Oil Production Greenhouse Gas Emissions Estimator

OPGEE v1.0

User guide & Technical documentation

DRAFT VERSION A

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Contents

I Introduction and user guide **8**

1 Introduction **9**
1.1 Model motivation 9
1.2 OPGEE model goals 10
1.3 OPGEE model construction 10

2 User guide **16**
2.1 Process stage worksheets 16
2.2 Supplementary sheets 18
2.3 Output gathering sheets 19
2.4 Working with OPGEE 20

II Technical documentation **27**

3 Process stage sheets **28**
3.1 Exploration emissions 28
3.2 Drilling & development 29
3.3 Production & extraction 33
3.4 Surface processing 53
3.5 Maintenance operations 67
3.6 Waste treatment and disposal 68
3.7 Crude oil transport 69
3.8 Bitumen extraction & upgrading 73

4 Supplemental calculations sheets **78**
4.1 Gas balance 78
4.2 Steam injection for thermal oil recovery 80
4.3 Venting, flaring and fugitives (VFF) 93
4.4 Drivers 110
4.5 Electricity 113
4.6 Emissions factors 114
4.7 Fuel cycle 118

5 Gathering sheets **119**
5.1 *'Energy Consumption'* gathering sheet 119
5.2 *'GHG Emissions'* gathering sheet 121
5.3 *'User Inputs & Results'* gathering sheet 121

6 Fundamental data inputs **123**
6.1 Global warming potentials 123
6.2 Properties of water and steam 123
6.3 Properties of air and exhaust gas components 124
6.4 Compositions and properties of fuels 124

A Terminology: Acronyms and abbreviations **126**

B Mathematical terms and defintions **128**

C Tabulated sources for each production stage **133**

D Statistical analysis of water oil ratios **140**
D.1 Methods of Analysis 140
D.2 Results 143

List of Figures

1.1 Schematic chart showing included stages within OPGEE. 11
1.2 Proposed workflow for improving emissions estimates using OPGEE. 13

2.1 Input data section of *'Production & Extraction'* sheet. User inputs are in column M, while defaults are kept as reference in column N. 20
2.2 Types of cells. *User Free* and *Default Free* cells can be changed, while *Locked* cells should not be changed due to possibility of compromising model functionality. 20
2.3 User inputs section of the *'User Inputs & Results'* sheet. 22
2.4 Input data section of *'Production & Extraction'* sheet. 25
2.5 Graphical results for a 'Generic' crude oil. *'User Inputs & Results'* Figure 1.1. 26
2.6 Tabular results for a 'Generic' crude oil. *'User Inputs & Results'* Table 1.1. 26

3.1 Drilling energy intensity as a function of well depth as measured for Canadian drilling operations. 30
3.2 Moody friction factor chart [1]. 37
3.3 An example of a linear pressure traverse curve (GLR= 0). 39
3.4 Distributions of global oilfield ages. Mean date of discovery (by count not by production-weighted average) is 1978.4. 46
3.5 Distributions of giant oilfield ages. Mean date of discovery (by production-weighted average) is 1960.2. 47
3.6 Distributions of global oilfield depths in bins of 500 ft depth. N = 4489 fields, mean = 7238 ft, SD = 3591 ft, median = 6807 ft. . . 48
3.7 Distributions of oilfield per-well productivity (bbl oil/well-d) for bins of 500 bbl/d, counted by numbers of countries (bar) and by fraction of production (dot) N = 92 countries. 49
3.8 Distributions of oilfield per-well productivity (bbl oil/well-d) for all countries with per-well productivities lower than 500 bbl/well-d, counted by numbers of countries (bar) and by fraction of production (dot) N = 55 countries. 50
3.9 Distributions of major gas species across 135 samples from California associated gas producers. 51

3.10 Distributions of California GORs, binned by crude density. . . . 52
3.11 Exponential WOR model using mean results for Alberta and California case cases. Default case is a moderate case that is between the Alberta and California cases. 52
3.12 Amine simple process flow diagram [2, p. 112]. 57
3.13 Glycol dehydrator simple process flow diagram [2, p. 141]. . . . 61
3.14 Composition of three diluent products from C1 to C12+ hydrocarbons. 76

4.1 Once-through steam generator with mass and energy balance terms. Lower case terms are defined per lbmol of input fuel. . . 81
4.2 Increase of crude contaminant load with increase in crude specific gravity (decrease in API gravity). Data from: Speight (1994) and Swafford (2009). 85
4.3 Gas turbine plus heat recovery steam generator model. Mass flows represented by m and energy flows represented by fuel higher heating value (HHV), electric power out (e) and enthalpy of gases (h). 86
4.4 Predicted turbine exit temperatures for variety of turbines from literature (*y-axis*) as compared to reported value from the literature (*x-axis*). 87
4.5 Distribution of SOR values for California and Alberta thermal EOR projects (steamflood, cyclic steam stimulation, steam-assisted gravity drainage). 92
4.6 Types of fixed-roof storage tanks and default dimensions used in OPGEE. 98

D.1 Example exponential fits to Alberta pool-level WOR dataset. Pool age is calculated relative to discovery date of pool (not initial year in dataset). 143
D.2 Histogram of R^2 for Albertan Crude Production (Exponential Fit).144
D.3 Plot of values of b_0 and b_1 for exponential fits to Alberta producing WORs. 145
D.4 Histogram of R^2 for Californian Crude Production (Exponential Fit). 146
D.5 Plot of values of b_0 and b_1 for exponential fits to California producing WORs. 148
D.6 Models using median (left) and mean (right) results for California cases. Default case is a moderate case that is between the Alberta and California cases. Sources for comparative cases are included in Table D.5. 149

List of Tables

1.1 Emissions classification, order of magnitude emissions, and significance description. 14

3.2 Default land use GHG emissions from field drilling and development in OPGEE for conventional oil operations [g CO_2 eq./MJ of crude oil produced]. Data from Yeh et al. (2010). . . . 32
3.1 Default inputs for drilling calculations. 32
3.3 Reynold's Number ranges of different flow patterns. Data from McAllister (2009). 37
3.4 Default inputs for production and extraction. 42
3.5 GOR values by crude oil API gravity bin. 49
3.6 OPGEE WOR relationships. 50
3.7 Typical concentration of process water pollutants. 62
3.8 Categorization of water treatment technologies. 63
3.9 Default inputs for surface processing. 65
3.10 Default inputs for crude transport. 72
3.11 Default inputs for bitumen extraction & upgrading calculations. 77

4.1 Hydrogen constant a_H as a function of API gravity. 84
4.2 Gas turbine model results for hypothetical turbines A-D. These results serve as input data to OPGEE GT model. 87
4.3 Default inputs for steam injection calculations. 88
4.4 Indicators of SOR distributions for California and Alberta thermal EOR production. 91
4.5 Stoichiometric relationships for complete combustion. 94
4.6 Emissions data used in the estimation of operational venting. Data from California oil fields, 2007 [3]. 96
4.7 Average W&S gas speciation profile. 101
4.8 Categorization of venting emissions sources by process stage. . 102
4.9 ARB data used in the estimation of fugitives. Data from ARB (2011). 103
4.10 Estimating the number of remaining components. 104
4.11 Speciation fractions for total hydrocarbon (THC) emissions calculated using API emissions factors [-]. 105
4.12 Categorization of fugitive emissions sources by process stage. . 106
4.13 Default inputs for venting, flaring, and fugitive emissions. . . . 107

4.14 Types and size ranges of the drivers embedded in OPGEE. . . . 110
4.15 Default inputs for drivers calculations. 112
4.16 Combustion technologies and fuels included in OPGEE. 114
4.17 ARB data used in the calculation of venting emissions factors (unit specified below) [3]. 115
4.18 ARB data used in the calculation of fugitives emissions factors (unit specified below). 116
4.19 An example of EPA emissions factors for oil and gas production components (g/unit-yr). 117

A.1 Acronyms and abbreviations. 126

B.1 Mathematical symbols and subscripts. 129

C.1 Emissions sources from exploratory operations. For inclusion: 0 = not included, 1 = included. 134
C.2 Emissions sources from drilling operations. 135
C.3 Emissions sources from production and extraction operations. . 136
C.4 Emissions sources from surface processing operations. 137
C.5 Emissions sources from maintenance operations. 137
C.6 Emissions sources from waste treatment and disposal operations. 138
C.7 Emissions sources from crude transport. 139

D.1 Characteristics of collected Alberta production and injection dataset. 141
D.2 Characteristics of collected California production and injection dataset. 142
D.3 Results for exponential fit to Alberta oil fields. 144
D.4 Results for exponential fit to California oil fields. 144
D.5 OPGEE WOR relationships. 146
D.6 Sources of WOR data for global oil fields. 147

Part I

Introduction and user guide

1 Introduction

The Oil Production Greenhouse gas Emissions Estimator (OPGEE) is an engineering based life cycle assessment (LCA) tool for the measurement of greenhouse gas (GHG) emissions from the production, processing, and transport of crude petroleum. The system boundary of OPGEE extends from initial exploration to the refinery gate (see Figure 1.1).

The aim of this technical documentation is to introduce OPGEE and explain the calculations and data sources in the model. First, the overall goals and motivation for OPGEE are described. Then, the general structure of OPGEE is introduced with a brief explanation of the worksheets contained in the model. Next, each production stage is explained in detail, outlining the methods and assumptions used to generate estimates of energy use and emissions for that stage. Following, supplemental calculation sheets are outlined. After this, the gathering sheets which collect and aggregate intermediate results are described. Lastly, we describe the sheets that contain fundamental data inputs.

1.1 Model motivation

Current research suggests that GHG emissions from petroleum production can be quite variable [4–11]. Facilities that do not rely on energy intensive production methods and use effective controls on fugitive emissions sources will have low GHG emissions per unit of energy produced. In contrast, some crude oil sources can have higher GHG emissions if they rely on energy-intensive production methods.

The variability in crude oil production emissions is partly due to the use of energy-intensive secondary and tertiary recovery technologies [9, 12, 13]. Another major factor is significant variation in the control of venting, flaring and fugitive (VFF) emissions [14–16]. Other emissions arise from increased pumping and separation work associated with increased fluid handling in depleted oil fields (i.e., fields with a high water-oil ratio).

The existing set of general fuel cycle emissions models, exemplified by GREET and GHGenius [13, 17], cover a wide range of transport fuels, from biofuels to electric vehicles. These broad models have the advantage of being publicly available and transparent. Unfortunately, they lack process-level detail for any particular fuel cycle and only represent pathway averages. For example, all conventional crude oil production in GREET is modeled using a

Box 1.1. Goals of OPGEE

1. Build a rigorous, engineering-based model of GHG emissions from oil production operations.
2. Use detailed data, where available, to provide maximum accuracy and flexibility.
3. Use public data wherever possible.
4. Document sources for all equations, parameters, and input assumptions.
5. Provide a model that is free to access, use, and modify by any interested party.
6. Build a model that easily integrates with existing fuel cycle models and could readily be extended to include additional functionality (e.g. refining)

common default production pathway, fuel mix, and energy efficiency. While these LCA tools have been useful to date, future regulatory approaches will require a more specific method of assessing the differences between crude oil sources.

1.2 OPGEE model goals

The goals of OPGEE development are listed in Box 1.1.

First, OPGEE is built using engineering fundamentals of petroleum production and processing. This allows more flexible and accurate emissions estimations from a variety of oil production emissions sources.

OPGEE is constructed using *Microsoft Excel* to ensure transparency and maximum accessibility by stakeholders, including industry, governments, and members of the public. OPGEE will be available for download from Stanford University servers, and servers of future institutions in which Adam Brandt is employed. This will ensure its future availability. Regular updates of the model are expected in intervals of 1-2 years.

Another goal of OPGEE is the generation of comprehensive documentation. Model functions and input data are documented within the *Excel* sheet to allow effective use and modification of the tool by users. This long-form model documentation serves to explain model calculations and assumptions and provides information on model data sources.

1.3 OPGEE model construction

1.3.1 Model functional unit

The functional unit of OPGEE is 1 MJ of crude petroleum delivered to the refinery entrance (a well-to-refinery, or WTR process boundary). This functional

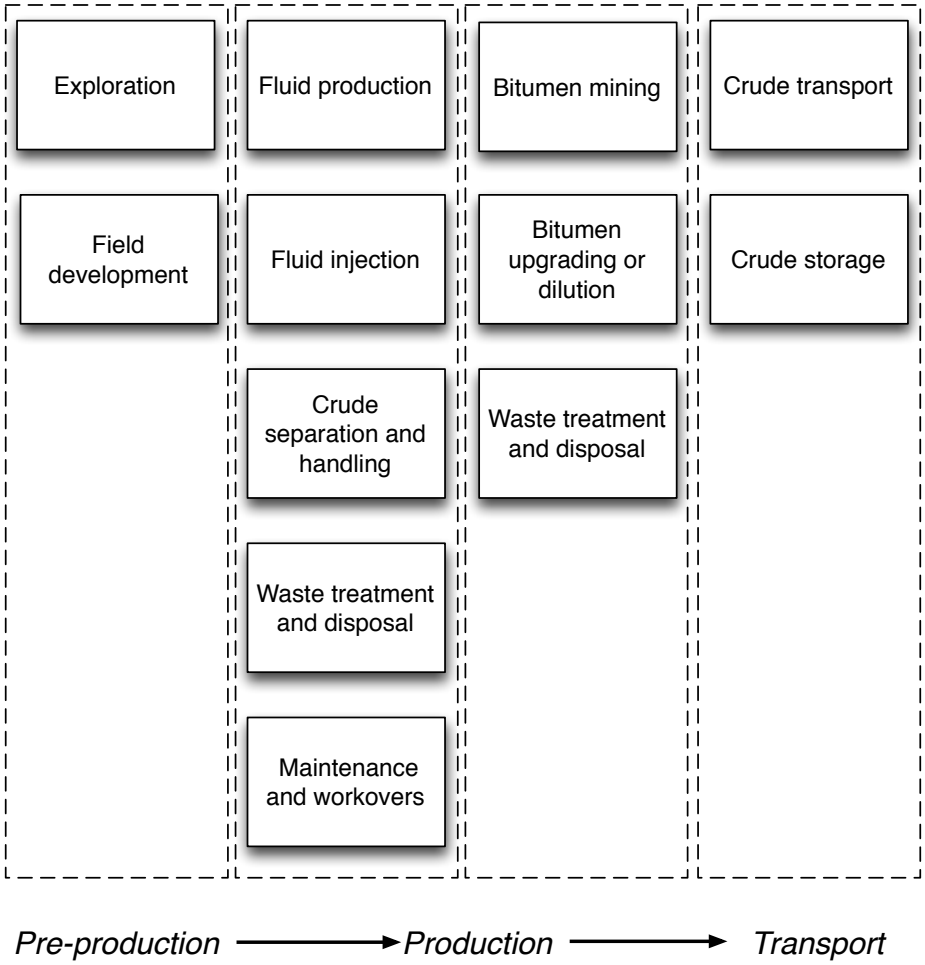


Figure 1.1: Schematic chart showing included stages within OPGEE.

unit is held constant across different production and processing pathways included in OPGEE. This functional unit allows integration with other fuel cycle models that calculate refinery emissions per unit of crude oil processed, and will allow easy integration with future work on refinery models. The heating value basis can be chosen as lower or higher heating value (LHV or HHV), depending on the desired basis for the emissions intensity. The model defaults to LHV for best interface with GREET.

1.3.2 Model scope and focus

OPGEE includes emissions from all production operations required to produce and transport crude hydrocarbons to the refinery gate (see Figure 1.1 for model system boundaries). Included production technologies are: primary production, secondary production (water flooding), and major tertiary recovery technologies (also called enhanced oil recovery or EOR). In addition, bitumen mining and upgrading is included in a simplified fashion.

1.3.3 Spreadsheet structure

OPGEE is modular in structure, with interlinked sheets representing each production stage. Within each major production stage, a number of activities and processes occur, such as fluid production or fluid injection. The number of processes and sub-processes varies depending on the process stage. The calculations take place sequentially and are numbered in a hierarchical fashion (see Box 1.1 for explanation of documentation pointers to the model).

1.3.4 Modeling detail and default specifications

OPGEE models oil production emissions in more detail than previous LCA models. For example, the energy consumed in lifting produced fluids (oil, water, and associated gas) to the surface is computed using the fundamental physics of fluid lifting, accounting for lifting efficiencies and pump efficiencies.

Increased modeling detail results in an increase in the number of model parameters. All required inputs to OPGEE are assigned default values that can be kept as is or changed to match the characteristics of a given oil field or marketable crude oil blend. If only a limited amount of information is available for a given facility, most of the input values will remain equal to defaults. In contrast, if detailed field-level data are available, a more accurate emissions estimate can be generated.

For some processes and sub-processes, correlations or relationships are developed for defaults, which we call "smart defaults". For example, the amount of water produced with oil (water-oil-ratio, or WOR) affects the energy consumed in lifting, handling, and separating fluids. If the WOR is known, it can be inputed directly. However, in some regions, water production is not reported, so OPGEE includes a statistical relationship for water production as a function of reservoir age (see Appendix D for a description of the analysis underlying this smart default).

A workflow for updating and improving the data basis and accuracy of an emissions estimate using OPGEE is given in Figure 1.2. This workflow represents one possible way that OPGEE could be used.

1.3.5 Emissions sources classification

Each process stage or sub-process in OPGEE could be associated with a variety of emissions sources. For example, the *'Drilling & Development'* process stage includes the terrestrial drilling sub-process. Terrestrial drilling includes the following emissions sources:

- Combustion emissions from drilling rig prime mover;
- Flaring emissions from drilling rig (for reservoirs with significant gas production);
- Vents and other upset emissions from drilling rig;

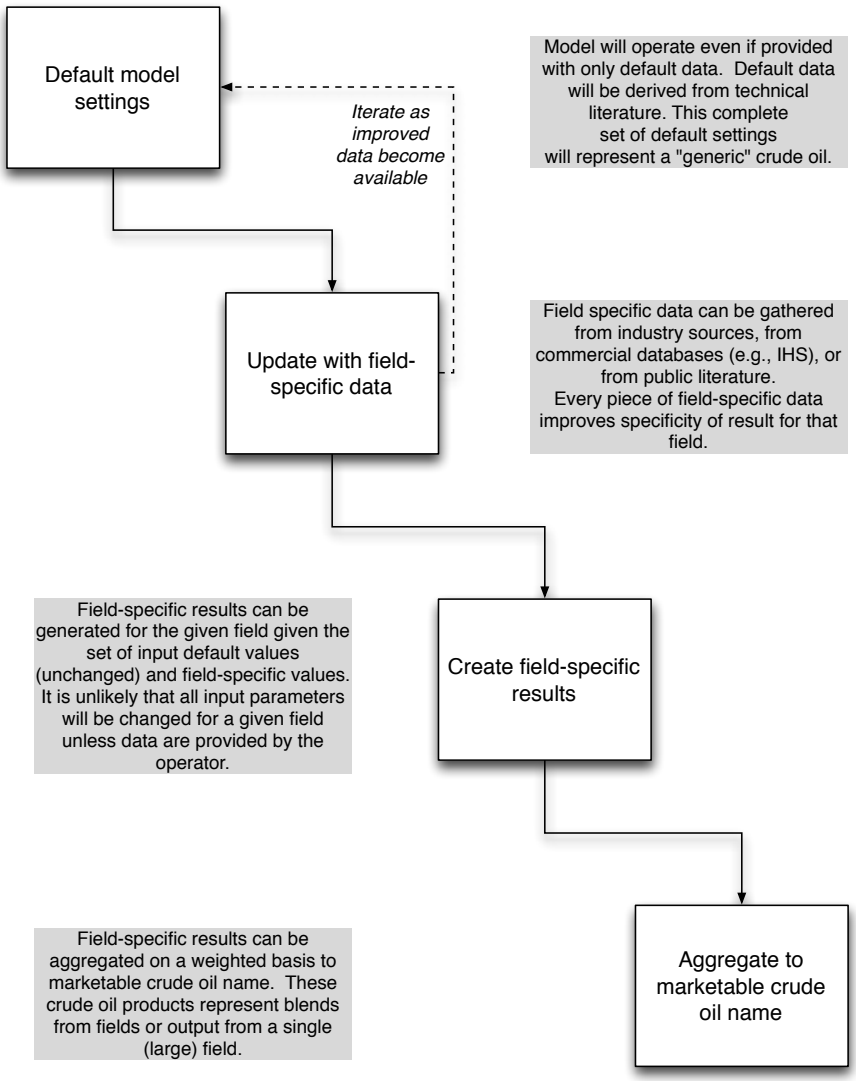


Figure 1.2: Proposed workflow for improving emissions estimates using OPGEE.

- Combustion emissions from work performed in land clearing and site preparation;
- Biogenic emissions from ecosystem disturbance during development;
- Embodied emissions in cement and casing;
- Embodied emissions in other consumable materials (e.g., fracturing sand)

Note that these emissions sources are of significantly different magnitude and have different causation and potential methods of mitigation. In total, over 100 emissions sources are classified in OPGEE v1.0 across all process stages (e.g., all included processes and sub-processes). See Appendix C for a complete tabulation and classification of emissions sources.

Table 1.1: Emissions classification, order of magnitude emissions, and significance description.

Class	Est. mag. [gCO_2/MJ]	Description
*	0.01	Minor emissions sources unworthy of further study or estimation. Numerous sources result in this being the most common classification. One-star emissions are accounted for by adding a value for miscellaneous minor emissions.
**	0.1	Minor emissions sources that are often neglected but may be included for physical completeness.
***	1	Sources that can have material impacts on the final GHG estimate, and therefore are explicitly modeled in OPGEE.
****	10	Sources that are large in magnitude (though uncommon). Examples include steam production for thermal oil recovery and associated gas flaring. These sources are significant enough to require their own dedicated OPGEE modules.

1.3.6 Emissions source significance cutoffs

OPGEE includes within its system boundaries over 100 possible emissions sources in oil and gas production (see Appendix C). It would be infeasible (and counter-productive) for regulators or producers to attempt to estimate or model the magnitude of every emissions source. Fortunately, a much smaller number of emissions sources will result in most of the emissions from petroleum production operations.

For this reason, emissions sources included in the OPGEE system boundary are classified by estimated emissions magnitude. These emissions magnitudes are meant to represent *possible* emissions magnitudes from a source, not the actual emissions that would result from that source for any particular field. An order-of-magnitude estimation approach is used, with each source assigned a rating in "stars" from one-star (*) to four-star (****) corresponding to 0.01 to 10 g CO_2 eq. per MJ of crude oil delivered to the refinery gate. These classifications are explained in more detail in Table 1.1.

Emissions estimated to be one-star emissions (*) are not modeled in OPGEE due to insignificant magnitude. These are included in the overall emissions estimate by including a small sources term. Two-star (**) sources are included simply or are included in the small sources term. Often, two-star sources are minor in magnitude, but are modeled due to the need to model the physics and chemistry of crude oil production and processing.[1] Three-star (***) sources are explicitly modeled in OPGEE. Four-star sources (****) are modeled in detail with stand-alone modules to allow variation and uncertainty analysis.

User Inputs & Results 3.6

[1] No strict criteria exist to determine the inclusion or exclusion of two-star sources. Modeler judgement is applied to determine the need for modeling these sources.

1.3.7 Data sources

Because of the need for transparent data basis, OPGEE uses data from a variety of technical reference works. For example, emissions factors are derived from standard engineering references from the American Petroleum Institute (API) and EPA [18, 19]. A large number of technical references, journal articles, and fundamental data sources have been consulted during the construction of OPGEE, including:

- Exploration and drilling [19–26]
- Production and surface separations [2, 18, 19, 27–55]
- Secondary and tertiary recovery [56–61]
- Water treatment and waste disposal [26, 50, 53, 62–65]
- Venting, flaring, and fugitive emissions [27–29, 29–36, 66–70]
- Petroleum transport and storage [33, 36, 46, 69, 71–75]

2 User guide

OPGEE is divided into three types of worksheets: (i) process stage sheets, (ii) supplementary sheets, and (iii) output sheets.

2.1 Process stage worksheets

Process stage worksheets form the core of OPGEE, and are where most model calculations occur. These sheets have red-colored tabs.

2.1.1 *'Exploration'* worksheet

The *'Exploration'* worksheet contains pre-production emissions that occur during primary exploration for petroleum. These emissions are generally very small in magnitude when amortized over the productive life of an oil field, as they occur only at the outset of production. For this reason, these sources are classified as below the significance cutoff in OPGEE v1.0. Exploration emissions are described in more detail in Section 3.1, and emissions sources from exploration are listed and classified in Table C.1.

2.1.2 *'Drilling & Development'* worksheet

The *'Drilling & Development'* sheet includes emissions that occur during development of crude oil production facilities. Key sources include drilling and land use impacts from land clearing and conversion. Drilling and development emissions tend to be relatively small because they only occur at the outset of production or sporadically during field life. Drilling and development emissions are described in more detail in Section 3.2, and emissions sources from drilling and development are listed and classified in Table C.2.

2.1.3 *'Production & Extraction'* worksheet

The *'Production & Extraction'* sheet models the work required to lift fluids from the subsurface and to inject fluids into the subsurface. A variety of fluid lifting and production technologies are included in OPGEE, including the two most common lifting technologies: sucker-rod pumps and gas lift. Also included are the energy requirements of water flooding, gas flooding, and steam flooding. The lifting model used for calculating lifting energy is a single phase

flow model which neglects gas slippage. Injection horsepower calculations are based on operating pressures and temperatures using fundamental physics. Production emissions are described in more detail in Section 3.3, and emissions sources from production are listed and classified in Table C.3.

2.1.4 *'Surface Processing'* worksheet

The *'Surface Processing'* sheet models handling of crude, water, and associated gas with a set of common industry technologies. By defining default configurations and parameter values, the amount of data required is reduced. For example, in gas processing, default processes are assumed such as the amine-based acid gas removal (AGR) and glycol-based gas dehydration units. Process flow diagrams are included in the surface processing sheet for improved readability. Surface processing emissions are described in more detail in Section 3.4, and emissions sources from surface processing are listed and classified in Table C.4.

2.1.5 *'Maintenance'* worksheet

The *'Maintenance'* sheet includes venting and fugitive emissions associated with maintenance. These emissions occur during compressor blowdowns, well workovers and cleanups, and gathering pipeline maintenance. Maintenance emissions are described in more detail in Section 3.5, and emissions sources from maintenance are listed and classified in Table C.5.

2.1.6 *'Waste Disposal'* worksheet

The *'Waste Disposal'* sheet includes emissions associated with waste disposal are within the system boundary of OPGEE. However, these sources are believed to be below the significance cutoff, so they are not explicitly modeled in OPGEE. Waste disposal emissions are described in more detail in Section 3.6, and emissions sources from waste disposal are listed and classified in Table C.6.

2.1.7 *'Crude Transport'* worksheet

The *'Crude Transport'* sheet calculations allow variation in transport modes and in the distance travelled. Transport emissions are modeled using the method established in GREET [76]. Transport emissions are described in more detail in Section 3.7, and emissions sources from transport are listed and classified in Table C.7.

2.1.8 *'Bitumen Extraction & Upgrading'* worksheet

The *'Bitumen Extraction & Upgrading'* sheet models extraction of crude bitumen separately from the production of conventional crude oil, due to the dif-

ferences in technologies applied (e.g., mining and upgrading equipment have no analogues in conventional crude oil operations). Instead of detailed process models, data from the GHGenius model are included in OPGEE [13]. Bitumen extraction and upgrading emissions are described in more detail in Section 3.8.

2.2 Supplementary sheets

Supplementary sheets support calculations throughout OPGEE, including: calculating intermediate outputs in the process stage sheets, compiling output in the gathering sheets, and calculating final results in the *'User Inputs & Results'* sheet. Supplementary sheets have blue-colored tabs.

'Gas Balance' worksheet This sheet tracks produced gas composition from production to final user or sale to ensure that all produced gas is accounted for in the gas processing equipment, VFF emissions, and final gas sales. The *'Gas Balance'* worksheet is described in Section 4.1

'Steam Injection' worksheet This sheet is supplementary to the production and extraction sheet and calculates in detail the natural gas consumed and electricity cogenerated (if applicable) during steam generation. The *'Steam Injection'* worksheet is described in Section 4.2

'Electricity' worksheet This sheet determines the offsite electricity mix and calculates the energy consumption in onsite electricity generation (other than electricity co-generated with steam). The *'Electricity'* worksheet is described in Section 4.5.

'Drivers' worksheet This sheet provides a database of energy consumption for different types and sizes of prime movers (gas and diesel engines, gas turbines and electric motors). The *'Drivers'* worksheet is described in Section 4.4

'Fuel Cycle' worksheet This sheet retrieves and calculates the fuel cycle energy consumption and GHG emissions for the calculation of credits/debits from fuel exports/imports. The *'Fuel Cycle'* worksheet is described in Section 4.7.

'Emission Factors' worksheet This sheet retrieves and builds emissions factors for the calculation of combustion and non-combustion GHG emissions from energy use and losses. The *'Emissions Factors'* worksheet is described in Section 4.6

'VFF' worksheet This sheet calculates in detail the GHG emissions associated with venting, flaring and fugitives. The *'VFF'*orksheet is described in Section 4.3.

'Fuel Specs' worksheet This sheet provides fuel specifications required for OPGEE calculations. The *'Fuel Specs'* worksheet is described in Section 6.

'Input Data' worksheet This sheet provides other needed data inputs such as conversion factors and steam enthalpies. The *'Input Data'* worksheet is described in Section 6.

2.3 Output gathering sheets

Output sheets gather the information from the process stage calculations and compile them into summed energy consumption (including energy co-production credits) and summed GHG emissions (including any offsets from co-produced energy). Also included in the output sheets is the sheet where users input key parameters and display summary results. Output sheets have green-colored tabs.

'Energy Consumption' worksheet The *'Energy Consumption'* sheet gathers data on energy consumption for sub-processes from all process sheets. Each main process sheet is included in the gathering table. All energy consumed is summed by type across all stages. This gross consumption is used to compute net consumption and energy imports and exports. The *'Energy Consumption'* worksheet is described in Section 5.1

'GHG Emissions' worksheet The *'GHG Emissions'* sheet takes the energy quantities consumed in each stage and converts them to emissions using emissions factors. It also gathers any emissions associated with land use change and VFF emissions. Emissions are computed as $gCO_2eq./d$. The *'GHG Emissions'* worksheet is described in Section 5.2.

'User Inputs & Results' worksheet The *'User Inputs & Results'* sheet serves two functions. First, it serves as the place for primary model interaction (see below). Also, this sheet presents summary results in tabular and graphical form. The *'User Inputs & Results'* worksheet is described in Section 5.3.

2.3.1 Structure of each worksheet

Each process stage sheet is divided into two main sections: (i) input data and (ii) calculations. The input data section (see Figure 2.1) is where the user enters the input parameters (e.g., API gravity, production volume). The input section of each sheet has two data columns: *User* and *Default*, in columns M and N, respectively. The cells within the *User* column are the active cells, and are used to generate results. The cells within the *Default* column are used for reference, bookkeeping of default values, and generating defaults using correlations based on field data.

Below the input data section is the the calculations section of a sheet, where intermediate model outputs are calculated. These intermediate outputs are summarized and compiled by the gathering sheets to provide the overall energy and emissions measures compiled in the *'User Inputs & Results'* sheet.

2.3.2 Types of model cells

Four main types of cells exist in the calculation columns M and N: *User Free*, *User Locked*, *Default Free*, *Default Locked* (See Figure 2.2). As might be expected,

27	Input data			
30	**1. Field and production parameters**			
32	**1.1 Product crude**	User	Default	Units
33	1.1.1 Crude location	USA	USA	
34	1.1.2 Crude name	Generic	Generic	
35	1.1.3 API	30.0	30.0	dimensionless
36	1.1.4 Specific gravity	0.9	0.9	dimensionless
37	1.1.5 Sulfur	2.6	2.0	wt%
38	1.1.6 Production volume	1000	545	bbl/d
40	**1.2 Associated gas**			
41	1.2.1 Gas composition			
43	N_2	0.0	0.0	mol%
44	CO_2	3.5	3.5	mol%
45	C_1	77.0	77.0	mol%
46	C_2	14.0	14.0	mol%
47	C_3	3.0	3.0	mol%
48	C_4	1.5	1.5	mol%
49	H_2S	1.0	1.0	mol%
50		OK		
53	1.2.2 Gas gravity	0.71	0.71	dimensionless
54	1.2.3 Gas-oil ratio (GOR)	500	500	scf/bbl
55	1.2.4 Fraction of remaining gas to reinjection	OK 100	50	%

Figure 2.1: Input data section of *'Production & Extraction'* sheet. User inputs are in column M, while defaults are kept as reference in column N.

User free cell	*Free to change*
User locked cell	*Do not change*
Default free cell	*Reference*
Default locked cell	*Reference*

Figure 2.2: Types of cells. *User Free* and *Default Free* cells can be changed, while *Locked* cells should not be changed due to possibility of compromising model functionality.

locked cells should not be changed.[1] This is typically because locked cells contain formulas that draw on other cells and therefore should not be changed. "User Free" cells are cells that allow entry of user data.

2.4 Working with OPGEE

This section explains how to work with OPGEE. Box 2.1 shows how to best use this documentation in concert with the OPGEE model itself.

2.4.1 Primary interaction

The first level of interaction with OPGEE (which this document calls "primary" interaction) consists of changing a small number of key parameters to

[1]Note: 'locked' cells are not locked via *Excel* password-protected locking mechanism, so they can be changed if desired by the user. However, this should be done with care, as the model can easily be rendered inoperable.

Box 2.1: Using OPGEE documentation and model together

OPGEE model documentation aligns with the model itself. Pointers to the model are contained in the right-hand margin of the model documentation in red, italic text. For example, a reference to the Production & Extraction sheet calculation of water specific gravity, which is calculation number 2.1.3.3 on that sheet (see Figure 2.4, Row 54), would be referred to in the right-hand margin as *Production & Extraction 2.1.3.3*

determine the energy consumption and emissions from an oil production facility. These key parameters have the following characteristics:

- They have a significant effect on the GHG emissions from an oil and gas operation;
- They vary significantly across different operations and therefore could cause variability between different fields or projects;
- They are likely to be measured or are well-understood by operators.

The list of key inputs is a relatively small list of important factors. Other factors are excluded from this list are left to process sheets.

The "User Inputs" section of the *'User Inputs & Results'* sheet is where key parameters can be changed (see Figure 2.3). The key parameters are: *User Inputs & Results 3.1 - 3.6*

Production methods Binary variables to turn on or off production methods including downhole pump, water reinjection, gas reinjection, water flooding, gas lifting, gas flooding, and steam flooding. *User Inputs & Results 3.1*

Field properties Field properties, including field location, field name, field age, field depth and reservoir pressure. *User Inputs & Results 3.2*

Fluid properties A variety of fluid properties, including API gravity of crude oil and composition of produced associated gas. *User Inputs & Results 3.3*

Production practices Diagnostic factors representing production practices or operating ratios. These include gas-to-oil ratio, water-to-oil ratio, water-injection ratio, gas lifting injection ratio, gas flooding injection ratio, steam-to-oil ratio, and fraction of required electricity generated on site. *User Inputs & Results 3.4*

Processing practices Binary variables which represent the use of heater/treaters and stabilizer columns, the ratio of gas flared to oil produced, and the ratio of gas vented to oil produced. *User Inputs & Results 3.5*

Small emissions sources An added term to account for all emissions sources that are not explicitly included in OPGEE through calculations. *User Inputs & Results 3.6*

After entry into *'User Inputs & Results'*, values for key parameters are propagated to other sheets as needed for calculations. Therefore, if a key parameter (such as API gravity) is to be changed, it **must** be changed on the front *'User Inputs & Results'* sheet so that it is changed identically in all calculations.

		User	Default	Unit
36				
37	**1 User inputs**			
38				
39	*Enter primary input parameters and choices*			
40				
41	1.1 Production methods			
42	Notes: Enter "1" where applicable and "0" where not applicable			
43				
44	1.1.1 Downhole pump	1	1	NA
45	1.1.2 Water reinjection	1	1	NA
46	1.1.3 Gas reinjection	1	1	NA
47	1.1.4 Water flooding	0	0	NA
48	1.1.5 Gas lifting	0	0	NA
49	1.1.6 Gas flooding	0	0	NA
50	1.1.7 Steam flooding	0	0	NA
51				
52	1.2. Field properties			
53	1.2.1 Field location *(Country)*	USA	USA	NA
54	1.2.2 Field name	Generic	Generic	NA
55	1.2.3 Field age	30	30	yr.
56	1.2.4 Field depth	6000	6000	ft
57	1.2.5 Reservoir pressure	500	1500	psi
58				
59	1.3 Fluid properties			
60	1.3.1 API gravity of produced crude	30	30	deg. API
61	1.3.2 Associated gas composition			

Figure 2.3: User inputs section of the *'User Inputs & Results'* sheet.

OPGEE provides fixed defaults for required input parameters; these can be replaced with user inputs where data are available. In some cases, OPGEE calculates 'smart default' values dynamically based on user inputs for other parameters. For instance, the default flaring volume is determined from NOAA data based on the specified field location [16]. These smart defaults can also be overruled by user inputs if available.

2.4.2 Secondary interaction

If more detailed data are available for a given oil production operation, and more specific estimates are desired, secondary interaction can be pursued by changing parameters on process-stage specific sheets and supplementary sheets.

It should not be necessary to change these secondary input parameters in general use of OPGEE. This is because these secondary parameters include parameters with less effect on the resulting emissions, that are not highly variable across operations, or that are less likely to be known by model users. Examples include compressor suction pressure and temperature, type of prime mover, or pump efficiency. Note that some of these parameters (e.g., pump efficiency) have significant effects on model results, but are not believed to be highly variable across fields (except in cases of especially old or poorly maintained equipment).

All secondary input parameters are free for the user to change in the input data sections of the process stage sheets. Parameters that are classified as *User Locked* (see Figure 2.2 above) should not be changed because they are either calculated from other primary inputs or derived from the *'User Inputs & Results'* sheet.

Figure 2.4 shows the input data section of the *'Production & Extraction'* sheet. Moving left to right across the screen, features of interest include:

Parameters and sub-parameters In columns A through K, the names and descriptions of parameters and calculation results are numbered in a hierarchical fashion. Each parameter or calculation result has a unique number to allow ease of reference to the model. For example, in the Produced Water group of parameters and calculations (2.1.3), the water specific gravity is calculated using the concentration of dissolved solids (2.1.3.2).

User and default columns Columns M and N include the user and default inputs for the production calculations. Column M is always used in the final calculations. Column N is included for reference, and includes default values. Before any user input is changed, all user values are equal to default values.

Free and locked cells As shown in Figure 2.2, *User Free* and *Default Free* cells are included with light tones, while *User Locked* and *Default Locked* cells are included with dark tones. For example, in Figure 2.4 the highlighted cell M40 represents the mol% of methane (C_1) in the associated gas. Because this quantity is a key input parameter and is defined on the *'User Inputs & Results'* sheet, it is marked here as *User Locked*. Therefore, if the user wishes to change the gas composition, this should be done on the *'User Inputs & Results'* sheet where gas composition is listed as *User Free*.

Units In column O, units are listed for all input parameters, variables, and calculation results (where applicable).

User and default reference Columns Q and S are spaces to record the data sources of input parameters. Where applicable, the source of the default value is listed in the *Default reference* column. If a user changes a parameter to a non-default value, they can place any desired information about the source (such as author, page, dataset, vintage, data quality, expected uncertainty, etc.) in the *User reference* column.

Notes To the right of the default reference column is the notes column (not shown, column Y). The *Notes* column contains explanatory notes or other information that may be useful to the user.

2.4.3 Checking for errors

It is possible to mistakenly enter data that are invalid, contradictory, or otherwise result in errors. In OPGEE, errors are checked at the bottom of the *'User Inputs & Results'* sheet. Before reporting results from an OPGEE calculation, the user should check that no errors appear in the error check section.

User Inputs & Results 7.1 - 7.2

A summary indicator for model errors is *'User Inputs & Results'* reported as the 'Overall error check.' An error found in the overall error check here can be traced to a particular sheet and cell by examining the 'Specific error checks.' Specific error checks can be debugged by moving to the sheet and cell

User Inputs & Results 7.1

User Inputs & Results 7.2.1 - 7.2.24

Box 2.2: Hints for using OPGEE without errors

1. Do not change formulas in *User locked* or *Default locked* cells, as these can result in mis-calculation;
2. Always check error reports in *'User Inputs & Results'* section 7.1 and 7.2 for errors before considering results final;
3. Use care to collect physically realistic and consistent data where default values will be overwritten (e.g., if depth of field is greatly increased, operating pressure will often increase as well);
4. To ensure reproducibility of results, document any sources for user inputs in the 'User Reference' column;
5. Save individual field assessments as separate sheets to prevent incorrect propagation of changed cells.

in question and tracing any logical or inputs errors that have flagged that error check. Common sources of errors include logical errors in pathway selection (e.g., more than one mutually exclusive technology selected) and input errors (e.g., gas composition sums to more than 100 mol%).

Hints for using OPGEE without errors are given in Box 2.2.

2.4.4 Results

After the user enters data, OPGEE computes the resulting GHG emissions from that project. Emissions results are presented in tabular form in gCO_2 equivalent GHG emissions per MJ LHV crude oil delivered to the refinery gate.[2] Emissions are broken down by stage (generally) or by type, with fugitive emissions for all process stages summed together for convenient interpretation as 'VFF' emissions. Emissions are plotted in graphical form as well, with space for up to 5 comparative assessments. Total energy consumed per unit of energy delivered to the refinery gate is also presented in tabular and graphical form. These tabular and graphical results are illustrated in Figures 2.5 and 2.6.

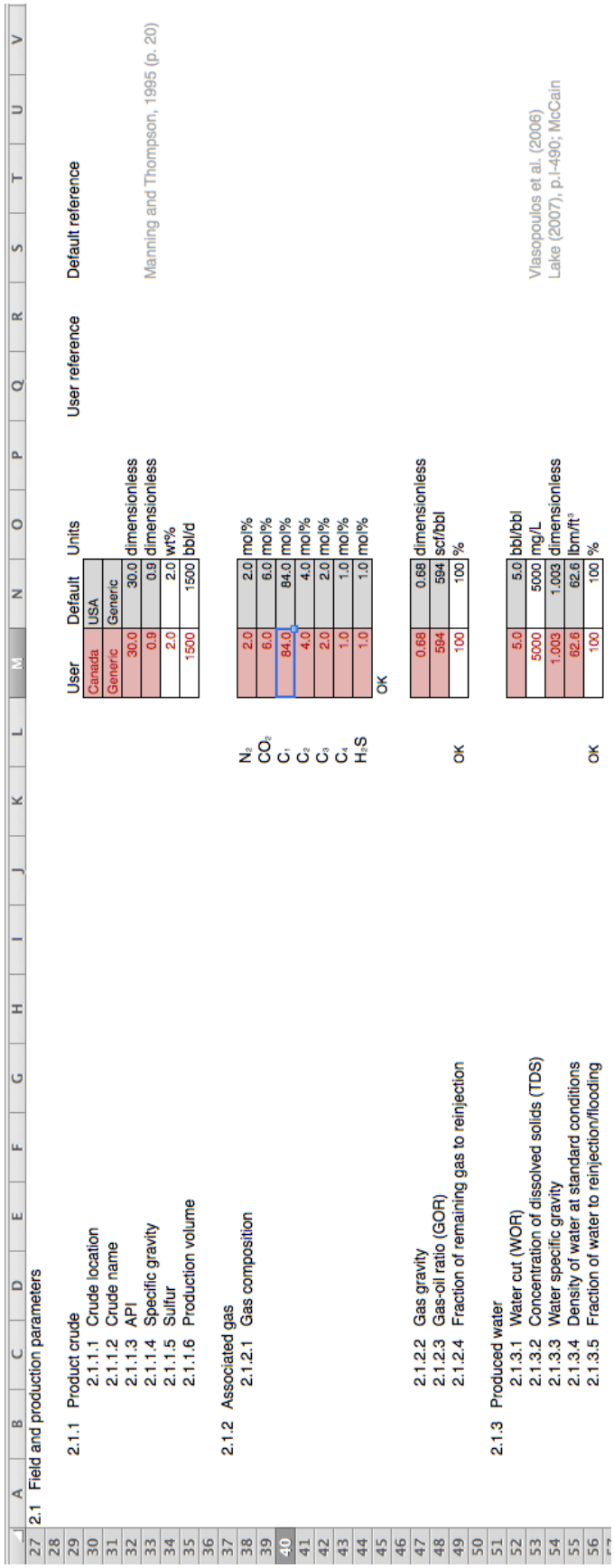
User Inputs & Results Table 1.1

User Inputs & Results Figure 1.1

User Inputs & Results Table 1.2, Figure 1.2

Results from multiple runs can be copied and pasted to the cells to the right of the current active column. This allows multiple results to be easily compared.

[2]The heating value basis of the denominator crude oil can be changed so that emissions are calculated per MJ HHV of refinery input. This can be changed on the *'Fuel Specs'* sheet. See discussion below in Section 6.4.



		User	Default	Units	User reference	Default reference
2.1	Field and production parameters					
2.1.1	Product crude	Canada	USA			
2.1.1.1	Crude location	Generic	Generic			
2.1.1.2	Crude name		30.0	dimensionless		
2.1.1.3	API	30.0	0.9	dimensionless		Manning and Thompson, 1995 (p. 20)
2.1.1.4	Specific gravity	0.9	2.0	wt%		
2.1.1.5	Sulfur	2.0	1500	bbl/d		
2.1.1.6	Production volume	1500				
2.1.2	Associated gas					
2.1.2.1	Gas composition					
	N_2	2.0	2.0	mol%		
	CO_2	6.0	6.0	mol%		
	C_1	84.0	84.0	mol%		
	C_2	4.0	4.0	mol%		
	C_3	2.0	2.0	mol%		
	C_4	1.0	1.0	mol%		
	H_2S	1.0	1.0	mol%		
		OK				
2.1.2.2	Gas gravity	0.68	0.68	dimensionless		
2.1.2.3	Gas-oil ratio (GOR)	594	594	scf/bbl		
2.1.2.4	Fraction of remaining gas to reinjection	100	100	%		
		OK				
2.1.3	Produced water					
2.1.3.1	Water cut (WOR)	5.0	5.0	bbl/bbl		
2.1.3.2	Concentration of dissolved solids (TDS)	5000	5000	mg/L		Vlasopoulos et al. (2006)
2.1.3.3	Water specific gravity	1.003	1.003	dimensionless		Lake (2007), p.I-490; McCain
2.1.3.4	Density of water at standard conditions	62.6	62.6	lbm/ft^3		
2.1.3.5	Fraction of water to reinjection/flooding	100	100	%		
		OK				

Figure 2.4: Input data section of *'Production & Extraction'* sheet.

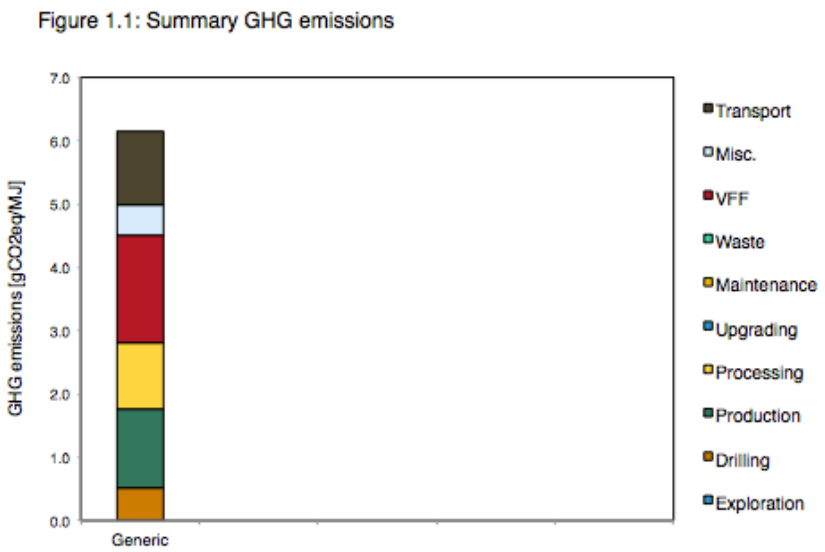


Figure 2.5: Graphical results for a 'Generic' crude oil. *'User Inputs & Results'* Figure 1.1.

Table 1.1: Summary GHG emissions

GHG emissions [gCO2eq/MJ]					
	Generic				
Exploration	0.0				
Drilling	0.5				
Production	1.3				
Processing	1.1				
Upgrading	0.0				
Maintenance	0.0				
Waste	0.0				
VFF	1.7				
Misc.	0.5				
Transport	1.2				

Notes: Copy highlighted column and paste 'as numbers' to generate a record

Figure 2.6: Tabular results for a 'Generic' crude oil. *'User Inputs & Results'* Table 1.1.

Part II

Technical documentation

3 Process stage sheets

This section explains the main assumptions and calculations for each process stage sheet. Items discussed include user assumptions and choices, process calculation assumptions, calculations of input parameters, and calculations of intermediate outputs.

3.1 Exploration emissions

3.1.1 Introduction to petroleum exploration

Emissions from petroleum exploration occur during clearing of land for seismic surveys, operation of seismic survey equipment, drilling of exploratory wells, and from fugitive emissions during drilling operations. Emissions also occur offsite due to other ancillary services consumed during drilling (e.g., computing energy consumed during seismic data processing). A complete list of emissions sources, along with their categorization and estimated magnitude, is shown in Table C.1.

3.1.2 Calculations for petroleum exploration

Because petroleum exploration emissions only occur at the outset of production, they are likely to be very small when amortized over the producing life of an oil field. For this reason, emissions from exploration are considered below the significance cutoff in the OPGEE v1.0.

3.1.3 Defaults for petroleum exploration

Because exploration activities are believed to be below the significance cutoff, modeled exploration emissions default to 0 gCO_2/MJ. Therefore, any exploration emissions are assumed to be part of the small emissions sources term.

User Inputs & Results 3.6

3.2 Drilling & development

3.2.1 Introduction to drilling & development

Drilling and development operations result in a variety of emissions. Well drilling and installation of production equipment results in on-site energy use (e.g., for rigs and other construction equipment) as well as indirect offsite energy use (e.g., embodied energy consumed to manufacture well casing). Drilling and development also results in land use impacts, which can release biogenic carbon from disturbed ecosystems [77]. In addition, fugitive emissions can occur during the drilling process. A list of emissions sources, along with their categorization and estimated magnitude, is shown in Table C.2.

3.2.2 Calculations for drilling & development

Two aspects of field drilling and development are modeled in OPGEE v1.0: drilling energy consumption and land use impacts. Any other emissions from drilling and development are not explicitly modeled and therefore would be accounted for in the small sources term. The parameters and variables used in the drilling and development model equations are listed in Table 3.1.

User Inputs & Results 3.6

3.2.2.1 Emissions from drilling

Drilling oil wells consumes fuel. This fuel is consumed on site in prime movers (generally diesel engines) for a variety of purposes: to power mud pumps; apply torque to drill string; pull drill string; raise, lower and retrieve subsurface monitoring equipment; and pump cement. The amount of fuel consumed per unit of depth drilled increases as a well gets deeper, due to slower drilling progress with depth.

Relationships for these functions are from Brandt [78]. Data from Canadian drilling operations are collected for the years 2000, 2001, 2002, and 2005 [79–81]. True drilling depth (not vertical depth) is related to amount of fuel consumed per well. An exponential relationship is found between drilling depth and fuel use (see Figure 3.1). High and low energy consumption curves are fit to these data:

Drilling & Development 1.2.2

$$e_{DR} = a_{DR} \exp\left(b_{DR} h_W\right) \qquad \text{[mmBtu/1000 ft]} \tag{3.1}$$

where e_{DR} = depth-specific drill rig energy intensity [mmBtu/1000 ft]; a_{DR} = drill rig energy intensity scaling constant [mmBtu/1000 ft]; b_{DR} =drill rig energy intensity growth constant [1/1000 ft]; and h_W = true well depth (not vertical depth) [1000 ft]. When fitting this equation to high and low-intensity drilling data, fits are of moderate predictive ability (R^2 = 0.708 for low intensity, 0.589 for high intensity).

Drilling energy consumption must be amortized over the producing life of a well. Also, drilling and development energy must account for drilling of

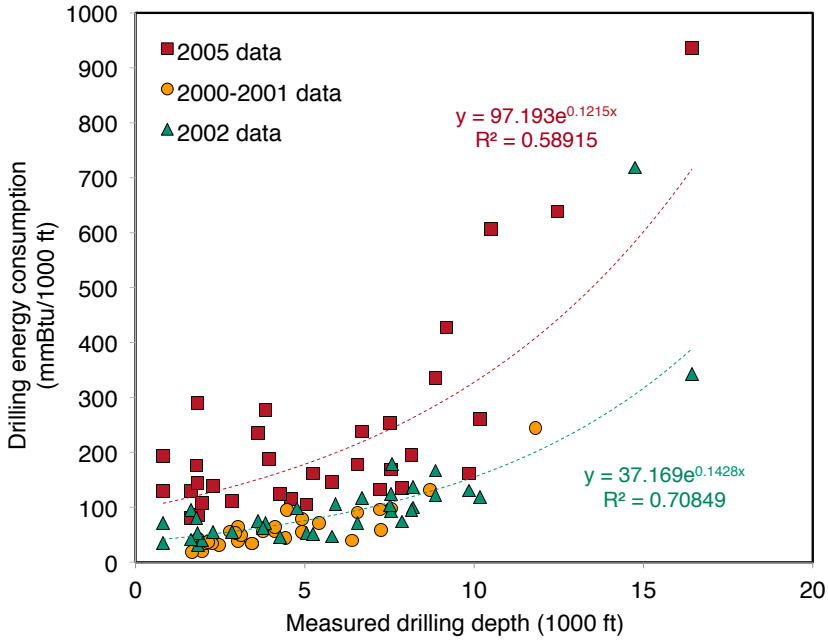


Figure 3.1: Drilling energy intensity as a function of well depth as measured for Canadian drilling operations.

water injection wells. The lifetime productivity of wells varies by orders of magnitude, depending on the quality of the oil reservoir and its size. In order to obtain a central estimate for the productivity of a well, we use historical data from California.

California reports the number of producing and shut-in wells, with ≈ 100,000 wells counted in recent years [77]. However, these datasets do not include:

- Wells that are fully abandoned and therefore not classed as "shut-in",
- Wells that were drilled and plugged in abandoned fields,
- Wells that were drilled before 1915, when reporting began.

To address these shortcomings, wells drilled on a yearly basis were compiled from the California Department of Oil, Gas, and Geothermal Resources (DOGGR) annual reports [82]. Production and injection wells drilled per year are compiled from 1919-2005, while exploration wells drilled per year are compiled from 1926 to 2005 (exploratory wells were not reported before 1926). Total exploratory and production/injection drilling activity over these years was equal to 188,508 wells. Due to missing wells (early exploratory wells, all wells prior to 1919, other missing wells) we assume total wells drilled = 200,000. Cumulative production in the entire state of California was ≈ 25.99 Gbbl at the end of 2005. Therefore, average oil produced per well drilled was ≈ 130,000 bbl/well.

Drilling & Development 1.3.1

The energy intensity of drilling per unit of energy produced is therefore calculated as follows:

Drilling & Development 1.4

$$ei_{DR} = \frac{e_{DR} h_W}{Q_{o,tot} LHV_o} \qquad \text{[mmBtu/mmBtu]} \tag{3.2}$$

where ei_{DR} = energy intensity of drilling [mmBtu/1000 ft]; h_W = average well depth [1000 ft]; $Q_{o,tot}$ = total lifetime productivity per well drilled [bbl oil/well]; and LHV_o = lower heating value of the crude produced [mmBtu LHV/bbl].

The energy intensity of drilling tends to be small when amortized over total well productivity, with default values on order 10^{-4} to 10^{-3} mmBtu/mmBtu.

3.2.2.2 *Emissions from land use impacts*

Land use impacts during drilling and field development are included in OPGEE for three categories: soil carbon that is oxidized upon disturbance of land, biomass carbon that is oxidized biomass disturbance, and emissions from foregone sequestration, due to the fact that biomass carbon sequestration is slowed on cleared land. For each of these impacts, emissions estimates from Yeh et al. [77] are included.

Drilling & Development 2.1 - 2.4

In order to estimate land use GHG emissions, three settings are required. First, the crude production method must be chosen. The options for crude production method include conventional production via wellbore (primary, secondary, and tertiary recovery of conventional and heavy hydrocarbons, including in situ recovery of bitumen) and mining-based production of bitumen.

Drilling & Development 2.1.3

Next, the carbon richness of the ecosystem must be specified. The options include low, moderate, and high carbon richness. The low carbon richness estimates are derived from California production in the semi-arid to arid central valley of California [77]. The high carbon richness estimates are derived from forested regions in Alberta (e.g., rocky mountain foothills) [77]. Moderate carbon richness is considered a mixed ecosystem with carbon richness between these two types of ecosystems.

Drilling & Development 2.1.4

Lastly, the intensity of field development must be specified. High intensity field development corresponds to high fractional disturbance, such as in a field drilled on tight spacing. Low intensity field development corresponds to a sparsely developed field with little fractional disturbance. Moderate field development occurs between these two extremes. Work by Yeh et al. [77] can be consulted for satellite images of low and high field development intensity.

Drilling & Development 2.1.5

The emissions associated with each choice are shown in Table 3.2 in units of gCO_2eq GHGs per MJ of crude oil produced. Land use emissions from oil sands operations are tracked separately on the *'Bitumen Extraction & Upgrading'* sheet (see Section 3.8).

Emissions Factors Table 1.4

3.2.3 Defaults for drilling & development

Default values for drilling & development calculations are shown in Tables 3.1 and 3.2.

Table 3.2: Default land use GHG emissions from field drilling and development in OPGEE for conventional oil operations [g CO_2 eq./MJ of crude oil produced]. Data from Yeh et al. (2010).

	Low carbon stock (semi-arid grasslands)			Moderate carbon stock (mixed)			High carbon stock (forested)		
	Low int.	Med. int.	High int.	Low int.	Med. int.	High int.	Low int.	Med. int.	High int.
Soil carbon	0.03	0.13	0.35	0.10	0.35	1.50	0.16	0.57	2.65
Biomass	0.00	0.00	0.00	0.01	0.09	0.33	0.02	0.17	0.65
Foregone seq.	0.00	0.00	0.00	0.02	0.03	0.05	0.03	0.05	0.09

Table 3.1: Default inputs for drilling calculations.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
a_{DR}	Drill rig energy consumption constant	-	37.169	37.169 - 97.193	[mmBtu/1000 ft]	[78]	a
b_{DR}	Drill rig energy consumption increase rate	-	0.1428	0.1215 - 0.1428	[1/1000 ft]	[78]	b
h_W	Well depth (true drilling depth)	-	$=h$	0.5 - 25	[1000 ft]	-	c
Q_{ot}	Total cumulative production per well over life of well	-	130,000	Unknown	[bbl/well]	[82, 83]	d
LHV	Lower heating value of crude oil	-	5.51	5.15 - 6.18	[mmBtu/bbl]	[84]	e

[a] Low and high drilling efficiency constants found from fitting data. Default set to low intensity.
[b] Exponential increase with drilling depth. Low intensity drilling actually has slightly higher growth rate.
[c] Default well depth chosen to be depth of field h. Range of field depths is large in practice.
[d] Cumulative production per well in California equals 130,000 bbl/well to the end of 2005.
[e] Higher heating value of crude depends on density and composition.

3.3 Production & extraction

3.3.1 Introduction to production & extraction

The production and extraction process transports reservoir fluids from the subsurface reservoir to the surface. Emissions from crude oil production and extraction mainly occur from fuel combustion for lifting and injection drivers, with other smaller sources such as fugitive emissions from wellbores.

The reservoir is the source of fluids for the production system. It can also furnish energy for production. In many cases, the reservoir is unable to furnish sufficient energy to produce fluids to the surface at economic rates throughout the life of the reservoir. When this occurs, artificial lift equipment is used to enhance production rates by adding energy to the fluids. Energy can be supplied to the fluids through a subsurface pump (e.g., downhole pump). Or, producers can reduce the back pressure on the reservoir with surface compression equipment that allows lower wellhead pressure. Also, producers can inject gas into the production string to reduce the flowing gradient of the fluid (i.e., gas lift) [44, p. 1].

In addition to artificial lifting, water can be injected into the reservoir to support reservoir pressure and increase oil recovery. Recovery is increased by maintaining reservoir pressure and by physically displacing oil with water from near injection wellbores to production wellbores [59, p. 1]. Tertiary recovery technologies (also known as enhanced oil recovery [EOR]) include gas flooding and steam injection.

Most common artificial lifting and improved oil recovery techniques are included in OPGEE. These include: downhole pump, gas lift, water flooding, gas flooding, and steam injection. In the *'User Inputs & Results'* sheet the user is prompted to choose a combination of techniques applicable to the modeled operation. Some techniques are not built in the current version of OPGEE, including CO_2 flooding and hydraulic fracturing (also known as "fracking"). These modules will be added in the future.

A complete list of emissions sources from production, along with their estimated magnitude, is shown in Table C.3. A list of all of the equation parameters and their default values (if applicable) and sources is included in Table 3.4.

3.3.2 Calculations for production and extraction

Energy for lifting is required to overcome the pressure traverse, i.e., the pressure drop between the subsurface reservoir and the surface wellhead. The pressure traverse arises due to two factors: (i) flow against gravity, and (ii) frictional losses. The pressure required for lifting is calculated by adding the wellhead pressure to the pressure traverse and subtracting the wellbore pressure. The artificial lifting methods that can be chosen in OPGEE are: (i) downhole pump, and (ii) gas lift. The pressure required for lifting is equal to the

discharge pressure of the downhole pump. The power required to generate the required discharge pressure depends on the discharge flow rate and pump efficiency. Finally the energy required to drive the pump is calculated based on the power requirement (expressed as brake horsepower).

The calculation of the energy required in water injection- and gas injection-based enhanced oil recovery uses the user inputs for injection volume and discharge pressure. Smart defaults are in place to help assign the discharge pressure taking into account the well depth and frictional losses.

The energy required for steam flooding requires rigorous modeling of steam generation. An additional complexity is caused by the modeling of electricity co-generation. This is explained in Section 4.2.

In the case of gas lift, if the user enters the volume of gas injected and the discharge pressure, OPGEE will compute the compression energy. However, OPGEE is not sensitive to changes in the gas lift, i.e. the dynamics between the volume of gas lift and the lifting head are not considered. The calculation of these dynamics is beyond the scope of a linear GHG estimator. This requires a two phase flow model, which is not included in OPGEE v1.0.

Default values for production and extraction calculations are shown in Tables 3.4.

3.3.2.1 *Oil specific gravity*

The specific gravity of crude oil is usually reported as API gravity, measured at 60 °F. The API gravity is related to the specific gravity γ_o by:

Production & Extraction 2.1.1.4

$$^{\circ}\text{API} = \frac{141.5}{\gamma_o} - 131.5 \qquad [\text{-}] \tag{3.3}$$

where API gravity and γ_o are dimensionless measures. The specific gravity is the ratio of the density of the liquid to the density of water at 60 °F [73, p. 478].

3.3.2.2 *Gas specific gravity*

The specific gravity of associated gas is calculated using air density at standard conditions with [85, p. 10]:

Production & Extraction 2.1.2.2

$$\gamma_g = \frac{\rho_{gsc}}{\rho_{asc}} \qquad [\text{-}] \tag{3.4}$$

where ρ_{gsc} = gas density at standard conditions [lbm/ft^3]; and ρ_{asc} = air density at standard conditions [lbm/ft^3]. Standard conditions refers to the temperature and pressure required to specify 1.0 scf (60 °F and 14.7 psia) [2, p. 35]. Accordingly, the gas density at standard conditions is calculated using:

$$\rho_{gsc} = \frac{p_b \text{MW}_g}{\text{R}T_b} \qquad \left[\frac{\text{lbm}}{\text{ft}^3}\right] \tag{3.5}$$

where MW_g = molecular weight of the associated gas mixture [lbm/lbmol]; p_b = base pressure [psia]; and T_b = base temperature [°R]; R = gas constant [ft^3-psia/lbmol-°R]. The molecular weight is calculated from the molecular weights and molar fractions of the gas constituents.

3.3.2.3 *Water specific gravity*

The specific gravity of produced water at standard conditions can be estimated with [45, p. I-481]:

Production & Extraction 2.1.3.3

$$\gamma_w = 1 + C_{sd} 0.695 \times 10^{-6} \qquad [-] \tag{3.6}$$

where C_{sd} = concentration of dissolved solids (also known as TDS) [mg/L]. The constant 0.695×10^{-6} has units of [L/mg].

3.3.2.4 *Gas compression ratio*

The total gas compression ratio is calculated using:

Production & Extraction 2.4.2.3

$$R_C = \frac{p_d}{p_s} \qquad [-] \tag{3.7}$$

where P_d = discharge pressure [psia]; and P_s = suction pressure [psia].

If ratio R_C is more than 5 to 1, two or more compressor stages will be required [73, p. 295]. The compression of gas generates significant amount of heat, but compressors can only handle a limited temperature change. Multiple stage compressors allow cooling between stages making compression less adiabatic and more isothermal. The same compression ratio is ideally used for each stage. Each stage has the same ratio if the compression ratio per stage is the Nth root of the total compression ratio, when N = number of stages:

Production & Extraction 2.1.2.3

$$\text{If } \frac{p_d}{p_s} < 5, \text{ then } R_C = \frac{p_d}{p_s}, \text{ otherwise if } \left(\frac{p_d}{p_s}\right)^{\frac{1}{2}} < 5, \text{ then } R_C = \left(\frac{p_d}{p_s}\right)^{\frac{1}{2}}, \ldots \tag{3.8}$$

where p_d = discharge pressure [psia]; and p_s = suction pressure [psia].

The number of stages is determined from the calculation of the compression ratio, as shown in eq. (3.8). OPGEE allows a maximum of 3 stages of compression.

3.3.2.5 *Gas compressor suction temperature*

When multiple stage compressors are used the gas must be cooled between stages to reduce the adiabatic work of compression. The discharge temperature of the compressor is calculated as [57, p. 105]:

$$\frac{T_d}{T_s} = \left(\frac{p_d}{p_s}\right)^{\left[\frac{\left(C_{p/v}-1\right)}{C_{p/v}}\right]} \qquad [-] \tag{3.9}$$

where T_d = discharge temperature [°R]; T_s = suction temperature [°R]; and $C_{p/v}$ = ratio of specific heats at suction conditions. Ideal gas behavior (i.e., gas compressibility factor (Z)= 1) is assumed.

The suction temperature of the subsequent compressor is estimated assuming 80% interstage cooling (imperfect cooling) so that:

Production & Extraction 2.4.2.6

$$T_{s2} = \lambda_{\Delta T} \left(T_d - T_s\right) + T_s \qquad [^\circ\mathrm{R}] \tag{3.10}$$

where T_{s2} = suction temperature of stage 2 compressor [°R]; and $\lambda_{\Delta T}$ = fraction of temperature increase remaining after cooling, 0.2 [fraction]. The default of ≈80% interstage cooling is taken from an example of imperfect cooling in [86, Table 7].

3.3.2.6 *Well pressure traverse*

The pressure traverse is the total pressure required to lift the crude oil mixture against gravity and overcome friction and kinetic losses. This is equal to the pressure drop along the well tubing from the wellbore to the wellhead which has two main components: (i) the elevation component, which is the pressure drop due to gravity; and (ii) the friction component, which is the pressure drop due to liquid contact with the inner walls of the well tubing.

The first step in the estimation of the pressure traverse is the calculation of the total head as:

Production & Extraction 3.1.1

$$h_{tot} = h_{el} + h_f \qquad [\mathrm{ft}] \tag{3.11}$$

where h_{tot} = total head [ft]; h_{el} = well depth [ft]; and h_f = friction head [ft]. The friction head is calculated using the Darcy formula [73, p. 447]:

Production & Extraction 3.1.1.2

$$h_f = \frac{f h_{el} v_{l,W}^2}{2 D_P g_c} \qquad [\mathrm{ft}] \tag{3.12}$$

where f = Moody friction factor [-]; h_{el} = well depth [ft]; $v_{l,W}$ = pipeline flow velocity [ft/s]; D_P = pipeline diameter [ft]; and g_c = gravitational constant, 32.2 [lbm-ft/lbf-s^2].

A Moody friction factor chart is shown in Figure 3.2 [1]. The friction factor can range from 0 to 1.0. In laminar flow f varies with Reynold's Number (NRe). In turbulent flow f varies with NRe and the roughness of the pipeline [73, p. 481]. Table 3.3 shows the NRe ranges of different flow patterns. The calculation of the friction factor in turbulent flow requires an iterative calculation. The friction component of the pressure traverse is generally not significant except for some wells with very high flow rate. As such, a conservative high Moody friction factor of 0.1 is assumed as default to avoid iterative calculations and improve the stability of OPGEE.

The pipeline flow velocity is calculated as:

$$v_{l,W} = \frac{Q_{l,W}}{A_P} \qquad [\mathrm{ft/s}] \tag{3.13}$$

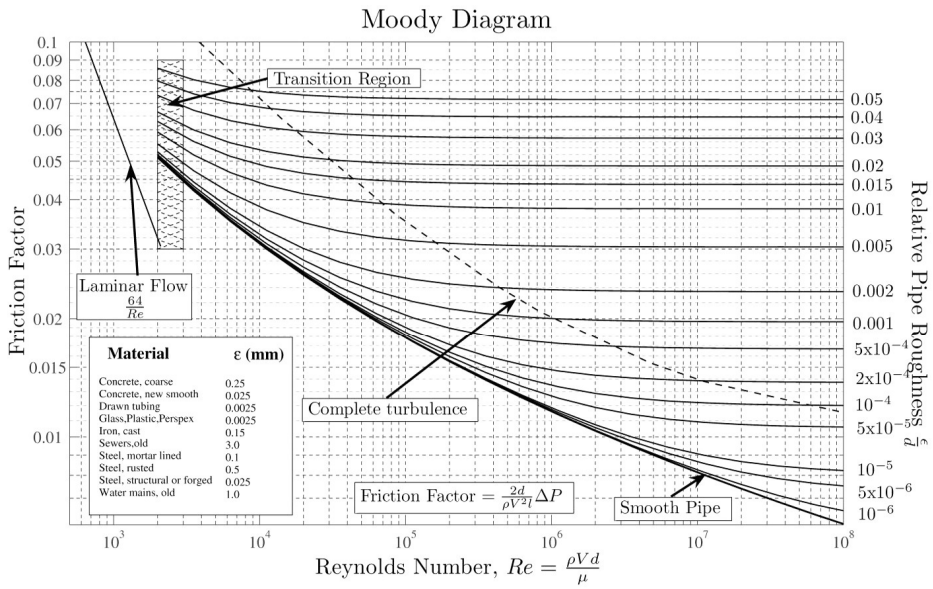


Figure 3.2: Moody friction factor chart [1].

Table 3.3: Reynold's Number ranges of different flow patterns. Data from McAllister (2009).

Flow pattern	NRe [-]
Laminar flow	NRe<2000
Transition flow	2000≤NRe≤4000
Turbulent flow	NRe> 4000

where $Q_{l,W}$ = wellbore flow rate or liquid production per well [ft^3/s]; and A_P = the cross sectional area of the pipe [ft^2]. The wellbore flow rate is calculated as:

Production & Extraction 3.1.1.2

$$Q_{l,W} = \frac{Q_l}{N_W} \qquad [\text{ft}^3/\text{s}] \tag{3.14}$$

where Q_l = total rate of liquid production [ft^3/s]; and N_W = number of producing wells. The total rate of liquid production is calculated as:

Production & Extraction 3.1.3.1

$$Q_l = Q_o(1 + \text{WOR}) \qquad [\text{ft}^3/\text{s}] \tag{3.15}$$

where Q_o = total rate of oil production [bbl/d]; WOR= water-to-oil ratio [bbl/bbl]. The total rate of liquid production is converted from [bbl/d] to [ft^3/s].

A column of fresh water at 60 °F exerts a gradient of ≈0.43 psi/ft [59, p. 25]. For brackish water, or to account for temperature, this gradient is multiplied by the specific gravity of the mixture at a given temperature. Accordingly the pressure traverse is estimated using the total head as [73, Table 1, p. 455]:

Production & Extraction 3.1.1.1

$$p_{trav,tot} = 0.43 h_{tot} \gamma_l \qquad \text{[psi]} \tag{3.16}$$

where $p_{trav,tot}$ = total pressure traverse [psi]; 0.43 = fresh water gradient at 60 °F [psi/ft]; $h_{tav,tot}$ = total head [ft]; and γ_l = the specific gravity of the crude oil mixture [-], calculated as:

$$\gamma_l = \gamma_o \lambda_o + \gamma_w \lambda_w \qquad \text{[-]} \tag{3.17}$$

where γ_o = the specific gravity of oil [-]; γ_w = the specific gravity of water [-]; λ_o = fraction of oil [fraction]; and λ_w = fraction of water [fraction]. The fraction of oil is calculated as:

$$\lambda_o = \frac{Q_o}{Q_o(1 + \text{WOR})} \qquad \text{[-]} \tag{3.18}$$

The elevation component of the pressure traverse is estimated using a linear one phase flow model where the gas-to-liquid ratio is equal to zero (GLR= 0) and the temperature and pressure effects are ignored. Figure 3.3 shows an example of a linear pressure-traverse curve for a particular production rate and fluid properties. The slope of the curve is the relative density of the flowing oil-water mixture. For GLR>0 the relationship becomes non-linear and the pressure traverse becomes less sensitive to changes in the well depth with increasing GLR [44, Fig 1.12]. However, the generation of a non-linear relationship requires the application of the multi-phase flow correlations which requires an iterative, trial-and-error solution to account for the changes in flow parameters as a function of pressure. Due to the complexity of this approach, this is not implemented in the OPGEE v1.0.

3.3.2.7 Pressure for lifting

The second step after estimating pressure traverse is the calculation of the pressure for lifting which is the pressure required by artificial means (e.g., pump) to lift the oil-water mixture to the surface at the desired wellhead pressure. The pressure for lifting is calculated as:

Production & Extraction 3.1.2

$$p_{lift} = (p_{trav,tot} + p_{wh}) - p_{wf} \qquad \text{[psi]} \tag{3.19}$$

where p_{lift} = pressure for lifting [psi]; $p_{tav,tot}$ = total pressure traverse [psi]; p_{wh} = wellhead pressure [psi]; and p_{wf} = bottomhole pressure [psi]. The wellbore pressure is calculated from the average reservoir pressure by subtracting the pressure drawdown. The pressure drawdown is the difference between the reservior pressure and the bottomhole pressure. This pressure drawdown causes the flow of reservoir fluids into the well and has the greatest impact on the production rate of a given well [85, p. 23].

$$\text{PI} = \frac{Q_{l_W}}{(p_{res} - p_{wf})} \qquad \left[\frac{\text{bbl oil}}{\text{psi-d}}\right] \tag{3.20}$$

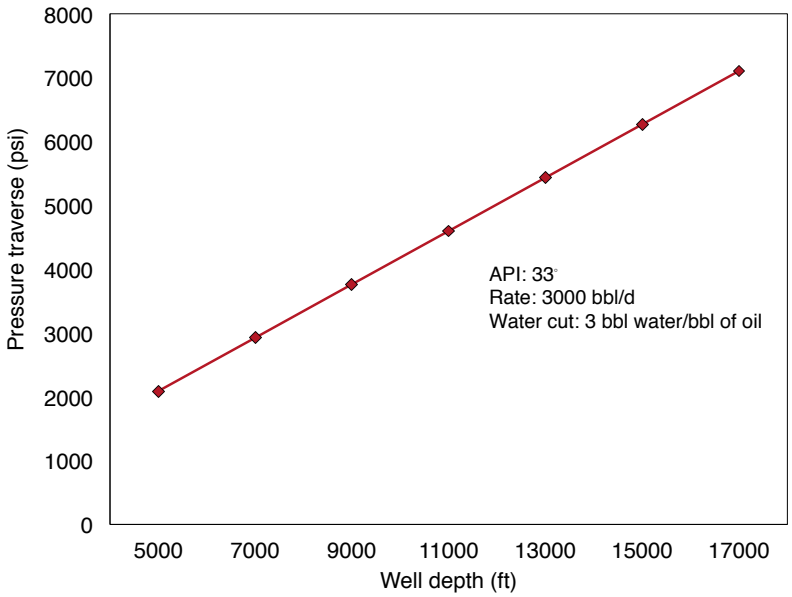


Figure 3.3: An example of a linear pressure traverse curve (GLR= 0).

where PI = well productivity index [bbl oil/psi-d]; Q_{l_W} = liquid production per well [bbl oil/d]; p_{res} = average reservior pressure [psi]; and p_{wf} = wellbore pressure [psi]. The increase in production requires an increase in pressure drawdown at a constant productivity index. In OPGEE a default productivity index of 1.0 [bbl oil/psi-d] is assumed to calculate the pressure drawdown. The user has to control the inputs to satisfy the condition of $p_{wf} \geq 0$.

The pressure for lifting can either be applied by a downhole pump or by gas injection into the production string. The latter technique is known as gas lift. In some wells both a downhole pump and gas lift is used where the injected gas reduces the flowing gradient of the fluid.

3.3.2.8 Pump brake horsepower

The input horsepower to a pump is stated in terms of brake horsepower (BHP). The input is greater than the output because of pump efficiency. The brake horsepower is calculated using the pump discharge flow rate and pressure as [59, p. 27]:

Production & Extraction 3.1.3

$$\mathrm{BHP}_P = \frac{1.701 \times 10^{-5} Q_d p_d}{\eta_P} \qquad [\mathrm{hp}]$$

This is broken down to:

$$\mathrm{BHP}_P\,[\mathrm{hp}] = \frac{\frac{1[\mathrm{hp}]}{1714[\text{gpm-psi}]} \frac{42\left[\frac{\mathrm{gal}}{\mathrm{bbl}}\right]}{24\left[\frac{\mathrm{hr}}{\mathrm{d}}\right]60\left[\frac{\mathrm{min}}{\mathrm{hr}}\right]} Q_d \left[\frac{\mathrm{bbl}}{\mathrm{d}}\right] p_d[\mathrm{psi}]}{\eta_P} \tag{3.21}$$

where BHP_P = brake horsepower [hp]; Q_d = pump discharge rate [bbl/d]; p_d = pump discharge pressure [psi]; and η_P = pump efficiency [%]. The term 1714 is a dimensionless factor that converts between [hp] and [gpm-psi]. In the case of a downhole pump the pump discharge pressure is equal to the pressure for lifting as calculated in eq. (3.19).

3.3.2.9 Compressor brake horsepower

In determining compressor horsepower, the conventional compressor equation apply. For multi-stage compressors, horsepower calculations are made for each stage and summed to determine the required driver size. For assumed reciprocating compressors, the ideal isentropic horsepower is calculated using [57, p. 105]:

Production & Extraction 3.3.1-3.3.3

$$-W_N = \left\{ \frac{C_{p/v}}{(C_{p/v} - 1)} \right\} \left(3.027 \cdot \frac{14.7}{520} \right) T_s \left\{ \left(\frac{p_d}{p_s} \right)^{\frac{(C_{p/v}-1)}{C_{p/v}}} - 1 \right\} \qquad \left[\frac{\text{hp-d}}{\text{MMscf}} \right] \tag{3.22}$$

where W_N = adiabatic work of compression of Nth stage [hp-d/MMscf] (-W denotes work output); $C_{p/v}$ = ratio of specific heats [-]; T_s = suction temperature [°R]; p_s = suction pressure [psia]; and p_d = discharge pressure [psia]. The constant 3.027 has a unit of [hp-d/MMscf-psia]. The base temperature and pressure is 14.7 [psia] and 520 [°R], respectively. Ideal gas behavior is assumed (i.e., $Z = 1$).

The total work of compression of the multiple stage compressor is multiplied by the compressor discharge rate and divided by the compressor efficiency to calculate the brake horsepower requirement as:

Production & Extraction 3.3.6

$$BHP_C = \sum_{N=1}^{3} \frac{W_N Q_d}{\eta_C} \qquad [\text{hp}] \tag{3.23}$$

where Q_d = compressor discharge rate [MMscf/d]; and η_C = compressor efficiency [fraction].

3.3.2.10 Driver fuel consumption

The total brake horsepower requirement (BHP) is used to determine the driver size. A database of drivers of different types and sizes (natural gas engine, diesel engine, electric motor, etc.) is built in the *'Drivers'* supplementary sheet using technical sheets of engine and motor manufacturers such as Caterpillar and General Electric [87, 88]. Natural gas fueled drivers, for example, range from 95 hp engine to 20,500 hp turbine. The appropriate driver is retrieved from a database based on the chosen driver type and the required driver size. Finally the fuel consumption of the component (pump, compressor, etc.) is calculated as:

Production & Extraction 3.3.7

$$E_j = \mathrm{BHP}_j \cdot E_D \cdot \frac{24}{10^6} \qquad \left[\frac{\mathrm{MMBtu}}{\mathrm{d}}\right] \tag{3.24}$$

where E_j = component fuel consumption [MMBtu/d]; and E_D = driver fuel consumption [Btu/hp-hr]. The type of fuel consumed (i.e. natural gas, diesel, etc.) is determined by the chosen type of driver.

The driver fuel consumption is required for the calculation of energy consumption of various production components. This includes sucker-rod pumps, electric submersible pumps, water injection pumps, and gas compressors.

3.3.3 Production and extraction defaults

Default values for production and extraction equations are shown in Table 3.4. The data basis for smart defaults for production and extraction modeling are described below.

Table 3.4: Default inputs for production and extraction.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
°API	API gravity	(3.3)	-	-	[-]	[50, p. 47]	
A_P	Pipeline cross sectional area	-	$\pi\left(\frac{D_P}{2}\right)^2$	-	[ft^2]		
BHP_P	Pump brakehorse power	(3.21)	-	-	[hp]	[59, p. 27]	
BHP_C	Compressor brakehorse power	(3.23)	-	-	[hp]		
BHP_j	Component j brakehorse power	-	-	-	[hp]		
C_{sd}	Concentration of dissolved solids	-	5000	-	[mg/L]	[89]	
$C_{p/v}$	Ratio of specific heats	-	1.28	1.16-1.40	[-]	[73, p. 320]	a
D_P	Well diameter	-	2.78	1.04-4.50	[in]	[44, p. 121]	
η_P	Pump efficiency	-	65%	70%	[-]	[59, p. 27]	b
η_C	Compressor efficiency	-	70%	75-85%	[-]	[57, p. 105]	c
E_j	Fuel consumption of component j	(3.24)	-	-	[MMBtu/d]		
E_D	Driver fuel consumption	-	var.	Section 4.4	[Btu/hp-hr]		
f	Friction factor	-	0.1	$\leq$0.1	[-]		d
γ_o	Oil specific gravity	-	0.84	0.8-1.05	[-]	[84]	e
γ_g	Gas specific gravity	(3.4)	-	-	[-]	[85, p. 10]	
γ_w	Water specific gravity	(3.6)	-	-	[-]	[45, p. I-481]	
γ_l	Liquid mixture specific gravity	(3.17)	-	-	[-]	[85]	
g_c	Gravitational constant	-	32.2	-	[lbm-ft/lbf-s^2]		
h	Well depth	-	7240	-	[ft]	Figure 3.6	
h_{tot}	Total head	(3.11)	-	-	[ft]		
h_{el}	Elevation head	-	h	-	[ft]		
h_f	Frictional head	(3.12)	-	-	[ft]	[73, p. 447]	
λ_o	Volume fraction of oil	(3.18)	-	-	[-]		
λ_w	Volume fraction of water	-	$1-\lambda_o$	-	[-]		

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
MW_g	Gas molecular weight	-	var.	-	[lbm/lbmol]	[2, p. 35]	f
N_W	Number of producing wells	-	$\frac{Q_o[\text{bbl/d}]}{183[\text{bbl/well-d}]}$	-	[-]	Section 3.3.3.3	
p_b	Base pressure	-	14.7	-	[psi]	[2, p. 35]	
p_d	Flow discharge pressure	-	var.	-	[psi] or [psia]		
p_s	Compressor suction pressure	-	125	-	[psia]		
$p_{trav,tot}$	Total pressure traverse	(3.16)	-	-	[psi]	[73, p. 455]	g
p_{lift}	Pressure for lifting	(3.19)	-	-	[psi]		
p_{wh}	Wellhead pressure	-	1000	-	[psi]	[2, p. 80]	
p_{res}	Reservoir pressure	-	$0.5\left(\frac{h[\text{ft}]}{2.31[\text{ft/psi}]}\right)$	-	[psi]		
p_{wf}	Bottomhole pressure	-	-	-	[psi]		
PI	Well performance index	(3.20)	-	-	[psi]		
$Q_{l,W}$	Wellbore flow rate	(3.14)	-	-	[ft^3/s]		
Q_d	Discharge flow rate	-	var.	-	[bbl/d] or [MMscf/d]		
Q_l	Total rate of liquid production	(3.15)	-	-	[ft^3/s]		
Q_o	Total rate of oil production	-	1500	-	[bbl/d]		
R_C	Compression ratio	(3.7)	-	-	[-]		
ρ_{gsc}	Gas density at standard conditions	(3.5)	-	-	[lbm/ft^3]	[2, p. 35]	
ρ_{asc}	Air density at standard conditions	-	0.0764	-	[lbm/ft^3]	[85, p. 10]	
T_b	Base temperature	-	520	-	[°R]	[2, p. 35]	
T_d	Compressor discharge temperature	(3.9)	-	-	[°R]	[57, p. 105]	
T_s	Compressor 1 suction temperature	-	656.7	-	[°R]		
T_{s2}	Compressor 2 suction temperature	(3.10)	-	-	[°R]		h
$v_{l,W}$	Pipeline flow velocity	(3.13)	-	-	[ft/s]	[85]	
WOR	Water-to-oil ratio	-	Section D	-	[bbl water/bbl oil]		
Z	Compressibility factor	-	1.0	-	[-]		

a - The default of the ratio of specific heats for methane (not pure) is 1.28. In the case of nitrogen gas the default is 1.40.
b - A typical centrifugal pump efficiency is 70% [59, p. 23]. OPGEE default is slightly more conservative.

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes

c - Compression efficiency accounts for losses of energy stemming from thermodynamics and mechanical causes. A typical range for compression efficiency is 75-85% [57, p.05]. OPGEE default is more conservative.
d - For the calculation of the friction head a high Moody friction factor of 0.1 is assumed.
e - See *'Fuel specs'*. Crude oil specific gravity varies between 0.8 and 1.05 in most cases.
f - Calculated based on the molecular weights and molar fractions of gas constituents.
g - Pressure traverse is calculated from the total head using the pressure gradient of fresh water.
h - Assume compressibility factor Z of 1.0 in the calculation of the compression energy.

3.3.3.1 Default field age

Field age data were collected for global oil fields. A total of 6502 global oil fields were collected from the Oil & Gas Journal *2010 Worldwide Oil Field Production Survey* [90]. A total of 4837 of these fields had reported discovery dates. No data are available on date of first production, although this commonly occurs less than 5 years after discovery.

The histogram of field discovery dates is shown in Figure 3.4. Because of a lack of field-specific production data in the same dataset, a production-weighted average age figure was not thought to provide an accurate representation of the true production-weighted age distribution, so this was not calculated. The mean date of discovery in the dataset was 1972.1. If a conservative 3 year development timeline is assumed, an average of 35 years has elapsed between 1975 and 2010.

User Inputs & Results 3.2.3

However, many of these fields are likely small fields that do not supply large quantities of oil to the global export markets. It is known that giant oilfields are somewhat older on average than the general field population [91–94]. A database of 116 giant oilfields was collected (defined as all producing over 100 kbbl/d in the year 2000) [92, Appendix A]. In total, these 116 fields produced ≈32,000 kbbl/d, or some 43% of global oil production in 2000.

These giant fields have a count distribution and produciton-weighted average age distribution that are somewhat older than the complete set of global fields. Figure 3.5 shows these distributions. The production-weighted average discovery year of the sample was 1960.2, for an average age of 40 years since discovery at the time of production data collection (weighted by year 2000 production data). Data on giant oilfield production in 2010 are not available. Due to the general global slowdown in the discovery of giant fields since the 1970s, it is likely that the age distribution of giant oilfields has not shifted in step with advancing years. Therefore, the production-weighted average age for large fields is likely now greater than 40 years.

3.3.3.2 Default field depth

Field depth data were collected for a large number of global oil fields [90]. A total of 6502 global oil fields were collected from the Oil & Gas Journal *2010 Worldwide Oil Field Production Survey*. Of these fields, 4489 fields had depth data presented. For fields where a range of depths was presented, the deeper depth is used.

The distribution of depths by number of fields per depth range is presented in Figure 3.6. Because of sporadic reporting of production data in the same dataset, a production-weighted depth figure was not thought to provide an accurate representation. The mean depth for these 4489 fields is 7238, or ≈ 7240 ft. The standard deviation is 3591 ft. The depth distribution has a longer right (deep) tail than left (shallow) tail, so the mean is somewhat larger than the median (median = 6807 ft).

User Inputs & Results 3.2.4

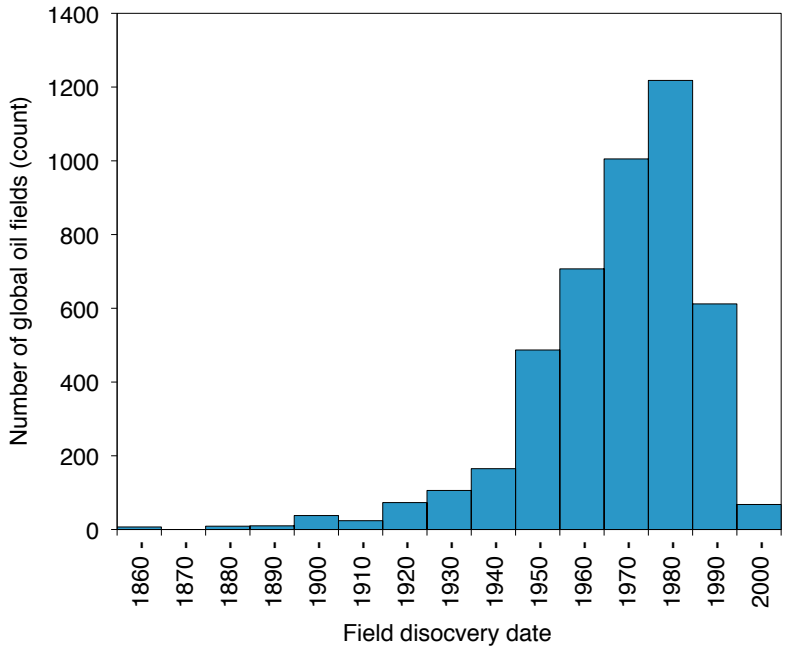

Figure 3.4: Distributions of global oilfield ages. Mean date of discovery (by count not by production-weighted average) is 1978.4.

3.3.3.3 Default production per well

Country-level oil production data and numbers of producing wells were collected for a large number of oil producing countries. Data from a total of 107 oil producing countries were collected from the Oil & Gas Journal *2010 Worldwide Oil Field Production Survey* [95]. Production data and operating well counts for 2008 were collected from 92 of these 107 countries.

The distribution of per-well productivities for all countries is shown in Figure 3.7. A majority of oil producing countries produced less than 500 bbl/well-d. Weighting these well productivities by country-level share of global production, we see a very similar distribution.

Because of the large number of countries producing less than 500 bbl/well-d, we plot the distribution for countries under 500 bbl/well-d (see Figure 3.8). For the 55 countries with per-well productivity less than 500 bbl/well-d, the most common productivity by number of countries was the 0-25 bbl/well-d. However, when weighted by total production, the most common productivity bin is 75-100 bbl/well-d.

In 2008, the world produced 72822 kbbl/d from 883691 wells, for an average per-well productivity of 82 bbl/well. However, the very low productivity of the US oil industry (representing ≈512000 wells) pulls down this average significantly. Non-US producers averaged a per-well productivity of 183 bbl/well-d, which is used as default well productivity in OPGEE.

User Inputs & Results 3.2.6

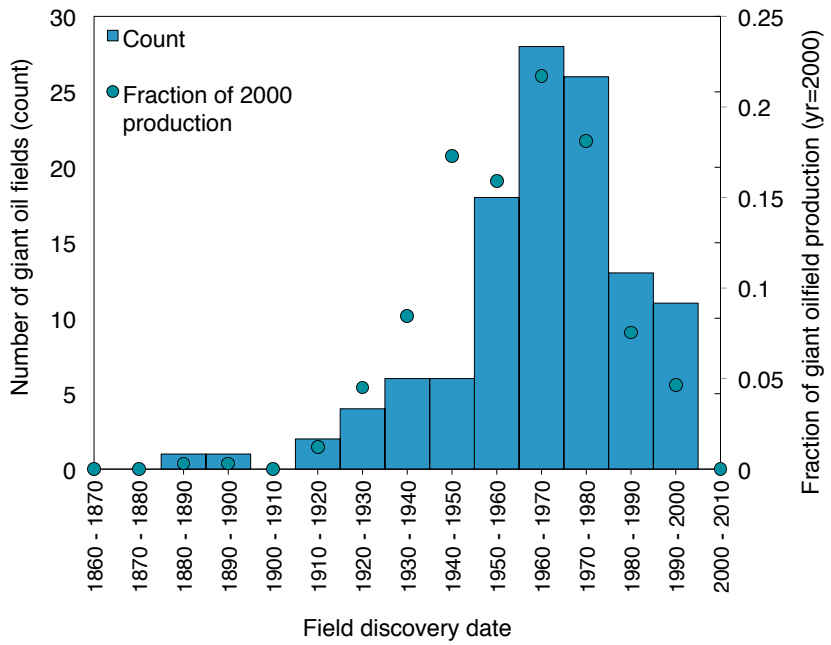

Figure 3.5: Distributions of giant oilfield ages. Mean date of discovery (by production-weighted average) is 1960.2.

3.3.3.4 *Default gas composition*

The default gas composition for associated gas from oil production is derived from reported gas composition data from 135 California oil fields [3]. Species concentration distributions for major gas species is shown in Figure 3.9. In order to remove outliers, all compositions with methane concentration less than 50% were removed from the dataset (17 data points removed out of 135). The resulting mean compositions were rounded and used in OPGEE for default gas composition.

User Inputs & Results 3.3.2

3.3.3.5 *Smart default for GOR*

The gas-oil ratio (GOR) varies over the life of the field. The amount of gas able to be evolved from crude oil depends on its API gravity, the gas gravity, and the temperature and pressure of the crude oil [96, p. 297]. As the reservoir pressure drops, increasing amounts of gas evolve from the liquid hydrocarbons (beginning at the bubble point pressure if the oil is initially undersaturated) [96]. This tends to result in increasing producing GOR over time. Also, lighter crude oils tend to have a higher GOR.

Because of this complexity, a static single value for GOR is not desirable. However, all data required to use empirical correlations for GOR is not likely to be available for all crude oils modeled. Therefore we use California producing GORs to generate average GORs for three crude oil bins.

User Inputs & Results 3.4.1

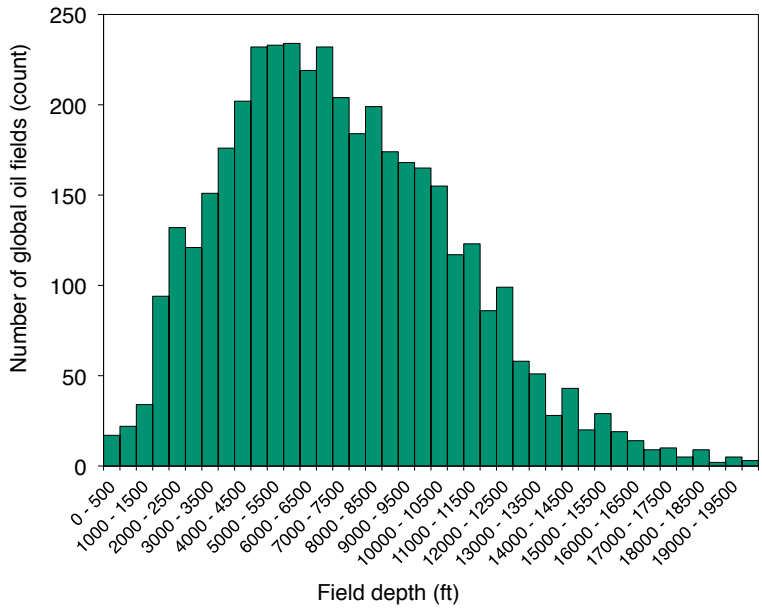

Figure 3.6: Distributions of global oilfield depths in bins of 500 ft depth. N = 4489 fields, mean = 7238 ft, SD = 3591 ft, median = 6807 ft.

Crude oils are binned by API gravity into heavy ($< 20\,^{\circ}$API), medium ($\geq 20, < 30\,^{\circ}$API), and light crude ($\geq 30\,^{\circ}$API). Each California oil field is assigned an average API gravity using the following procedure:

1. API gravity by pool is collected from DOGGR datasets [97–99] and digitized.

2. If a range of API gravities is given for a single pool, the high and low value are averaged to obtain a single value per pool.

3. The above steps give a set of single API values by pool. Each field has between 1 and 17 pools that have data in DOGGR field properties datasets.

4. Each field is assigned an average API gravity using the following method: a) if a single pool API value is given for the field, that is used; b) if multiple pool API gravities are given, and production data are available by pool, the pools are weighted by production level; c) if multiple pool API gravities are given but no relative production data exist to weight the pools, the API gravities are averaged.

5. The above procedure results in a single average API gravity for each field in California.

The associated gas GOR for 174 California oil fields was compiled for January to December 2010 [100, 101]. Five of these fields had very high GORs

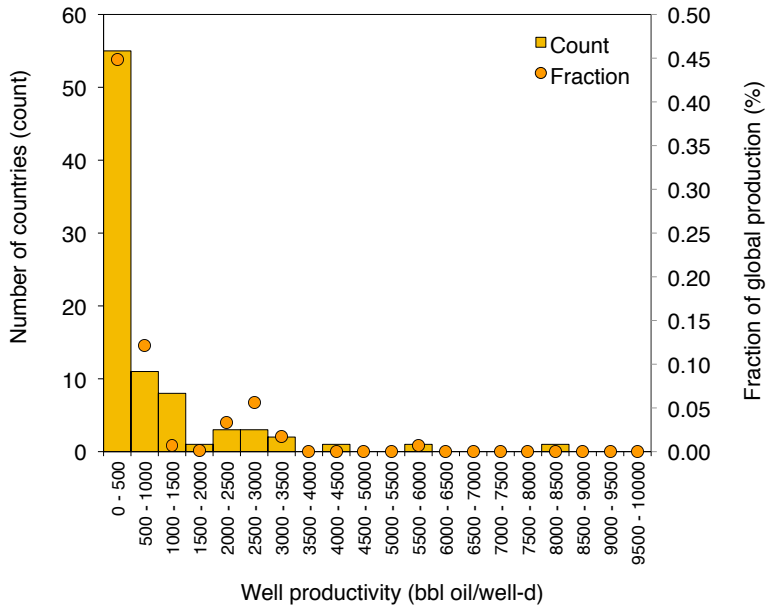

Figure 3.7: Distributions of oilfield per-well productivity (bbl oil/well-d) for bins of 500 bbl/d, counted by numbers of countries (bar) and by fraction of production (dot) $N = 92$ countries.

Table 3.5: GOR values by crude oil API gravity bin.

Crude bin	Num. fields [#]	Gravity range [°API]	Avg. gravity [°API]	Mean GOR [scf/bbl]	Median GOR [scf/bbl]
Heavy	53	< 20	15.6	361	105
Medium	65	$\geq 20, < 30$	25.0	843	594
Light	51	≥ 30	35.4	1431	959

of above 10,000 scf/bbl and were removed as outliers, leaving 169 fields with data. These data are binned as above based on their average API gravity value. The distributions, mean, and median values for each crude bin were generated (see Figure 3.10 for plot of distributions and Table 3.5 for listing of mean and median GORs by bin).

The median GORs are used to assign a smart default for each bin.

3.3.3.6 Default water oil ratio (WOR)

A smart default for the water oil ratio as a function of field age was generated using data from hundreds of oil pools/fields in Alberta and California. Appendix D gives a thorough methodological explanation of the analysis underlying the WOR smart default.

User Inputs & Results 3.4.2

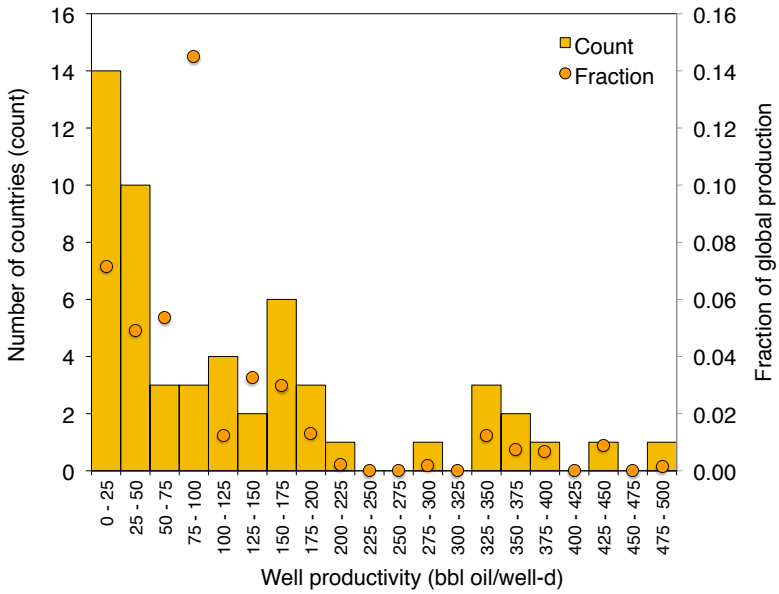

Figure 3.8: Distributions of oilfield per-well productivity (bbl oil/well-d) for all countries with per-well productivities lower than 500 bbl/well-d, counted by numbers of countries (bar) and by fraction of production (dot) N = 55 countries.

Table 3.6: OPGEE WOR relationships.

Case	b_0	b_1	Source
Low	2.486	0.032	CA Mean
OPGEE Default	1.75	0.05	User spec.
High	1.168	0.091	AB mean

The default WOR is represented by an exponential function:

$$WOR(t) = a_{WOR} \exp[b_{WOR}(t - t_0)] \qquad [\frac{\text{bbl water}}{\text{bbl oil}}] \tag{3.25}$$

where a_{WOR} = fitting constant for the initial WOR in time = t_0 [bbl water/bbl oil]; b_{WOR} = exponential growth rate [1/y]; t_0 = initial year of analysis [y]; and t = year being modeled (independent variable) [y].

The results of fitting this model to the mean initial WOR and WOR growth rates in Alberta and California are shown in Figure 3.11, compared to oil fields from a variety of world regions. The tabular results for b_0 and b_1 for the California, Alberta, and default OPGEE cases are shown in Table 3.6.

3.3.3.7 Default waterflooding volume

The volume of water injected in a waterflooding project is meant to maintain reservoir pressure. As a default value, OPGEE assumes that the surface vol-

User Inputs & Results 3.4.3

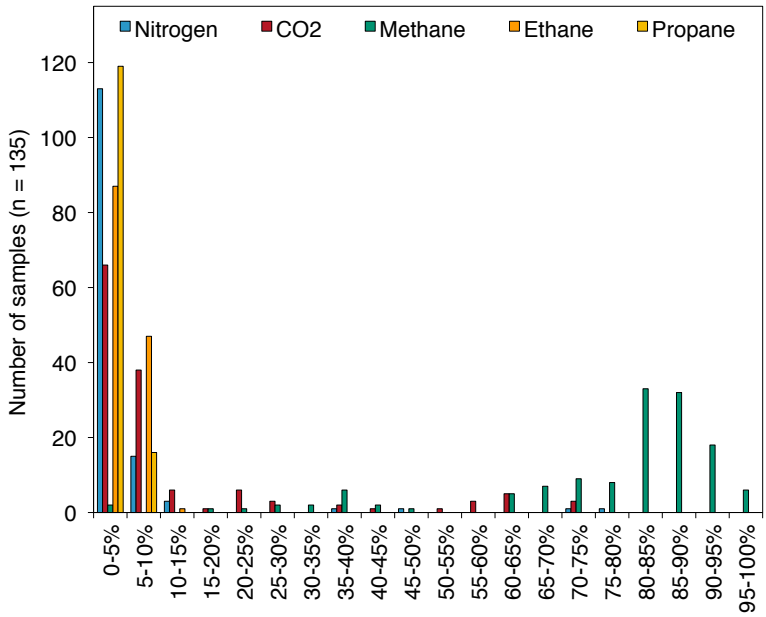

Figure 3.9: Distributions of major gas species across 135 samples from California associated gas producers.

ume is replaced, such that the total oil produced plus the water produced is reinjected, or the injection per bbl = 1 + WOR.

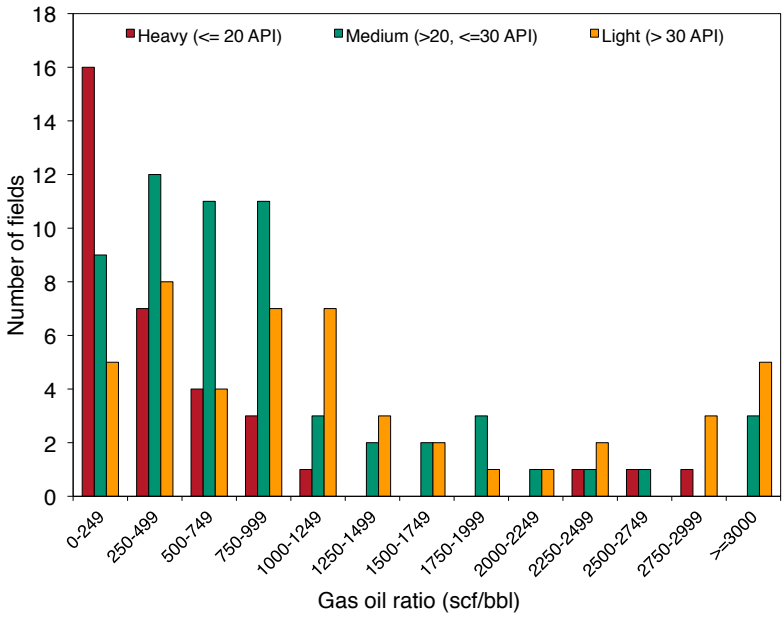

Figure 3.10: Distributions of California GORs, binned by crude density.

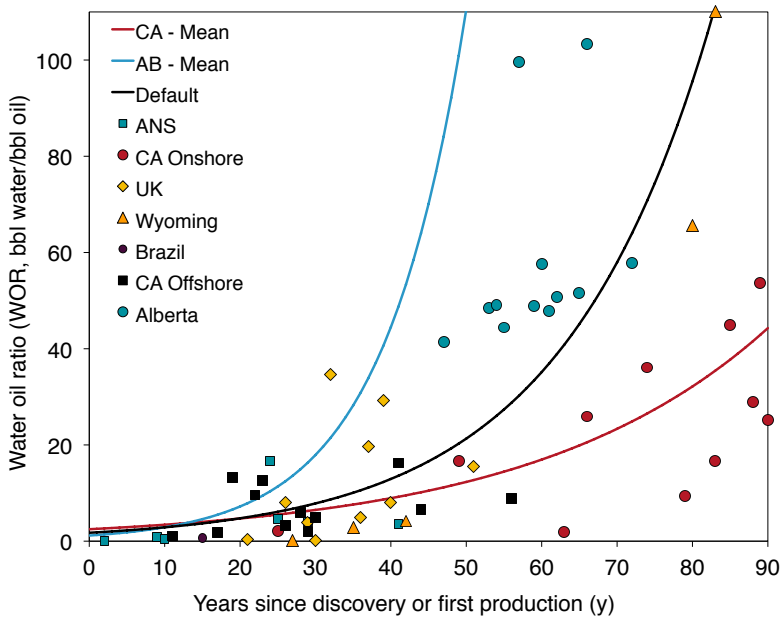

Figure 3.11: Exponential WOR model using mean results for Alberta and California case cases. Default case is a moderate case that is between the Alberta and California cases.

3.4 Surface processing

3.4.1 Introduction to surface processing

Surface processing of crude oil includes all production steps required after lifting the crude oil from the subsurface and before it is transported to the refinery. Activities undertaken in surface processing include oil-water-gas separation, treatment and stabilization of crude oil, and treatment and cleanup of produced gas.

The first step in the processing of crude oil is the separation of individual phases (gas, liquid hydrocarbon, liquid water and solids). This is performed as early as is practical. Field processing schemes can vary considerably depending on the nature of produced fluids (water cut, gas-to-oil ratio and the nature of crude oil, e.g., API gravity), the location and size of the field, availability of gas and electricity, the relative value of gas and crude oil [50, p. 65].

In OPGEE it is not possible to account for the wide variations in surface processing. The goal is to include the most frequently applied processes in the industry, while still retaining some flexibility to model varying operating modes.

A complete list of emissions sources from surface processing, along with their estimated magnitude, is shown in Table C.4. A list of all equation parameters and their default values (if applicable) and data sources is included in Table 3.9.

3.4.2 Calculations for surface processing

3.4.2.1 Crude oil dehydration

The production separator can be a gas-liquid separator or a gas-water-oil separator. The type of production separator determines whether free water is removed at an early stage in the processing scheme. After free water removal, produced oil often contains excessive emulsified water. Treating via crude oil dehydration is required to reduce the water content to a level acceptable for transportation and sale.

Crude oil dehydration can be accomplished by gravitational / chemical means without heat. If this separation is not sufficient, heat can be applied to aid the separation of crude oil and water. The application of heat in the dehydration of crude oil is a significant source of fuel consumption in surface processing.

Gravity separation occurs in large holding vessels called wash tanks, settlers, or gun barrels, and in free-water knockouts (FWKO). FWKOs remove only free water. Emulsion breaking chemicals can be added upstream from the FWKO to improve separation. Better gravitational/chemical separation can be achieved in holding vessels. Holding vessels generate a “washing” action with mild agitation that causes contact between the entrained water drops and the retained water volume, thus coalescing and removing water droplets

from the oil stream [50, p. 118]. The advantage of wash tanks is that they use coalescence and retention time instead of heat (no fuel use) [102] [50, p. 119]. Because no fuel is used in these gravitational separation techniques, no significant GHG emissions occur from gravity separation units.

Depending on the nature of the well stream, the above gravity separation techniques may not be sufficient to produce crude oil with the desired water content. Additional treatment may be provided by a heater/treater.

Heater/treater placement in the processing scheme affects the total heater treater duty. If the full well stream is the feed stream, then the section of the heater/treater below the firetube is sized to allow for significant retention time to drop out more than half of the free water. Heaters/treaters, however, are not suitable for removing large amounts of free water, and this limitation becomes more acute in older fields as WOR increases [50, p. 120]. Removing free water before flowing the crude oil mixture into a fired heater saves considerable fuel. It takes 350 Btu to heat 1 bbl of water 1 °F but only 150 Btu to raise 1 bbl of oil 1 °F [50, p. 188]. The removal of free water upstream from the heater/treater is therefore desirable from a cost and emissions perspective.

OPGEE allows the user to switch on and off the heater/treater. If the heater/treater applies, the user choses whether the total well stream is the feed stream or whether free water is removed upstream from the heater/treater unit. For upstream removal of free water, the user choses between a production separator at the well head or an FWKO/tank. In either case, the user can change the amount of water removed as a percentage of water cut.

The first step in the calculation of the heat duty of the heater/treater is the calculation of the volume of heated water. If the total well stream is the feed stream then the volume of heated water is calculated using the fraction of water entrained in oil as:

Surface Processing 2.1.1

$$Q_{w,heat} = Q_{w,ent} + \lambda_{w,rem}(Q_w - Q_{w,ent}) \qquad \left[\frac{\text{bbl}}{\text{d}}\right] \tag{3.26}$$

where $Q_{w,heat}$ = volume of heated water [bbl/d]; $Q_{w,ent}$ = volume of entrained water, [bbl/d]; $\lambda_{w,rem}$ = the fraction of non-entrained water removed prior to heater/treater firetube [-]; and Q_w = volume of produced water [bbl/d]. The volume of entrained water $Q_{w,ent}$ is calculated from the fraction of water entrained in oil as:

Surface Processing 2.1.1.1

$$\lambda_{w,ent} = \frac{Q_{w,ent}}{Q_{w,ent} + Q_o}, \quad \text{therefore} \quad Q_{w,ent} = \lambda_{w,ent}\frac{Q_o}{1 - \lambda_{w,ent}} \qquad \left[\frac{\text{bbl}}{\text{d}}\right] \tag{3.27}$$

where $\lambda_{w,ent}$ = fraction of water entrained in oil [-]; and Q_o = rate of oil production [bbl/d]. The volume of produced water Q_w is calculated from the water-to-oil ratio as:

Surface Processing 2.1 Figure

$$Q_w = \text{WOR} \cdot Q_o \qquad \left[\frac{\text{bbl water}}{\text{d}}\right] \tag{3.28}$$

where WOR = water-to-oil ratio [bbl of water/bbl of oil]. The produced water is the sum of free and entrained waters.

In the calculation of the volume of heated water in eq. (3.26) it is assumed that the heater/treater is designed to drop out 60% of the free water below the fire tube, so $\lambda_{w,rem}$ = 0.4 by default. The fraction of water entrained in oil is a user input with a default value of 14% [50, p. 136].

Surface Processing 2.1.1.1

If free water is removed upstream of the heater/treater, the volume of heated water is calculated from the volume of water remaining in the well stream after initial separation. The fraction of water removed as a percentage of produced water is variable. For example, crude oil leaving the FWKO may still contain emulsified water content ranging from 1% to as much as 30 or 40 % [50, p. 118]. The default values for the production separator and gravitational treatment are 60% and 70% of produced water, respectively.[1]

Surface Processing 1.1.1.1.2, 1.1.1.2.2

Once the volume of heated water is calculated, the heat duty is calculated using:

Surface Processing 2.1.1.4

$$\Delta H_{CD} = \Delta T_{CD} \left(Q_o C_{p_o} + Q_{w,heat} C_{p_w} \right) (1 + \epsilon_{CD}) \left(\frac{1}{10^6} \right) \qquad \left[\frac{\text{MMBtu}}{\text{d}} \right] \tag{3.29}$$

where ΔH_{CD} = heat duty [MMBtu/d]; C_{p_o} = specific heat of oil [Btu/bbl-°F]; C_{p_w} = specific heat of water [Btu/bbl-°F]; ΔT_{CD} = difference between treating and feed temperatures [°F]; and ϵ_{CD} = heat loss [fraction]. Default values are 90 and 165 °F for feed and treating temperatures, respectively; 150 and 350 Btu/bbl-°F for specific heats of oil and water, respectively; and 0.02 for heat loss [50, p. 136].

3.4.2.2 Crude oil stabilization

Dissolved gas in the wellhead crude oil must be removed to meet pipeline, storage, or tanker Reid vapor pressure (RVP) specifications. Removal of the most volatile organic hydrocarbons decreases the RVP dramatically and is called crude oil stabilization. Crude oil can be stabilized by passing it through a series of flash drums or separator vessels at successively lower pressures. Tray tower with reboilers, alternatively or in conjunction with separators, are also used, though less often [50, p. 159].

The use of a reboiled stabilizer column is the most important user assumption in the oil-gas separation scheme. Stabilizer columns are tray columns usually provided with sieve trays for vapor-liquid contacting. Vapor, which is produced in the reboiler, flows up the column, stripping out methane, ethane, propane, and sufficient butane to produce a stabilized crude oil [50, p. 160].

[1] As mentioned earlier the efficiency of the initial water-oil separation is significantly variable. For gravitational treatment 70% was assumed given the literature range of 1-40% of water remaining with crude oil from FWKO. The three-phase production separator has a lower assumed efficiency of 60% because gravitational treatment generally has the advantage of adding demulsifiers and/or generating a "washing' action.

The separation achieved is better than in a simple flash drum. Higher pressures correlate with higher separation efficiency. The default type of stabilizer in OPGEE is a high-pressure stabilizer (100 psi) which requires a higher reboiler temperature compared to a low-pressure stabilizer.

The use of a stabilizer column is an important assumption because a heat source is required to provide the neccessary temperature. OPGEE assumes a direct-fired heater. The use of a stabilizer column and the overall complexity of crude oil processing depends on the nature of the well fluids. For instance, when the gas-to-oil ratio (GOR) is between 25-100 scf/bbl, onshore locations are likely to use one stage of flash separation followed by wash tanks. Offshore, two stages of separation might be attractive [50, p. 172]. The comparisons between a series of flash drums and/or reboiled stabilization are of real economic benefit only for high volume, high GOR streams (>150 scf/bbl) [50, p. 163].

The heat duty of the stabilizer column is calculated as:

Surface Processing 2.1.2.2

$$\Delta H_S = \Delta T_S Q_o C_{p_o} \left(1 + \epsilon_S\right) \left(\frac{1}{10^6}\right) \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{3.30}$$

where ΔH_S = heat duty [MMBtu/d]; C_{p_o} = specific heat of oil [Btu/bbl-°F]; ΔT_S = difference between reboiler and feed temperatures [°F]; and ϵ_S = heat loss [fraction]. All of these parameters are user inputs. The default values are 120 and 344 °F for feed and reboiler temperatures, respectively; 150 Btu/bbl-°F for the specific heat of oil; and 0.02 for heat loss [50, p. 161, 163, tables 9-1, 9-3].

3.4.2.3 Acid gas removal

The second step after the separation of individual phases is the treatment of associated gas. Treatment of associated gas starts with acid gas removal (gas sweetening). There are more than 30 natural gas sweetening processes. OPGEE assumes that the amine process is used. The batch and amine processes are used for over 90% of all onshore wellhead applications with amines being preferred when lower operating costs justifies the higher equipment cost. The chemical cost of batch processes may be prohibitive [2, p. 99].

In the amine process an aqueous *alkanolamine* solution is regenerated and used to remove large amounts of sulfur and CO_2 when needed. The model scheme allows the user to choose between the commonly used amine solutions (MEA, DEA, DGA, etc.). Each amine solution is characterized by a K value which is inversely proportional to both the acid gas removal rate (pick up) and amine concentration [2, p. 115]. When choosing an "other" amine solution, the user must enter a K value. The default contactor operating pressure is the median value of the pressures reported in the calculation of the contact tower diameter [103] [2, p. 117]. A schematic of the amine process is shown in Figure 3.12.

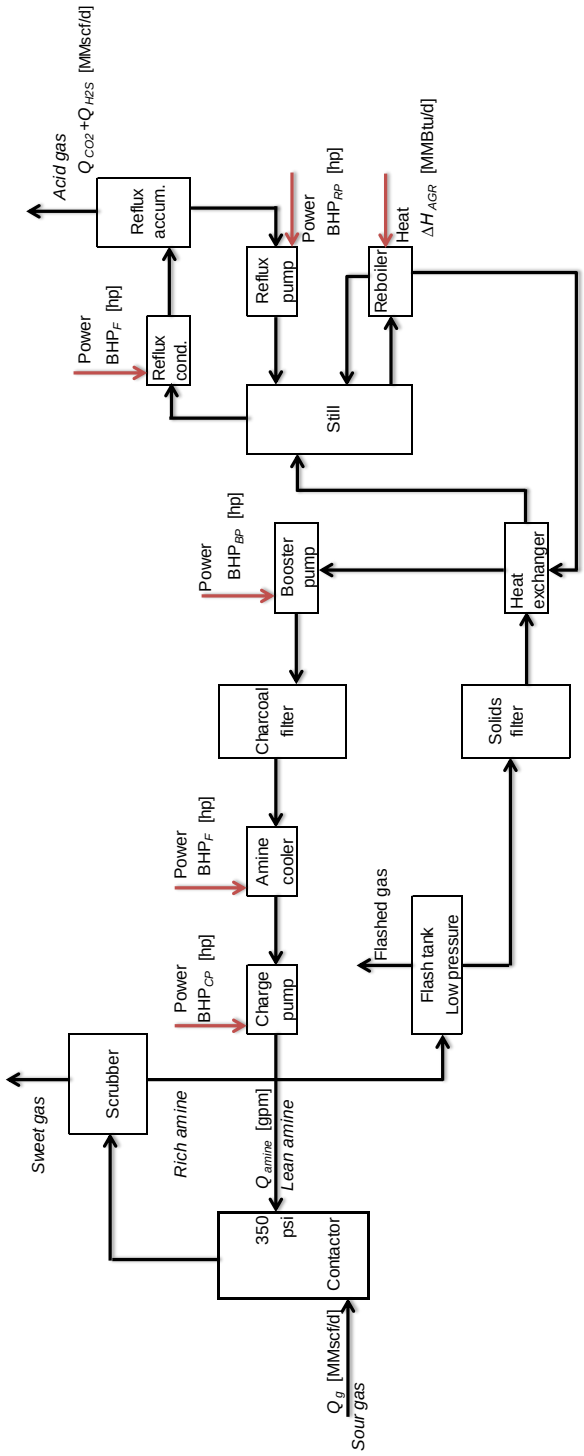

Figure 3.12: Amine simple process flow diagram [2, p. 112].

The inlet gas flow rate of the gas processing stage in the gas balance (see *'Gas Balance'* sheet) is calculated as:

Surface Processing 2.2.1 Figure

$$Q_g = Q_o \cdot \text{GOR}\left(\frac{1}{10^6}\right) - Q_F \qquad \left[\frac{\text{MMscf}}{\text{d}}\right] \tag{3.31}$$

where Q_g = inlet gas flow rate [MMscf/d]; Q_o = rate of oil production [bbl/d]; Q_F = flaring rate [MMscf/d]; and GOR = gas-to-oil ratio [scf/bbl]. The inlet gas flow rate is used in the calculation of the amine circulation rate in eq. (3.33). Although the accumulation of gases to flare likely occurs at various points throughout the process, OPGEE assumes that the gas flared is removed before gas processing occurs. This allows for OPGEE to account for "early field production" or production in locations without a gas market. For these situations, no surface processing exists and all produced gas is flared.

The amine reboiler in OPGEE is a direct fired heater that uses natural gas. The reboiler duty is: (i) the heat to bring the acid amine solution to the boiling point, (ii) the heat to break the chemical bonds between the amine and acid gases, (iii) the heat to vaporize the reflux, (iv) the heat load for the makeup water, and (v) the heat losses from the reboiler and still [2, p. 117].

The heat duty of the amine reboiler can be estimated from the circulation rate of the amine solution as [2, p. 119—originally Jones and Perry, 1973]:

Surface Processing 2.2.1.4

$$\Delta H_{AGR} = \frac{24 \cdot 72000 \cdot Q_{amine}}{10^6} 1.15 \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{3.32}$$

where ΔH_{AGR} = heat duty [MMBtu/d]; and Q_{amine} = amine flow rate [gpm]. A gallon of amine solution requires approximately 72000 Btu for regeneration [104]. A safety factor of 15% is added for start up heat losses and other inefficiencies. The flow rate of the amine solution can be estimated using the following equation [2, p. 115]:

Surface Processing 2.2.1.1.1

$$Q_{amine} = 100\, K(Q_{H_2S} + Q_{CO2}) \qquad \text{[gpm]} \tag{3.33}$$

where Q_{amine} = amine flow rate [gpm]; K = amine solution K value [gpm-d/100MMscf]; Q_{H_2S} = H_2S removal [MMscf/d]; and Q_{CO2} = CO_2 venting from AGR unit [MMscf/d]. The venting of CO_2 from the AGR unit is calculated in the *'Gas Balance'* sheet. The rate of H_2S removal is calculated as:

$$Q_{H_2S} = x_{H_2S} \cdot Q_g \qquad \left[\frac{\text{MMscf}}{\text{d}}\right] \tag{3.34}$$

where x_{H_2S} = molar fraction of H_2S [-]; and Q_g = inlet gas flow rate [MMscf/d]. The calculation of the inlet gas flow rate is shown in eq. (3.31). The molar fraction of H_2S is determined from the composition of associated gas.

In OPGEE all H_2S remaining in the associated gas is removed in the AGR unit. Removed H_2S is calculated in eq. (3.34) by multiplying the inlet gas flow rate with the molar percent of H_2S. Also all the CO_2 removed is vented and that is calculated in the *'Gas Balance'* sheet.

Other equipment in the amine regeneration system that consume power and energy include the reflux condenser and the amine cooler. There also are reflux, booster, and circulation pumps. The reflux condenser and the amine cooler are air-cooled, forced-draft heat exchangers. In OPGEE both services are combined into one structure with a common fan.

The motor size of the amine cooler fan can be estimated from the amine circulation rate as [2, p. 118]:

Surface Processing 2.2.1.3.1

$$\mathrm{BHP}_F = 0.36 \cdot Q_{amine} \qquad \text{[hp]} \tag{3.35}$$

where BHP_F = fan brake horsepower [hp]; and Q_{amine} = amine circulation rate [gpm].

The heat duty of the reflux condenser is approximately twice the heat duty of the amine cooler [2, p. 117]. Therefore the motor size of the 'common' fan is estimated by multiplying the brake horsepower of the amine cooler by 3.

Similarly motor sizes of pumps can also be estimated from the amine circulation rate as [2, p. 118]:

Surface Processing 2.2.1.2

$$\mathrm{BHP}_{RP} = 0.06 \cdot Q_{amine} \qquad \text{[hp]} \tag{3.36}$$

$$\mathrm{BHP}_{BP} = 0.06 \cdot Q_{amine} \qquad \text{[hp]} \tag{3.37}$$

$$\mathrm{BHP}_{CP} = 0.00065 \cdot Q_{amine} \cdot p_d \qquad \text{[hp]} \tag{3.38}$$

where BHP_{RP} = reflux pump brake horsepower [hp]; BHP_{BP} = booster pump brake horsepower [hp]; BHP_{CP} = circulation pump brake horsepower [hp]; and p_d = pump discharge pressure [psi]. The circulation pump discharge pressure = 50 psi over contactor operating pressure [2, p. 121]. The default contactor operating pressure as mentioned earlier is 350 psi.

3.4.2.4 Gas dehydration

Fluids at the wellhead almost invariably contain water. Except for a few shallow wells, natural gas is produced saturated with water. There are many reasons for the dehydration of natural gas, including avoiding: (i) solid hydrates formation which can plug valves, fittings or even pipelines; (ii) corrosivity in case the acid gases are still present; (iii) condensation of water which creates a slug flow and increases pressure losses in the pipeline due to slippage; and (iv) decreases in heating value [2, p. 139]. There are several methods for the dehydration of natural gas including liquid (glycols) and solid (e.g., alumina) desiccants. The method assumed in OPGEE as default is triethylene glycol (TEG) desiccant. For more than 40 years sweet and sour gases have been dehydrated using TEG which has general acceptance as the most cost effective choice [2, p. 140].

The wet or "rich" glycol that leaves the absorber is preheated in the glycol-glycol heat exchanger before it enters the stripping column and flows down the packed bed section into the reboiler. The steam generated in the reboiler strips

water from the liquid glycol as it rises up the packed bed. The water vapor and desorbed gas are vented from the top of the stripper [2, p. 140]. The venting from glycol dehydrator is discussed in the VFF section of this document (see Section 4.3). A schematic of the glycol dehydrator is shown in Figure 3.13.

The first step in the estimation of the reboiler duty is the calculation of the rate of water removed using the assumed weight of water vapor in the inlet and exit gases as:

Surface Processing 2.2.2.1.3

$$\Delta M_{w,rem} = M_{w,in} - M_{w,out} \qquad \left[\frac{\text{[lb H}_2\text{O}}{\text{MMscf}}\right] \tag{3.39}$$

where $\Delta M_{w,rem}$ = water removed [lb H_2O/MMscf]; $M_{w,in}$ = water in inlet gas [lb H_2O/MMscf]; $M_{w,out}$ = water in outlet gas [lb H_2O/MMscf]. The weights of water vapor in the inlet and exist gases are user inputs. The default values are 52 and 7 lb H_2O/MMscf, respectively [2, p. 160]. The weight of water removed is converted to rate of water removal ($\Delta Q_{w,rem}$) in lb H_2O/d by multiplying with the gas flow rate, MMscf/d.

The regenerator duty is estimated using the rule of thumb [2, p. 158]:

Surface Processing 2.2.2.2.1

$$\Delta H_{GD} = 900 + 966\, q_{TEG} \left(\frac{1}{10^6}\right) \qquad \left[\frac{\text{MMBtu}}{\text{lb H}_2\text{O}}\right] \tag{3.40}$$

where ΔH_{GD} = reboiler heat duty [MMBtu/lb H_2O] removed; and q_{TEG} = TEG circulation rate [gal TEG/lb H_2O] removed. The heat duty is converted to MMBtu/d by multiplying with the rate of water removed, lb H_2O/d, as calculated in eq. (3.39).

The main parameter in eq. (3.40) is the TEG circulation rate. The water picked up by glycol increases with increasing inlet-glycol concentration and higher circulation rates. The concentration of TEG used typically ranges from 98.5 to 99.9 wt% [2, p. 155]. The default concentration assumed is 99 wt%. In the past a conservative TEG circulation rate of 3 gal TEG/lb H_2O removed was common. However, energy conservation practices have lowered the circulation to 2 gal TEG/lb H_2O removed and this is used as default in OPGEE [2, p. 147].

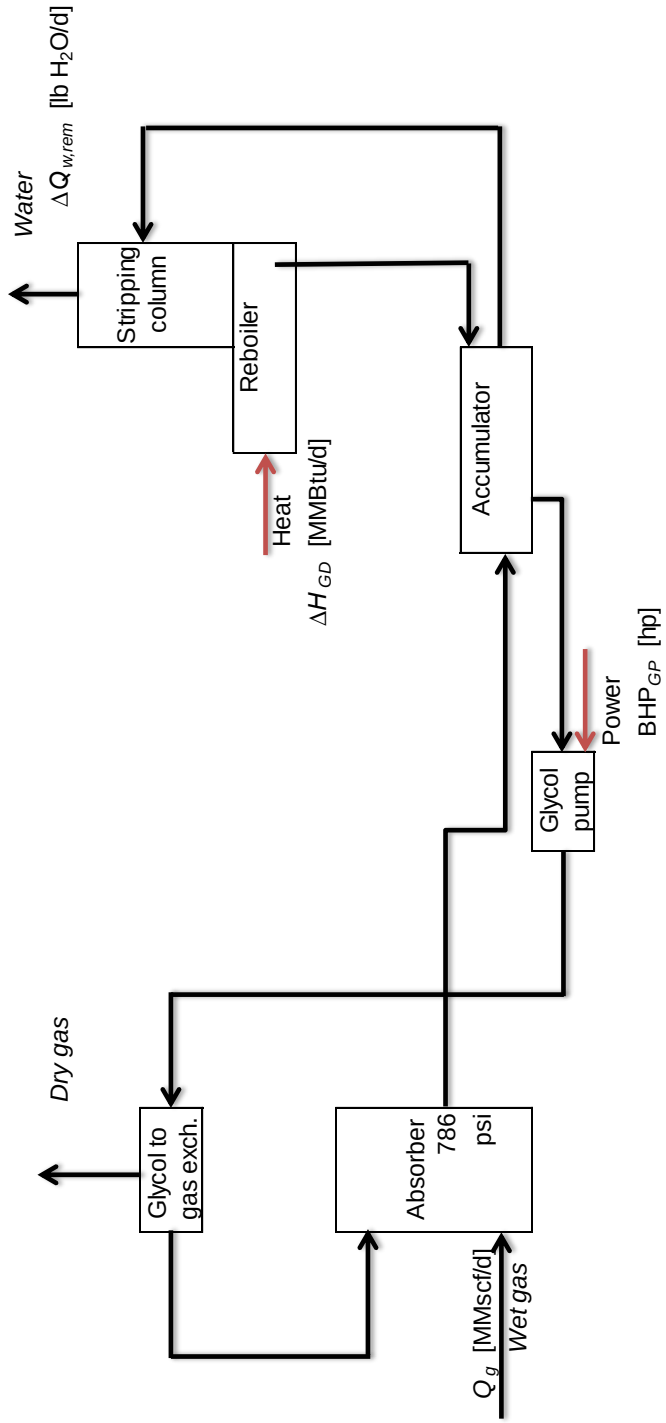

Figure 3.13: Glycol dehydrator simple process flow diagram [2, p. 141].

Table 3.7: Typical concentration of process water pollutants.

Pollutants	Concentration (mg/l)
Oil and grease	200
Boron	5
Total dissolved solids (TDS)	5000
Sodium	2100

The glycol pump in the gas dehydration process is assumed to be electric by default. The horsepower is calculated using the conventional brake horsepower equation:

Surface Processing 2.2.2.3

$$\mathrm{BHP}_{GP} = \frac{Q_{TEG} \cdot p_d}{1714 \eta_{GP}} \qquad \text{[hp]} \tag{3.41}$$

where BHP_{GP} = glycol pump brake horsepower [hp]; Q_{TEG} = TEG circulation rate [gpm]; p_d = pump discharge pressure [psi]; and η_{GP} = glycol pump efficiency [-]. The glycol pump discharge pressure is equal to contactor operating pressure. The default contactor operating pressure is 786 psi [2, p. 160]. The TEG circulation rate in gpm is calculated as:

Surface Processing 2.2.2.1.5

$$Q_{TEG} = q_{TEG} \Delta Q_{w,rem} \left(\frac{1}{24 \cdot 60} \right) \qquad \text{[gpm]} \tag{3.42}$$

where q_{TEG} = TEG circulation rate [gal TEG/lb H_2O removed]; and $\Delta Q_{w,rem}$ = rate of water removal [lb H_2O/d]. The calculation of the rate of water removal is shown in eq. (3.39).

3.4.2.5 *Water treatment*

Oil production generates a significant amount of produced water, which can be contaminated with hydrocarbons, salts, and other undesirable constituents. The fraction of water produced is determined by the WOR. After cleaning, produced water is reinjected, discharged to the local environment, or injected into aquifers. Produced water can contain a variety of pollutants at varying concentrations. The pollutant nature and concentration are largely source dependent including location, geology and age of the oil field [89]. A typical concentration of pollutants found in oil extraction process waters is shown in Table 3.7 [89, p. 59].

Process water from oil production can be treated in a variety of different ways. The technologies in OPGEE are grouped into 4 different treatment stages according to the categorization of water treatment technologies as shown in Table 3.8 [105]. This categorization and the energy consumption of each technology in kWh per m^3 of water *input* (converted to kWh per bbl of water) was adopted from Vlasopoulos et al. [89].

The user can set up a water treatment system or treatment train composed of 1-4 stages of treatment with one option from each treatment stage as shown

Table 3.8: Categorization of water treatment technologies.

Name	Signifier
Stage 1	
Dissolved air flotation	DAF
Hydrocyclones	HYDRO
Stage 2	
Rotating biological contactors	RBC
Absorbents	ABS
Activated sludge	AS
Trickling filters	TF
Air stripping	AIR
Aerated lagoons	AL
Wetlands	CWL
Microfiltration	MF
Stage 3	
Dual media filtration	DMF
Granular activated carbon	GAC
Slow sand filtration	SSF
Ozone	OZO
Organoclay	ORG
Ultrafiltration	UF
Nanofiltration	NF
Stage 4	
Reverse osmosis	RO
Electrodialysis reversal	EDR

in Table 3.8. Stage 1 to 3 technologies are used to reduce the oil and grease to levels that can be either discharged or reused. The fourth stage of treatment is used to reduce the sodium, TDS, and boron levels to produce high quality water required by some end uses [89, p. 60]. The technology combinations are selected according to the target water qualities that need to be achieved.

The model scheme has two treatment trains: (i) one for the treatment of process water generated from oil production and (ii) another for the treatment of imported water, e.g., sea water, if applicable.

The user can set up a treatment train by switching on/off the treatment technologies listed under each treatment stage. One option is allowed for each treatment stage. Based on the user selections, OPGEE retrieves the corresponding electricity consumption and calculates the total electricity consumption:

Surface Processing 2.3.1

$$E_{tot} = e_{s1}Q_{w1} + e_{s2}Q_{w2} + e_{s3}Q_{w3} + e_{s4}Q_{w4} \qquad \left[\frac{\text{kWh}}{\text{d}}\right] \tag{3.43}$$

where E_{tot} = total electricity consumption [kWh/d]; $e_{s,N}$ = electricity consumption of stage N [kWh/ bbl of water input]; and $Q_{w,N}$ = water feed into stage N

[bbl of water/d].

For the produced water treatment train the water feed of stage 1 is equal to the water flow in the well stream as calculated in eq. (3.28). The default volume losses are assumed 0% for all treatment technologies except for wetlands which is assumed 26% [89]. The water feed of stages 2-4 is calculated as:

Surface Processing 2.3.1 Figure

$$Q_{w,N} = Q_{w,(N-1)}[1 - \epsilon_{V,(N-1)}] \qquad \left[\frac{\text{bbl of water}}{\text{d}}\right] \tag{3.44}$$

where $\epsilon_{V,(N-1)}$ = volume loss in stage $N-1$ [fraction].

For the imported water treatment train, if applicable, the same calculations apply but the water feed is calculated backwards starting from stage 4 where the output is equal to the amount of water supplied to the process in excess of the output from the produced water train. The volume losses are set to be direct user inputs in the mass balance to avoid circular references.

3.4.3 Defaults for surface processing

Defaults for surface operations are shown in Table 3.9.

Table 3.9: Default inputs for surface processing.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
BHP_F	Fan brakehorse power	(3.35)	-	-	[hp]	[2, p. 118]	
BHP_{RP}	Reflux pump brakehorse power	(3.36)	-	-	[hp]	[2, p. 118]	
BHP_{BP}	Booster pump brakehorse power	(3.37)	-	-	[hp]	[2, p. 118]	
BHP_{CP}	Circulation pump brakehorse power	(3.38)	-	-	[hp]	[2, p. 118]	
BHP_{GP}	Glycol pump brakehorse power	(3.41)	-	-	[hp]	[73, p. 455]	
C_{p_o}	Specific heat of oil	-	150	-	[Btu/bbl-°F]	[50, p. 136]	
C_{p_w}	Specific heat of water	-	350	-	[Btu/bbl-°F]	[50, p. 136]	
E_{tot}	Total electricity consumption	(3.43)	-	-	[Kwh/d]		
$e_{s1} \dots e_{s4}$	Electricity consumption by stage	-	-	-	[Kwh/d]		
ϵ_j	Fraction of heat loss in unit j	-	0.02	-	[-]	[50, p. 136]	
$\epsilon_{V,(N-1)}$	Fraction of volume loss in stage $N-1$	-	var.	-	[-]	[89]	a
η_P	Pump efficiency	-	0.65	-	[-]		
$\lambda_{w,rem}$	Fraction of water removed below fire tube	-	0.4	-	[-]	[50, p.136]	
GOR	Gas-to-oil ratio	-	Section 3.3.3.5	-	[scf/bbl]		
ΔH_{AGR}	Amine process reboiler heat duty	(3.32)	-	-	[MMBtu/d]	[2, p. 119]	
ΔH_{GD}	Glycol dehydrator reboiler heat duty	(3.40)	-	-	[MMBtu/d]	[2, p. 158]	
K	Amine solution K value	-	2.05	0.95-2.05	[gpm-d/100MMscf]	[2, p. 115]	b
$\lambda_{w,ent}$	Fraction of water entrained in oil	-	0.14	-	[-]	[50, p. 136]	
q_{TEG}	TEG circulation rate	-	2	-	[gal TEG/lb H_2O]	[2, p. 147]	
p_d	Pump discharge pressure	-	786	-	[psi]	[2, p. 160]	
$\Delta Q_{w,rem}$	Rate of water removal	-	$Q_g\ \Delta M_{w,rem}$	-	[lb H_2O/d]		
Q_{amine}	Amine flow rate	(3.33)	-	-	[gpm]	[2, p. 115]	
Q_{CO_2}	Volume of CO_2 removed	-	var.	-	[MMscf/d]	*'Gas Balance'*	
$Q_{w,ent}$	Volume of entrained water	(3.27)	-	-	[bbl/d]	[50, p. 136]	

Continued on next page...

Continued from previous page

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
Q_F	Flaring volume	-	Section 4.3.2	-	[MMscf/d]		
Q_g	Inlet gas flow rate	(3.31)	-	-	[MMscf/d]	*'Gas Balance'*	
Q_{H_2S}	Volume of H_2S removed	-	var.	-	[MMscf/d]	*'Gas Balance'*	
$Q_{w,heat}$	Volume of heated water	(3.26)	-	-	[bbl/d]	[50, p. 136]	
Q_o	Volume of oil production	-	1500	-	[bbl/d]		
Q_{TEG}	TEG circulation rate in gpm	(3.42)	-	-	[gpm]		
Q_w	Volume of produced water	(3.28)	-	-	[bbl/d]		
$Q_{w1} \ldots Q_{w4}$	Water feed by stage	(3.44)	-	-	[bbl water/d]		
ΔT_{CD}	Crude dehyd. temp. difference	-	75	-	[°F]	[50, p. 136]	
ΔT_S	Crude stabilizer temp. difference	-	224	-	[°F]	[50, p. 161, 163]	
$\Delta M_{w,rem}$	Weight of water removed	(3.39)	-	-	[lb H_2O/MMscf]		
$M_{w,in}$	Weight of water in inlet gas	-	52	-	[lb H_2O/MMscf]	[2, p. 160]	
$M_{w,out}$	Weight of water in outlet gas	-	7	-	[lb H_2O/MMscf]	[2, p. 160]	
WOR	Water-to-oil ratio	(3.25)	-	-	[bbl water/bbl oil]]		

a - This is a user input. No defaults are available for most of the treatment technologies. The default for wetlands (CWL) where volume losses are significant is 26% [89].
b - The default is monoethanolamine (MEA).

3.5 Maintenance operations

3.5.1 Introduction to maintenance operations

Emissions from maintenance include venting and fugitives associated with compressor blowdowns, well workovers and cleanups, separator cleaning and repair, and gathering pipeline maintenance and pigging. Other maintenance emissions are believed to be below the significance cut-off and are not included.

3.5.2 Calculations for maintenance operations

Emissions from maintenance operations are classified in Table C.5. Emissions from maintenance operations are either very small (e.g., embodied energy consumed in maintenance parts) or are tracked in the VFF modeling page (see Section 4.3). For this reason, OPGEE does not perform specific maintenance emissions calculations in the separate *'Maintenance'* sheet.

3.5.3 Defaults for maintenance operations

Defaults used in the calculation of emissions from maintenance operations are discussed in Section 4.3.

3.6 Waste treatment and disposal

3.6.1 Introduction to waste treatment and disposal

Emissions from waste disposal occur during routine oilfield maintenance operations (e.g., disposal of residual hazardous waste products) due to clean up operations, or due to one-time events such as decommissioning of oilfield equipment. Emissions occur offsite due to the energy demands of waste disposal and the transport requirements for moving waste to waste treatment or disposal sites. A complete list of emissions sources, along with their categorization and estimated magnitude, is shown in Table C.6.

3.6.2 Calculations for waste treatment and disposal

Because waste treatment emissions only occur sporadically, they are likely to be small when amortized over the producing life of an oil field. For this reason, emissions from waste treatment are considered below the significance cutoff in OPGEE v1.0.

Possible exceptions could be the treatment and disposal of fracturing fluids and fracturing flow-back water, due to the large volumes produced. Future versions of the model may include these factors.

3.6.3 Defaults for waste treatment

Waste treatment emissions default to 0 gCO_2/MJ. Any waste treatment emissions are assumed to be captured in the small sources emissions default parameter.

User Inputs & Results 3.6

3.7 Crude oil transport

3.7.1 Introduction to crude oil transport

Crude oil transport includes all activities associated with moving crude oil from a production facility to a refinery. In the case of land transport, this generally involves transport via pipeline to the refinery. Pipelines are powered by natural gas, oil, or electric-powered drivers. In some instances, rail transport is used for overland transport. In the case of inter-continental trade, crude oil is transported to a loading dock, loaded onto a tanker or barge, transported via ship over water, unloaded at the destination, and finally transported to a refinery.

Transport emissions occur due to energy consumption by transport equipment and due to fugitive emissions from loading and unloading operations. In OPGEE, transport emissions are modeled using methods and data from GREET [17, 76]. Transport emissions calculations allow for variations in transport modes, distance travelled, and fuel mix in each mode.

3.7.2 Calculations for crude oil transport

OPGEE crude oil transport calculations use sets of transport modes, transport propulsion technologies in each mode (most commonly one technology per mode), and transport fuels. Emissions are tracked per species of GHG. Transport modes include tanker (T), barge (B), pipeline (P), and rail (R). Pipelines include two propulsion technologies: turbines (GT) and reciprocating engines (RE). Fuels used in transport include diesel fuel (di), residual oil (ro), natural gas (ng), and electricity (el).

The effectiveness crude oil transport [Btu/ton-mi] is calculated for a variety of modes using a similar general form. Each mode has an effectiveness U. For example, tanker transport effectiveness is calculated as:

Crude Transport Table 2.7

$$U_T = \frac{\eta_T l_T P_T}{v_T C_T} \qquad \left[\frac{\text{Btu}}{\text{ton-mi}}\right] = \frac{\left[\frac{\text{Btu}}{\text{hp-hr}}\right][-][\text{hp}]}{\left[\frac{\text{mi}}{\text{hr}}\right][\text{ton}]}, \tag{3.45}$$

where U_T = specific energy intensity of crude oil transport via tanker [Btu/ton-mi]; η_T = efficiency of tanker transport [Btu/hp-hr]; l_T = load factor of tanker (different on outbound and return trip) [-]; P_T = tanker power requirements [hp]; v_T = tanker velocity [mi/hr]; and C_T is tanker capacity [ton/tanker]. Barge transport is calculated in an analogous fashion.

For the case of pipeline and rail transport, the calculation is simpler. For pipeline transport the effectiveness is calculated as follows:

Crude Transport Table 2.7

$$U_P = \sum_{j \in GT,RE} \lambda_{Pj} U_{Pj} \qquad \left[\frac{\text{Btu}}{\text{ton-mi}}\right] = [-]\left[\frac{\text{Btu}}{\text{ton-mi}}\right] \tag{3.46}$$

where λ_{Pj} = fraction of each pipeline pumping technology j [-]; and U_{Pj} = effectiveness of pipeline transport for technology j [Btu/ton-mi]. For rail transport, only one technology exists, so no summation is required.

Back haul trips are calculated using GREET factors for the energy intensity of return trips [17]

The energy-specific transport energy intensity is calculated from the transport effectiveness using the energy density of crude oil. For example, in the case of tanker transport:

Crude Transport Table 2.7

$$e_T = U_T \frac{1}{LHV_o} \rho_w \gamma_o \frac{1}{2000} \tag{3.47}$$

$$\left[\frac{\text{Btu}}{\text{MMBtu-mi}}\right] = \left[\frac{\text{Btu}}{\text{ton-mi}}\right] \left[\frac{\text{bbl}}{\text{MMBtu}}\right] \left[\frac{\text{lb}}{\text{bbl water}}\right] \left[\frac{\text{lb/bbl oil}}{\text{lb/bbl water}}\right] \left[\frac{\text{lb}}{\text{ton}}\right] \tag{3.48}$$

where UE_T = crude oil transport intensity per unit of energy transported [Btu/MMBtu-mi], LHV_o = crude lower heating value [MMBtu/bbl]; ρ_w = density of water [lb/bbl]; γ_o = crude specific gravity [-]; and 1/2000 = conversion factor between lb and ton.

Calculating emissions of GHG species associated with the consumption of a given energy type in a given device is performed via multiplication with the appropriate emissions factor. For example, in the case of tanker emissions:

Crude Transport Table 2.7

$$\begin{aligned} EM_{Ti} &= e_T \sum_k \lambda_{Tk} EF_{Tki}, \qquad (k \in di, ro, ng) \\ \left[\frac{\text{g}}{\text{MMBtu-mi}}\right] &= \left[\frac{\text{Btu}}{\text{MMBtu-mi}}\right] [-] \left[\frac{\text{g}}{\text{Btu}}\right] \end{aligned} \tag{3.49}$$

where EM_{Ti} = emissions of species i from tankers [g/MMBtu-mi]; λ_{Tk} = fraction of fuel k used in tankers [-]; and EF_{Tki} = emissions factor for fuel k, species i consumed in tankers [g/Btu]. Other modes are calculated similarly.

The total CO_2 equivalent emissions are then computed by weighting by gas global warming potential (GWP). Again, for the case of tanker transport:

Crude Transport Table 2.7

$$EM_T = \sum_i EM_{Ti} GWP_i, \qquad \left[\frac{\text{g CO}_2\text{ eq.}}{\text{MMBtu-mi}}\right] = \left[\frac{\text{g}}{\text{MMBtu-mi}}\right] \left[\frac{\text{g CO}_2\text{ eq.}}{\text{g}}\right] \tag{3.50}$$

where GWP_i = GWP of species i.

The total energy consumption from transport is computed using the distances and fractions of transport, along with the mode-specific energy intensity of transport:

Crude Transport 3.1

$$\begin{aligned} E_{TR} &= \sum_j \lambda_j D_j UE_j \qquad (j \in T, B, P, R) \\ \left[\frac{\text{Btu}}{\text{MMBtu}}\right] &= [\text{mi}] \left[\frac{\text{Btu}}{\text{MMBtu-mi}}\right] [-] \end{aligned} \tag{3.51}$$

where D_j = distance of crude oil transport in mode j [mi]; UE_j = energy-specific transport effectiveness for mode j [Btu/MMBtu-mi]; and λ_j = fraction of crude oil transported in mode j. The sum of fractional transport λ can be greater than 1, because some crude may be transported via both pipeline and tanker, for example.

The total emissions are calculated identically:

Crude Transport 3.2

$$EM_{TR} = \sum_j \lambda_j D_j EM_j \qquad (j \in T, B, P, R)$$
$$\left[\frac{\text{g CO}_2\text{ eq.}}{\text{MMBtu}}\right] = [\text{mi}]\left[\frac{\text{g CO}_2\text{ eq.}}{\text{MMBtu-mi}}\right][-] \tag{3.52}$$

where EM_j are the emissions from mode j on a CO_2 equivalent basis.

3.7.3 Defaults for crude oil transport

Defaults for crude oil transport are generally taken from the GREET model, with some modifications and simplifications applied. Defaults for surface operations are given below in Table 3.10.

Table 3.10: Default inputs for crude transport.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
C_j	Transport capacity of mode j	-	*'Crude Transport'* Table 2.1		[ton]	[17]	
e_m	Energy intensity of transport in mode j by energy unit transported	(3.47)	-	-	[Btu/MMBtu-mi]		
EF_{jki}	Emissions factor for fuel k, species i, mode j	-	*'Emissions Factors'* Table 1.5		[g/MMBtu]		a
EM_{ji}	Emissions of species i by mode j	(3.49)	-	-	[g/MMBtu-mi]		
EM_j	Emissions of all GHGs in CO_2 eq. units by mode j	(3.50)	-	-	[g CO_2 eq./MMBtu-mi]		
E_{TR}	Total energy use in transport	(3.51)	-	-	[Btu/MMBtu]		a
EM_{TR}	Total emissions from in transport	(3.52)	-	-	[g/MMBtu]		a
η_j	Efficiency of transport mode j	-	*'Crude Transport'* Table 2.3		[Btu/hp-hr]	[17]	
GWP_i	Global warming potential for species i	-	*'Input data'* Table 2.1		[gCO_2eq./g]		
γ_o	Specific gravity of crude oil	-	0.876	0.8-1.05	[-]	[84]	
l_j	Load factor of mode j	-	*'Crude Transport'* Table 2.3		[%]	[17]	
$\lambda_{j_1 J_2}$	Fraction of technology j_2 used in mode j_1	-	*'Crude Transport'* Table 2.6		[%]	[17], Est.	
λ_{jk}	Fraction of fuel k used in mode j	-	*'Crude Transport'* Table 2.7		[-]	Est.	a
P_j	Power consumption of mode j	-	*'Crude Transport'* Table 2.2		[hp]	[17]	
ρ_w	Density of fresh water	-	350.4	-	[lb/bbl]	[106]	
U_j	Transport effectiveness in mode m	(3.46); (3.45)	-	-	[Btu/ton-mi]		
$U_{j_1 j_2}$	Transport effectiveness of propulsion tech j_2 used in mode j_1	-	*'Crude Transport'* Table 2.5		[Btu/ton-mi]	[17]	
v_j	Velocity of mode j	-	*'Crude Transport'* Table 2.3		[mi-hr]	[17]	

[a] Default crude oil shipment distance in GREET is 750 mi for a one-way trip [17].

3.8 Bitumen extraction & upgrading

3.8.1 Introduction to bitumen extraction & upgrading

Bitumen extraction and upgrading is modeled separately from conventional oil extraction because the technologies applied differ. OPGEE v1.0 does not include process models as for bitumen extraction. Instead, OPGEE uses energy consumption and fugitive emissions data from GHGenius [13].

3.8.2 Calculations for bitumen extraction & upgrading

The OPGEE bitumen module tracks three hydrocarbon products: raw bitumen, synthetic crude oil, and hydrocarbon diluent. For each product, the API gravity, specific gravity (γ), and lower heating value (LHV) are generated. Blends of SCO and raw bitumen (synbit) or diluent-SCO-bitumen (dil-synbit) are not included in OPGEE. For bitumen and SCO, γ and LHV are derived from API gravity via formula or lookup [84]. The table of heating values as a function of API gravity does not account for composition differences between SCO of a given density and conventional crude of the same density. This introduces uncertainty of an unknown (though likely small) magnitude.

Fuel Specs Table 1.1

Diluent composition, density, and heating value are derived from tabulated diluent compositions [107]. Three diluent streams were selected from literature sources [107]. Hydrocarbon species are combined into bins (see notes in model) and the composition of diluent samples is plotted in Figure 3.14. Element fractions of C and H are calculated and the resulting heating value is calculated using the Dulong formula [106].

Bitumen Extraction & Upgrading Table 4.7

After specifying the properties of the hydrocarbon streams, production pathways are defined. First, the product is chosen as upgraded SCO or diluted bitumen:

Bitumen Extraction & Upgrading 2.6.1

$$y_{sco} \text{ or } y_{db} = 1 \tag{3.53}$$

where y is a binary variable representing a SCO product y_{sco} or a diluted bitumen product y_{db}.

Next, the primary extraction and (if applicable) upgrading technology pathway is defined:

Bitumen Extraction & Upgrading 2.6.2

- Bitumen mining with integrated upgrading, $y_{MI} = (0 \text{ or } 1)$
- Bitumen mining with non-integrated upgrading, $y_{MN} = (0 \text{ or } 1)$
- In situ production via non-thermal methods (e.g., production via cold heavy oil production with sand (CHOPS) or polymer flood), $y_{IP} = (0 \text{ or } 1)$
- In situ production via steam assisted gravity drainage (SAGD), $y_{IS} = (0 \text{ or } 1)$
- In situ production via cyclic steam stimulation (CSS), $y_{IC} = (0 \text{ or } 1)$

In this case, only one path can be chosen so the sum of binary pathway variables y_j must equal 1:

$$\sum_j y_j = 1 \qquad (j \in MI, MN, IP, IS, IC) \tag{3.54}$$

An important parameter is the fraction diluent blending rate λ_{db}. Dilbit blending rates depend on the input bitumen density, the quality of product being produced, and the relative market value of diluent and bitumen (i.e., heavy-light refining value differential).

Bitumen Extraction & Upgrading 2.8

The calculation of emissions from bitumen extraction and upgrading operations is based on energy intensities from GHGenius [13]. OPGEE estimates diesel, natural gas, electricity, coke, and still gas use. Values are derived from GHGenius as energy consumed, to avoid divergence due to varying energy densities.[2] GHGenius energy intensities are derived from industry-reported energy use [108].

Bitumen Extraction & Upgrading Table 4.1 - 4.4

The energy consumed of a given fuel type k per unit of energy produced is given by e_k:

$$e_k = e_{EX,k} + e_{UP,k} \qquad [\text{mmBtu/bbl SCO}] \tag{3.55}$$

where the primary resource extraction energy use $e_{EX,k}$ for fuel type k is equal to:

Bitumen Extraction & Upgrading 3.1.1

$$e_{EX,k} = y_{sco}\left(\sum_j y_j e_{EX,jk}\right)\frac{1}{\Delta V_{UP}} + y_{db}\left(\sum_{\forall j \neq MI} y_j e_{EX,kj}\right)(1-\lambda_{db}) \tag{3.56}$$

$$(j \in MI, MN, IP, IS, IC) \quad (k \in di, ng, el, ck, sg) \qquad [\text{mmBtu/bbl SCO}]$$

where in this equation $e_{EX,jk}$ = specific energy use in extraction pathway j of fuel type k [mmBtu/bbl bitumen]; ΔV_{UP} = volumetric gain upon upgrading [bbl SCO/bbl bitumen]; and λ_{db} = fraction of diluent blended into the dilbit product. Depending on whether y_{sco} or y_{db} is equal to 1, only one of these sums is performed. If the bitumen is upgraded, the energy consumed per bbl of bitumen mined is reduced by the factor $1/\Delta V_{UP}$ because 1 bbl of bitumen results in the production of more than 1 bbl of SCO. In the case of blended dilbit, the energy consumed per bbl of bitumen is reduced by the factor (1-λ_{db}) because the dilbit contains diluent in addition to bitumen.

For modeling natural gas consumption, a special consideration is made for the steam oil ratio. In this case:

Bitumen Extraction & Upgrading 3.1.1.2

$$e_{EX,ng} = y_{sco}\left(\sum_j y_j e_{EX,jk}\frac{SOR_j}{SOR_{j0}}\right)\frac{1}{\Delta V_{UP}} + y_{db}\left(\sum_{\forall j \neq MI} y_j e_{EX,kj}\frac{SOR_j}{SOR_{j0}}\right)(1-\lambda_{db})$$

$$(j \in MI, MN, IP, IS, IC)$$

[2] For example, natural gas heating values are quite variable between GHGenius and GREET per scf of gas

(3.57)

where SOR_j = steam oil ratio observed in pathway j and SOR_{j0} = default SOR in that pathway. In pathways without steam injection,the SOR term is equal to 1. Energy demand in thermal extraction will scale nearly linearly with steam injection rates because of the increase in steam energy consumption and increase in fluid handling energy requirements with increasing SOR [4, 12].

Energy of type k consumed in upgrading is modeled using the following function:

Bitumen Extraction & Upgrading 3.1.2

$$e_{UP,k} = y_{sco}\left(\sum_{\forall j \neq MI} y_j e_{UP,jk} + y_{MI}\left(e_{UP,MI,k} - \frac{e_{EX,MN,k}}{\Delta V_{UP}}\right)\right) \tag{3.58}$$

$$(j \in MI, MN, IP, IS, IC) \quad (k \in di, ng, el, ck, sg) \qquad [\text{mmBtu/bbl SCO}]$$

Where $e_{UP,k}$ is energy consumption of fuel type k for stand alone upgrading, and $e_{UP,MI,k}$ and $e_{EX,MN,k}$ are energy use of type k for integrated mining and upgrading and non-integrated mining. Therefore, the upgrading energy consumption for an integrated operation is modeled as the difference between an integrated mining and upgrading operation and the volumetric gain adjusted energy consumption for a stand-alone mining operation.

Venting, flaring and fugitive emissions are calculated using volumetric dilbit and SCO adjustments as above. As with conventional pathways in OPGEE, country-level average satellite flaring rates for Canada are applied to oil sands operations. This is done because of preference for the verifiable nature of satellite-derived data. For fugitive emissions, tabulated fugitive emissions factors from GHGenius are used as reported in GHGenius documentation [108].

Bitumen Extraction & Upgrading 3.2

External energy requirements are tabulated from total net energy inputs by making the following default assumptions about internal vs. external fueling of oil sands projects :

Bitumen Extraction & Upgrading 2.9

- Diesel, coke, and still gas consumed are generated onsite in upgraders or purchased from other local oil sands operations. This is generally the case due to the remote location of the oil sands operations;
- Natural gas and net electricity demand (on site consumption less on site generation) are purchased from external operations.

Using these assumptions, net energy requirements from the external energy system are computed. These net inputs are used to generate off-site emissions credits or debits from oil sands operations. Because diluent is typically a natural gas condensate, diluent consumed is counted as external natural gas production. In order to maintain congruence with other OPGEE pathways, upstream fuel cycle emissions are used from GREET.

Bitumen Extraction & Upgrading 3.3

Bitumen Extraction & Upgrading 3.3.1.6

Total net energy consumed and fugitive emissions, per bbl of output hydrocarbon product produced (e.g., diluted bitumen or SCO), are integrated with the overarching OPGEE emissions calculation framework.

Fuel Cycle Tables 1.2, 1.4

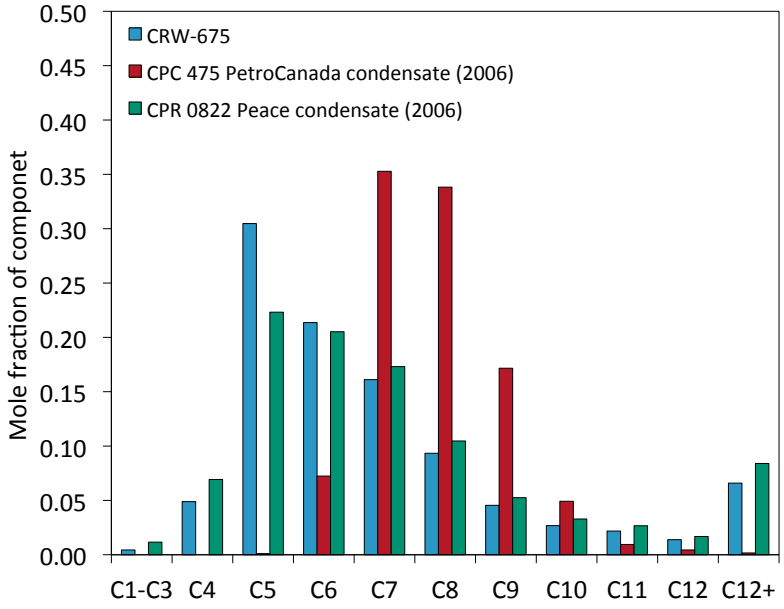

Figure 3.14: Composition of three diluent products from C1 to C12+ hydrocarbons.

Land use emissions from bitumen extraction operations are calculated similarly to those from conventional oil operations [77]. See Section 3.2 for a detailed description.

Bitumen Extraction & Upgrading 3.5

3.8.3 Defaults for bitumen extraction

The complete list of model terms, along with default values (if applicable) are included for all parameters in Table 3.11.

Table 3.11: Default inputs for bitumen extraction & upgrading calculations.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
$^\circ API_{db}$	API gravity of bitumen	-	8	4 - 12	[-]	[13]	
$^\circ API_{sco}$	API gravity of SCO	-	32	20 - 34	[-]	[13]	
$^\circ API_{dl}$	API gravity of diluent	-	59.4	55 - 63	[-]	[107]	
$e_{EX,k}$	Cons. of fuel k in extraction	(3.56)	-	-	[mmBtu/bbl]	-	
$e_{EX,j,k}$	Cons. of fuel k pathway j in extraction	-	var.	-	[mmBtu/bbl]	[13]	a
$e_{UP,k}$	Cons. of fuel k in upgrading	(3.58)	-	-	[mmBtu/bbl]	-	
$e_{UP,j,k}$	Cons. of fuel k for pathway j in upgrading	-	var.	-	[mmBtu/bbl]	[13]	a
e_k	Total cons. of fuel k in bitumen extraction & upgrading	(3.55)	-	-	[mmBtu/bbl]	-	
λ_{db}	Diluent blending fraction in dilbit	-	0.33	0.15 - 0.5	[%]	[107, 109]	
SOR_{IS}	Steam oil ratio, SAGD	-	3.0	2.5 - 5	[bbl steam/bbl bit]	[110]	
SOR_{IC}	Steam oil ratio, CSS	-	3.9	3.5 - 6	[bbl steam/bbl bit]	[110]	
SOR_{IS0}	Default steam oil ratio, SAGD	-	3.0		[bbl steam/bbl bit]	[110]	
SOR_{IC0}	Default steam oil ratio, CSS	-	3.9		[bbl steam/bbl bit]	[110]	
ΔV_{UP}	Volumetric gain upon upgrading	-	1.17	Unknown	[bbl SCO/bbl bitumen]	[13]	b
y_{sco}	Binary var. for producing SCO	-	1	0 or 1	[y/n]		c
y_{db}	Binary var. for producing diluted bitumen	-	0	0 or 1	[y/n]		c
y_{MI}	Binary var. for integrated mine & upgrade	-	1	0 or 1	[y/n]		d
y_{MN}	Binary var. for non-integrated mine & upgrade	-	0	0 or 1	[y/n]		d
y_{IP}	Binary var. for in situ, primary	-	0	0 or 1	[y/n]		d
y_{IS}	Binary var. for in situ, SAGD	-	0	0 or 1	[y/n]		d
y_{IC}	Binary var. for in situ, CSS	-	0	0 or 1	[y/n]		d

[a] Data are presented in OPGEE tables 'Bitumen Extraction & Upgrading' sheet.
[b] Volumetric gain upon upgrading is based on 1:1 mass throughput rate for bitumen to SCO [13] and reduction in density from 8 to 32 °API.
[c] The most common pathway for bitumen production is mining and upgrading to synthetic crude oil, so upgrading is selected by default.
[d] The most common pathway for bitumen production is integrated mining and upgrading to synthetic crude oil, so y_{mi} is chosen by default.

4 Supplemental calculations sheets

4.1 Gas balance

This sheet tracks the gas balance across the process stages and ensures that gas is conserved in the system. Due to the complexity of allocating VFF emissions some simplifications were made to the overall structure of the system.

The gas-to-oil ratio (GOR) is defined as the total gas evolved while reducing the oil to atmospheric pressure divided by the volume of the remaining crude oil [2]. The GOR is used to calculate the volume of the produced gas stream. The total GOR depends on the crude oil, on the number of stages used in the oil-gas separation sequence, as well as the operating pressure of each stage [2]. The GOR and the associated gas composition is calculated after three or more separation stages when the GOR approaches a limiting value. Fugitives from active wells, well cellars, and well maintenance events (such as well workovers and cleanups) are assumed to occur upstream from surface separation. Therefore these emissions sources do not affect the volume and composition of the initial produced gas stream in the gas balance.

Gas Balance Table 1.1

The flaring of associated gas is assumed to occur upstream of the gas processing stage. Although the accumulation of gases to flare likely occurs at various points throughout the process, the flared gas is modeled as being flared before gas processing in OPGEE. This allows for an added flexibility in OPGEE to account for early field production or production in locations without a gas market. For these situations, no surface processing occurs and all produced gas is flared.

Gas Balance Table 1.2

Gas processing is presented in the gas balance as one process stage which includes gas treatment and dehydration as well as all the fugitives and venting of associated gas in these two processes system. These fugitive emissions do not include the venting from crude oil storage tanks. The associated gas GOR is computed at the last stage in the surface oil-gas separator. In reality the gas dehydrator can process both sweet and sour gases. The simplification of gas processing into one stage eliminates the need to determine which gas processing unit comes first (AGR unit or gas dehydrator). Accordingly, no differentiation is made between the inlet gas volumes of the gas treatment and gas dehydration units.

Gas Balance Table 1.4

A user control is placed at the composition of the inlet gas to the gas processing stage to make sure that the total fugitives and venting of associated gas components (i.e., CO_2, CH_4, and C2+) are conserved in the gas stream. In

the event of "ERROR" the user has to increase either the molar fraction of the gas component or the GOR.

The last stage in the gas balance before the generation of the product gas is the demethanizer where heavy gas components (C3+) are condensed and produced as natural gas liquid (NGL). The product NGL left after the use of NGL as a process fuel is either added to the crude oil output to increase its market value or exported. The export of NGL incurs a GHG emissions credit. The user determines the proportion of each gas component that is condensed in the demethanizer in the *'Surface Processing'* sheet. The default assumption is 50% ethane, 100% propane, and 100% butane.

Gas Balance Table 1.7

The volume of lifting gas, if applicable, is subtracted from the volume of product gas stream to calculate the volume of gas remaining for use as a process fuel and/or re-injection into the reservoir for pressure maintenance. Any product gas left after supplying the process fuel requirements and gas re-injection is exported.

4.2 Steam injection for thermal oil recovery

4.2.1 Introduction to steam injection

Steam injection for thermal enhanced oil recovery (TEOR) is practiced globally, with significant operations in California, Alberta, Indonesia, and Venezuela [111]. Steam injection reduces the viscosity of heavy crude oils by multiple orders of magnitude, even with relatively small temperature increases [12, 58, 61, 112, 113]. This viscosity reduction results in improved flow characteristics and improved reservoir sweep [61]. Many fields that would not produce economic volumes of hydrocarbons without steam injection become large producers after steam injection.

4.2.2 Calculations for steam injection

Steam generation for thermal oil recovery is modeled using two technologies: steam generation via once-through steam generators (OTSG) (Figure 4.1) and steam and electricity co-production via gas turbine and heat recovery steam generator (HRSG) combination (4.3).

Steam Injection 1.1.6

4.2.2.1 Steam system properties

The quantity of steam required is given by the oil production rate and the steam oil ratio:

Steam Injection 1.2.4

$$Q_{ws} = SOR\rho_w Q_o \qquad \left[\frac{\text{lbm water}}{\text{d}}\right] \tag{4.1}$$

Where Q_{ws} = steam required to be generated per day [lbm water/d]; SOR = steam oil ratio [bbl steam as cold water equivalent/bbl water]; ρ_w = density of water [lbm/bbl]; and Q_o = quantity of oil produced [bbl/d]. Steam quantities are measured as volume of cold water equivalent.

The enthalpy of steam generated ($h_{ws} = h_{ws}(p_{ws}, T_{ws})$) at steam quality X_{ws}, steam pressure p_{ws}, saturated steam temperature T_{ws} is given by:

Steam Injection 1.2.13

$$h_{ws} = h_{ws,g}X_{ws} + h_{ws,f}(1 - X_{ws}) \quad \text{where} \quad h_{ws} = h_{ws}(p_{ws}, T_{ws}) \qquad \left[\frac{\text{Btu}}{\text{lbm}}\right] \tag{4.2}$$

Steam temperature T_{ws} [°F] is tabulated for saturated steam as a function of saturation pressure p_{ws} [psia] (assuming that pressure is the controlled variable) [114]. Because we are using steam tables rather than direct computation, steam pressure is rounded before lookup. $h_{ws,g}$ = enthalpy of vapor phase water at p_{ws} [Btu/lbm] while $h_{ws,f}$ = enthalpy of saturated water at p_{ws} [Btu/lbm].

Input Data Table 5.3

Steam is generated at sufficient pressure to ensure that it will flow into the subsurface (eliminating the need for wellhead compressors). Due to friction and thermal losses in piping and wellbore, the steam pressure drops before reaching the reservoir:

Steam Injection 1.2.8

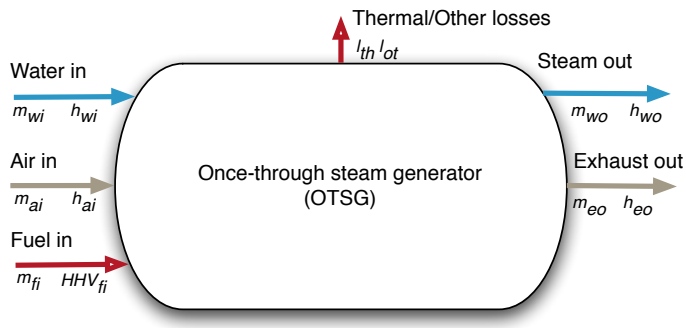

Figure 4.1: Once-through steam generator with mass and energy balance terms. Lower case terms are defined per lbmol of input fuel.

$$p_{ws} = p_{res}\epsilon_{ws} \qquad [\text{psia}] \tag{4.3}$$

where ϵ_p = pressure loss factor which is ≥ 1 [psia generator/psia reservoir]. Chilingarian et al. [41, p. 228] note that 10-50% of the pressure in the steam at steam generator outlet can be lost by the time the steam reaches the reservoir.

Steam quality X_{ws} [lbm vapor/lbm steam] is governed by the needs of the project. Higher steam qualities impart more energy into the formation, but steam quality is limited by the steam generator configuration. Once-through steam generators cannot generate 100% quality steam because of deposition of solids in boiler tubes. In practice, ≈20% of water mass is left in fluid state to carry solutes ($X_{ws} \approx 0.8$) [115].

The enthalpy increase of water is given by the difference between water inlet enthalpy and exit enthalpy:

Steam Injection 1.2.14

$$\Delta h_{ws} = h_{ws} - h_{w,in} \qquad \left[\frac{\text{Btu}}{\text{lbm water}}\right] \tag{4.4}$$

Where $h_{w,in}$ is water inlet enthalpy [Btu/lbm] for compressed water enthalpy at inlet water pressure $p_{w,in}$ and inlet water temperature $T_{w,in}$ [114]. Inlet pressure is assumed equal to required steam outlet pressure (e.g., no pressure gradient in boiler).

Input Data Table 5.4

4.2.2.2 Once-through steam generator modeling (OTSG)

Once-through steam generators are modeled [12, 115], as shown in Figure 4.1. Fuel inputs include pipeline quality natural gas, produced gas, or produced crude oil. A binary choice is required for gaseous or liquid fuels. For gaseous fuels, a mixture of produced gas and purchased gas is allowed.

Steam Injection 2.1.1, 2.1.2

The operating conditions of combustion must be specified. These include the inlet air temperature $T_{a,in}$ [°F], the outlet exhaust temperature $T_{e,out}$ [°F] and the excess air in combustion $R_{a,comb}$ [mol O_2/ mol stoichiometric O_2].

Gaseous fuel combustion for steam generation The gas species tracked in the OTSG are described below in Section 6.4. For an arbitrary fuel makeup, the composition, average molar mass, and higher heating value (HHV) are calculated.

Steam Injection 2.3.1

OTSG inlet air composition, combustion stoichiometry, and excess air ratio are used to compute the mass of air required per lbmol of fuel consumed. For each reactive species, the reactants needed per mol of input fuel are computed:

Fuel Specs Table 2.3

$$N_i = \frac{x_{a,i}}{x_{a,O2}} \left(x_{f,C} + \frac{x_{f,H}}{4} \right) \qquad \left[\frac{\text{lbmol}}{\text{lbmol fuel}} \right] \tag{4.5}$$

where N_i = number of moles of air species i [mol]; x_a, i = mole fraction of species i in air [mol/mol]; $x_{f,C}$ = mol of carbon per mol of fuel (e.g., 2 for C_2H_6) [mol/mol]; and $x_{f,H}$ = mol of hydrogen per mol of fuel [mol/mol]. The sum over all species i gives air required for stoichiometric combustion, which is multiplied by the excess air ratio $R_{a,comb}$ to get real air requirements:

Steam Injection 2.4.3.1

$$N_a = R_{a,comb} \sum_{i=1}^{n} N_i \qquad \left[\frac{\text{lbmol air}}{\text{lbmol fuel}} \right] \tag{4.6}$$

Where $R_{a,comb}$ = ratio of combustion air to stoichiometric air [lbmol air / min lbmol air for combustion]. In this case there are n species present in air.

At constant pressure the change in enthalpy with temperature is given as:

$$\delta h = C_p \delta T \qquad \left[\frac{\text{Btu}}{\text{lbmol}} \right] \tag{4.7}$$

Specific heat capacity C_p as a function of T can be defined for gas species i as [116, Table A-2E]:

$$C_{p,i} = a_i + b_i T + c_i T^2 + d_i T^3 \qquad \left[\frac{\text{Btu}}{\text{bmol-}^\circ\text{R}} \right] \tag{4.8}$$

Which can be integrated between outlet and inlet temperatures

$$h_i = \int_{T_{in}}^{T_{out}} C_{p,i} dT = a_i + \frac{b_i}{2} T^2 + \frac{c_i}{3} T^3 + \frac{d_i}{4} T^4 + e_i \qquad \left[\frac{\text{Btu}}{\text{lbmol}} \right] \tag{4.9}$$

where e_i is a constant of integration. OPGEE sets h = 0 at T = 300 K to solve for e_i. Terms a through d are given in OPGEE for N_2, O_2, CO_2, SO_2, air, $H_2O_{(v)}$ and fuel inputs (approximated as CH_4) [116].

Input Data Table 4.1

For example, inlet air enthalpy is computed using the inlet air temperature:

Input Data Table 4.1 - 4.6

$$h_{a,in} = \sum_{i=1}^{n} \left(a_i T_{a,in} + \frac{b_i}{2} T_{a,in}^2 + \frac{c_i}{3} T_{a,in}^3 + \frac{d_i}{4} T_{a,in}^4 + e_i \right) \qquad \left[\frac{\text{Btu}}{\text{lbmol air}} \right] \tag{4.10}$$

where again we have $i \in 1 \ldots n$ components in air.

The outlet lbmol of all gases per lbmol of fuel consumed are computed

Steam Injection 2.5.1.1

assuming complete combustion (e.g., no unburned hydrocarbons, no CO produced), and no reactions with nitrogen.

The enthalpy of OTSG outlet exhaust $h_{e,out}$ is computed with eq. (4.10), using user input OTSG exhaust outlet temperature $T_{e,out}$. In practice, efficient steam generation is achieved by reducing $T_{e,out}$ to as low as practicable, thus removing as much heat as possible from OTSG combustion products. $T_{e,out}$ has a lower limit due to the need to avoid condensing corrosive flue gas moisture onto heat transfer tubes [115]. *Steam Injection 2.5.1.4*

A wide range of exhaust gas temperatures is cited. Buchanan et al. cite ideal (minimum) exhaust gas temperatures of 266 °F [130 °C] or higher [117, p. 78]. Other sources cite temperatures of 350 °F [113, p. 36], 400 °F [41, p. 227] and even greater than 550 °F for older Russian units [112, p. 181]

In some cases, the exhaust gas temperature is limited by the approach to the inlet water temperature. In SAGD operations hot produced water is used as inlet water, and $T_{e,out}$ comes to within 15 °C of the inlet water temperature. An air preheater would allow utilization of this excess energy if hot produced fluids are used for water source [117].

In addition to losses from flue gas exhaust, other losses occur in an OTSG. We lump all thermal losses into a thermal shell loss term. For simplicity, it is assumed that 4% of fuel enthalpy is lost as thermal shell loss ϵ_{th} [Btu/lbmol fuel consumed]. Other losses (start up inefficiencies, fouling, etc.) ϵ_{ot} are assumed ≈1% of the fuel HHV [Btu/lbmol fuel consumed]. These total losses are supported by references, which cite losses of approximately 4% [115]. *Steam Injection 2.6.2, 2.6.3*

The enthalpy available for transfer to the incoming water is given by the difference between incoming enthalpy sources (incoming combustion air, fuel inputs) and outgoing enthalpy sources (hot exhaust, shell losses, other losses):

$$\Delta h_{comb} = HHV + h_{a,in} - h_{e,out} - \epsilon_{th} - \epsilon_{ot} \qquad \left[\frac{\text{Btu to water}}{\text{lbmol fuel}}\right] \tag{4.11}$$

Steam Injection 2.6.4

The efficiency of steam generation η_{OTSG} (HHV basis) can be computed by comparing the enthalpy imparted on steam to the higher heating value of the fuel inputs:

$$\eta_{OTSG} = \frac{\Delta h_{comb}}{HHV} \qquad \left[\frac{\text{Btu to steam}}{\text{Btu fuel}}\right] \tag{4.12}$$

Steam Injection 2.6.5

Using the enthalpy provided to steam and ΔH_{comb}, the total fuel consumption rate required per day can be computed.

$$m_f = \frac{Q_{ws}\Delta h_{ws}}{\Delta h_{comb}} \qquad \left[\frac{\text{lbmol fuel}}{\text{d}}\right] \tag{4.13}$$

Steam Injection 2.7.2

Liquid fuels for steam generation Liquid fuels can be used for steam generation. In general, these are produced heavy crude oils that are consumed on site for steam generation. This was common practice in California TEOR developments until the 1980s, when air quality impacts stopped the practice.

Table 4.1: Hydrogen constant a_H as a function of API gravity.

API gravity	a_H
0 - 9	24.50
10 - 20	25.00
21 - 30	25.20
31 - 45	25.45

Because liquid fuels do not have consistent molar compositons, computations generate lbm of fuel consumed. The heating value of crude oil as a function of API gravity is tabulated [84]. The bulk chemical composition of crude oil is calculated [84, p. 41]. The mass fraction hydrogen w_H as a function of crude specific gravity sg is given as:

Fuel Specs Table 1.1

Fuel Specs Table 1.2

$$w_H = a_H - 15\gamma_o \qquad [\text{mass frac. H}] \tag{4.14}$$

Where a_H is a constant that varies with crude API gravity (and therefore specific gravity) as show in Table 4.1.

The mass fraction of sulfur and other contaminants decreases with increasing API gravity, as seen in Figure 4.2 [118, Ch. 8, tables 3, 4] [118, Ch. 7, tables 2, 3, and 19] [119]. We therefore include default values of w_S that vary with API gravity from 5 wt.% (API gravity 4-5) to 0.5 wt.% (API gravity greater than 35). Nitrogen and oxygen content $w_N + w_O$ is assumed constant at 0.2 wt.% and in element balance it is assumed to be entirely made up of N. Mass fraction carbon w_C is calculated by difference using above mass fractions. Using the relative molar proportions of C, H, S, and N, the stoichiometric oxygen demand per carbon atom is computed assuming complete combustion.

Fuel Specs Table 1.2

Using the oxygen requirement for combustion and the excess air ratio $R_{a,comb}$, the lbmol of air required is computed similarly to eq. (4.6) above. The inlet air enthalpy for combustion is computed using eq. (4.10) above. The outlet exhaust composition is computed via element balance assuming complete oxidation (including S to SO_2). The outlet exhaust enthalpy is computed as in eq. (4.10) for gaseous fuels combustion. The energy balance for combustion of liquid fuels is computed as in eq. (4.11).

Steam Injection 2.4.4

4.2.2.3 Gas turbine with heat recovery steam generator

Cogeneration is used to co-produce electricity and steam for thermal oil recovery. These systems combine a gas turbine (GT) with a heat recovery steam generator (HRSG) to produce steam from the exhaust gas of the gas turbine (see Figure 4.3).

Gas turbine modeling The chemical kinetics software tool Cantera [120] is used with MATLAB to compute the efficiency, losses, and turbine exit temperature for four hypothetical gas turbines labeled A, B, C, and D. The general method is as follows:

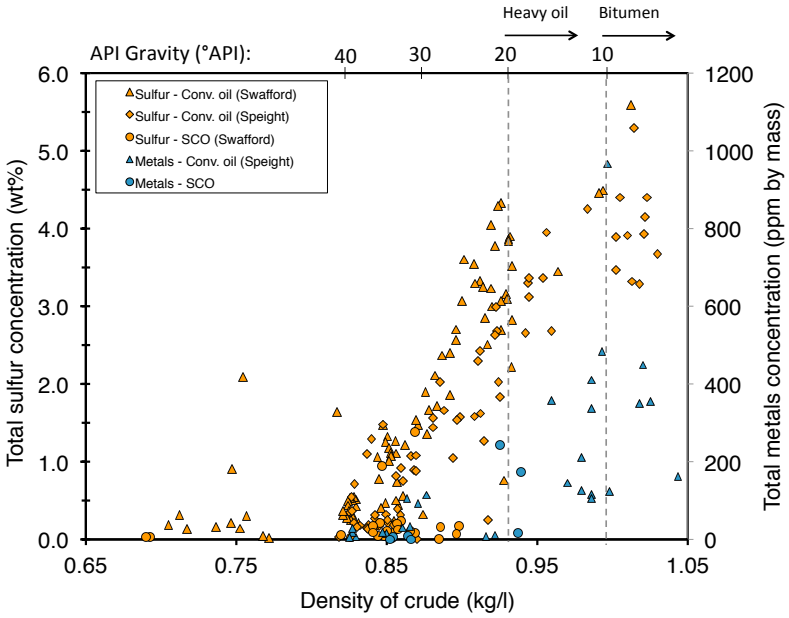

Figure 4.2: Increase of crude contaminant load with increase in crude specific gravity (decrease in API gravity). Data from: Speight (1994) and Swafford (2009).

- Fuel and air compositions are specified in OPGEE for purchased natural gas (95% CH_4, 3% C_2H_6, 1.5% C_3H_8, and 0.5% inert) and air (dry air with 2% moisture).
- The LHV of the fuel is computed assuming complete combustion.
- Using the excess air fraction for a given turbine, the amount of O_2 (and therefore air) required relative to stoichiometric air requirements is used to compute relative air and fuel inputs into a mixture. The masses of fuel inputs $m_{f,in}$ and air inputs $m_{a,in}$ are normalized to a 1 kg mixture, as is default in Cantera.
- The fuel and air mixture is equilibrated using the assumption of adiabatic combustion.
- The enthalpy of products of adiabatic combustion is recorded as h_e, or the mass-specific enthalpy after combustion.
- The enthalpy of products of combustion is computed when returned to initial conditions (300 K, 101.325 kPa) to compute the reference enthalpy $h_{e,atm}$.
- The difference between the enthalpy of hot combustion products and the reference enthalpy of completely cool exhaust is partitioned into losses (pressure and temperature losses due to real machine imperfections), work provided by turbine (W_{GT}), and enthalpy of hot exhaust ($h_{e,out}$).

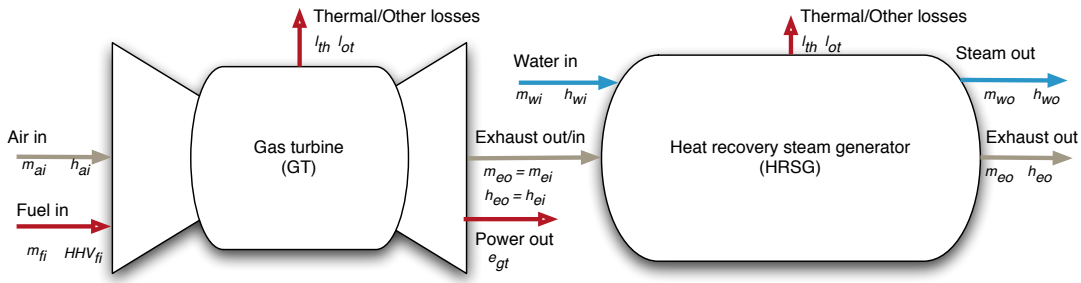

Figure 4.3: Gas turbine plus heat recovery steam generator model. Mass flows represented by m and energy flows represented by fuel higher heating value (HHV), electric power out (e) and enthalpy of gases (h).

- The resulting temperature of hot exhaust gases is computed.

The gas turbine model was tested against reported gas turbine data. Data for turbine heat rate, power output, turbine exhaust mass flow rate, and turbine exhaust temperature were collected for commercial turbines from Siemens, GE, and Hitachi [121–123]. The code assumes consistent 4% thermal and other losses ($\epsilon_{th} + \epsilon_{ot}$) for each turbine. Results show excellent agreement between predicted turbine exhaust temperature and manufacturer-reported turbine exhaust temperatures (Figure 4.4).

The GT model is used to model four hypothetical turbines A - D, using characteristics similar to those specified by Kim [124]. The results from our code are used to generate required inputs for turbines A-D including turbine exhaust temperature [F], turbine efficiency [Btu e- per Btu HHV fuel input], turbine specific power [Btu e-/lb exhaust], turbine excess air [lbmol O_2 / lbmol stoichiometric O_2], and turbine loss factor [Btu/Btu HHV fuel input]. These results are shown in Table 4.2.

Input data Table 3.1

Using turbine efficiency and turbine loss from Table 4.2, energy balances for each turbine are computed. Using turbine excess air ratios from Table 4.2, total air requirements per lbmol of fuel input to gas turbine are computed. Inlet air enthalpy is computed as shown in eq. (4.10). Moles of combustion products are computed via stoichiometric relationships. Using turbine exhaust temperature, turbine exhaust composition, and relationships from eq. (4.10), the enthalpy of gas turbine exhaust is computed.

Steam Injection 4.3.1

Steam Injection 4.3.4.4

Steam Injection 4.3.5.2

The enthalpy of the gas turbine exhaust is the useful energy input to the HRSG. Steam production via the HRSG is modeled analogously to that of the OTSG.

Steam Injection 4.3.5.7

4.2.3 Defaults for steam injection

4.2.3.1 General default parameters

Parameters and variables in the steam injection model are listed below in Table 4.3.

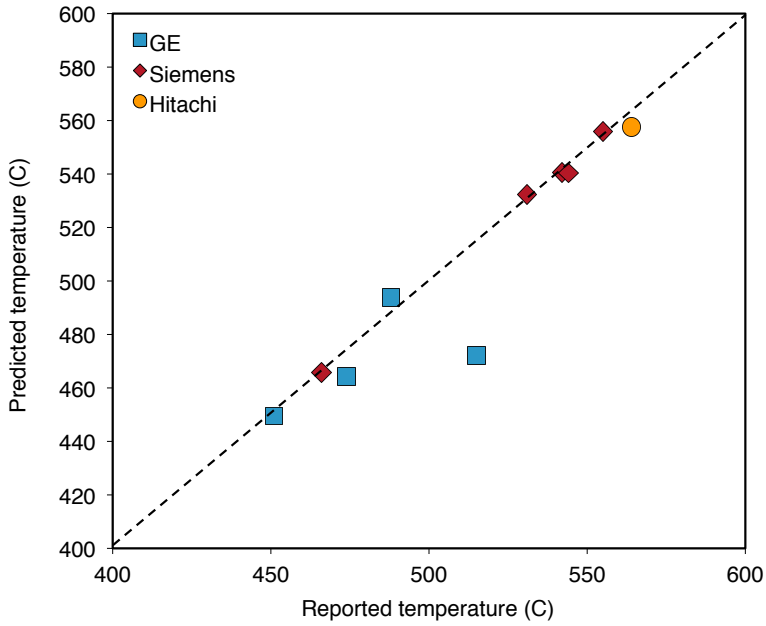

Figure 4.4: Predicted turbine exit temperatures for variety of turbines from literature (*y-axis*) as compared to reported value from the literature (*x-axis*).

Table 4.2: Gas turbine model results for hypothetical turbines A-D. These results serve as input data to OPGEE GT model.

Parameter	Unit	Turb. A	Turb. B	Turb. C	Turb. D
Turbine exhaust temp.	[°F]	932.0	947.9	950.0	1074.1
Turbine efficiency	$\left[\frac{\text{Btu e-}}{\text{Btu HHV}}\right]$	0.205	0.237	0.280	0.324
Turbine specific power	$\left[\frac{\text{Btu e-}}{\text{lb exhaust}}\right]$	69.5	85.4	108.0	155.7
Turbine excess air	$\left[\frac{\text{Mol } O_2 \text{ real}}{\text{Mol } O_2 \text{ stoich.}}\right]$	4.00	3.75	3.50	2.80
Turbine loss	$\left[\frac{\text{Btu loss}}{\text{Btu HHV}}\right]$	0.041	0.036	0.032	0.027

Table 4.3: Default inputs for steam injection calculations.

Param.	Description	Eq. no.	Default	Lit. range	Unit	Sources	Notes
a_H	Crude hydrogen fraction constant	-	Table 4.1	-	[lbm H / lbm crude oil]	[84]	
$a_i \ldots e_i$	Species-specific heat capacity constants	-	var.	-	[various]	[116]	
C_p	Heat capacity at constant pressure	(4.8)	-	-	[Btu/lbmol-°R]		
η_{OTSG}	OTSG efficiency	(4.12)	-	-	[Btu steam / Btu HHV fuel]		
ϵ_{th}	Thermal losses from OTSG	-	0.04	-	[Btu/Btul fuel]	[115]	
$\epsilon_{ot,ng}$	Other losses from OTSG fueled with natural gas	-	5000	-	[Btu/lbmol fuel]	[115]	c
$\epsilon_{ot,co}$	Other losses from OTSG fueled with crude oil	-	250	-	[Btu/lbml fuel]	[115]	c
ϵ_{ws}	Steam pressure loss factor	-	1.25	0.1 - 0.5	[frac.]	[41]	d
λ_{ng}	Fraction natural gas	-	1	0 - 1	[frac]	-	b
λ_{pg}	Fraction processed associated gas	-	0	0 - 1	[frac]	-	b
$h_{a,in}$	Inlet air enthalpy	(4.10)	-	-	[Btu/lbmol]		
$h_{e,out}$	Enthalpy of OTSG exhaust	(4.10)	-	-	[Btu/lbmol]		
$h_{ws,f}$	Enthalpy of liquid phase water in steam	-	var.	180 - 730	[Btu/lbm]		
$h_{ws,g}$	Enthalpy of vapor phase water in steam	-	var.	1090 - 1205	[Btu/lbm]		
h_{ws}	Enthalpy of injected steam ($<$ 100% quality)	(4.2)	-	-	[Btu/lbm]		
$h_{w,in}$	Inlet water enthalpy	-	9.8	-	[Btu/lbm]		
Δh_{ws}	Change in water enthalpy upon boiling	(4.4)	-	-	[Btu/lbm]		
Δh_{comb}	Heat available from combustion to water	(4.11)	-	-	[Btu / lbmol fuel]		
h_i	Enthalpy of species i	(4.9)	-	-	[Btu/lbmol]		
HHV	Higher heating value of fuel	-	var.	-	[Btu HHV / lbmol fuel]		
N_i	Number of moles of air species i	(4.5)	-	-	[lbmol]		
N_a	Number of moles of air for real (non-stoichiometric) combustion	(4.6)	-	-	[lbmol]		

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Param.	Description	Eq. no.	Default	Lit. range	Unit	Sources	Notes
$p_{w,in}$	Inlet water pressure	-	$= p_s$	-	[psia]		
p_{ws}	Steam pressure	(4.3)	-	-	[psia]		
Q_o	Quantity of oil produced	-	1000	-	[bbl oil/d]		
Q_{ws}	Steam required	(4.1)	-	-	[lbm water/d]	-	
$R_{a,comb}$	Excess air combustion ratio	-	1.2	1.075 - 1.25	[lbmol air/lbmol air stoich.]		e
ρ_w	Density of water	-	350.4	-	[lbm/ft^3]	[106]	f
γ_o	Crude specific gravity	(3.3)	-	-	[-]		
SOR	Ratio of steam injected to oil produced	-	3.0	2.5 - 6	[bbl water/bbl oil]	[110, 125]	g
$T_{a,in}$	Inlet air temperature	-	540	500 - 560	[°R]		h
$T_{e,out}$	Temperature of OTSG exhaust	-	810	725 - 910	[°R]	[various]	i
$T_{w,in}$	Inlet water temperature	-	40	-	[°F]		j
T_{ws}	Steam temperature	-	var.	-	[°F]		
w_H	Mass fraction hydrogen in crude	(4.14)	-	-	[lbm H / lbm oil]		
$x_{a,i}$	Mole fraction of species i in air	-	var.	-	[lbmol/lbmol]		m
x_C	Moles of carbon per mole of fuel	-	var.	-	[lbmol/lbmol]		a
x_H	Moles of hydrogen per mole of fuel	-	var.	-	[lbmol/lbmol]		a
X_s	Steam quality	-	0.8	-	[lbm vap./lbm steam]	[61]	k
y_{ng}	Binary variable: gaseous fuel in OTSG?	-	1	0 or 1	[y/n]	-	l
y_{co}	Binary variable: crude oil in OTSG?	-	0	0 or 1	[y/n]	-	l

a - See *'Fuel specs'* Table 2.3 for combustion factors for gas inputs.
b - Assumption: Gas is purchased due to typical low GORs for heavy crudes.
c - Assumption to account for incomplete combustion, fouling, warm up and cool-down, and other real-world inefficiencies.
d - Piping friction losses can represent 10-50% of the steam pressure developed at the outlet of the steam generator." [41, p. 228]
e - Conservative assumption for input excess air. Can be lower with special combustion equipment.
f - Fresh water input
g - Common SOR for efficient TEOR project. Range is quite variable, especially in early years of steam injection.
h - Equal to 300 K. Chosen for ease of gas turbine modeling.
i - Equal to 350 °F. Reported range is wide in literature. See [41, 112, 113, 117].

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Param.	Description	Eq. no.	Default	Lit. range	Unit	Sources	Notes
j - Assumption for cool water inlet.							
k - Most commonly cited steam quality. Other qualities cited include 75%.							
l - Assumption: Most steam generation in California and Alberta is natural gas fired.							
m - See *'Input Data'* Table 2.4 for air composition.							

Table 4.4: Indicators of SOR distributions for California and Alberta thermal EOR production.

	Mean - SOR_t	Mean - SOR_i
California - 2009	3.32	4.29
California - 2010	3.41	Unk.
Alberta - 2009	3.58	NA
Alberta - 2010	3.32	NA

4.2.3.2 Default for steam-oil-ratio (SOR)

Because the SOR is a key parameter driving GHG emissions from thermal oil production operations, we examine default values for SOR in more detail.

SOR data are collected for California and Alberta thermal oil recovery operations for 2010 and 2011 [101, 110, 125–127].

For California operations, incremental SOR is calculated for 2009 using volumes of steam injected and reported incremental production due to steam injection. 'Total' SOR is also calculated for 2009 using total production by field and total steam injection. For 2010, only monthly data are available, so incremental production data are not available. Therefore, only total SOR is reported.

For Alberta operations, data on bitumen produced and steam injected were collected for 24 thermal recovery projects (SAGD and CSS). No data were available on incremental rather than total production, and it is not clear what incremental production figures would represent bitumen operations where non-enhanced production would be very small.

Production volumes are binned by SOR for both regions and reported in Figure 4.5. Averages for SOR are presented in Table 4.4.

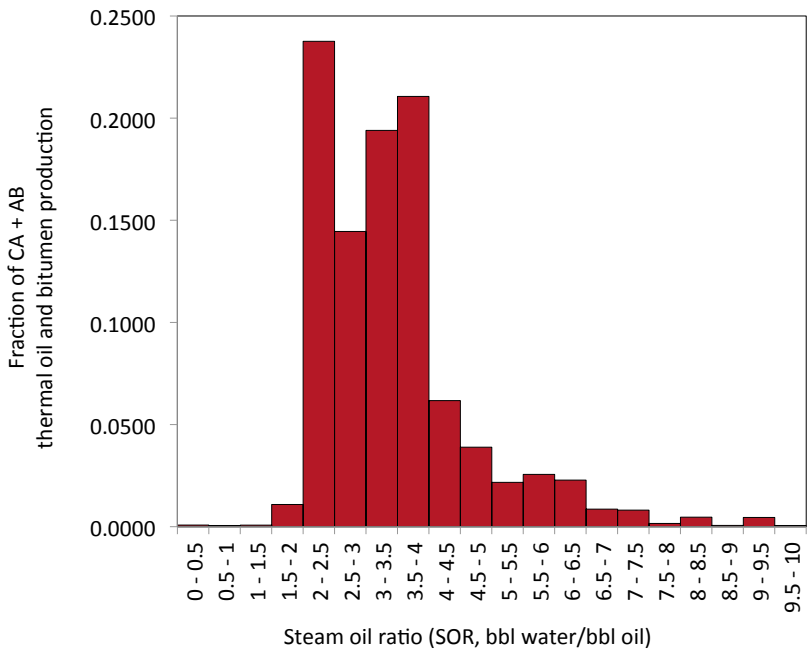

Figure 4.5: Distribution of SOR values for California and Alberta thermal EOR projects (steamflood, cyclic steam stimulation, steam-assisted gravity drainage).

4.3 Venting, flaring and fugitives (VFF)

4.3.1 Introduction to venting, flaring, and fugitive emissions

Venting, flaring and fugitive emissions can be a significant source of GHG emissions from oil production operations. We use these definitions here:

Venting emissions Purposeful release of non-combusted hydrocarbon gases to the atmosphere. Venting emissions generally occur during maintenance operations and other intermittent, infrequent activities.

Flaring emissions Purposeful combustion of hydrocarbon gases for disposal purposes. Results in CO_2 emissions rather than hydrocarbon species, with the exception of unoxidized hydrocarbon gases released due to flare inefficiency.

Fugitive emissions Non-purposeful or non-planned emissions of non-combusted hydrocarbon gases to the atmosphere. Fugitive emissions commonly result from leaking equipment and tanks.

Flaring is used to dispose of associated natural gas where there is no economic use for the gas. Associated gas evolves from crude oil as it is brought to surface temperatures and pressures, and is separated from oil before transport (see Section 3.4). Gas flaring resulted in emissions of 0.28 Gt CO_2 eq. in 2008, or about 1% of global GHG emissions [16]. Because gas flaring is used to dispose of gas (typically at remote locations), the volume of flared gas is uncertain.

Venting and fugitive emissions arise from oil field operations and devices. Sources include well workovers and cleanups, compressor startups and blowdowns, pipeline maintenance, gas dehydrators, AGR units, well cellars, separators (wash tanks, free knock outs, etc.), sumps and pits, and components (valves, connectors, pump seals, flanges, etc.). The heterogenous nature of these sources makes venting and fugitive sources difficult to monitor and track.

4.3.2 Calculation of flaring emissions

The NOAA National Geophysical Data Center have used earth observation satellite data for the estimation of gas flaring volumes since 1994 [16]. Gas flaring volumes are estimated for individual countries. Results show that gas flaring is concentrated in a small number of countries: in 2008, Russia and Nigeria together accounted for 40% of global gas flaring [16].

For the calculation of flaring emissions, the key input parameter is the flaring-to-oil ratio, or FOR [scf/bbl]. The FOR is converted into flaring volume using the volume of oil produced:

VFF 2.1.1

$$Q_F = \frac{FOR \cdot Q_o}{10^6} \quad \text{[MMscf/d]} \tag{4.15}$$

where Q_F = flaring volume [MMscf/d]; FOR = flaring-to-oil ratio [scf/bbl of oil]; and Q_o = volume of oil produced [bbl/d].

Table 4.5: Stoichiometric relationships for complete combustion.

Fuel	Stoichiometric factor Π
CO_2	1
CH_4	44/16
C_2H_6	88/30
C_3H_8	132/44
C_4H_{10}	176/58

The OPGEE default FOR is given by country-level flaring data [128] and production volume [129] for 2010. The default flaring rate is retrieved from *'VFF'* sheet based on the field location specified in the *'User Inputs & Results'* sheet. The flaring rate in a specific oil field could be significantly higher or lower than the country-average. In the case no default is available for the specified field location, the world wide average is taken as the default value. *VFF Table 1.1*

Carbon-dioxide-equivalent flaring emissions are calculated from the flaring volume using the flare efficiency η_F. The flare efficiency is the fraction of flared gas that is combusted. The remaining gas undergoes fuel stripping and is emitted as unburned hydrocarbons.

Flare efficiency varies with flare exit velocities and diameters, cross wind speed, and gas composition [14, 15]. For example, flare efficiencies in Alberta were estimated to range from 55% to $\geq$ 99%, with a median value of 95%, adjusted for wind speed distributions [14].

Emissions from non-combusted gas are calculated using the composition of associated gas from the *'Gas Balance'* sheet: *VFF 3.1.2*

$$EM_{F,str} = Q_F(1-\eta_F)\sum_i x_i \rho_i GWP_i \qquad [\text{tCO}_2\text{eq/d}] \tag{4.16}$$

where $EM_{F,str}$ = flaring emissions from stripped, non-combusted gas [tCO_2eq/d]; η_F = flaring efficiency [%]; Q_F = flaring volume [MMscf/d]; i = index of gas species CO_2, CH_4, and volatile organic compounds C_2H_6, C_3H_8 and C_4H_{10}; x_i = molar fraction of gas component i [mol/mol]; ρ_i = density of gas component i [g/ft^3]; and GWP_i = GWP of gas component i [g CO_2 eq. /g gas].

Emissions from flare combustion products assume complete combustion: *VFF 3.1.1*

$$EM_{F,comb} = Q_F \eta_F \sum_i x_i \rho_i \Pi_i \qquad [\text{tCO}_2\text{eq/d}] \tag{4.17}$$

where $EM_{F,comb}$ = flaring emissions from combusted gas [$tCO_2eq./d$]; Π_i = stoichiometric relationship between component i and product CO_2 for complete combustion [g CO_2/g gas]. Combustion factors are listed in Table 4.5.

Total flaring emissions are the sum of stripped and combustion emissiosn: *VFF 3.1*

$$EM_{F,tot} = EM_{F,str} + EM_{F,comb} \qquad [\text{tCO}_2\text{eq/d}] \tag{4.18}$$

4.3.3 Calculation of venting emissions

Two types of venting occur in production and processing facilities: (i) operational venting, and (ii) venting to dispose of associated gas where there is no infrastructure for the use of gas. Operational venting is associated with production, processing and maintenance operations such as well workovers and cleanups, compressor blowdowns, and gas processing units (AGR and glycol dehydrator). These operations necessitate the venting of some gas. For instance, in a glycol dehydrator, steam generated in the reboiler strips water from the liquid glycol as it rises up the packed bed and the water vapor and desorbed natural gas are vented from the top of the stripper [2, p. 140].

Disposal venting is not common, due to safety concerns and environmental impacts, but may be practiced in some fields as an alternative to flaring. Venting as an alternative to flaring is not environmentally acceptable because methane and volatile organic compounds (VOCs) have higher GWPs compared to carbon dioxide. The venting of produced gas is a user input and is presented by the venting-to-oil ratio or VOR in the *'User Inputs & Results'* sheet. The calculation of emissions from vented gas is as shown in eq. (4.16).

Venting associated with production and surface operations is estimated using data collected in the 2007 oil & gas GHG emissions survey in California, performed by California Air Resources Board (ARB) [3], and the API manual of petroleum measurement standards [68].

4.3.3.1 Venting from general sources

Operational venting may be associated with units (e.g., compressors), events (e.g., well workovers), or distance of product transport (e.g., gathering pipelines). The amount of gas vented from various sources is calculated using the number of unit-years, mile-years, or events associated with the volume of oil produced. A unit-year (abbreviated unit-yr), for example, is one unit operating over a time period of one year.

The sources for general venting are listed in Table 4.6. The first step in calculating venting emissions from general sources is to estimate the number of unit-years, mile-years, or events associated with one barrel of oil, as shown in Table 4.6. The venting emissions from general sources are calculated as: *VFF 3.2.2*

$$EM_{V_G} = \sum_s c_{V_G,s} Q_o EF_{V_s} \qquad \text{[g/d]} \tag{4.19}$$

where EM_{V_G} = venting emissions from general sources as listed in Table 4.6 [g/d]; $c_{V_G,s}$ = activity factor per unit of oil produced [unit-years/bbl, event/bbl or mile-years/bbl]; Q_o = total rate of oil production [bbl/d]; and EF_{V_s} = vent emissions factors for source s [g/unit-yr, g/mile-yr, or g/event]. $c_{V_G,s}$ is calculated as shown in Table 4.6 by multiplying $a_{V_G,s}$ which is the total number of units, events or miles surveyed [mile, unit, or event/yr] with $b_{V_G,s}$ which is the reported oil production volumes [bbl/yr].

Table 4.6: Emissions data used in the estimation of operational venting. Data from California oil fields, 2007 [3].

Source	Activity a_{V_G}	Unit	Oil Prod. (bbl/yr) b_{V_G}	Activity factor c_{V_G}	Unit [event/bbl]
Well workovers					
- Ultra-heavy	0	[event/yr]	614,683	0	[event/bbl]
- Heavy	12,889	[event/yr]	156,304,520	8.25×10^{-5}	[event/bbl]
- Light	5,424	[event/yr]	61,524,698	8.82×10^{-5}	[event/bbl]
- Ultra-light	599	[event/yr]	15,649,398	3.83×10^{-5}	[event/bbl]
Well cleanups					
- Ultra-heavy	0	[event/yr]	614,683	0	[event/bbl]
- Heavy	956	[event/yr]	156,304,520	6.12×10^{-6}	[event/bbl]
- Light	1977	[event/yr]	61,524,698	3.21×10^{-5}	[event/bbl]
- Ultra-light	187	[event/yr]	15,649,398	1.19×10^{-5}	[event/bbl]
Compressors	$\simeq$643[a]	[unit]	234,093,299	2.75×10^{-6}	[unit-yr/bbl]
Gathering pipelines	1218[b]	[mile]	234,093,299	5.20×10^{-6}	[mile-yr/bbl]
Pigging launcher openings	$\simeq$850[a]	[event/yr]	234,093,299	3.63×10^{-6}	[event/bbl]

a - Estimated from the total number of compressors which is shared by both the crude oil and dry gas businesses in California. The number of crude oil wells surveyed makes ≈60% of the total number of wells [3]. Accordingly the crude oil business is roughly allocated 60% of the total number of compressors reported in the survey.
b - Estimated by summing the number of miles associated with the crude oil business. Miles associated with dry gas production and gas storage facilities are not counted. For central gas processing facilities 75% of the miles are allocated to the crude oil business. This assumption is based on the split between the types of gases produced in California where ≈75% of the produced gas is associated gas [3].

The emissions factors and therefore the emissions estimates are specific to gas components (e.g., CO_2). The emissions factors for the venting of CO_2 and CH_4 are also estimated using data from the ARB survey [3]. Calculations of emissions factors are explained in Section 4.6.

4.3.3.2 *Venting from gas processing units*

Other than the general venting emissions sources that are listed in Table 4.6 there are major venting sources which include venting from gas processing units like glycol dehydrator unit and amine acid gas removal (AGR) unit. The methods for calculating venting from glycol dehydration and amine AGR units are volume based. For the glycol dehydrator unit the venting emissions of both CO_2 and CH_4 are calculated based on the gas unit volume as: *VFF 3.2.2*

$$EM_{V_{GD}} = Q_{GD} EF_{V_{GD}} \qquad [\mathrm{g/d}] \tag{4.20}$$

where $EM_{V_{GD}}$ = venting emissions from the glycol dehydrator unit [g/d]; Q_{GD} = volume throughput of the glycol dehydrator unit [MMscf/d]; and $EF_{V_{GD}}$ = vent emissions factors for glycol dehydrator [g/MMscf]. The emissions factors as noted above are calculated from the ARB survey data [3] as explained above. The approximate volume throughput of the glycol dehydrator is determined by the gas balance and is calculated as shown in eq. (3.31). A description of the gas balance is found in Section 4.1.

The calculation of CH_4 venting from the AGR unit is performed as outlined above for the glycol dehydrator: *VFF 3.2.2*

$$EM_{V_{AGR}} = Q_{AGR} EF_{V_{AGR}} \qquad [\mathrm{g/d}] \tag{4.21}$$

where $EM_{V_{AGR}}$ = CH_4 venting emissions from the amine AGR unit [g/d]; Q_{AGR} = volume of the amine AGR unit [MMscf/d]; and $EF_{V_{AGR}}$ = vent emissions factor for AGR unit [gCH_4/MMscf]. On the other hand, the calculation of the CO_2 emissions from the amine AGR unit is determined by the gas balance where all the CO_2 left in the gas after flaring, fugitives and other venting is assumed to be absorbed and stripped in the amine treater.

4.3.3.3 *Venting from crude oil storage tanks*

The calculation of venting emissions from storage tanks is based on API standards for the measurement of evaporative loss from crude oil storage tanks [68]. Fixed-roof tanks are assumed as default for the estimation of venting emissions. Figure 4.6 shows the types and default dimensions of the fixed-roof tanks that can be chosen by the user to model venting emissions from crude oil storage. *VFF 2.2.7*

Fixed-roof tanks are vessels that have a vertical cylindrical shell and a fixed roof as shown in Figure 4.6. These are available in a range of sizes from 20 to 300 feet in diameter and up to 65 feet in shell height [68, p. 42]. The default

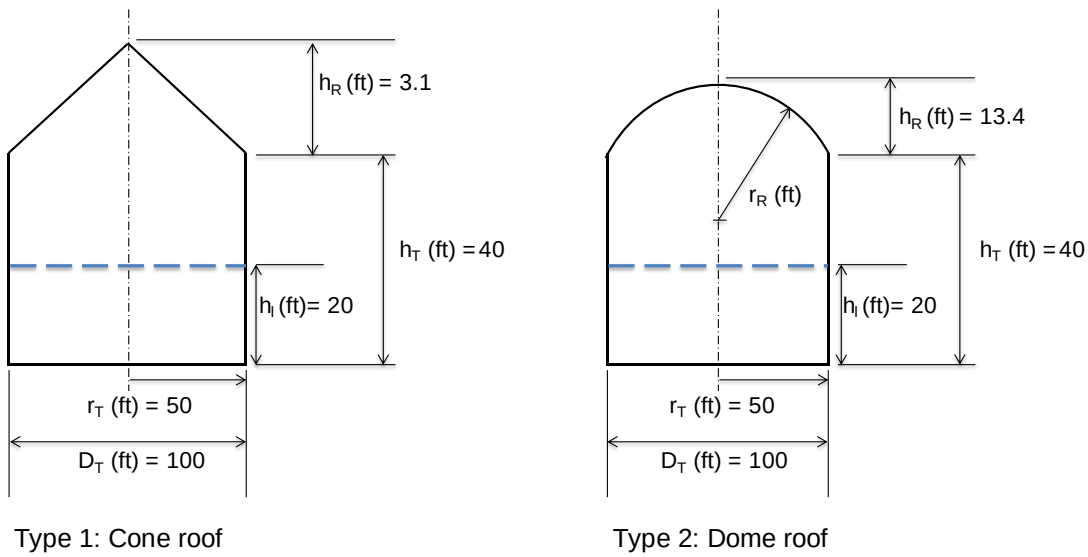

Figure 4.6: Types of fixed-roof storage tanks and default dimensions used in OPGEE.

dimensions used in OPGEE are shown in Figure 4.6. The fixed roof may be cone-shaped or dome-shaped as shown in Figure 4.6. Other storage tanks have a floating roof, but these types of tanks are not considered in OPGEE for the estimation of venting emissions.

Crude oil has a finite vapor pressure that creates a tendency for dissolved gases and volatile organic compounds (VOCs) to evaporate. Through evaporation, crude oil establishes an equilibrium concentration of vapors above the oil surface. Under static conditions, an equilibrium vapor concentration would be established, after which no further evaporation would occur. However, fixed-roof tanks are exposed to dynamic conditions (e.g., heating) that disturb the equilibrium, leading to additional evaporation. These dynamic conditions are responsible for continued evaporation, resulting in stock loss and atmospheric emissions [68, p. 45].

The total evaporative loss from the fixed-roof tank is the sum of the standing storage loss and the working loss. Standing storage loss is the evaporative loss of the stock vapor resulting from the thermal expansion and contraction of the tank air-vapor mixture resulting from the daily heating cycle. This loss occurs without any change in the stock level in the tank. Working loss is the evaporative loss of stock vapor resulting from a change in liquid level in the tank [68, p. 45].

The calculations of storage tank losses are outlined below with a description of each parameter [68]. The total loss is calculated by multiplying single tank loss with the number of storage tanks. Therefore, OPGEE assumes a number of storage tanks of identical characteristics and dimensions. The total evaporative loss from storage tanks is calculated as: *VFF 3.2.3*

$$L_T = L_S + L_W \qquad \text{[lb/yr]} \tag{4.22}$$

where L_T = total evaporative loss from storage tanks [lb/yr]; L_S = standing storage loss [lb/yr]; and L_W = working storage loss [lb/yr]. The standing loss is calculated as: *VFF 3.2.3.1*

$$L_S = N_T \left[365\, K_E\, h_{VO} \left(\frac{\pi}{4} D_T^2 \right) K_S\, \rho_V \right] \qquad \text{[lb/yr]} \tag{4.23}$$

where L_S = standing storage loss [lb/yr]; N_T = number of storage tanks; K_E = vapor space expansion factor [-]; h_{VO} = vapor space outage [ft]; D_T = tank diameter [ft]; K_S = vented vapor saturation factor [-]; ρ_V = stock vapor density [lbm/ft]. The constant, 365, is the number of daily events in a year [yr^{-1}].

The vapor space expansion factor, K_E, in eq. (4.23) is calculated [68, p. 3] as:

$$K_E = 0.0018 \Delta T_V \qquad \text{[-]} \tag{4.24}$$

where K_E = vapor space expansion factor [-]; and ΔT_V = daily vapor temperature range [°R]. The constant 0.0018 has units of [°R^{-1}]. The daily vapor temperature range in eq. (4.24) is calculated as:

$$\Delta T_V = 0.72\,(T_{max} - T_{min}) + 0.028 \alpha I \qquad \text{[°R]} \tag{4.25}$$

where ΔT_V = daily vapor temperature range [°R]; T_{max} = daily maximum ambient temperature [°F]; T_{min} = daily minimum ambient temperature [°F]; α = tank surface solar absorptance [-]; and I = daily solar insolation on a horizontal surface [Btu/ft^2-d]. The constant 0.72 is dimensionless and the constant 0.028 has a unit of [°R-ft^2-d/Btu].

The vapor space outage, h_{VO}, in eq. (4.23) is calculated as: *VFF 3.2.3.1.2*

$$h_{VO} = h_T - h_l + h_{RO} \qquad \text{[ft]} \tag{4.26}$$

where h_{VO} = vapor space outage [ft]; h_T = shell height [ft]; h_l = liquid level [ft]; and h_{RO} = roof outage [ft] which is calculated depending on whether the roof type is cone or dome [68, p. 3]. For a cone roof the outage is calculated as:

$$h_{RO_{Cone}} = \frac{1}{3} h_R \qquad \text{[ft]} \tag{4.27}$$

where h_R = tank roof height [ft] as shown in Figure 4.6. Alternatively for a dome roof the outage is calculated as:

$$h_{RO_{Dome}} = h_R \left[\frac{1}{2} + \frac{1}{6} \left(\frac{h_R}{r_T} \right)^2 \right] \qquad \text{[ft]} \tag{4.28}$$

where r_T = tank radius [ft] as shown in Figure 4.6.

The vented vapor saturation factor, K_S, in eq. (4.23) is calculated as: *VFF 3.2.3.1.3*

$$K_S = \frac{1}{1 + 0.053\, p_{VA}\, h_{VO}} \qquad [\text{-}] \tag{4.29}$$

where K_S = vented vapor saturation factor [-]; p_{VA} = stock vapor pressure at daily average liquid surface temperature [psia]; and h_{VO} = vapor space outage [ft] [68, p. 3]. The calculation of the vapor space outage is shown in eq. (4.26). The stock vapor pressure at daily average liquid surface temperature is calculated as: *VFF 3.2.3.1.3.1*

$$p_{VA} = \exp\left[a_{VA} - \left(\frac{b_{VA}}{T_{l,avg}}\right)\right] \qquad [\text{psia}] \tag{4.30}$$

where p_{VA} = stock vapor pressure at daily average liquid surface temperature [psia]; a_{VA} = constant in the vapor pressure equation [-]; b_{VA} = constant in the vapor pressure equation [°R]; and $T_{l,avg}$ = daily average liquid surface temperature [°R] [68, p. 31]. The constants a_{VA} and b_{VA} are calculated as [68, p. 34]: *VFF 3.2.3.1.3.1.1, 3.2.3.1.3.1.2*

$$\begin{aligned} a_{VA} &= 12.82 - 0.9672 \ln(RVP) \qquad [\text{-}] \\ b_{VA} &= 7261 - 1216 \ln(RVP) \qquad [^\circ\text{R}] \end{aligned} \tag{4.31}$$

where RVP = Reid vapor pressure [psia]. The Reid vapor pressure is calculated as [66, p. ES-1]:

$$RVP = -1.699 + 0.179^\circ\text{API} \qquad [\text{psia}] \tag{4.32}$$

where °API = Stock API gravity [-]. The daily average liquid surface temperature, $T_{l,avg}$, in eq. 4.30 is calculated as [68, p. 19]: *VFF 3.2.3.1.3.2*

$$T_{l,avg} = T_{atm,avg} + 0.56(6\alpha - 1) + 0.0079\alpha\, I \qquad [^\circ\text{R}] \tag{4.33}$$

where $T_{l,avg}$ = daily average liquid surface temperature [°R]; $T_{atm,avg}$ = daily average ambient temperature [°R]; α = tank surface solar absorptance [-]; and I = daily solar insolation on a horizontal surface [Btu/ft^2-d]. The constant, 6, in eq. (4.33) has unit of [°R]. The constant 0.56 is dimensionless. The constant 0.0079 has units of [°R-ft^2-d/Btu]. The stock vapor density, ρ_V, in eq. (4.23) is calculated using [68, p. 3]: *VFF 3.2.3.1.4*

$$\rho_V = \frac{MW_V\, p_{VA}}{\text{R}\, T_{l,avg}} \qquad [\text{lb/ft}^3] \tag{4.34}$$

where ρ_V = stock vapor density [lb/ft^3]; MW_V = vapor molecular weight [lb/lb-mole]; p_{VA} = stock vapor pressure at daily average liquid surface temperature [psia]; $T_{l,avg}$ = daily average liquid surface temperature [°R]; and R = ideal gas constant, 10.73 [psia-ft^3/lbmole °R].

Table 4.7: Average W&S gas speciation profile.

Species	Mol%
CH_4	22.36
C_2H_6	20.49
C_3H_8	28.00
i-C_4H_{10}	6.84
n-C_4H_{10}	10.92
C5+	11.40

The total working storage loss, L_W, is calculated as: *VFF 3.2.3.4*

$$L_W = N_T \left[N_{to}\, h_{l,max} \left(\frac{\pi}{4} D_T^2 \right) K_N\, K_P\, K_B\, \rho_V \right] \qquad \text{[lb/yr]} \tag{4.35}$$

where N_T = number of storage tanks [-]; N_{to} = stock turnover rate [turnover/yr]; $h_{l,max}$ = stock maximum liquid height [ft]; D_T = tank diameter [ft]; K_N = working loss turnover factor [-]; K_P = working loss product factor [-]; K_B = vent setting correction factor [-]; and ρ_V = stock vapor density [lb/ft^3] as calculated in eq. (4.34) [68, p. 9]. The stock turnover rate is calculated [68, p. 9] from the stock annual net throughput as: *VFF 3.2.3.4.1*

$$N_{to} = \frac{5.614\, Q_T}{h_{l,max} \left(\frac{\pi}{4} D_T^2 \right)} \qquad \text{[bbl/yr]} \tag{4.36}$$

where Q_T = stock annual net throughput [bbl/yr]. The constant, 5.614, has units of [ft^3/bbl]. The working loss turnover factor, K_N, is calculated using the stock turnover rate as [68, p. 9]:

$$\begin{aligned} K_N &= 1 && \text{(for } N_{to} \leq 36) \\ K_N &= \frac{(180 + N_{to})}{6 N_{to}} && \text{(for } N_{to} \geq 36) \end{aligned} \tag{4.37}$$

The constants, 180 and 6, in eq. (4.37) are dimensionless. The vent setting correction factor, K_B, in eq. (4.35) is assumed equal to 1 for a breather vent setting range not greater than the typical range of +/- 0.03 psi [68, p. 9]. The working loss product factor, K_P, in eq. (4.35) is equal to 0.75 for crude oil stocks [68, Table 3, p.8].

Once the total weight of standing and working (W&S) losses is calculated using eq. (4.22) the emissions of CH_4 and VOCs is calculated using an average speciation of W&S gas as shown in Table 4.7 [66, p. ES-2]. The C_2 to C_4 species compose most of the VOCs.

4.3.3.4 Venting emissions gathering

All the methods that have been discussed for the estimation of emissions from venting generate weight of gas species lost into the atmosphere. The balancing

Table 4.8: Categorization of venting emissions sources by process stage.

Process stage	Venting emissions sources
Exploration	None
Drilling & development	None
Production & extraction	None
Oil field processing	Flaring substitute
	Gas dehydrator
	AGR unit
	Storage standing losses
	Storage working losses
Maintenance	Well workovers and cleanups
	Gathering pipelines maintenance and pigging
	Compressor blowdowns and startups
Waste disposal	None

of the gas as is discussed in Section 4.1. Therefore weight is converted to volume using the densities of gas species (e.g., CH_4) [106]. The estimated weight of the gas species emissions is converted to [g/d] and divided by the species density [g/ft^3]. *VFF 3.2.2, 3.2.3.5*

After the weight and volume of emissions from each source is calculated, categorization of the emissions sources is required to allocate venting emissions to the different stages in OPGEE (e.g., *'Production & Extraction'*). Table 4.8 lists the sources of venting emissions under each process stage. Crude oil transport is not included because it is a separate process.

The emissions volumes from each process stage are converted into CO_2 equivalent GHG emissions using the IPCC GWPs of the gas constituents [130].

4.3.4 Calculation of fugitive emissions

The estimation of fugitive emissions from various components is difficult due to the non-planned nature of the losses and the number of sources. This includes fugitive emissions from active wells, well cellars, gas processing units, gathering pipelines, sumps and pits, storage tanks (e.g., free knock out vessel) and various equipment (valves, connectors, flanges, etc). Fugitives associated with production and surface operations are estimated using data collected by ARB [3], and emissions factors from the API workbook for oil and gas production equipment fugitive emissions [30].

The approach used to estimate fugitive emissions is similar to the approach used in the calculation of venting emissions except for venting from storage tanks, which is modeled using API measurement standards as described in Section 4.3.3. Fugitive losses are linked to various units (e.g., equipment and active wells), gathering pipeline miles, and volumes of gas processing units (e.g., AGR unit). Most fugitive losses are linked to units and equipment. The number of unit-years or mile-years associated with the total volume of oil produced is estimated using the ARB survey data [3]. *VFF 3.3.1*

Table 4.9: ARB data used in the estimation of fugitives. Data from ARB (2011).

Source	Activity a_{F_G}	Unit	Oil prod. (bbl/yr) b_{F_G}	Activity factor c_{F_G}	Unit
Active wells					
- Ultra-heavy	47	[unit]	614,683	7.65×10^{-5}	[unit-yr/bbl]
- Heavy	36,619	[unit]	156,304,520	2.34×10^{-4}	[unit-yr/bbl]
- Light	14,261	[unit]	61,524,698	2.32×10^{-4}	[unit-yr/bbl]
- Ultra-light	1,323	[unit]	15,649,398	8.45×10^{-5}	[unit-yr/bbl]
Well cellars					
- Ultra-heavy	22	[unit]	614,683	3.58×10^{-5}	[unit-yr/bbl]
- Heavy	7,461	[unit]	156,304,520	4.77×10^{-5}	[unit-yr/bbl]
- Light	4,998	[unit]	61,524,698	8.12×10^{-5}	[unit-yr/bbl]
- Ultra-light	2,168	[unit]	15,649,398	1.39×10^{-4}	[unit-yr/bbl]
Gathering pipelines[a]	1218	[mile]	234,093,299	5.20×10^{-6}	[mile-yr/bbl]
Separators	$\simeq$3557[b]	[unit]	234,093,299	1.52×10^{-5}	[unit-yr/bbl]
Sumps & pits	250	[unit]	234,093,299	1.07×10^{-6}	[unit-yr/bbl]
Valves (without open-ends)	$\simeq$2,647,951[c]	[unit]	234,093,299	1.13×10^{-2}	[unit-yr/bbl]
Pump seals	$\simeq$48,444[c]	[unit]	234,093,299	2.07×10^{-4}	[unit-yr/bbl]

a - Miles of pipeline. Same as Table 4.6.
b - Estimated by summing the number of separators associated with the crude oil business. Separators associated with dry gas production and gas storage facilities are not counted. For gas processing facilities 75% of the separators are allocated to the crude oil business. This assumption is based on the split between the types of gases produced in California where $\approx$75% of the produced gas is associated gas [3].
c - Estimated by summing the number of valves associated with crude oil service. Valves associated with natural gas service are shared by both the crude oil and dry gas businesses in California. The number of crude oil wells surveyed makes $\approx$60% of the total number of wells [3]. Accordingly the crude oil business is roughly allocated 60% of the valves associated with natural gas service.

Table 4.10: Estimating the number of remaining components.

Component	Number
Valves (with open ends)	N
Pumps	No correlation
Flanges	N
Connectors	$3N$
Open-ends	$0.1N$
Others[a]	$0.05N$

a - Includes compressor seals, diaphragms, drains, etc.

4.3.4.1 *Fugitives from general sources*

Fugitive emissions from general sources are listed in Table 4.9. This table does not include all equipment fugitives. API research suggests that a good approximation of the number of components can be obtained by estimating the number of valves and pumps and then calculating the probable number of flanges, connectors, open-ended lines, and other components from the number of valves [30, p. 14]. During a field study of petroleum production operations, API found that the number of flanges is usually about the same as the number of valves, while the number of connectors (threaded pipes and tubing fittings) is about three times the number of valves. API also found that about 10% of all valves have one side that can be opened to the atmosphere (open-ended lines) and that the number of other components is approximately 5% of the number of valves. No correlation was found between the number of valves and the number of pumps [30, p. 14]. The number of valves and pump seals are estimated from the ARB survey data as shown in Table 4.9 and the number of remaining components is estimated from the number of valves using the API method.

As shown in Table 4.9 the number of unit-years or mile-years associated with one barrel of oil production is estimated using data from the ARB survey [3]. The number of remaining sources of fugitive emissions is estimated from the number of valves as outlined in Table 4.10. Therefore the total number of unit-years or mile-years associated with the amount of oil produced in OPGEE and the fugitive emissions from the various sources listed in Tables 4.9 and 4.10 is calculated as:

VFF 2.3 3.3.1

$$EM_{F_G} = \sum_s c_{F_G,s} Q_o EF_{F_s} \qquad \text{[g/d]} \tag{4.38}$$

where EM_{F_G} = fugitive emissions [g/d]; $c_{F_G,s}$ = number of unit-years or mile-years per barrel of oil and is calculated as shown in Table 4.9; Q_o = total rate of oil production entered by the user [bbl/d]; and EF_{F_s} = fugitive emissions factors for source s [g/unit-yr, g/mile-yr]. $c_{F_G,s}$ is calculated by multiplying $a_{F_G,s}$ which is the total number of units or miles surveyed [mile, unit] with $b_{F_G,s}$ which is the reported oil production volumes [bbl/yr]

Table 4.11: Speciation fractions for total hydrocarbon (THC) emissions calculated using API emissions factors [-].

Emissions component	Gas	Heavy oil	Light oil
Methane	0.687	0.942	0.612
VOC	0.171	0.030	0.296

The emissions factors generated from the ARB survey, and therefore the calculated emissions, are specific to gas components (e.g., CO_2). The calculation of the emissions factors is explained in Section 4.6. Emissions factors for equipment fugitives that are listed in Table 4.10 are taken from the API documentation [30, p. 20]. The emissions factors from API are not speciated. The speciation in Table 4.11 is used to allocate the total hydrocarbon (THC) emissions calculated using the API emissions factors to the main gas components, i.e. methane and VOC [30, p. 15].

As shown in Table 4.11 the fractions are different for fugitives from different streams. For the division of THC emissions, 75% of the components are assumed in oil service, and 25% in gas service. This assumption is based on an example from the API methods on the calculation of fugitive emissions from a crude oil production operations which co-produce natural gas [30, p. 16]. For oil service components the fraction is determined by the API gravity of the oil. For the calculation of the volume of VOC emissions the VOC is broken down into 31% C_2, 42% C_3, and 27% C_4. The fraction of C_5+ VOC components is negligible. This breakdown is based on average THC emissions speciation profiles [66, p. ES-2].

4.3.4.2 *Fugitives from gas processing units*

Other than the general fugitive emissions sources that are listed in Tables 4.9 and 4.10, fugitives sources include gas processing units like glycol dehydrator units and amine acid gas removal (AGR) units. The methods for calculating fugitives from glycol dehydration and amine AGR units are volume based. The fugitive emissions of both CO_2 and CH_4 are calculated based on the gas unit throughput volume as:

VFF 2.3 3.3.1

$$EM_{F_{GP}} = Q_{GP} EF_{F_{GP}} \qquad [\mathrm{g/d}] \tag{4.39}$$

where $EM_{F_{GP}}$ = fugitive emissions from the gas processing unit [g/d]; Q_{GP} = volume throughput of the gas processing unit [MMscf/d]; and $EF_{F_{GP}}$ = fugitive emissions factors for gas processing unit [g/MMscf]. The emissions factors are calculated from the ARB survey data [3] as explained in Section 4.6.2. The emissions factor for fugitive CH_4 emissions from AGR unit is taken from [131, p. 23]. The approximate volume of the gas processing unit is determined by the gas balance and is calculated as shown in eq. (3.31). A description of the gas balance is found in Section 4.1.

Table 4.12: Categorization of fugitive emissions sources by process stage.

Process stage	Fugitive emissions sources
Exploration	None
Drilling and development	None
Production and extraction	Active wells
	Well cellars
Oil field processing	Separators
	Gas dehydrator
	AGR unit
	Gathering pipelines
	Sumps and pits
	Components (valves, connectors, flanges, etc)
Maintenance	None
Waste disposal	None

4.3.4.3 *Fugitive emissions gathering*

All the methods that have been discussed for the estimation of fugitives end up generating mass of gas species lost into the atmosphere. The balancing of the gas is discussed in Section 4.1. Therefore mass is converted to volume using the densities of gas species [106]. After the mass and volume of emissions from each source is calculated, categorization of the emissions sources is required to allocate fugitive emissions to the different stages in OPGEE (e.g., *'Production & Extraction'*). Table 4.12 lists the sources of fugitive emissions under each process stage. Fugitive emissions from crude oil transport are not included because it forms a separate process.

VFF 3.3.1

The emissions volumes of each process stage are converted into CO_2 equivalent GHG emissions using the IPCC GWPs [130].

4.3.5 Default values for VFF emissions

The default emissions factors and the number of associated unit-years, mile-years or events/yr are generated from the ARB survey data [3]. The estimation of the number of unit-years, mile-years or events/yr was previously discussed. The user is allowed to overwrite these defaults. As these defaults represent the average case in California, in some cases they might not be a good representation of the level of venting and fugitives in other areas of the world. This is particularly true where practices and environmental regulations are significantly different than California regulations. The average EPA emissions factors for fugitives from the various components listed in Table 4.10 are used as default [30, p. 20]. These defaults represent the average US case and can also be overwritten by the user to represent changes in equipment condition, practices, and environmental regulations.

Table 4.13: Default inputs for venting, flaring, and fugitive emissions.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
a_{VA}	Constant	(4.31)	-	-	[-]	[68, p. 34]	
α	Tank surface solar absorptance	-	0.17		[-]	[68, p. 19]	a
b_{VA}	Constant	(4.31)	-	-	[°R]	[68, p. 34]	
$c_{F_G,s}$	Number of fugitive source per oil barrel	-	Table 4.9	-	[unit-yr/bbl]	[3]	b
$c_{V_G,s}$	Number of vent source per oil barrel	-	Table 4.6	-	[event/bbl]	[3]	c
D_T	Storage tank diameter	-	100	20-300	[ft]	[68, p. 41-42]	
$EF_{F_{GP}}$	Fugitive em. factors for gas proc. unit	-	Section 4.6	-	[g/MMscf]	[3, 131]	
EF_{F_s}	Fugitive emissions factors for source s	-	Tables 4.18 & 4.19	-	[g/unit-yr]	[3, 30]	d
$EF_{V_{AGR}}$	Vent emissions factors for AGR	-	0	-	[gCH_4/MMscf]	[3]	e
$EF_{V_{GD}}$	Vent emissions factors for gas dehydrator	-	Section 4.6	-	[g/MMscf]	[3]	
EF_{V_s}	Vent emissions factors for source s	-	Table 4.17		[g/event]	[3]	f
$EM_{F,comb}$	Flare combustion emissions	(4.17)	-		[tCO_2eq/d]		
EM_{F_G}	Fugitive emissions general	(4.38)	-	-	[g/d]		
$EM_{F_{GP}}$	Fugitive emissions from gas proc. unit	(4.39)	-	-	[g/d]		
$EM_{F,str}$	Flare stripping emissions	(4.16)	-	-	[tCO_2eq/d]		
$EM_{V_{AGR}}$	Vent emissions from AGR	(4.21)	-	-	[g/d]		
$EM_{V_{GD}}$	Vent emissions from gas dehydrator	(4.20)	-	-	[g/d]		
EM_{V_G}	Vent emissions general	(4.19)	-	-	[g/d]		
η_F	Flaring efficiency	-	0.95	0.54 - $\geq$ 0.99	[-]	[14, 15, 132]	g
FOR	Flaring-to-oil ratio	-	177	11-3010	[scf/bbl]		
GWP_i	Global warming potential for species i	-	*'Input data'* Table 2.1	-	[$gCO_2eq.$/g]	[130]	h
h_L	Stock liquid level	-	20	-	[ft]	[68, p. 41]	
$h_{l,max}$	Stock maximum liquid height	-	38	-	[ft]	[68, p. 42]	
$h_{RO_{Cone}}$	Tank cone roof outage	(4.27)	-	-	[ft]	[68, p. 11]	
$h_{RO_{Dome}}$	Tank dome roof outage	(4.28)	-	-	[ft]	[68, p. 11]	

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
h_R	Tank roof height	-			[ft]		
h_T	Shell height	-	40	$\leq$65	[ft]	[68, p. 41-42]	
h_{VO}	Vapor space outage	(4.26)	-	-	[ft]	[68, p. 3]	
I	Daily solar insolation on a horizontal surface	-	1643		[Btu/ft^2-d]	[68, p. 14]	i
K_B	Vent setting correction factor	-			[-]		
K_E	Vapor space expansion factor	(4.24)	-	-	[-]	[68, p. 3]	
K_N	Working loss turnover factor	(4.37)	-		[-]	[68, p. 9]	
K_P	Working loss product factor	-			[-]		
K_S	Vented vapor saturation factor	(4.29)	-	[-]	[68, p. 3]		
L_T	Total storage loss	(4.22)	-	-	[lb/yr]		
L_S	Standing storage loss	(4.23)	-		[lb/yr]	[68, p. 3]	
L_W	Working storage loss	(4.35)	-		[lb/yr]	[68, p. 9]	
MW_V	Vapor molecular weight	-	50	-	[lbm/lbmole]	[68, p. 20]	j
N_T	Number of storage tanks	-	2	-	[-]		
N_{to}	Stock turnover rate	(4.36)	-	-	[turnover/yr]	[68, p. 9]	
p_{VA}	Stock vapor pressure	(4.30)	-	-	[psia]	[68, p. 31]	
Π_i	Stoichiometric combustion ratios	-	Table 4.5	-	[gCO_2/g]	-	k
Q_{AGR}	Volume of amine treater	-	*'Gas Balance'*	-	[MMscf/d]		
Q_{GD}	Volume of gas dehydrator	-	*'Gas Balance'*	-	[MMscf/d]		
Q_F	Flaring volume	(4.15)	-	-	[MMscf/d]		
Q_o	Volume of oil production	-	1500	-	[bbl/d]		
Q_{GP}	Volume of gas processing unit	-	*'Gas Balance'*	-	[MMscf/d]		
Q_T	Stock annual net throughput	-	273,750	-	[bbl/yr]		
R	Ideal gas constant	-	10.73		$\left[\frac{\text{psia-ft}^3}{\text{lbmole}\,^\circ\text{R}}\right]$		
r_R	Dome roof radius	-	$1D$	$0.8D$-$1.2D$	[ft]	[68, p. 11]	
r_T	Tank radius	-	50		[ft]	[68, p. 41]	
RVP	Reid vapor pressure	(4.32)	-	-	[psia]	[66, p. ES-1]	

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Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
ρ_i	Gas density for species i	-	*'Input Data'* Table 2.2	-	[g/ft^3]	-	l
ρ_V	Stock vapor density	(4.34)	-	-	[lbm/ft]	[68, p. 3]	
S_R	Cone roof slope	-	0.0625	-	[-]	[68, p. 11]	
$T_{atm,avg}$	Daily average ambient temperature	-	520.3		[°R]		
$T_{l,avg}$	Daily average liquid surface temperature	(4.33)			[°R]	[68, p. 19]	
$T_{l,max}$	Maximum daily ambient temperature	-	67.6	-	[°F]	[68, p. 14]	i
$T_{l,min}$	Minimum daily ambient temperature	-	45.1	-	[°F]	[68, p. 14]	
ΔT_V	Daily vapor temperature range	(4.25)	-	-	[°R]	[68, p. 20]	
x_i	Mole fraction of gas composition	-	*'Gas Balance'* Table 1.1	-	[-]	[3]	m

a - Default is white surface in a good condition.
b - Most of the fugitives are associated with units. Therefore the most common unit for the number of sources per oil barrel is [unit-yr/bbl]. Other units include [mile-yr/bbl] for fugitives associated with pipeline miles.
c - Most venting is associated with events. Therefore the most common unit for number of sources per oil barrel is [event/bbl]. Other units include [unit-yr/bbl] and [mile-yr/bbl] for venting associated with units and pipeline miles, respectively.
d - Most of the fugitives are associated with units. Therefore the most common unit for fugitive emissions factors is [q/unit-yr]. Other units include [g/mile-yr] for fugitives associated with pipeline miles.
e - Venting of CO_2 from the AGR unit is calculated from the gas balance.
f - Most of the venting is associated with events. Therefore the most common unit for vent emissions factors is [g/event]. Other units include [q/unit-yr] and [g/mile-yr] for venting associated with units and pipeline miles, respectively.
g - Average efficiency for Alberta found to be ≈0.95 across 4 years of data using known wind distributions and flaring volumes [14]. Very low efficiencies are seen in high cross winds and with high fractions of non-combustible gas components (e.g., CO_2, N_2).
h - 100-year GWPs from the IPCC Fourth Assessment Report [130].
i - Default is Sacramento, CA, annual average.
j - Default is US midcontinent crude oils.
k - Standard combustion stoichiometry assuming complete combustion.
l - Standard gas densities [106]
m - Gas composition can vary. Default gas composition given from [3].

Table 4.14: Types and size ranges of the drivers embedded in OPGEE.

Type	Fuel	Size range [bhp]
Internal combustion engine	Natural gas	95 - 2,744
Internal combustion engine	Diesel	1590 - 20,500
Simple turbine	Natural gas	384 - 2,792
Motor	Electricity	1.47 - 804

4.4 Drivers

Drivers (also known as prime movers) of pumps, compressors, and onsite electricity generators come in different types and sizes. Drivers in OPGEE include natural gas driven engines, natural gas turbines, diesel engines, and electric motors. The size and energy consumption of the driver is required to convert power requirements (e.g., downhole pump brake horsepower) into energy consumption as explained in Section 3.3.2.10. A database of drivers specifications of different types and sizes is included in OPGEE. Table 4.14 shows the types and size ranges of the drivers included in OPGEE.

The specifications of natural gas driven engines and diesel driven engines are taken from Caterpillar technical sheets [87]. The specifications of natural gas turbines are taken from Solar Turbines technical sheets, a subsidiary of Caterpillar [133]. The specifications of electric motors are taken from General Electric technical sheets [88]. Data were reported in different forms and with different levels of completeness.

The data for each driver model was converted into [bhp] for power and [Btu/bhp-hr] for energy consumption. In some cases the data on engine power was given in [bhp] and energy consumption is given in [Btu/bhp-hr], so no conversion is required. In other cases only data on the electricity generator set is given. The generator set includes an engine and an electricity generator. The brake horsepower of the engine is calculated from the electric power of the generator set as:

$$P_D = \frac{P_{GS}}{\eta_G} \cdot 1.34 \qquad [\text{bhp}] = \frac{[\text{ekW}]}{[\text{-}]} \left[\frac{\text{bhp}}{\text{bkW}}\right] \tag{4.40}$$

where P_D = driver brake horsepower [bhp]; P_{GS} = electric power of the electricity generator set [ekW]; and η_G = efficiency of the electricity generator (not including engine) [-]. For the calculation of the electric power [ekW] of the electricity generator sets Caterpillar assume an electricity generator (without engine) of efficiency 96% [134, p. 4]. Accordingly η_G in eq. (4.40) is equal to 0.96 [-].

In the case where the overall efficiency of the electricity generator set is given, but the energy consumption of the engine component is not, the latter

is calculated as:

$$e_D = \frac{3.6}{\eta_{GS}}\eta_G \qquad \left[\frac{\text{MJ}}{\text{bkW-hr}}\right] = \frac{\left[\frac{\text{MJ}}{\text{bkW-hr}}\right]}{[\text{-}]}[\text{-}]$$

$$e_D = \frac{E_D \cdot 947.8}{1.34} \qquad \left[\frac{\text{Btu}}{\text{bhp-hr}}\right] = \frac{\left[\frac{\text{MJ}}{\text{bkW-hr}}\right]\left[\frac{\text{Btu}}{\text{MJ}}\right]}{\left[\frac{\text{bhp}}{\text{bkW}}\right]} \tag{4.41}$$

where e_D = driver energy consumption [Btu/bhp-hr]; η_{GS} = efficiency of generator set (engine + generator) [-]; η_G = efficiency of generator (without engine) [-].

The diesel engines energy consumption is reported in the technical sheets in the form of gallons per hour [gal/hr]. This is converted into [Btu/bhp-hr] by:

$$e_D = \frac{e_D 137,380}{P_D} \qquad \left[\frac{\text{Btu}}{\text{bhp-hr}}\right] = \frac{\left[\frac{\text{gal}}{\text{hr}}\right]\left[\frac{\text{Btu}}{\text{gal}}\right]}{[\text{bhp}]} \tag{4.42}$$

where e_D = driver energy consumption [Btu/bhp-hr]; P_D = driver brake horsepower [bhp]. The driver brake horsepower, P_D , is calculated from the electric power [ekW] of the given generator set as shown in eq. (4.40).

The calculation used to convert the efficiency of electric motors from the General Motors technical sheets into energy consumption in [Btu/bhp-hr] is very similar to the calculation of the energy consumption of the engine component from the overall efficiency of the generator set in eq. (4.41):

$$e_D = \frac{3.6}{\eta_M} \qquad \left[\frac{\text{MJ}}{\text{kWh}}\right] = \frac{\left[\frac{\text{MJ}}{\text{kWh}}\right]}{[\text{-}]} \tag{4.43}$$

where e_D = driver energy consumption [Btu/bhp-hr]; η_M = electric motor efficiency [-]. The energy consumption is converted to [Btu/bhp-hr] as shown in eq. (4.41).

As mentioned before in Section 3.3.2.10 OPGEE retrieves the energy consumption of the appropriate driver based on the user input and the required size.

Table 4.15: Default inputs for drivers calculations.

Param.	Description	Eq. no.	Default	Literature range	Unit	Sources	Notes
e_D	Driver energy consumption	(4.41)	-	-	[Btu/bhp-hr]		a
η_M	Electric motor efficiency	-	var.	0.84-0.96	[-]	[88]	b
$\eta_G S$	Efficiency of electricity generator set	-	var.	0.36-0.40	[-]	[87]	c
η_G	Efficiency of electricity generator (no engine)	-	0.96	-	[-]	[134, p. 4]	d
P_D	Driver brakehorse power	(4.40)	-	-	[bhp]		
P_{GS}	Electric power of elect. gen. set	-	var.	275-2000	[ekWh]	[87]	e

[a] The cited equation is for gas drivers. Energy consumption of diesel and electricity drivers is calculated in eq. (4.42) and (4.43), respectively.
[b] Motor efficiency ranges from 0.84 to 0.96 for commonly applied motor size ranges [88].
[c] Literature range cited only for gas generator sets with gas engine sizes ranging from 1535-2744 [bhp].
[d] Standard electicity generator efficiency [134, p. 4].
[e] Literature range cited for diesel generator sets [87].

4.5 Electricity

The *'Electricity'* sheet calculates the energy consumption of onsite electricity generation. The *'Electricity'* sheet does not include electricity co-generation in steam generation system. Available generation technologies include natural gas generator set, natural gas turbine, and diesel generator set. The user enters the capacity of onsite electricity generation as a fraction of the electricity required. The fraction of electricity above 1.0 is exported. In the *'Electricity'* sheet the amount of electricity generated onsite is calculated as:

$$E_{el,gen} = \lambda_{el} \cdot E_{el,req} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{4.44}$$

where $E_{el,gen}$ = onsite electricity generation [MMBtu/d]; λ_{el} = fraction of required electricity generated onsite; and $E_{el,req}$ = electricity required. The electricity required is calculated in the *'Energy Consumption'* sheet.

The energy consumption of the generator is calculated from the appropriate driver in the *'Drivers'* sheet as:

$$e_{GS} = \frac{e_D}{0.75\eta_G} \qquad \left[\frac{\text{Btu}}{\text{kWh}}\right] = \frac{\left[\frac{\text{Btu}}{\text{bhp-hr}}\right]}{\left[\frac{\text{bkW}}{\text{bhp}}\right]\ [\text{-}]} \tag{4.45}$$

where e_{GS} = energy consumption of generator set [Btu/kWh]; η_G = efficiency of the electricity generator (not including driver) [-]; and e_D = driver energy consumption [Btu/bhp-hr]. The appropriate driver is determined by the required size based on the electricity generation capacity as calculated in eq. (4.44).

Once the onsite electricity generation, $E_{el,gen}$, and the energy consumption of the electricity generator, e_{GS}, are calculated the total energy consumption of onsite electricity generation is calculated as:

$$E_{EG} = E_{el,gen} \cdot 0.000293 \cdot e_{GS} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] = \left[\frac{\text{MMBtu}}{\text{d}}\right]\left[\frac{\text{kWh}}{\text{Btu}}\right]\left[\frac{\text{Btu}}{\text{kWh}}\right] \tag{4.46}$$

where E_{EG} = energy consumption of onsite electricity generation [MMBtu/d].

In addition to calculating the energy consumption of onsite electricity generation, this sheet determines the grid electricity mix and the allocation method of credits from electricity export (see Section 4.7 on the *'Fuel Cycle'* sheet). The user is allowed to choose between two allocation methods for credit from electricity export: (i) allocation by substitution of grid electricity, and (ii) allocation by substitution of natural-gas-based electricity. The default allocation method is the substitution of natural-gas-based electricity. This method prevents achieving unreasonably large credits from operations with significant power generation.

Table 4.16: Combustion technologies and fuels included in OPGEE.

	Natural gas	Diesel	Crude	Residual oil	Pet. coke	Coal
Industrial boiler	✓	✓	✓	✓	✓	✓
Turbine	✓	✓				
CC gas turbine	✓					
Reciprocating engine	✓	✓				

4.6 Emissions factors

Emissions factors are required for the calculation of GHG emissions from combustion (fuel combustion) and non-combustion (venting and fugitives) sources.

4.6.1 Combustion emissions factors

The emissions factors for fuel combustion are from GREET v1.8d [17]. Table 4.16 shows the technologies and fuels included. Gas species tracked include VOC, CO, CH_4, N_2O, and CO_2. Emissions are converted into carbon dioxide equivalent using IPCC GWPs [130] as shown in eq. (4.47).

$$EM_{CO_2eq,i} = EM_i \cdot \mathrm{GWP}_i \qquad [\mathrm{gCO_2eq}] \tag{4.47}$$

where $EM_{CO_2eq,i}$ = emissions of species i in carbon dioxide equivalent [gCO_2eq]; EM_i = emissions of species i [g]; and GWP_i = GWP of species i [$gCO_2eq./g$]. GWPs are discussed in Section 6.1.

4.6.2 Non-combustion emissions factors

Section 4.3 describes how emissions factors for venting and some fugitives sources are generated from the ARB survey data [3]. Emissions factors from ARB are specified by gas component. The ARB survey data used to generate emissions factors for venting are shown in Table 4.17.

The emissions factors for venting by gas component were calculated using ARB survey data as:

$$\begin{aligned} EF_{CO_2Vent} &= \frac{a_{EF_V}}{c_{EF_V}} 10^6 \qquad \left[\frac{\mathrm{g}}{\mathrm{event}}\right], \text{ etc.} \\ EF_{CH_4Vent} &= \frac{b_{EF_V}}{c_{EF_V}} 10^6 \qquad \left[\frac{\mathrm{g}}{\mathrm{event}}\right], \text{ etc.} \end{aligned} \tag{4.48}$$

where EF_{CO_2Vent} = emissions factor of CO_2 venting [g/event; g/mile-yr; g/MMscf]. For a description of a_{EF_V}, b_{EF_V}, and c_{EF_V} parameters see Table 4.17.

Table 4.17: ARB data used in the calculation of venting emissions factors (unit specified below) [3].

Source	Total CO_2 emissions (tonne/yr) a_{EF_V}	Total CH_4 emissions (tonne/yr) b_{EF_V}	# units (event/yr, otherwise noted) c_{EF_V}
Well workovers			
- Ultra-heavy	0	0	–
- Heavy	405	1,428	12,889
- Light	225	575	5,424
- Ultra-light	9	65	599
Well cleanups			
- Ultra-heavy	0	0	–
- Heavy	103	90	956
- Light	113	201	1977
- Ultra-light	3	21	187
Compressor startups	4	69	1071
Compressor blowdowns	172	3,238	1071
Gathering pipelines maintenance	2659	2490	2295 (mile)
Gathering pipelines pigging	104	5	1417
Gas dehydrator[a]	308	10829	701123.3 (MMscf/yr)

[a] Emissions factors of venting from gas dehydrator are calculated on volume throughput basis.

Table 4.18: ARB data used in the calculation of fugitives emissions factors (unit specified below).

Source	Total CO_2 emissions (tonne/yr) a_{EF_F}	Total CH_4 emissions (tonne/yr) b_{EF_F}	# units (event/yr, otherwise noted) c_{EF_F}
Active wells			
- Ultra-heavy	0	0	–
- Heavy	66	155	36,619
- Light	459	1,415	14,261
- Ultra-light	19	139	1,323
Well cellars			
- Ultra-heavy	–	3	22
- Heavy	–	933	7,461
- Light	–	850	4,998
- Ultra-light	–	369	2,168
Gathering pipelines	327	867	2,295 (mile)
Separators	11	170	4,618
Sumps and pits	–	264	250
Gas dehydrator[a]	16,682	10,802	701123.3 (MMscf/yr)

[a] Emissions factors of fugitives from gas dehydrator are calculated on volume basis.

Table 4.19: An example of EPA emissions factors for oil and gas production components (g/unit-yr).

Source	CH_4	VOC emissions
Non-leaking components (< 10,000 ppmv)		
Valves		
Gas service	148	37
Heavy oil service	69	2
Light oil service	101	49
Connectors		
Gas service	60	15
Heavy oil service	62	2
Light oil service	52	25
Leaking components (> 10,000 ppmv)		
Valves		
Gas service	590,678	147,025
Heavy oil service	–	–
Light oil service	465,479	225,134
Connectors		
Gas service	159,029	39,584
Heavy oil service	–	–
Light oil service	141,668	68,519

Similar calculations were performed for emissions factors for fugitives from the sources listed in Table 4.18. Emissions factors for fugitives from other sources (valves, flanges, etc) are taken from API [30, p. 20].

Emissions factors for gas dehydrators and AGR units are calculated on volume basis (i.e., in grams per MMscf processed gas). The emissions factors for venting and fugitives from the gas dehydrator are calculated as shown in Tables 4.17 and 4.18. As mentioned in Section 3.4.2.3, venting from the AGR unit is calculated from the gas balance of OPGEE by assuming that all CO_2 left in the gas stream after flaring, fugitives, and other venting is vented. The emissions factor for CH_4 fugitives from the AGR unit is 965 scf CH_4/MMscf of gas throughput [131, p. 23].

EPA emissions factors for fugitives from the components listed in Table 4.10 are reported by API as total hydrocarbons (THC) by service type, i.e. gas service, heavy oil service [30, p. 20]. As explained in Section 4.3.4.1 the THC emissions factors are calculated assuming that 25% of the components are associated with gas service and the remaining 75% are associated with oil service. An example of EPA emissions factors for oil and gas production components after speciation is shown in Table 4.19 for valves and connectors [30, p. 20]. Fugitives from non-leaking components are negligible. The user determines the percentage of leaking components in the *'VFF'* sheet.

Emissions factors for land use change are discussed in Section 3.2. Table 3.2 shows the emissions factors per unit of crude oil produced for low, medium, and high intensity development in low, medium, and high ecosystem produc-

tivity environments [77].

4.7 Fuel cycle

For fuels consumed in OPGEE, the upstream or "fuel cycle" energy consumption and GHG emissions are required to calculate the indirect energy consumption and GHG emissions of imported fuel. For example, if purchased electricity is used on site, the emissions associated with generating and transporting that purchased electricity must be accounted for and added to the direct emissions burden. Similarly, any co-products that are sold separately from the produced oil (e.g., natural gas, electricity, NGL) must be assigned a co-production credit for emissions avoided from the system that they displace. The approach here can therefore be described as a co-product emissions assessment via system boundary expansion rather than via allocation between products [135, 136]. In all cases, the energy consumption and GHG emissions of the displaced production system is calculated from GREET v.1.8d [17].

For the calculation of credit from the export of natural gas or natural gas liquid (NGL), the natural gas production system is displaced. For NGL export, the natural gas production system is displaced because NGL is a byproduct of gas production and does not have an independent fuel cycle. Credit is not given for avoided gas transport emissions, because it is assumed that the gas will be transported to a remote consumer.

For the calculation of credit from electricity exports, the boundary of the system is extended to the user "plug": the displaced system includes electricity generation and transport to the end user. This choice was made because exported electricity will naturally flow to the nearest consuming entity and not require long-distance transport. OPGEE calculates the energy consumption and GHG emissions of electricity generation based on the grid electricity mix (entered in the *'Electricity'* sheet) using GREET data of different electricity sources (natural gas, biomass, etc).

5 Gathering sheets

This section explains three sheets in OPGEE which are used to collect output from intermediate calculations in process stage and supplemental sheets. This collected output is used to calculate the overall WTR energy consumption and GHG emissions of the study crude. These gathering sheets are the *'Energy Consumption'*, *'GHG Emissions'*, and *'User Inputs & Results'* sheets.

5.1 *'Energy Consumption'* gathering sheet

In the *'Energy Consumption'* gathering sheet, energy use is summed in order of process stages, from Exploration to Waste disposal. For consistency, all energy inputs are summed on a daily basis, either as thermal energy (MMBtu/d) or as electrical energy (kWh/d). All energy types are classified using a fuel code. The primary energy types included are: 1A) Natural gas; 1B) Natural gas liquids; 2) Diesel fuel; 3) Electricity; 4) Crude oil.

First, the amount and type of fuel consumed by each component of the model (e.g., downhole pump, gas compressor, etc) is collected using nested if then statements. Second, the fuel consumption is summed by fuel type (e.g., natural gas, diesel) to calculate the gross energy consumption.

Energy Consumption Table 2

Energy Consumption Table 3

The gross energy consumption can include double counted energy. For example, the electricity consumed to drive a pump may be generated onsite and the energy consumed to generate that electricity would also be counted as natural gas or diesel, resulting in double counting.

The net energy consumption is calculated by fuel type. The net energy consumption is equal to the gross energy consumption for all fuels except for electricity. The net energy consumption of electricity is calculated as:

Energy Consumption Table 5

$$E_{el,net} = E_{el,gr} - E_{el,gen} \qquad \text{[MMBtu]} \tag{5.1}$$

where $E_{el,net}$ = net electricity consumption [MMBtu/d]; $E_{el,gr}$ = gross electricity consumption [MMBtu/d]; and $E_{el,gen}$ = total electricity generated onsite [MMBtu/d]. The total electricity generated onsite includes electricity generated using an onsite generator or simple turbine and electricity co-generated in the steam generation system, if applicable. In other words, the net electricity consumption is equal to the electricity imported from the grid, if any.

Once the net energy consumption is calculated by fuel type the energy exports/imports are calculated by fuel type. Energy exports/imports are used

Energy Consumption Table 4

to calculate indirect (offsite) energy consumption and GHG emissions by fuel type. Indirect energy consumption and GHG emissions are associated with the production and transport (production only in case of exports) of the fuel consumed directly. The exports/imports of natural gas are calculated as:

$$E_{ng,exp} = E_{ng,gr} - E_{ng,fuel} + E_{ng,mu} - E_{ng,rec} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{5.2}$$

where $E_{ng,exp}$ = natural gas export/import [MMBtu/d]; $E_{ng,gr}$ = gross natural gas consumption [MMBtu/d]; $E_{ng,fuel}$ = natural gas produced as fuel after gas lifting/re-injection [MMBtu]; $E_{ng,mu}$ = make up natural gas for gas flooding [MMBtu/d], if applicable; and $E_{ng,rec}$ = natural gas recovered from venting and fugitives. The produced gas remaining to be used as a process fuel is equal to 0 MMBtu/d in the case of gas flooding where 100% of produced gas is re-injected. Negative $E_{ng,exp}$ represents gas exports. Positive $E_{ng,exp}$ represents gas imports.

The exports/imports of natural gas liquid (NGL) is calculated as:

$$E_{ngl,exp} = E_{ngl,gr} - E_{ngl,fuel} \qquad \left[\frac{\text{MMBtu}}{\text{d}}\right] \tag{5.3}$$

where $E_{ngl,exp}$ = NGL export/import [MMBtu/d]; $E_{ngl,gr}$ = gross NGL consumption [MMBtu/d]; and $E_{ngl,fuel}$ = amount of NGL produced as fuel [MMBtu/d].

The import of diesel is equal to gross diesel consumption. The export of diesel does not apply because diesel is not produced in upstream operations. The export/import of electricity is equal to electricity net consumption as calculated in eq. (5.1). Positive net electricity consumption is equal to electricity imported from the grid and negative net electricity consumption is equal to electricity exported to the grid. Crude oil export/import does not apply because crude oil is the main product. Any crude oil used as a process fuel on site is subtracted from the amount produced and shipped (see Section 5.3).

Finally, the indirect energy consumption by fuel type is calculated. The indirect energy consumption is calculated as:

Energy Consumption Table 6

$$\begin{aligned} E_{k,ind} &= E_{k,exp}\, E_{k,FC} \qquad \text{for } E_{k,exp} < 0 \\ E_{k,ind} &= E_{k,exp}\, E_{k,DS} \qquad \text{for } E_{k,exp} > 0 \end{aligned} \tag{5.4}$$

where k refers to the fuel type; $E_{k,ind}$ = indirect energy consumption [MMBtu/d]; $E_{k,exp}$ = fuel export/import [MMBtu/d]; $E_{k,FC}$ = fuel cycle energy consumption [MMBtu/MMBtu]; and $E_{k,DS}$ = energy consumption of displaced system in case of fuel export [MMBtu/MMBtu]. For details on the energy consumption of fuel cycles and displaced systems, see Section 4.7.

5.2 *'GHG Emissions'* gathering sheet

The GHG emissions gathering sheet compiles and computes emissions of all emissions types across all process stages. The first step is the calculation of direct GHG emissions from the different components of the model. Direct GHG emissions are calculated as:

GHG Emissions Table 1

$$EM_{s,k} = E_{s,k,gr}\, EF_{s,k} \qquad \left[\frac{\mathrm{gCO_2eq}}{\mathrm{d}}\right] \tag{5.5}$$

where s = emissions source (e.g., downhole pump driver); k = fuel type; $EM_{s,k}$ = direct GHG emissions from the consumption of fuel k in source s [gCO_2eq/d]; and $E_{s,k,gr}$ = gross energy consumption of fuel k in source s [MMBtu/d]; and $EF_{s,k}$ = emissions factor of source s using fuel k [g CO_2 eq./MMBtu]. This equation does not apply to electricity, where direct GHG emissions are equal to 0 $gCO_2eq./d$.

Next, the GHG emissions from land use VFF are calculated by process stage. This includes gathering emissions calculated in each process stage and supplemental sheets.

GHG Emissions Table 1

The next step is the calculation of indirect GHG emissions by fuel import type. The indirect GHG emissions are calculated as:

GHG Emissions Table 2

$$\begin{aligned} EM_{k,ind} &= E_{k,exp}\, EM_{k,FC} \qquad \text{for } E_{k,exp} < 0 \\ EM_{k,ind} &= E_{k,exp}\, EM_{k,DS} \qquad \text{for } E_{k,exp} > 0 \end{aligned} \tag{5.6}$$

where k refers to the fuel type; $EM_{k,ind}$ = indirect GHG emissions from fuel consumption [gCO_2eq/d]; $E_{k,exp}$ = fuel export/import [MMBtu/d]; $EM_{k,FC}$ = fuel cycle GHG emissions [$gCO_2eq/MMBtu$]; and $EM_{k,DS}$ = GHG emissions from displaced system in case of fuel export [$gCO_2eq/MMBtu$]. For details on the GHG emissions of fuel cycles and displaced systems, see section 4.7.

5.3 *'User Inputs & Results'* gathering sheet

In this sheet the total energy consumption and GHG emissions are calculated and displayed in graphical form. Both the total energy consumption and total GHG emissions are calculated by process stage (e.g., Production & Extraction). First the total energy consumption is calculated as:

User Inputs & Results 5.1.1. - 5.7.1

$$E_{tot} = \frac{E_{tot,dir} + E_{tot,ind} + EL_{VFF}}{E_{tot,out}} \qquad [\mathrm{MJ/MJ}_{out}] \tag{5.7}$$

where E_{tot} = total energy consumption of the process [MJ/MJ_{out}]; $E_{tot,dir}$ = total direct energy consumption (calculated in the *'Energy Consumption'* sheet as net energy consumption) [MMBtu/d]; $E_{tot,ind}$ = total indirect energy consumption (calculated in the *'Energy Consumption'* sheet) [MMBtu/d]; EL_{VFF} = total energy loss from VFF emissions [MMBtu/d]; and $E_{tot,out}$ = total process energy output [MMBtu/d]. The total process energy output is calculated as:

User Inputs & Results 5.1.1. - 5.7.1

$$E_{tot,out} = Q_o \, \mathrm{HV}_o + E_{ngl,blend} - E_{co,net} \qquad [\mathrm{MMBtu/d}] \tag{5.8}$$

where $E_{tot,out}$ = total process energy output [MMBtu/d]; Q_o = volume of oil production [bbl/d]; HV_o = heating value of crude oil [MMBtu/bbl]; $E_{ngl,blend}$ = amount of produced NGL that is added to crude oil [MMBtu/d]; and $E_{co,net}$ = net crude oil consumption, if applicable [MMBtu/d]. The heating value HV for the denominator crude oil can be selected as LHV or HHV.

Fuel Specs 1.1

Total energy consumption is allocated by process stage using the fraction of direct energy consumed in a stage (not including the energy consumption of electricity generation). The allocation of energy consumption to different process stages has no effect on the total energy consumption.

For each process stage, GHG emissions are broken down into three categories: (i) combustion/land use, (ii) VFF, and (iii) credit/debt. For combustion/land use emissions, the direct GHG emissions and land use GHG emissions associated with the process stage are summed in the *'GHG emissions'* sheet. The direct GHG emissions from electricity generation, if any, are divided between the production & extraction and surface processing stages based on the shares of total direct energy consumption between these stages.

GHG Emissions Table 1

VFF emissions associated with a process stage are summed from the *'GHG emissions'* sheet. Indirect GHG emissions calculated in the *'GHG emissions'* sheet represent the total net credit/debt, which is allocated by process stage using the same allocation method used for allocating the total energy consumption.

GHG Emissions Table 1

GHG Emissions Table 2

Finally, the total energy consumption and GHG emissions from the process stages of crude oil extraction and surface processing of associated fluids are integrated with the total energy consumption and GHG emissions of crude oil transport to the refinery to calculate the life cycle energy consumption and GHG emissions on a well-to-refinery basis. The life cycle GHG emissions, for example, are calculated as:

$$EM_{LC} = EM_{PP,tot} \, \epsilon_{CT} + EM_{CT,tot} \qquad \left[\frac{\mathrm{gCO_2eq}}{\mathrm{MJ}_{ref}}\right] \tag{5.9}$$

where EM_{LC} = life cycle GHG emissions [$\mathrm{gCO_2eq/MJ}_F$]; $EM_{PP,tot}$ = total GHG emissions from the process stages of crude oil production and processing [$\mathrm{gCO_2eq/MJ}_{out}$]; ϵ_{CT} = crude oil transport loss factor (calculated based on the amount of crude oil lost in transportation) [-]; and $EM_{CT,tot}$ = total GHG emissions from crude transport [$\mathrm{gCO_2eq/MJ}_{ref}$]. 1 MJ_{out} is one MJ of energy output from crude oil production and processing; and 1 MJ_{ref} is one MJ at refinery gate.

The life cycle energy consumption and GHG emissions are shown in tabular and graphical formats with full GHG emissions breakdown. The total GHG emissions has a separate category for VFF emissions. The energy content of fuels lost to VFF emissions is not tracked as a separate category of energy consumption.

User Inputs & Results Tables 1.1 - 1.2
Figures 1.1 - 1.2

6 Fundamental data inputs

A variety of fundamental data inputs and conversions are required in OPGEE. These data inputs are included in the sheets *'Input data'* and *'Fuel Specs'*. These inputs are described below, organized by broad class of property.

6.1 Global warming potentials

Global warming potentials (GWPs) for gases with radiative forcing are taken from the IPCC Fourth Assessment Report [130]. The GWPs used are the 100-year GWPs.

Input data Table 2.1

6.2 Properties of water and steam

The density of fresh water at 32 °F is used as the base density of water for lifting, boiling and other calculations in OPGEE. Thermodynamic properties of water and steam are required for steam generation calculations. The following data tables are required for use in steam generation calculations in OPGEE:

Input data Table 5.1

- Saturation properties as a function of temperature;
- Saturation properties as a function of pressure;
- Properties of compressed water and superheated steam.

6.2.1 Saturation properties as a function of temperature

Saturation properties of saturated water and steam as a function of saturation temperature are produced using Knovel steam tables [114, Table 1b]. Properties are derived for temperatures starting at 32 °F and in increments of 20 °F from 40 °F to the critical temperature of 705.1 °F. Properties included are liquid and vapor specific volume v [ft^3/lb], specific enthalpy h [Btu/lbm], specific internal energy u (Btu/lbm), and specific entropy s [Btu/lbm °R]

Input Data Table 5.2

6.2.2 Saturation properties as a function of pressure

Saturation properties of saturated water and steam as a function of saturation pressure are produced using Knovel steam tables [114, Table 1d]. Properties are derived for pressures starting at 15 psia in increments of 5 psia from 15 to 2500 psia. Identical properties are included as above.

Input Data Table 5.3

6.2.3 Properties of compressed water and superheated steam

Properties of compressed water and superheated steam are compiled from Knovel steam tables [114, Table 2b]. Pressures are included from 100 to 1500 psia in increments of 100. The following temperatures are included: 32°F and in increments of 20 °F from 40 °F to 1500 °F. Identical properties are included as above.

Input Data Table 5.4

6.3 Properties of air and exhaust gas components

The composition of dry air and densities of gases required in OPGEE are derived from online tabulations [106]. Moisture in atmospheric air varies as a function of temperature and relative humidity. Assumed moisture content is 2 mol%.

Input Data Table 2.2

6.3.1 Enthalpies of air and exhaust gas components

The enthalpy of air and exhaust gas at various temperatures and atmospheric pressure is modeled as described above in the Steam Injection methods description (see Section 4.2). Coefficients for the specific heats of gases as a function of temperature are taken from literature tabulations [116, Table A2-E]. Specific heats are integrated to derive the enthalpy change between two temperatures for combustion products (exhaust gases) and inlet air/fuel mixtures.

Input Data Tables 4.1 - 4.7

6.4 Compositions and properties of fuels

6.4.1 Heating value of crude oil as a function of density

Crude oil heating values are a function of the chemical composition of the crude oil. Crude oil density can be used to determine the approximate heating value (gross and net heating value, or HHV and LHV) of crude oils. Gross and net crude oil heating values (in Btu per lb and Btu per gallon) are presented as a function of API gravity and are given for API gravities from 0 to 46 °API [84, Table 11]. These heating values are converted to SI units and specific gravity for broader applicability.

Fuel Specs Table 1.1

6.4.2 Crude oil chemical composition as a function of density

Crude oil chemical compositions (C, H, S, (O+N)) are given as a function of the density of crude oil [84, Table 9]. Values are interpolated between those given in the table using a relationship for fraction H as a function of API gravity. O + N contents are assumed to sum to 0.2 wt.%. Sulfur content ranges from 5 wt% to 0.5 wt.%, with approximate concentrations derived from Figure 4.2. Carbon mass fraction is computed by difference.

Fuel Specs Table 1.2

6.4.3 Heat of combustion of gaseous fuel components

A variety of properties were collected for gaseous fuel components, including N_2, Ar, O_2, CO_2, H_2O, CH_4, C_2H_6, C_3H_8, n-C_4H_{10}, CO, H_2, H_2S, and SO_2 [137, Chapter 17] [115]. For simplicity, N_2, Ar and all other inert species are lumped and given properties of N_2. The following properties were collected for each species:

Fuel Specs Table 1.3

- Molar mass [g/mol, mol/kg];
- Moles of C and H per mole of each species (for stoichiometric combustion calculations);
- Higher and lower heating value (HHV, LHV) on a volumetric [Btu/scf], gravimetric [Btu/lbm] and molar basis [Btu/mol, Btu/lbmol]. For completeness, gravimetric energy densities in SI units [MJ/kg] are also included.

6.4.4 Refined and processed fuels heating values

The heating values and densities of refined and processed fuels are taken from the GREET model [17] for a variety of fuels.

Fuel Specs Table 4.1

A Terminology: Acronyms and abbreviations

Table A.1: Acronyms and abbreviations.

Acronym or abbreviation	Description
ABS	Absorbents
AGR	Acid gas removal
AIR	Air stripping
AL	Aerated lagoons
ANS	Alaska North Slope
API	American Petroleum Institute
ARB	California Air Resources Board
AS	Activated sludge
BHP	Brake horsepower
CHOPS	Cold heavy oil production with sand
CSS	Cyclic steam stimulation
CWL	Wetlands
DAF	Dissolved air flotation
DEA	Di-ethanol amine
DGA	Diglycolamine
DMF	Dual media filtration
DOGGR	State of California Department of Conservations Division of Oil, Gas and Geothermal Resources
EDR	Electrodialysis reversal
EGOR	Onsite electricity generation to oil ratio
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERCB	Alberta Energy Resources Conservation Board
FOR	Flaring to oil ratio
FWKO	Free-water knockouts
GAC	Granular activated carbon
GGFR	Global Gas Flaring Reduction Partnership at the World Bank
GHG	Greenhouse gases
GLR	Gas to liquid ratio
GOR	Gas to oil ratio
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
GT	Gas turbine

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Acronym or abbreviation	Description
GWP	Global warming potential
HHV	Higher heating value
HRSG	Heat recovery steam generator
HYDRO	Hydrocyclones
IPCC	Intergovernmental Panel on Climate Change
LCA	Life cycle assessment
LHV	Lower heating value
MEA	Monoethanolamine
MF	Microfiltration
NF	Nanofiltration
NGL	Natural gas liquid
NOAA	National Oceanic and Atmospheric Administration
OPGEE	Oil Production Greenhouse Gas Emissions Estimator
ORG	Organoclay
OTSG	Once-through steam generators
OZO	Ozone
RBC	Rotating biological contactors
RO	Reverse osmosis
RVP	Reid vapor pressure
SAGD	Steam assisted gravity drainage
SCO	Synthetic crude oil
SOR	Steam to oil ratio
SSF	Slow sand filtration
TDS	Total dissolved solids
TEG	Triethylene glycol
TEOR	Thermal enhanced oil recovery
TF	Trickling filters
THC	Total hydrocarbon
UF	Ultrafiltration
VFF	Venting, flaring and fugitives
VOC	Volatile organic compounds
VOR	Venting to oil ratio
W&S	Standing and working losses
WOR	Water to oil ratio
WTR	Well to refinery

B Mathematical terms and defintions

Mathematical terms and subscripts are defined in Table B.1. Parameters and variables serve as the key signifiers in the formulae. A variety of subscripts are used in the mathematics, and can be divided into:

1. Process stages, represented by a a two- or three-letter capitalized symbol (e.g., DD = Drilling & Development)
2. Sub-processes, represented by two- or three-letter capitalized symbol (e.g. GP = Gas processing)
3. Process flows or environments, represented by lower-case symbols (e.g., a = air)
4. Technologies or technology components, represented by capitalized symbols (e.g., GD = glycol dehydrator)
5. Primary fuels and energy carriers, represented by one- to three-letter lower-case symbols (e.g., di = Diesel fuel)
6. Modifiers, represented by lower-case symbols or word fragments (e.g., avg = averge)
7. Gas species, represented by capitalized species formulae (e.g., $O2$ = oxygen)

In general, a term in the equation will follow the above order as in:

$$[Param]_{[PROCESS][SUB-PROCESS][flow][TECHNOLOGY][fuel][modifier(s)][SPECIES]} \quad \text{(B.1)}$$

if an element is not needed, it is simply excluded. To create a (relatively extreme) example, one might have: $p_{OTSG,ng,avg,in}$, which represents average inlet natural gas pressure to the once-through steam generator. Most equation elements will not require this many elements.

Table B.1: Mathematical symbols and subscripts.

Symbol	Description
Parameters and variables	
α	Solar absorbance
δ	Change
ϵ	Loss
η	Efficiency
γ	Specific gravity
λ	Fraction or share
ρ	Density
$a, b, c, d \ldots$	Constants in fitting equations or from data
C	Capacity
C	Concentration
D	Diameter
API	Degrees API
e	Energy (per unit of something)
E	Energy quantity
EF	Emissions factor
EL	Energy loss
EM	Emissions
f	Friction factor
FOR	Flaring oil ratio
GOR	Gas oil ratio
GWP	Global warming potential
h	Height
h	Enthalpy
H	Head
I	Solar insolation
l	Load factor
m	Mass
MW	Molecular weight
N	Number of something
p	Pressure
P	Power
Q	Flow rate
R	Ratio
r	Radius
RVP	Reid vapor pressure
T	Temperature
U	Effectiveness
v	Velocity
V	Volume
W	Work
w	Mass fraction
WOR	Water oil ratio
x	Mole fraction

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Symbol	Description
y	Binary variable
Process stages (Index = j)	
EX	Exploration
DD	Drilling & Development
PE	Production & Extraction
SP	Surface Processing
MA	Maintenance
CT	Crude Transport
BE	Bitumen Extraction & Upgrading
SI	Steam Injection
EL	Electricity
FC	Fuel cycle
VFF	Venting, flaring and fugitives
LC	Life cycle
DS	Displaced system
PP	Process stages of curde oil production and processing
Sub-processes (Index = j)	
EX	Extraction
GP	Gas processing
IC	In situ production via CSS
IP	In situ productio via primary prod.
IS	In situ production via SAGD
MI	Integrated mining & upgrading
MN	Non-integrated mining & upgrading
UP	Upgrading
Process flows & Environment (Index = i)	
a	Air
atm	Atmosphere
e	Exhaust
f	Fuel
g	Gas
l	Liquid
o	Oil
w	Water
ws	Water as steam
Technologies (Index = j)	
AGR	AGR unit
B	Barge
BP	Booster pump
C	Compressor
CD	Crude dehydrator
CP	Circulation pump
D	Driver

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Symbol	Description
DR	Drill rig
EG	Electricity generator
F	Flaring
F	Fan
F	Fugitives
G	Generator
GD	Gas dehydrator (glycol dehydrator)
GP	Glycol pump
GS	Generator set
GT	Gas turbine
$HRSG$	Heat recovery steam generator
M	Motor
$OTSG$	Once-through steam generator
P	Pipeline
R	Rail
R	Roof
RE	Reciprocating engine
RP	Reflux pump
S	Stabilizer
T	Tanker
T	Tank
V	Vent
W	Well

Fuels and energy carriers (Index = k)

ag	Associated gas
c	Coal
ck	Coke
co	Crude oil
db	Diluted bitumen
di	Diesel
dl	Diluent
el	Electricity
ng	Natural gas
ngl	Natural gas liquids
pg	Processed gas (processed associated gas)
ro	Residual oil
sco	Synthetic crude oil
sg	Still gas

Modifiers

avg	Average
atm	Atmospheric
b	Base
wf	Bottomhole (well-formation)
$comb$	Combusted
dir	Direct

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Symbol	Description
d	Discharge
ent	Entrained
exp	Exported
gen	Generated
gr	Gross
$heat$	Heated
im	Imported
ind	Indirect
in	Input
l	Lost
mu	Make-up
max	Maximum
min	Minimum
net	Net
ot	Other
out	Output
rem	Removed
req	Required
res	Reservoir
rec	recovered
ref	refinery
s	Stages
sc	Standard conditions
str	Stripped
s	Suction
th	Thermal
tot	Total
to	Turn over
wh	Wellhead
$trav$	traverse
$lift$	lifting

Gas species (Index = i)

C	Carbon
$CO2$	Carbon dioxide
H	Hydrogen
$H2O$	Water
$H2S$	Hydrogen sulfide
$N2$	Nitrogen
$O2$	Oxygen

C Tabulated sources for each production stage

The full classification of emissions sources for each production stage is given below in Tables C.1 to C.7.

Each emissions source is classified according to process, sub-process, and specific emissions source. Any variants of that emissions source are listed (if they have material effects on emissions or energy consumption). A sensitivity code is given from 1 to 4 stars (* to ****) based on judgement of the likely magnitude of the source. Lastly, the table indicates whether or not an emissions source is included (incl. = 1 means that the source is included).

Table C.1: Emissions sources from exploratory operations. For inclusion: 0 = not included, 1 = included.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Exploration	Seismic exploration	Terrestrial seismic	Vehicular emissions	-	*	≤ 0.01 g	0
			Data processing	-	*	≤ 0.01 g	0
			Consumed materials (charges etc.)	-	*	≤ 0.01 g	0
			Land use impacts	-	*	≤ 0.01 g	0
		Oceanic seismic	Ship emissions	-	*	≤ 0.01 g	0
			Data processing	-	*	≤ 0.01 g	0
			Consumed materials	-	*	≤ 0.01 g	0
	Exploratory drilling	Terrestrial drilling	Prime mover emissions	-	*	≤ 0.01 g	0
			Land clearing and construction	-	*	≤ 0.01 g	0
			Vents and upset emissions	-	*	≤ 0.01 g	0
			Drilling flares	-	*	≤ 0.01 g	0
			Casing and cement	-	*	≤ 0.01 g	0
			Other material consumption (e.g., frac sand)	-	*	≤ 0.01 g	0
			Land use impacts	-	*	≤ 0.01 g	0
			Indirect land use impacts (opening of inaccessible land)	-	*	≤ 0.01 g	0
		Offshore drilling	Prime mover emissions	-	*	≤ 0.01 g	0
			Drilling flares	-	*	≤ 0.01 g	0
			Vents and upset emissions	-	*	≤ 0.01 g	0
			Casing and cement	-	*	≤ 0.01 g	0
	Waste handling and disposal	Mud and fluid handling	Energy consumption (other than prime mover)	-	*	≤ 0.01 g	0
			Fugitives from mud	-	*	≤ 0.01 g	0
			Disposal of mud	-	*	≤ 0.01 g	0
		Fracturing fluid disposal	Processing and disposal of fracturing fluid	-	*	≤ 0.01 g	0
		Produced water disposal	Processing of produced water	-	*	≤ 0.01 g	0
			Disposal of produced water (remote or on-site reinjection)	-	*	≤ 0.01 g	0

Table C.2: Emissions sources from drilling operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Drilling and development	Developmental drilling	Terrestrial drilling	Prime mover emissions	-	**	0.1 g	1
			Drilling flares	-	*	$\leq$ 0.01 g	0
			Vents and upset emissions	-	**	0.1 g	0
			Land use impacts	-	**	0.1 g	1
			Clearing and construction	-	*	$\leq$ 0.01 g	0
			Casing and cement embodied emissions	-	*	$\leq$ 0.01 g	0
			Other materials consumption (e.g., frac sand)	-	*	$\leq$ 0.01 g	0
		Oceanic drilling	Prime mover emissions	-	**	0.1 g	1
			Drilling flares	-	*	$\leq$ 0.01 g	0
			Vents and upset emissions	-	**	0.1 g	0
			Casing and cement embodied emissions	-	*	$\leq$ 0.01 g	0
	Processing capital investment	Oil/gas/water separators	Separator assembly	-	*	$\leq$ 0.01 g	0
			Separator fabrication	-	*	$\leq$ 0.01 g	0
			Separator transport	-	*	$\leq$ 0.01 g	0
			Raw materials manufacture	-	*	$\leq$ 0.01 g	0
		Water reinjection wells	Various drilling emissions from reinjection wells (see above)	-	*	$\leq$ 0.01 g	0
		Pumps	Pump assembly	-	*	$\leq$ 0.01 g	0
			Pump fabrication and raw materials manufacture	-	*	$\leq$ 0.01 g	0
			Pump transport	-	*	$\leq$ 0.01 g	0
	Storage capital investment	Storage capital investment	Tank assembly	-	*	$\leq$ 0.01 g	0
			Tank fabrication	-	*	$\leq$ 0.01 g	0
			Tank transport	-	*	$\leq$ 0.01 g	0
			Raw materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
	Transport capital investment	Pipeline capital investment	Pipeline assembly	-	*	$\leq$ 0.01 g	0
			Pipe fabrication	-	*	$\leq$ 0.01 g	0
			Pipe transport	-	*	$\leq$ 0.01 g	0
			Raw materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
		Other transport capital investment	Other infrastructure fabrication and assembly	-	*	$\leq$ 0.01 g	0

Table C.3: Emissions sources from production and extraction operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Production and extraction	Lifting	Pumping	Combustion for pump driver	-	***	1 g	1.0
			Electricity for pump driver	-	***	1 g	1.0
			Casing and wellhead fugitive emissions	-	***	1 g	1.0
		Gas lift	Compressor prime mover emissions	-	***	1 g	1.0
			Compression electricity emissions	-	***	1 g	1.0
			Casing and wellhead fugitive emissions	-	***	1 g	1.0
	Injection	Gas injection	External gas processing (e.g., N2 production)				1.0
			Gas compression energy		***	1 g	1.0
			[-] Gas sequestration credit (CO2 flood)	-	***	1 g	0.0
		Water injection	Water pumping energy	-	***	1 g	1.0
		Steam injection	Water pre-treatment	-	*	¡= 0.01 g	0.0
			OTSG fuel combustion	NG, produced oil	****	10 g	1.0
			Turbine gas consumption (combined cycle)	Low, med, high efficiency	****	10 g	1.0
			HRSG duct firing (combined cycle)	-	***	1 g	1.0
			[-] Electricity co-production offsets (combined cycle)	Grid mix variation	****	10 g	1.0
			Steam pumping energy (if any)	-	*	¡= 0.01 g	0.0
		Polymer flood	Polymer embodied energy	-	*	¡= 0.01 g	0.0
			Polymer mixing	-	*	¡= 0.01 g	0.0
			Polymer/water mixture pumping energy	-	*	¡= 0.01 g	0.0
		Surfactant/other injection	Surfactant/other embodied energy	-	*	¡= 0.01 g	0.0
			Surfactant/other mixing	-	*	¡= 0.01 g	0.0
			Surfactant/other mixture pumping energy	-	*	¡= 0.01 g	0.0

Table C.4: Emissions sources from surface processing operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Separation and surface processing	Fluid separation	Oil-water-gas separation	Oil-water-gas separation	-	**	0.1 g	1
			Oil-water-gas separation with heater-treaters	-	**	0.1 g	1
			Associated gas venting	Variations in flare efficiency	****	10 g	1
			Associated gas flaring	Variations in flare efficiency	****	10 g	1
	Solid/fluid separation	Solid separation from fluids	Solids removal from separation	-	*	$\leq$ 0.01 g	0
	Gas processing	Gas processing	Produced gas dehydration	-	*	$\leq$ 0.01 g	1
			Produced gas venting and flaring	-	***	1 g	1
	Water treatment and disposal	Water treatment	Produced water cleanup	-	**	0.1 g	1
			Produced water handling and pumping	-	**	0.1 g	1
		Water reinjection and disposal	Produced water reinjection	-	***	1 g	1
			Produced water disposal	-	**	0.1 g	1
	Storage (as part of separation)	Storage	Storage pumping energy	-	*	$\leq$ 0.01 g	0
			Tank assembly and installation	-	*	$\leq$ 0.01 g	0
			Evaporative and fugitive emissions	-	**	0.1 g	1
			Tank materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0

Table C.5: Emissions sources from maintenance operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Maintenance and workovers	Well workover	Terrestrial well workover	Workover rig energy use	-	*	$\leq$ 0.01 g	0
			Fugitive emissions during workover	-	**	0.1 g	1
			Embodied energy in consumed replacement parts	-	*	$\leq$ 0.01 g	0
		Offshore well workover	Workover rig energy use	-	*	$\leq$ 0.01 g	0
			Fugitive emissions during workover	-	**	0.1 g	1
			Embodied energy in consumed replacement parts		*	$\leq$ 0.01 g	0
	Other maintenance	Other maintenance	Solids removal from separation	-	*	$\leq$ 0.01 g	0

Table C.6: Emissions sources from waste treatment and disposal operations.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Waste treatment and disposal	Water processing waste	Water treatment waste disposal	Subsurface disposal of concentrated WW residuals	-	*	$\leq$ 0.01 g	0
			Surface disposal of separated solids	-	*	$\leq$ 0.01 g	0
			Surface disposal of concentrated WW residuals	-	*	$\leq$ 0.01 g	0
	Other waste separation and disposal	Other waste separation and processing	Other waste separation and processing	-	*	$\leq$ 0.01 g	0
			Other waste storage	-	*	$\leq$ 0.01 g	0
			Spills and other upsets	-	*	$\leq$ 0.01 g	0
		Other waste disposal	Other waste transport	-	*	$\leq$ 0.01 g	0
			Other waste disposal (non-hazardous)	-	*	$\leq$ 0.01 g	0
			Other waste disposal (hazardous)	-	*	$\leq$ 0.01 g	0
	Solid waste disposal and project decommissioning	Solid waste disposal	Solid waste separation and processing	-	*	$\leq$ 0.01 g	0
			Solid waste transport and disposal	-	*	$\leq$ 0.01 g	0
		End of life and decommissioning	Demolition and decommissioning	-	*	$\leq$ 0.01 g	0
			Scrap and waste disposal	-	*	$\leq$ 0.01 g	0
			[-] Credit for waste recycling (embodied energy)	-	*	$\leq$ 0.01 g	0

Table C.7: Emissions sources from crude transport.

Main stage	Process	Sub-process	Emissions source	Variants	Sensitivity code	Estimated magnitude	Incl.
Crude product transport	Pipeline transport	Pipeline transport	Combustion for pump prime mover	-	***	1 g	1
			Electricity for pump use	-	***	1 g	1
			Process upsets (one-time events)	-	*	$\leq$ 0.01 g	1
			Leaks (pipeline losses)	-	***	1 g	1
		Pipeline construction	Construction equipment energy use	-	*	$\leq$ 0.01 g	0
			Embodied energy in pipeline materials (cement and steel)	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0
	Tanker transport	Tanker transport	Combustion in tanker prime mover (bunker fuels)	-	***	1 g	1
			Loading and unloading pumping	-	*	$\leq$ 0.01 g	1
			Flares	-	*	$\leq$ 0.01 g	1
			Vents, leaks and upsets	-	*	$\leq$ 0.01 g	1
		Tanker construction	Embodied energy in tanker materials (steel)	-	*	$\leq$ 0.01 g	0
			Construction energy	-	*	$\leq$ 0.01 g	0
	Storage (as part of transport)	Storage	Storage pumping energy	-	*	$\leq$ 0.01 g	0
			Tank assembly and installation	-	*	$\leq$ 0.01 g	0
			Evaporative and fugitive emissions	-	**	0.1 g	1
			Tank materials manufacture	-	*	$\leq$ 0.01 g	0
			Land use impacts	-	*	$\leq$ 0.01 g	0

D Statistical analysis of water oil ratios

This appendix outlines the analysis underlying the smart default for the water oil ratio (WOR) as a function of field age. The WOR is a determining factor influencing the energy consumed in lifting, handling and separating fluids.

A default value for WOR as a function of time is generated by performing statistical analysis of historical oil production data in Alberta and California.

First, the data sources used in the analysis are described. Second, a review of the theoretical and practical drivers of WOR is presented. Third, a description of the methodology used to find the best model fit for WOR in Alberta and California is conducted. Finally, the results and default values to be used in OPGEE are presented.

D.1 Methods of Analysis

D.1.1 Data sources

Data on oil and water production are collected from the Alberta Energy Resources Conservation Board (ERCB) and DOGGR.

From ERCB, the data set ST-16 [138] was obtained, containing monthly pool/deposit-level production and injection records from 1962 to 2011. Data from 2011 were discarded, as observations were available only for the first four months. Overall, 26 injection and 11 production variables are included in the data set. Four out of 975 fields included in the data set were classified as unconventional, meaning that their primary output was crude bitumen and not crude oil. The WOR was provided within the dataset and was also calculated on a monthly basis for each pool.

The data set was transferred from pdf into a *Stata* data file so that a longitudinal/panel data set could be created. A longitudinal/panel data set contains observations on multiple production and injection variables over multiple time periods for the same unit of observation. In this case, the unit of observation is the unique identifier (ID) which was created for each possible pool and field combination (51,272) which interacts with a time variable that corresponds to the number of months (588) included in the analysis. Reservoir age was calculated relative to the first year for which production was recorded for each unique pool and field combination. Not all combinations have produced uninterruptedly since 1962, so the data set is referred to as an unbalanced panel.

Table D.1: Characteristics of collected Alberta production and injection dataset.

Data element	Number
Fields	975
Pools	8,043
Months	588
Years	49
Unique field + pool combinations (IDs)	55,104[a]
IDs with 6 months of WOR values	17,082
Production variables	11
Injection variables	26
Total observations	5,579,496

[a] As can be seen, most of these field/pool combinations do not have significant data available, and likely represent failed production projects or non-commercial discoveries.

Only pool and field combinations for which WOR data are available for at least 6 non-consecutive months and for which the value differed from zero are included in the analysis.[1] A total of 17,082 pool and field combinations satisfied these conditions.

A preliminary analysis suggested that many of these pools are extremely small producers and exhibited erratic or sporadic production behavior. We therefore limited the analysis to the top 100 pool/fields. These pools contributed over 65% of Alberta crude production over the dataset time period.

For California, crude production and water injection data was obtained from the State of California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR). DOGGR data was available on a ten-year interval from 1955 to 2005 for a total of 306 California oil fields [78, 82]. Because of data quality concerns, small fields were excluded. Cumulative production over all sampled years was summed, and all fields contributing less than 0.1% of California production were excluded from the dataset. This resulted in a sample of 80 fields.

D.1.2 Determining the best fitting model

The producing WOR in a field is generally a function of the oil and water viscosities, total and relative reservoir permeabilities, geologic heterogenaity, and field age. The WOR tends to increase over the producing life of a field [139]. A common method used to plot WOR over time is to plot cumulative production on the x-axis and WOR on a logarithmic scale on the y-axis [139, Fig. 7.5]. The trend in WOR is often nearly linear in this semi-log space, but is often interspersed with periods of more or less rapid increase as layers in

[1] This data cleaning was performed because one must have a minimum number of observations with variance to compute a regression. At a minimum, the number of observations should double the number of parameters used in the estimation of the model and be different from zero so as to have variance within the set of observations.

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Table D.2: Characteristics of collected California production and injection dataset.

Data element	Number
Fields	306[a]
Years	6
Production variables	3
Field characteristic variables	6
Total observations	1836

[a] Most of these fields are rejected in an initial screen that removes all fields that do not contribute more than 0.1% of total California cumulative production over the years of the dataset (see text for explanation).

a field or pool breakthrough with water at different times. This trend implies exponential behavior of WOR. Because cumulative production data are not likely to be available in general, we develop an alternative model with time as the independent variable rather than cumulative production.

Three models were tested to fit the relationship between WOR and field age. The parametric models tested included an exponential function, a logistic function and a Gompertz function. To determine the best fitting model, non-linear regression functions by least squares were fitted to the data and their relative coefficients of determination (R^2) compared to determine which model had the greatest predictive power.

Although there is no precise rule for the number of observations required in nonlinear regressions, observations should substantially exceed the number of predictor variables in a model. For the case of Alberta, given the extensive data set the ratio of observations to variables was 68:1 whereas for California the ratio was 3:1 (exponential model).

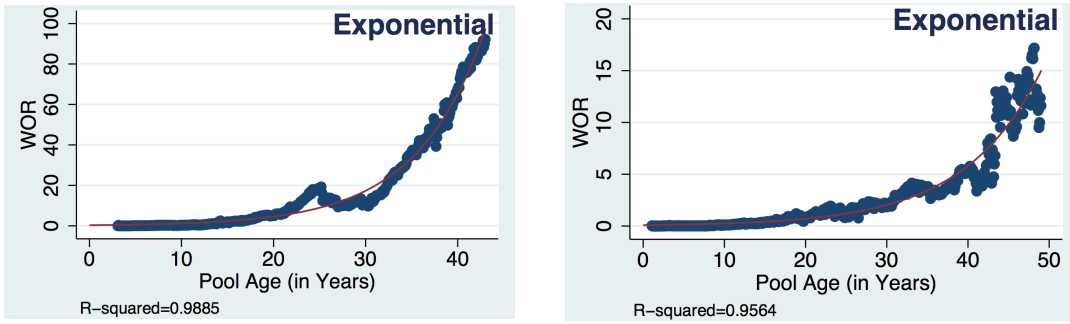
D.1.2.1 Exponential Function

The exponential function is fitted to the available pool level data as seen in Figure D.1. This function is defined as follows:

$$WOR(t) = a_{WOR} \exp[b_{WOR}(t - t_0)] \tag{D.1}$$

where a_{WOR} = initial WOR in time = t_0 [bbl water/bbl oil]; b_{WOR} = exponential growth rate [1/y]; t_0 = initial year of analysis [y]; and t = year being modeled (independent variable) [y].

The exponential function shows WOR consistently increasing over time with the age of the reservoir (see Figure D.1). In the cases shown in the figure, the model is an excellent predictor of WOR, as demonstrated by the R^2 coefficients (here, the model captures over 95% of the variation due to the independent variable).



(a) Grand Forks, Upper Mannville K (b) Snipe Lake, Beaverhill Lake

Figure D.1: Example exponential fits to Alberta pool-level WOR dataset. Pool age is calculated relative to discovery date of pool (not initial year in dataset).

D.1.2.2 Logistic and Gompertz models

In addition to the exponential model, two other models were tested: a logistic function and a Gompertz function. Both are sigmoidal in shape, increasing initially and then leveling off (symmetrically in the case of the logistic function, asymmetrically in the case of the Gompertz function). These models were not chosen for the analysis because they did not fit significantly better than the exponential model (increase in mean R^2 of 0.014 and 0.015 for logistic and Gompertz models respectively) and they constitute a significant increase in model complexity (3 parameters rather than 2). Increased model complexity should not be favored if it does not result in meaningful improvement to model fit [140].

D.2 Results

Results for the exponential fits are included below in tabular and graphical form.

D.2.1 Alberta WOR analysis

Table D.3 summarizes the results for the exponential fit to Alberta oil pools and fields. The model results in a strong fit with a mean R^2 of 0.866 and a standard deviation of 0.184. Figure D.2 shows a histogram of R^2 values. There are some model fits with R^2 below 0.6, but most have high predictive value, suggesting that the exponential model is generally useful.

The WOR growth rate (b_1) has a mean value of 0.091 across 100 fits, with a standard deviation of 0.061 and a median value of 0.082. Hence, WOR values in Alberta tend to grow at a rate of 9.1% per year. Figure D.3 shows the dis-

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Table D.3: Results for exponential fit to Alberta oil fields.

Var.	Obs.	Mean	Median	Std. dev.	Min	Max
R^2	100	0.866	0.82	0.184	0.034	0.994
b_0	100	1.168	0.279	3.295	$2 \times 10^{-}9$	29.43
b_1	100	0.091	0.082	0.061	-0.061	0.512

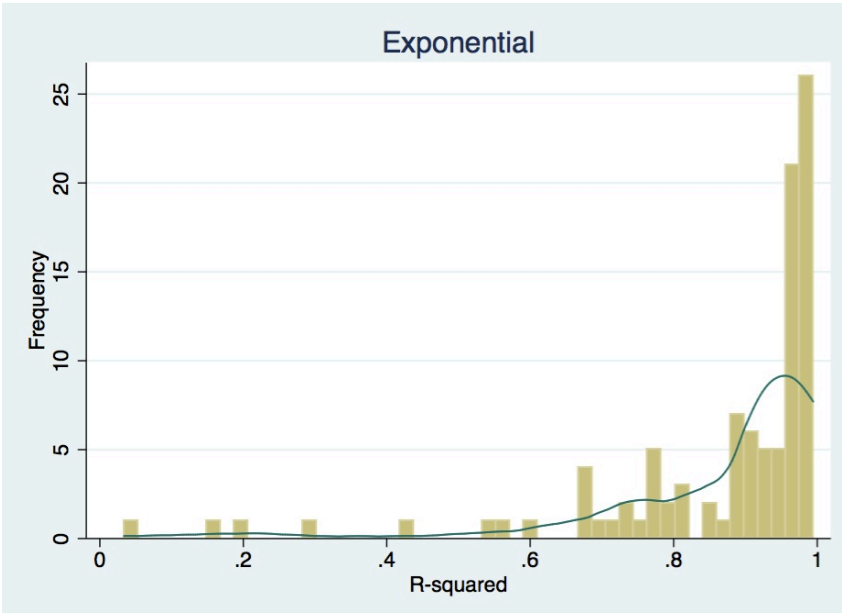


Figure D.2: Histogram of R^2 for Albertan Crude Production (Exponential Fit).

tribution of WOR growth rates with relation to initial WOR values. As can be seen, most fields have initial WOR below 2 bbl/bbl.

D.2.2 Californian WOR analysis

Table D.4 summarizes the results for the exponential fit for the Californian oil fields. The model results in a stronger fit relative to Albertan production with a mean R^2 of 0.893 and a standard deviation of 0.152. As can be seen in the histogram of R^2 values (see Figure D.4), the fit of the model is very good overall.

Table D.4: Results for exponential fit to California oil fields.

Var.	Obs.	Mean	Median	Std. dev.	Min	Max
R^2	80	0.893	0.950	0.152	0.317	0.999
b_0	80	2.486	0.905	4.399	0.000	30.9
b_1	80	0.030	0.031	0.029	-0.019	0.182

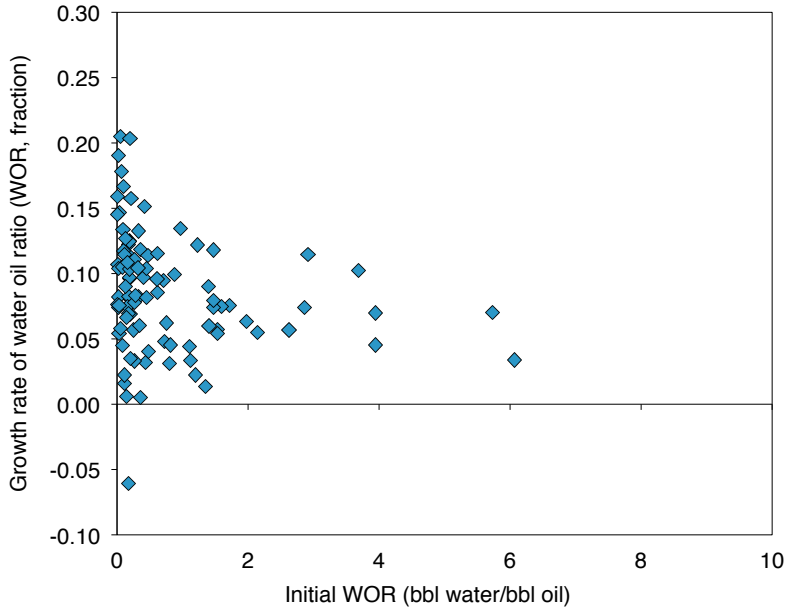


Figure D.3: Plot of values of b_0 and b_1 for exponential fits to Alberta producing WORs.

California WOR trends are different than Alberta trends. In California, b_1 shows a mean value of 0.032 with a standard deviation of 0.029. Hence, WOR increases at a slower rate of 3.2% per year. Figure D.5 shows the distribution of WOR growth rates with relation to initial WOR values. As can be seen, much of the growth is clustered in pool/fields with initial WOR values below 2 but there is a significant amount of fields with initial WOR above 2.

D.2.3 Combined results

In order to establish values for the WOR smart default, four different scenarios were considered:

- Median initial WOR and WOR growth rates for Alberta and California
- Mean initial WOR and WOR growth rates for Alberta and California

The median and mean measures are derived from Alberta and California data from Tables D.3 and D.4. The plots of these median and mean values are included in Figure D.6.

In addition, WOR values are collected for a variety of fields in diverse geographic locations and are included in Figure D.6. These WOR values, along with field age, are included to provide more comparative information. The sources and field names for the comparative cases are included in Table D.6.

A default case is also plotted in addition to the California and Alberta mean and median models. This default takes a value of b_0 and b_1 that is in between

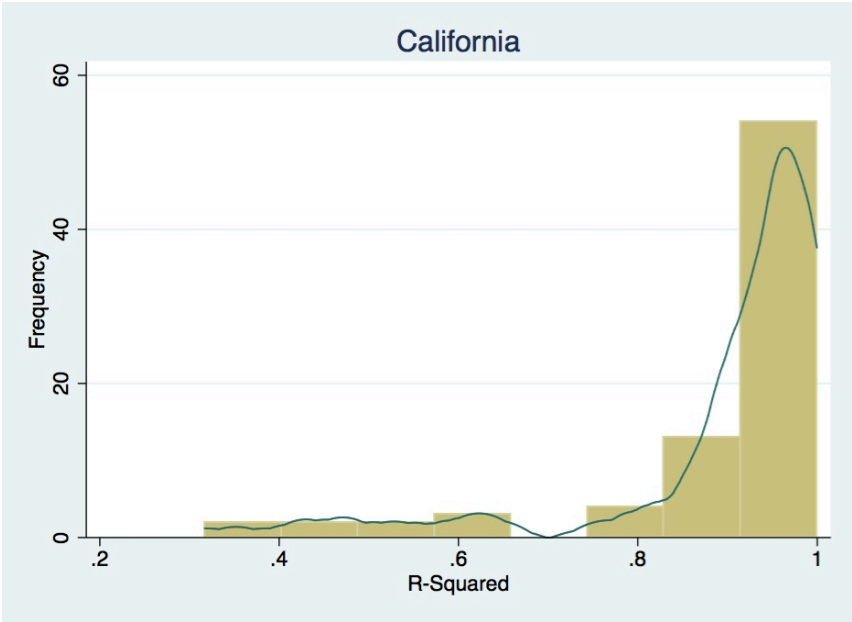


Figure D.4: Histogram of R^2 for Californian Crude Production (Exponential Fit).

Table D.5: OPGEE WOR relationships.

Case	b_0	b_1	Source
Low	2.486	0.032	CA Mean
Default	1.75	0.05	User spec.
High	1.168	0.091	AB mean

the observed mean values for California and Alberta. The resulting default is also shown in Figure D.6

Table D.6: Sources of WOR data for global oil fields.

Location	Fields	Sources	Notes
Alaska North Slope (ANS)	Colville River, Kupuruk Rover, Milne Point, Prudhoe Bay, Northstar, Endicott, Oooguruk	[141]	
Brazil	Marlim	[142]	
CA onshore	Huntington Beach, Inglewood, La Cienegas, Montalvo West, San Miguelito, Santa Fe Springs, Seal Beach, Shafter North, Tejon	[125]	
CA offshore	Beta, Carpenteria, Dos Cuadras, Hondo, Hueneme, Pescado, Point Arguello, Point Pedernales, Sacate, Santa Clara, Sockeye, Ellwood South Offshore, Belmont Offshore	[126, 143]	a
UK	Humbly Grove, Singleton, Welton, Magnus, Stockbridge, Forties, Wytch Farm, Piper, Brent, Ninian	[144]	b
Alberta	Provost, Wimborne, Hayter, Bantry, Bellshill Lake, Judy Creek, Leduc-Woodbend, Sturgeon Lake South, Virginia Hills, Carson Creek North, Fenn-Big Valley, Nipsi, Swan Hills South, Redwater	[138]	
Wyoming	Salt Creek, Houise Creek, Hartzog Draw, Hornbuckle, Finn-Shurley, Oregon Basin, Spring Creek South, Elk Basin, Hamilton Dome, Garland	[145]	c

[a] In addition to data from the Bureau of Ocean Energy Management, Regulation and Enforcement data, a variety of other web data sources were use to generate first production dates for California offshore fields.

[b] In addition to data from the UK Department of Energy and Climate Change, a variety of other sources were consulted to obtain field age.

[c] Wyoming fields were taken from the top five producing fields in the Powder River Basin and Bighorn Basin. Not all fields had available start dates.

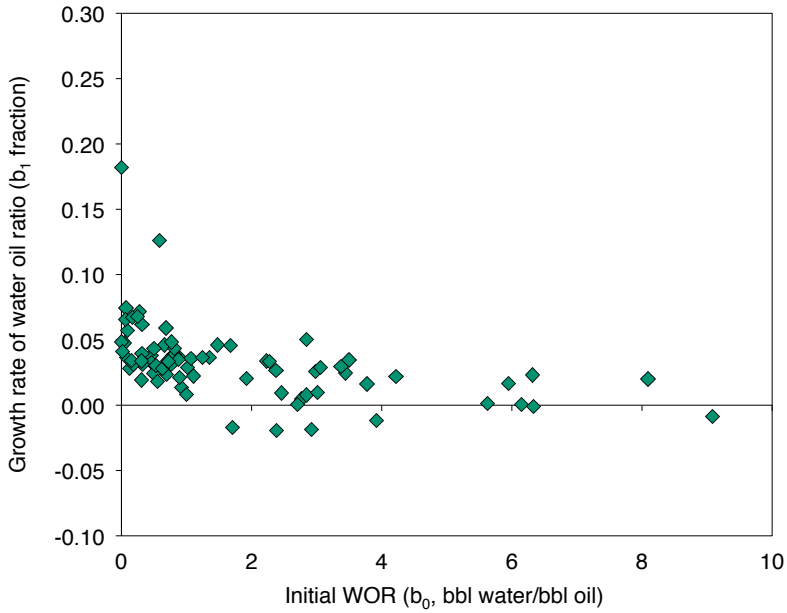
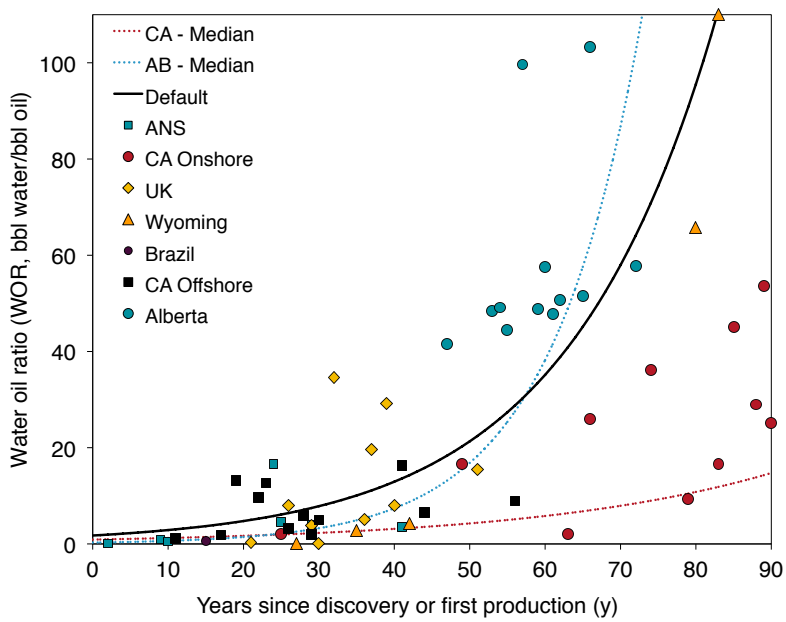
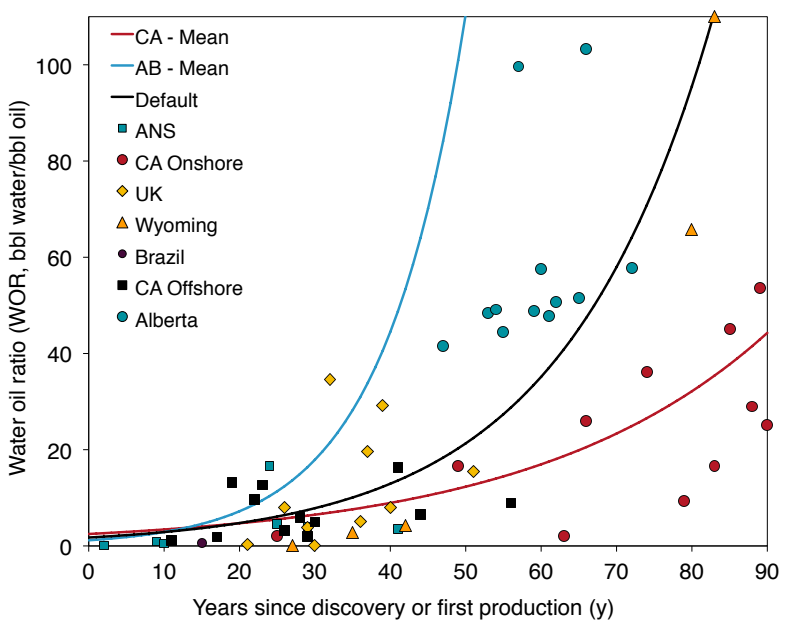


Figure D.5: Plot of values of b_0 and b_1 for exponential fits to California producing WORs.



(a) Fit to median model results.



(b) Fit to mean model results.

Figure D.6: Models using median (left) and mean (right) results for California cases. Default case is a moderate case that is between the Alberta and California cases. Sources for comparative cases are included in Table D.5.

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