Mountaineer Plant CCS Project and the Role of Environmental and Financial Regulation: The US Coal-Fired Fleet is Transitioning and Needs Economical CCS Technology

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IEA WPFF – MOST CCUS Workshop:
Joint Activities and Opportunities
September 19, 2011
Beijing, China
American Electric Power

One of the largest U.S. electricity generators

The largest U.S. electricity transmitter

One of the largest U.S. electricity distributors

Serving electric customers in 11 states

<table>
<thead>
<tr>
<th>Generation owned(^1) (GW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Southern Co</td>
</tr>
<tr>
<td>NextEra Energy</td>
</tr>
<tr>
<td>AEP</td>
</tr>
<tr>
<td>Duke Energy</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Transmission miles(^1) ('000s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
</tr>
<tr>
<td>Southern Co</td>
</tr>
<tr>
<td>Duke Energy</td>
</tr>
<tr>
<td>First Energy</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Electric customers(^1) (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>First Energy</td>
</tr>
<tr>
<td>Exelon</td>
</tr>
<tr>
<td>AEP</td>
</tr>
<tr>
<td>Pacific Gas &amp; Electric</td>
</tr>
</tbody>
</table>
$7.2 billion capital invested from 1990-2010 to reduce emissions approximately 1.7 million tons

Estimated $6-$8 billion additional capital investment from 2012-2020 for further reductions of approximately 440,000 tons
AEP’s Mountaineer Project: A Look Into The Future of Coal-Fired Generation

Characterization...
Simulation...
Validation...
AEP CCS Validation Facility
1,300 MWe Mountaineer Plant, New Haven, WV

- **Scale:** 20 MWe slipstream
  - ~1.5% of power plant flue gas

- **Cost:** >$100M
  - Project initiated in September 2007
  - Funding by AEP, Alstom, RWE, & EPRI

- **Capture:** Alstom Chilled Ammonia Process
  - Ammonium Carbonate/Bicarbonate Reaction
  - >85% CO₂ capture rate

- **Sequestration:** Deep saline formation storage
  - ~100,000 tons CO₂ per year
  - ~1.5 miles below the plant surface

- **First CO₂ Capture:** September 1, 2009
- **First CO₂ Storage:** October 1, 2009
- **Planned operation:** 1 to 5 years
AEP CCS Commercialization Project on Hold
1,300 MWe Mountaineer Plant, New Haven, WV

- **Scale:** Full commercial demonstration
  - 235 MWe Slipstream

- **Cost:** ~$668M

- **Funding:** CCPI Round III Selection
  - DOE awarded 50% cost share, up to $334M
  - Cooperative agreement signed in January, 2010

- **Capture:** Alstom Chilled Ammonia Process
  - ~90% CO₂ capture rate

- **Sequestration:** Battelle is Storage Contractor
  - Deep saline reservoirs
  - ~1,500,000 tons CO₂ per year
  - ~1.5 miles below the surface
  - Pipeline system with off-site wellheads

- **NEPA Process Underway**

- **Geologic Experts Advisory Group:** Actively Meeting
  - Battelle, CONSOL, RWE, MIT, Univ. of Texas, Ohio State, WVU, Virginia Tech, LLNL, WV Geo. Survey, OH Geo. Survey, WV DOE, NETL, & CATF

- **Planned Operation:** Startup in second half of 2015
Validation Facility Results
October 2009 - May 2011

- ~6,500 hours operation
- ~50,000 metric tons captured
- ~37,000 metric tons stored
- Process availability approaching 100%
  - Both capture and storage
- >90% CO₂ capture rate
Near Term Environmental Regulations and Deadlines Before CO₂ Emission Reductions are Required

- Cross State Air Pollution Rule (CSAPR): Sets state-specific SO₂ and NOx limits in two phases (2012 & 2014)
- Final Rule Issued July 7, 2011
- Assumed Rule Finalization Nov 2011
- Assumed Rule Finalization Nov
- Assumed Rule Finalization Mid 2012

- Hazardous Air Pollutants (HAPS)
- Regional Haze
- Establishes SO₂ and NOx limits for Oklahoma and Arkansas
- Sets:
  - HCl limit at 0.002 lb/mmBTU
  - PM limit at 0.030 lb/mmBTU
  - Hg limit at 1.2 lb/MMBTU

- Coal Combustion Residual (CCR)
- Requires lined wet ash ponds and/or conversion to dry ash handling
- - Impingement requirements (2020)
- - Entrainment requirements (varies)

- Water (316b)
- Assumed Rule Finalization Mid 2012

* Units that will be retrofit are eligible for a one year compliance extension from the EPA

AEP
AMERICAN ELECTRIC POWER
To meet compliance deadlines for new environmental regulations, AEP expects it will need to invest $6 billion to $8 billion to:

- Retire nearly 6,000 MW of existing coal-fired generation by Dec. 31, 2014.
- Refuel, retrofit with new or upgrade existing environmental controls on another 11,000 MW.*see appendix
- Temporarily (1 – 4 years) idle / curtail 1,500 MW – 5,200 MW.
- Build approximately 1,700 MW of new generation, mostly natural gas.

This will create:

- Abrupt rate increases ranging from 10% to 35%.
- Significant reliability concerns, particularly in the 2014 – 2016 time frame.
- The need to install additional equipment to address impacts on the transmission system due to the reduction in generating capacity.
- Net loss of 600 Jobs
- Annual lost wages of $40 million
- $20 million decline in payroll taxes
- $12 million decline in property tax payments
A Phased-in Approach Will Arrive at the Same Destination

AEP Plant NOx and SO2 Emissions

- 80.5% reduction in total NOx & SO2 emissions at a cost of approximately $7 billion
- Approximately 15.5% further reduction in emissions at a cost of $6-8 billion
Main reasons are uncertain status of climate policy, weak US and State economy

As a financially regulated utility, impossible to gain regulatory approval to recover our share of costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions are already in place.

Uncertainty also makes it difficult to attract partners to help fund the industry’s share.

Commercialization vital to comply with future CO2 regulations without prematurely retiring efficient cost-effective generating capacity.

AEP will continue to be engaged in an advisory role in engineering CCS technology development and active in developing enabling public policies for development and commercial deployment.
Appendix

Containing

Background and Detail Slides

(Not showing on screen)
The United States relies on Coal for almost 50% of the Electricity Generated in the Nation

Transition Concerns

- Implementation Schedule
- Electric System Reliability
- Costs and Job Losses
- Labor Availability
- Retirement Decisions
- Equipment Availability
- Natural Gas Infrastructure and Deliverability
Mercury and HAPs MACT

- Proposed rule issued in March 2011, comment period extended to Aug. 4

- Final HAP regulations must be issued by November 2011
  - Maximum Achievable Control Technology (MACT) standards for Hg, other metals and acid gases, with combustion practices for organics

- Compliance Required 3 Yrs. After Final Rule, EPA could grant a 1 year extension

- Very little flexibility in the proposal; opportunity to average across a plant and limited sub-categorization

- MACT could require FGD or DSI for acid gases and/or baghouses with activated carbon injection for Hg and metals.
Coal Ash (CCR) Rules

- Proposed coal ash disposal rules issued in May 2010; final rule expected mid-2012

- **EPA proposed two different regulatory designations:**
  - “Non-hazardous”, solid waste - action required by ~2017
  - “Special” hazardous waste - action required by ~2018-2020

- **AEP supports Subtitle D Prime Option of RCRA (solid waste NOT hazardous)**

- **AEP capital cost of ~$4 billion for solid waste option**

- “Hazardous” option could cost DOUBLE this amount
316(b) Proposal

- **EPA issued proposal March 28, comment period extended to Aug 19; final rule expected mid-2012**

- Addresses impingement and entrainment of aquatic species

- **Proposes upgraded intake screens for impingement**

- Suggests cooling towers as an effective technology for entrainment, but defers the decision until a site-specific study is conducted

- **Cost impact very uncertain at this time**
AEP Emissions/Retrofit Facts

- AEP built nine scrubbers between 2003 and 2010 retrofitting approx. 8,000 MWs of coal generating capacity.

- In 2007, AEP had the 2nd largest construction effort in the US when labor peaked at 8,500 craft workers.

- SO$_2$ and NOx emissions have been reduced by more than 80% since 1980.

- AEP’s mercury emissions were 36% lower in 2009 than in 2000, SO2 emissions were 63% lower than in 2000 and NOx emissions were 79% lower during this same timeframe.
Potential Impact of Proposed Rules

- Nearly 60% of AEP’s Coal Generating Capacity is expected to be impacted by the EPA’s proposed Clean Air Transport Rule (CATR) and Hazardous Air Pollutants (HAPs) Rule.
  - > 14,000 MWs, either retire/replace or retrofit

- The proposed Coal Combustion Residuals Rule (CCR) will impact 20,000 MWs of AEP’s Coal Generating Capacity.

- It is not possible to meet proposed deadlines for CATR and HAPs - estimated 25,000 peak craft workers (three times more than historical peak year) is needed for AEP construction requirements.

- The cost to meet the deadlines would more than double our costs-to-date for environmental retrofits.

- Safety, productivity, and quality of projects would suffer under such a tight schedule
Potential Impact of Proposed Rules

- Unit Retirements would be significant due to inability to meet schedules for retrofit/replacement. As of Sept. 2011, 34GW announced to be retired, Fed. Energy Reg. Comm. states up to 81GW (8% installed capacity) likely retired. This produces Grid reliability and stranded cost issues. See ERCOT and Southwest Power Pool July 19, 2011 statement and letter respectively, NARUC Resolution July 20, 2011.

- Cost recovery and Regional Transmission Organization (RTO) approval process would be extremely challenging and lengthy.

- Craft labor demands would produce a huge "boom-bust" cycle.

- Local economies would be impacted significantly.
  - Customer rates would see very sharp increases in deadline years
  - Internal labor, service support labor, and industrial customer labor would all see net reductions. (Charles River Associates estimates over 1,000,000 job reduction nationally)
There is a Better Way...

- More flexibility in regulations (e.g., HAPs emissions averaging, low capacity factor allowed during retrofit construction)
- Phase-in requirements over 2015-2020
- Allow off-ramp for units that commit to retire or repower through 2020
- Continues emission reduction progress starting today, but reduces capital cost, rate shock and other economic impacts
- All coal units “well controlled” by 2020
Legislation, not regulation, is a smarter approach

We need legislation from our elected representatives in Congress that balances economic growth, energy security, reliability and affordability and environmental protection by giving more time for pollution control retrofits and a fully integrated and coordinated emissions reduction program that efficiently uses the hard earned money of Americans.
Benefits of a phased-in approach

- Will provide the time utilities need to install environmental retrofits without idling or curtailing generating units.
- Will allow unit retirements to occur over a more reasonable timeframe needed to address grid reliability issues raised by ERCOT, Southwest Power Pool RTOs July 19, 2011 and NARUC July 20, 2011.
- Will support construction jobs over a longer period of time.
- Will provide long-term environmental benefits.
- Will give local communities time to plan for economic losses.
The tables below represent our estimated $6 - $8 billion capital investment from 2012 to 2020 for environmental retrofits on 10,500 MW and new/refueled generation of 2,152 MW. The below costs include management estimates for compliance with CATR, HAPs MACT, CCR and 316(b) regulations as currently proposed.

<table>
<thead>
<tr>
<th>Plant</th>
<th>MW</th>
<th>Type of retrofit</th>
<th>Low Cost Estimate 2012-2020 ($MM)</th>
<th>High Cost Estimate 2012-2020 ($MM)</th>
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</thead>
<tbody>
<tr>
<td>Conesville 5</td>
<td>400</td>
<td>SCR, DSI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conesville 6</td>
<td>400</td>
<td>SCR, DSI</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Muskingum River 5</td>
<td>510</td>
<td>Refuel with Natural Gas</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gavin 1</td>
<td>1320</td>
<td>FGD upgrade</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gavin 2</td>
<td>1320</td>
<td>FGD upgrade</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Zimmer 1</td>
<td>330</td>
<td>FGD upgrade</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Expected Cost</strong></td>
<td></td>
<td></td>
<td>2,100</td>
<td>2,800 *</td>
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<tr>
<td>Clinch River 1</td>
<td>211</td>
<td>Refuel with Natural Gas</td>
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<td></td>
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<tr>
<td>Clinch River 2</td>
<td>211</td>
<td>Refuel with Natural Gas</td>
<td></td>
<td></td>
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<tr>
<td>Dresden</td>
<td>580</td>
<td>New Natural Gas</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Expected Cost</strong></td>
<td></td>
<td></td>
<td>580</td>
<td>765 **</td>
</tr>
<tr>
<td>Rockport 1</td>
<td>1320</td>
<td>FGD, SCR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rockport 2</td>
<td>1320</td>
<td>FGD, SCR</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tanners Creek 4</td>
<td>500</td>
<td>DSI, ACI</td>
<td></td>
<td></td>
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<tr>
<td><strong>Total Expected Cost</strong></td>
<td></td>
<td></td>
<td>1,240</td>
<td>1,670 ***</td>
</tr>
<tr>
<td>Big Sandy 1</td>
<td>640</td>
<td>New Natural Gas</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total Expected Cost</strong></td>
<td></td>
<td></td>
<td>400</td>
<td>525</td>
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</table>

* Assumes regulatory cost recovery for environmental investments including refuel are non-bypassable surcharges as proposed in the 2012 - 2014 ESP

** Total capital invested is expected to be $366 million for the Dresden plant once completed; $343 million of which is forecasted to be spent prior to 2012.

*** Includes AEG portion of costs related to Rockport upgrade
Average KW Price for Coal Generation

The more coal used, the lower the consumers electric costs
**Principal factors driving energy costs**

- Household expenditures for gasoline have more than doubled since 2001.

- Increased gasoline costs account for nearly three-fourths of average household energy cost increases since 2001.

- The average household electric bill has increased from $938 in 2001 to an estimated $1,369 in 2011 (46%).
Impacts on senior citizens

Senior citizens also are vulnerable to energy price increases due to their relatively low incomes.

In 2009, the median gross income of 25 million senior households over 65 years was $31,354, some $19,000 below the national median income of $50,200.

Seniors have the highest per capita residential energy consumption among all age categories.
In 2009, Electric Generating Units (EGUs) Contributed Just 8% of Total Ozone Precursor Emissions in the Eastern U.S.

PERCENTAGE SHARE OF NOX EMISSIONS
Eastern United States, 2009

- 15% Electric generating units
- 32% Onroad vehicles
- 26% Offroad vehicles
- 13% Industrial fuel
- 5% Other fuel
- 8% Industrial processes
- 1% Miscellaneous

PERCENTAGE SHARE OF TOTAL NOX PLUS VOC EMISSIONS
Eastern United States, 2009

- 8% Electric generating units
- 26% Onroad vehicles
- 21% Offroad vehicles
- 7% Industrial fuel
- 7% Other fuel
- 29% Industrial processes
- 2% Miscellaneous

“The Nightmare on Utility Street?”

- **Transport Rule**
  - SO$_2$ and NOx caps in 2012, tighter SO$_2$ caps in 2014
  - FGD effectively “required” for most all AEP East units in 2014

- **Mercury and Other HAPs MACT Rules**
  - Compliance in 3 years = 1/2015 (or 1/2016 “case by case”)
  - FGD for acid gases likely required on most AEP-East units
  - Baghouses (BH) w/ activated carbon injection (ACI) COULD ALSO be required to meet Hg and heavy metal limits
  - Some AEP-West coal units may be able to comply with only BH and ACI; however other EPA requirements (CAVR) likely to force scrubbers at most units

- **CCR Rule (e.g. ash disposal)**
  - Compliance estimated by 2017
  - AEP capital + pond closure cost: $1.4-2.4 billion if “non-hazardous”
  - Costs DOUBLE with “hazardous” designation by EPA
Typical AEP FGD Retrofit Timeline

- Timeline milestone lengths based on actual AEP construction experience
- Phases could be longer if the support system becomes strained from multiple companies facing similar compliance deadlines
- From 2003-10 AEP retrofitted 7,800 MWs (9 units), using over 35 million work hours at a cost of over $3.6 billion
Energy price impacts in brief

- One-half of U.S. households have average pre-tax annual incomes less than $50,000.

- In 2001, these families spent an average of 12% of their after-tax income ($21,834) on residential and transportation energy.

- In 2011, these households will spend an estimated 20% of their after-tax income of $22,727 on energy.
Ongoing air quality improvements

- AEP has improved its environmental performance.
  - Since 1990, AEP has reduced its NOx emissions by 80% and its SO$_2$ emissions by 73%.
  - AEP has invested more than $7 billion since 1990 to reduce emissions from its coal-fueled generation fleet.
- AEP will continue to improve the environmental performance of its power plants.
In 2009, Electric Generating Units (EGUs) Contributed Just 8% of Total Ozone Precursor Emissions in the Eastern U.S.

## Regional NOx and VOC Emissions, 1999 and 2009

(Thousand tons/year)

<table>
<thead>
<tr>
<th>Region</th>
<th>Total EGU NOx</th>
<th>Coal EGU NOx</th>
<th>Onroad vehicle NOx</th>
<th>All other NOx</th>
<th>Total NOx</th>
<th>Total VOCs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northeast</td>
<td>527</td>
<td>220</td>
<td>400</td>
<td>161</td>
<td>1,478</td>
<td>681</td>
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<tr>
<td></td>
<td>3,038</td>
<td>1,803</td>
<td>3,059</td>
<td>2,645</td>
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</tr>
<tr>
<td>Midwest</td>
<td>1,369</td>
<td>441</td>
<td>1,334</td>
<td>414</td>
<td>1,392</td>
<td>798</td>
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<tr>
<td></td>
<td>4,042</td>
<td>2,379</td>
<td>4,073</td>
<td>2,361</td>
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<tr>
<td>Southeast</td>
<td>1,964</td>
<td>516</td>
<td>1,719</td>
<td>436</td>
<td>2,092</td>
<td>1,226</td>
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<tr>
<td></td>
<td>5,934</td>
<td>3,271</td>
<td>5,973</td>
<td>3,989</td>
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<tr>
<td>Central</td>
<td>1,185</td>
<td>606</td>
<td>841</td>
<td>470</td>
<td>1,671</td>
<td>927</td>
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<td></td>
<td>5,405</td>
<td>4,127</td>
<td>5,473</td>
<td>3,109</td>
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<tr>
<td>Total</td>
<td>5,044</td>
<td>1,782</td>
<td>4,294</td>
<td>1,480</td>
<td>6,633</td>
<td>3,631</td>
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<td></td>
<td>18,419</td>
<td>11,581</td>
<td>14,773</td>
<td>12,105</td>
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</tbody>
</table>

Source: Alpine Geophysics/ENVIRON
Cross-State Air Pollution Rule (SO₂ and NOx) Final July 7, 2011

- Further limits power sector SO₂ and NOx emissions

- SO₂ and NOx subject to caps in 2012, with further SO₂ reductions required in most Eastern states by 2014

- Major concerns with the rule:
  - Not enough time is provided for environmental control installations (i.e. FGD/SCR)
  - Rule does not account for recent improvements in air quality from retrofits made after 2005
  - Inability to trade and bank allowances effectively
Cross States Air Pollution Rule July 7, 2011

- Coverage of states changed slightly from proposed rule.
- Most notably for AEP, Texas is now in the SO2 program while Louisiana is not.
Curtail or Retire to Comply with the Air Rule in 2012

- Significant reductions are required in as soon as 6 months in many states. Most notably, 47% and 46% reductions in SO2 in TX and OH respectively.

- Additionally, major seasonal NOx reductions are required in LA and proposed for OK.

<table>
<thead>
<tr>
<th>State</th>
<th>2012 SO2</th>
<th>2014 SO2</th>
<th>2012 NOx</th>
<th>2012 S NOx</th>
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<tbody>
<tr>
<td>Alabama</td>
<td>6%</td>
<td>4%</td>
<td>15%</td>
<td>15%</td>
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<tr>
<td>Arkansas</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>-16%</td>
</tr>
<tr>
<td>Florida</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>-25%</td>
</tr>
<tr>
<td>Georgia</td>
<td>-28%</td>
<td>-56%</td>
<td>2%</td>
<td>4%</td>
</tr>
<tr>
<td>Illinois</td>
<td>7%</td>
<td>-44%</td>
<td>-37%</td>
<td>-24%</td>
</tr>
<tr>
<td>Indiana</td>
<td>-31%</td>
<td>-61%</td>
<td>-3%</td>
<td>-5%</td>
</tr>
<tr>
<td>Iowa</td>
<td>2%</td>
<td>-28%</td>
<td>-15%</td>
<td>-13%</td>
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<tr>
<td>Kansas</td>
<td>-8%</td>
<td>-8%</td>
<td>-37%</td>
<td>-39%</td>
</tr>
<tr>
<td>Kentucky</td>
<td>-14%</td>
<td>-61%</td>
<td>-7%</td>
<td>-7%</td>
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<td>N/A</td>
<td>N/A</td>
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<td>Maryland</td>
<td>1%</td>
<td>-6%</td>
<td>-14%</td>
<td>-24%</td>
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<tr>
<td>Michigan</td>
<td>-6%</td>
<td>-41%</td>
<td>-25%</td>
<td>-26%</td>
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<td>Minnesota</td>
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<td>1%</td>
<td>-5%</td>
<td>N/A</td>
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<td>N/A</td>
<td>N/A</td>
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<td>-11%</td>
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<td>1%</td>
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<td>-63%</td>
<td>-63%</td>
<td>-24%</td>
<td>-35%</td>
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<tr>
<td>New York</td>
<td>-45%</td>
<td>-63%</td>
<td>-33%</td>
<td>-35%</td>
</tr>
<tr>
<td>North Carolina</td>
<td>14%</td>
<td>-52%</td>
<td>-7%</td>
<td>-10%</td>
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<tr>
<td>Ohio</td>
<td>-46%</td>
<td>-76%</td>
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<td>Oklahoma</td>
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<td>N/A</td>
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<td>-73%</td>
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<tr>
<td>South Carolina</td>
<td>-6%</td>
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<td>18%</td>
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<td>-50%</td>
<td>14%</td>
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<tr>
<td>Texas</td>
<td>-47%</td>
<td>-47%</td>
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</tr>
<tr>
<td>Virginia</td>
<td>-24%</td>
<td>-62%</td>
<td>-13%</td>
<td>-21%</td>
</tr>
<tr>
<td>West Virginia</td>
<td>34%</td>
<td>-31%</td>
<td>12%</td>
<td>4%</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>-27%</td>
<td>-63%</td>
<td>-5%</td>
<td>-6%</td>
</tr>
</tbody>
</table>

AEP Generating States
The Final Air Rule affects at least 7600 MWs, requiring perhaps more than 2100 MWs of FGD retrofits. Units that show no economic value to retrofit with emission controls or fuel switching options could be forced to prematurely retire by 2012.

The HAPs ruling affects total of 12,340 MWs, requiring an additional 6000 MW of retrofits beyond what would be required under the Transport Rule.

CCR affects over 20,000 MWs, requiring 18,000 MWs of coal-fired generation to have lined wet ash ponds and/or conversion to dry ash handling systems.

All retrofits will require regulatory approval for financing. Also, units prematurely retired in response to these EPA rules will have remaining book value issues to address.

*Affected MWs do not reflect the possibility of fabric filters being required under HAPs
Updated data and models show more air quality improvement than EPA recognizes

- EPA did not include SO2 and NOx retrofits after 2005 in the proposed and final regulations

- When all retrofits are included, most locations are in compliance
Announced Retirements Before Cross-State Air Pollution Rule Finalized July 7, 2011

<table>
<thead>
<tr>
<th>Operating Company</th>
<th>Plant</th>
<th>MW</th>
<th>Expected Retirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP Ohio</td>
<td>Sporn 5</td>
<td>450</td>
<td>2011</td>
</tr>
<tr>
<td></td>
<td>Conesville 3</td>
<td>165</td>
<td>2012</td>
</tr>
<tr>
<td></td>
<td>Muskingum River 1-4</td>
<td>840</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Picway 5</td>
<td>100</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Sporn 2-4</td>
<td>300</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Kammer 1-3</td>
<td>630</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Total MW</td>
<td>2,485</td>
<td></td>
</tr>
<tr>
<td>APCO</td>
<td>Glen Lyn 5</td>
<td>95</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Glen Lyn 6</td>
<td>240</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Clinch River 3</td>
<td>235</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Sporn 1</td>
<td>150</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Sporn 3</td>
<td>150</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Kanawha River 1</td>
<td>200</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Kanawha River 2</td>
<td>200</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Total MW</td>
<td>1,270</td>
<td></td>
</tr>
<tr>
<td>I&amp;M</td>
<td>Tanners Creek 1</td>
<td>145</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Tanners Creek 2</td>
<td>145</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Tanners Creek 3</td>
<td>205</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Total MW</td>
<td>495</td>
<td></td>
</tr>
<tr>
<td>KPCo</td>
<td>Big Sandy 1</td>
<td>278</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Big Sandy 2</td>
<td>800</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Total MW</td>
<td>1,078</td>
<td></td>
</tr>
<tr>
<td>SWEPCO</td>
<td>Welsh 2</td>
<td>528</td>
<td>2014</td>
</tr>
<tr>
<td></td>
<td>Total MW</td>
<td>528</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Grand Total</td>
<td>5,856</td>
<td></td>
</tr>
</tbody>
</table>

- AEP plant units are located in Ohio, West Virginia, Virginia, Indiana, Kentucky and Texas
- AEP units to be retrofitted and new generation (mostly natural gas) are listed in the appendix
- Approximately 28,000MW of retirements has been announced by US plant owners as of July 1, 2011
- Industry estimates were 50,000-60,000 MW by 2015 for US before the rule.
- EPA estimate was 10,000 MW for US
Other Economic Impacts of EPA Regulations

- Higher natural gas use and related price increases affects ALL consumers
- $0.50/MMBtu gas price change increases other consumer costs about $8-9 billion/year
- Net Job Impacts are Negative:
  - Near term increases in temporary (2-5 years) construction jobs
  - BUT, “NET” NEGATIVE for Total Jobs mostly due to large electricity price increases
  - ‘Green jobs’ studies such as PERI study don’t consider big negatives of higher electricity & energy prices
John W. Turk Jr. Ultra-Supercritical Coal Plant is a base load 600-MW advanced coal combustion plant. Located in Arkansas. SWEPCo owns 73 percent or roughly 440 megawatts of the total unit.

Will begin commercial operation in 2012.

The Turk Plant will use low-sulfur coal and state-of-the-art emission control technologies, including a design that allows for the retrofit of carbon dioxide controls.

EPA’s MACT standards are technology, not health based, requirements that are supposed to reflect the capabilities of emission control technologies in use now by the best performing units.

EPA overstates these capabilities with proposed standards that cannot all be met by any state-of-the-art plants now being built.

EPA data show that no coal plant in operation could meet all of the standards.

Air permits issued by states for new units reflect vendor guarantees, fuel data, variable operating condition that are practical and achievable and will protect public health.
Today’s CCS Technology is Expensive
New Plant Basis

COE by Cost Component

<table>
<thead>
<tr>
<th>Cost Component</th>
<th>Supercritical PC</th>
<th>Supercritical PC w/CCS</th>
<th>NGCC</th>
<th>NGCC w/CCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO2 TS&amp;M Costs</td>
<td>$14.2</td>
<td>$19.6</td>
<td>$44.5</td>
<td>$52.2</td>
</tr>
<tr>
<td>Fuel Costs</td>
<td>$31.7</td>
<td>$59.6</td>
<td>$10.1</td>
<td>$22.3</td>
</tr>
<tr>
<td>Variable Costs</td>
<td>$8</td>
<td>$13</td>
<td>$1.3</td>
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<tr>
<td>Fixed Costs</td>
<td>$5</td>
<td>$8</td>
<td>$3</td>
<td>$2.6</td>
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<tr>
<td>Capital Costs</td>
<td>$5</td>
<td>$10.1</td>
<td>$1.3</td>
<td>$5.7</td>
</tr>
</tbody>
</table>

COE, $/MWh (2007$)

Source: NETL, Cost and Performance Baseline for Fossil Energy Power Plants study, Vol 1, Nov 2010

$59/MWh

$107/MWh

$86/MWh

+81%

+46%