Heat Integration with 25 MW KM-CDR at Plant Barry

- Funded by industry consortium
- Fully integrated CO$_2$ capture/compression
- Storage in Citronelle Dome
- 500 metric tons CO$_2$/day
Total Project Budget ($MM)

12.9

3.7

DOE Share
Cost Share
Waste heat sources include flue gas and CCS plant streams.
Boiler feed water will be heated with CO₂ Cooler and Flue Gas Cooler

**CO₂ Cooler**
Standard heat exchanger

**Flue Gas Cooler**
MHI proprietary heat exchanger
Flue Gas Cooler proven on low S coals

Carbon steel tubes in good condition after 2 years operation at Japanese plant

What happens with higher sulfur coals (>1% S) fired in US?
Flue Gas Cooler captures $\text{SO}_3$

- Operates downstream of the APH
- Mechanism for removal of $\text{SO}_3$ from flue gas
  - $\text{SO}_3 (g) + \text{H}_2\text{O} (g) \rightarrow \text{H}_2\text{SO}_4 (g)$
  - $\text{H}_2\text{SO}_4 (g) \rightarrow \text{H}_2\text{SO}_4 (l)$
  - $\text{H}_2\text{SO}_4 (l)$ condenses on fly ash in flue gas and a protective layer of ash on tube bundles
- Flue Gas Cooler tube skin temperature $<$ $\text{SO}_3$ dewpoint
  - Alkaline species in fly ash (Ca, Na) neutralize $\text{H}_2\text{SO}_4$
  - Silicates, etc. physically adsorb $\text{H}_2\text{SO}_4$
Other benefits of Flue Gas Cooler

• Improve removal of Hg, Se, SO$_3$ across the ESP
• Reduce AQCS cost
  – Improve ESP performance
  – Improve FGD performance
  – Improve CCS performance
• Potential to simplify boiler/steam turbine cycles
• Improve plant heat rate
Heat integration eliminates LP heaters 1-3
Heat integration eliminates LP heaters 1-3
Heat integration increases plant efficiency

- Reduced steam extractions for:
  - BFW heating
  - CCS solvent regeneration

Graph showing:
- CCS: 28.9%
- CCS + FGC + CO2 Cooler: 29.7%
Heat integration decreases cost of CCS

Analysis per 2010 DOE Cost and Performance Baseline
Heat Integration Challenges

• Highly integrated systems incorporating waste heat recovery have yet to be demonstrated at any scale in the U.S.

• Overcome skepticism in U.S. by proving system reliability

• Process control during transients/perturbations, which are typical in power plant operations

• Removal performance of specific impurities not yet quantified for varying operating conditions

• Uncertainty around the reliability of the system with higher sulfur fuels (> 1% S)
Project Objectives

- Better ESP performance
- Increase SO$_3$, Hg, Se capture
- Reduce CCS solvent consumption
- Reduce FGD H$_2$O consumption

Quantify tangential benefits

Resolve operational problems of integration

Quantify energy efficiency improvements
PROJECT = Boiler feed water will be heated with CO₂ Cooler and Flue Gas Cooler
General Layout

Unit 5

Flue Gas Cooler

SCR

CO₂ Cooler

CCS
Flue Gas Cooler Area – Plan View

- Flue Gas Tie-in
- Flow
- Booster Fan
- ESP inlet test ports
- ESP outlet test ports
- Mini ESP
- FGC outlet test ports
- FGC inlet test ports
- ESP inlet test ports
- Flue Gas Return
- Flue Gas Cooler
- Balance of Plant
Flue Gas Cooler Installed
CO$_2$ Cooler General Arrangement
CO₂ Cooler Installed
Baseline Performance

Confirmed heat integration performance
- 240-300 MMBTU/hr heat recovery for 550 MW base plant (Case 9)
- Up to 65% reduction of FGD makeup water

<table>
<thead>
<tr>
<th>Source</th>
<th>Data collected</th>
<th>Units</th>
<th>w/o HES heat integration</th>
<th>w/ HES heat integration</th>
<th>w/ HES heat integration</th>
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<tr>
<td>FGC</td>
<td>Flue gas flow rate</td>
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<td>Recovered heat</td>
<td>MMBtu/h</td>
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<td>CO₂</td>
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<td>CO₂ removal performance*</td>
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<td>&gt; 90</td>
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<td>BC temp CO₂ cooler inlet</td>
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<td>BC temp CO₂ cooler outlet</td>
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<td>Plant</td>
<td>Boiler Load net</td>
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<td>50</td>
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<td>128</td>
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<td>Recovered heat</td>
<td>MMBtu/h</td>
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<td>13.6</td>
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<td></td>
<td>Recovered heat for 550 MW base plant</td>
<td>MMBtu/h</td>
<td>NA</td>
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<td>300</td>
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Impurities Removal Test

Test Conditions
- No FGC 300F: No water flowed through the FGC, the flue gas was not cooled
- FGC 203F + SO₃: The flue gas was cooled to 203F and SO₃ was injected
- FGC 203F: The flue gas at the FGC outlet was cooled to 203F
- FGC 185F: The flue gas was further cooled down to 185F

Test Methods and Locations

<table>
<thead>
<tr>
<th>Sampling Location</th>
<th>Sampling Method Analyte</th>
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</thead>
<tbody>
<tr>
<td>FGC Inlet</td>
<td>US EPA Method 17/Method 29</td>
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<tr>
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<td>Particulate Matter and Metals (total)</td>
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<td>IGS/Method 29</td>
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<tr>
<td></td>
<td>Metals (gas-phase)</td>
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<tr>
<td>ESP Inlet</td>
<td>US EPA Method 5</td>
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<tr>
<td></td>
<td>Particulate Matter</td>
</tr>
<tr>
<td>ESP Outlet</td>
<td>US EPA Method 5/Method 29</td>
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<tr>
<td></td>
<td>Particulate Matter and Metals (total)</td>
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<td></td>
<td>IGS/Method 29</td>
</tr>
<tr>
<td></td>
<td>Metals (gas-phase)</td>
</tr>
</tbody>
</table>
Impurities removal is enhanced by the Flue Gas Cooler operation due to operation of the FGC:

- Native mercury removal by fly ash increased significantly from 22 to >85%
- ESP Outlet SO$_3$ decreased by 40%
- Selenium removal increased from 95 to 98%
- No discernable effect due to temperature decrease from 203 to 185F
SO\textsubscript{3} Injection Inhibits Mercury Capture, No Effect on Selenium or Particulate Matter Due to SO\textsubscript{3} Injection:

- Mercury removal decreased from 93 to 40%
- But removal still higher than without FGC operation
- Selenium removal unchanged
- Particulate matter removal unchanged
Confirmed ESP performance improvement

- PM removal: > 99.5%
- SO₃ removal: less than 0.05 ppm at ESP outlet
- Hg removal: > 85% w/o SO₃ injection, ~40% w/ SO₃ injection
- Se removal: > 98%

<table>
<thead>
<tr>
<th>Condition, Day</th>
<th>Run Number, Day</th>
<th>SO₃ con. at ESP outlet (ppmd at 3% O₂)</th>
<th>Percent Removal Across FGC/ESP</th>
</tr>
</thead>
<tbody>
<tr>
<td>NO FGC 300F</td>
<td>R3-0 Day 2 (12/16/15)</td>
<td>0.03</td>
<td>99.2% 22% 95%</td>
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<tr>
<td>FGC 203F+ SO₃</td>
<td>R3-2 Day 1 (12/18/15)</td>
<td>0.04</td>
<td>NM 40% 98%</td>
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<tr>
<td>FGC 203F</td>
<td>R3-1-1 Day 2 (09/24/15)</td>
<td>0.02</td>
<td>NM &gt;92% 98%</td>
</tr>
<tr>
<td>FGC 185F</td>
<td>R3-1-2 Day 2 (09/26/15)</td>
<td>0.02</td>
<td>99.6% 85% 98%</td>
</tr>
</tbody>
</table>
Durability Test (Preliminary)

- No significant corrosion on tube bundles
  - 4 wks w/o SO$_3$ injection, 3 wks w/ SO$_3$ injection
  - Detailed analysis is in progress

(a) Before operation  (b) October, 2015  (c) January, 2016*

*The remaining fly ash can be easily removed by soot-blowers.
## Techno-Economic Analysis

<table>
<thead>
<tr>
<th>Case</th>
<th>11</th>
<th>12</th>
<th>12a</th>
<th>12b</th>
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<tbody>
<tr>
<td>Plant Configuration</td>
<td>Supercritical PC w/out CCS</td>
<td>Supercritical PC w MEA CCS</td>
<td>Supercritical PC w KM CDR® CCS</td>
<td>Supercritical PC w KM CDR® CCS w heat integration</td>
</tr>
<tr>
<td>Avoided Cost $/ton</td>
<td>$95.9</td>
<td>$78.5</td>
<td>$75.0</td>
<td>$75.0</td>
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<tr>
<td>CO₂ Captured Cost $/ton</td>
<td>$66.4</td>
<td>$59.9</td>
<td>$58.8</td>
<td>$58.8</td>
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<tr>
<td>Cost of Electricity mils/kWh</td>
<td>80.95</td>
<td>147.27</td>
<td>135.94</td>
<td>133.73</td>
</tr>
<tr>
<td>Percent Decrease in COE from Case 12</td>
<td>-</td>
<td>-</td>
<td>7.7%</td>
<td>9.2%</td>
</tr>
</tbody>
</table>
BP3 completes by December 2016

BP1
- FEED and Target Cost Estimate
- Permitting

BP2
- Engineering, Procurement, Construction

BP3
- Operations
- Field Testing Analysis
Remaining project work

- Data analysis
- Estimate reduction of power penalty
- Detailed measurement of tubes corrosion & erosion
- Reporting
Summary

• Completed operation & testing
• Confirmed heat integration performance
  – 240-300 MMBTU/hr heat recovery for 550 MW base plant (Case 9)
  – Up to 65% reduction of FGD makeup water
• Confirmed ESP performance improvement
  – PM removal: > 99.5%
  – SO\textsubscript{3} removal: less than 0.05 ppm at ESP outlet
  – Hg removal: > 85% w/o SO\textsubscript{3} injection, ~40% w/ SO\textsubscript{3} injection
  – Se removal: > 98%
• Confirmed no significant corrosion on tube bundles
  – 4 wks w/o SO\textsubscript{3} injection, 3 wks w/ SO\textsubscript{3} injection
  – Detailed analysis is in progress
• Data analysis & reporting will be completed by December 2016
Questions?