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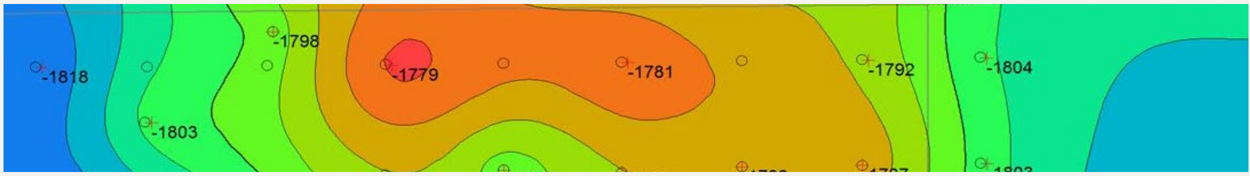

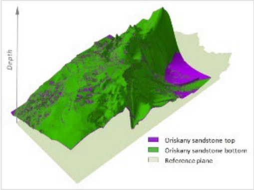

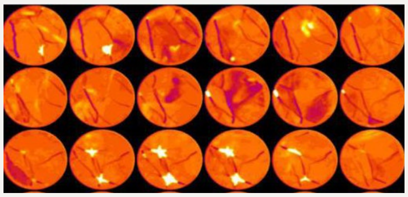

FECM/NETL Hydrogen Pipeline Cost Model (2024): Description and User's Manual

March 26, 2024

DOE/NETL-2024/4841

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TABLE OF CONTENTS

List of Equations....................iv
Acronyms and Abbreviations....................vii
1 Model Introduction and Orientation....................1
1.1 Model Overview....................1
1.1.1 "READ_ME_FIRST" Worksheet....................1
1.1.2 Two Fundamental Modules....................1
1.1.3 H2_P_COM Ribbon Tab and Running Macros....................2
1.1.4 "Cases" and "Cases_def" Worksheets....................2
1.1.5 Other Worksheets....................3
1.2 How the H2_P_COM Works....................4
1.2.1 Basic Mode with No Macro Use....................4
1.2.2 Basic Mode Using the Macro to Calculate the First-year Break-even Price of H_2....................6
1.2.3 Basic Mode Using the Macro to Determine the Optimal Number of Compressor Stations....................7
1.2.4 Using the Macro to Calculate Results for Multiple Values of Input Variables 9
1.3 Overview of This Manual....................13
2 Main Module....................14
2.1 Overview....................14
2.2 Key Inputs for the Main Module....................18
3 Engineering Module....................23
3.1 Part 1: Engineering Calculations....................23
3.2 Part 2: CAPEX (Capital Costs or Expenses)....................29
3.3 Part 3: OPEX (Operating Costs or Expenses)....................38
3.4 Key Inputs for the Engineering Module....................39
4 Model Results....................43
4.1 Capital Costs for Natural Gas Pipeline Equations....................43
4.2 H2_P_COM Break-Even Costs by Pipeline Length and Capacity....................46
4.3 Comparison of H2_P_COM Outputs to HDSAM and Technical Literature....................48
References....................53
Appendix A: Rationale Behind Key Financial Parameters....................56
Appendix B: Pipe Flow Equations....................59
B.1 Pipe Situation....................59
B.2 Incompressible Fluid Flow....................60
B.3 Compressible Fluid Flow....................63
B.4 Empirical Equations for Fanning Friction Factors....................66
B.5 Equations for Average Pressure in Pipe Segment....................66

LIST OF EXHIBITS

Exhibit 2-1. Key inputs on the "Main" sheet in the H2_P_COM 20
Exhibit 3-1. Values for parameters in equation provided by Parker [3] 30
Exhibit 3-2. Regions defined by EIA for segregating pipeline costs....................................31
Exhibit 3-3. Values for parameters in equation provided by McCoy and Rubin [4] 32
Exhibit 3-4. Values for parameters in equation provided by Rui et al. [5] 33
Exhibit 3-5. States in each region for equation provided by Brown et al. [6].....................34
Exhibit 3-6. Values for parameters in equation provided by Brown et al. by region [6] ...34
Exhibit 3-7. Values for cost indices used to adjust pipeline capital costs 35
Exhibit 3-8. Key inputs on the "Eng Mod" sheet in the H2_P_COM 40
Exhibit 4-1. Natural gas pipeline capital costs using different equations (2023$/mi)........44
Exhibit 4-2. Breakdown of natural gas pipeline capital costs using different equations (2023$/mi)..45
Exhibit 4-3. First-Year Break-Even Hydrogen Price by Pipeline Length and Flow Capacity (2023$/t)..47
Exhibit 4-4. Table of First-Year Break-Even Hydrogen Price by Pipeline Length and Flow Capacity (2023$/t) 47
Exhibit 4-5. Table of Nominal Pipeline Diameter (in.) by Pipeline Length (mi) and Flow Capacity (Mt/yr)..48
Exhibit 4-6. Comparison of Calculated Nominal Pipeline Diameter by Pipeline Length and 0.22 Mt/yr Flow Capacity...49
Exhibit 4-7. Comparison of Calculated Nominal Pipeline Diameter by Pipeline Length and 1.1 Mt/yr Flow Capacity...50
Exhibit 4-8. Comparison of Calculated Nominal Pipeline Diameter by Pipeline Length and 2.2 Mt/yr Flow Capacity...50
Exhibit 4-9. Di Lullo et al. Long-Range Hydrogen Pipeline Specifications and Price ($2020 USD/t) [25]...51
Exhibit 4-10. Comparison of Calculated Hydrogen Price for Di Lullo et al. and H2_P_COM ($2020 USD/t)..52
Exhibit A-1. Key financial parameters in the H2_P_COM...56

LIST OF EQUATIONS

Eq. 2-1 16
Eq. 2-2 17
Eq. 2-3 17
Eq. 2-4 17
Eq. 2-5 18
Eq. 3-1 24
Eq. 3-2 24
Eq. 3-3 26
Eq. 3-4 26
Eq. 3-5 26
Eq. 3-6 26
Eq. 3-7 27
Eq. 3-8 27

Eq. 3-9 27
Eq. 3-10 27
Eq. 3-11 27
Eq. 3-12 27
Eq. 3-13 28
Eq. 3-14 28
Eq. 3-15 29
Eq. 3-16 29
Eq. 3-17 30
Eq. 3-18 31
Eq. 3-19 32
Eq. 3-20 33
Eq. 3-21 36
Eq. 3-22 37
Eq. 3-23 37
Eq. 3-24 37
Eq. 3-25 38
Eq. 3-26 39
Eq. 3-27 39
Eq. A-1 57
Eq. A-2 58
Eq. B-1 60
Eq. B-2 60
Eq. B-3 60
Eq. B-4 60
Eq. B-5 60
Eq. B-6 61
Eq. B-7 61
Eq. B-8 61
Eq. B-9 61
Eq. B-10 61
Eq. B-11 61
Eq. B-12 61
Eq. B-13 61
Eq. B-14 62
Eq. B-15 62
Eq. B-16 62
Eq. B-17 62
Eq. B-18 62
Eq. B-19 62
Eq. B-20 62
Eq. B-21 62
Eq. B-22 63
Eq. B-23 63
Eq. B-24 63
Eq. B-25 63
Eq. B-26 63
Eq. B-27 64

Eq. B-28 64
Eq. B-29 64
Eq. B-30 64
Eq. B-31 64
Eq. B-32 64
Eq. B-33 64
Eq. B-34 64
Eq. B-35 64
Eq. B-36 64
Eq. B-37 65
Eq. B-38 65
Eq. B-39 65
Eq. B-40 65
Eq. B-41 65
Eq. B-42 65
Eq. B-43 66
Eq. B-44 66
Eq. B-45 66
Eq. B-46 66
Eq. B-47 67
Eq. B-48 67

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
D	Diameter
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
Eq.	Equation
FCF	Free cash flow
FECM	Fossil Energy and Carbon Management
ft	Foot, feet
ft^2	Square foot/square feet
H_2	Hydrogen
HDSAM	Hydrogen Delivery Scenario Analysis Model
hr	Hour(s)
in.	Inch(es)
IRROE	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)
mi	Mile(s)
Misc	Miscellaneous
mol	Mole(s)
Mt, Mtonne	Million tonne(s)
MW	Megawatt
NETL	National Energy Technology Laboratory
NOL	Net operating loss
NPV	Net present value
O&M	Operation and maintenance
OPEX	Operation expenses or costs
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 after taxes
yr	Year(s)

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 hydrogen (H_2) by pipeline. This model is called the FECM/NETL Hydrogen Pipeline Cost Model, also known as H2_P_COM [1]. The H2_P_COM is an Excel-based tool that estimates revenues and capital, operating, and financing costs for transporting gaseous phase H_2 by pipeline. It is assumed that the H_2 delivered to the pipeline meets pipeline specifications for purity. Costs are estimated for a single point-to-point pipeline, which may have compressors along the pipeline to boost the pressure.

The purpose of this manual is to assist the user in understanding the H2_P_COM including model inputs, outputs, and calculations.

1.1 MODEL OVERVIEW

The H2_P_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 to support key functions, 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 user 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 user 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 H2_P_COM consists of two fundamental modules, the main 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 main and Section 3 for engineering).

1. Main 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 main 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 compressor stations and estimate the capital and annual operating costs for the equipment comprising the pipeline. This sheet provides several inputs, provides 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 H2_P_COM Ribbon Tab and Running Macros

The H2_P_COM includes a custom ribbon tab labeled "H2_P_COM." Located on the top right of the ribbon, this ribbon tab controls the execution of a 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 the drop down menu on the "H2_P_COM" ribbon tab. For example, "Combo" is one of the "Goal_Seek_Price" "Macro Options" and provides results in the "Combo Results" worksheet. The macro and the use of this ribbon tab to run the macro are 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 H_2 mass flow rate, capacity factor, average annual H_2 mass flow rate, and elevation difference from the inlet to the outlet of the pipeline. The capacity factor multiplied by the maximum H_2 mass flow rate gives the average annual H_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 labeled "Start" in Column A (Cell A56). The "Process_Cases" macro is run by clicking the "Run Process_Cases" button in the "Cases" worksheet within Cell A19. After running the "Process_Cases" macro, the results for each case are provided starting in Row 56, to the right of the input cells.

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 H_2 price associated with these variables. This H_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 variable inputs by the user and variable outputs by the "Process_Cases" macro provided 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"), the remaining six sheets in the model are discussed below. Of the remaining sheets, four provide useful information but are not necessarily critical to the model's performance, and the other two ("Parameters" and "Version") 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. Pipe Cost Modifiers

   This sheet includes lookup tables for adjusting capital costs to account for the differences between H_2 pipelines versus natural gas pipelines.

2. Cost Indices

   This sheet contains a variety of cost indices for adjusting costs to the base year of 2011.

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

   This sheet includes tables and plots of capital costs for different aspects of constructing a natural gas pipeline using four different cost equations. 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 "H2_P_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 H2_P_COM Works

The H2_P_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 "H2_P_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 (see Section 2.1 for additional information).

1.2.1 Basic Mode with No Macro Use

In its most basic mode, the H2_P_COM requires the following key inputs from the user, which are specified in the main module on the "Main" sheet in Table 1A:

- First-year price for transporting H_2 in the base year of 2011$/tonne (Cell E10)
- Average annual H_2 mass flow rate in Mt/yr or Mtonne/yr (Cell E11)
- Capacity factor in % (used to calculate the maximum H_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 compressor stations along the pipeline (can be zero if there are no compressors) (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, inlet and outlet pressure for the compressors, the equation to use for calculating capital costs of natural gas pipelines, and the region of the U.S. or Canada where the pipeline is constructed. 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 compressor station 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 compressor station increasing the pressure at the outlet from one segment to the pressure at the inlet of the next segment. It is assumed that the organization receiving the H_2, such as an industrial facility using H_2 to power part of their manufacturing operation, will have compressor stations if the pressure of the H_2 needs to be increased.

The model calculates the minimum inner diameter needed for a pipe that can transport the maximum H_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 inches (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 compressor stations. Setting the nominal pipe size to 2,000 in. (which is an unrealistically large 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 compressor stations; 3) capital costs for the pipeline control system; 4) annual operating expenses for maintaining the pipeline, compressor stations, and other equipment; and 5) electricity demand and electricity costs for operating the compressor stations.

These capital and operating costs are accessed in the main module, which also includes the financial model used by the H2_P_COM. In the financial model, cash flows are developed for revenues from transporting H_2, capital costs for constructing the pipeline with all its equipment, and operating costs for the pipeline, compressor stations, and miscellaneous equipment. The revenues for transporting H_2 are calculated by multiplying the price of H_2 by the mass of H_2 transported in each year. Cash flows for revenues and costs are first reported in real or constant dollars, depending on the user's selection. 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, detailed in the "Main" sheet. 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 H_2 is too low. If the price for H_2 is increased until the NPV for the project is zero, the project can pay all costs including financial costs, but just barely. This H_2 price is called the first-year break-even H_2 price since this price just barely makes the project viable or break-even.

1.2.2 Basic Mode Using the Macro to Calculate the First-year Break-even Price of H_2

The first-year break-even price of H_2 is an extremely useful quantity since it is the minimum H_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 H_2 price is determined by adjusting the price until the NPV for the project is zero.

The H2_P_COM provides the user with the ability to calculate the first-year break-even price by running a macro from the "H2_P_COM" ribbon tab. To perform this option:

- Specify inputs (e.g., annual average H_2 mass flow rate, percent equity, etc.) in light orange cells within Table 1A, Table 2, and Table 3 on the "Main" sheet and Table 1, Table 2, and Table 3 in the "Eng Mod" sheet.
- Toggle the "Optimal Compressor Station Number" button on or off in the "H2_P_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of compressor stations 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 compressor stations they have input, so the "Optimal Compressor Station Number" should be toggled off.
- Select the "Basic" option in the drop-down box next to the "Macro Option" label on the "H2_P_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "H2_P_COM" ribbon tab to activate the "Goal_Seek_Price" macro to find the first-year price of H_2 that generates a NPV for the project of zero. This value, which is the first-year break-even H_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 compressor stations 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 Compressor Stations

As discussed above, the H2_P_COM allows the user to specify the number of compressor stations with the model calculating the minimum pipe diameter and nominal pipe size associated with this number of compressor stations. As the number of compressor stations increases, the cost of all the compressors 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 compressor stations and nominal pipe size will give the lowest overall first-year break-even H_2 price. However, this combination of number of compressor stations and nominal pipe size is something most users would like to explore and have some sense on since it affects the break-even price.

The H2_P_COM provides the user the ability to calculate the optimal number of compressor stations by running different options of the "Goal_Seek_Price" macro from the "H2_P_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 Table 1, Table 2, and Table 3 in the "Eng Mod" sheet.
- Toggle the "Optimal Compressor Station Number" button on in the "H2_P_COM" ribbon tab.
- Select the "Basic" option in the drop-down box next to the "Macro Option" label on the "H2_P_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "H2_P_COM" ribbon tab to run VBA code that executes an algorithm that determines the nominal pipe size and number of compressor stations that gives the lowest first-year break-even H_2 price. The algorithm cycles through nominal pipe sizes, starting with the largest, to determine the nominal pipe size and number of compressor stations that give the lowest first-year break-even H_2 price. In the algorithm, the variables D_{nom_x}, N_{comp_x}, and p_{H2_x} (Finance_Calcs Macro) store values for the nominal pipe size, number of compressors, and first-year break-even H_2 price that are being evaluated. The variables D_{nom_min}, N_{comp_min}, and p_{H2_min} store values for the nominal pipe size and number of compressors associated with the lowest first-year break-even H_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 compressors 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 H_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 compressors are needed for a nominal pipe size of 48 in. The model sets the number of compressors to zero, calculates the minimum

inner pipe diameter for this number of compressors, 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 compressor 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 compressors that generate the lowest first-year break-even H_2 price, p_{H2_min}. The algorithm begins by setting p_{H2_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 H_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 compressors, N_{comp_x}, for this nominal pipe size, D_{nom_x}. The algorithm then calculates the first-year break-even H_2 price, p_{H2_x}, associated with the nominal pipe size D_{nom_x} and number of compressors N_{comp_x}. If p_{H2_x} is smaller than p_{H2_min}, then p_{H2_x} is the current lowest first-year break-even H_2 price. In this case, p_{H2_min} is set to p_{H2_x}, N_{comp_min} is set to N_{comp_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 compressor stations needed exceeds an irrationally high number (i.e., 200 times the current value for N_{comp_min} plus one).

When the algorithm is finished, the result is the number of compressor stations, N_{comp_min}, and associated nominal pipe size, D_{nom_min}, that gives the lowest first-year break-even H_2 price, p_{H2_min}. The values for N_{comp_min}, D_{nom_min}, and p_{H2_min} are displayed in Table 1A in the "Main" sheet. This set of values is considered the optimal solution for the required hydrogen flow rate and pressure needs.

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 no. of compress statns" is displayed in the cell next to the cell with the number of compressors (Cell F15 in the "Main" sheet).

Note: The basic mode using the "Goal_Seek_Price" macro to determine the optimal number of compressor stations is likely to be the most popular mode with users, since it provides the combination of number of compressor stations and nominal pipe size that gives the overall lowest first-year break-even H_2 price.

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

The H2_P_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 compressor stations. Results are the minimum inner pipe diameter for the number of compressors, the nearest nominal pipe size with an inner diameter larger than this minimum inner pipe diameter, and first-year break-even H_2 prices associated with the number of compressors 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 Table 1, Table 2, and Table 3 in the "Eng Mod" sheet.
- Enter the number of desired compressor stations in Column J of Table 1B. The user can input up to 21 values in this column.
- Toggle the "Optimal Compressor Number" button on or off in the "H2_P_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of compressor stations; whereas, when toggled off, the macro will use the number of compressor stations input by the user.
- Select the "Compressor Stations" option in the drop-down box next to the "Macro Option" label on the "H2_P_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "H2_P_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 populate results for each number of compressor stations input by the user. If the user toggled the "Optimal Compressor Station Number" button on, then the last row in Table 1B (Row 33) will provide the number of compressor stations that give the lowest first-year break-even H_2 price.

The macro saves the original (i.e., user input) number of compressors in Table 1A before any calculations are performed. After Table 1B is populated, the macro enters the original number of compressors in Table 1A. If the "Optimal Compressor Station Number" button is toggled on, then the macro finds the optimal number of compressors that yields the lowest first-year break-even H_2 price (this may be different than the original number of compressors in Table 1A). If the

"Optimal Compressor Station Number" button is toggled off, then the macro finds the first-year break-even H_2 price associated with the original number of compressors in Table 1A.

Table 1C in the "Main" sheet provides results for different pipeline lengths. Results are the number of compressor stations, the minimum pipe inner diameter for the number of compressors, the nearest nominal pipe size with an inner diameter larger than this minimum diameter, and first-year break-even H_2 prices associated with the number of compressors and nominal pipe size. The results in Table 1C are for fixed values of the elevation change along the pipeline, average annual H_2 mass flow rate, and capacity factor. The user can fix the number of compressor stations or let the "Goal_Seek_Price" macro find the optimal number of compressor stations depending on whether or not the "Optimal Compressor Station Number" button on the "H2_P_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 Table 1, Table 2, and Table 3 in the "Eng Mod" sheet. The user should enter the number of compressor stations if the user desires the number of compressor stations to be fixed for all pipeline lengths.
- 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 Compressor Station Number" button on or off in the "H2_P_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of compressor stations; whereas, when toggled off, the macro will use the number of compressor stations input by the user.
- Select the "Length" option in the drop-down box next to the "Macro Option" label on the "H2_P_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "H2_P_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 Compressor Station Number" button on, then the column with the number of compressor stations (Column U) will have the optimal number of compressor stations, and the title of this column will have the word "Optimal" in the first cell. Otherwise, this column will have the number of compressors 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 compressors in Table 1A before any calculations are performed. After Table 1C is populated, the macro enters the original pipeline length and number of compressors in Table 1A. If the "Optimal Compressor Station Number" button is toggled on, then the macro finds the number of compressors that gives the lowest first-year break-even H_2 price for this original pipeline length in Table 1A. The optimal number of compressors may be different from the original number of compressors in Table 1A. If the "Optimal Compressor Station Number" is toggled off, then the macro finds the first-year break-even H_2 price associated with the original pipeline length and number of compressors in Table 1A.

Table 1D in the "Main" sheet provides results for different annual average H_2 mass flow rates. Results are the number of compressor stations, the minimum pipe inner diameter for the number of compressors, the nearest nominal pipe size with an inner diameter larger than this minimum inner pipe diameter, and first-year break-even H_2 prices associated with the number of compressors 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 compressor stations or let the "Goal_Seek_Price" macro find the optimal number of compressor stations depending on whether or not the "Optimal Compressor Station Number" button on the "H2_P_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 Table 1, Table 2, and Table 3 in the "Eng Mod" sheet. The user should enter the number of compressor stations if the user desires the number of compressor stations to be fixed for all H_2 mass flow rates.
- Enter the annual average H_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 Compressor Station Number" button on or off in the "H2_P_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of compressor stations; whereas, when toggled off, the macro will use the number of compressor stations input by the user.
- Select the "Rate" option in the drop-down box next to the "Macro Option" label on the "H2_P_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "H2_P_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 H_2 mass flow rate input by the user. If the user toggled the "Optimal Compressor Station Number" button on, then the column with the number of compressor stations (Column AC) will have the optimal number of compressor stations, and the title of this column will have the word "Optimal" in the first cell. Otherwise, this column will have the number of compressors 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 H_2 mass flow rate and number of compressors in Table 1A before any calculations are performed. After Table 1D is populated, the macro enters the original annual average H_2 mass flow rate and number of compressors in Table

1A. If the "Optimal Compressor Station Number" button is toggled on, then the macro finds the number of compressors that gives the lowest first-year break-even H_2 price for this original annual average H_2 mass flow rate in Table 1A. The optimal number of compressors may be different from the original number of compressors in Table 1A. If the "Optimal Compressor Station Number" button is toggled off, then the macro finds the first-year break-even H_2 price associated with the original annual average H_2 mass flow rate and number of compressors in Table 1A.

Table 1E in the "Combo Results" sheet provides results for different values of the annual average H_2 mass flow rate, pipeline length, and elevation change along the pipeline. Results for each combination of input values are the number of compressor stations, 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 H_2 prices associated with the number of compressors 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 compressor stations or let the "Goal_Seek_Price" macro find the optimal number of compressor stations depending on whether or not the "Optimal Compressor Station Number" button on the "H2_P_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 H_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 compressor stations on the "Main" sheet if a fixed number of compressor stations is desired. The user should specify any site-specific inputs in Table 1, Table 2, and Table 3 on the "Eng Mod" sheet.
- Enter values for the annual average H_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 Compressor Station Number" button on or off in the "H2_P_COM" ribbon tab. When toggled on, the macro will calculate the optimal number of compressor stations; whereas, when toggled off, the macro will use the number of compressor stations input by the user.
- Select the "Combo" option in the drop-down box next to the "Macro Option" label on the "H2_P_COM" ribbon tab.
- Click the "Break-even Analysis" button on the "H2_P_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 H_2 mass flow rate, pipeline length, and elevation change along the pipeline that was input by the user. If the user toggled the "Optimal

Compressor Station Number" button on, then the column with the number of compressor stations (Column G) will have the optimal number of compressor stations, and the title of this column will have the word "Optimal" in the first cell. Otherwise, this column will have the number of compressors 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 H_2 mass flow rate, pipeline length, and elevation change along the pipeline and number of compressors in Table 1A before any calculations are performed. After Table 1E is populated, the macro enters the original annual average H_2 mass flow rate, pipeline length, elevation change along the pipeline, and number of compressors in Table 1A. If the "Optimal Compressor Station Number" button is toggled on, then the macro finds the number of compressors that gives the lowest first-year break-even H_2 price for the original values of annual average H_2 mass flow rate, pipeline length, and elevation change along the pipeline in Table 1A. The optimal number of compressors may be different from the original number of compressors in Table 1A. If the "Optimal Compressor Station Number" button is toggled off, then the macro finds the first-year break-even H_2 price associated with the original annual average H_2 mass flow rate, pipeline length, elevation change along the pipeline, and number of compressors in Table 1A.

1.3 Overview of This Manual

This manual has the following modules which have been embedded in the multiple sheets as stated above. Further details of such modules and other remaining sections are described below.

- **Section 2 Main Module**: Describes the main module, provides equations for calculating the WACC, and gives key inputs needed for the module
- **Section 3 Engineering Module**: Describes the engineering module, provides equations for determining the minimum practical pipe diameter and power requirements for compressor stations, as well as the capital and operating costs for all aspects of the pipeline, and gives key inputs needed for the module
- **Section 4 Model Results**: Provides example results from the model
- **References**: 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 MAIN MODULE

As mentioned in Section 1, the main module for the H2_P_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 associated key results. More information on the inputs within this sheet is provided in Section 2.2.

2.1 OVERVIEW

Much of the main 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, to generate cash flows in nominal dollars, the cash flows of real revenues and costs are escalated with an escalation rate provided by the user (i.e., they escalate over time).

The "Main" sheet has seven tables:

- Table 1 contains key inputs and presents model outputs.
- Table 2 contains financial, operational, and related technical inputs. Table 2 specifies the duration of construction of the pipeline and values in Table must be consistent with this duration.
- Table 3 presents 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 2023 by default. The cash flows in real dollars in the first year of the project (e.g., 2023) 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 H_2 transported each year, the price of transporting H_2 in each year, and the annual cash flows for revenues. The H_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., 2023). The H_2 prices and revenues in real dollars in the first year of the project are then escalated to nominal dollars. There is also escalated and discounted (i.e., present value) revenues 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 model uses the capital, operation and maintenance (O&M), and electricity costs developed in the engineering module (discussed in Section 3) 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 price for the transport of H_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 main 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)
- Minimum internal rate of return on equity ($IRROE_{min}$) 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 for pipeline transportation either a 150% declining balance method (designated as DB150) with a recovery period of 15 years or straight line method (designated SL) with recovery periods of 15 or 22 years [2]. 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 2023, and the model provides a default escalation rate from 2011 to 2023. 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 main module adds project contingency costs to all capital costs. The default in the model is 15% of capital costs for the project contingency costs. Project contingency costs are often added for technologies that are not yet at commercial scale. Because H_2 pipelines are not a commercial-scale technology yet, project contingency costs were 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$, the base year for costs in the model. These cash flows are escalated to real dollars in the first year of the project using the first escalation rate input by the user (i.e., escalation rate from the base year [2011] to the project start year). As discussed above, the default project start year is 2023, and the model provides a default escalation rate for escalating cash flows to real 2023$. 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., CAPEX and 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 H_2).

The user inputs an annual average H_2 mass flow rate (q_{av}) as needed and inputs the price for transporting H_2 in 2011$/tonne. This H_2 price is used to calculate revenues in each year in real 2011$ by multiplying this H_2 price by the mass of H_2 transported each year. The H_2 price in real 2011$ is escalated using the first escalation rate to an H_2 price in the first year of the project. This H_2 price is used to calculate revenues in real dollars in the start year of the project. Finally, the H_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 H_2 in each year. The nominal H_2 price in each year is multiplied by the mass of H_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 after taxes (%/yr)

f_{equity} = fraction of total financing that is equity (%/yr)

$IRROE_{min}$ = minimum desired internal rate of return on equity or IRROE (%/yr)

r_{tax} = effective tax rate (includes federal corporate income tax, state, and local tax rates) (%/yr)

i_d = interest rate on debt (%/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:

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

Where

TBEBITN = tax basis earnings before interest, taxes, and NOL (in escalated dollars)

revenue = revenue for transporting H_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 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 H2_P_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 H2_P_COM allows NOL to accumulate or accrue which is generally consistent with tax policy. If the price charged for transporting H_2 is high enough, TBEBITN is eventually positive, and these positive earnings are subtracted from the accrued NOL until the accrued NOL becomes zero. 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 in each year for transporting H_2 by pipeline (in escalated dollars) using the tax-basis EBIT and Eq. 2-3:

$$taxespaid = \mathrm{TB}EBITAN \cdot r_{tax} \quad \textbf{Eq. 2-3}$$

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

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

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 in each year (in escalated dollars) per Eq. 2-5:

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

Where

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 MAIN MODULE

Several operational and financial inputs can be changed by the user within the "Main" sheet of the H2_P_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 H_2 and number of compressors, but they are not required if the user chooses a Macro Option to calculate the break-even price and number of compressors 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 main module resides, and the capital costs and 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 has the ability to 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 H_2 mass flow rate, pipeline length, 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 H2_P_COM

Parameter		Default Value	Location in "Main" Sheet	Note
Operational	First-year break-even price to transport H_2	---	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 H_2 transported (Mt/yr)	0.1	Cell E11	Maximum daily flow of H_2 is annual average mass flow of H_2 divided by 365 days/yr to convert this to a daily mass flow rate and then divided again by the capacity factor. This is a placeholder default value.
	Capacity factor (%)	90	Cell E12	
	Length of pipeline (mi)	50	Cell E14	
	Number of compressor stations	1	Cell E15	Only use when it is desired to use user-defined compressor stations instead of the calculated optimal number when running any macro option; toggle off the "Optimal Compressor Station Number" button in the "H2_P_COM" ribbon tab
	Change in elevation from inlet to outlet of pipeline (ft)	0	Cell E16	If the outlet is at a higher elevation than the inlet, the change is positive
	Calendar year for the start of the project (yr)	2023	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
	Inlet pressure for pipeline (psig)	1,000	Cell E76	
	Outlet pressure for pipeline (psig)	705	Cell E78	

Parameter	Default Value	Location in "Main" Sheet	Note	
Equation to use for calculating capital costs for pipeline (specify one)	BROWN	Cell E82	PARKER for the equations from Parker [3] MCCOY for the equations from McCoy and Rubin [4] RUI for the equations from Rui et al. [5] BROWN for the equations from Brown et al. [6]	
Region of United States for McCoy and Rubin equations (specify one region) [4]	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 United States 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) [5]	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 United States Regions)	This Cell will be light orange when the Brown option is selected.
Region of United States for Brown et al. equations (specify one region) [6]	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)	This Cell will be light orange when the Brown option is selected.

	Parameter	Default Value	Location in "Main" Sheet	Note
				CA (California) Avg (Average of all United States Regions)
Financial	Percent equity (%)	45	Cell E45	Remainder is debt Per "Cost Estimation Methodology for NETL Assessments of Power Plant Performance" QGESS [7]
Financial	Cost of equity or $IRROE_{min}$ (%/yr)	10.77 (real) 13.3 (nominal)	Cell E46	See Appendix A: Rationale Behind Key Financial Parameters
Financial	Cost of debt or interest rate on debt (%/yr)	3.91 (real) 6.3 (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 4.74% state and local tax See Appendix A: Rationale Behind Key Financial Parameters
Financial	Escalation rate from base year to project start year (%/yr)	4.8	Cell E49	Default escalation rate is from base year of 2011 to first year of project of 2023 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]) [7]
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 compressor stations deployed along the pipeline. It also includes the equations used to estimate the capital and operating costs for the piping, compressor stations, 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 related to technical calculations and/or user inputs.

Sub-part 1.1: General Characteristics. This sub-part has one item, the ground temperature. The H_2 pipeline is assumed to be buried, so the temperature of the H_2 in the pipeline will equilibrate to the ground temperature. The user can input a value or use the default ground temperature (53 degrees Fahrenheit [°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 of these values are references to input cells in the "Main" sheet.

Sub-part 1.3: Compressor Characteristics. This sub-part presents the molecular weight of hydrogen (2.016 kg/kg-mole), the temperature of the hydrogen entering the compressor (default value 53 degrees Fahrenheit [°F] equal to the ground/pipeline temperature), the number of compressor stations referenced in the "Main" sheet, the number of active compressor stations (if different from the total number of compressor stations), the number of backup compressor stations, the number of stages per compressor, the isentropic efficiency of each compressor (default value of 85%), the ratio of specific heats (default value 1.4), the compressor motor sizing factor (default value 1.1), and the compressor motor efficiency (default value of 96%). Many of the values specified in this sub-part are taken from the "Hydrogen Delivery Scenario Analysis Model" (HDSAM) developed by Argonne National Laboratory (ANL) [8].

Sub-part 1.4: H_2 Mass Flowrate. This sub-part presents the annual average H_2 mass flow rate, the capacity factor, and maximum H_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 H_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 H_2 resulting from each average pressure are provided in this sub-part. The density of H_2 calculated in this sub-part is used in later calculations to determine the power requirement for the compressor stations. Since H_2 is a gas in the pipeline, the density for a compressible fluid (i.e., gas) is used in the power requirement calculations. Also, the compressor is designed to move gases, not liquids.

The density and compressibility factor (or Z factor) for hydrogen were calculated with the algorithms developed by Lemon et al. [9]. The viscosity of hydrogen was calculated with an algorithm developed by Muzny et al. [10].

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 meters (m)), one for incompressible fluids (i.e., liquids) and one for compressible fluids (i.e., gases) [11], 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 H_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:

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

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

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

Where

q_{m-max}	= maximum mass flow rate of H_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 or the inlet to a compressor. The 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). 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 H_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 gas (i.e., H_2) (kg/mol)

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

Z_{av} = average compressibility of H_2 (dimensionless)

T_{av} = average temperature of H_2 (K). The temperature of H_2 is assumed to be constant across the pipeline, so the average temperature is this constant value.

P_{av} = average pressure of H_2 (Pa). The equations for calculating the average pressure of H_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 [12], 2) Zigrang and Sylvester [11], and 3) Colebrook-White [13]. 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 of 0.00015 ft for a commercial steel pipe [4]. 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 H_2 is present as a gas in the pipeline, it is recommended that the equation for compressible 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.

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 H_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 compressor stations and associated nominal pipe size that give the lowest first-year break-even H_2 price for transporting H_2.

The "Goal_Seek_Price" macro finds the optimal combination of number of compressor stations 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 compressor stations 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:

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

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:

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

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

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

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:

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

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

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

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: Compressor Power. This sub-part calculates the power requirement for one compressor station. The equations in this section are adapted from the HDSAM [8]. The total power for one compressor station (in kW) is equal to the motor power rating per compressor, which is equal to the actual shaft power required for one compressor multiplied by the compressor motor sizing factor divided by the motor efficiency.

First the maximum mass flow rate to each compressor is calculated using the equation:

$$q_{m\_comp\_max} = \frac{q_{m-max}}{n_{comp\_act}} \quad \textbf{\textit{Eq. 3-10}}$$

Where

$q_{m\_comp\_max}$= maximum mass flow rate of H_2 to each compressor station (Mt/yr)

$q_{m\text{-}max}$ = maximum mass flow rate of H_2 in pipe (Mt/yr)

n_{comp_act} = number of active compressors per compressor station

The maximum molar flow rate is then calculated using the equation:

$$q_{mol\_comp\_max} = q_{m\_comp\_max} * \frac{10^9}{365 * 24 * 3600 * \ MW_{H2}} \quad \textbf{\textit{Eq. 3-11}}$$

Where

$q_{mol\_comp\_max}$= maximum hydrogen molar flow rate to each compressor station (kg-mol/sec)

$q_{m\_comp\_max}$= maximum mass flow rate of H_2 to each compressor station (Mt/yr)

MW_{H2} = molecular weight of hydrogen (kg/kg-mole or g/g-mole)

The quantity 10^9 is the kg in one Mt. The quantity 365 * 24 * 3600 is the seconds in a year.

The average compressibility factor is then calculated using the equation:

$$Z_{av} = (Z_2 + \ Z_1)/2 \quad \textbf{\textit{Eq. 3-12}}$$

Where

Z_{av} = average Z-factor

Z_2 = Z-factor at compressor outlet

Z_1 = Z-factor at compressor inlet

The theoretical power requirement per compressor (in kW) is then calculated using an equation from the ANL HDSAM "H2 Compressor" sheet [8]. This equation assumes the hydrogen gas cools to the pipeline temperature between compressor stations. The factor is calculated using the equation:

$$W_{comp\_theor} = q_{mol\_comp\_max} * Z_{av} * R * T_1 * n_{stage} * \left(\frac{K}{K-1}\right) * [\left(\frac{P_{in}}{P_{out}}\right)^{\frac{K-1}{K*n_{stage}}} - 1] \qquad \textbf{\textit{Eq. 3-13}}$$

Where

W_{comp_theor} = average theoretical power requirement per compressor (kW)

$q_{mol\_comp\_max}$= maximum hydrogen molar flow rate to each compressor station (kg-mol/sec)

Z_{av} = average Z-factor

R = universal gas constant (KJ/kg-mol-K)

T_1 = temperature of hydrogen entering the compressor (deg F)

n_{stage} = number of stages per compressor

K = ratio of specific heats

P_{in} = pressure into the pipeline/out of the compressor

P_{out} = pressure out of the pipeline/into the compressor

The actual shaft power required per compressor (in kW) is then calculated using an equation from the ANL HDSAM "H2 Compressor" sheet [8]. The factor is calculated using the equation:

$$W_{shaft} = W_{comp\_theor}/n_{comp\_eff\_isen} \qquad \textbf{\textit{Eq. 3-14}}$$

Where

W_{shaft} = actual shaft power required per compressor (kW)

W_{comp_theor} = average theoretical power requirement per compressor (kW)

$n_{comp\_ef\_isen}$= isentropic efficiency of each compressor

The motor power rating per compressor (in kW) is then calculated using an equation from the ANL HDSAM "H2 Compressor" sheet. The factor is calculated using the equation:

$$W_{motor} = W_{shaft} * f_{motor_{size}} / n_{motor\_eff} \quad \textbf{Eq. 3-15}$$

Where

W_{motor} = motor power rating per compressor (kW)

W_{shaft} = actual shaft power required per compressor (kW)

f_{motor_size} = compressor motor sizing factor

n_{motor_eff} = compressor motor efficiency

The power needed for one compressor is equal to the motor power rating per compressor:

$$W_{comp} = W_{motor} \quad \textbf{Eq. 3-16}$$

Where

W_{comp} = power needed for one compressor (kW)

W_{motor} = motor power rating per compressor (kW)

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 H_2 transportation begins.

Sub-part 2.1: Pipeline Cost. This sub-part presents capital costs for the H_2 pipeline. These capital costs are based on the capital costs of natural gas pipelines with a cost modifier applied since H_2 pipelines require a marginally higher capital cost for development.

The *Oil & Gas Journal* provides data on the capital cost of constructing natural gas, oil, and petroleum pipelines [14]. 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 [14]. 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 [14]. Capital costs are provided for four categories [14]:

- 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 [3, 4, 6, 5].

Parker used cost data for the overall United States and estimated parameters in the form of Eq. 3-17 [3]:

$$C_{i\_NG\_park\_\mathrm{mi}} = a_{i-0} + L \cdot (a_{i-1} \cdot D^2 + a_{i-2} \cdot D + a_{i-3})$$

Eq. 3-17

Where

$C_{i\_NG\_park\_mi}$	= 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$) [3]
L	= length of the pipeline (mi)
D	= nominal 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 for each cost category (see Exhibit 3-1) [3]. The result of applying Eq. 3-17 with the parameter values in Exhibit 3-1 are capital costs in 2000$.

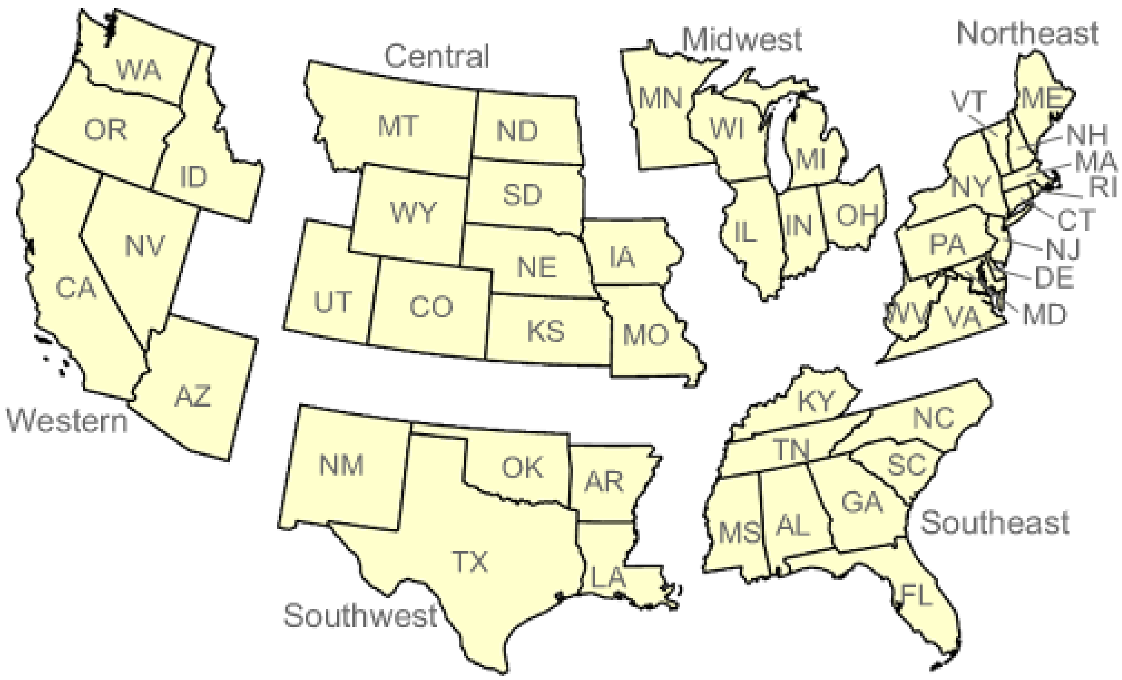
Exhibit 3-1. Values for parameters in equation provided by Parker [3]

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, [3] two different equations were provided for ROW capital costs. Figure 18, which can be found on page 17 of the Parker study [3], 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 [3]), 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 [3] 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 [4].

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



Source: U.S. EIA [15]

McCoy and Rubin estimated parameters in the form of Eq. 3-18 [4]:

$$C_{i\_NG\_mcy\_mi} = 10^{(a_{i-0}+a_{i-reg})} \cdot L^{a_{i-1}} \cdot D^{a_{i-2}} \qquad \textbf{Eq. 3-18}$$

Where

$C_{i\_NG\_mcy\_mi}$	= 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$) [4]
L	= length of the pipeline (km)
D	= standard diameter of pipeline (in.)

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

The parameter $a_{i\text{-}reg}$ is region-specific, where "reg" can refer to "NE" (Northeast), "SE" (Southeast), "MW" (Midwest), "Cen" (Central), "SW" (Southwest), or "West" (Western). Using pipeline capital cost data for different regions in the United States from 1995 to 2005, McCoy and Rubin estimated values for the parameters in Eq. 3-18 for each cost category (see Exhibit 3-3) [4]. The result of applying Eq. 3-18 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 H2_P_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 [4]

Parameter	Materials	Labor	ROW & Damages	Miscellaneous
$a_{i\text{-}0}$	3.112	4.487	3.950	4.390
$a_{i\text{-}NE}$	0	0.075	0	0.145
$a_{i\text{-}SE}$	0.074	0	0	0.132
$a_{i\text{-}MW}$	0	0	0	0
$a_{i\text{-}Cen}$	0	-0.187	-0.382	-0.369
$a_{i\text{-}SW}$	0	-0.216	0	0
$a_{i\text{-}West}$	0	0	0	-0.377
$a_{i\text{-}1}$	0.901	0.820	1.049	0.783
$a_{i\text{-}2}$	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. 3-19) with a form like that used by McCoy and Rubin [4, 5]:

$$C_{\mathrm{i\_NG}\_rui\_mi} = e^{(a_{i-0}+a_{i-reg})} \cdot L^{a_{i-1}} \cdot SA^{a_{i-2}} \qquad \textbf{\textit{Eq. 3-19}}$$

Where

$C_{i\_NG\_rui\_mi}$ = 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$) [5]

L = length of the pipeline (ft)

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

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

The parameter $a_{i\text{-}reg}$ is region-specific, where "reg" can refer to "NE," "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. 3-19 for each cost category (see Exhibit 3-4) [5]. The result of applying Eq. 3-19 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 H2_P_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. [5]

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. 3-20 [6]:

$$C_{png-\mathrm{brn}-i} = a_{i-0} \cdot D^{a_{i-1}} \cdot L^{a_{i-2}} \qquad \textbf{\textit{Eq. 3-20}}$$

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$) [6]
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. [6]

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. 3-20 for each cost category (see Exhibit 3-6) [6]. The result of applying Eq. 3-20 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 H2_P_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 [6]

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$ [3, 4, 5]. Within the model, all costs are adjusted to 2011$ using the Handy-Whitman gas transmission pipeline index for the material and labor categories, [16] the gross domestic product chain type price index for the ROW category, and the producer price index [17] 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$ [6]. These costs need to be de-escalated from 2018 to 2011 to be consistent with other base costs in the H2_P_COM. If the user chooses 2018 as the start year for the H_2 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 H_2 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 [18].

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 either McCoy and Rubin [4], Rui et al., [5], or Brown et al. [6], then the user must also select the region (or an average of all regions) of the United States to use in the analysis.

Eq. 3-17, Eq. 3-18, and Eq. 3-19 give the capital costs for a natural gas pipeline. H_2 pipelines require marginally higher capital costs for development based on special treatment of seals and flanges due to the effects of transporting hydrogen gas. The user can choose between two methods for adjusting material and labor natural gas capital costs. The first method is a user defined cost factor with a default value of 1.1. The default value is based on the ANL HDSAM model, which estimates that hydrogen pipelines incur a 10% higher capital cost for development compared to natural gas pipelines [19]. The second method uses cost modifiers published by Brown et al., where materials and labor costs are calculated based on the pipeline class location, operating pressure, and nominal diameter of the pipe [6]. The materials costs are modified using a cost factor and labor costs are adjusted using an incremental cost per inch-mile ($/in.-mi) modifier [6] (Eq. 3-21).

$$C_{pH2-x-i} = C_{png-x-i} \cdot f_{i\_z\_\mathrm{p\_H2}} \qquad \textbf{\textit{Eq. 3-21}}$$

Where

$C_{pH2\text{-}x\text{-}i}$ = capital costs for an H_2 pipeline using equation from author x and category i (2011$)

x = "par" for Parker, [3] "mcc" for McCoy and Rubin, [4] "rui" for Rui et al. [5], or "brn" for Brown et al. [6]

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

$f_{i\_z\_p\_H2}$ = factor/modifier that adjusts costs of natural gas pipeline to costs for an H_2 pipeline

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

z = cl1 for first class location or cl2 for second class location

The cost modifiers are only applied to the capital costs for the materials and labor categories. The cost modifiers depend on the type of steel used for the pipe (X52 or X70), the maximum operating pressure for the pipeline and the "class location". The pipeline must be built to a more stringent standard depending on how populated the area is where the pipeline is located. There are four class locations:

- Class location 1 applies to any 1 mile pipeline section that has 10 or fewer occupied buildings. Generally representative of sparsely populated areas.
- Class location 2 applies to any 1 mile pipeline section that has more than 10 but fewer than 46 occupied buildings. Generally representative of fringe areas around cities.
- Class location 3 applies to any 1 mile pipeline section that has 46 or more occupied buildings other than where class location 4 applies. Generally representative of suburban residential and commercial areas.
- Class location 4 applies to any areas with four-story or higher buildings, heavy traffic, or numerous other underground utilities.

Cost modifiers are provided for class locations 1 and 3.

Sub-part 2.2: Additional Pipeline Related Costs. This sub-part presents capital costs for an H_2 surge tank and pipeline control system. It is not anticipated that a surge tank would be required for hydrogen gas transportation, so the default value is set to zero unless the user overrides the input cost. Analog costs for a pipeline control system were based on prior work for CO_2 pipeline control systems [20]. In a supplementary spreadsheet to NETL's 2010 "Estimating Carbon Dioxide Transport and Storage Costs" QGESS*,* capital costs for a pipeline control system of $94,000 were provided, with costs in 2000$ [20]. 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 in 2011 [21]. 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: Compressor Costs. This sub-part presents capital costs for the compressor stations, including the uninstalled capital cost per compressor, the installed cost per compressor, and the installed cost per compressor station. The compressor capital costs include an installation factor to convert from uninstalled to installed cost. The default installation factor of 2 that is used in the model is from the ANL HDSAM model [8].

The uninstalled capital cost per compressor (in 2007$) are given in Eq. 3-22 from the ANL HDSAM model "H2 Compressor" sheet [8]:

$$C_{comp\_uninst} = a * W_{comp}{}^{b} \qquad \textbf{\textit{Eq. 3-22}}$$

Where

C_{comp_uninst} = uninstalled capital cost per compressor

a, b = compressor cost variables in compressor cost equation

W_{comp} = power needed for one compressor (kW)

The installed capital cost per compressor (in 2007$) are given in Eq. 3-23 from the ANL HDSAM model "H2 Compressor" sheet [8]:

$$C_{comp\_inst} = f_{comp\_inst} * C_{comp\_uninst} \qquad \textbf{\textit{Eq. 3-23}}$$

Where

C_{comp_inst} = installed capital cost per compressor

f_{comp_inst} = installation factor

C_{comp_uninst} = uninstalled capital cost per compressor

The value for f_{comp_inst} in the ANL HDSAM model "H2 Compressor" sheet is 2, which is the default in the H2_P_COM.

The installed capital cost per compressor station (in 2007$) are given in Eq. 3-24 from the ANL HDSAM model "H2 Compressor" sheet:

$$C_{station\_inst} = n_{comp\_tot} * C_{comp\_inst} \qquad \textbf{\textit{Eq. 3-24}}$$

Where

$C_{station\_inst}$ = installed capital cost per compressor station

n_{comp_tot} = total number of compressors in each compressor station

C_{comp_inst} = installed capital cost per compressor

The installed capital cost for all the compressor stations (in 2007$) are given in Eq. 3-25:

$$C_{station\_tot} = N_{station} * C_{station\_inst} \quad \textbf{Eq. 3-25}$$

Where

$C_{station\_tot}$ = installed capital cost for all compressor stations

$N_{station}$ = total number of compressor stations

The compressor capital cost is adjusted from 2007$ to 2011$ in the model using the CEPCI for pumps and compressors. This index is 830.9 for 2007 and 898.5 for 2011 [21].

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 compressor stations 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 H_2.

Sub-part 3.1: Pipeline O&M. This sub-part presents O&M costs for the pipeline. The H2_P_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 $5,000/mi-yr in 1999$ [22]. 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 G222 in the "Eng Mod" sheet, default is 2.5% per McCollum and Ogden [12]).

Sub-part 3.2: Pipeline Related Equipment and Compressor Station O&M. This sub-part presents O&M costs for the H_2 control system, and compressor station. 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 (Cells G229 and G232 in the "Eng Mod" sheet, default is 4% per best professional judgement). The annual O&M costs for the compressor stations calculated in this sub-part are the costs for maintaining the compressors. The cost for the electricity needed to operate the compressors is calculated in the next sub-part.

Sub-part 3.3: Electricity for Compression. This sub-part calculates the cost of the electricity needed to operate the compressor stations (in kW-hr/yr). The energy used to operate the compressor stations is given by Eq. 3-26:

$$E_{station\_elec} = W_{comp} \cdot n_{comp\_act} \cdot N_{station} \cdot CF \cdot 8{,}760\ hr/yr \qquad \textbf{\textit{Eq. 3-26}}$$

Where

$E_{station\_elec}$ = electric energy needed for compression (MWhr/yr)

W_{comp} = power requirement for the compressor (kW)

n_{comp_act} = number of active compressors per station

$N_{station}$ = number of compressor stations

CF = capacity factor of the pipeline from Table 1A in the "Main" sheet

The cost of the electricity used (in 2011$/yr) is given by Eq. 3-27:

$$CA_{elec} = E_{comp\_elec} \cdot C_{elec} \qquad \textbf{\textit{Eq. 3-27}}$$

Where

CA_{elec} = annual cost of electricity for compression (2011$/yr)

C_{elec} = cost of electricity (2011$/kW-hr). The user needs to supply the price of the electricity (Cell D238 in the "Eng Mod" sheet). A default value of $0.0682/kW-hr for industrial electricity users for 2011 from EIA is provided in the model [23].

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 main module (see Section 2.2), several inputs can also be changed by the user within the "Eng Mod" sheet of the H2_P_COM. If a user wants to perform simultaneous runs, some key inputs (i.e., annual average H_2 mass flow rate, pipeline length, and elevation change) also need to be incorporated into the "Combo Results" sheet. Any cell that is an input cell is highlighted in light orange. The "Eng Mod" sheet is divided into four parts. Default values are provided in the sheet for all parameters. In Part 1, a variety of engineering calculations are performed, particularly, the pipe diameter (Sub-part 1.6) and power requirement for the compressor station (Sub-part 1.8). Key inputs include the method for calculating inside diameter or maximum pipeline segment length and method for calculating 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 compressor 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 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 H2_P_COM

Parameter	Default Value	Location in "Eng Mod" Sheet	Note
Temperature of the ground where pipes are buried (°F)	53	Cell D13	Also, the temperature of hydrogen entering the compressor, Cell D23
Number of active compressors in each compressor station	2	Cell D25	Value from "H2 Compressor" sheet in HDSAM [8]
Number of backup compressors in each compressor station	1	Cell D26	Value from "H2 Compressor" sheet in HDSAM [8]
Number of stages per compressor	2	Cell D28	Value from "H2 Compressor" sheet in HDSAM [8]
Isentropic efficiency of each compressor	85%	Cell D29	Value from "H2 Compressor" sheet in HDSAM [8]
Ratio of specific heats	1.4	Cell D30	Value from "H2 Compressor" sheet in HDSAM [8]
Compressor motor sizing factor	1.1	Cell D31	Value from "H2 Compressor" sheet in HDSAM [8]
Compressor motor efficiency	96%	Cell D32	Value from "H2 Compressor" sheet in HDSAM [8]

Parameter	Default Value	Location in "Eng Mod" Sheet	Note
Method for calculating the minimum pipe diameter (specify one)	2	Cell D59	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 [11]
Method for calculating Fanning friction factor (specify one)	3	Cell D60	1 for equation developed by Haaland given by McCollum and Ogden [12] 2 for equation developed by Zigrang and Sylvester given by McCoy [11] 3 for Colebrook-White equation [13] See Appendix B: Pipe Flow Equations for these equations
Pipe inside surface roughness	0.00015	Cell D61	Value based on McCoy and Rubin [4]
Steel Grade of Pipeline	X70	Cell D105	Steel grade X52 is only available for an inlet pressure ≤ 1,000 psig and for class location 1
First Pipeline Class Location	1	Cell D113	Class Location 1 is any one-mile section with 10 or fewer occupied dwellings (i.e., sparsely populated areas) [6] Class Location 3 is any one-mile section with 46 or more occupied dwellings (i.e., outskirts of a city) [6]
Percentage of Pipeline Length in Class Location (%)	100	Cell D114	100% = Entire pipeline located in a single class location <100% = Pipeline is located in two different class locations
Material Cost Factor Option for First Pipeline Class Location	2	Cell D122	1 = User input material cost factor 2 = Calculated material cost factor based on class location, pipeline operating pressure, and nominal pipe diameter [6]
Labor Cost Modifier Option for First Pipeline Class Location	2	Cell D135	1 = User input labor cost factor 2 = Calculated incremental cost modifier (2011$/in.-mi) based on class location, pipeline operating pressure, and nominal pipe diameter [6]
Pipeline control system capital costs ($)	94,000	Cell D196	In 2000$ Per supplementary spreadsheet to "Estimating Carbon Dioxide Transport and Storage Costs" QGESS [20]
Compressor installation factor	2	Cell D205	Value from "H2 Compressor" sheet in HDSAM [8]
Method for calculating annual pipeline O&M costs (specify one)	2	Cell D216	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

Parameter	Default Value	Location in "Eng Mod" Sheet	Note
Annual pipeline O&M costs per mile of pipe ($/mi-yr)	5,000	Cell D218	In 1999$/mi-yr Per supplementary spreadsheet to "Estimating Carbon Dioxide Transport and Storage Costs" QGESS [20]
Percent of CAPEX to use as annual O&M costs for pipeline (%)	2.5	Cell G222	Per McCollum and Ogden [12]
Percent of compressor station costs to use as annual O&M costs (%)	4.0	Cell G2291	Best professional judgment
Percent of control system costs to use as annual O&M costs (%)	4.0	Cell G232	Best professional judgment
Electricity for compression ($/MW-hr)	68.20	Cell D238	In 2011$/MW-hr From EIA, electricity price for industrial sector [23]

4 Model Results

The Model Results section includes graphical output and explanation of equations used to calculate natural gas pipeline costs, as well as a discussion of the H2_P_COM outputs for first-year break-even hydrogen prices for a range of hydrogen pipeline lengths and transportation capacities. These graphical results are intended to provide a quick reference for the model functionality.

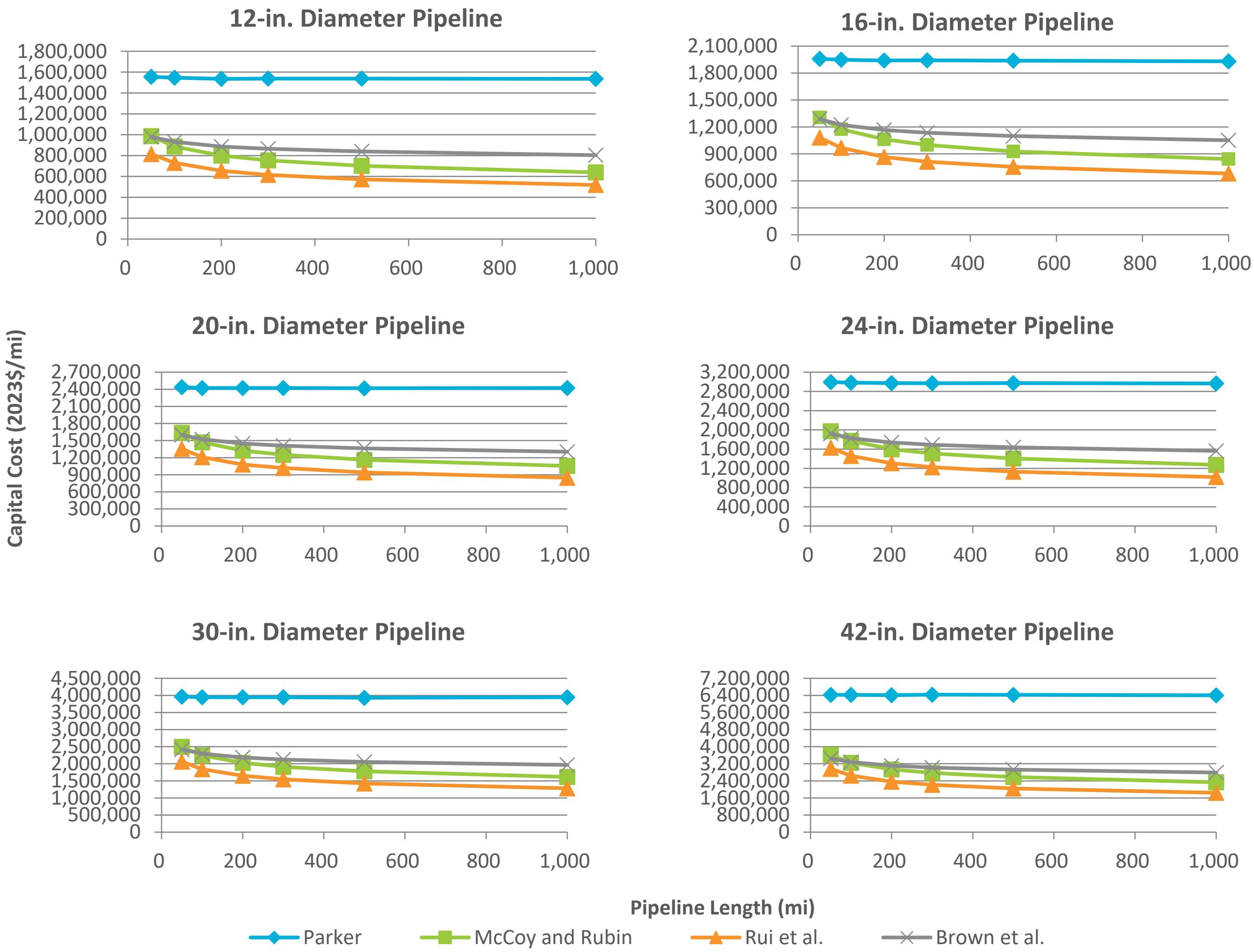
This section also includes comparison of the model outputs to other calculated and estimated hydrogen pipeline specifications and costs including the Argonne National Laboratory HDSAM model and calculated hydrogen costs in technical literature.

4.1 Capital Costs for Natural Gas Pipeline Equations

This section provides the capital costs for natural gas pipelines generated by the equations from Parker, [3] McCoy and Rubin, [4] Rui et al. [5], and Brown et al. [6], as well as the breakdown of these capital costs by the four cost categories (materials, labor, ROW & damages, and miscellaneous). Default values discussed in Section 2.2 and Section 3.4 of this manual and presented in the H2_P_COM were used to produce results.

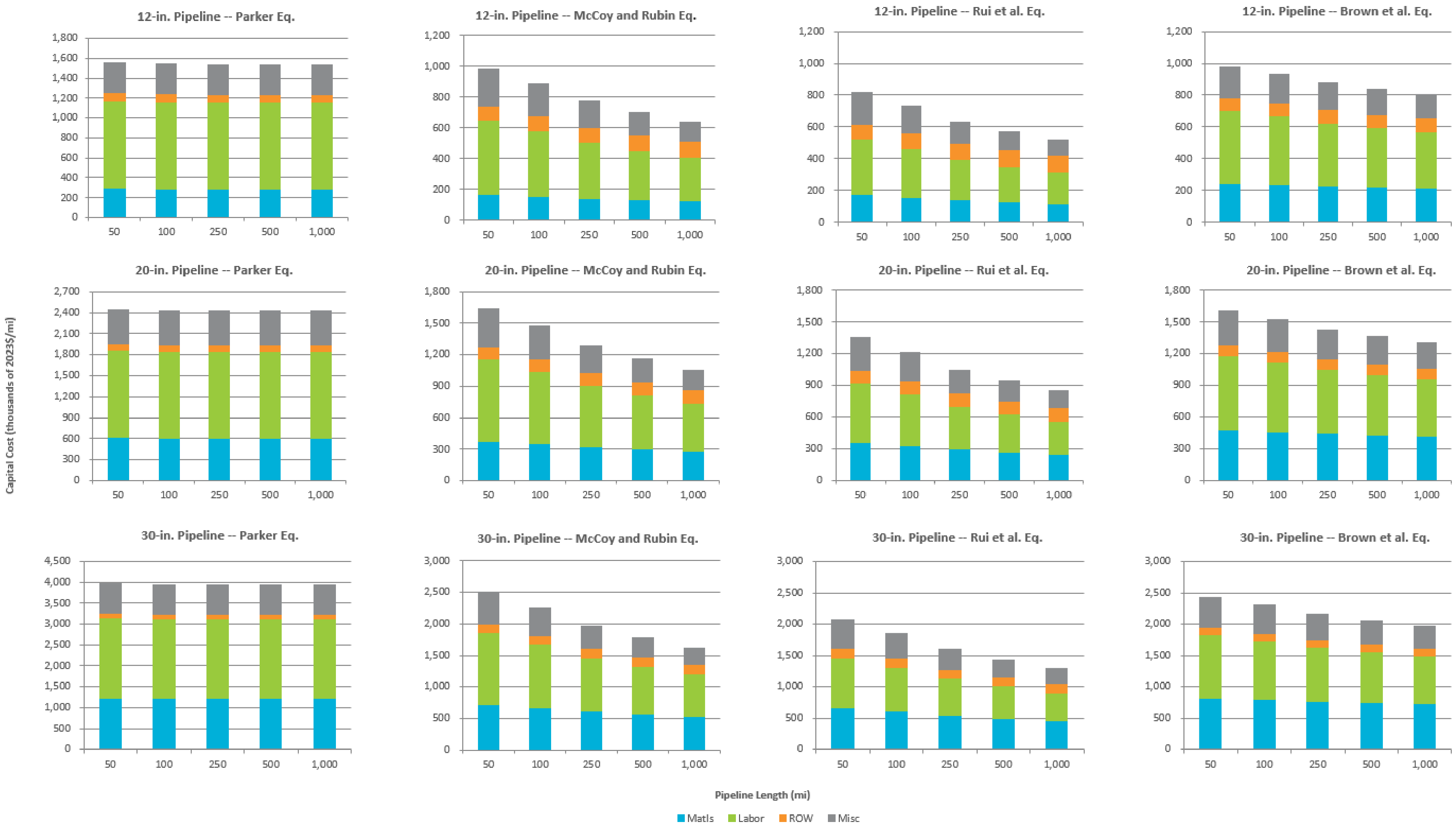
The four sets of equations for natural gas pipeline capital costs gave different results, as illustrated in Exhibit 4-1, which presents the $/mi data escalated to 2023$ (2023$/mi) for different pipeline lengths and diameters. Note that results for Parker are national, while the results for McCoy and Rubin, Rui et. al, and Brown et al. are an average of all regions in the United States [3, 4, 5, 6]. 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. The equations from Parker gave significantly higher costs than the other three equations. 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 [3, 4, 5, 6].

Exhibit 4-1. Natural gas pipeline capital costs using different equations (2023$/mi)



The breakdown of natural gas pipeline capital costs by cost category, which were escalated to 2023$ and are displayed in thousands of 2023$ per mile, is illustrated in Exhibit 4-2 for 12-, 20-, and 30-in. diameter pipelines for the four different sets of equations. Note that results for Parker are national, while the results for McCoy and Rubin, Rui et. al, and Brown et al. are an average of all regions across the United States [3, 4, 5, 6]. Labor costs were the largest component of capital costs followed by materials and miscellaneous costs. The ROW & damages cost was the smallest component of the capital costs, with the possible exception of costs generated by the equations from Rui et al. [5] for 12-in. diameter pipelines.

Exhibit 4-2. Breakdown of natural gas pipeline capital costs using different equations (2023$/mi)



4.2 H2_P_COM Break-Even Costs by Pipeline Length and Capacity

The figures below show the model outputs for first-year break-even price of hydrogen based on a range of hydrogen pipeline lengths and transport capacities. The metrics used for this model demonstration is intended to cover designs ranging from a single dedicated pipeline transporting hydrogen from a single facility over a short distance to a large hydrogen trunkline gathering hydrogen from multiple industrial facilities for long-range transportation. The current DOE National Clean Hydrogen Strategy and Roadmap calls for transporting and utilizing 50 million metric tons of hydrogen per year by 2050 [24].

The model outputs of first-year break-even hydrogen prices for variable pipeline distance and transport capacity are displayed on a log-scale in Exhibit 4-3. The individual cases output break-even prices listed in Exhibit 4-4. Default model settings were used for data generation, with a matrix of pipeline lengths and transport capacities loaded into the "Combo" sheet.

The results of the model show economies of scale with hydrogen break-even price decreasing for each pipeline length given an increase in transport capacity. For a representative single-source, dedicated pipeline (0.25 Mt/yr and 100 mile pipeline) the first-year, break-even hydrogen price is $71.16/t, or $0.071/kg. Costs increase significantly with increased pipeline length. Transporting the same volume of hydrogen 1,000 miles would increase the first-year break-even price of hydrogen to $715.61/t or $0.72/kg.

For a representative hydrogen trunkline transporting hydrogen from multiple industrial sources (5.0 Mt/yr) there are economies of scale benefits when the pipeline distance is under 25 miles. For distances over 25 miles, the first-year break-even price of hydrogen greatly increases and no longer benefits from economies of scale. This is because the largest nominal pipe diameter in the model is 48 in., which is required to transport 5.0 Mt/yr 25 miles and further. When the pipe diameter can no longer be increased, the only option is to add additional compressor stations, which increases electricity costs, and therefore the first-year break-even price.

Exhibit 4-3. First-Year Break-Even Hydrogen Price by Pipeline Length and Flow Capacity (2023$/t)

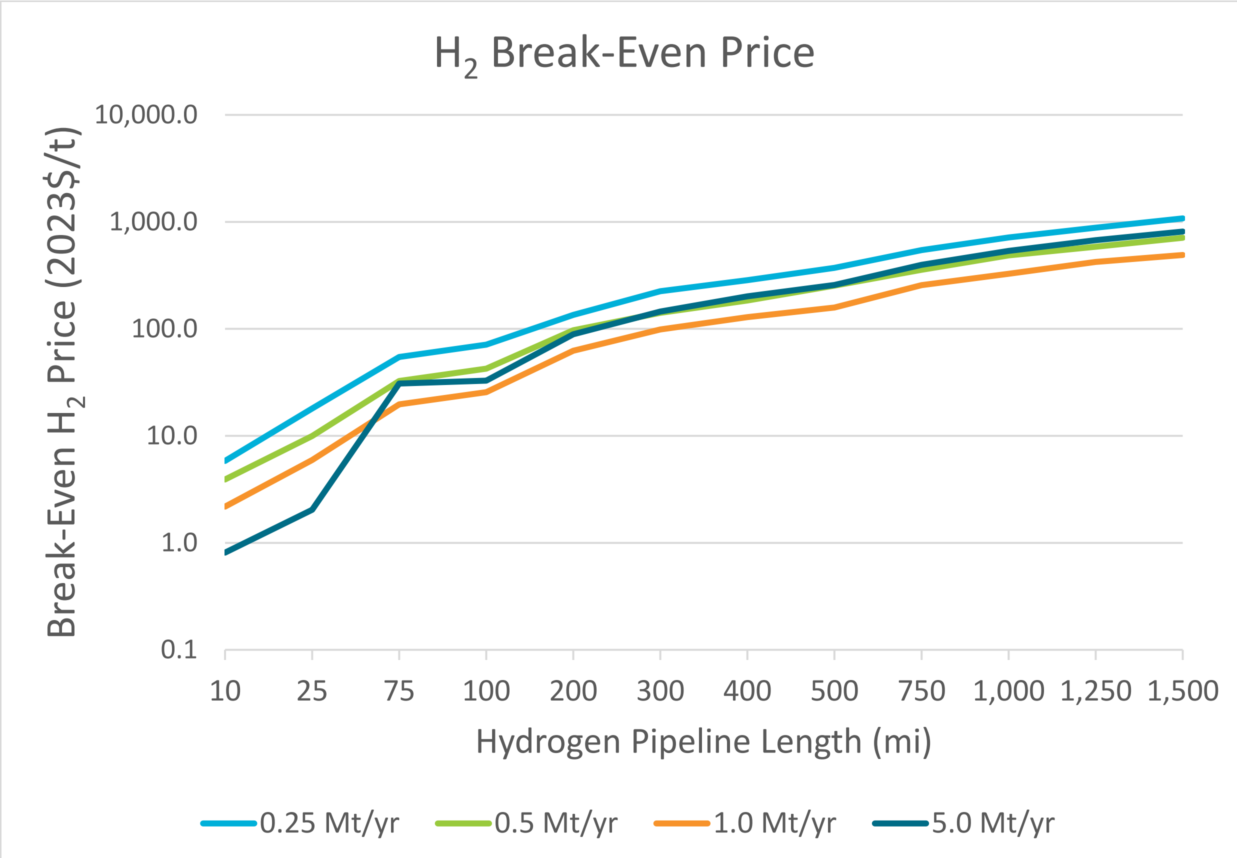


Exhibit 4-4. Table of First-Year Break-Even Hydrogen Price by Pipeline Length and Flow Capacity (2023$/t)

Pipeline Length (mi)	Transport Capacity (Mt/yr)			
	0.25	0.5	1.0	5.0
10	$5.83	$3.91	$2.18	$0.81
25	$18.03	$9.97	$5.95	$2.04
75	$54.59	$32.58	$19.69	$30.87
100	$71.16	$42.46	$25.64	$32.79
200	$135.08	$97.12	$62.36	$89.18
300	$224.71	$141.24	$98.73	$145.30
400	$285.00	$184.33	$128.76	$201.26
500	$372.25	$253.68	$158.25	$257.07
750	$545.46	$357.23	$256.44	$396.23
1000	$715.61	$485.45	$326.77	$534.98
1250	$883.60	$585.00	$422.06	$673.47
1500	$1,077.84	$710.27	$490.24	$811.73

4.3 Comparison of H2_P_COM Outputs to HDSAM and Technical Literature

Determination of optimal pipeline size (diameter) based on hydrogen flow capacity and pipeline length is an important calculation in the H2_P_COM for calculating overall project capital costs. Providing an accurate estimation of pipeline diameter is critical for calculating material costs, especially over longer distances.

The comparison below shows that the H2_P_COM provides relatively similar calculations for pipeline diameter based on flow capacity and pipeline length compared to the ANL HDSAM estimation of pipeline diameter. Note that the HDSAM model provides calculated pipeline diameter to the nearest quarter-inch, whereas the H2_P_COM rounds the pipeline diameter estimation to the nearest industry-standard pipeline diameter. These pipeline diameters are available from suppliers, whereas many of the diameters calculated by the HDSAM model are not produced on a large scale and would not be used in the field. Additionally, the H2_P_COM determines the optimal number of compressor stations and nominal pipe diameter to produce the lowest first year break-even price while still meeting the operational needs of the pipeline. For example, in some scenarios it is less expensive to increase the nominal pipe diameter and decrease the number of compressor stations, in other scenarios it could be less expensive to keep increase the number of compressor stations and keep the nominal pipe diameter the same.

Comparison of the two models used varying pipeline lengths and flow capacities while using the same gas compressibility (1.03), temperature (53 F), inlet pressure (1,015 psi), and outlet pressure (500 psi). In general, the HDSAM calculated diameter is one to several inches less than the H2_P_COM calculated diameter. This could be observed because H2_P_COM calculated diameter aligns to the industry-standard diameter thresholds and optimizes the number of compressor stations. Overall, the calculated diameters are similar between the two models.

Comparison of the model outputs is shown in Exhibit 4-5. The data is graphically displayed for three different pipeline flow rates, including 0.22 Mt/yr in Exhibit 4-6, 1.1 Mt/yr in Exhibit 4-7, and 2.2 Mt/yr in Exhibit 4-8. These flow capacities represent hydrogen transportation pipelines for a single source up to a trunkline gathering hydrogen regionally from multiple sources.

Exhibit 4-5. Table of Nominal Pipeline Diameter (in.) by Pipeline Length (mi) and Flow Capacity (Mt/yr)

Pipeline Length (mi)	Transport Capacity (Mt/yr)					
	0.22 Mt/yr		1.1 Mt/yr		2.2 Mt/yr	
	HDSAM	H2_P_COM	HDSAM	H2_P_COM	HDSAM	H2_P_COM
100	13.25	16	24.75	30	32.50	36
200	15.25	20	28.50	36	37.50	42
300	16.50	20	31.00	36	40.50	48
400	17.50	20	32.75	36	43.00	48

500	18.25	20	34.25	42	45.00	48
600	18.75	20	35.50	42	46.75	48
700	19.50	20	36.75	42	48.25	48
800	20.00	20	37.75	42	49.50	48
900	20.50	20	38.50	42	50.75	48
1000	21.00	20	39.25	42	51.75	48

Exhibit 4-6. Comparison of Calculated Nominal Pipeline Diameter by Pipeline Length and 0.22 Mt/yr Flow Capacity

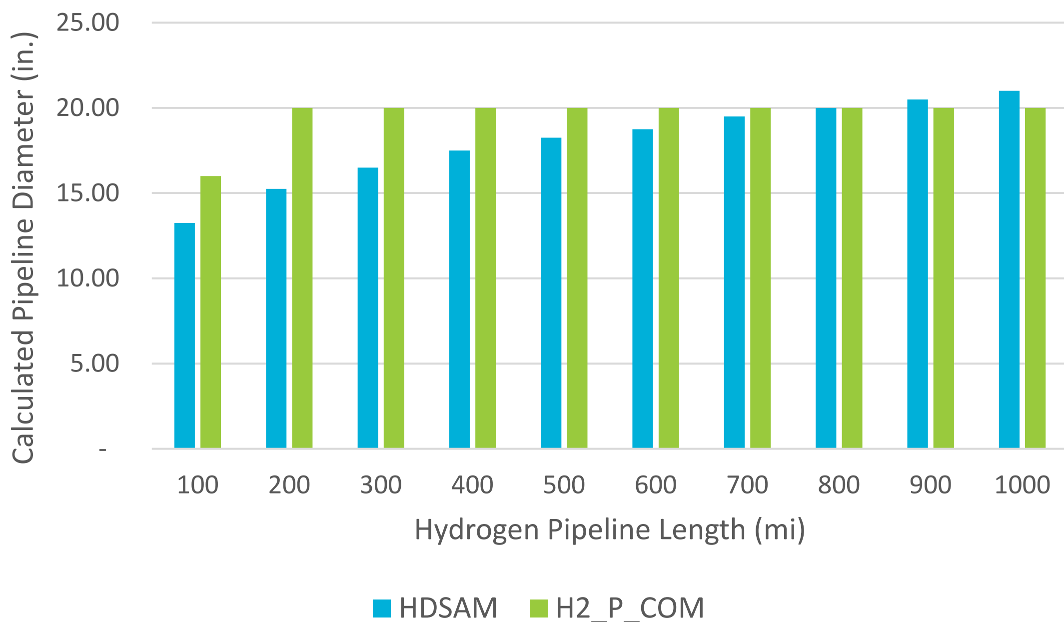


Exhibit 4-7. Comparison of Calculated Nominal Pipeline Diameter by Pipeline Length and 1.1 Mt/yr Flow Capacity

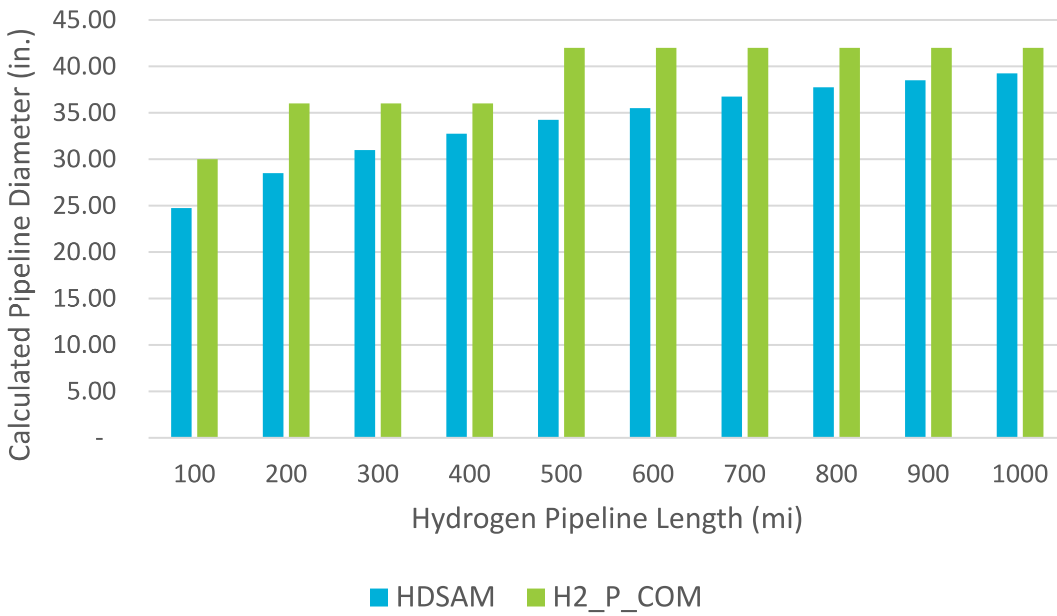
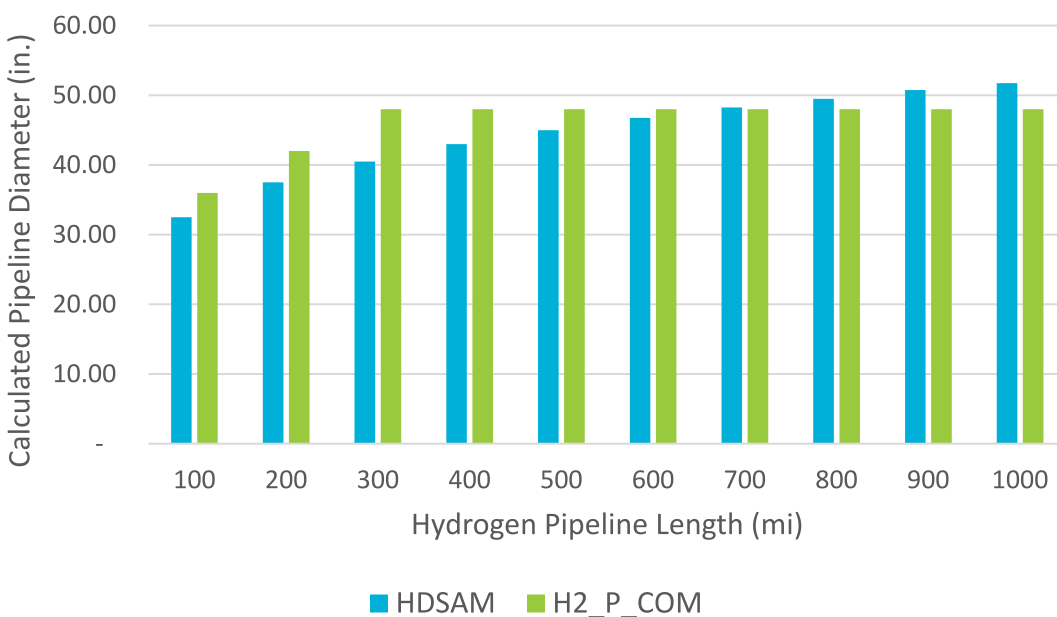


Exhibit 4-8. Comparison of Calculated Nominal Pipeline Diameter by Pipeline Length and 2.2 Mt/yr Flow Capacity



The technical paper "Large-scale long-distance land-based hydrogen transportation systems: A comparative techno-economic and greenhouse gas emission assessment" includes hydrogen cost calculations for relatively long hydrogen pipeline systems [25]. The paper was developed to address research gaps in hydrogen pipeline analysis due to lack of pipeline assessments for distances over 600 miles.

Techno-economic analysis for hydrogen pipelines was developed to cover capital and operating costs of hydrogen pipeline installation. Cost estimation was then performed for two pipeline lengths: 1,000 km (620 mi) for Pipeline A and 3,000 km (1,860 mi) for Pipeline B [25]. The criteria used for each pipeline analysis is shown in Exhibit 4-9. Each pipeline has the same operating pressure, diameter, elevation, OPEX % of CAPEX, and flow rate. Pipeline A assumed a total of 4 compressor stations, and Pipeline B assumed a total of 12 compressor stations [25]. The calculated hydrogen cost is $492/t for Pipeline A and $1,475/t for Pipeline B. Note that these costs were adjusted from $2020 CAD to $2020 USD using a conversion factor of 1.342.

Exhibit 4-9. Di Lullo et al. Long-Range Hydrogen Pipeline Specifications and Price ($2020 USD/t) [25]

Parameter	Pipeline A	Pipeline B
Length (mi)	620	1,860
Compressor Stations	4	12
Operating P (psi)	1,015	1,015
Diameter (in.)	16	16
Elevation	0	0
OPEX % of CAPEX	1.5%	1.5%
H_2 Flow Rate (Mt/yr)	0.222	0.222
H_2 Price (2020$ USD/t)	$492	$1,475

A comparison of these calculated costs was performed using the H2_P_COM to assess its capability to estimate pipeline design and cost for long-range pipelines. The pipeline data included in Exhibit 4-9 for Pipeline A and Pipeline B was loaded into the H2_P_COM. Additional model settings included using a 100% capacity factor, manually entering the number of compressor stations to match the model data, using a 2-year construction period to begin transportation in year 2020, using an inlet pressure of 1,015 psi and outlet pressure of 500 psi, and adjusting the OPEX% of CAPEX to be 1.5%. The remaining H2_P_COM settings used default values.

The results of the comparison are shown in Exhibit 4-10. The results show that the H2_P_COM is able to generate relatively accurate and consistent estimates of break-even hydrogen price compared to the Di Lullo et al. study [25]. For both Pipeline A (620 miles) and Pipeline B (1,860 miles) the H2_P_COM generated a hydrogen price estimate similar to the Di Lullo et al. calculated hydrogen price, with a difference of about 12% for Case A and 16% for Case B. This provides confidence in the H2_P_COM for estimating techno-economic specifications and costs for long-range hydrogen pipelines.

Exhibit 4-10. Comparison of Calculated Hydrogen Price for Di Lullo et al. and H2_P_COM ($2020 USD/t)

Case	Pipeline Length (mi)	Di Lullo et al. H_2 Price ($2020 USD/t)	H2_P_COM H_2 Price ($2020 USD/t)	Difference from H2_P_COM
Pipeline A	620	$492	$431	12%
Pipeline B	1,860	$1,475	$1,239	16%

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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 hydrogen gas (H_2) by pipeline. This model is called the FECM/NETL Hydrogen Pipeline Cost Model, also known as H2_P_COM.

To be consistent with costs in NETL's energy system studies, which are in 2023$, 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 2023. In addition, a methodology to obtain costs in real dollars is included in the model. 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 H2_P_COM

Financial Parameter	Real Value	Nominal Value	Location in "Main" Sheet
Escalation rate from base year to project start year (%/yr)	4.8	4.8	Cell E49
Escalation rate beyond project start year (%/yr)	0	2.3	Cell E51
Cost of equity (%/yr)	10.77	13.3	Cell E46
Cost of debt (%/yr)	3.91	6.3	Cell E47
Percent equity (remainder is debt) (%)	45	45	Cell E45
Tax rate (%/yr)	25.74	25.74	Cell E48

Notes: Base year = 2011 and project start year = 2023. The "escalation rate from base year to project start year" in the "Real Value" column is to escalate revenues and costs from the base year to the start year. The real or constant dollar analysis refers to escalation of revenues and costs after the project starts (i.e., the "escalation rate beyond project start year").

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 H2_P_COM provides two escalation rates. The first escalation rate escalates costs from the base year to the project start year (i.e., 2011 to 2023 for the purposes of this manual). The Handy-Whitman indices of public utilities were used to estimate escalation rates from 2011 to 2023. The closest analog to H_2 pipeline transportation within these indices is gas transmission; thus, the Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1, 2023 –

Cost Trends of Gas Utility Construction was used [26]. Handy-Whitman provides cost indices for six regions in the lower 48 states within the U.S. Cost indices were used to estimate annual escalation rates for each region. Table 2A in the "Main" sheet of the H2_P_COM Excel file provides the annual escalation rates for each region and identifies the states in each region. The calculated escalation rates ranged from 4.5%/yr to 5.0%/yr with an average value of 4.8%/yr. The 4.8%/yr value is used within the model as a representative value for the U.S. When this rate is compounded from 2011 to 2023, a cost in 2023 is roughly 1.755 times greater than the cost for the same item in 2011. Using the CPI Inflation Calculator provided online by the U.S. Bureau of Labor Statistics, the general rate of inflation from 2011 to 2023 resulted in an item in 2023 costing 1.36 times as much as the same item in 2011. Thus, natural gas transmission costs increased at a faster rate than the general rate of inflation [27].

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 H_2 pipeline transport industry will increase over the next 30–40 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. This is consistent with the Federal Reserve's 30-year expected inflation rate of about 2.3%/yr in February 2024. This rate is the default for the second escalation rate in the model [28] [29].

The nominal and real rate of return on equity were determined in a two-step process. A nominal rate of return for 2018 was determined using the capital asset pricing model (CAPM). Data from 1990–2018 was collected on the nine largest natural gas storage and transportation holding companies since natural gas pipeline transport is a reasonable analog to H_2 pipeline transport. The working natural gas and return on equity for each of these managed companies were determined using the CAPM. The return on equity for these companies ranged from 5.9%/yr–19.8%/yr. The average of these companies weighted by the working natural gas they managed was 13.0%/yr. This is the nominal rate of return on equity for 2018.

The nominal and real interest rate on debt were also determined in a two-step process. A nominal rate of return on debt for 2018 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) [7]. 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 [7]. As such, a slightly higher nominal interest rate on debt of 6.0%/yr is used for 2018.

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): [29]

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

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 starting inflation rate. 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.

To calculate the nominal minimum rate of return on equity and nominal interest rate on debt for 2023 and beyond, these real rates are used in Eq. A-1 with the expected long-term interest rate of 2.3%/yr. Using Eq. A-1 with a real minimum rate of return on equity of 10.77%/yr and inflation rate of 2.3%/yr results in a nominal minimum rate of return on equity of 13.3%/yr. Similarly, using Eq. A-1 with a real interest rate of 3.91%/yr for debt and inflation rate of 2.3%/yr results in a nominal interest rate for debt of 6.3%/yr. These are the default nominal minimum rate of return on equity and default nominal interest rate on debt in the model.

To be consistent with NETL energy system studies, even though the natural gas and transportation industries may pose a higher investment risk, the fraction of equity used for financing in the electric industry, 45%, was used as the default in the H2_P_COM [7].

An effective tax rate, which is the average rate a corporation's pre-tax earnings are taxed, [30] was included as a default in the model to be consistent with the tax rate used in NETL energy system studies [7]. The effective tax rate is 25.74%/yr which is comprised of 21%/yr federal corporate income tax and 4.74%/yr to cover all state and local taxes. The 4.74%/yr is 6.0%/yr on a gross basis that is then reduced to 4.74%/yr since state and local taxes can be deducted from federal corporate income taxes.

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 hydrogen (H_2) by pipeline. This model is called the FECM/NETL Hydrogen Pipeline Cost Model, also known as H2_P_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 H2_P_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 hydrogen saline storage operation) or the inlet to a compressor. The 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 [31], 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.

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

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:

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

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

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

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

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

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

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

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

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

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

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. [32] and McCollum and Ogden [12].

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:

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

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 H_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 H_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 H_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. [11] 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:

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

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 of 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.

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

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

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

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:

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

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

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

Integrating this equation yields Eq. B-31:

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

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

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

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

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

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:

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

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

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

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

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

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 H_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:

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

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

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

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

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

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

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

Solving for L gives Eq. B-42:

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

As before, L_{max} is the maximum segment length that will sustain the specified maximum H_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 H2_P_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: [13]

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

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 H2_P_COM, the Newton Raphson method is used to solve this equation for f_D.

The H2_P_COM provides two additional methods for calculating the Darcy friction factor. One is the Haaland equation (given in Eq. B-44): [12]

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

The second is the Zigrang and Sylvester equation, provided in Eq. B-45: [11]

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

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:

$$f_F = \frac{1}{4} \cdot f_{\mathrm{D}} \qquad \textbf{\textit{Eq. B-46}}$$

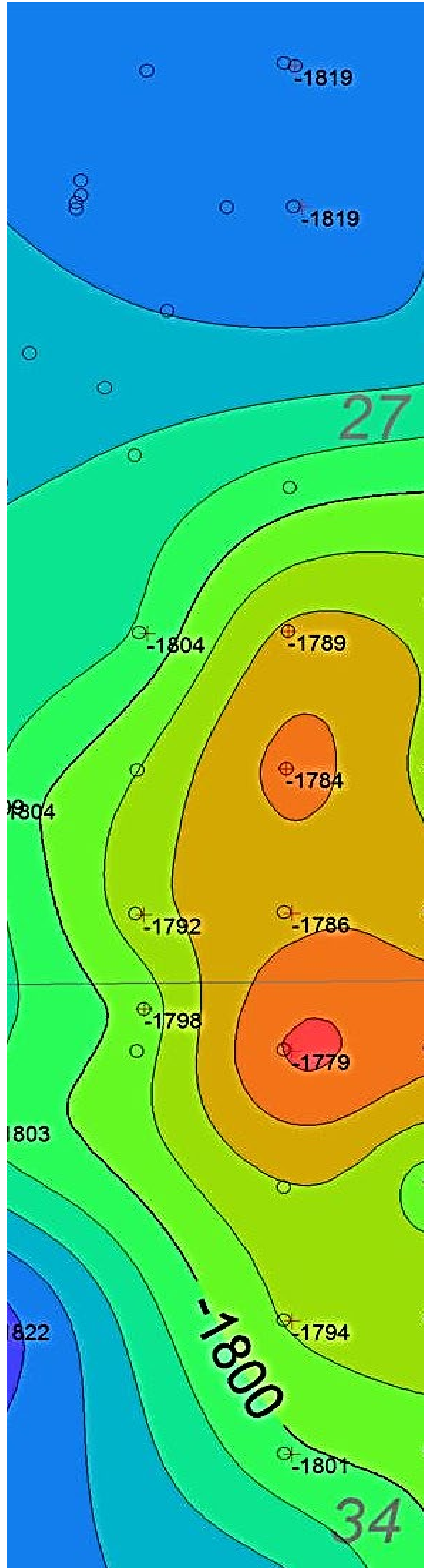
B.5 EQUATIONS FOR AVERAGE PRESSURE IN PIPE SEGMENT

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) [11].

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



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