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<YEAR> = 2018

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# Acronyms and Abbreviations

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<th>Symbol</th>
<th>Description</th>
<th>Unit</th>
<th>Description</th>
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</thead>
<tbody>
<tr>
<td>°C</td>
<td>Degree Celsius, degrees Celsius</td>
<td>mi</td>
<td>Mile, miles</td>
</tr>
<tr>
<td>°F</td>
<td>Degree Fahrenheit, degrees Fahrenheit</td>
<td>MIT</td>
<td>Massachusetts Institute of Technology</td>
</tr>
<tr>
<td>ADS</td>
<td>Alternative Depreciation System</td>
<td>mol</td>
<td>Mole, moles</td>
</tr>
<tr>
<td>CAPEX</td>
<td>Capital costs or expenses</td>
<td>NETL</td>
<td>National Energy Technology Laboratory</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
<td>NPV</td>
<td>Net present value</td>
</tr>
<tr>
<td>DOE</td>
<td>Department of Energy</td>
<td>O&amp;M</td>
<td>Operation and maintenance</td>
</tr>
<tr>
<td>EIA</td>
<td>Energy Information Administration</td>
<td>OPEX</td>
<td>Operations and maintenance costs or expenses</td>
</tr>
<tr>
<td>FE</td>
<td>Fossil Energy</td>
<td>Pa</td>
<td>Pascal, pascals</td>
</tr>
<tr>
<td>ft</td>
<td>Foot, feet</td>
<td>psig</td>
<td>Pound per square inch gage, pounds per square inch gage</td>
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<tr>
<td>ft²</td>
<td>Square foot, square feet</td>
<td>ROW</td>
<td>Right-of-way, rights-of-way</td>
</tr>
<tr>
<td>GDS</td>
<td>General Depreciation System</td>
<td>s</td>
<td>Second, seconds</td>
</tr>
<tr>
<td>hr</td>
<td>Hour, hours</td>
<td>s²</td>
<td>Second squared, seconds squared</td>
</tr>
<tr>
<td>in</td>
<td>Inch, inches</td>
<td>tonne</td>
<td>Metric ton, metric tons (1,000 kg)</td>
</tr>
<tr>
<td>IRROE</td>
<td>Internal rate of return on equity</td>
<td>U.S.</td>
<td>United States</td>
</tr>
<tr>
<td>IRS</td>
<td>Internal Revenue Service</td>
<td>W</td>
<td>Watt, watts</td>
</tr>
<tr>
<td>K</td>
<td>Kelvin</td>
<td>WACC</td>
<td>Weighted average cost of capital</td>
</tr>
<tr>
<td>kg</td>
<td>Kilogram, kilograms</td>
<td>yr</td>
<td>Year, years</td>
</tr>
<tr>
<td>km</td>
<td>Kilometer, kilometers</td>
<td></td>
<td></td>
</tr>
<tr>
<td>kW</td>
<td>Kilowatt, kilowatts</td>
<td></td>
<td></td>
</tr>
<tr>
<td>m</td>
<td>Meter, meters</td>
<td></td>
<td></td>
</tr>
<tr>
<td>m³</td>
<td>Cubic meter, cubic meters</td>
<td></td>
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</tr>
<tr>
<td>MACRS</td>
<td>Modified Accelerated Cost Recovery System</td>
<td></td>
<td></td>
</tr>
<tr>
<td>m²</td>
<td>Second squared, seconds squared</td>
<td></td>
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<tr>
<td>mi</td>
<td>Mile, miles</td>
<td></td>
<td></td>
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<tr>
<td>mi²</td>
<td>Square mile, square miles</td>
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<td>Pa</td>
<td>Pascal, pascals</td>
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<td>psig</td>
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<td>Right-of-way, rights-of-way</td>
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<td>s</td>
<td>Second, seconds</td>
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<tr>
<td>s²</td>
<td>Second squared, seconds squared</td>
<td></td>
<td></td>
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<tr>
<td>tonne</td>
<td>Metric ton, metric tons (1,000 kg)</td>
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<tr>
<td>U.S.</td>
<td>United States</td>
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<tr>
<td>W</td>
<td>Watt, watts</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WACC</td>
<td>Weighted average cost of capital</td>
<td></td>
<td></td>
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<tr>
<td>yr</td>
<td>Year, years</td>
<td></td>
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This page intentionally left blank.
The United States (U.S.) Department of Energy’s (DOE) Office of Fossil Energy (FE) at the National Energy Technology Laboratory (NETL) developed the FE/NETL CO₂ Transport Cost Model (Transport Cost Model). [1] This model is an Excel-based mathematical model that estimates the cost of transporting dense phase (liquid) carbon dioxide (CO₂) using a pipeline. Costs are estimated for a single point-to-point pipeline, which may have pumps along the pipeline to boost the pressure. The Transport Cost Model calculates the first-year break-even price, or break-even cost, of transporting CO₂ (in dollars per tonne) that covers all costs (including taxes and debt) and provides investors with their desired minimum return on investment. The purpose of this model is to mimic CO₂ transport operations to estimate the costs associated with a potential CO₂ pipeline project. The Transport Cost Model provides a flexible way to allow users to tailor the model to fit the requirements of each individual project by adjusting parameters (e.g., financial parameters and project duration). It includes the capital costs for purchasing and installing the pipeline, a surge tank, a control system, and, if economical, the booster pumps. Costs are not included for a relatively high-resolution meter to measure the flow of CO₂ in the pipeline. It is assumed that the cost for such meters, one at the CO₂ source and one at the CO₂ storage site, are borne by the generator of the CO₂ source and the operator of the CO₂ storage site. The Transport Cost Model also includes operation and maintenance (O&M) costs for the pipeline and pumps and the cost of the electricity used to power the pumps. The model has an engineering module with equations for pipe size, booster pumps, and equipment capital and operating costs and a financial module with project cash flows including capital costs, operating costs, debt, equity, depreciation, and taxes. The costs that are estimated using the Transport Cost Model are screening-level costs that are accurate at the +50/-30 level of accuracy.

This report describes the Transport Cost Model, discusses user inputs and instructions for use, and provides example output from the model. It is outlined as follows:

- Section 2 – Describes the engineering module and provides equations for determining the minimum practical pipe diameter and power requirements for booster pumps, as well as the capital and operating costs for all aspects of the pipeline
- Section 3 – Explains the financial module and provides equations for calculating the weighted average cost of capital (WACC)
- Section 4 – Describes the inputs needed for the model and how to use the model
- Section 5 – Provides example results from the model
- Section 6 – Presents a list of references cited in the report

The Transport Cost Model consists of eight worksheets along with Visual Basic macros and user-defined functions. Of the eight worksheets, one is introductory (“READ_ME_FIRST”), two are core (“Main” and “Eng Mod”), and the remaining five (“PL Pressure Relation,” “Cost Indices,” “Pipe Cap,” “Pipe Cap plot1,” and “Pipe Cap plot2”) provide useful information but are not critical to the functioning of the model. The eight worksheets and a summary on each are discussed below.
1. **READ_ME_FIRST**

A brief overview of the model and a brief description of the tabs in the workbook are within this sheet. The “READ_ME_FIRST” tab also provides information on color and font conventions along with fundamental model assumptions. The color conventions are specific colors used consistently throughout the model to provide immediate visual indicators of the purpose of certain cells. The most important convention, the light orange input cell color, is listed first. This sheet also has the BSD 1 open source software license.

2. **Main**

This tab is the primary user interface for the model. It includes critical inputs and outputs, the financial module, and a macro that determines the break-even price for transporting CO\(_2\) in the pipeline. Actual calculations are performed in this sheet. More information on the financial module is described in Section 3. Other content within this tab is described in Section 4.

3. **Eng Mod**

The engineering module includes engineering equations and capital and operating expenses. The equations within the “Eng Mod” sheet are used to size the pipe and booster pumps and estimate the capital and annual operating costs for the equipment composing the pipeline. This tab provides several inputs and summarizes results. Actual calculations are performed in this sheet. More information on the engineering module is described in Section 2. Other content within this tab is described in Section 4.

4. **PL Pressure Relation**

This sheet provides information from ICF International [2] on pressures in natural gas and CO\(_2\) pipelines (which are generally higher) and how capital costs for CO\(_2\) pipelines need to be increased to accommodate the higher pressures. It also includes data for developing a factor to translate natural gas pipeline capital costs to CO\(_2\) pipeline capital costs.

5. **Cost Indices**

Indices for adjusting costs and prices from a basis in one year to another year are provided in this tab.

6. **Pipe Cap**

This sheet has tables with capital costs for different aspects of constructing a natural gas or petroleum pipeline using three different cost models.

7. **Pipe Cap plot1**

Tables and plots of capital costs for different aspects of constructing a natural gas or petroleum pipeline using three different cost models are within this tab. The plots are used within this report in Section 5.

8. **Pipe Cap plot2**

This sheet contains tables of capital costs for different aspects of constructing a natural gas or petroleum or CO\(_2\) pipeline using three different cost models.
2 ENGINEERING MODULE

The engineering module is within the “Eng Mod” sheet. The engineering module includes the equations used to size the pipeline and booster pumps deployed along the pipeline. It also includes the equations used to estimate the capital and operating costs for the piping, booster pumps, and other equipment that compose the pipeline. These equations are explained in the following subsections. Within the “Eng Mod” tab, the user can provide inputs (e.g., ground temperature and pump efficiency) and see certain results. More information on the inputs within this sheet are in Section 4.1.

The costs of procuring materials and installing a pipeline depend on the length and diameter of the pipeline. The diameter of the pipeline depends on the mass flow rate of CO$_2$ in the pipe, allowable pressure losses in the pipeline, elevation differences along the pipeline, and the number of booster pumps in the pipeline. Thus, important inputs to the Transport Cost Model include the following: the length of the pipeline, the mass flow rate of CO$_2$, the inlet pressure and temperature, the required delivery pressure, the elevation of the pipeline at the inlet, the elevation of the pipeline at the outlet, and the number of booster pumps along the pipeline. The CO$_2$ fluid is assumed to have relatively few impurities (including water) such that the properties of pure CO$_2$ (such as density and viscosity) can be considered reasonable approximations for the properties of the fluid in the pipe.

If there are one or more booster pumps, it is assumed that the pipeline is divided into segments of equal length with the length of a segment equal to the length of the pipeline divided by the number of pumps plus one. Each booster pump is assumed to boost the pressure at the beginning of a new pipe segment to the pressure at the inlet of the pipeline. The pressure at the end of a pipe segment is assumed to be equal to the pressure at the outlet of the pipeline. The elevation difference is assumed to be evenly distributed along all segments of the pipeline. With these assumptions, each segment in the pipeline is identical with respect to pressure loss and elevation changes.

2.1 CALCULATION OF INNER PIPELINE DIAMETER

The Transport Cost Model provides three equations for calculating the minimum inner diameter of the pipeline based on work done by McCollum and Ogden, Heddle et al., the Massachusetts Institute of Technology (MIT), and McCoy and Rubin. [3, 4, 5, 6] It is important to note that Heddle et al. and MIT are listed together as one of the three methods for calculating inner pipeline diameter within the model. However, they both, along with McCollum and Ogden, provided the following equation for the inner diameter: [3, 4, 5]

$$D = \left( \frac{32 \cdot f_r \cdot q_{max}^2}{\pi^2 \cdot \rho_{CO2} \cdot \left(\frac{\Delta P}{L}\right)} \right)^{0.2}$$

**Eq. 1**

Where:

- $D$ = inner diameter of pipe (m)
- $q_{max}$ = maximum mass flow rate of CO$_2$ in pipe (kg/s)
- $f_r$ = Fanning friction factor (dimensionless)
\[ \rho_{\text{CO}_2} = \text{density of CO}_2 (\text{kg/m}^3) \]

\[ \Delta P = \text{change in pressure along pipe segment (Pa)} \]

\[ L = \text{length of pipe segment (m)} \]

To solve Eq. 1, the maximum mass flow rate, the maximum allowable pressure drop in a pipe segment, and the length of the pipe segment must be determined. The length of the pipeline is user specified. If the pipeline has booster pumps, the pipeline is assumed to be divided into equal length segments with a booster pump at the end of all segments except the last. Thus, the length of a pipeline segment is calculated by the model based on the number of booster pumps.

The maximum mass flow rate depends on the capacity factor for the pipeline.

\[ q_{\text{max}} = \frac{q_{\text{av}}}{CF} \quad \text{Eq. 2} \]

Where:

\[ q_{\text{av}} = \text{annual average mass flow rate of CO}_2 \text{ in pipe (kg/s)} \]

\[ CF = \text{capacity factor of the pipeline (80 percent is default value in model)} \]

The pressure loss is the pressure lost from friction plus the pressure lost or gained from the increase or decrease of elevation along the pipe segment.

\[ \Delta P = (P_{\text{in}} - P_{\text{out}}) - (h_{\text{out}} - h_{\text{in}}) \cdot \rho_{\text{CO}_2} \cdot g \quad \text{Eq. 3} \]

Where:

\[ P_{\text{in}} = \text{pressure at the inlet of the pipe segment (Pa)} \]

\[ P_{\text{out}} = \text{pressure at the outlet of the pipe segment (Pa)} \]

\[ h_{\text{in}} = \text{elevation of the inlet of the pipe segment above a reference elevation (m)} \]

\[ h_{\text{out}} = \text{elevation of the outlet of the pipe segment above a reference elevation (m)} \]

\[ g = \text{acceleration due to gravity (9.80665 m/s}^2) \]

The Fanning friction factor is a dimensionless quantity that is defined as \( \frac{1}{4} \) the Darcy friction factor. The Darcy friction factor is the same as the Moody friction factor; the term “Darcy friction factor” is used in this document. The Darcy friction factor must be determined empirically, but there are many correlation equations for determining the Darcy friction factor as a function of the Reynolds number, the inner diameter of the pipe, and the roughness height of the inner surface of the pipe. In the model, the Colebrook equation is used to estimate the Darcy friction factor.

\[ \frac{1}{\sqrt{f_D}} = -2 \cdot \log_{10} \left( \frac{e}{3.7} + \frac{2.51}{Re\sqrt{f_D}} \right) \quad \text{Eq. 4} \]

Where:
\( \varepsilon \) = roughness height of the inner surface of the pipe (m)  
\( \text{Re} \) = Reynolds number (dimensionless)  
\( f_D \) = Darcy friction factor (dimensionless)

The Reynolds number is a dimensionless quantity given by the following equation for flow in a circular pipe:

\[
Re = \frac{4 \cdot q_{\text{max}}}{\pi \cdot \mu \cdot D} \quad \text{Eq. 5}
\]

Where:
\( \mu \) = viscosity of CO\(_2\) in the pipe (Pa·s)

Eq. 1, Eq. 3, and Eq. 4 have interdependencies, with Eq. 1 (for diameter \( D \)) dependent on the Fanning friction factor (\( f_f \)), which depends, through Eq. 4 on diameter \( D \) and the Reynolds number (\( \text{Re} \)). The Reynolds number depends on diameter \( D \) (see Eq. 5). Thus, to determine the diameter, an iterative procedure is needed.

- Step 1: Provide an initial guess for the diameter, \( D_{\text{cur}} \)
- Step 2: Calculate the Reynolds number using \( D_{\text{cur}} \) and Eq. 5
- Step 3: Calculate \( f_D \) using Eq. 4 and \( D_{\text{cur}} \). Eq. 4 is an implicit equation and is solved using the Newton-Raphson method.\(^a\) The Fanning friction factor, \( f_f \), is \( \frac{1}{4} \) the Darcy friction factor
- Step 4: Calculate a new value for the diameter, \( D_{\text{new}} \), using Eq. 1 and \( q_{\text{max}} \) calculated per Eq. 2
- Step 5: Calculate the absolute relative difference between the two estimates for the diameter using \( D_{\text{cur}} \) and \( D_{\text{new}} \) from Step 4

\[
\Delta D = \text{abs} \left( \frac{D_{\text{new}} - D_{\text{cur}}}{D_{\text{new}}} \right) \quad \text{Eq. 6}
\]

- Step 6: If the relative difference \( \Delta D \) is less than \( 10^{-6} \), then the two values are considered to have converged, and \( D_{\text{new}} \) is used as the minimum inner diameter needed for the pipeline. If the relative difference \( \Delta D \) is greater than or equal to \( 10^{-6} \), then \( D_{\text{cur}} \) is set to the value of \( D_{\text{new}} \) and the procedure is repeated starting at Step 2.

McCoy and Rubin utilized a similar procedure to calculate the inner pipeline diameter; however, they began with an energy balance on the pipe segment and developed the equation below.\(^{[6]}\) McCoy and Rubin indicated that their derivation was adapted from that provided in Mohitpouri et al.\(^{[6, 7]}\)

\(^a\) For more information on the Newton-Raphson method, please refer to a journal article by Akram and ul Ann that explains the method and provides examples.\(^{[21]}\)
\[ D = \left\{ \frac{-64 \cdot Z_{ave}^2 \cdot R^2 \cdot T_{ave}^2 \cdot f_f \cdot q_{max}^2 \cdot L}{\pi^2 (M \cdot Z_{ave} \cdot R \cdot T_{ave} \cdot (P_{ave}^2 - P_{in}^2) + 2 \cdot g \cdot P_{ave}^2 \cdot M^2 \cdot (h_{out} - h_{in})} \right\}^{0.2} \]  \text{Eq. 7}

Where:

- \( R \) = universal gas constant (8.314 m³·Pa/K·mol)
- \( M \) = molecular weight of CO₂ (44.01×10⁻³ kg/mol)
- \( Z_{ave} \) = compressibility factor for CO₂ (dimensionless)
- \( T_{ave} \) = average temperature of CO₂ in the pipeline (K), assumed to be the ground temperature (about 285 K, 12 °C, or 53 °F)
- \( P_{ave} \) = average pressure of CO₂ in the pipe (Pa), given in Eq. 8

\[ P_{ave} = \frac{2}{3} \left( P_{out} + P_{in} - \frac{P_{out} \cdot P_{in}}{P_{out} + P_{in}} \right) \]  \text{Eq. 8}

Eq. 7 replaces Eq. 1 in the above procedure for calculating the minimum inner diameter for a pipe.

In the above equations, the density of CO₂ and the compressibility factor for CO₂ are calculated using the Peng-Robinson equation of state\(^b\) and implemented as user defined functions in Excel with Visual Basic. The average pressure and average temperature in the pipeline are used to calculate the density and compressibility factor.

When there is no elevation difference (i.e., \( h_{in} = h_{out} \)), Eq. 1 and Eq. 7 yield very similar estimates for the inner diameter of the pipeline (within 1 percent of each other). When there is an elevation difference, the diameter calculated with Eq. 1 is smaller than the diameter calculated with Eq. 7. Eq. 7 is derived from an energy balance on the pipe segment where the influence of elevation on the potential energy of the fluid in the pipe is explicitly included in the derivation, whereas the influence of elevation on pressure is included in Eq. 1 (through Eq. 3) in a more ad hoc manner.

The minimum calculated inner diameter is almost never the actual inner diameter for a standard pipe. The model rounds up to one of the following standard pipe diameters: 4, 6, 8, 12, 16, 20, 24, 30, 36, 42, or 48 inches (in). The standard pipe diameters, 4, 6, 8, and 12 in, are inner diameters, while the remaining diameters – 16, 20, 24, 30, 36, 42, and 48 in – are outer diameters. The model rounds up to a corresponding inner diameter for each pipe. In the model, the minimum diameter is determined in metric units (meters), and then converted to inches for comparison to the inner diameters of standard pipe sizes.

\(^b\) For more information on the Peng-Robinson equation of state, please refer to a journal article by Lopez-Echeverry et. al. that discusses the history of the equation as well as modifications. [22]
2.2 EQUATIONS FOR CAPITAL AND OPERATING COSTS FOR THE PIPELINE

The Transport Cost Model calculates both capital and operating costs for the pipeline, CO$_2$ surge tank, and pipeline control system. The cost calculations are based on numerous equations from different pipeline related studies. Capital costs are incurred during the project construction years, while operating costs are incurred during the project operation years.

2.2.1 Capital Costs for Pipeline

The Oil and Gas Journal provides data on the capital cost of constructing natural gas, oil, and petroleum pipelines. It provides this data on an annual basis and provides cost data in that year by state with the diameter and length of each pipeline specified. The numbers provided are supposed to be as-built costs, although the numbers in a given year may be estimates of the as-built costs that the pipeline companies file with the U.S. Federal Energy Regulatory Commission. The Oil and Gas Journal also provides the capital cost in dollars per mile for pipelines of different diameters for the previous ten years for the whole United States. While the Oil and Gas Journal provides costs for oil and petroleum pipelines as well as natural gas pipelines, most of the pipelines are natural gas. Capital costs are provided for four categories:

- **Materials**: Can include line pipe, pipe coating, and cathodic protection
- **Labor**: Labor costs
- **Right-of-way (ROW) & damages**: Include obtaining ROW and allowances for damages
- **Miscellaneous**: Generally cover surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction, administration and overheads, and regulatory filing fees

Studies done by Parker, McCoy and Rubin, and Rui et al. have used the capital cost data provided in the Oil and Gas Journal to estimate parameters in cost models. [6, 8, 9]

Parker used cost data for the overall United States and estimated parameters in an equation of the following form: [8]

\[
C_{\text{png-par-i}} = a_{i-0} + L \cdot (a_{i-1} \cdot D^2 + a_{i-2} \cdot D + a_{i-3})
\]

Eq. 9

Where:

- $C_{\text{png-par-i}}$ = natural gas pipeline capital cost for category i (i = “mat” for materials, “lab” for labor, “ROW” for ROW & damages, or “misc” for miscellaneous) using the equation from Parker (cost in 2000 dollars [2000$]) [8]
- L = length of the pipeline (mi)
- D = standard diameter of pipeline (in)
- $a_{i-0}, a_{i-1}, a_{i-2}, a_{i-3}$ = parameters that are determined by fitting the equation to the capital cost data
Using pipeline capital cost data for the whole United States from 1991 to 2003, Parker estimated values for the parameters in Eq. 9 for each cost category (see Exhibit 2-1). [8] The result of applying Eq. 9 with the parameter values in Exhibit 2-1 are capital costs in 2000$.

It is important to note that in the study done by Parker [8], two different equations were provided for ROW capital costs. Figure 18 within the Parker study [8] shows data for ROW capital costs (dollars per mile) versus pipeline diameter (inches) fitted to a polynomial equation. This equation is linear with respect to pipeline diameter. When the best-fit equation for the ROW capital costs was transcribed to text with the estimated parameters (displayed below Figure 18 in the Parker study [8]), all variables were the same as the equation shown in Figure 18, but the pipeline diameter term was squared instead of linear. After testing both equations with different pipeline diameters and comparing the results to the data in Figure 18, the equation with the pipeline diameter as a linear term provided a better fit to the ROW data. The equation with the squared pipeline diameter term provided ROW costs that were much higher than any of the measured ROW costs when the pipeline diameter exceeded 20 in. Therefore, the ROW capital cost equation with the linear pipeline diameter term was used in the model. The equations for the capital costs of the other categories (materials, labor, and miscellaneous) in the Parker study [8] were the same between the figure and the text.

### Exhibit 2-1 Values for parameters in equation provided by Parker [8]

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Materials</th>
<th>Labor</th>
<th>ROW &amp; Damages</th>
<th>Miscellaneous</th>
</tr>
</thead>
<tbody>
<tr>
<td>$a_{i-0}$</td>
<td>35,000</td>
<td>185,000</td>
<td>40,000</td>
<td>95,000</td>
</tr>
<tr>
<td>$a_{i-1}$</td>
<td>330.5</td>
<td>343</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>$a_{i-2}$</td>
<td>687</td>
<td>2,074</td>
<td>577</td>
<td>8,417</td>
</tr>
<tr>
<td>$a_{i-3}$</td>
<td>26,960</td>
<td>170,013</td>
<td>29,788</td>
<td>7,324</td>
</tr>
</tbody>
</table>

McCoy and Rubin segregated the pipeline capital costs into six different regions of the United States using the regional definitions that the U.S. Energy Information Agency (EIA) uses when segregating natural gas pipeline costs, as illustrated in Exhibit 2-2. [6]
McCoy and Rubin estimated parameters in an equation of the following form: [6]

\[ C_{\text{png-mcc-i}} = 10^{(a_{i-0} + a_{i-\text{reg}})} \cdot L^{a_{i-1}} \cdot D^{a_{i-2}} \]  

*Eq. 10*

Where:

- \( C_{\text{png-mcc-i}} \) = natural gas pipeline capital cost for category \( i \) (\( i = \) “mat” for materials, “lab” for labor, “ROW” for ROW & damages, or “misc” for miscellaneous) using the equation from McCoy and Rubin (cost in 2004 dollars [2004$]) [6]
- \( L \) = length of the pipeline (km)
- \( D \) = standard diameter of pipeline (in)
- \( a_{i-0}, a_{i-\text{reg}}, a_{i-1}, a_{i-2} \) = parameters that are determined by fitting the equation to the capital cost data

The parameter \( a_{i-\text{reg}} \) is region-specific, where “reg” can refer to “NE” (Northeast), “SE” (Southeast), “MW” (Midwest), “Cen” (Central), “SW” (Southwest), or “West” (Western). Using pipeline capital cost data for different regions in the United States from 1995 to 2005, McCoy and Rubin estimated values for the parameters in Eq. 10 for each cost category (see Exhibit 2-3). [6] The result of applying Eq. 10 with the parameter values in Exhibit 2-3 are capital costs in 2004$. 
Rui et al. also segregated the pipeline capital costs into the six different regions of the United States defined by EIA, developed costs for constructing natural gas pipelines in Canada, and estimated parameters in an equation with a form like that used by McCoy and Rubin: [6, 9]

\[
C_{p,n,g-rui-i} = e^{(a_{i-0} + a_{i-reg})} \cdot L^{a_{i-1}} \cdot S A^{a_{i-2}}
\]

Eq. 11

Where:

\(C_{p,n,g-rui-i}\) = natural gas pipeline capital cost for category i (i = “mat” for materials, “lab” for labor, “ROW” for ROW & damages, or “misc” for miscellaneous) using the equation from Rui et al. (cost in 2008 dollars [2008$]) [9]

\(L\) = length of the pipeline (ft)

\(SA\) = cross-sectional surface area of the pipeline (i.e., \(\pi D^2/4\)) (ft²)

\(a_{i-0}, a_{i-reg}, a_{i-1}, a_{i-2}\) = parameters that are determined by fitting the equation to the capital cost data

The parameter \(a_{i-reg}\) is region-specific, where “reg” can refer to “NE,” “SE,” “MW,” “Cen,” “SW,” “West,” or “Can” (Canada). Using pipeline capital cost data for different regions in the United States and Canada from 1992 to 2008, Rui et al. estimated values for the parameters in Eq. 11 for each cost category (see Exhibit 2-4). [9] The result of applying Eq. 11 with the parameter values in Exhibit 2-4 are capital costs in 2008$. 

### Exhibit 2-3 Values for parameters in equation provided by McCoy and Rubin [6]

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Materials</th>
<th>Labor</th>
<th>ROW &amp; Damages</th>
<th>Miscellaneous</th>
</tr>
</thead>
<tbody>
<tr>
<td>a(_{i-0})</td>
<td>3.112</td>
<td>4.487</td>
<td>3.950</td>
<td>4.390</td>
</tr>
<tr>
<td>a(_{i-NE})</td>
<td>0</td>
<td>0.075</td>
<td>0</td>
<td>0.145</td>
</tr>
<tr>
<td>a(_{i-SE})</td>
<td>0.074</td>
<td>0</td>
<td>0</td>
<td>0.132</td>
</tr>
<tr>
<td>a(_{i-MW})</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>a(_{i-Cen})</td>
<td>0</td>
<td>-0.187</td>
<td>-0.382</td>
<td>-0.369</td>
</tr>
<tr>
<td>a(_{i-SW})</td>
<td>0</td>
<td>-0.216</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>a(_{i-West})</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-0.377</td>
</tr>
<tr>
<td>a(_{i-1})</td>
<td>0.901</td>
<td>0.820</td>
<td>1.049</td>
<td>0.783</td>
</tr>
<tr>
<td>a(_{i-2})</td>
<td>1.590</td>
<td>0.940</td>
<td>0.403</td>
<td>0.791</td>
</tr>
</tbody>
</table>
Exhibit 2-4 Values for parameters in equation provided by Rui et al. [9]

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Materials</th>
<th>Labor</th>
<th>ROW &amp; Damages</th>
<th>Miscellaneous</th>
</tr>
</thead>
<tbody>
<tr>
<td>$a_{i,0}$</td>
<td>4.814</td>
<td>5.697</td>
<td>1.259</td>
<td>5.580</td>
</tr>
<tr>
<td>$a_{i,NE}$</td>
<td>0</td>
<td>0.784</td>
<td>0.645</td>
<td>0.704</td>
</tr>
<tr>
<td>$a_{i,SE}$</td>
<td>0.176</td>
<td>0.772</td>
<td>0.798</td>
<td>0.967</td>
</tr>
<tr>
<td>$a_{i,MW}$</td>
<td>-0.098</td>
<td>0.541</td>
<td>1.064</td>
<td>0.547</td>
</tr>
<tr>
<td>$a_{i,Cen}$</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>$a_{i,SW}$</td>
<td>0</td>
<td>0.498</td>
<td>0.981</td>
<td>0.699</td>
</tr>
<tr>
<td>$a_{i,West}$</td>
<td>0</td>
<td>0.653</td>
<td>0.778</td>
<td>0</td>
</tr>
<tr>
<td>$a_{i,Cen}$</td>
<td>-0.196</td>
<td>0</td>
<td>-0.830</td>
<td>0</td>
</tr>
<tr>
<td>$a_{i-1}$</td>
<td>0.873</td>
<td>0.808</td>
<td>1.027</td>
<td>0.765</td>
</tr>
<tr>
<td>$a_{i-2}$</td>
<td>0.734</td>
<td>0.459</td>
<td>0.191</td>
<td>0.458</td>
</tr>
</tbody>
</table>

The costs given by Parker are in 2000$, McCoy and Rubin in 2004$, and Rui et al. in 2008$. [6, 8, 9] Within the model, all costs are adjusted to 2011 dollars (2011$) using the Handy-Whitman gas transmission pipeline index for the material and labor categories [11], the gross domestic product chain type price index for the ROW category, and the producer price index [12] for the miscellaneous category. Exhibit 2-5 provides the values for each index in the applicable years used to make the adjustments to the capital costs.

Exhibit 2-5 Values for cost indices used to adjust pipeline capital costs

<table>
<thead>
<tr>
<th>Index Type</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Handy-Whitman gas transmission pipeline index</td>
<td>261</td>
</tr>
<tr>
<td>Gross domestic product chain type price index</td>
<td>88.7</td>
</tr>
<tr>
<td>Producer price index</td>
<td>122.3</td>
</tr>
</tbody>
</table>

Eq. 9, Eq. 10, and Eq. 11 give the capital costs for a natural gas pipeline. CO$_2$ pipelines operate at higher pressure and must be constructed with thicker pipe walls which increase the costs. Data from ICF International were used to estimate a factor that increases the costs for a natural gas pipeline to reflect the costs for a CO$_2$ pipeline. [2]

$$C_{pc02-x-i} = C_{png-x-i} \cdot e_{CO2}$$  \hspace{1cm} \text{Eq. 12}
Where:

- $C_{\text{pCO}_2-x-i}$ = capital costs for a CO$_2$ pipeline using equation from author x (x = “par” for Parker [8], “mcc” for McCoy and Rubin [6], or “rui” for Rui et al. [9]) for category i (i = “mat” for materials or “lab” for labor) (2011$)

- $e_{\text{CO}_2}$ = factor that adjusts costs of natural gas pipeline to costs for a CO$_2$ pipeline depending on the diameter of the pipeline
  - 1 for $D \leq 12$ in
  - 1.12 for $12$ in < $D \leq 16$ in
  - 1.18 for $16$ in < $D \leq 20$ in
  - 1.25 for $20$ in < $D$

The cost adjustment factor $e_{\text{CO}_2}$ is only applied to the capital costs for the materials and labor categories.

### 2.2.2 Operating Costs for Pipelines

Bock et al. provided an annual O&M cost for pipelines of $5,000 per mile-year in 1999 dollars (1999$). [13] This cost is adjusted from 1999$ to 2011$ in the model using the producer price index. The producer price index for 1999 is 112.6, and the value in 2011 is 190.9.

### 2.2.3 Capital and Operating Costs for Other Pipeline-Related Equipment

In a supplementary spreadsheet to their “Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs” report, NETL provided capital costs for a CO$_2$ surge tank of $701,600 and a pipeline control system of $94,000, with both costs in 2000$. [14] The surge tank capital cost is adjusted from 2000$ to 2011$ in the model using the Chemical Engineering index for heat exchangers and tanks. This index is 370.6 for 2000 and 657.5 for 2011. [15] The control system capital cost is adjusted from 2000$ to 2011$ in the model using the Chemical Engineering index for process instruments. This index is 368.5 for 2000 and 438.7 in 2011. [15]

In the model, the annual O&M costs for these two pieces of equipment are assumed to be 4 percent of the capital costs.

### 2.3 Power Requirements for Booster Pumps

To estimate the capital and operating costs for a booster pump, the power requirement for the pump must be estimated. The power needed by a booster pump to increase the pressure of the CO$_2$ from $P_{\text{pump-in}}$ to $P_{\text{pump-out}}$ is calculated as follows (from McCollum and Ogden [3]):

$$W_{\text{pump}} = \frac{q_{\text{max}} \cdot (P_{\text{pump-out}} - P_{\text{pump-in}}) \cdot 10^{-3} \text{ kW/W}}{\eta_{\text{pump}} \cdot \rho_{\text{CO}_2}} \quad \text{Eq. 13}$$

Where:
\( W_{\text{pump}} \) = power requirement for the pump (kW)

\( P_{\text{pump-in}} \) = pressure at the inlet of the pump (equal to \( P_{\text{out}} \) for the pipe segment) (Pa)

\( P_{\text{pump-out}} \) = pressure at the outlet of the pump (equal to \( P_{\text{in}} \) for the pipe segment) (Pa)

10^{-3} = conversion from W to kW

\( \eta_{\text{pump}} \) = efficiency of the pump (typically around 75 percent, default value in model)

### 2.4 Equations for Capital and Operating Costs for the Booster Pumps

The Transport Cost Model calculates capital cost and operating cost for booster pumps. These costs are based on pump power, pump efficiency, and electricity price.

#### 2.4.1 Capital Costs for Booster Pumps

The capital costs for the pump are given as follows by McCollum and Ogden: [3]

\[
C_{\text{pump}} = C_{\text{pump-fix}} + C_{\text{pump-var}} \cdot W_{\text{pump}} \quad \text{Eq. 14}
\]

Where:

- \( C_{\text{pump}} \) = capital cost of the booster pump (2005 dollars [2005$])
- \( C_{\text{pump-fix}} \) = fixed capital cost of the booster pump ($), a value of $70,000 in 2005$ from McCollum and Ogden is used in the model [3]
- \( C_{\text{pump-var}} \) = variable capital cost of the booster pump ($/kW), a value of $1,110/kW in 2005$ from McCollum and Ogden is used in the model [3]

The pump capital cost is adjusted from 2005$ to 2011$ in the model using the Chemical Engineering index for pumps and compression. This index is 752.5 for 2005 and 898.5 for 2011. [15]

#### 2.4.2 Operating Costs for Booster Pumps

In the model, the annual O&M cost for the booster pumps is assumed to be 4 percent of the capital costs.

Operating the booster pumps requires electricity, and there are costs associated with the electrical energy used. The energy used is given by the following equation:

\[
E_{\text{pump-elec}} = W_{\text{pump}} \cdot \eta_{\text{pump}} \cdot CF \cdot 8,760 \, \text{hr/yr} \quad \text{Eq. 15}
\]

Where:
\( E_{\text{pump-elec}} \) = electricity used by booster pump each year (kW-hr/yr)

The cost of the electricity used is given by the following equation:

\[
C_{\text{pump-elec}} = E_{\text{pump-elec}} \cdot P_{\text{elec}}
\]

\text{Eq. 16}

Where:

\( C_{\text{pump-elec}} \) = cost of electricity used by booster pump each year ($/yr)

\( P_{\text{elec}} \) = price of electricity ($/kW-hr), a price of $0.1023/kW-hr for commercial electricity users for 2011 from EIA is used in the model [16]
3 Financial Module

As mentioned in Section 1, the financial module is within the “Main” sheet. The user can provide inputs (e.g., length of pipeline and percent equity) within this tab and see some results. More information on the inputs within this sheet are in Section 4.1. The “Main” tab has eight tables.

- Table 1 provides a summary of output from the model and the means for running the model. Some variables are inputs in this table.
- Tables 2 and 3 are principally used to provide inputs (discussed in Section 4.1).
- Table 4 provides annual escalation factors for calculating the nominal value of cash flows and annual discount factors for calculating the present value of cash flows.
- Table 5 provides annual cash flows for capital costs and operating expenses. The cash flows are first determined in real dollars and then escalated to nominal dollars. The nominal cash flows for capital costs are used to determine a depreciation schedule utilizing straight line depreciation or 150 percent declining balance depreciation.
- Table 6 provides the mass of CO$_2$ transported each year, the escalated price of transporting CO$_2$ in each year, and the annual cash flows for revenues. The cash flows are first determined in nominal dollars and then de-escalated to real dollars.
- Table 7 provides the annual returns to owners using the WACC methodology (discussed below). The free cash flow to owners is first determined in nominal dollars and is then discounted to present value dollars.
- Table 8 calculates the capital charge factor using the WACC methodology discussed below.

The financial module uses the capital, O&M, and electricity costs developed in the engineering module as inputs. It develops cash flows of revenues and costs, including taxes and financing costs, and calculates the net present value (NPV) of returns to the owners. The cash flows for revenues are developed once a price for the transport of CO$_2$ has been specified. The financial module can be executed in two basic modes, which are described briefly below and in more detail in Section 4.2.

To use the financial module, the user must specify a few financial parameters which include the percent of financing provided by debt versus equity, the interest rate on debt, the desired minimum rate of return on equity, the escalation rate, the tax rate, and the depreciation method. The tax rate in the model is an overall tax rate that includes federal, state, and local taxes, and the taxes are assumed to be levied against the earnings of the pipeline operations (i.e., revenue minus the sum of depreciation, operating costs, and interest on debt). The model has three options for applying depreciation which consists of a depreciation method and the recovery period for depreciation (referred to as the "depreciation method – recovery period for depreciation" in the model): DB150– 15 years (default in the model), SL – 15 years, and SL – 22 years where DB150 is 150 percent declining balance and SL is straight line. These options are based on information provided in the Internal Revenue Service (IRS) Publication 946.[17] According to this IRS publication, property owners need to use the Modified Accelerated Cost Recovery System (MACRS) to depreciate most property which consists of...
two depreciation systems, General Depreciation System (GDS) and Alternative Depreciation System (ADS). Under GDS there are three depreciation methods – 200 percent declining balance, 150 percent declining balance, and straight line – with each method applied over a specific recovery period based on the property. ADS only has the straight line depreciation method. Generally, GDS is used to depreciate property, but a property owner may be required by law to use ADS or elect to use it. The recovery periods for pipeline transportation (asset class 46) using the MACRS GDS or ADS systems is indicated in Table B-2 in Appendix B of the IRS publication, 15 years for GDS and 22 years for ADS. Within the Transport Cost Model, the depreciation factors for the three depreciation methods are from the tables in Appendix A of the IRS publication for half-year conventions (Table A-1 for 150 percent declining balance and Table A-8 for straight-line); these tables were chosen based on the percentage table guidance given in Chart 1 of Appendix A.

The user must also specify the project start year (e.g., 2011), the length of the construction period, and the length of the operating period. The construction period can be one to five years. The total of the construction period and operating period must be equal to or less than 100 years. The user must also specify the fraction of the capital costs that are incurred in each year of construction.

The financial module adds a project contingency (15 percent is default in the model) to all capital costs but does not add a process contingency. A process contingency is added for technologies that are not yet at the commercial scale. However, because CO₂ pipelines are a commercial technology, process contingency was not included in the model.

With the information discussed above, the model generates cash flows of capital and operating costs that extend over the construction and operating periods. Cash flows are generated for real costs and then these real costs are escalated to give nominal cash flows for capital and operating costs (i.e., capital costs or expenses [CAPEX] and O&M costs or expenses [OPEX]). The nominal capital cash flows are used to generate a schedule of depreciated capital costs using the depreciation method selected by the user. Depreciation begins in the first year of operation (when the pipeline is put into service).

The user selects an average mass rate of CO₂ transported each year (q_{av}) and can specify a price for transporting CO₂ in dollars per tonne (in 2011$). This price is escalated over time and used to calculate the revenue in nominal dollars that accrues to the pipeline owner in each year of operation.

The free cash flow to owners is determined within the model using a WACC methodology. The first step in the WACC methodology is to calculate the WACC using the following equation:

\[
WACC = f_{eq} \cdot IRROE_{min} + (1 - f_{eq}) \cdot (1 - i_{tax}) \cdot i_{debt} \tag{Eq. 17}
\]

Where:
- \(WACC\) = weighted average cost of capital (percent per year)
- \(f_{eq}\) = fraction of total financing that is equity (dimensionless)
- \(IRROE_{min}\) = minimum internal rate of return on equity (percent per year)
\( i_{\text{tax}} \) = tax rate (includes federal, state, and local tax rates) (percent per year)
\( i_{\text{debt}} \) = interest rate on debt (percent per year)

The quantity \((1 - i_{\text{tax}}) \cdot i_{\text{debt}}\) is the tax affected cost of debt.

The second step in the WACC methodology is to calculate the earnings before interest and taxes (EBIT) in each year as follows:

\[
EBIT = \text{revenue} - \text{COGS} - \text{OPEX} - \text{depreciation}
\]

Eq. 18

Where:
- **revenue** = cost of transporting CO\(_2\) times the mass of CO\(_2\) transported (in escalated dollars)
- **COGS** = cost of goods sold, which is always zero for the pipeline operation (in escalated dollars)
- **OPEX** = expenses to operate the pipeline (in escalated dollars)
- **depreciation** = depreciated capital value in a given year (in escalated dollars)

The third step is to calculate the earnings before interest and after taxes (EBIAT) in each year (in escalated dollars) using the following equation:

\[
EBIAT = EBIT - \text{taxespaid}
\]

Eq. 19

Where:
- **taxespaid** = federal, state, and local taxes for transporting CO\(_2\) by pipeline (in escalated dollars), given in Eq. 20

\[
taxespaid = EBIT \cdot i_{\text{tax}}
\]

Eq. 20

The fourth step is to calculate the free cash flow to owners (FCF) in each year as follows:

\[
FCF = EBIAT + \text{depreciation} - \text{CAPEX} - \text{change in net working capital}
\]

Eq. 21

Where:
- **CAPEX** = capital cost to construct the pipeline (in escalated dollars)
- **change in net working capital** = assumed to be zero for the pipeline operation (in escalated dollars)
The fifth step is to discount the free cash flow to owners in each year using the WACC as the discount rate, and sum the resulting discounted cash flows to yield the NPV of the project to the owners.

An NPV for the project that is positive implies that the project returns will exceed the minimum internal rate of return on equity (IRROE) desired by the owners. Conversely, a negative NPV indicates the project returns will not satisfy the minimum IRROE desired by the owners.

The model can operate in two basic modes. In the first mode, the user can specify a price for CO$_2$, and the model will calculate the resulting NPV and IRROE. Alternatively, the user can specify a minimum IRROE, and the model will calculate the price that needs to be charged to transport CO$_2$ for the NPV for the project to be zero. When the NPV is zero, the IRROE will equal the minimum IRROE desired by the owners. This price is the first-year break-even price for CO$_2$.

The financial module also calculates the capital charge factor or capital recovery factor. The equation for this factor is adapted from NETL. [18]

\[
CCF = \left( \frac{p_{CO2} \cdot q_{CO2} - C_{OM}}{TOC} \right)
\]

Eq. 22

Where:

- **CCF** = capital charge factor
- **$p_{CO2}$** = first-year price of CO$_2$ (2011$/tonne$)
- **$q_{CO2}$** = annual mass flow rate of CO$_2$ (tonnes/yr)
- **$C_{OM}$** = annual operational expenses (O&M and electricity costs) (2011$/yr$)
- **TOC** = total overnight capital costs (essentially total capital costs) (2011$)
4 USER’S MANUAL

This section discusses inputs the user can change within the Transport Cost Model, which are within the “Main” and “Eng Mod” sheets, and provides information on how to use the model. It is important to note that the user must first enable macros after opening the model for it to function properly.

4.1 INPUTS

The inputs to the model are specified in either the “Main” or “Eng Mod” sheets. In these two tabs, any cell that is an input cell is highlighted in light orange.

“Main” sheet: Divided into eight tables with Tables 2 and 3 requiring inputs from the user (although default values are provided in the sheet for all parameters). The user can also provide inputs in Table 1 (price to transport CO₂, number of pumps, and length of pipeline) but the first two inputs are not required if the user chooses for the macro to calculate the break-even price and number of pumps needed. Table 2 requires the following inputs, with the default value discussed in the text or presented in parentheses:

- Financial parameters
  - Percent equity (50 percent for low-risk investor-owned utility) [18]
  - Cost of equity or minimum IRROE (12 percent for low-risk investor-owned utility) [18]
  - Cost of debt or interest rate on debt (4.5 percent for low-risk investor-owned utility) [18]
  - Total effective tax rate (includes federal, state, and local tax rates) (24 percent, 21 percent for federal income tax on corporations and 3 percent for effective rate to account for state and local taxes)
  - Escalation rate (3 percent) [18]
  - Project contingency factor, which is applied to all capital costs (a project contingency in the range of 15 to 30 percent is recommended for the level of detail provided by the cost equations used in the model; since the miscellaneous cost category in the pipeline capital costs includes contingency [and some taxes], the lower value of 15 percent is specified as the default) [18]
  - Depreciation method, DB150 – 15 years, SL – 15 years, or SL – 22 years where DB150 is 150 percent declining balance and SL is straight line (DB150 – 15 years is default)
  - Calendar year for the start of the project (2011)
  - Duration of construction in years (can be up to five years with a default of three years)
  - Duration of operation in years (must be less than 95 years with a default of 30 years) [19]

- Operational characteristics
• Annual average mass flow of CO₂ transported in the pipeline (3.2 million tonnes/yr) [19]; note: maximum daily flow of CO₂ is annual average mass flow of CO₂ divided by 365 days per year to convert this to a daily mass flow rate and then divided again by the capacity factor

• Capacity factor (80 percent) [19]

• Length of pipeline (62.14 mi or 100 km) [19]

• Inlet pressure for pipeline (2,200 psig) and outlet pressure for pipeline (1,200 psig) [19]

• Change in elevation from inlet to outlet of pipeline; if outlet is at a higher elevation, the change is positive (0 ft)

• Equations to use for calculating capital costs for pipeline (specify one of the following):
   PARKER for the equations from Parker [8] (default)
   MCCOY for the equations from McCoy and Rubin [6]
   RUI for the equations from Rui et al. [9]

• Region of United States or Canada pipeline (specify one of the following):
   NE (northeast United States)
   SE (southeast United States)
   MW (Midwest United States) (default)
   Cen (central United States)
   SW (southwest United States)
   West (western United States)
   Can (Canada)

Note: The equations of Parker have no regional component and the equations of McCoy and Rubin do not have costs for Canada. [6, 8]

Table 3 provides a link between the “Main” sheet, where the financial module resides, and the capital costs and operating expenses which are calculated in the “Eng Mod” sheet. In Table 3, the user must specify the fraction of each capital cost that is incurred during each year of construction.

“Eng Mod” sheet: Divided into four sections. In Section 1 of the “Eng Mod” sheet, a variety of engineering calculations are performed, particularly, the pipe diameter (Section 1.6) and power requirement for the pump (Section 1.7). The primary inputs are:

• Temperature of the ground where pipes are buried (53 °F)
• Pump efficiency (75 percent from McCollum and Ogden [3])
• Method for calculating the minimum pipe diameter:
  o 0 for McCollum and Ogden [3]
Units can also be changed for additional calculations (e.g., pressure change from elevation change) but there are default units within the model.

In Section 2 of the “Eng Mod” sheet, capital costs are estimated. The primary cost inputs here are the natural gas pipeline capital costs, which are calculated by one of the three sets of equations, the surge tank, the pipeline control system, and the pump costs (fixed and variable), all of which are discussed in Section 2 of this report and have default values within the model. Other inputs within Section 2 of the “Eng Mod” sheet are the indices to adjust costs to the common basis of 2011$. However, there are default values for these indices within the model.

In Section 3 of this sheet, annual operating expenses are estimated. Primary cost inputs are annual O&M cost per mile of pipe and electricity cost. The annual O&M costs for the surge tank and pipeline control system are assumed to be a percentage of the CAPEX for these pieces of equipment. Indices to adjust costs to the common basis of 2011$ are other inputs within Section 3 of the “Eng Mod” sheet. There are default values for all these inputs within the model.

Section 4 of this sheet lists references cited in the sheet.

4.2 Running the Model

After the inputs described in the previous section have been specified, the model can be run from the “Main” sheet in four ways. Methods 2 through 4 require running the macro.

Note: In the discussion below, the term “blank cell” means a cell devoid of any characters, even spaces. The cell cannot have blank spaces in it, because Excel treats blank spaces as characters. The term “blank out a cell” means to make a cell empty. To “blank out a cell,” click on the cell and hit the delete key.

- **Method 1**: To have the model determine the pipeline diameter needed to transport CO$_2$ the specified distance and calculate the NPV of cash to owners and the rate of return on the weighted debt and equity, specify the number of pumps, the length of the pipeline, and the price that will be charged to transport CO$_2$ in the pipeline in Table 1A. The results are displayed under the “Key Outputs” section of Table 1A.

- **Method 2**: To determine the first-year break-even price of CO$_2$ for a specified number of pumps:
  - Specify the number of pumps and length of the pipeline in Table 1A.
  - Blank out the first cell in the “Number of pumps” list in Table 1B (i.e., the cell in Table 1B enclosed by a thick, black border).
  - Blank out the first cell in the “Length of pipeline” list in Table 1C (i.e., the cell in Table 1C enclosed by a thick, black border).
  - Start the macro by clicking the button labeled “Solve for Break-even First Year Price for Transporting CO$_2$ in $/tonne.” The macro determines the first-year
break-even price by repeatedly changing the price until the NPV of cash to owners is zero. This is accomplished by using Excel’s goal seek capability.

In Table 1A, the macro reports the first-year break-even price for transporting CO₂ for the “number of pumps” specified by the user. This price calculated by Excel’s goal seek capability may have several digits after the decimal point, but the macro rounds this price up to the nearest cent for reporting purposes.

- **Method 3**: To determine the cheapest combination of pipe diameter and number of pumps for a single pipeline length that gives the lowest first-year break-even price of CO₂:
  
  o Specify the length of the pipeline in Table 1A.
  
  o List the number of pumps where results are desired in Table 1B. Table 1B provides space for up to 21 pumps. The “number of pumps” must be listed in increasing order in this table, but the list does not need to start with zero or be in steady increments (e.g., the list of 1, 2, 3, 4, 5, 10, 15, 20, 25, 50 is acceptable). The list must start with the cell in Table 1B enclosed by a thick, black border and end with a blank cell or the 21st cell in the list of cells highlighted in light orange.
  
  o Blank out the first cell in the “Length of pipeline” list in Table 1C, enclosed by a thick, black border.
  
  o Start the macro by clicking the button labeled “Solve for Break-even First Year Price for Transporting CO₂ in $/tonne.” The macro then calculates the first-year break-even price for transporting CO₂, assuming there are no pumps, and repeats this calculation for one pump, then two pumps, and so on until the largest “number of pumps” in Table 1B is reached. In other words, the macro starts with zero for the “number of pumps” and increases this value by increments of one until it reaches the maximum “number of pumps” in the list in Table 1B. For a specified number of pumps, the first-year break-even price is determined by repeatedly changing this price until the NPV of cash to owners is zero. This is accomplished by using Excel’s goal seek capability. The calculated first-year break-even price for CO₂ using Excel’s goal seek capability may be a value with several digits after the decimal point. The macro rounds up this price to the nearest cent for reporting purposes. The macro keeps track of the number of pumps that gives the lowest first-year break-even price.

  The macro reports results in Table 1B for each “number of pumps” listed. In Table 1A, the macro displays the number of pumps that gives the lowest first-year break-even price for all the “number of pumps” evaluated. The macro also displays in Table 1A the first-year break-even price for transporting CO₂ for this optimal “number of pumps.”

- **Method 4**: To determine the cheapest combination of pipe diameter and number of pumps for a series of pipe lengths (with term “cheapest” again meaning the combination of pipe diameter and number of pumps for a specified pipeline length that gives the lowest first-year break-even price of CO₂):
  
  o List the number of pumps where results are desired in Table 1B. Table 1B provides space for up to 21 pumps. The “number of pumps” must be listed in
increasing order in this table, but the list does not need to start with zero or be in steady increments (e.g., the list of 1, 2, 3, 4, 5, 10, 15, 20, 25, 50 is acceptable). The list must start with the cell in Table 1B enclosed by a thick, black border and end with a blank cell or the 21st cell in the list of cells highlighted in light orange.

- List the lengths of pipelines (in miles) where results are desired. This list goes in Table 1C, which provides space for up to 41 “lengths of pipelines.” The “lengths of pipelines” can be listed in any order that the user desires (e.g., the list of 62, 25, 50, 1000, 100 is acceptable). The list must start with the cell in Table 1C enclosed by a thick, black border and end with a blank cell or the 41st cell in the list of cells highlighted in light orange.

- Start the macro by clicking the button labeled “Solve for Break-even First Year Price for Transporting CO₂ in $/tonne.” The macro sets the pipeline length in Table 1A to the first pipeline length in Table 1C. The model then calculates the first-year break-even price for transporting CO₂, assuming there are no pumps, and repeats this calculation for one pump, then two pumps, and so on until the largest “number of pumps” in Table 1B is reached. In other words, the macro starts with zero for the “number of pumps” and increases this value by increments of one until it reaches the maximum “number of pumps” in the list in Table 1B. For a specified number of pumps, the first-year break-even price is determined by repeatedly changing this price until the NPV of cash to owners is zero. This is accomplished by using Excel’s goal seek capability. The calculated first-year break-even price for CO₂ using Excel’s goal seek capability may be a value with several digits after the decimal point, but the macro rounds this price up to the nearest cent for reporting purposes. The macro keeps track of the number of pumps that give the lowest first-year break-even price. The macro then goes to the next pipeline length in Table 1C and repeats the process outlined above in this bullet for the pipeline length. This process is repeated until all the pipeline lengths listed in Table 1C have been evaluated.

The macro records results in Table 1C for each of the pipeline lengths. Table 1C includes the first-year break-even price in the base year (i.e., 2011), first year of the pipeline project, and first year of pipeline operation for the number of pumps and pipeline diameter that give the lowest first-year price. The number of pumps and the pipeline diameter are also presented in Table 1C. Results are also provided in Table 1A and Table 1B, but these are for a single pipeline length, specifically the last pipeline length listed in Table 1C.
5 Model Results

This section provides the capital costs for natural gas pipelines generated by the equations from Parker, McCoy and Rubin, and Rui et al. [6, 8, 9] as well as the breakdown of these capital costs by the four cost categories (materials, labor, ROW & damages, and miscellaneous). It also presents the results from the model compared to cost data from actual CO₂ pipelines. Default values discussed in Section 4 and presented in the Transport Cost Model were used to produce results.

The three sets of equations for natural gas pipeline capital costs gave different results, as illustrated in Exhibit 5-1, which presents the cost per mile in 2011$ (2011$/mi) for different pipeline lengths and diameters. Note that in McCoy and Rubin and Rui et. al, the Midwest region was selected for the results. [6, 9] In general, the equations from Parker gave the highest costs followed by the equations from McCoy and Rubin and then Rui et al. [6, 8, 9] The equations from Parker gave significantly higher costs than the other two equations. [6, 8, 9] The equations from Parker did not show decreasing costs with increasing pipeline length whereas the other two set of equations gave costs that showed this behavior. [6, 8, 9]

Exhibit 5-1 Natural gas pipeline capital costs using different equations (2011$/mi)
The breakdown of natural gas pipeline capital costs (in 2011$/mi) by cost category is illustrated in Exhibit 5-2 for 12-, 20-, and 30-in diameter pipelines for the three different sets of equations. Note that in McCoy and Rubin and Rui et. al, the Midwest region was selected for the results. [6, 9] Labor costs were the largest component of capital costs followed by materials and miscellaneous costs. The ROW & damages cost was the smallest component of the capital costs, with the possible exception of costs generated by the equations from Rui et al. for 12-in diameter pipelines. [9]

Exhibit 5-2 Breakdown of natural gas pipeline capital costs using different equations (2011$/mi)

The three sets of pipeline capital cost equations were compared to pipeline capital cost data from a variety of sources. Note that in McCoy and Rubin and Rui et. al, the Midwest region was selected for the results. [6, 9] The capital costs for a CO$_2$ pipeline per inch (diameter, from 12 in to 42 in) and mile (length, from 50 mi to 500 mi) including 15 percent contingency factor were as follows for the different sets of equations:
• Parker: $83,900/in-mi (12-in pipe) to $150,000/in-mi (42-in pipe) [8]
• McCoy and Rubin: $88,625/in-mi (50-mi pipe) to $41,000/in-mi (500-mi pipe) [6]
• Rui et al.: $67,000/in-mi (50-mi pipe) to $32,000/in-mi (500-mi pipe) [9]

The capital costs per inch-mile using the equations from Parker increased with increasing diameter but were relatively insensitive to the length of the pipeline. [8] The capital costs per inch-mile using the equations from McCoy and Rubin increased somewhat with increasing diameter but decreased with increasing pipeline length. [6] The capital costs per inch-mile using the equations from Rui et al. showed the same type of behavior as the equations from McCoy and Rubin. [6, 9]

These costs were compared to contemporary pipeline costs quoted by industry experts, such as Kinder-Morgan and Denbury Resources. Exhibit 5-3 details typical rule-of-thumb costs for various terrains and scenarios as quoted by a representative of Kinder-Morgan at the Spring Coal Fleet Meeting in 2009. [20] It is not known if these rule-of-thumb estimates include contingencies. Comparing the results above with the Kinder Morgan cost metrics, the costs using the equations from Parker are on the high end of this range, while the costs using the equations from McCoy and Rubin fall on the low end of this range, and the costs using the equations from Rui et al. tend to fall below this range. [6, 8, 9]

<table>
<thead>
<tr>
<th>Terrain</th>
<th>Capital Cost ($/in-mi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flat, Dry</td>
<td>$50,000</td>
</tr>
<tr>
<td>Mountainous</td>
<td>$85,000</td>
</tr>
<tr>
<td>Marsh, Wetland</td>
<td>$100,000</td>
</tr>
<tr>
<td>River</td>
<td>$300,000</td>
</tr>
<tr>
<td>High Population</td>
<td>$100,000</td>
</tr>
<tr>
<td>Offshore (150-ft to 200-ft depth)</td>
<td>$700,000</td>
</tr>
</tbody>
</table>

A further comparison was made to cost data for two Denbury CO₂ pipelines. The first is the Green pipeline with the following characteristics.

• Location: Southeast United States
• Pipeline length: 314 mi
• Pipeline diameter: 24 in
• CO₂ flow capacity: 42,320 tonnes/day, assumed to be maximum daily flow, which translates to annual average flow of 12.6 million tonnes/yr
• Capital cost: About $660 million according to trade journals and
About $884 million excluding capitalized interest according to the annual report

- Status: Completed around 2010

The Transport Cost Model was run with the project beginning in 2007 and the construction completing in 2010 with an escalation rate of 3 percent and a capacity factor of 80 percent. Method 2 from Section 4.2, with two pumps specified in Table 1A, was used to obtain capital costs in nominal dollars for this project. The model determined that a 24-in pipeline of this length would result from two pumps. The capital cost in nominal dollars for this project was estimated by the model to be as follows for the different sets of equations.

- Parker: $692 million
- McCoy and Rubin: $411 million
- Rui et al.: $351 million

The result using the Parker equations exceeded the value in trade journals but was less than the value in the annual report. The results from the McCoy and Rubin and Rui et al. equations were significantly less than both published capital costs. [6, 8, 9]

The second CO$_2$ pipeline is the Greencore pipeline with the following characteristics.

- Location: Wyoming
- Pipeline length: 232 mi
- Pipeline diameter: 20 in
- CO$_2$ flow capacity: 38,280 tonnes/day, assumed to be maximum daily flow, which translates to annual average flow of 11.2 million tonnes/yr
- Capital cost: About $285 million according to trade journals
  
  About $135 million for second half of project according to annual report
- Status: Completed in 2012 or 2013

The Transport Cost Model was run with the project beginning in 2010 and the construction completing in 2013 with an escalation rate of 3 percent and a capacity factor of 80 percent. Method 2 from Section 4.2, with four pumps specified in Table 1A, was used to obtain capital costs in nominal dollars for this project. The model determined that a 20-in pipeline of this length would result from four pumps. The capital cost in nominal dollars for this project was estimated by the model to be as follows for the different set of equations.

- Parker: $453 million
- McCoy and Rubin: $190 million
- Rui et al.: $154 million

The result using the Parker equations exceeded the value in trade journals. The results from the McCoy and Rubin and Rui et al. equations were less than the published capital costs. [6, 8, 9]
These results indicated that the equations from Parker and McCoy and Rubin give costs that are close to published CO$_2$ pipeline costs. [6, 8] The equations from Parker tend to give costs on the high side, while the equations from McCoy and Rubin tend to give costs on the low side. [6, 8]
6 References


