CCUS Economics:
Capture Costs, EOR Demand &
Regional Supply and Demand Curves

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Jeffrey D. Brown
jdb79@stanford.edu
Sections of Today’s Discussion

1. Basic feasibility equation for CCUS today: With new 45Q tax credits projects are feasible if capture cost is in the $50-60/MT range, assuming (i) projects can sell CO2 to EOR producers and (ii) that pipeline transport issues are solved.

2. During 2019, several projects examining cost of capture have helped us get a better handle on costs and on the individual emitters most likely to have feasible projects. That lets us create location-specific CO2 supply curves.

3. The potential volumes and prices for sales to CO2-EOR are a black box, but at least ARI data lets us create location-specific CO2 demand curves.

4. We can link those supply and demand curves with pipeline modeling systems such as LANL’s SimCCS to find regional market equilibriums of supply and demand.
Part I: Basic Feasibility Test

85 Broad Street, NY, NY
Feasibility: Capture Cost has to be Less Than Revenues, Credits & Transport Costs

$35/MT Section 45 Q Tax Credit* + EOR Sales Revenues - Transport Cost to EOR field

< OR >

$50/MT Section 45 Q Tax Credit* + Storage Charges by Saline Operator - Transport Cost to Saline Reservoir

*For simplicity we are showing the maximum amount, before adjustments for inflation. In the analyses we account for the fact that the credits can only be earned for 12 years. We are showing solely for analytical purposes that the credits are received by the injectors. Clearly, the tax credit may not be worth its full nominal amount if it is monetized through an inefficient financial transaction, a factor we are not able to systematically quantify at present.
Why Cost, Drivers and Selection Matter: Current CO$_2$ Cost Feasibility Cutoff @ $\sim$50s/MT

<table>
<thead>
<tr>
<th>Cost /Revenue Item</th>
<th>$/MT</th>
<th>Key Factors</th>
</tr>
</thead>
</table>
| Sales of CO$_2$ to EOR producer                | $\sim$20-30/MT | Price of oil, because CO$_2$ contract sales prices typically linked to oil. Could be higher in most productive EOR fields—if they lack access to geologic CO$_2$.
|                                               |              |                                                                                                                                                                                                                                                                          |
| Less Cost of Transport to EOR field           | ($5-10)/MT   | Depends whether can use existing trunk line or whether need new build trunk. Also very sensitive to length of any spur/connector lines.                                                                                                                                 |
| Value of §45Q Tax Credit (non-cash)            | $\sim$35/MT  | Rises year-by-year per statute reaching $35/MT by 2026. Rises with inflation thereafter (similar to renewable Production Tax Credit).
|                                               | $\sim$45-60/MT | Range likely includes best SMR/H2, Cement, and Coal Power Projects, perhaps FFCUs.                                                                                                                                                                                        |
# Saline Disposal Makes Feasibility Harder (except Special Cases*)

<table>
<thead>
<tr>
<th>Cost /Revenue Item</th>
<th>$/MT</th>
<th>Key Factors</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fees paid to Operator of Saline Storage Site</td>
<td>($5-15)/MT</td>
<td>Source:</td>
</tr>
<tr>
<td>Less Cost of Transport to EOR field</td>
<td>($5-10)/MT</td>
<td>Depends whether can use existing trunk line or whether need new build trunk. Also very sensitive to length of any spur/connector lines.</td>
</tr>
<tr>
<td>Value of §45Q Tax Credit (non-cash)</td>
<td>$50/MT</td>
<td>Rises year-by-year per statute reaching $50/MT by 2026. Rises with inflation thereafter (similar to renewable Production Tax Credit).</td>
</tr>
<tr>
<td></td>
<td>~$25-40/MT maximum for feasibility</td>
<td>Unlikely to include any projects build new separation equipment funded solely by 45Q and EOR sales. Ethanol and special cases.</td>
</tr>
</tbody>
</table>

*Special case example: Wabash gasifier/ammonia plant already has to build Rectisol in due course, so saline storage is almost free money.
Part II: Capture Project Costs, Drivers, and Selection

Cheap carbon capture equipment.

Expensive carbon capture equipment.
NPC/RDI Research

• I led a group during the NPC process that will publish a Topic Paper on regional supply and demand curves for CO2. Carbon Capture Coalition’s Regional Deployment Initiative is continuing and extending the work.

• Went through multiple carbon capture project engineering studies for each of the most promising industries. Tore them apart to distinguish real “capture cost” differences vs. mere noise in the assumptions.

• Bottom line(s):
  • Studies were relatively consistent in terms of the basic cost of capture equipment, compression, and balance of plant given size of project (MTPA) and CO2 molar concentration.
  • The headline “capture cost” (or avoided cost) numbers vary wildly because studies made wildly different assumptions about contractor process and project contingencies, estimates of remodeling/brownfield risks, extra non-capture equipment needed, owner costs and contingencies, financing rates, host plant capacity factors, project physical configurations, etc.
  • There were also plenty of straight up errors or strange assumptions made.
  • Studies that showed capture numbers in the $80-$150/MT had either gone to the expensive side of every assumption, made major mistakes, or both.
Cost, Drivers & Selection

• Costs:
  1. Function of original equipment cost (per ton captured) X financing rates,
  2. Operating & maintenance costs,
  3. and the fuel/electricity needed to run the capture equipment.

• Drivers:
  1. Lower equipment costs if capture plants are big,
  2. Lower equipment costs if emissions are concentrated,
  3. and lower operating costs where electricity and gas prices are low.

• Project selection/identification:
  1. Even if costs and drivers are similar need to look for emitters that operate most hours of the year,
  2. efficient emitter plants that are competitive in their particular industries,
  3. and the best streams of emissions inside complex plants.
Costs

• Biggest factor each year is **financing**: the original equipment cost ($ millions), multiplied times the annual financing rate (%).

• Remaining costs, typically in the area of ~$15-20/MT.
  - Typically about 3-6% of original equipment cost each year for overhead, taxes, and labor.
  - Balance for electric power and fuel. The fuel typically used to “regenerate” the materials (liquid or solid) that capture the CO2.

• The values of individual coefficients and prices vary widely among governments and consultants, but the calculation methodology is simple.
Simplified Example: Cement @ $43.25/MT CO2 Captured

• Financing:
  • $200 million plant x 10% per year financing rate = $20 million per year
  • Captures 1 million MT per year
  • So financing cost is $20/MT captured

• Running Costs:
  • $200 million plant x 5% O&M costs per year = $10 million per year.
  • Captures 1 million MT per year.
  • So $10/MT captured

• Fuel and electricity:
  • 2.5 MMBtu/MT x $3.50/MMBTU = $8.75/MT captured
  • 0.15 MWh/MT x $50/MWh = $4.50/MT
## Putting Studies on Comparable Basis: Cement

<table>
<thead>
<tr>
<th>Author</th>
<th>NETL/Booz</th>
<th>IEA/ Mott MacDonald</th>
<th>CEMCAP</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
<td>2008</td>
<td>2019</td>
</tr>
<tr>
<td><strong>TPY Product</strong></td>
<td>~ 1 million MT/yr cement</td>
<td>~ 1 million MT/yr cement</td>
<td>Approx 685 MT/yr Cement @ 85%</td>
</tr>
<tr>
<td><strong>Estimated actual captured tonnage</strong></td>
<td>~1 million MT/yr CO2</td>
<td>~1 million MT/yr CO2</td>
<td>0.791 million MT/yr CO2</td>
</tr>
<tr>
<td><strong>Cap Cost MT/yr</strong></td>
<td>$189.42</td>
<td>$132.61</td>
<td>$125.55</td>
</tr>
<tr>
<td><strong>O&amp;M as % CapCost</strong></td>
<td>8.9%</td>
<td>10.3%</td>
<td>10.1%</td>
</tr>
<tr>
<td><strong>O&amp;M per MT ex fuel, w/ tax ins</strong></td>
<td>$12.98</td>
<td>$13.71</td>
<td>$12.71</td>
</tr>
<tr>
<td><strong>Fuel MMBtu/MT for regen</strong></td>
<td>4.09</td>
<td>3.16</td>
<td>3.8016</td>
</tr>
<tr>
<td><strong>Elec. MMBtu/MT for capture</strong></td>
<td>0.16</td>
<td>0.19</td>
<td>0.15</td>
</tr>
<tr>
<td><strong>Est Cost 13% CRF, $3.5 gas, $50 elec</strong></td>
<td>$63.78</td>
<td>$51.48</td>
<td>$49.84</td>
</tr>
<tr>
<td><strong>Per Source Study unadjusted</strong></td>
<td>$100.44/MT &quot;first year break-even&quot;</td>
<td>$88 /MT cost of capture and $158/MT avoided cost</td>
<td>$90/MT avoided cost</td>
</tr>
<tr>
<td><strong>MDEA Unit $/MTPA</strong></td>
<td>$68.40</td>
<td>$46.75</td>
<td>~$45-50 (not broken out)</td>
</tr>
</tbody>
</table>

NETL study had mistaken ~$10/MT for spare parts each year.

70% of IEA capex was irrelevant, and they double counted interest during construction.

CEMCAP used 18% contingencies just on MEA unit; NETL used 22% contingencies on whole project.
<table>
<thead>
<tr>
<th>Industry</th>
<th>CO2 % in Gas Stream</th>
<th>Capturable Emissions MTPA @ 85% NCF</th>
<th>Construction Cost for Project</th>
<th>Construction Capital Cost $/MTPA</th>
<th>Capital Recovery/MT Captured @ 9.6% CRF</th>
<th>(5-8% x Cap Cost)</th>
<th>$3.50/MMBtu</th>
<th>$50.00/MWh</th>
<th>Total @ 9.6% CRF</th>
<th>Total @ 13% CRF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Processing</td>
<td>100%</td>
<td>600,000</td>
<td>$23,523,777</td>
<td>$39.2</td>
<td>$3.8</td>
<td>$2.4</td>
<td>$0.0</td>
<td>$4.8</td>
<td>$11.0</td>
<td>$13.8</td>
</tr>
<tr>
<td>Ethanol</td>
<td>100%</td>
<td>500,000</td>
<td>$24,468,162</td>
<td>$48.9</td>
<td>$4.7</td>
<td>$3.4</td>
<td>$0.0</td>
<td>$5.8</td>
<td>$13.9</td>
<td>$17.5</td>
</tr>
<tr>
<td>Ammonia</td>
<td>100%</td>
<td>400,000</td>
<td>$27,238,098</td>
<td>$68.1</td>
<td>$6.5</td>
<td>$3.4</td>
<td>$0.0</td>
<td>$5.0</td>
<td>$14.9</td>
<td>$19.7</td>
</tr>
<tr>
<td>Hydrogen</td>
<td>15-20% @ 20 Atm.</td>
<td>350,000</td>
<td>$58,781,549</td>
<td>$167.9</td>
<td>$16.1</td>
<td>$8.4</td>
<td>$8.9</td>
<td>$9.0</td>
<td>$42.4</td>
<td>$54.2</td>
</tr>
<tr>
<td>FCCU(Cat Cracker)</td>
<td>12-15%</td>
<td>1,000,000</td>
<td>$224,567,075</td>
<td>$224.6</td>
<td>$21.6</td>
<td>$9.9</td>
<td>$8.9</td>
<td>$7.2</td>
<td>$47.6</td>
<td>$63.0</td>
</tr>
<tr>
<td>Cement</td>
<td>21%</td>
<td>1,000,000</td>
<td>$187,382,810</td>
<td>$187.4</td>
<td>$18.0</td>
<td>$13.1</td>
<td>$8.9</td>
<td>$8.2</td>
<td>$48.3</td>
<td>$62.1</td>
</tr>
<tr>
<td>Blast Furnace Gas</td>
<td>26%</td>
<td>3,000,000</td>
<td>$841,816,517</td>
<td>$280.6</td>
<td>$26.9</td>
<td>$14.0</td>
<td>$8.9</td>
<td>$8.2</td>
<td>$58.1</td>
<td>$77.8</td>
</tr>
<tr>
<td>Pulverized Coal</td>
<td>13%</td>
<td>1,600,000</td>
<td>$478,097,307</td>
<td>$298.8</td>
<td>$28.7</td>
<td>$12.4</td>
<td>$8.9</td>
<td>$8.2</td>
<td>$58.3</td>
<td>$78.7</td>
</tr>
<tr>
<td>NGCC (gas power)</td>
<td>4%</td>
<td>1,000,000</td>
<td>$356,073,692</td>
<td>$356.1</td>
<td>$34.2</td>
<td>$17.8</td>
<td>$8.2</td>
<td>$0.0</td>
<td>$60.2</td>
<td>$85.1</td>
</tr>
</tbody>
</table>

(1) 9.6% is reasonable for projects with strong sponsors or balance sheets, or for utilities (NETL uses ~ this rate). 13% would be more appropriate for industrial companies.
(2) Only applies when there is an existing capture unit & not all captured CO2 is used to make final products such as urea.
(3) Few well-documented public studies isolating the high value Fluidized Catalytic Cracking Units in oil refineries or “stoves” burning Blast Furnace Gases in integrated steel mills.
Cost Drivers

• Physical factors:
  • Concentration of CO$_2$ in exhaust gases: higher = cheaper
  • Pressure of gas treated: higher = cheaper
  • Scale: bigger = cheaper

• Commodity prices:
  • Gas cost: low = better. Buy gas to make steam for capture process
  • Electricity cost: low = better. Buy electricity to run capture and compression equipment
Theory: CO₂ Concentration vs. Cost

Practice: Project Engineering Sample Confirms Theory

MEA Solvent AGR: $\text{Capex/MT/yr vs. CO}_2$ Concentration

- $\text{Capex/MTpy w/o Contingencies}$
- Molar Concentration of CO2 at System Inlet
## GCCSI and NETL Show Capture Cost RISING with Rising CO2 Concentration: Why?

<table>
<thead>
<tr>
<th>Industry</th>
<th>Capture Plant Size MMTPA</th>
<th>Flue Gas Concentration mol/mol</th>
<th>Steyer-Taylor Estimate of Capture Cost/MT*</th>
<th>Navigant Capture Median ($/ε @ 1.12)</th>
<th>Comello, Reichelstein, Wilcox et al Capture (added $10 for compression)</th>
<th>GCCSI Avoided FOAK (USA-Germany)</th>
<th>Booz Allen NETL Capture for NETL **</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pulverized Coal Plant</td>
<td>1.5</td>
<td>13%</td>
<td>$58</td>
<td>$47-53</td>
<td>$74-121</td>
<td>$56</td>
<td></td>
</tr>
<tr>
<td>Steel blast furnace gas</td>
<td>2.0</td>
<td>26%</td>
<td>$58</td>
<td>$60</td>
<td>$41-$44</td>
<td>$77-113</td>
<td>$99</td>
</tr>
<tr>
<td>Cement</td>
<td>1.0</td>
<td>21%</td>
<td>$48</td>
<td>$44</td>
<td>$38-$49</td>
<td>$124-188</td>
<td>$96-100</td>
</tr>
<tr>
<td>Hydrogen SMR</td>
<td>1.0</td>
<td>16% @ 20 ATM</td>
<td>$43</td>
<td>$32</td>
<td>~$38 [earlier paper]</td>
<td></td>
<td>$112-118</td>
</tr>
</tbody>
</table>

*used 9.6% capital recovery factor for 12 year project life.

** H2 p. 88, Steel p. 101, Cement p. 112. The coal number was 2013 case 11A vs 11B w/ extra $210.5 M/yr cost and 3.72 MMTPA captured.

Everybody is pretty close on coal.

Huge divergence on BFG, Cement, SMR
Selection and Configuration: Capturing CO$_2$ Efficiently

• Inside multi-emitter industrial complexes: focus on sub-systems with lowest-cost CO$_2$ capture

• Capture at the cost-minimizing spot in process (e.g., at a high pressure vs. low pressure stream point)—H$_2$ example.

• Customize capacity of equipment: don’t add extra capture equipment that won’t run very often

• Supply parasitic steam and electric loads cheaply

• Turnkey EPC if possible
1. Both Point “A” & Point “B” capture same number of CO2 molecules. But partial pressure $p_{CO2}$ at “A” is 5X $p_{CO2}$ at “B”. Thus “A” capex is only about 60% of “B” capex.

2. Average cost rises $30/MT from “A” to “C” ($31 to $61). However the marginal cost of additional tons captured at “C” = $108/MT.

*These are IEA figures converted to USD, and with energy costs at US levels. My study used “point A” configuration but more conservative capital costs, contingencies, etc. Using the IEA figures because they were only study I have seen that clearly examined all three capture points.
Selection: Cherry-picking Bigger and/or Higher Concentration Units

13 Largest of 33 CO$_2$ Emitters at a Large Refinery

- FCCU is biggest and has highest CO$_2$ concentration
- Three gas turbines could feed into a single ~2 million MTPA capture unit. Low concentration but large size and high NCF.
Selection Example: Sizing Capture Equipment so it Will Be Used Most Hours of the Year

CO2 Emissions tons WA Parish #7 2017

- 43% of Capacity of 2nd Train Idle
- 57% of Capacity of 2nd Train Used
- 8% of Capacity of 1st Train Idle
- 92% of Capacity of 1st Train Used

$85/MT Cost

$60/MT Cost
# Selection: Digging Through Top US Emitting Facilities

<table>
<thead>
<tr>
<th>Industry Type (subparts)</th>
<th>Captured Emissions (tons)</th>
<th>Total reported direct emissions</th>
<th>Total Expected Cost</th>
<th>Total Sensitivity</th>
<th>Cumulative MT in region (MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>C, D</td>
<td>3,200,000</td>
<td>11,494,053</td>
<td>$54.5</td>
<td>$71.4</td>
<td>82.33</td>
</tr>
<tr>
<td>C, D</td>
<td>3,200,000</td>
<td>8,543,454</td>
<td>$54.5</td>
<td>$71.4</td>
<td>85.53</td>
</tr>
<tr>
<td>C, H</td>
<td>629,042</td>
<td>711,186</td>
<td>$54.6</td>
<td>$70.0</td>
<td>86.15</td>
</tr>
<tr>
<td>C, D</td>
<td>3,043,300</td>
<td>5,431,750</td>
<td>$54.7</td>
<td>$71.7</td>
<td>89.20</td>
</tr>
<tr>
<td>C, MM, REF, F</td>
<td>116,035</td>
<td>1,995,829</td>
<td>$55.0</td>
<td>$71.3</td>
<td>89.32</td>
</tr>
<tr>
<td>C, H</td>
<td>607,184</td>
<td>674,956</td>
<td>$55.1</td>
<td>$70.7</td>
<td>89.92</td>
</tr>
<tr>
<td>D</td>
<td>1,600,000</td>
<td>3,554,771</td>
<td>$55.4</td>
<td>$75.2</td>
<td>91.52</td>
</tr>
<tr>
<td>D</td>
<td>1,600,000</td>
<td>2,322,417</td>
<td>$55.4</td>
<td>$76.2</td>
<td>93.12</td>
</tr>
<tr>
<td>C, D</td>
<td>1,600,000</td>
<td>1,357,688</td>
<td>$55.4</td>
<td>$76.2</td>
<td>94.72</td>
</tr>
<tr>
<td>C, Q, S</td>
<td>4,372,598</td>
<td>6,972,176</td>
<td>$55.5</td>
<td>$72.3</td>
<td>98.10</td>
</tr>
<tr>
<td>C, D</td>
<td>2,400,000</td>
<td>7,998,057</td>
<td>$55.6</td>
<td>$73.0</td>
<td>101.50</td>
</tr>
<tr>
<td>C, H</td>
<td>548,429</td>
<td>616,524</td>
<td>$56.6</td>
<td>$72.8</td>
<td>102.04</td>
</tr>
<tr>
<td>C, MM, REF, F</td>
<td>522,113</td>
<td>1,750,804</td>
<td>$56.7</td>
<td>$75.0</td>
<td>102.55</td>
</tr>
<tr>
<td>C, P, Y</td>
<td>520,251</td>
<td></td>
<td>$56.8</td>
<td>$75.1</td>
<td>103.08</td>
</tr>
<tr>
<td>C, Q</td>
<td>2,885,381</td>
<td>10,134,131</td>
<td>$57.1</td>
<td>$74.7</td>
<td>105.97</td>
</tr>
</tbody>
</table>

- **Reason Selected**: 3x720MW, could hook up different.
- **Facility Name**: WESTAR ENERGY, INC.
- **State**: KS
- **Latitude**: 39.2825
- **Longitude**: -96.1153
- **Total Expected Cost**: $54.5
- **Total Sensitivity**: $71.4
- **Cumulative MT in region (MM)**: 82.33

- **Reason Selected**: New runs at high ncf & big.
- **Facility Name**: Nebraska City Station
- **State**: NE
- **Latitude**: 40.6215
- **Longitude**: -95.7765
- **Total Expected Cost**: $54.5
- **Total Sensitivity**: $71.4
- **Cumulative MT in region (MM)**: 85.53

- **Reason Selected**: Cement
- **Facility Name**: Ash Grove Cement
- **State**: NE
- **Latitude**: 41.005565
- **Longitude**: -96.1549
- **Total Expected Cost**: $54.6
- **Total Sensitivity**: $70.0
- **Cumulative MT in region (MM)**: 86.15

- **Reason Selected**: IGCC
- **Facility Name**: Edgewood IGCC
- **State**: IN
- **Latitude**: 38.8067
- **Longitude**: -87.2472
- **Total Expected Cost**: $54.7
- **Total Sensitivity**: $71.7
- **Cumulative MT in region (MM)**: 89.20

- **Reason Selected**: H2 >100k useful
- **Facility Name**: Phillips 56 Ponca
- **State**: OK
- **Latitude**: 35.68807
- **Longitude**: -97.0879
- **Total Expected Cost**: $55.0
- **Total Sensitivity**: $71.3
- **Cumulative MT in region (MM)**: 89.32

- **Reason Selected**: Cement
- **Facility Name**: Ash Grove Cement
- **State**: TX
- **Latitude**: 32.51093
- **Longitude**: -97.0068
- **Total Expected Cost**: $55.1
- **Total Sensitivity**: $70.7
- **Cumulative MT in region (MM)**: 89.92

- **Reason Selected**: Two 3x1, 70% NCEF, ERCOT, 71% ORHR
- **Facility Name**: Forney Power Plan
- **State**: TX
- **Latitude**: 32.7563
- **Longitude**: -96.4916
- **Total Expected Cost**: $55.4
- **Total Sensitivity**: $75.2
- **Cumulative MT in region (MM)**: 91.52

- **Reason Selected**: ERCOT, 7900hrs, 7100HR, 83% NCEF
- **Facility Name**: Lamar Power (Paris)
- **State**: TX
- **Latitude**: 33.6314
- **Longitude**: -95.589
- **Total Expected Cost**: $55.4
- **Total Sensitivity**: $76.2
- **Cumulative MT in region (MM)**: 93.12

- **Reason Selected**: 2 units CC2 2017 built, 6800HR
- **Facility Name**: Wolf Hollow II
- **State**: TX
- **Latitude**: 32.35793
- **Longitude**: -97.7387
- **Total Expected Cost**: $55.4
- **Total Sensitivity**: $76.2
- **Cumulative MT in region (MM)**: 94.72

- **Reason Selected**: Steel
- **Facility Name**: Mittal Steel USA - Ind In
- **State**: TX
- **Latitude**: 41.68
- **Longitude**: -87.4264
- **Total Expected Cost**: $55.5
- **Total Sensitivity**: $72.3
- **Cumulative MT in region (MM)**: 98.10

- **Reason Selected**: #3 37yo, 9800hr, ren 7500hrs, 799
- **Facility Name**: Thomas Hill Energy
- **State**: MO
- **Latitude**: 39.58511
- **Longitude**: -92.6392
- **Total Expected Cost**: $55.6
- **Total Sensitivity**: $73.0
- **Cumulative MT in region (MM)**: 101.50

- **Reason Selected**: Medium size cement
- **Facility Name**: LEHIGH CEMENT CO L I A
- **State**: TX
- **Latitude**: 43.1788
- **Longitude**: -93.2186
- **Total Expected Cost**: $56.6
- **Total Sensitivity**: $72.8
- **Cumulative MT in region (MM)**: 102.04

- **Reason Selected**: FCC 6MM Mthy
- **Facility Name**: Lemont Refinery
- **State**: IL
- **Latitude**: 41.6463
- **Longitude**: -88.0467
- **Total Expected Cost**: $56.7
- **Total Sensitivity**: $75.0
- **Cumulative MT in region (MM)**: 102.55

- **Reason Selected**: Small FCC
- **Facility Name**: Flint Hills Resources
- **State**: MN
- **Latitude**: 44.7684
- **Longitude**: -93.0406
- **Total Expected Cost**: $56.8
- **Total Sensitivity**: $75.1
- **Cumulative MT in region (MM)**: 103.08

- **Reason Selected**: Large blast
- **Facility Name**: ARCELORMITTAL BURNIN
- **State**: IN
- **Latitude**: 41.627864
- **Longitude**: -87.1438
- **Total Expected Cost**: $57.1
- **Total Sensitivity**: $74.7
- **Cumulative MT in region (MM)**: 105.97
Part III: Sales to CO2-EOR Market
CO2-EOR Break-evens by Field with Varying Oil Prices

Neighboring Oilfields Have Very Different CO₂ Price Points for any Given Oil Price

Field X
- buys at $80 WTI/ $55 CO₂

Field Y
- will also buy @ $55 CO₂

Field Z
- can’t afford that price
Part IV: Regional Supply & Demand
Because supply curve so flat, small shifts in demand make a quantum change.
Supply/Demand Balances in Mid-West w TX Permian exc. TX8

- Reduced Cost
- High Cost
- Demand $40 Oil
- Demand $60 Oil

Millions of Metric Tons per Annum Purchased & Injected

$Cost/MT Capture & $3545Q less Transport

Revenue/MT

- ~45, $63
- ~90, $55
- 103; $75
- 135; $60
Supply/Demand Balances in Rockies plus WTX8

- Reduced Cost
- High Cost
- Demand $40 Oil
- Demand $60 Oil

Cost/MT Capture & Revenue/MT (EOR + $3545Q less Transport)

- $10
- $20
- $30
- $40
- $50
- $60
- $70
- $80
- $90
- $100

- $5, $62
- $15, $52
- $27, $72
- $50, $58

Millions of Metric Tons per Annum Purchased & Injected

- ~5
- ~15
- ~27
<table>
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<th>Region</th>
<th>Commodity price risk not addressed: Low/unstable oil</th>
<th>Commodity price risk is addressed: High/stable oil</th>
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<tr>
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<td>#1 Worst/Worst</td>
<td>#2 Oil Mitigated</td>
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<td>Gulf 15</td>
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<td>Midwest 45</td>
<td>Midwest 103</td>
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<th>Region</th>
<th>#3 1st Mover Mitigated</th>
<th>#4 Best Case</th>
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Three-Region Pipeline Optimization for "Best Cases"
Key Policy Issues

• Taking the fear factor out of “first-mover through fifth-mover projects”. Much more active commercial deployment support at DOE is mandatory in my view.

• Mitigating commodity price risk and its consequences for capital structure and cost of funds.
  • Federal Contract for Differences program similar to UK
  • In power sector, Clean Energy Standards procurement with solid long term capacity payments

• Mitigating the timing/logistical risk of assembling large groups of shippers—all at the same time—to contract for CO2 pipeline capacity.
What data & analysis are needed to inform policymakers and stakeholders in order to spur more CO2 EOR activity in the US?