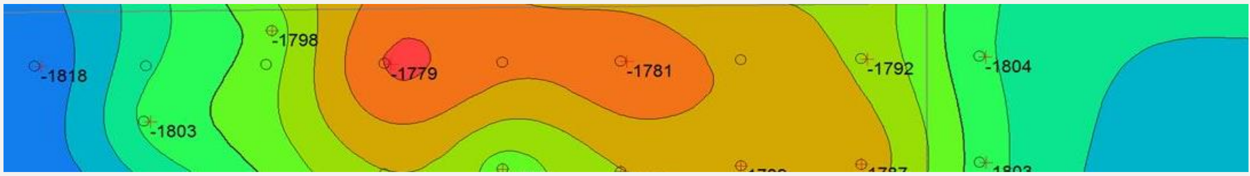

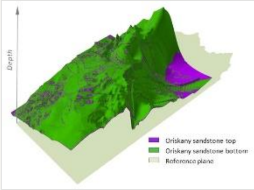

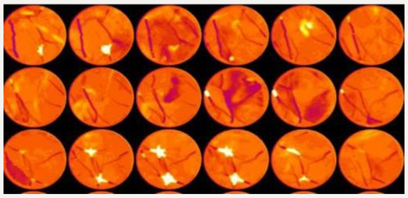

FECM/NETL CO_2 Transport Cost Model (2023): Description and User's Manual

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All images in this manual were created by NETL, unless otherwise noted.

Open Source Software License for Excel Spreadsheet

David Morgan [1*]*: Conceptualization, Methodology, Software, Validation, Investigation, Writing – Original Draft, Writing – Review & Editing;* ***Allison Guinan*** [1,2]*: Methodology, Validation, Formal Analysis, Writing – Original Draft, Writing – Review & Editing, Visualization, Supervision;* ***Alana Sheriff*** [1,2]*: Methodology, Software, Validation, Investigation, Writing – Original Draft, Writing – Review & Editing*

[1] National Energy Technology Laboratory (NETL)
[2] NETL support contractor
*Corresponding contact: David.Morgan@netl.doe.gov, 412.386.7405

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Shangmin Lin, NETL support contractor
Chung Shih, NETL support contractor
Elizabeth Basista, NETL support contractor
Laura Demetrion, NETL support contractor
Paul Myles, NETL support contractor
Andrea Poe, NETL support contractor
James Simpson, NETL support contractor
Jason Valenstein, NETL support contractor

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LIST OF EXHIBITS

LIST OF EQUATIONS

ACRONYMS AND ABBREVIATIONS

%	Percent
°F	Degree(s) Fahrenheit
$/tonne	Dollar(s) per tonne
CAPEX	Capital costs or expenses
CAPM	Capital asset pricing model
CEPCI	Chemical Engineering Plant Cost Index
CO_2	Carbon dioxide
DB150	150 percent declining balance
DOE	Department of Energy
EBIAT	Earnings before interest and after taxes
EBIT	Earnings before interest and taxes
EIA	Energy Information Administration
EOR	Enhanced oil recovery
Eq.	Equation
FCF	Free cash flow
FECM	Fossil Energy and Carbon Management
ft	Foot, feet
ft^2	Square foot, square feet
hr	Hour(s)
in.	Inch(es)
$IRROE_{min}$	Minimum internal rate of return on equity
K	Kelvin
kg	Kilogram(s)
km	Kilometer(s)
kW	Kilowatt(s)
kWh	Kilowatt hour
m	Meter(s)
m^3	Cubic meter(s)
Matls	Materials
mi	Mile(s)
Misc	Miscellaneous
mol	Mole(s)
Mtonne	Megatonne(s) (million tonne[s])
MWh	Megawatt hour
NETL	National Energy Technology Laboratory
NOL	Net operating loss
NPV	Net present value
O&M	Operation and maintenance
OPEX	Operating costs or expenses
Pa	Pascal(s)
psig	Pound(s) per square inch gauge
QGESS	Quality Guidelines for Energy System Studies
ROW	Right-of-way
s	Second(s)
s^2	Second(s) squared
SL	Straight line
TBEBITAN	Tax basis earnings before interest and taxes but after NOL
TBEBITN	Tax basis earnings before interest, taxes and NOL
tonne	Metric ton (1,000 kg)
U.S.	United States
VBA	Visual Basic for Applications
W	Watt(s)
WACC	Weighted average cost of capital
yr	Year(s)

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1 MODEL INTRODUCTION AND ORIENTATION

The United States (U.S.) Department of Energy (DOE) Office of Fossil Energy and Carbon Management (FECM) National Energy Technology Laboratory (NETL) has developed a techno-economic model for the transport of carbon dioxide (CO_2) by pipeline. This model is called the FECM/NETL CO_2 Transport Cost Model, also known as CO2_T_COM. [1] The CO2_T_COM is an Excel-based tool that estimates revenues and capital, operating, and financing costs for transporting liquid phase CO_2 by pipeline. It is assumed that the CO_2 delivered to the pipeline meets pipeline specifications for purity. Costs are estimated for a single point-to-point pipeline, which may have pumps along the pipeline to boost the pressure.

The purpose of this manual is to assist the user in understanding the CO2_T_COM including model inputs and outputs.

1.1 MODEL OVERVIEW

The CO2_T_COM consists of twelve worksheets (or sheets) along with Visual Basic for Applications (VBA) macros and user-defined functions. The model has several features that simplify the computational process and increase functionality. These items include two fundamental modules and a custom tab on the ribbon where several VBA macros can be run. An overview of these items as well as the worksheets within the Excel file are described below. Of the twelve worksheets within the model, four are key to the model's function, six provide useful information but are not critical to model performance, and two are hidden and should not be modified.

1.1.1 "READ_ME_FIRST" Worksheet

A brief overview of the model and a brief description of the worksheets in the workbook are provided in this sheet. The "READ_ME_FIRST" worksheet also provides information on color and font conventions along with fundamental model assumptions that a modeler is not able to modify. The color conventions are specific colors used consistently throughout the spreadsheet to provide immediate visual indicators of the purpose of certain cells. The most important convention, the light orange input cell color, is listed first. The modeler can change values in any light orange cell. To use the spreadsheet, the user must first enable macros after opening the spreadsheet file. The "READ_ME_FIRST" sheet also has a disclaimer and a BSD 1 open source software license.

1.1.2 Two Fundamental Modules

The CO2_T_COM consists of two fundamental modules, the financial module and engineering module, with each module having its own sheet within the Excel workbook. These modules are discussed further in Section 1.2 and in the appropriate module sections (Section 2 for financial and Section 2.2 for engineering).

1. Financial module ("Main" worksheet)

   This module is the primary user interface for the model. The "Main" worksheet includes key inputs, calculates all the cash flows determined by the financial model, and provides the key results generated by the model. More information on the financial module is described in Section 2 and Appendix A: Rationale Behind Key Financial Parameters. Key inputs for this sheet are described in Section 2.2.

2. Engineering module ("Eng Mod" worksheet)

   Calculations related to fluid flow in the pipe and capital and operating expenses for specific pieces of equipment are included in this sheet. The equations within the "Eng Mod" worksheet are used to size the pipe and booster pumps and estimate the capital and annual operating costs for the equipment comprising the pipeline. This sheet provides several inputs, presents key technical results, and calculates capital costs and operating expenses for the equipment that comprises the pipeline. More information on the engineering module is described in Section 3 and Appendix B: Pipe Flow Equations. Key inputs for this sheet are described in Section 3.4.

1.1.3 "CO2_T_COM" Ribbon Tab and Running Macros

The CO2_T_COM includes a custom ribbon tab labeled "CO2_T_COM." Located on the far right of the ribbon, this ribbon tab controls the execution of the VBA macro called "Goal_Seek_Price" that provides much of the functionality of the model. This macro has different options for its execution that are controlled by the user through inputs on the "CO2_T_COM" ribbon tab. The macro and the use of this ribbon tab to run the macro are discussed in Section 1.2. One of the "Goal_Seek_Price" options (i.e., "Combo") provides results in the "Combo Results" worksheet. More information on this sheet is discussed in Section 1.2.

1.1.4 "Cases" and "Cases_def" Worksheets

The "Cases" worksheet provides the inputs for running the "Process_Cases" VBA macro and presents the results for each case. Each case is defined by a specific pipeline length, maximum CO_2 mass flow rate, capacity factor, average annual CO_2 mass flow rate, and elevation difference from the inlet to the outlet of the pipeline. The capacity factor multiplied by the maximum CO_2 mass flow rate gives the average annual CO_2 mass flow rate. The top part of the "Cases" sheet describes the "Process_Cases" macro and how to run it as well as the key inputs or factors used in evaluating the cases. The inputs for each case are provided starting with the row with the label "Start" in Column A. After running the "Process_Cases" macro, the results for each case are provided starting in this row. The "Process_Cases" macro is run by clicking the "Process Cases Macro" button in the "Cases" worksheet at or near Cell A19.

The "Process_Cases" macro stores the original values in Table 1A (on the "Main" sheet) for pipeline length, annual average CO_2 mass flow rate, capacity factor, number of booster pumps, and elevation difference from the inlet to the outlet of the pipeline before any of the cases are processed. After all the cases are processed, the macro restores the original values for these variables in Table 1A and finds the first-year break-even CO_2 price associated with these variables. This CO_2 price is displayed in Table 1A when the "Process_Cases" macro finishes its execution.

The "Cases_def" worksheet provides a brief description of the variables input by the user and variables output by the "Process_Cases" macro in the "Cases" sheet for each case. The user can add or remove output variables. If the user adds or removes output variables, these definitions can be updated by the user.

1.1.5 Other Worksheets

In addition to the six sheets previously described ("READ_ME_FIRST," "Main," "Combo Results," "Eng Mod," "Cases," and "Cases_def"), there are six remaining sheets in the model. Of the remaining sheets, four provide useful information but are not critical to the model's performance, and the other two are hidden since they are used internally by the model or the developers and should not be modified by the user. These worksheets are

1. 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.

2. Cost Indices

   Indices for adjusting costs to the base year of 2011 are provided in this sheet.

3. Pipe Cap

   This sheet has tables with capital costs for different aspects of constructing a natural gas pipeline using four different cost equations.

4. Pipe Cap Plot

   Tables and plots of capital costs for different aspects of constructing a natural gas pipeline using four different cost equations are within this sheet. The plots within this sheet are used to show examples of results in Section 4.

5. Parameters

   This sheet contains input values for drop-down menus in the "Main" and "Eng Mod" sheets and stores values selected by the user from the "CO2_T_COM" ribbon tab. These values are used in macros run from the ribbon. All information within this sheet is used internally by the model and should not be modified; therefore, the sheet is hidden.

6. Version

   This sheet provides information used by the developers to track edits made within the model. All information within this sheet should not be modified and is not particularly useful to users; therefore, the sheet is hidden.

1.2 How the CO2_T_COM Works

The CO2_T_COM has several operating modes depending on whether the user decides to use the VBA "Goal_Seek_Price" macro for calculating a variety of quantities. This section describes how to use the "CO2_T_COM" ribbon tab in the Excel workbook to execute different options of the "Goal_Seek_Price" macro. It is important to note that the user must first enable macros after opening the model for it to function properly. Also, the model has the ability to provide costs in real (i.e., constant) or nominal (i.e., escalated) dollars.

1.2.1 Basic Mode with No Macro Use

In its most basic mode, the CO2_T_COM requires the following key inputs from the user, which are specified in the financial module on the "Main" sheet in Table 1A:

- First-year price for transporting CO_2 in the base year of 2011$/tonne (Cell E10)
- Average annual CO_2 mass flow rate in Mtonnes/yr (Cell E11)
- Capacity factor in % (used to calculate the maximum CO_2 mass flow rate that the pipeline needs to be able to sustain) (Cell E12)
- Pipeline length in mi (including any bends or diversions the pipeline needs to get from its starting point to its end point) (Cell E14)
- Number of booster pumps along the pipeline (can be zero if there are no pumps) (Cell E15)
- Elevation change along the pipeline in ft (if the elevation increases from the inlet to the outlet, the elevation change is a positive value; otherwise, the elevation change is a negative value or zero) (Cell E16)

The model also requires the user specify other values such as several financial variables, the duration of the construction period for the pipeline, years the pipeline operates, pump efficiency, and method for calculating the inner diameter of the pipeline. These input variables are specified within the "Main" sheet (Table 2 and Table 3) and the "Eng Mod" sheet.

The model divides the pipeline into equal length segments with a booster pump at the end of all segments except the last segment. The model assumes the inlet pressure and outlet pressure in each segment are the same with the booster pump increasing the pressure at the outlet from one segment to the pressure at the inlet of the next segment. There is no booster pump at the end of the pipeline. It is assumed that the organization receiving the CO_2, such as a CO_2 saline storage operation or CO_2 enhanced oil recovery (EOR) operation, will have booster pumps if the pressure of the CO_2 needs to be increased.

The model calculates the minimum inner diameter needed for a pipe that can transport the maximum CO_2 mass flow rate the length of the pipe segment, overcome friction losses along the pipe segment, and accommodate any change in elevation along the pipe segment given the specified pressure drop along the pipe segment. The model then determines the nearest standard or nominal pipe size that has an inner diameter greater than the minimum inner diameter. The model currently allows nominal pipe sizes of 4, 6, 8, 10, 12, 16, 20, 24, 30, 36, 42, and 48 in. For pipe sizes of 12 in. or less, the pipe size is approximately the inner diameter. For pipe sizes greater than 12 in., the pipe size is the outer diameter. The calculations of the minimum inner diameter and determining the appropriate nominal pipe size are in the engineering module in the "Eng Mod" sheet. These calculations are performed through VBA user-defined functions in the Excel workbook.

> **Important Note**: In certain situations, the equations for calculating the minimum inner pipe diameter provide results that are not physically meaningful (such as minimum inner diameters that are imaginary or complex numbers). In these situations, the VBA function returns a value of 99.9 in. as the minimum inner pipe diameter. In other situations, the VBA function may calculate a minimum inner pipe diameter that exceeds the inner diameter of the largest nominal pipe size included in the model (i.e., 48 in.). When the calculated inner pipe diameter exceeds the inner diameter of the largest nominal pipe size, the VBA function that determines the nominal pipe size returns a nominal pipe size of 2,000 in. The model has VBA macros that can determine the lowest cost combination of nominal pipe size and number of booster pumps. Setting the nominal pipe size to 2,000 in. (which is an unrealistic pipe diameter) ensures that the cost of this pipeline will be exorbitant and will never be selected as the lowest cost option.

With the pipeline length and nominal pipeline size, several calculations occur for several items in the engineering module: 1) capital costs for the pipeline; 2) power requirements and capital costs for the booster pumps; 3) capital costs for the pipeline control system and a small surge tank; 4) annual operating expenses for maintaining the pipeline, booster pumps, and other equipment; and 5) electricity demand and electricity costs for operating the booster pumps.

These capital and operating costs are accessed in the financial module, which also includes the financial model used by the CO2_T_COM. In the financial model, cash flows are developed for revenues from transporting CO_2, capital costs for constructing the pipeline with all its equipment, and operating costs for the pipeline, booster pumps, and miscellaneous equipment. The revenues for transporting CO_2 are calculated by multiplying the price of CO_2 in each year by the mass of CO_2 transported in each year. Cash flows for revenues and costs are first reported in real or constant dollars. The base year for costs in the model is currently 2011, but an escalation rate is provided to escalate these costs to the first year of the project. Thus, real or constant dollar cash flows are reported in both 2011$ and dollars in the first year of the project.

The cash flows in real dollars in the first year of the project are escalated with a different escalation rate to nominal dollars. Nominal capital costs are depreciated, and income taxes are then calculated. The nominal earnings before interest and after taxes (EBIAT) are then calculated as the revenues minus capital costs, operating costs, and taxes. The EBIAT are discounted with the weighted average cost of capital (WACC) after taxes to give the present value EBIAT. These present value earnings are summed to give the net present value (NPV) for the project.

The NPV for the project is the critical measure of the financial viability of the pipeline project.

- If the NPV for the project is greater than zero, revenue is sufficient to cover all costs (capital costs, operating expenses, and taxes), pay for the interest and principal on debt, and provide equity investors with their minimum desired internal rate of return on equity ($IRROE_{min}$).

- If the NPV for the project is less than zero, revenues are not sufficient to cover all costs including financial costs.

Revenues being too low indicate the price charged for transporting CO_2 is too low. If the price for CO_2 is increased until the NPV for the project is zero, the project can pay all costs including financial costs, but just barely. This CO_2 price is called the first-year break-even CO_2 price since this price just barely makes the project viable or break-even.

Note: The basic mode with no macro use gives the user the greatest control over the values specified for input variables.

1.2.2 Basic Mode Using the Macro to Calculate the First-year Break-even Price of CO_2

The first-year break-even price of CO_2 is an extremely useful quantity since it is the minimum CO_2 price that a pipeline operator can charge and still cover all their costs including financial costs. This price is referred to as the first-year price because it is the price set in the first year of the project, and this price escalates at the same rate as all the costs in the model. As discussed above, the first-year break-even CO_2 price is determined by adjusting the price until the NPV for the project is zero.

The CO2_T_COM provides the user with the ability to calculate the first-year break-even price by running a macro from the "CO2_T_COM" ribbon tab. To perform this option

- Specify inputs (e.g., annual average CO_2 mass flow rate, percent equity, etc.) in light orange cells within Table 1A, Table 2, and Table 3 on the "Main" sheet and in the "Eng Mod" sheet.
- Toggle the "Optimal Pump Number" on or off in the "CO2_T_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of booster pumps as discussed in the next sub-section. For the discussion within this sub-section, it is assumed the user desires to use the number of booster pumps they have input, so the "Optimal Pump Number" should be toggled off.
- Select the "Basic" option in the drop-down box next to the "Macro Option" label on the "CO2_T_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "CO2_T_COM" ribbon tab to activate the "Goal_Seek_Price" macro to find the first-year price of CO_2 that generates a NPV for the project of zero. This value, which is the first-year break-even CO_2 price, is then rounded up to the nearest penny and displayed in Table 1A of the "Main" sheet. When the macro is finished, a message box will pop up that says, "Execution Complete for Goal_Seek_Price Macro! Run time of X minutes" where "X" denotes the number of minutes. Also, the message "User specified (may not be optimal)" is displayed in the cell next to the cell with the number of booster pumps that the user has input (Cell F15 in the "Main" sheet).

1.2.3 Basic Mode Using the Macro to Determine the Optimal Number of Booster Pumps

As discussed above, the CO2_T_COM allows the user to specify the number of booster pumps with the model calculating the minimum pipe diameter and nominal pipe size associated with this number of pumps. As the number of pumps increases, the cost of all the pumps will increase, but a smaller pipe size may be appropriate, and thus, reduce the cost of the pipeline. It is typically not obvious what combination of number of booster pumps and nominal pipe size will give the lowest overall first-year break-even CO_2 price. However, this combination of number of booster pumps and nominal pipe size is something most users would like to know.

The CO2_T_COM provides the user the ability to calculate the optimal number of booster pumps by running different options of the "Goal_Seek_Price" macro from the "CO2_T_COM" ribbon. To perform this option

- Specify inputs (e.g., capacity factor, cost of equity, etc.) in light orange cells within Table 1A, Table 2, and Table 3 on the "Main" sheet and in the "Eng Mod" sheet.
- Toggle the "Optimal Pump Number" on in the "CO2_T_COM" ribbon tab.
- Select the "Basic" option in the drop-down box next to the "Macro Option" label on the "CO2_T_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "CO2_T_COM" ribbon tab to run VBA code that executes an algorithm that determines the nominal pipe size and number of pumps that gives the lowest first-year break-even CO_2 price. The algorithm cycles through nominal pipe sizes, starting with the largest, to determine the nominal pipe size and number of pumps that give the lowest first-year break-even CO_2 price. In the algorithm, the variables D_{nom_x}, N_{pump_x}, and p_{CO2_x} store values for the nominal pipe size, number of pumps, and first-year break-even CO_2 price, respectively, that are being evaluated. The variables D_{nom_min}, N_{pump_min}, and p_{CO2_min} store values for the nominal pipe size and number of pumps associated with the lowest first-year break-even CO_2 price. The algorithm is implemented in two steps.
    - Step 1: The purpose of this step is to find the smallest nominal pipe size where the number of pumps is zero. The algorithm begins by determining the maximum length of a pipe segment for a pipe with a nominal pipe size of 48 in. This length is the longest pipe segment length that can sustain the maximum CO_2 mass flow rate with the specified elevation change and pressure drop across the pipe segment given the inner diameter associated with a pipe size of 48 in.
        - If this maximum pipe segment length exceeds the length of the pipeline, then no pumps are needed for a nominal pipe size of 48 in. The model sets the number of pumps to zero, calculates the minimum inner pipe diameter for this number of pumps, and determines the smallest nominal pipe size (D_{nom_x}) with an inner diameter that is larger than the minimum inner pipe diameter. The algorithm proceeds to Step 2.

- If this maximum pipe segment length is less than the length of the pipeline then at least one pump is needed. The algorithm sets the nominal pipe size variable D_{nom_x} to 48 in. and proceeds to Step 2.

- Step 2: The algorithm begins with the nominal pipe size determined in Step 1 and cycles through successively smaller nominal pipe sizes to determine the nominal pipe size and number of pumps that generate the lowest first-year break-even CO_2 price, p_{CO2_min}. The algorithm begins by setting p_{CO2_min} to a very large number (10^{99} $/tonne) and starts with the nominal pipe size, D_{nom_x}, determined in Step 1. In each cycle, the algorithm determines the maximum pipe segment length that can sustain the maximum CO_2 mass flow rate with the specified elevation change and pressure drop across the pipe segment given the inner diameter associated with the nominal pipe size D_{nom_x}. The pipeline length divided by the maximum pipe segment length rounded up to the nearest integer gives the number of pipe segments and, after subtracting one, the number of pumps, N_{pump_x}, for this nominal pipe size, D_{nom_x}. The algorithm then calculates the first-year break-even CO_2 price, p_{CO2_x}, associated with the nominal pipe size D_{nom_x} and number of pumps N_{pump_x}. If p_{CO2_x} is smaller than p_{CO2_min}, then p_{CO2_x} is the current lowest first-year break-even CO_2 price. In this case, p_{CO2_min} is set to p_{CO2_x}, N_{pump_min} is set to N_{pump_x}, and D_{nom_min} is set to D_{nom_x}. The cycle is repeated with the next smallest nominal pipe size until either the smallest nominal pipe size has been evaluated (4 in.) or the number of booster pumps needed exceeds a ridiculous number (i.e., 200 times the current value for N_{pump_min}).

When the algorithm is finished, the result is the number of booster pumps, N_{pump_min}, and associated nominal pipe size, D_{nom_min}, that gives the lowest first-year break-even CO_2 price, p_{CO2_min}. The values for N_{pump_min}, D_{nom_min}, and p_{CO2_min} are displayed in Table 1A in the "Main" sheet.

The calculation of the maximum pipe segment length for an inner pipe diameter associated with a nominal pipe size is performed in the engineering module in the "Eng Mod" sheet. This calculation is done through a VBA user-defined function in the Excel workbook.

Once again, when the macro is finished, a message box will pop up that says, "Execution Complete for Goal_Seek_Price Macro! Run time of X minutes" where "X" denotes the number of minutes. Also, the message "Optimal number of pumps" is displayed in the cell next to the cell with the number of booster pumps (Cell F15 in the "Main" sheet).

Note: The basic mode using the "Goal_Seek_Price" macro to determine the optimal number of booster pumps is likely to be the most popular mode with users, since it provides the combination of number of booster pumps and nominal pipe size that gives the overall lowest first-year break-even CO_2 price.

1.2.4 Using the Macro to Calculate Results for Multiple Values of Input Variables

The CO2_T_COM can generate results for multiple values for the same input variables. This capability uses different options of the "Goal_Seek_Price" macro and, depending on the option selected, generates results for **Table 1B**, **Table 1C**, or **Table 1D** in the "Main" sheet or **Table 1E** in the "Combo Results" sheet.

Table 1B in the "Main" sheet provides results for different numbers of booster pumps. Results are the minimum inner pipe diameter for the number of pumps, the nearest nominal pipe size with an inner diameter larger than this minimum inner pipe diameter, and first-year break-even CO_2 prices associated with the number of pumps and nominal pipe size.

To generate results in Table 1B

- Specify inputs (e.g., pipeline length, cost of debt, etc.) in light orange cells within Table 1A, Table 2, and Table 3 on the "Main" sheet and in the "Eng Mod" sheet.
- Enter the number of desired pumps in Column J of Table 1B. The user can input up to 21 values in this column.
- Toggle the "Optimal Pump Number" on or off in the "CO2_T_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of booster pumps; whereas, when toggled off, the macro will use the number of booster pumps input by the user.
- Select the "Pump" option in the drop-down box next to the "Macro Option" label on the "CO2_T_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "CO2_T_COM" ribbon tab to activate the "Goal_Seek_Price" macro. When the macro is finished, a message box will pop up that says, "Execution Complete for Goal_Seek_Price Macro! Run time of X minutes" where "X" denotes the number of minutes.

Table 1B will now have results for each number of booster pumps input by the user. If the user toggled the "Optimal Pump Number" on, then the last row in Table 1B (Row 33) will provide the number of booster pumps that give the lowest first-year break-even CO_2 price.

The macro saves the original (i.e., user input) number of pumps in Table 1A before any calculations are performed. After Table 1B is populated, the macro enters the original number of pumps in Table 1A. If the "Optimal Pump Number" is toggled on, then the macro finds the optimal number of pumps that yields the lowest first-year break-even CO_2 price (this may be different than the original number of pumps in Table 1A). If the "Optimal Pump Number" is toggled off, then the macro finds the first-year break-even CO_2 price associated with the original number of pumps in Table 1A.

Table 1C in the "Main" sheet provides results for different pipeline lengths. Results are the number of booster pumps, the minimum pipe inner diameter for the number of pumps, the nearest nominal pipe size with an inner diameter larger than this minimum diameter, and first-year break-even CO_2 prices associated with the number of pumps and nominal pipe size. The results in Table 1C are for fixed values of the elevation change along the pipeline, average annual CO_2 mass flow rate, and capacity factor. The user can fix the number of booster pumps or let the "Goal_Seek_Price" macro find the optimal number of booster pumps depending on whether or not the "Optimal Pump Number" on the "CO2_T_COM" ribbon tab is toggled on.

To generate results in Table 1C

- Specify inputs (e.g., elevation change along the pipeline, tax rate, etc.) in light orange cells within Table 1A, Table 2, and Table 3 on the "Main" sheet and in the "Eng Mod" sheet. The user should enter the number of booster pumps if the number of booster pumps to be fixed for all pipeline lengths is desired.
- Enter the pipeline lengths where results are desired in Column Q of Table 1C. The user can input up to 45 values in this column.
- Toggle the "Optimal Pump Number" on or off in the "CO2_T_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of booster pumps; whereas, when toggled off, the macro will use the number of booster pumps input by the user.
- Select the "Length" option in the drop-down box next to the "Macro Option" label on the "CO2_T_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "CO2_T_COM" ribbon tab to activate the "Goal_Seek_Price" macro. When the macro is finished, a message box will pop up that says, "Execution Complete for Goal_Seek_Price Macro! Run time of X minutes" where "X" denotes the number of minutes.

Table 1C will now have results for each pipeline length input by the user. If the user toggled the "Optimal Pump Number" on, then the column with the number of booster pumps (Column U) will have the optimal number of booster pumps, and the title of this column will have the word "Optimal" in the first cell. Otherwise, this column will have the number of pumps specified by the user in Table 1A, and the title of this column will have the phrase "User-Defined" in the first cell.

The macro saves the original (i.e., user input) pipeline length and number of pumps in Table 1A before any calculations are performed. After Table 1C is populated, the macro enters the original pipeline length and number of pumps in Table 1A. If the "Optimal Pump Number" is toggled on, then the macro finds the number of pumps that gives the lowest first-year break-even CO_2 price for this original pipeline length in Table 1A. The optimal number of pumps may be different from the original number of pumps in Table 1A. If the "Optimal Pump Number" is toggled off, then the macro finds the first-year break-even CO_2 price associated with the original pipeline length and number of pumps in Table 1A.

Table 1D in the "Main" sheet provides results for different annual average CO_2 mass flow rates. Results are the number of booster pumps, the minimum pipe inner diameter for the number of pumps, the nearest nominal pipe size with an inner diameter larger than this minimum inner pipe diameter, and first-year break-even CO_2 prices associated with the number of pumps and nominal pipe size. The results in Table 1D are for fixed values of the pipeline length, elevation change along the pipeline, and capacity factor. The user can fix the number of booster pumps or let the "Goal_Seek_Price" macro find the optimal number of booster pumps depending on whether or not the "Optimal Pump Number" on the "CO2_T_COM" ribbon tab is toggled on.

To generate results in Table 1D

- Specify inputs (e.g., duration of construction, escalation rate from base year to project start year, etc.) in light orange cells within Table 1A, Table 2, and Table 3 on the "Main" sheet and in the "Eng Mod" sheet. The user should enter the number of booster pumps if the number of booster pumps to be fixed for all CO_2 mass flow rates is desired.
- Enter the annual average CO_2 mass flow rates where results are desired in Column Y of Table 1D. The user can input up to 45 values in this column.
- Toggle the "Optimal Pump Number" on or off in the "CO2_T_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of booster pumps; whereas, when toggled off, the macro will use the number of booster pumps input by the user.
- Select the "Rate" option in the drop-down box next to the "Macro Option" label on the "CO2_T_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "CO2_T_COM" ribbon tab to activate the "Goal_Seek_Price" macro. When the macro has finished, a message box will pop up that says, "Execution Complete for Goal_Seek_Price Macro! Run time of X minutes" where "X" denotes the number of minutes.

Table 1D will now have results for each annual average CO_2 mass flow rate input by the user. If the user toggled the "Optimal Pump Number" on, then the column with the number of booster pumps (Column AC) will have the optimal number of booster pumps, and the title of this column will have the word "Optimal" in the first cell. Otherwise, this column will have the number of pumps specified by the user in Table 1A, and the title of this column will have the phrase "User-Defined" in the first cell.

The macro saves the original (i.e., user input) annual average CO_2 mass flow rate and number of pumps in Table 1A before any calculations are performed. After Table 1D is populated, the macro enters the original annual average CO_2 mass flow rate and number of pumps in Table 1A. If the "Optimal Pump Number" is toggled on, then the macro finds the number of pumps that gives the lowest first-year break-even CO_2 price for this original annual average CO_2 mass flow rate in Table 1A. The optimal number of pumps may be different from the original number of pumps in Table 1A. If the "Optimal Pump Number" is toggled off, then the macro finds the first-year break-even CO_2 price associated with the original annual average CO_2 mass flow rate and number of pumps in Table 1A.

Table 1E in the "Combo Results" sheet provides results for different values of the annual average CO_2 mass flow rate, pipeline length, and elevation change along the pipeline. Results for each combination of input values are the number of booster pumps, the minimum pipe inner diameter, the nearest nominal pipe size with an inner diameter larger than this minimum inner pipe diameter, and first-year break-even CO_2 prices associated with the number of pumps and nominal pipe size. The results in Table 1E are for a fixed value of the capacity factor. The user can fix the number of booster pumps or let the "Goal_Seek_Price" macro find the optimal number of booster pumps depending on whether or not the "Optimal Pump Number" on the "CO2_T_COM" ribbon tab is toggled on.

To generate results in Table 1E

- Specify inputs (e.g., project start year, escalation rate beyond the project start year, etc.) in light orange cells within Table 1A, Table 2, and Table 3 on the "Main" sheet except the annual average CO_2 mass flow rate, pipeline length, and elevation change since those are input in Table 1E of the "Combo Results" sheet. The user should enter the number of booster pumps on the "Main" sheet if a fixed number of booster pumps is desired and other inputs on the "Eng Mod" sheet.
- Enter values for the annual average CO_2 mass flow rate, pipeline length, and elevation change along the pipeline in columns A, B, and C, respectively, of Table 1E in the "Combo Results" sheet. The cell in the row after the last row with input data in Column A needs to be blank to indicate to the macro that no more input data should be evaluated.
- Toggle the "Optimal Pump Number" on or off in the "CO2_T_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of booster pumps; whereas, when toggled off, the macro will use the number of booster pumps input by the user.
- Select the "Combo" option in the drop-down box next to the "Macro Option" label on the "CO2_T_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "CO2_T_COM" ribbon tab to activate the "Goal_Seek_Price" macro. When the macro is finished, a message box will pop up that says, "Execution Complete for Goal_Seek_Price Macro! Run time of X minutes" where "X" denotes the number of minutes.

Table 1E will now have results for each annual average CO_2 mass flow rate, pipeline length, and elevation change along the pipeline that was input by the user. If the user toggled the "Optimal Pump Number" on, then the column with the number of booster pumps (Column G) will have the optimal number of booster pumps, and the title of this column will have the word "Optimal" in the first cell. Otherwise, this column will have the number of pumps specified by the user in Table 1A on the "Main" sheet, and the title of this column will have the phrase "User-Defined" in the first cell.

The macro saves the original (i.e., user input) annual average CO_2 mass flow rate, pipeline length, and elevation change along the pipeline and number of pumps in Table 1A before any calculations are performed. After Table 1E is populated, the macro enters the original annual average CO_2 mass flow rate, pipeline length, elevation change along the pipeline, and number of pumps in Table 1A. If the "Optimal Pump Number" is toggled on, then the macro finds the number of pumps that gives the lowest first-year break-even CO_2 price for the original annual average CO_2 mass flow rate, pipeline length, and elevation change along the pipeline values in Table 1A. The optimal number of pumps may be different from the original number of pumps in Table 1A. If the "Optimal Pump Number" is toggled off, then the macro finds the first-year break-even CO_2 price associated with the original annual average CO_2 mass flow rate, pipeline length, elevation change along the pipeline, and number of pumps in Table 1A.

1.3 OVERVIEW OF THIS MANUAL

This manual has the following sections:

- Section 2: Describes the financial module, provides equations for calculating the WACC, and gives key inputs needed for the module.
- Section 3: Describes the engineering module, 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, and gives key inputs needed for the module.
- Section 4: Provides example results from the model.
- Section 5: Presents a list of references cited in the manual.
- Appendix A: Explains the rationale behind the financial parameters provided in the financial model.
- Appendix B: Provides the equations used in the engineering module to calculate quantities related to fluid flow in the pipe.

2 Financial Module

As mentioned in Section 0, the financial module for the CO2_T_COM is the "Main" sheet. The "Main" sheet provides more than just the financial model; it allows the user to enter inputs (e.g., pipeline length and percent equity) and provides key results. More information on the inputs within this sheet is provided in Section 2.2.

2.1 Overview

Much of the financial module is the financial model, which comprises cash flows of various quantities. Cash flows for revenues, capital costs, and operating costs are first provided in real or constant dollars. In the model, the word "real" indicates that after the effect of inflation is factored out of prices and unit costs, these prices or unit costs are the same in each year (i.e., they are constant over time). However, the cash flows of real revenues and costs are eventually escalated with an escalation rate provided by the user to generate cash flows in nominal dollars.

The "Main" sheet has seven tables:

- Table 1 contains key inputs and presents model outputs.
- Table 2 contains many inputs and also provides several calculations.
- Table 3 provides capital costs and annual operating expenses in different categories. These costs are calculated in the "Eng Mod" sheet. The capital costs in each category are distributed over the period of construction depending on the number of years of construction, which is specified in Table 2. There are several supplementary tables to the right of Table 3 that provide the percentage of the capital cost that is incurred in each year of construction. Supplementary tables are provided for two-, three-, four- and five-year construction periods. The user can adjust the percentages in the supplementary tables. There is no supplementary table for a one-year construction period because 100% of each capital cost is incurred in that one year of construction.
- 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. Costs in real dollars are given in 2011$, which is the base year in the model, and then these costs are adjusted to real costs in the first year of the project which is 2018 by default. The cash flows in real dollars in the first year of the project (e.g., 2018) are then escalated to nominal dollars. The nominal cash flows for capital costs are used to determine a depreciation schedule utilizing straight line (SL) depreciation or 150 percent declining balance (DB150) depreciation. There are also escalated and discounted (i.e., present value) costs for two cash flows provided.
- Table 6 provides the mass of CO_2 transported each year, the price of transporting CO_2 in each year, and the annual cash flows for revenues. The CO_2 prices and cash flows are first determined in real 2011$, then presented in real dollars in the first year of the project (e.g., 2018). The CO_2 prices and revenues in real dollars in the first year of the

project are then escalated to nominal dollars. Also, escalated and discounted (i.e., present value) revenues are provided.

- 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 then discounted to present value dollars.

The financial module uses the capital, operation and maintenance (O&M), and electricity costs developed in the engineering module (discussed in Section 2.2) as inputs. It develops cash flows of revenues and costs, including taxes and financing costs, and calculates the NPV of returns to the owners. The cash flows for revenues are developed once a cost for the transport of CO_2 has been specified.

As mentioned above, the model has the ability to perform real and nominal dollar analyses. To incorporate one of these options and use the financial module, the user must specify the financial parameters listed below. More information on financial parameters can be found in Appendix A: Rationale Behind Key Financial Parameters.

- Fraction of financing provided by equity (the remainder is provided by debt)
- $IRRROE_{min}$ desired by the owners (i.e., equity investors)
- Interest rate on debt
- Escalation rate from the base year (2011) to the project start year
- Escalation rate beyond the project start year
- Effective income tax rate that includes the federal corporate income tax and a factor to account for state and local taxes. The taxes are assumed to be levied against the tax-basis earnings of the pipeline operations as discussed below.
- Depreciation method
    - The Internal Revenue Service Publication 946 recommends either a DB150 method or SL method for pipeline transportation with recovery periods of 15 or 22 years. [3] Therefore, the model has three options for applying depreciation that consists of a depreciation method and the recovery period for depreciation (referred to as the "Depreciation method – recovery period for depreciation" in the model within the "Main" sheet):
        - DB150– 15 years (default in the model)
        - SL – 15 years
        - SL – 22 years

Within the "Main" sheet, the user must also specify items related to the project like the project start year, length of the construction period, and length of the operating period. The user must provide an escalation rate from the base year (2011) to the project start year chosen by the user. The default start year in the model is 2018, and the model provides a default escalation rate from 2011 to 2018. 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 project contingency costs to all capital costs. The default in the model is 15% of capital costs for the project contingency costs. Process contingency costs are often added for technologies that are not yet at commercial scale. Because CO_2 pipelines are a commercial-scale technology, process contingency costs were 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 in real or constant 2011$, the base year for costs in the model. These cash flows are escalated to real dollars in the first year of the project using the first escalation rate input by the user (i.e., escalation rate from the base year [2011] to the project start year). As discussed above, the default project start year is 2018, and the model provides a default escalation rate for escalating cash flows to real 2018$. The cash flows in real dollars in the first year of the project are escalated to give nominal cash flows for capital and operating costs (i.e., capital costs or expenses [CAPEX] and operating 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 and begins transporting CO_2).

The user inputs an annual average CO_2 mass flow rate (q_{av}) and inputs the price for transporting CO_2 in 2011$/tonne. This CO_2 price is used to calculate revenues in each year in real 2011$ by multiplying this CO_2 price by the mass of CO_2 transported each year. The CO_2 price in real 2011$ is escalated using the first escalation rate to a CO_2 price in the first year of the project. This CO_2 price is used to calculate revenues in real dollars in the start year of the project. Finally, the CO_2 price in the first year of the project is escalated in each year of the project using the second escalation rate (i.e., escalation rate beyond the project start year) to give the nominal price of CO_2 in each year. The nominal CO_2 price in each year is multiplied by the mass of CO_2 transported in each year to give the nominal revenues in each year of the project.

The NPV for the project is determined using a WACC methodology. The first step in the WACC methodology is to calculate the WACC using Eq. 2-1:

$$WACC = f_{equity} \cdot IRROE_{min} + \left(1 - f_{equity}\right) \cdot (1 - r_{tax}) \cdot i_d \qquad \textbf{\textit{Eq. 2-1}}$$

Where

WACC	= weighted average cost of capital (1/yr)
f_{equity}	= fraction of total financing that is equity (1/yr)
$IRROE_{min}$	= minimum IRROE (1/yr)
r_{tax}	= effective tax rate (includes federal corporate income tax, state, and local tax rates) (1/yr)
i_d	= interest rate on debt (1/yr)

The quantity $(1 - r_{tax}) \cdot i_d$ is the tax affected cost of debt (i_{dtax}).

The second step in the WACC methodology is to calculate the tax-basis earnings before interest, taxes and net operating losses (NOL) (TBEBITN) in each year (in escalated dollars) per Eq. 2-2:

$$TBEBITN = revenue - COGS - OPEX - depreciation \qquad \textbf{\textit{Eq. 2-2}}$$

Where

TBEBITN	= tax basis earnings before interest, taxes and NOL (in escalated dollars)
revenue	= revenue for transporting CO_2 in each year (in escalated dollars)
COGS	= cost of goods sold, which is zero in all years for the pipeline operation (in escalated dollars)
OPEX	= operating expenses or costs in each year 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 tax basis earnings before interest and taxes but after NOL (TBEBITAN). If TBEBITN is negative in a year then revenues are not sufficient to cover COGS, OPEX and depreciation. This is known as a net operating loss or NOL. In the early part of a pipeline project, there are large capital costs and no revenues since the pipeline is not operating. In the CO2_T_COM, NOL is zero if TBEBITN is positive, whereas NOL equals the absolute value of TBEBITN if TBEBITN is negative. Since there are often several years with NOL at the start of a project, the financial model in the CO2_T_COM allows NOL to accumulate or accrue which is generally consistent with tax policy. If the price charged for transporting CO_2 is high enough, TBEBITN is eventually positive, and these positive earnings are subtracted from the accrued NOL until the accrued NOL becomes zero. The tax basis earnings before interest and taxes but after NOL (TBEBITAN) is zero in any year when the accrued NOL is positive. When the accrued NOL is zero, TBEBITAN equals TBEBITN or TBEBITN minus the accrued NOL from the previous year if that accrued NOL is less than TBEBITN.

The fourth step is to calculate the effective federal corporate income, state, and local taxes paid (taxespaid) in each year for transporting CO_2 by pipeline (in escalated dollars) using TBEBITAN and Eq. 2-3:

$$taxespaid = TBEBITAN \cdot r_{tax} \qquad \textbf{\textit{Eq. 2-3}}$$

The fifth step is to calculate the earnings before interest but after taxes (EBIAT) in each year using Eq. 2-4:

$$EBIAT = revenue - COGS - OPEX - CAPEX - taxespaid \qquad \textbf{\textit{Eq. 2-4}}$$

Where

EBIAT	= earnings before interest and after taxes (in escalated dollars)

CAPEX = capital expenses or costs (in escalated dollars)

The sixth step is to calculate the free cash flow (FCF) to owners of equity in each year (in escalated dollars) per Eq. 2-5:

$$FCF = EBIAT - CINWC \quad \textbf{\textit{Eq. 2-5}}$$

Where

FCF = free cash flow to owners of equity (in escalated dollars)

CINWC = change in net working capital, which is assumed to be zero in all years for the pipeline operation (in escalated dollars)

The seventh step is to discount the FCF to owners of equity in each year using the WACC as the discount rate and sum the resulting discounted FCFs to yield the NPV of the project to the owners of equity.

An NPV for the project that is positive implies that revenues are sufficient to cover capital costs, operating expenses, taxes, principal and interest on debt, and the $IRROE_{min}$ desired by the owners of equity. Conversely, a negative NPV indicates the project returns will not satisfy the $IRROE_{min}$ desired by the owners of equity.

2.2 Key Inputs for the Financial Module

Several operational and financial inputs can be changed by the user within the "Main" sheet of the CO2_T_COM. The "Main" sheet is divided into seven tables with Tables 1, 2, and 3 requiring inputs (although default values are provided in the sheet for all parameters). The user can provide inputs, such as the price to transport CO_2 and number of pumps, but they are not required if the user chooses a Macro Option to calculate the break-even CO_2 price and number of pumps needed. Any cell that is an input cell is highlighted in light orange. Exhibit 2-1 provides key inputs for only Tables 1 and 2 of the "Main" sheet along with default values.

Table 3 in the "Main" sheet provides a link between the "Main" sheet, where the financial module resides, and the capital costs and annual operating expenses that are calculated in the "Eng Mod" sheet. As mentioned above, the capital costs for different categories are distributed over the period of construction in Table 3. There are several supplementary tables to the right of Table 3 that provide the percentage of the capital cost that is incurred in each year of construction. The user can adjust the percentages in the supplementary tables, but the percentages for each category in a supplementary table must sum to 100%. Depending on the user's input for the duration of construction (Cell E61 in Table 2), columns F to J in Table 3 will populate automatically with the supplementary table values.

It is important to note that the model can provide costs in real or nominal dollars which is why some financial parameters in Exhibit 2-1 provide defaults for both real and nominal dollars. The financial default values in the model are for nominal dollar calculations, but defaults for performing a real dollar methodology, where appropriate, are also given. More information on the rationale behind the financial parameters can be found in Appendix A: Rationale Behind Key Financial Parameters.

If a user wants to perform simultaneous runs, some key inputs (i.e., annual average or maximum CO_2 mass flow rate, pipeline length, capacity factor, and/or elevation change) also need to be incorporated into the "Combo Results" sheet or "Cases" sheet.

Exhibit 2-1. Key inputs on the "Main" sheet in the CO2_T_COM

	Parameter	Default Value	Location in "Main" Sheet	Note
Operational	First-year price to transport CO_2 (2011$/tonne)	---	Cell E10	User input is only applied when running the model in basic mode with no macro use (Section 1.2.1)
	Average annual mass flow of CO_2 transported (Mtonnes/yr)	4.30	Cell E11	Maximum daily flow of CO_2 is annual average mass flow of CO_2 divided by 365 days/yr to convert this to a daily mass flow rate and then divided again by the capacity factor Default value per "Carbon Dioxide Transport and Storage Costs in NETL Studies" Quality Guidelines for Energy System Studies (QGESS) [4]
	Capacity factor (%)	85	Cell E12	Default value per "Carbon Dioxide Transport and Storage Costs in NETL Studies" QGESS [4]
	Length of pipeline (mi)	62	Cell E14	Default value per "Carbon Dioxide Transport and Storage Costs in NETL Studies" QGESS [4]
	Number of booster pumps	1	Cell E15	Only use when the user desires to input the number of booster pumps instead of having the macro calculate the optimal number of pumps; toggle off the "Optimal Pump Number" in the "CO2_T_COM" ribbon tab
	Change in elevation from inlet to outlet of pipeline (ft)	0	Cell E16	If the pipeline outlet is at a higher elevation than the inlet, the change is positive, otherwise the change is negative
	Calendar year for the start of the project (yr)	2018	Cell E60	
	Duration of construction (yr)	3	Cell E61	Can be up to five years
	Duration of operation (yr)	30	Cell E62	Must be less than 95 years Default value per "Carbon Dioxide Transport and Storage Costs in NETL Studies" QGESS [4]
	Inlet pressure for pipeline (psig)	2,200	Cell E76	Default value per "Carbon Dioxide Transport and Storage Costs in NETL Studies" QGESS [4]
	Outlet pressure for pipeline (psig)	1,200	Cell E78	Default value per "Carbon Dioxide Transport and Storage Costs in NETL Studies" QGESS [4]
	Equation to use for calculating capital costs for pipeline (specify one)	PARKER or BROWN	Cell E82	PARKER for the equations from Parker [5] MCCOY for the equations from McCoy and Rubin [6] RUI for the equations from Rui et al. [7] BROWN for equations from Brown et al. [8] Equations from Parker give highest costs and have no regional component. [5] Equations from Brown et al. are based on most recent pipeline capital cost data. [8]

	Parameter	Default Value	Location in "Main" Sheet	Note	
Operational (continued)	Region of United States for McCoy and Rubin equations (specify one region) [6]	Avg	Cell E83	NE (Northeast United States) SE (Southeast United States) MW (Midwest United States) Cen (Central United States) SW (Southwest United States) West (Western United States) Avg (average of all U.S. regions)	This cell will be light orange when the McCoy option is selected.
	Region of United States or Canada for Rui et al. equations (specify one region) [7]	Avg	Cell E84	NE (Northeast United States) SE (Southeast United States) MW (Midwest United States) Cen (Central United States) SW (Southwest United States) West (Western United States) Can (Canada) Avg (average of all U.S. regions)	This cell will be light orange when the Rui option is selected.
	Region of United States for Brown et al. equations (specify one region) [8]	Avg	Cell E85	NE (New England) MA (Mid-Atlantic) SE (Southeast) GL (Great Lakes) GP (Great Plains) RM (Rocky Mountains) PN (Pacific Northwest) SW (Southwest) CA (California) Avg (average of all U.S. regions)	This cell will be light orange when the Brown option is selected.

	Parameter	Default Value	Location in "Main" Sheet	Note
Financial	Percent equity (%)	45	Cell E45	Remainder is debt Per "Cost Estimation Methodology for NETL Assessments of Power Plant Performance" QGESS [9]
Financial	Cost of equity or $IRROE_{min}$ (%/yr)	10.77 (real) 13.00 (nominal)	Cell E46	See Appendix A: Rationale Behind Key Financial Parameters
Financial	Cost of debt or interest rate on debt (%/yr)	3.91 (real) 6.00 (nominal)	Cell E47	See Appendix A: Rationale Behind Key Financial Parameters
Financial	Total effective tax rate (%/yr)	25.74	Cell E48	21% federal corporate income tax and 6% state and local tax with effective tax rate reflecting deduction of state and local taxes from federal income taxes See Appendix A: Rationale Behind Key Financial Parameters
Financial	Escalation rate from base year to project start year (%/yr)	2.8	Cell E49	Default escalation rate is from base year of 2011 to first year of project of 2018 See Appendix A: Rationale Behind Key Financial Parameters
Financial	Escalation rate beyond project start year (%/yr)	0 (real) 2.3 (nominal)	Cell E51	See Appendix A: Rationale Behind Key Financial Parameters
Financial	Project contingency factor (%)	15	Cell E52	Applied to all capital costs (a project contingency in the range of 15–30% 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]) [9]
Financial	Depreciation method – recovery period for depreciation	DB150 – 15 years	Cell E53	DB150 – 15 years, SL – 15 years, or SL – 22 years

3 ENGINEERING MODULE

The engineering module is 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.

The engineering module is divided into four parts with some consisting of multiple sub-parts: 1) engineering calculations, 2) CAPEX (capital costs or expenses), 3) OPEX (operating costs or expenses), and 4) references.

3.1 PART 1: ENGINEERING CALCULATIONS

This part has eight sub-parts involving technical calculations and some areas for user inputs.

Sub-part 1.1: General Characteristics. This sub-part has one item, the ground temperature. The CO_2 pipeline is assumed to be buried, so the temperature of the CO_2 in the pipeline will equilibrate to the ground temperature. The user can input a value or use the default ground temperature (53°F). Ground temperatures tend to vary little over the year.

Sub-part 1.2: Pipeline Characteristics. This sub-part presents the pipeline length and elevation change. The pressures at the inlet and outlet of a pipe segment (the same as the inlet and outlet for the pipeline) are also presented. All these values are references to inputs in the "Main" sheet.

Sub-part 1.3: Pump Characteristics. This sub-part presents the number of pumps, which is a reference to the value in the "Main" sheet, and the pump efficiency. As discussed previously, the number of pumps can be a user input or it can be the number that gives the lowest first-year break-even CO_2 price that is determined by running the "Goal_Seek_Price" macro. The user can input a value for the pump efficiency or use the default value (75%).

Sub-part 1.4: CO_2 Mass Flowrate. This sub-part presents the annual average CO_2 mass flow rate, the capacity factor, and maximum CO_2 mass flow rate, all referenced from values in the "Main" sheet.

Sub-part 1.5: Additional Calculations. This sub-part includes the calculation of several variables. As will be discussed below, the model provides the ability to calculate the minimum diameter of the pipe using equations for either an incompressible fluid (i.e., liquid) or compressible fluid (i.e., gas). The calculation of the average pressure in a pipe segment, which is needed to calculate the density of CO_2, is different for incompressible and compressible fluids. These equations are presented in Appendix B: Pipe Flow Equations. The average pressure for the two types of fluids and the density of CO_2 resulting from each average pressure are provided in this sub-part. The density of CO_2 and the temperature are used to calculate the viscosity of CO_2. The compressibility factor for CO_2 is calculated as a function of temperature and pressure. The density of CO_2 calculated in this sub-part is used in later calculations to determine the power requirement for the booster pumps. Since CO_2 is a liquid in the pipeline, the density for an incompressible fluid (i.e., liquid) is used in the power requirement calculations. Also, the pump is designed to move liquids, not gases.

This sub-part also includes the calculation of the pressure drop across the pipeline segment or, equivalently, the pressure increase provided by the booster pump. The pressure increase is used in the equation for determining the power requirement of the pump.

Other variables calculated in this sub-part are for informational purposes and are not used in any additional calculations.

Sub-part 1.6: Minimum Inner Diameter of Pipe and Nominal Pipe Size. This sub-part calculates the minimum inner diameter of the pipe and the smallest nominal pipe size that has an inner diameter greater than this minimum inner pipe diameter.

The model provides two equations for calculating this minimum inner pipe diameter (D, in m), one for incompressible fluids (i.e., liquids) and one for compressible fluids (i.e., gases), which is constant across the pipe. Given a pipe segment length and elevation change across the pipe segment, these equations provide the smallest inner pipe diameter that can sustain the maximum CO_2 mass flow rate input by the user given the pressure drop across the pipe segment that is also input by the user. The derivation of these equations from the energy equation for fluid flow in a pipe segment are presented in Appendix B: Pipe Flow Equations.

For an incompressible fluid, the minimum inner pipe diameter is given in Eq. 3-1:

$$D^5 = \frac{32 f_F L {q_{m-max}}^2}{\pi^2 \rho[(P_1 - P_2) + g\rho(h_1 - h_2)]} \qquad \textit{\textbf{Eq. 3-1}}$$

For a compressible fluid, the minimum inner pipe diameter is provided in Eq. 3-2:

$$D^5 = \frac{-64 R^2 {Z_{av}}^2 {T_{av}}^2 f_F {q_{m-max}}^2 L}{\pi^2 [MRZ_{av}T_{av}({P_2}^2 - {P_1}^2) + 2gM^2 {P_{av}}^2 (h_2 - h_1)]} \qquad \textit{\textbf{Eq. 3-2}}$$

Where

q_{m-max} = maximum mass flow rate of CO_2 in the pipe segment (kg/s)

L = length of the pipe segment (m)

P_1, P_2 = pressure at the inlet (P_1) and outlet (P_2) of the pipe segment (Pa). The flow is from the inlet to the outlet. The outlet is either the end of the pipeline (e. g., CO_2 saline storage operation or CO_2 EOR operation) or the inlet to a pump. The pump increases the pressure from P_2 to P_1.

h_1, h_2 = elevation at the inlet (h_1) and outlet (h_2) of the pipe segment (m). If h_2 is greater than h_1, then the pipe segment outlet is at a higher elevation (the potential energy of the fluid has increased at the outlet relative to the inlet). The user inputs the elevation change across the entire pipeline, so the elevation change across a pipeline segment will be a fraction of the elevation change across the entire pipeline.

ρ = density of CO_2 (kg/m^3)

g = acceleration due to gravity (9.80665 m/s^2)

f_F = Fanning friction factor (dimensionless). The Fanning friction factor is one-quarter of the Darcy or Moody friction factor, which is the friction factor displayed in most graphs in textbooks and calculated by most empirical equations of friction factors.

M = molecular weight of the fluid (i.e., CO_2) (kg/mol)

R = universal gas constant (8.314 m^3-Pa/K-mol)

Z_{av} = average compressibility factor for CO_2 (dimensionless)

T_{av} = average temperature of CO_2 (K). The temperature of CO_2 is assumed to be constant across the pipeline, so the average temperature is this constant value.

P_{av} = average pressure of CO_2 (Pa). The equations for calculating the average pressure of CO_2 in the pipe are different for an incompressible fluid and compressible fluid and are presented in Appendix B: Pipe Flow Equations.

The Fanning friction factor is one-quarter of the Darcy friction factor. This friction factor must be determined experimentally. Appendix B: Pipe Flow Equations provides three empirical equations for estimating the Darcy friction factor: 1) Haaland, 2) Zigrang and Sylvester, and 3) Colebrook-White. The user can select the equation to use to calculate the Darcy friction factor and, subsequently, the Fanning friction factor for use in the minimum inner pipe diameter calculations within this sub-part.

The three equations for the Darcy friction factor depend on the roughness of the inner surface of the pipe, and a value for this variable can be input by the user or the user can use the default value (Colebrook-White). The three equations are all functions of the inner diameter of the pipe and the Reynolds number, which is also a function of the inner diameter of the pipe. Thus, the equations for the minimum inner pipe diameter are implicit equations since the diameter is present on both sides of the equal sign. The equations for the minimum inner pipe diameter must be solved by an iterative process as discussed in Appendix B: Pipe Flow Equations. The equations for calculating the minimum inner diameter of the pipe are implemented as VBA user-defined functions in the model.

As mentioned above, within this sub-part, the minimum inner pipe diameter is calculated for both incompressible and compressible fluids. The user can choose which value to use when determining the appropriate pipe size for the pipeline. Since CO_2 is present as a liquid in the pipeline, it is recommended that the equation for incompressible fluids be used.

The smallest pipe size with an inner diameter greater than or equal to the minimum inner pipe diameter is also determined in this sub-section. As discussed previously, the model assumes nominal or standard pipe sizes of 4, 6, 8, 10, 12, 16, 20, 24, 30, 36, 42, and 48 in. are available. Pipe sizes less than or equal to 12 in. are approximately the inner diameter of the pipe while pipe sizes greater than 12 in. are the outer diameter of the pipe.

In this sub-part, the outer pipe diameter, inner pipe diameter, and pipe wall thickness are presented for the nominal pipe size or diameter. Table C in the "PL Pressure Relation" sheet describes how these values are determined for all the nominal pipe sizes included in the model.

Sub-part 1.7: Maximum Pipe Segment Length. This sub-part calculates the maximum length for a pipe segment given the inner diameter of the pipe, the maximum CO_2 mass flow rate in the segment, the pressure drop across the segment, and the elevation change across the segment. The calculations in this sub-part are used by the "Goal_Seek_Price" macro when the user desires to find the number of booster pumps and associated nominal pipe size that give the lowest first-year break-even CO_2 price for transporting CO_2.

The "Goal_Seek_Price" macro finds the optimal combination of number of booster pumps and nominal pipe size by cycling through the nominal pipe sizes, starting with the largest nominal pipe size supported by the model, 48 in. The macro finds the inner diameter associated with this nominal pipe size and uses this inner diameter to find the maximum pipe segment length associated with this inner pipe diameter. This maximum pipe segment length is used to calculate the number of segments the pipeline should be divided into and the number of booster pumps needed. These calculations are presented in this sub-part.

The equations for determining the maximum pipe segment length (in m) for a specific inner pipe diameter are reformulations of the equations for the minimum inner pipe diameter given in Sub-part 1.6. There are different equations for incompressible and compressible fluids, but both equations follow the form of Eq. 3-3:

$$L_{max} = \frac{b_1}{a_1 - c_1} \qquad \textit{\textbf{Eq. 3-3}}$$

Where

a_1, b_1, c_1 = variables that depend on whether the fluid is incompressible or compressible

For incompressible fluids, the variables a_1, b_1, and c_1 are given in Eq. 3-4, Eq. 3-5, and Eq. 3-6, respectively:

$$a_1 = \frac{32\, f_F\, {q_{m-max}}^2}{\pi^2 \rho D^5} \qquad \textit{\textbf{Eq. 3-4}}$$

$$b_1 = P_1 - P_2 \qquad \textit{\textbf{Eq. 3-5}}$$

$$c_1 = \frac{g\rho(h_{P1} - h_{P2})}{L_{PT}} \qquad \textit{\textbf{Eq. 3-6}}$$

The variables in these equations were defined in Sub-part 1.6 except for the following variables which relate to the entire pipeline, not a pipeline segment:

h_{P1} = elevation at the inlet to the pipeline (m)

h_{P2} = elevation at the outlet from the pipeline (m)

L_{PT} = length of the pipeline (m)

For compressible fluids, the variables a_1, b_1, and c_1 are given in Eq. 3-7, Eq. 3-8, and Eq. 3-9, respectively:

$$a_1 = \frac{-64R^2 {Z_{av}}^2 {T_{av}}^2 f_F \, {q_{m-max}}^2}{\pi^2 D^5} \qquad \textbf{\textit{Eq. 3-7}}$$

$$b_1 = MRZ_{av}T_{av}({P_2}^2 - {P_1}^2) \qquad \textbf{\textit{Eq. 3-8}}$$

$$c_1 = \frac{2gM^2 {P_{av}}^2 P_{av}^2 (h_{p2} - h_{p1})}{L_{PT}} \qquad \textbf{\textit{Eq. 3-9}}$$

Because the inner diameter is an input to these equations, the Reynolds number and friction factor can be determined directly. The equations are explicit unlike the equations for the minimum inner pipe diameter and do not require an iterative solution.

Sub-part 1.8: Pump Power. This sub-part calculates the power requirement for the pump. The power needed by a booster pump (in kW) to increase the pressure of the CO_2 from P_{in} to P_{out} is calculated per Eq. 3-10 (from McCollum and Ogden [10]):

$$W_{pump} = \frac{q_{m-max} \cdot (P_{out} - P_{in}) \cdot 10^{-3} kW/W}{\eta_{pump} \cdot \rho} \qquad \textbf{\textit{Eq. 3-10}}$$

Where

q_{m-max}	= maximum mass flow rate of CO_2 in pipe (kg/s)
P_{out}	= pressure at the outlet of the pump (equal to the inlet pressure, P_1, for the pipe segment) (Pa)
P_{in}	= pressure at the inlet of the pump (equal to the outlet pressure, P_2, for the pipe segment) (Pa)
10^{-3}	= conversion from W to kW
η_{pump}	= efficiency of the pump (typically around 75%, default value in model)
ρ	= density of CO_2 (kg/m^3)

3.2 PART 2: CAPEX (CAPITAL COSTS OR EXPENSES)

This part has three sub-parts involving CAPEX. Capital costs are incurred during the pipeline construction period before CO_2 transportation begins.

Sub-part 2.1: Pipeline Cost. This sub-part presents capital costs for the CO_2 pipeline. These capital costs are based on the capital costs of natural gas pipelines with an adjustment factor applied since CO_2 pipelines operate at a higher pressure than natural gas pipelines.

The *Oil & 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 & Gas Journal* also provides the capital cost in $/mi for pipelines of different diameters for the previous ten years for the whole United States. While the *Oil & 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: [11]

- Materials: Can include line pipe, pipe coating, and cathodic protection
- Labor: Labor costs
- Right-of-way (ROW) & damages: Includes obtaining ROW and allowances for damages
- Miscellaneous: Generally, covers 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, Rui et al., and Brown et al. have used the capital cost data provided in the *Oil & Gas Journal* to estimate parameters in cost equations that are functions of the pipeline length and nominal pipe diameter. [5] [6] [7] [8]

Parker used cost data for the overall United States and estimated parameters in the form of Eq. 3-11: [5]

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

Eq. 3-11

Where

$C_{png-par-i}$	= 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$) [5]
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 for each cost category (see Exhibit 3-1). [5] The result of applying Eq. 3-11 with the parameter values in Exhibit 3-1 are capital costs in 2000$.

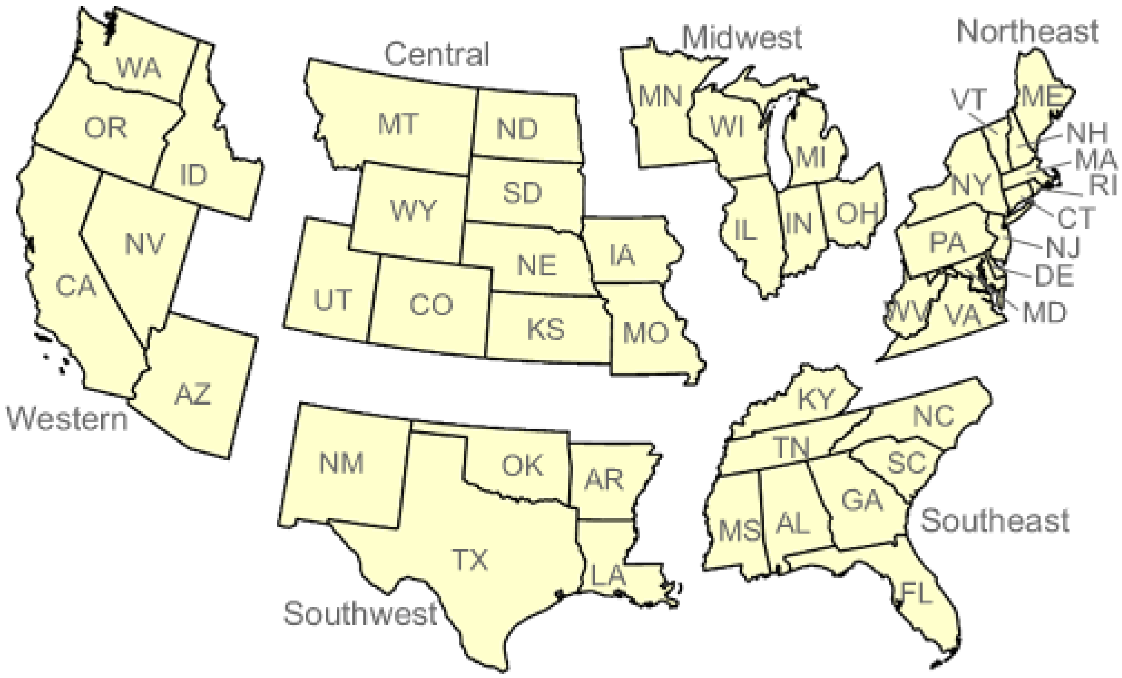
Exhibit 3-1. Values for parameters in equation provided by Parker [5]

Parameter	Materials	Labor	ROW & Damages	Miscellaneous
a_{i-0}	35,000	185,000	40,000	95,000
a_{i-1}	330.5	343	0	0
a_{i-2}	687	2,074	577	8,417
a_{i-3}	26,960	170,013	29,788	7,324

It is important to note that in the study done by Parker, [5] two different equations were provided for ROW capital costs. Figure 18 within the Parker study [5] shows data for ROW capital costs ($/mi) versus pipeline diameter (in.) 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 [5]), 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 [5] were the same between the figure and the text.

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 Administration (EIA) uses when segregating natural gas pipeline costs, as illustrated in Exhibit 3-2. [6]

Exhibit 3-2. Regions defined by EIA for segregating pipeline costs



Source: U.S. EIA [12]

McCoy and Rubin estimated parameters in the form of Eq. 3-12: [6]

$$C_{png-mcc-i} = 10^{(a_{i-0}+a_{i-reg})} \cdot L^{a_{i-1}} \cdot D^{a_{i-2}} \qquad \textbf{Eq. 3-12}$$

Where

$C_{png-mcc-i}$	= 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$) [6]
L	= length of the pipeline (km)
D	= standard diameter of pipeline (in.)
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" (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. 3-12 for each cost category (see Exhibit 3-3). [6] The result of applying Eq. 3-12 with the parameter values in Exhibit 3-3 are capital costs in 2004$. Instead of calculating costs for a specific region in the United States, the user can have the CO2_T_COM calculate the average of costs for all the regions in the United States by selecting "Avg" for the region variable in Cell E83 on the "Main" sheet.

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

Parameter	Materials	Labor	ROW & Damages	Miscellaneous
a_{i-0}	3.112	4.487	3.950	4.390
a_{i-NE}	0	0.075	0	0.145
a_{i-SE}	0.074	0	0	0.132
a_{i-MW}	0	0	0	0
a_{i-Cen}	0	-0.187	-0.382	-0.369
a_{i-SW}	0	-0.216	0	0
a_{i-West}	0	0	0	-0.377
a_{i-1}	0.901	0.820	1.049	0.783
a_{i-2}	1.590	0.940	0.403	0.791

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 (Eq. 3-13) with a form like that used by McCoy and Rubin: [6] [7]

$$C_{png-rui-i} = e^{(a_{i-0}+a_{i-reg})} \cdot L^{a_{i-1}} \cdot SA^{a_{i-2}} \qquad \textbf{\textit{Eq. 3-13}}$$

Where

$C_{png-rui-i}$	= 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$) [7]
L	= length of the pipeline (ft)
SA	= cross-sectional surface area of the pipeline (i.e., $\pi D^2/4$) (ft^2)
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. 3-13 for each cost category (see Exhibit 3-4). [7] The result of applying Eq. 3-13 with the parameter values in Exhibit 3-4 are capital costs in 2008$. Instead of calculating costs for a specific region in the United States, the user can have the CO2_T_COM calculate the average of costs for all the regions in the United States by selecting "Avg" for the region variable in Cell E84 on the "Main" sheet.

Exhibit 3-4. Values for parameters in equation provided by Rui et al. [7]

Parameter	Materials	Labor	ROW & Damages	Miscellaneous
$a_{i\text{-}0}$	4.814	5.697	1.259	5.580
$a_{i\text{-NE}}$	0	0.784	0.645	0.704
$a_{i\text{-SE}}$	0.176	0.772	0.798	0.967
$a_{i\text{-MW}}$	-0.098	0.541	1.064	0.547
$a_{i\text{-Cen}}$	0	0	0	0
$a_{i\text{-SW}}$	0	0.498	0.981	0.699
$a_{i\text{-West}}$	0	0.653	0.778	0
$a_{i\text{-Can}}$	-0.196	0	-0.830	0
$a_{i\text{-}1}$	0.873	0.808	1.027	0.765
$a_{i\text{-}2}$	0.734	0.459	0.191	0.458

Brown et al. segregated the pipeline capital costs into nine different regions of the United States (Exhibit 3-5) and estimated parameters in the form of Eq. 3-14: [8]

$$C_{png-\mathrm{brn}-i} = a_{i-0} \cdot D^{a_{i-1}} \cdot L^{a_{i-2}} \qquad \textbf{\textit{Eq. 3-14}}$$

Where

$C_{png\text{-}brn\text{-}i}$	= 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 Brown et al. (cost in 2018$) [8]
D	= standard diameter of the pipeline (in.)
L	= length of the pipeline (ft)
$a_{i\text{-}0}$, $a_{i\text{-}1}$, $a_{i\text{-}2}$	= parameters that are determined by fitting the equation to the capital cost data. All parameter values are region-specific.

Exhibit 3-5. States in each region for equation provided by Brown et al. [8]

Region	State
New England (NE)	CT, MA, ME, NH, RI, VT
Mid-Atlantic (MA)	DE, MD, NJ, NY, PA, VA, WV
Southeast (SE)	AL, AR, FL, GA, KY, LA, MS, NC, SC, TN
Great Lakes (GL)	IL, IN, OH, MI, WI
Great Plains (GP)	IA, KS, MN, MO, ND, NE, OK, SD
Rocky Mountain (RM)	CO, ID, MT, NM, NV, UT, WY
Pacific Northwest (PN)	OR, WA
Southwest (SW)	AZ, TX
California (CA)	CA

Using pipeline capital cost data for different regions in the United States from 1980 to 2017, Brown et al. estimated values for the parameters in Eq. 3-14 for each cost category (see Exhibit 3-6). [8] The result of applying Eq. 3-14 with the parameter values in Exhibit 3-6 are capital costs in 2018$. Instead of calculating costs for a specific region in the United States, the user can have the CO2_T_COM calculate the average of costs for all the regions in the United States by selecting "Avg" for the region variable in Cell E85 on the "Main" sheet.

Exhibit 3-6. Values for parameters in equation provided by Brown et al. by region [8]

Region	Parameter	Materials	Labor	ROW & Damages	Miscellaneous
New England (NE)	a_{i-0}	10,409	249,131	83,124	65,990
	a_{i-1}	0.296847	-0.33162	-0.66357	-0.29673
	a_{i-2}	-0.07257	-0.17892	-0.07544	-0.06856
Mid-Atlantic (MA)	a_{i-0}	9,113	43,692	1,942	14,616
	a_{i-1}	0.279875	0.05683	0.17394	0.16354
	a_{i-2}	-0.0084	-0.10108	-0.01555	-0.16186
Great Lakes (GL)	a_{i-0}	8,971	58,154	14,259	41,238
	a_{i-1}	0.255012	-0.14821	-0.65318	-0.34751
	a_{i-2}	-0.03138	-0.10596	0.06865	-0.11104
Great Plains (GP) and Rocky Mountain (RM)	a_{i-0}	5,813	10,406	2,751	4,944
	a_{i-1}	0.31599	0.20953	-0.28294	0.17351
	a_{i-2}	-0.00376	-0.08419	0.00731	-0.07621

Region	Parameter	Materials	Labor	ROW & Damages	Miscellaneous
Pacific Northwest (PN) and Southeast (SE)	a_{i-0}	6,207	32,094	9,531	11,270
	a_{i-1}	0.38224	0.0611	-0.37284	0.19077
	a_{i-2}	-0.05211	-0.14828	0.02616	-0.13669
Southwest (SW) and California (CA)	a_{i-0}	5,605	95,295	72,634	19,211
	a_{i-1}	0.41642	-0.53848	-1.07566	-0.14178
	a_{i-2}	-0.06441	0.0307	0.05284	-0.04697

The costs given by Parker are in 2000$, McCoy and Rubin in 2004$, and Rui et al. in 2008$. [5] [6] [7] Within the model, the costs from these equations are adjusted to 2011$ using the Handy-Whitman gas transmission pipeline index for the material and labor categories, [13] the gross domestic product chain type price index for the ROW category, and the producer price index [14] for the miscellaneous category. Exhibit 3-7 provides the values for each index in the applicable years used to make the adjustments to the capital costs.

Exhibit 3-7. Values for cost indices used to adjust pipeline capital costs

Index Type	Year			
	2000	2004	2008	2011
Handy-Whitman gas transmission pipeline index	261	400	604	525
Gross domestic product chain type price index	88.7	96.8	108.5	113.8
Producer price index	122.3	139.6	196.3	190.9

The costs given by Brown et. al. are in 2018$. [8] These costs need to be de-escalated from 2018 to 2011 to be consistent with other base costs in the CO2_T_COM. If the user chooses 2018 as the start year for the CO_2 storage project, then the first escalation rate input by the user is used to convert pipeline capital costs from 2018 to 2011. If the user chooses any year other than 2018 as the year when the CO_2 storage project starts, then the Handy-Whitman gas transmission pipeline index for 2011 is divided by the index for 2018 and this ratio (0.824) is used to de-escalate natural gas pipeline costs from 2018 to 2011. [15]

In Table 2 of the "Main" sheet, the user selects which of the four regression equations to use in the analysis. If the user selects McCoy and Rubin, [6] Rui et al., [7] or Brown et al. [8], then the user must also select the region of the United States to use in the analysis.

Eq. 3-11, Eq. 3-12, Eq. 3-13, and Eq. 3-14 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 increases 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 (Eq. 3-15). [2]

$$C_{pCO2-x-i} = C_{png-x-i} \cdot e_{CO2}$$ ***Eq. 3-15***

Where

$C_{pCO2-x-i}$ = capital costs for a CO_2 pipeline using equation from author x and category i (2011$)

x = "par" for Parker, [5] "mcc" for McCoy and Rubin, [6] "rui" for Rui et al., [7] or "brn" for Brown et al. [8]

i = "mat" for materials or "lab" for labor

e_{CO2} = factor that adjusts costs of natural gas pipeline to costs for a CO_2 pipeline depending on the nominal diameter of the pipeline D (dimensionless)

= 1 for D ≤ 12 in.

= 1.12 for 12 in. < D ≤ 16 in.

= 1.18 for 16 in. < D ≤ 20 in.

= 1.25 for 20 in. < D

The cost adjustment factor e_{CO2} is only applied to the capital costs for the materials and labor categories.

It is important to note that the user can collapse natural gas pipeline capital costs and CO_2 pipeline capital costs data for all four equations (rows 85-133), but all the data is visible in the model.

Sub-part 2.2: Additional Pipeline Related Costs. This sub-part presents capital costs for a CO_2 surge tank and pipeline control system. In a supplementary spreadsheet to NETL's 2010 "Estimating Carbon Dioxide Transport and Storage Costs" QGESS*,* capital costs for a CO_2 surge tank of $701,600 and a pipeline control system of $94,000 were provided, with both costs in 2000$. [16] The surge tank capital cost is adjusted from 2000$ to 2011$ in the model using the Chemical Engineering Plant Cost Index (CEPCI) for heat exchangers and tanks. This index is 370.6 for 2000 and 657.5 for 2011. [17] The control system capital cost is adjusted from 2000$ to 2011$ in the model using the CEPCI for process instruments. This index is 368.5 for 2000 and 438.7 for 2011. [17] This sub-part also includes total pipeline cost, which is the sum of pipeline cost from Sub-part 2.1 and the total additional pipeline-related cost from the surge tank and control system from Sub-part 2.2.

Sub-part 2.3: Pump Costs. This sub-part presents capital costs for the booster pumps. The capital costs for the booster pump (in 2005$) are given in Eq. 3-16 by McCollum and Ogden: [10]

$$C_{pump} = C_{pump\_var} \cdot W_{pump} + C_{pump\_fix}$$ ***Eq. 3-16***

Where

C_{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 [10]
W_{pump}	= power requirement for the pump (kW), calculated per Eq. 3-10
C_{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 [10]

The pump capital cost is adjusted from 2005$ to 2011$ in the model using the CEPCI for pumps and compression. This index is 752.5 for 2005 and 898.5 for 2011. [17]

Sub-part 2.4: Total CAPEX. This sub-part presents total CAPEX (in 2011$), which is the sum of total pipeline cost from Sub-part 2.2 and costs for the number of pumps from Sub-part 2.3.

3.3 Part 3: OPEX (Operating Costs or Expenses)

This part has three sub-parts involving OPEX. These costs are sometimes referred to as O&M costs. O&M costs are incurred during the period when the pipeline transports CO_2.

Sub-part 3.1: Pipeline O&M. This sub-part presents O&M costs for the pipeline. The CO2_T_COM provides the user with two options for calculating pipeline O&M costs, which are highlighted in the first two sub-sections. The last sub-section provides the annual pipeline O&M based on the selected option.

In the first option, the annual O&M costs are calculated as a function of the pipeline length independent of the nominal pipe size. Bock et al. provided an annual O&M cost for pipelines of $5,000/mi-yr in 1999$. [18] 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. It is not clear if this O&M cost is relevant for very large diameter pipelines. Details on using fixed O&M cost per mile are within Sub-section 3.1.1 of this sub-part in the model.

In the second option, the annual pipeline O&M costs are assumed to be a fraction of the total capital costs for the pipeline. Details on using fraction of capital costs are within Sub-section 3.1.2 of this sub-part in the model. The user must specify the fraction of total pipeline capital costs to use with this method (Cell G170 in the "Eng Mod" sheet, default is 2.5% per McCollum and Ogden [10]).

Sub-part 3.2: Pipeline Related Equipment and Pump O&M. This sub-part presents O&M costs for the CO_2 surge tank, control system, and booster pumps. The annual O&M costs for these pieces of equipment are assumed to be a fraction of the total capital costs for the equipment. The user must specify the fraction of the total capital costs to use to calculate the annual O&M costs (Cell G177 in the "Eng Mod" sheet, default is 4% per best professional judgement). The annual O&M costs for the booster pumps calculated in this sub-part are the costs for maintaining the pumps. The cost for the electricity needed to operate the pumps is calculated in the next sub-part.

Sub-part 3.3: Electricity for Pumping. This sub-part calculates the cost of the electricity needed to operate the booster pumps (in kWh/yr). The energy used to operate the booster pumps is given by Eq. 3-17:

$$E_{pump\_elec} = W_{pump} \cdot n_{pump} \cdot CF \cdot 8{,}760\ hr/yr \qquad \textbf{\textit{Eq. 3-17}}$$

Where

W_{pump} = power requirement for the pump (kW), calculated per Eq. 3-10

n_{pump} = number of pumps

CF = capacity factor of the pipeline (85% is default value in model)

The cost of the electricity used (in 2011$/yr) is given by Eq. 3-18:

$$CA_{elec} = E_{pump\_elec} \cdot C_{elec} \qquad \textbf{\textit{Eq. 3-18}}$$

Where

C_{elec} = cost of electricity (2011$/kWh). The user needs to supply the price of the electricity (Cell D182 in the "Eng Mod" sheet). A default value of $0.0682/kWh for industrial electricity users for 2011 from EIA is provided in the model. [19]

Sub-part 3.4: Total OPEX. This sub-part presents total OPEX (in 2011$/yr), which is the sum of annual pipeline O&M from Sub-section 3.1.3 in Sub-part 3.1, annual O&M costs from Sub-part 3.2, and annual electricity cost from Sub-part 3.3.

3.4 KEY INPUTS FOR THE ENGINEERING MODULE

Besides changing inputs in the financial module (see Section 2.2), several inputs can also be changed by the user within the "Eng Mod" sheet of the CO2_T_COM. If a user wants to perform simultaneous runs, some key inputs (i.e., annual average or maximum CO_2 mass flow rate, pipeline length, capacity factor, and/or elevation change) also need to be incorporated into the "Combo Results" sheet or "Cases" sheet. The "Eng Mod" sheet is divided into four parts with parts 1, 2, and 3 requiring inputs (although default values are provided in the sheet for all parameters). Any cell that is an input cell is highlighted in light orange.

In Part 1, a variety of engineering calculations are performed, particularly, the pipe diameter (Sub-part 1.6) and power requirement for the pump (Sub-part 1.8). Key inputs include the method for calculating inside diameter or maximum pipeline segment length and the method for calculating the Fanning friction factor. Units can be changed for additional calculations (e.g., pressure change from elevation change), but there are default units within the model.

In Part 2, capital costs are estimated. The primary cost inputs are the natural gas pipeline capital costs, which are calculated by one of the four sets of equations (method selected in the "Main" sheet), the surge tank, the pipeline control system, and the pump costs (fixed and variable), all of which are discussed within Section 3.1, Section, 3.2, and Section 3.3 in this manual and have default values within the model. The user can change the indices to adjust costs to the common basis of 2011$ in Part 2. However, there are default values for these indices within the model.

In Part 3, annual operating expenses are estimated. Primary cost inputs are method for calculating annual O&M costs, 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. The user can change the indices to adjust costs to the common basis of 2011$ within Part 3, but there are default values for all these indices within the model.

Part 4 lists references used throughout the model worksheets.

Exhibit 3-8 provides key inputs along with their defaults for parts 1, 2, and 3 in the "Eng Mod" sheet.

Exhibit 3-8. Key inputs on the "Eng Mod" sheet in the CO2_T_COM

Parameter	Default Value	Location in "Eng Mod" Sheet	Note
Temperature of the ground where pipes are buried (°F)	53	Cell D7	
Pump efficiency (%)	75	Cell D17	From McCollum and Ogden [10]
Method for calculating the minimum pipe diameter (specify one)	1	Cell D46	1 = methodology for incompressible fluid (i.e., liquid) using equations presented in Appendix B: Pipe Flow Equations 2 = methodology for compressible fluid (i.e., gas) using equations presented in Appendix B: Pipe Flow Equations based on McCoy [20]
Method for calculating Fanning friction factor (specify one)	3	Cell D47	1 for equation developed by Haaland given by McCollum and Ogden [10] 2 for equation developed by Zigrang and Sylvester given by McCoy [20] 3 for Colebrook-White equation [21] See Appendix B: Pipe Flow Equations for these equations
CO_2 surge tank capital costs ($)	701,600	Cell D146	In 2000$ Per supplementary spreadsheet to "Estimating Carbon Dioxide Transport and Storage Costs" QGESS [16]
Pipeline control system capital costs ($)	94,000	Cell D147	In 2000$ Per supplementary spreadsheet to "Estimating Carbon Dioxide Transport and Storage Costs" QGESS [16]
Pump costs – fixed capital costs ($)	70,000	Cell D153	In 2005$ Per McCollum and Ogden [10]
Pump costs – variable capital costs ($/kW)	1,110	Cell D154	In 2005$/kW Per McCollum and Ogden [10]

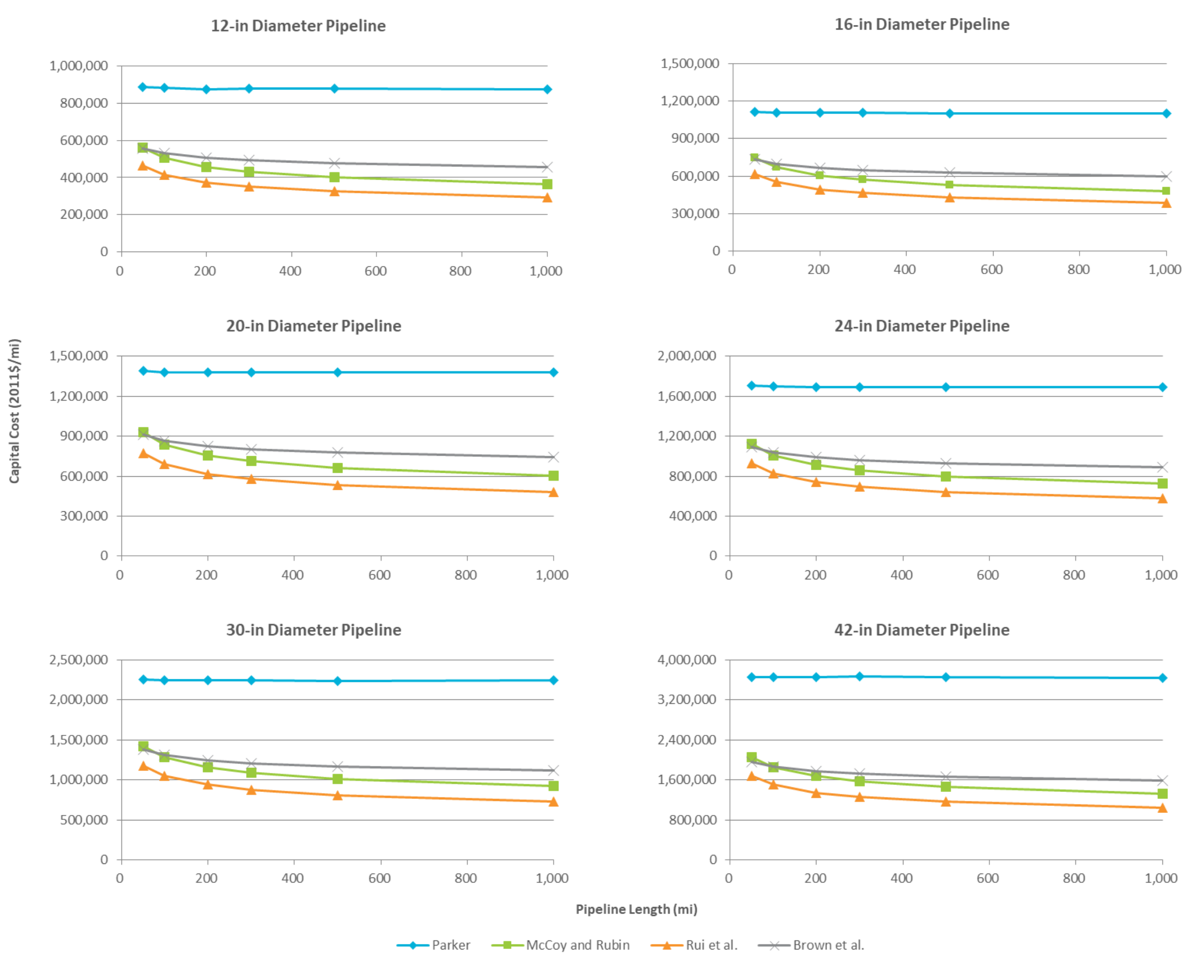
Parameter	Default Value	Location in "Eng Mod" Sheet	Note
Method for calculating annual pipeline O&M costs (specify one)	2	Cell D164	1 = use fixed O&M costs per mile of pipeline independent of diameter 2 = use fraction of capital costs, which depend on pipeline length and diameter
Annual pipeline O&M costs per mile of pipe ($/mi-yr)	5,000	Cell D166	In 1999$/mi-yr Per supplementary spreadsheet to "Estimating Carbon Dioxide Transport and Storage Costs" QGESS [16]
Percent of CAPEX to use as annual O&M costs for pipeline (%)	2.5	Cell G170	Per McCollum and Ogden [10]
Percent of pump, control system, and surge tank CAPEX to use as annual O&M costs for these pieces of equipment (%)	4.0	Cell G177	Best professional judgment
Electricity cost for pumping ($/MWh)	68.20	Cell D182	In 2011$/MWh From EIA, electricity price for industrial sector [19]

4 Model Results

This section provides the capital costs for natural gas pipelines generated by the equations from Parker, McCoy and Rubin, Rui et al., and Brown et al. [5] [6] [7] [8] 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 CO_2 pipelines. Default values discussed in Section 2.2 and Section 3.4 of this manual and presented in the CO2_T_COM were used to produce results.

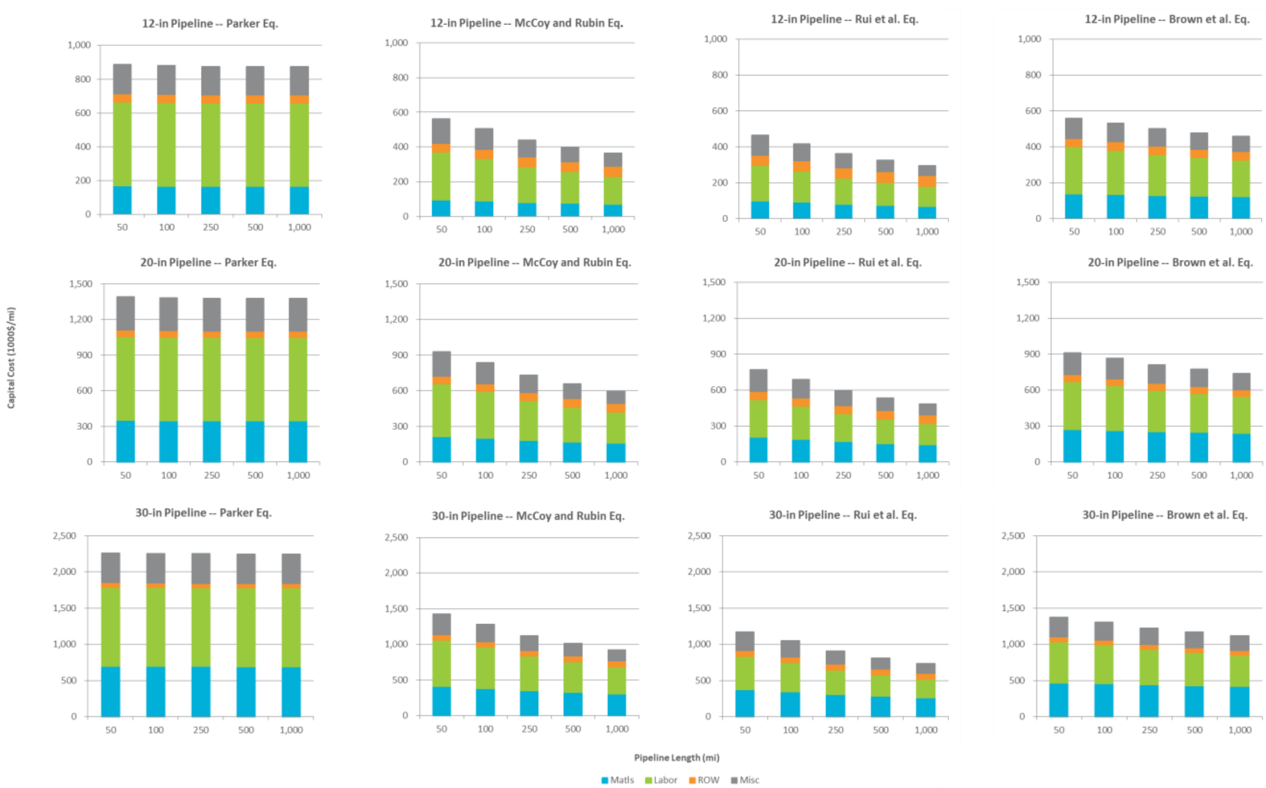
The four sets of equations for natural gas pipeline capital costs gave different results, as illustrated in Exhibit 4-1, which presents the $/mi data in 2011$ (2011$/mi) for different pipeline lengths and diameters. The results for Parker are national, while the results for McCoy and Rubin, Rui et al., and Brown et al. are average costs across all the regions in the United States. [5] [6] [7] [8] In general, the equations from Parker gave the highest costs followed by the equations from Brown et al., McCoy and Rubin, and then Rui et al. [5] [6] [7] [8] The equations from Parker gave significantly higher costs than the other three equations. [5] [6] [7] [8] The equations from Parker did not show decreasing costs with increasing pipeline length whereas the other three set of equations gave costs that showed this behavior. [5] [6] [7] [8]

Exhibit 4-1. Natural gas pipeline capital costs using different equations (2011$/mi)



The breakdown of natural gas pipeline capital costs by cost category (in thousands of 2011$/mi) is illustrated in Exhibit 4-2 for 12-, 20-, and 30-in. diameter pipelines for the four different sets of equations. The results for Parker are national, while the results for McCoy and Rubin, Rui et al., and Brown et al. are average costs across all the regions in the United States. [5] [6] [7] [8] 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 exception of costs generated by the equations from Rui et al. for very long 12-in. diameter pipelines. [7]

Exhibit 4-2. Breakdown of natural gas pipeline capital costs using different equations (thousands of 2011$/mi)



The four sets of pipeline capital cost equations were compared to pipeline capital cost data from a variety of sources. Note that results for Parker are national, while the results for McCoy and Rubin, Rui et. al., and Brown et al. are average costs across all the regions in the United States. [5] [6] [7] [8] The range of total capital costs for a CO_2 pipeline per inch (diameter, 8–42 in.) and mile (length, 50–1,000 mi) ($/in.-mi) including 15% contingency factor for the different sets of equations (costs in 2011$) are shown in Exhibit 4-3.

Exhibit 4-3. CO_2 pipeline capital cost for four equations (2011$/in.-mi)

Equation	Diameter (in.)	Length (mi)					
		50	100	200	300	500	1,000
Parker	8	100,749	99,826	99,365	99,211	99,088	98,995
	12	85,001	84,386	84,078	83,976	83,894	83,832
	16	89,873	89,356	89,097	89,011	88,942	88,891
	20	94,260	93,824	93,607	93,534	93,476	93,432
	24	102,147	101,762	101,570	101,506	101,454	101,416
	30	108,337	108,029	107,875	107,824	107,783	107,752
	42	125,426	125,206	125,096	125,060	125,030	125,008
McCoy and Rubin	8	55,034	49,572	44,805	42,304	39,426	35,962
	12	53,792	48,396	43,669	41,182	38,312	34,844
	16	59,883	53,866	48,582	45,795	42,573	38,668
	20	63,188	56,851	51,274	48,328	44,916	40,773
	24	67,306	60,580	54,651	51,513	47,877	43,452
	30	68,128	61,366	55,392	52,226	48,549	44,065
	42	70,208	63,342	57,257	54,022	50,256	45,649
Rui et al.	8	45,408	40,768	36,741	34,637	32,224	29,329
	12	44,502	39,831	35,766	33,637	31,190	28,246
	16	49,608	44,334	39,735	37,323	34,545	31,197
	20	52,362	46,758	41,864	39,293	36,330	32,753
	24	55,751	49,764	44,528	41,775	38,599	34,758
	30	56,347	50,283	44,972	42,175	38,945	35,033
	42	57,782	51,571	46,117	43,239	39,908	35,866
Brown et al.	8	55,514	52,956	50,640	49,388	47,912	46,077
	12	53,445	50,879	48,544	47,277	45,777	43,903
	16	59,014	56,124	53,486	52,051	50,349	48,215
	20	61,914	58,848	56,045	54,517	52,703	50,423
	24	65,635	62,365	59,369	57,735	55,791	53,345
	30	66,012	62,707	59,674	58,017	56,043	53,556
	42	67,215	63,841	60,738	59,039	57,012	54,451

The capital costs using all four equations decreased from the 8-in. diameter to the 12-in. diameter and then increased with increasing diameter. The capital costs using the equations from Parker were relatively insensitive to the length of the pipeline, whereas the capital costs using equations from McCoy and Rubin decreased with increasing pipeline length. [5] [6] The capital costs using the equations from Rui et al. and Brown et al. showed the same type of behavior as the equations from McCoy and Rubin. [6] [7] [8]

These costs were compared to contemporary pipeline costs quoted by industry experts at Kinder Morgan and Denbury Resources. Exhibit 4-4 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. [22] 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 mid end of this range, while the costs using the equations from McCoy and Rubin fall below or on the low end of this range. [5] [6] The costs using the equations from Rui et al. tend to fall below this range, and the costs using the equations from Brown et al. fall on the low end of this range. [7] [8]

Exhibit 4-4. Kinder Morgan pipeline cost metrics [22]

Terrain	Capital Cost ($/in.-mi)
Flat, Dry	$50,000
Mountainous	$85,000
Marsh, Wetland	$100,000
River	$300,000
High Population	$100,000
Offshore (150-ft to 200-ft depth)	$700,000

A further comparison was made to cost data for two Denbury CO_2 pipelines. The first is the Green pipeline with the following characteristics:

- Location: Southeast United States
- Pipeline length: 314 mi
- Pipeline diameter: 24 in.
- CO_2 flow capacity: 42,320 tonnes/day, assumed to be maximum daily flow, which translates to annual average flow of 12.6 Mtonnes/yr
- Capital cost: About $660 million according to trade journals

  About $884 million excluding capitalized interest according to the annual report
- Status: Completed around 2010

The CO2_T_COM was run with the defaults mentioned in Section 2.2 and Section 3.4 (including those financial parameters for real dollar analysis) except the annual average CO_2 mass flow rate was 12.6 Mtonnes/yr, pipeline length was 314 mi, project start year was 2011, escalation rate from base year to project start year was 0%, capacity factor was 82%, and region was SE. Two pumps were specified in Table 1A, "Optimal Pump Number" was toggled off, and "Basic" mode using the macro to calculate the first-year break-even price (Section 1.2.2) was used to obtain capital costs in real 2011$ for this project for each pipeline equation. The model determined that a 24-in. pipeline of this length would result from two pumps. The capital cost in real dollars for this project was estimated by the model to be as follows for the different sets of equations:

- Parker: $747 million
- McCoy and Rubin: $444 million
- Rui et al.: $380 million
- Brown et al. $395 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, Rui et al., and Brown et al. equations were significantly less than both published capital costs. [5] [6] [7] [8]

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 Mtonnes/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 CO2_T_COM was run with the defaults mentioned in Section 2.2 and Section 3.4 (including those financial parameters for real dollar analysis) except the annual average CO_2 mass flow rate was 11.2 Mtonnes/yr, pipeline length was 232 mi, project start year was 2011, escalation rate from base year to project start year was 0%, capacity factor was 80%, and regions were Cen (McCoy and Rubin and Rui et al.) and RM (Brown et al.). Four pumps were specified in Table 1A, "Optimal Pump Number" was toggled off, and "Basic" mode using the macro to calculate the first-year break-even price (Section 1.2.2) was used to obtain capital costs in real 2011$ for this project for each pipeline equation. The model determined that a 20-in. pipeline of this length would result from four pumps. The capital cost in real dollars for this project was estimated by the model to be as follows for the different set of equations:

- Parker: $447 million
- McCoy and Rubin: $188 million
- Rui et al.: $152 million

- Brown et al. $199 million

The result using the Parker equations exceeded the value in trade journals and the annual report. The results from the McCoy and Rubin, Rui et al., and Brown et al. equations were less than the published capital costs. [5] [6] [7] [8]

These results indicated that the equations from Parker and McCoy and Rubin give costs that are close to published CO_2 pipeline costs. [5] [6] The results also indicated that equations from Parker tend to give costs on the high side, while the equations from McCoy and Rubin, Rui et al., and Brown et al. tend to give costs on the low side. [5] [6] [7] [8]

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APPENDIX A: RATIONALE BEHIND KEY FINANCIAL PARAMETERS

The United States (U.S.) Department of Energy Office of Fossil Energy and Carbon Management (FECM) National Energy Technology Laboratory (NETL) has developed a techno-economic model for the transport of carbon dioxide (CO_2) by pipeline. This model is called the FECM/NETL CO_2 Transport Cost Model, also known as CO2_T_COM. To be consistent with costs in NETL's energy system studies, which are in 2018 dollars, an escalation rate was introduced to escalate prices, revenues, and costs in the model from the base year of 2011 to a different project start year which, by default, is 2018. In addition, a methodology to obtain costs in real dollars was incorporated in the model. Because of this new methodology, the financial parameters within the model were reassessed. Exhibit A-1 provides the suggested values for key financial variables in the model. This appendix provides the basis behind the values provided in Exhibit A-1.

Exhibit A-1. Key financial parameters in the CO2_T_COM

Financial Parameter	Real Value	Nominal Value	Location in "Main" Sheet
Escalation rate from base year to project start year (%/yr)	2.8	2.8	Cell E49
Escalation rate beyond project start year (%/yr)	0	2.3	Cell E51
Cost of equity (%/yr)	10.77	13.00	Cell E46
Cost of debt (%/yr)	3.91	6.00	Cell E47
Percent equity (remainder is debt) (%)	45	45	Cell E45
Tax rate (%/yr)	25.74	25.74	Cell E48

Note: Base year = 2011 and project start year = 2018.

In the model, the term "real" dollar analysis means that all prices, revenues, and costs are held constant throughout the analysis. In other words, the escalation rate applied to cash flows is zero. This analysis type is often called a constant dollar analysis since it is assumed that after the effects of inflation are factored out, all prices, revenues, and costs will be constant for the duration of the project. In the future, inflation-adjusted prices, revenues, and costs are likely to increase or decrease but no attempt was made to estimate these effects in the model. In a financial analysis that uses nominal (i.e., escalated) revenues and costs, the interest on debt and the minimum desired internal rate of return on equity are provided as nominal rates that depend on the assumed escalation rate. In a real or constant dollar analysis, these rates need to be adjusted to remove the influence of inflation.

The CO2_T_COM provides two escalation rates. The first escalation rate escalates costs from the base year to the project start year (i.e., 2011 to 2018 for the purposes of this manual). The Handy-Whitman indices of public utilities were used to estimate escalation rates from 2011 to 2018. The closest analog to CO_2 pipeline transportation within these indices is gas transmission; thus, the Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1, 2020 – Cost Trends of Gas Utility Construction was used. [15] Handy-Whitman divides the lower 48 states in the United States into six regions and provides indices for each region. Escalation rates for 2011 to 2018 derived from the indices for each region are provided in the CO2_T_COM in Table 2A on the "Main" sheet. The escalation rates for the six regions range from 2.7%/yr to 2.9%/yr with a median value of 2.8%/yr. This median value is considered a representative value for the lower 48 states in the United States and was selected as the default value for the first escalation rate. When this rate is compounded from 2011 to 2018, a cost in 2018 is roughly 1.213 times greater than the cost for the same item in 2011.

The second escalation rate escalates prices, revenues, and costs from the project start year onward. It can be set to 0%/yr if the user desires to conduct an analysis in real or constant dollars. For nominal dollar analysis, the second escalation rate should be the user's best estimate for how costs in the CO_2 pipeline transport industry will increase over the next 30 to 40 years. In recent years, the U.S. Energy Information Administration has used an escalation rate of about 2.3%/yr as their long-term inflation rate in the National Energy Modeling System; thus, this rate is the default for the second escalation rate in the model. [23]

The nominal return on equity was determined using the capital asset pricing model (CAPM). Data from 1990 to 2018 was collected on the nine largest natural gas storage and transportation holding companies since natural gas pipeline transport is a reasonable analog to CO_2 pipeline transport. The working natural gas and return on equity for each of these managed companies was determined using the CAPM. The return on equity for these companies ranged from 5.9%/yr to 19.8%/yr. The average of these companies weighted by the working natural gas they managed was 13.0%/yr. Thus, 13.0% is the default value for the nominal minimum desired return on equity in the CO2_T_COM.

The nominal interest on debt was determined by referencing the nominal interest on debt (5.0%/yr) used in NETL energy system studies for the electric industry (i.e., power plants). [9] The rate of return on equity in this industry is roughly 10%/yr which is lower than the rate of return on equity for natural gas storage and transportation holding companies, suggesting that the electric industry is viewed as a lower risk investment. [9] As such, a slightly higher nominal interest rate on debt of 6.0%/yr is used as the default for financing CO_2 pipelines in the CO2_T_COM.

To be consistent with NETL energy system studies, even though the natural gas and transportation industries may pose a higher risk, the equity/debt ratio for the electric industry, 45%/55%, was used as the default in the CO2_T_COM. [9]

The nominal minimum rate of return on equity and nominal interest rate on debt were converted to real values using the Fisher equation (Eq. A-1): [24]

$$(1 + i) = (1 + e) \cdot (1 + r) \qquad \textbf{\textit{Eq. A-1}}$$

Where

- i = nominal interest rate on debt or nominal minimum rate of return on equity (1/yr)
- e = escalation or inflation rate (1/yr)
- r = real interest rate on debt or real minimum rate of return on equity (1/yr)

Rearranging the variables results in Eq. A-2 for the real minimum rate of return on equity or real interest rate on debt:

$$r = \frac{(1+i)}{(1+e)} - 1 \qquad \textbf{\textit{Eq. A-2}}$$

The average real gross domestic product deflator of 2.01%/yr from 1990 to 2018 was used as the inflation rate in this analysis. Using Eq. A-2 with a nominal minimum rate of return on equity of 13.0%/yr and inflation rate of 2.01%/yr results in a real minimum rate of return on equity of 10.77%/yr. Similarly, using Eq. A-2 with a nominal interest rate of 6.0%/yr for debt and inflation rate of 2.01%/yr results in a real interest rate for debt of 3.91%/yr.

An effective tax rate, which is the average rate a corporation's pre-tax earnings are taxed, [25] was included as a default in the model to be consistent with the tax rate used in NETL energy system studies. [9] The effective tax rate includes 21% federal corporate income tax and 6% to cover all state and local taxes. Because state and local taxes are deductible from federal income taxes, the effective tax rate is lower than the sum of these two individual tax rates. The effective tax rate is derived as follows. The state and local taxes are calculated with Eq. A-3:

$$tax_{S-L} = EBIT \cdot r_{S-L} \qquad \textbf{\textit{Eq. A-3}}$$

Where

tax_{S-L} = state and local taxes (in escalated dollars)

EBIT = tax-basis earnings before interest and taxes (in escalated dollars)

r_{S-L} = effective state and local income tax rate (1/yr)

The federal income taxes are calculated with Eq. A-4:

$$tax_F = (EBIT - tax_{S-L}) \cdot r_F \qquad \textbf{\textit{Eq. A-4}}$$

Where

tax_F = federal income taxes (in escalated dollars)

r_F = federal income tax rate (1/yr)

This equation includes the deduction of state and local taxes from EBIT before federal income taxes are paid. When Eq. A-3 is substituted into Eq. A-4 the following equation results (after some grouping of terms) (Eq. A-5).

$$tax_F = EBIT \cdot (1 - r_{S-L}) \cdot r_F \qquad \textbf{\textit{Eq. A-5}}$$

The total taxes paid is the sum of federal income taxes and state and local taxes, which is determined by adding Eq. A-3 and Eq. A-5 together. After grouping terms, the total taxes paid is given by Eq. A-6:

$$tax_T = EBIT \cdot ((1 - r_{S-L}) \cdot r_F + r_{S-L}) \qquad \textit{\textbf{Eq. A-6}}$$

Where

tax_T = total taxes paid (in escalated dollars)

The effective income tax rate is the expression used to multiply EBIT (Eq. A-7).

$$r_{eff} = (1 - r_{S-L}) \cdot r_F + r_{S-L} \qquad \textit{\textbf{Eq. A-7}}$$

Where

r_{eff} = effective income tax rate (1/yr)

Substituting 0.21 (21%) for the federal income tax rate and 0.06 (6%) for the effective state and local income tax rate into Eq. A-7 gives an effective income tax rate of 0.2574 (25.74%).

APPENDIX B: PIPE FLOW EQUATIONS

The United States (U.S.) Department of Energy Office of Fossil Energy and Carbon Management (FECM) National Energy Technology Laboratory (NETL) has developed a techno-economic model for the transport of carbon dioxide (CO_2) by pipeline. This model is called the FECM/NETL CO_2 Transport Cost Model, also known as CO2_T_COM. This appendix presents equations for determining two quantities related to fluid flow in a pipe segment, which are used in the engineering module within the CO2_T_COM:

- Minimum inner diameter for a pipe segment that sustains a specified maximum mass flow rate, overcomes frictional losses in the pipe segment, and accommodates any change in the elevation across the pipe segment. For this quantity, the length of the pipe segment and pressure drop across the pipe segment are fixed.
- Longest length a pipe segment can be that will sustain a specified maximum mass flow rate, overcome frictional losses in the pipe segment, and accommodate any change in the elevation across the pipe segment. For this quantity, the inner diameter of the pipe segment and pressure drop across the pipe segment are fixed.

This appendix is organized into five sections

- **Pipe Situation:** Describes the assumed situation for the pipeline and pipe segment
- **Incompressible Fluid Flow:** Gives equations for calculating the two aforementioned quantities for an incompressible fluid (i.e., a liquid)
- **Compressible Fluid Flow:** Presents equations for calculating the two aforementioned quantities for a compressible fluid (i.e., a gas)
- **Empirical Equations for Fanning Friction Factors:** Provides three equations available for calculating the Fanning friction factor
- **Equations for Average Pressure in Pipe Segment:** Describes the equations for calculating the average pressure in the pipe segment based on incompressible and compressible fluids

B.1 PIPE SITUATION

The pipe segment is defined, in part, by the following variables with the indicated characteristics:

L = length of the pipe segment (m)

P_1, P_2 = pressure at the inlet (P_1) and outlet (P_2) of the pipe segment (Pa). The flow is from the inlet to the outlet. The outlet is either the end of the pipeline (e.g., a CO_2 enhanced oil recovery operation or CO_2 saline storage operation) or the inlet to a pump or compressor. The pump or compressor increases the pressure from P_2 to P_1.

h_1, h_2	= elevation at the inlet (h_1) and outlet (h_2) of the pipe segment (m). If h_2 is greater than h_1, then the pipe segment outlet is at a higher elevation (the potential energy of the fluid has increased at the outlet relative to the inlet).
V_1, V_2	= average fluid velocity at the inlet (V_1) and outlet (V_2) of the pipe segment (m/s)
D	= inner diameter of the pipe, which is constant across the pipe segment (m)
ρ	= density of the fluid (kg/m^3)
$q_{m\text{-}max}$	= maximum mass flow rate of the fluid in the pipe segment (kg/s)
$q_{m\text{-}av}$	= average mass flow rate of the fluid in the pipe segment (kg/s)

From Shames, [26] the differential form of the energy balance equation in "head" form across a differential length of the pipe segment (dL) is given by Eq. B-1:

$$-h_f = \frac{1}{\rho g}\frac{dP}{dL} + \frac{dh}{dL} + \frac{V}{g}\frac{dV}{dL} \qquad \textbf{\textit{Eq. B-1}}$$

Where

h_f	= head loss due to friction per unit pipe length (m/m)
g	= acceleration due to gravity (9.80665 m/s^2)

Using the Fanning friction factor (f_F), which is a dimensionless quantity, the head loss (h_f) is given by Eq. B-2:

$$h_f = \frac{2V^2}{gD} f_F \qquad \textbf{\textit{Eq. B-2}}$$

Substituting Eq. B-2 into Eq. B-1 and integrating along the pipe segment length (dL) gives Eq. B-3:

$$\int_{L_1}^{L_2} \frac{1}{\rho g}\frac{dP}{dL} dL + \int_{L_1}^{L_2} \frac{dh}{dL} dL + \int_{L_1}^{L_2} \frac{V}{g}\frac{dV}{dL} dL = -\int_{L_1}^{L_2} \frac{2V^2}{gD} f_F dL \qquad \textbf{\textit{Eq. B-3}}$$

B.2 Incompressible Fluid Flow

For incompressible fluids, ρ is constant, so Eq. B-3 after multiplying all terms by g is Eq. B-4:

$$\frac{1}{\rho}\int_{P_1}^{P_2} dP + g\int_{h_1}^{h_2} dh + \int_{V_1}^{V_2} V dV = -\int_{L_1}^{L_2} \frac{2V^2 f_F}{D} dL \qquad \textbf{\textit{Eq. B-4}}$$

Since the pipe segment has a constant diameter and the fluid is incompressible, the average fluid velocity (V) is constant (Eq. B-5):

$$V_1 = V_2 = V \qquad \textbf{\textit{Eq. B-5}}$$

The third term in Eq. B-4 involving integration between V_1 and V_2 is zero since V_1 and V_2 are the same number. Also, the $\frac{2V^2 f_F}{D}$ term in Eq. B-4 is constant. Eq. B-4 can be re-written as Eq. B-6.

$$\frac{1}{\rho}\int_{P_1}^{P_2} dP + g\int_{h_1}^{h_2} dh = -\frac{2V^2 f_F}{D}\int_{L_1}^{L_2} dL \qquad \textit{Eq. B-6}$$

Integrating Eq. B-6 with $L = L_2 - L_1$ and rewriting some terms to get rid of the negative sign in the friction loss term gives Eq. B-7:

$$\frac{P_1 - P_2}{\rho} + g(h_1 - h_2) = \frac{2V^2 f_F}{D} L \qquad \textit{Eq. B-7}$$

The average fluid velocity is calculated from the maximum mass flow rate as in Eq. B-8:

$$V = \frac{4q_{m-max}}{\pi D^2 \rho} \qquad \textit{Eq. B-8}$$

Substituting Eq. B-8 into Eq. B-7 results in Eq. B-9 and Eq. B-10:

$$\frac{P_1 - P_2}{\rho} + g(h_1 - h_2) = \frac{2f_F L}{D}\left(\frac{4q_{m-max}}{\pi D^2 \rho}\right)^2 \qquad \textit{Eq. B-9}$$

$$\frac{P_1 - P_2}{\rho} + g(h_1 - h_2) = \frac{32 f_F L {q_{m-max}}^2}{\pi^2 \rho^2 D^5} \qquad \textit{Eq. B-10}$$

Multiplying all terms by ρ results in Eq. B-11:

$$P_1 - P_2 + g\rho(h_1 - h_2) = \frac{32 f_F L {q_{m-max}}^2}{\pi^2 \rho D^5} \qquad \textit{Eq. B-11}$$

The expression for the inner diameter (D) is Eq. B-12:

$$D^5 = \frac{32 f_F L {q_{m-max}}^2}{\pi^2 \rho[(P_1 - P_2) + g\rho(h_1 - h_2)]} \qquad \textit{Eq. B-12}$$

Eq. B-12 can be used to find the minimum inner diameter, that sustains the maximum mass flow rate and overcomes frictional losses and any change in elevation given the specified pressure drop (P_1-P_2) and pipe segment length (L). A similar equation (without the elevation term involving h_1 and h_2) is provided in Heddle et al. [27] and McCollum and Ogden. [10]

The Fanning friction factor can be calculated using a variety of empirical equations. These equations are functions of the Reynolds number, pipe roughness, and inner diameter. Three of these equations are provided later in the appendix.

The Reynolds number (dimensionless) is given by Eq. B-13:

$$R_e = \frac{\rho V D}{\mu} \qquad \textit{Eq. B-13}$$

Since the Reynolds number and Fanning friction factor depend on the inner diameter, Eq. B-12, Eq. B-13, and the Fanning friction factor equation must be solved using an iterative process where an inner diameter is guessed and updated with each iteration until the newest value for D varies little from the value for D from the previous iterations.

It should be noted that the Fanning friction factor is one-quarter of the Moody or Darcy friction factor. The Moody or Darcy friction factors are often the friction factors displayed in graphs in books or papers discussing friction factors for fluid flows in pipes.

Eq. B-12 and Eq. B-13 along with an equation for the Fanning friction factor result in the minimum inner diameter for a pipe segment that supports the specified maximum CO_2 mass flow rate with the specified pressure drop across the pipe segment, friction losses, and elevation head. In some calculations, the inner diameter is specified and the longest pipe segment is desired where the specified pressure drop across the pipe segment will sustain the specified CO_2 mass flow rate and overcome friction losses and any increases in the elevation head.

In Eq. B-12, the variable h_1-h_2 is a function of the segment length (L). If h_{p1} and h_{p2} are the elevations at the beginning and end of the pipeline and L_{PT} is the length of the pipeline, then h_1-h_2 is given by Eq. B-14:

$$h_1 - h_2 = \frac{h_{P1} - h_{P2}}{L_{pT}} L \qquad \textbf{\textit{Eq. B-14}}$$

Substituting Eq. B-14 into Eq. B-12 yields Eq. B-15:

$$D^5 = \frac{32 f_F L {q_{m-max}}^2}{\pi^2 \rho [(P_1 - P_2) + g\rho \left(\frac{h_{P1} - h_{P2}}{L_{PT}}\right) L]} \qquad \textbf{\textit{Eq. B-15}}$$

This can be rewritten as Eq. B-16:

$$\left(\frac{32 f_F {q_{m-max}}^2}{\pi^2 \rho D^5}\right) L = (P_1 - P_2) + \left(\frac{g\rho (h_{P1} - h_{P2})}{L_{PT}}\right) L \qquad \textbf{\textit{Eq. B-16}}$$

Defining groups of variables in Eq. B-16 gives Eq. B-17, Eq. B-18, and Eq. B-19:

$$a_1 = \frac{32 f_F {q_{m-max}}^2}{\pi^2 \rho D^5} \qquad \textbf{\textit{Eq. B-17}}$$

$$b_1 = P_1 - P_2 \qquad \textbf{\textit{Eq. B-18}}$$

$$c_1 = \frac{g\rho (h_{P1} - h_{P2})}{L_{PT}} \qquad \textbf{\textit{Eq. B-19}}$$

Substituting these variables into Eq. B-16 yields Eq. B-20:

$$a_1 L = b_1 + c_1 L \qquad \textbf{\textit{Eq. B-20}}$$

Solving for L gives Eq. B-21:

$$L_{max} = \frac{b_1}{a_1 - c_1} \qquad \textbf{\textit{Eq. B-21}}$$

In this expression, L_{max} is the maximum segment length that will sustain the specified maximum CO_2 mass flow rate and overcome friction losses and elevation increases given the specified pressure drop across the pipe segment and specified inner pipe diameter.

B.3 Compressible Fluid Flow

This section derives the equations for the minimum inner diameter and maximum pipe segment length for compressible fluid flow following the derivation presented by McCoy. [20] Eq. B-3 is rewritten in differential form after multiplying all terms by g (Eq. B-22):

$$\frac{1}{\rho}dP + gdh + VdV = -\frac{2V^2}{D}f_F L \qquad \textbf{\textit{Eq. B-22}}$$

In compressible fluid flow, the density is not constant but can vary along the pipe segment particularly as the pressure varies. The specific volume (v_m) is useful. The specific volume is the inverse of the density, specifying the volume associated with a fixed mass of fluid (Eq. B-23):

$$v_m = \frac{1}{\rho} \qquad \textbf{\textit{Eq. B-23}}$$

Using $\frac{1}{v_m}$ instead of ρ in Eq. B-22 and dividing all terms by $v_m{}^2$ gives Eq. B-24:

$$\frac{1}{v_m}\,dP + \frac{g}{v_m{}^2}\,dh + \frac{V}{v_m{}^2}\,dV = -\,\frac{2V^2}{Dv_m{}^2}f_F dL \qquad \textbf{\textit{Eq. B-24}}$$

The variable v_m varies with temperature and pressure according to the equation of state (Eq. B-25):

$$v_m = \frac{RTZ}{PM} \qquad \textbf{\textit{Eq. B-25}}$$

Where

R	= universal gas constant (8.314 m^3-Pa/K-mol)
T	= temperature of the fluid (K)
Z	= compressibility factor for the fluid (dimensionless)
P	= pressure of the fluid (Pa)
M	= molecular weight of the fluid (kg/mol)

The velocity (V) and the specific volume (v_m) can also be related through the maximum mass flow rate (Eq. B-26):

$$q_{m-max} = \frac{V\rho\pi D^2}{4} = \left(\frac{V}{v_m}\right)\left(\frac{\pi D^2}{4}\right) \qquad \textbf{\textit{Eq. B-26}}$$

Each term in Eq. B-24 will be evaluated separately. When Eq. B-25 is substituted into the first term in Eq. B-24, Eq. B-27 results.

$$\frac{1}{v_m} dP = \frac{M}{RTZ} PdP \qquad \textbf{Eq. B-27}$$

Using average values for the temperature and compressibility and integrating this equation yields Eq. B-28:

$$\int_{P_1}^{P_2} \frac{M}{RT_{av}Z_{av}} PdP = \frac{M}{2RT_{av}Z_{av}} ({P_2}^2 - {P_1}^2) \qquad \textbf{Eq. B-28}$$

Substituting Eq. B-25 into the second term in Eq. B-24, using average values for P, Z, and T, and integrating the equation gives Eq. B-29:

$$\int_{h_1}^{h_2} g \frac{P^2M^2}{R^2Z^2T^2} dh = \frac{gM^2{P_{av}}^2}{R^2{Z_{av}}^2{T_{av}}^2} (h_2 - h_1) \qquad \textbf{Eq. B-29}$$

Substituting Eq. B-26 into the third term in Eq. B-24 results in Eq. B-30:

$$\frac{V}{{v_m}^2} dV = \left(\frac{4q_{m-max}}{\pi D^2}\right)^2 \frac{1}{V} dV \qquad \textbf{Eq. B-30}$$

Integrating this equation yields Eq. B-31:

$$\int_{V_1}^{V_2} \frac{16{q_{m-max}}^2}{\pi^2 D^4} \frac{dV}{V} = \frac{16{q_{m-max}}^2}{\pi^2 D^4} \ln\left(\frac{V_2}{V_1}\right) \qquad \textbf{Eq. B-31}$$

Substituting Eq. B-26 into the fourth term in Eq. B-24 gives Eq. B-32:

$$\frac{-2f_F}{D}\left(\frac{V}{v_m}\right)^2 dL = \frac{-2f_F}{D}\left(\frac{4q_{m-max}}{\pi D^2}\right)^2 dL \qquad \textbf{Eq. B-32}$$

Collecting terms and integrating this equation yields Eq. B-33:

$$-\int_{L_1}^{L_2} \frac{32f_F{q_{m-max}}^2}{\pi^2 D^5} dL = \frac{-32f_F\,{q_{m-max}}^2 L}{\pi^2 D^5} \qquad \textbf{Eq. B-33}$$

For steady state compressible fluid flow in a pipe segment with constant inner diameter, the variation in velocity from the inlet to the outlet will be small so the third term in Eq. B-24 is eliminated from further consideration. Substituting Eq. B-28, Eq. B-29, and Eq. B-33 into Eq. B-24 gives Eq. B-34:

$$\frac{M}{2RT_{av}Z_{av}}({P_2}^2 - {P_1}^2) + \frac{gM^2{P_{av}}^2}{R^2{Z_{av}}^2{T_{av}}^2}(h_2 - h_1) = \frac{-32f_F{q_{m-max}}^2 L}{\pi^2 D^5} \qquad \textbf{Eq. B-34}$$

Rearranging Eq. B-34 and collecting some terms gives Eq. B-35:

$$-\left(\frac{32f_F{q_{m-max}}^2 L}{\pi^2}\right)\frac{1}{D^5} = \left(\frac{1}{2R^2{Z_{av}}^2{T_{av}}^2}\right)\left[MRZ_{av}T_{av}({P_2}^2 - {P_1}^2) + 2gM^2{P_{av}}^2(h_2 - h_1)\right] \qquad \textbf{Eq. B-35}$$

Eq. B-35 can be rearranged to give an expression for D^5 (Eq. B-36):

$$D^5 = \frac{-64R^2{Z_{av}}^2{T_{av}}^2 f_F {q_{m-max}}^2 L}{\pi^2\left[MRZ_{av}T_{av}({P_2}^2 - {P_1}^2) + 2gM^2{P_{av}}^2(h_2 - h_1)\right]} \qquad \textbf{Eq. B-36}$$

As discussed for incompressible fluid flow, the empirical equations for the Fanning friction factor depend on the Reynolds number, pipe roughness, and inner diameter. The Reynolds number also depends on the inner diameter. Eq. B-36 is solved using an iterative procedure where an initial inner diameter is specified. The Fanning friction factor is calculated with this value and then a new diameter is calculated with Eq. B-36. The new diameter is compared to the initial guess and if they differ by more than a user specified tolerance, the new diameter becomes the initial value, and this procedure is repeated until the new value and initial value are within the user specified tolerance.

As also discussed for incompressible fluid flow, in some calculations the inner diameter is specified along with the pressure drop across the pipe segment and the longest pipe segment is desired where this pipe segment can sustain the maximum CO_2 mass flow rate and overcome friction losses and any elevation changes along the pipe segment.

As presented for incompressible fluid flow, the quantity h_2–h_1 in Eq. B-36 can be related to the elevations at the beginning and end of the pipeline (h_{P1} and h_{P2}) and the total pipeline length, L_{PT}, by Eq. B-14. Substituting Eq. B-14 into Eq. B-36 yields Eq. B-37:

$$D^5 = \frac{\left(\frac{-64R^2{Z_{av}}^2{T_{av}}^2 f_F {q_{m-max}}^2}{\pi^2}\right)L}{MRZ_{av}T_{av}\left({P_2}^2 - {P_1}^2\right) + \left[\frac{2gM^2{P_{av}}^2(h_{P2} - h_{P1})}{L_{PT}}\right]L} \qquad \textbf{\textit{Eq. B-37}}$$

Defining variables for Eq. B-37 gives Eq. B-38, Eq. B-39, and Eq. B-40:

$$a_1 = \frac{-64R^2{Z_{av}}^2{T_{av}}^2 f_F\, {q_{m-max}}^2}{\pi^2 D^5} \qquad \textbf{\textit{Eq. B-38}}$$

$$b_1 = MRZ_{av}T_{av}({P_2}^2 - {P_1}^2) \qquad \textbf{\textit{Eq. B-39}}$$

$$c_1 = \frac{2gM^2{P_{av}}^2 P_{av}^2(h_{p2} - h_{p1})}{L_{PT}} \qquad \textbf{\textit{Eq. B-40}}$$

Substituting these variables into Eq. B-37 provides Eq. B-41:

$$a_1 L = b_1 + c_1 L \qquad \textbf{\textit{Eq. B-41}}$$

Solving for L gives Eq. B-42:

$$L_{max} = \frac{b_1}{a_1 - c_1} \qquad \textbf{\textit{Eq. B-42}}$$

As before, L_{max} is the maximum segment length that will sustain the specified maximum CO_2 mass flow rate and overcome friction losses and any elevation changes given the specified pressure drop across the pipe segment and the inner diameter of the pipe.

B.4 Empirical Equations for Fanning Friction Factors

The CO2_T_COM provides three equations for calculating the Fanning friction factor. These equations all involve the Darcy or Moody friction factor rather than the Fanning friction factor. The Fanning friction factor is one-quarter of the Darcy friction factor.

The first equation is the Colebrook-White equation. This equation is an implicit equation for the Darcy friction factor and uses the inner diameter (D), the Reynolds number (Re), and a new variable, the roughness height (ε), which is a measure of the roughness of the inner surface of the pipe. The Colebrook-White equation is given in Eq. B-43: [21]

$$\frac{1}{\sqrt{f_D}} = -2 \cdot log_{10}\left(\frac{(\frac{\varepsilon}{D})}{3.7} + \frac{2.51}{Re\sqrt{f_D}}\right) \qquad \textbf{Eq. B-43}$$

Where

ε = roughness height of the inner surface of the pipe (m)

Because the variable f_D is on both sides of this equation, an iterative method must be used to find f_D. In the CO2_T_COM, the Newton Raphson method is used to solve this equation for f_D.

The CO2_T_COM provides two additional methods for calculating the Darcy friction factor. One is the Haaland equation (given in Eq. B-44): [10]

$$\frac{1}{\sqrt{f_D}} = -1.8 \cdot log_{10}\left(\left(\frac{\frac{\varepsilon}{D}}{3.7}\right)^{1.11} + \frac{6.9}{Re}\right) \qquad \textbf{Eq. B-44}$$

The second is the Zigrang and Sylvester equation, provided in Eq. B-45: [20]

$$\frac{1}{\sqrt{f_D}} = -2.0 \cdot log_{10}\left(\frac{(\frac{\varepsilon}{D})}{3.7} - \frac{5.02}{Re} log_{10}\left\{\frac{(\frac{\varepsilon}{D})}{3.7} - \frac{5.02}{Re} log_{10}\left[\frac{(\frac{\varepsilon}{D})}{3.7} + \frac{13}{Re}\right]\right\}\right) \qquad \textbf{Eq. B-45}$$

These latter two equation are explicit so they can be solved directly for the Darcy friction factor f_D.

As noted above, the Fanning friction factor f_F is one-quarter of the Darcy friction factor f_D. Thus, the Fanning friction factor is calculated per Eq. B-46:

$$f_F = \frac{1}{4} \cdot f_D \qquad \textbf{Eq. B-46}$$

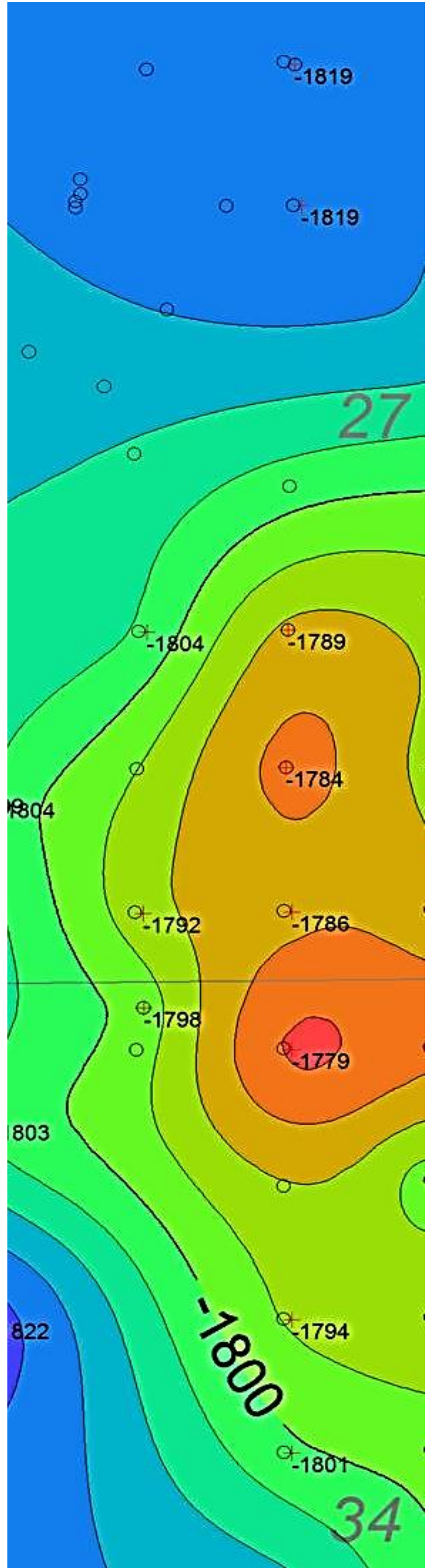
B.5 Equations for Average Pressure in Pipe Segment

The equations for calculating the average pressure in the pipe segment are different for incompressible and compressible fluids. For incompressible fluids, the density changes very little with changes in the pressure and, since the viscosity is also a function of the density, it too will change little. The frictional losses are a function of the density and viscosity and since these quantities change little, the frictional losses will be similar across the pipe segment. Hence, the pressure drop across the pipe segment should be a linear function of the segment length. The average pressure for an incompressible fluid will be simply the arithmetic average of the inlet and outlet pressure in the pipe (Eq. B-47).

$$P_{av} = 0.5 \cdot (P_1 + P_2) \qquad \textbf{\textit{Eq. B-47}}$$

For compressible fluids, the fluid density is a function of the pressure and can, in theory, change along the pipe segment as the pressure drops. Since the viscosity is also a function of the density, the viscosity can also change. This can result in the friction losses being different along the pipe segment and result in the pressure varying in a nonlinear manner along the pipe segment. As presented in McCoy, the average pressure for a compressible fluid in a pipe segment is given by the following equation (Eq. B-48). [20]

$$P_{av} = \frac{2}{3} \cdot \left(P_1 + P_2 - \frac{P_1 \cdot P_2}{P_1 + P_2}\right) \qquad \textbf{\textit{Eq. B-48}}$$



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