 2004	Illinois	E-Gas	544			0.040	0.360	0.059	0.531	0.033	0.297	0.009	0.083	0.003	0.026
	D	Taylorville Energy Center	IL	Permit Issued 2008	Illinois	GE Energy	630	20.00	0.19	0.042	0.378	0.030	0.273	0.018	0.158	0.017	0.154	0.001	0.012
1	B	PMEC IGCC (Energy NW)	WA	Permit Filed 2006	PRB	E-Gas	600	1.20	0.01	0.036	0.331	**0.012**	**0.110**	0.016	0.147	0.001	0.009	0.003	0.028
2		Mesaba I and II IGCC	MN	Permit Filed 2006	PRB	E-Gas	606	0.50	0.00	0.035	0.311	0.057	0.514	0.025	0.225	0.009	0.081	0.003	0.029
		Mountaineer&MeigsCo IGCC	WV	Permits Filed Sept 2006	Eastern Bit	GE Energy	629	2.10	0.02	0.080	0.763	0.050	0.477	**0.007**	**0.067**	0.008	0.072	0.005	0.048
4		Neuces IGCC Plant	TX	Permit Filed 2007	PRB Coke	Shell				0.040		0.019		0.019		0.014		0.004	
		Stanton Energy Center-Unit B	FL	Permit Issued 2007	PRB	TRIG	285	1.19	0.01	0.038	0.318	0.077	0.318	0.015	0.125			0.003	0.028
5	C	Duke Edwardsport	IN	Permit Issued 2008	Indiana	GE Energy	630	**0.29**	**0.003**	0.044	0.395	**0.027**	0.243	0.014	0.126	0.002	0.018	0.002	0.018
	E	Lowest IGCC Emission Rate						0.290	0.003	0.024	0.201	0.012	0.110	0.014	0.126	0.001	0.009	0.001	0.012
		Median New IGCC Applications						1.189	0.010	0.039	0.331	0.054	0.477	0.018	0.158	0.009	0.073	0.003	0.028
3		VCHEC CFB Project	VA	Permit Filed 2007	ROM Coal	CFB	585 Mw	1.45	0.02	0.150	1.620	0.070	0.756	0.120	1.296	0.012	0.130	0.005	0.054
		Ratio VCHEC to Median IGCC						1.22	1.56	3.85	4.89	1.31	1.59	6.57	8.21	1.33	1.79	1.61	1.96
		Ratio of VCHEC to Minimum IGCC						4.99	6.00	6.25	8.04	5.83	6.85	8.57	10.30	12.00	14.09	5.00	4.46

Notes:
- A SO2 adjusted to reflect published operating data
- B Pacific Mountain Energy Center includes SCR for NOX Controls
- C Excludes Startup/Shutdown, other intermittant. Steady State Operations
- D Includes Startup/Shutdown, Calc'd by HEC using final Permit Data
- E For Sox, only high sulfur coal and coal projects considered for minimum emission rate
- F Emission Rates per KwHr computed by HEC using published system performance data

Ref:
- 1 Pacific Mountain Energy Center, Application for Site Certification Agreement Appendix B
  Washington Energy Facility Site Evaluation Council, Application 2006-01, September 12, 2006
- 2 Mesaba Energy Project Mesaba I and II. June 16, 2006
  Application to the Minnesota Pollution Control Agency for a NSR Construction Authorization Permit
- 3 PSD Application, Dominion Resources, Virginia Dept of Environmental Quality , August, 2007
- 4 Application for a TCEQ Flexible Air Quality Permit, Nueces County, Texas,Nueces Syngas LLC
- 5 PSD Application, Duke Indiana, Indiana Dept of Environmental Management, August 2006

EXHIBIT DHC-4

List of Referenced Reports

Studies of SCPC and IGCC with and without Carbon Capture

1. Parsons Energy and Chemicals, on behalf of U.S. Dep't of Energy, Nat'l Energy Tech. Lab., "Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal," (2002) (*as reported in* Reference 9).
2. J. Klara, U.S. Dept. of Energy, Nat'l Energy Tech. Lab., "IGCC: Coal's Pathway to the Future," Gasification Tech. Council Annual Meeting, Washington D.C. (Oct. 2-4, 2006).
3. U.S. Department of Energy National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants, DOE/NETL-2007/1281, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report, May 2007, available at http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf.
4. Massachusetts Institute of Technology, The Future of Coal: Options for a Carbon-Constrained World, March 2007, available at http://web.mit.edu/coal/The_Future_of_Coal.pdf.
5. Integrated Environmental Control Model (IECM) US DOE/NETL and Carnegie Mellon. Website: http://www.iecm-online.com/