What Energy Modelers Need to Know About Carbon Capture and Storage

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Outline of Talk

• Current status of CCS technology
• Costs and impacts on plant performance
• Factors affecting deployment of CCS
• Incorporating uncertainty in models
**Status of CCS technology**

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**Schematic of a CCS System**

- **Carbonaceous Fuels**
- **Air or Oxygen**
- **Power Plant or Industrial Process**
- **CO₂ Capture & Compress**
- **CO₂ Transport**
- **CO₂ Storage (Sequestration)**

- Post-combustion
- Pre-combustion
- Oxyfuel combustion
- Pipeline
- Tanker
- Depleted oil/gas fields
- Deep saline formations
- Unmineable coal seams
- Ocean
- Mineralization
- Reuse

Useful Products
(Electricity, Fuels, Chemicals, Hydrogen)

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Many Ways to Capture CO₂

CO₂ Separation and Capture

Absorption

- Chemical
  - MEA
  - Caustic
  - Other

- Physical
  - Selexol
  - Rectisol
  - Other

Adsorption

- Adsorber Beds
- Regeneration Method
  - Pressure Swinging
  - Temperature Swinging
  - Washing

Cryogenics

- Gas Separation
  - Polyphenyleneoxide
  - Polydimethylsiloxane

Membranes

- Gas Absorption
  - Polypropylene

Microbial/Agal Systems

- Ceramic Based Systems

Choice of technology depends strongly on application

Leading Candidates for CCS

- Fossil fuel power plants
  - Pulverized coal combustion (PC)
  - Natural gas combined cycle (NGCC)
  - Integrated coal gasification combined cycle (IGCC)

- Other large industrial sources of CO₂ such as:
  - Refineries, fuel processing, and petrochemical plants
  - Hydrogen and ammonia production plants
  - Pulp and paper plants
  - Cement plants

  – Main focus is on power plants, the dominant source of CO₂ –
CO₂ Capture Options for Power Plants: Pre-Combustion Capture

CO₂ Capture Options for Power Plants: Post-Combustion Capture

Also for NGCC plants
**CO₂ Capture Options for Power Plants: Oxy-Combustion Capture**

- Steam Turbine Generator
- PC Boiler
- Air Separation Unit
- Air Pollution Control Systems (NOₓ, PM, SO₂)
- Distillation System
- CO₂ Compression
- CO₂ Storage

**Geological Storage Options**

- Overview of Geological Storage Options:
  1. Depleted oil and gas reservoirs
  2. Use of CO₂ in enhanced oil and gas recovery
  3. Deep saline formations — (a) off-shore (b) on-shore
  4. Use of CO₂ in enhanced coal bed methane recovery

Source: IPCC, 2007
Status of CCS Technology

- Pre- and post-combustion CO₂ capture technologies are commercial and widely used in industrial processes; also at several gas-fired and coal-fired power plants, at small scale (~40 MW); CO₂ capture efficiencies are typically 85-90%. Oxyfuel capture is still under development.

- CO₂ transport via pipelines is a mature technology.

- Geological storage of CO₂ is commercial on a limited basis, mainly for EOR; several projects in deep saline formations are operating at scales of ~1 Mt CO₂ /yr.

- Large-scale integration of CO₂ capture, transport and geological sequestration has been demonstrated at several industrial sites (outside the U.S.) — but not yet at an electric power plant at full-scale.

Examples of Pre-Combustion CO₂ Capture Systems

- Petcoke Gasification to Produce H₂
  (Coffeyville, Kansas, USA)

- Coal Gasification to Produce SNG
  (Beulah, North Dakota, USA)
Pre-Combustion Capture at IGCC Plants

Pilot plants under construction at two IGCC plants (startup expected in late 2010)

Post-Combustion Technology for Industrial CO₂ Capture

Source: IEA GHG, 2008
Post-Combustion CO₂ Capture at U.S. Power Plants

Gas-fired
Bellingham Cogeneration Plant
(Bellingham, Massachusetts, USA)
(E.S. Rubin, Carnegie Mellon)

Coal-fired
Warrior Run Power Plant
(Cumberland, Maryland, USA)
(Source: IEA GHG)

Oxy-Combustion CO₂ Capture from a Coal-Fired Boiler

30 MWₜ Pilot Plant (~10 MWₑ) at Vattenfall Schwarze Pumpe Station
(Germany)

Source: Vattenfall, 2008
(E.S. Rubin, Carnegie Mellon)
CO₂ Pipelines in the Western U.S.

> 3000 miles of pipeline
~40 MtCO₂/yr transported

Large-Scale CCS Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>Operator</th>
<th>Geological Reservoir</th>
<th>Injection Start Date</th>
<th>Injection Rate (MtCO₂/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sleipner (Norway)</td>
<td>StatoilHydro</td>
<td>Saline Formation</td>
<td>1996</td>
<td>1.0</td>
</tr>
<tr>
<td>Weyburn (Canada)</td>
<td>EnCana</td>
<td>Oil Field (EOR)</td>
<td>2000</td>
<td>1.2*</td>
</tr>
<tr>
<td>In Salah (Algeria)</td>
<td>Sonatrach, BP, StatoilHydro</td>
<td>Depleted Gas Field</td>
<td>2004</td>
<td>1.2</td>
</tr>
<tr>
<td>Snohvit (Norway)</td>
<td>StatoilHydro</td>
<td>Saline Formation</td>
<td>2008</td>
<td>0.7</td>
</tr>
</tbody>
</table>

* Average rate over 15 year contract. Recent expansion to ~3 Mt/yr for Weyburn + Midale field.

A 500 MW coal plant would inject about 3 MtCO₂/yr

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Geological Storage of Captured CO₂ in a Deep Saline Formation

Sleipner Project
(Norway)

Source: Statoil

Geological Storage of Captured CO₂ in a Deep Saline Formation

Snohvit LNG Project
(Norway)

Source: www.Snohvit, 2009
Geological Storage of Captured CO₂ in a Depleted Gas Formation

In Salah / Krechba (Algeria)

Source: BP

Geological Formations in North America

Oil & Gas Fields

Deep Saline Formations

Source: NETL, 2009

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Geological Storage of Captured CO$_2$ with Enhanced Oil Recovery (EOR)

Sources: IEAGHG; NRDC; USDOE

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Weyburn Field, Canada

Dakota Coal Gasification Plant, ND

CCS at a Coal-Fired Power Plant with Storage in a Deep Saline Formation
(Pilot plant scale)

20 MW capture unit at AEP’s Mountaineer Power Plant
(West Virginia)

Source: AEP, 2009

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Still Missing

- Full-scale power plant demo #1
- Full-scale power plant demo #2
- Full-scale power plant demo #3
- Full-scale power plant demo #4
- Full-scale power plant demo #5
- Full-scale power plant demo #6
- Full-scale power plant demo #7
- Full-scale power plant demo #8
- Full-scale power plant demo #9
- Full-scale power plant demo #10

Many projects are planned or underway at various scales

- Map shows operating plus proposed or planned projects in the U.S. and Canada. They encompass power plants, industrial sources and research projects spanning a large range of scale.

Source: DOE, 2009
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Substantial CCS Activity Globally

Source: DOE, 2009

Roadmaps for CCS Deployment

DOE Roadmap

Capture Technology Laboratory-Bench-Scale R&D
Capture Technology Corporate Site Training
Capture Technology Full-Scale Demonstration
Capture Technology Large-Scale Field Testing
CCS Commercialization

EPRI Roadmap

Testing Demonstrations and Demonstrations be Performed in Parallel

Commercialization expected by 2020

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The cost of CCS

Many Factors Affect CCS Costs

• Choice of Power Plant and CCS Technology
• Process Design and Operating Variables
• Economic and Financial Parameters
• Choice of System Boundaries; e.g.,
  ▪ One facility vs. multi-plant system (regional, national, global)
  ▪ GHG gases considered (CO₂ only vs. all GHGs)
  ▪ Power plant only vs. partial or complete life cycle
• Time Frame of Interest
  ▪ First-of-a-kind plant vs. nth plant
  ▪ Current technology vs. future systems
  ▪ Consideration of technological “learning”
**Common Measures of Cost**

- **Cost of Electricity (COE) ($/MWh)**
  
  \[
  \text{COE} = \frac{(\text{TCC})(\text{FCF}) + \text{FOM}}{(\text{CF})(8760)(\text{MW})} + \text{VOM} + (\text{HR})(\text{FC})
  \]

- **Cost of CO₂ Avoided ($/ton CO₂ avoided)**
  
  \[
  \text{Cost of CO₂ Avoided} = \frac{(\$/\text{MWh}_{\text{CCS}}) - (\$/\text{MWh}_{\text{reference}})}{(\text{CO₂/MWh})_{\text{ref}} - (\text{CO₂/MWh})_{\text{CCS}}}
  \]

**Ten Ways to Reduce CCS Cost**

*(inspired by D. Letterman)*

1. Assume high power plant efficiency
2. Assume high plant utilization (capacity factor)
3. Assume low interest rate (discount rate)
4. Assume long plant lifetime
5. Report $/ton CO₂ based on short tons
6. Omit certain capital costs
7. Assume EOR credits for CO₂ storage
8. Assume low fuel price
9. Assume high-quality fuel properties
10. Assume all of the above!

...and we have not yet considered the CCS technology!
Sources of Recent Cost Estimates

- IPCC, 2005: Special Report on CCS
- Rubin, et.al, 2007: Energy Policy, 35
- EPRI, 2007: Report No. 1014223
- EPRI, 2008: Report No. 1018329
- DOE, 2009: Pgh Coal Conference Presentation
- DOE, 2010: Low-Rank Coal Study (forthcoming)

DOE vs. EPRI

- EPRI’s capital costs ($/kW) are higher than DOE’s
- EPRI’s levelized costs of electricity ($/MWh) are lower than DOE’s

Source: EPRI, 2007
Estimated Cost of New Power Plants with and without CCS

Cost of Electricity ($ / MWh) vs. CO₂ Emission Rate (tonnes / MWh)

* 2007 costs for bituminous coals; gas price ≈ $4–7/GJ; 90% capture; aquifer storage

Current Coal Plants

Incremental Cost of CCS for New Power Plants Using Current Technology

<table>
<thead>
<tr>
<th>Incremental Cost of CCS relative to same plant type without CCS based on bituminous coals</th>
<th>Supercritical Pulverized Coal Plant</th>
<th>Integrated Gasification Combined Cycle Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increases in capital cost ($/kW) and generation cost ($/kWh)</td>
<td>~ 60–80%</td>
<td>~ 30–50%</td>
</tr>
</tbody>
</table>

The added cost to consumers due to CCS will be much smaller, reflecting the number and type of CCS plants in the generation mix at any given time.

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Typical Cost of CO₂ Avoided
(Relative to a SCPC reference plant; bituminous coals)

Levelized cost in US$ per tonne CO₂ avoided

<table>
<thead>
<tr>
<th>Power Plant System</th>
<th>New Supercritical Pulverized Coal Plant</th>
<th>New Integrated Gasification Combined Cycle Plant</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deep aquifer storage</td>
<td>~ $70 /tCO₂ ±$15/t</td>
<td>~ $50 /tCO₂ ±$10/t</td>
</tr>
<tr>
<td>Enhanced oil recovery (EOR) storage</td>
<td>Cost reduced by ~ $20–30 /tCO₂</td>
<td></td>
</tr>
</tbody>
</table>

Source: Based on IPCC, 2005; Rubin et al, 2007; DOE, 2007

- Capture accounts for most (~80%) of the total cost

DOE Cost Results for Low-Rank Coals at Western Power Plants

Avoided Cost of CO₂ Emissions
Includes Owners Costs

Subbituminous  Lignite

Source: NETL, 2009

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Draft Final Results – Subject to Revision
CCS energy requirements affect plant efficiency, emissions, and cost

Changes in plant efficiency due to CCS energy requirements also affect plant-level pollutant emission rates (per MWh). A site-specific context is needed to evaluate the net impacts.

<table>
<thead>
<tr>
<th>Power Plant Type</th>
<th>Added fuel input (%) per net kWh output</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing subcritical PC</td>
<td>~40%</td>
</tr>
<tr>
<td>New supercritical PC</td>
<td>25-30%</td>
</tr>
<tr>
<td>New coal gasification (IGCC)</td>
<td>15-20%</td>
</tr>
<tr>
<td>New natural gas (NGCC)</td>
<td>~15%</td>
</tr>
</tbody>
</table>

A Power Plant Cost & Performance Model

(AIECM: The Integrated Environmental Control Model)

- A desktop/laptop computer model developed for DOE/NREL; free and available at: [www.iecm-online.com](http://www.iecm-online.com)
- Provides systematic estimates of performance, emissions, costs and uncertainties using user-specified designs and parameter values for:
  - PC, IGCC and NGCC plants
  - All flue/fuel gas treatment systems
  - CO₂ capture and storage options (pre- and post-combustion, oxy-combustion; transport, storage)
- Major 2010 update now available
What is the potential for future cost reductions?

Better Capture Technologies Are Emerging

- Post-combustion (existing, new PC)
- Pre-combustion (IGCC)
- Oxycombustion (new PC)
- CO₂ compression (all)

- Amine solvents
- Physical solvents
- Cryogenic oxygen
- Advanced physical solvents
- Advanced chemical solvents
- Ammonia
- CO₂ compression

- PBI membranes
- Solid sorbents
- Membrane systems
- ITMs
- Biomass co-firing

- Ionic liquids
- Metal organic frameworks
- Enzymatic membranes

- Chemical looping
- OTM boiler
- Biological processes
- CAR process

Time to Commercialization
Cost Reduction Benefit
Present 5+ years 10+ years 15+ years 20+ years

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Two Approaches to Estimating Future Technology Costs

- **Method 1**: Engineering-Economic Analysis
  - A “bottom up” approach based on engineering process models, informed by judgments regarding potential improvements in key process parameters

Potential Cost Reductions Based on Engineering-Economic Analysis

Source: DOE/NETL, 2006
Potential Cost Reductions Based on Engineering-Economic Analysis

Two Approaches to Estimating Future Technology Costs

- **Method 1**: Engineering-Economic Analysis
  - A “bottom up” approach based on engineering process models, informed by judgments regarding potential improvements in key process parameters

- **Method 2**: Use of Historical Experience Curves
  - A “top down” approach based on applications of mathematical “learning curves” or “experience curves” that reflect historical trends for analogous technologies or systems

*Source: DOE/NETL, 2010*
Projected Learning Curve for an IGCC Plant with CCS

Assumes learning begins with first CCS plant

![Projected Learning Curve for an IGCC Plant with CCS](image1)

Range of Learning Rate Results for Four Plant Types w/ CO₂ Capture

![Range of Learning Rate Results for Four Plant Types w/ CO₂ Capture](image2)

Source: Rubin, et.al, 2007
Potential Cost Reductions for 4 Plant Types Based on Learning Curves

(*After 100 GW of cumulative CCS capacity worldwide)

- Upper bounds are similar to estimates from DOE’s “bottom-up” analyses
- Lower bounds are smaller by factors of 2 to 3

Source: Rubin, et al., 2007

Many Sources of Uncertainty

Early Trend of FGD Capital Cost

Costs of early FGD installations were low and performance was poor

Source: Rubin, Carnegie Mellon
Best-fit models for initial deployment of FGD/SCR differ from classic model

Hypothesis:
The regulatory-driven deployment of these environmental technologies results in large initial capacity increments without the subsequent benefits of LBD, R&D, etc, which reduces the cost of future generations of these technologies.

Who would use it and why?
Why Would CCS be Adopted?

**Carrots**
- Financial subsidies or other government incentives
- Profit from sale of captured CO₂ (for EOR, etc.)

**Sticks**
- A carbon price or tax greater than the cost of CCS
- A performance standard or other type of regulation that requires the use of CCS for compliance

Most energy models focus on carbon prices, but other policy drivers also can be important

Constraints on CCS Use

- Retrofits on existing plants could be precluded by:
  - Limitations on available physical space
  - Limited or no access to geological storage capacity
  - Unacceptable costs related to plant characteristics (e.g., size, age, efficiency, energy penalty, etc.)
  - Public opposition to CCS

- Applications to new plants could be precluded by:
  - Limited or no access to geological storage capacity
  - Public opposition to CCS
  - Industry aversion to CCS (or to some forms of it)
CCS Needs Are Feasible But Urgency Is Required

Least-cost U.S. energy mix in 2050 for a GHG policy scenario (80% below 1990 levels):
Results from five models
(Source: EMF22, 2009)

CCS Needed in 2035 (EMF22): 230 – 1600 TWh (~30–230 GW)
Technical Potential (AEP, 2009): 3000 TWh (~ 430 GW)

Deployment of Post-Combustion SO₂ and NOₓ Capture at Coal-Fired Plants

Flue Gas Desulfurization (FGD) systems:
Average ≈ 10 GW/yr

Selective Catalytic Reduction (SCR) systems:
Average ≈ 5 GW/yr
How can we better represent uncertainties in model results?

Typical Display of a Model Run
What I’d Like to See

Thank You

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