Life Cycle Water Demand Coefficients for Crude Oil Production from Five North American Locations

Babkir Ali and Amit Kumar[1]

Department of Mechanical Engineering, Donadeo Innovation Centre for Engineering, University of Alberta, Edmonton, Alberta, Canada, T6G 1H9

Abstract

The production of liquid fuels from crude oil requires water. There has been limited focus on the assessment of life cycle water demand footprints for crude oil production and refining. The overall aim of this paper is address this gap. The objective of this research is to develop water demand coefficients over the life cycle of fuels produced from crude oil pathways. Five crude oil fields were selected in the three North American countries to reflect the impact of different spatial locations and technologies on water demand. These include the Alaska North Slope, California's Kern County heavy oil, and Mars in the U.S.; Maya in Mexico; and Bow River heavy oil in Alberta, Canada. A boundary for an assessment of the life cycle water footprint was set to cover the unit operations related to exploration, drilling, extraction, and refining. The recovery technology used to extract crude oil is one of the key determining factors for water demand. The amount of produced water that is re-injected to recover the oil is essential in determining the amount of fresh water that will be required. During the complete life

[1] Corresponding Author. Tel.: +1-780-492-7797.
E-mail address: Amit.Kumar@ualberta.ca (A. Kumar).

cycle of one barrel of conventional crude oil, 1.71-8.25 barrels of fresh water are consumed and 2.4-9.51 barrels of fresh water are withdrawn. The lowest coefficients are for Bow River heavy oil and the highest coefficients are for Maya crude oil. Of all the unit operations, exploration and drilling require the least fresh water (less than 0.015 barrel of water per barrel of oil produced). A sensitivity analysis was conducted and uncertainty in the estimates was determined.

Keywords: Life cycle water footprint; water-energy nexus; crude oil; water consumption; extraction; refining

1. Introduction

Petroleum oil is one of the largest sources of energy and its extraction has environmental impacts on air, water, and land (Khoo and Tan, 2006). One of the key environmental indicators is the life cycle water footprint, which can be used to measure the impacts of petroleum oil on water resources (OECD, 2008; Galera et al. 2010). The demand for fuels extracted from petroleum oil is highest in the transportation sector, and there is no expectation that this situation will change in near future.

The U.S., Canada, and Mexico are the three North American countries and each has a key role to play in crude oil production (Stillwell et al., 2011; CAPP, 2014; Sanders et al. 2013). The U.S. is the largest consumer of oil products in the world and in 2016 consumed 19.63 million bbl/d. The country produced 49% of this consumption and imported 51%. The largest oil supplier to the U.S. in 2016 was Canada (38% of the total imports) and Mexico was the fourth largest (7%) after Venezuela (8%) (EIA, 2016a). Canada's total crude oil production in 2015 was 3.85 million bbl/d and is projected to reach 4.93 million bbl/d by 2030, with more than half coming from Alberta's oil sands (CAPP, 2016). Mexico is among the top ten oil producers in the world and the third largest North American producer after the U.S. and Canada, although its production has been in continuous decline since 2005 (EIA, 2014).

The concern about the use of water for energy is high all over the world (IEA, 2012; McMahon and Price, 2011; King et al. 2013; Glassman et al. 2011), and the great challenge in the production of primary fuels is not only the absolute amount of water required for extraction, but also the geographical location of the resources, should these be in an area with limited water. The geographical location of oil resources cannot be controlled by humans, unlike electricity generation or oil refining, for which water availability is a consideration at the plant design phase. The other challenge with petroleum production is that most of water withdrawn is consumed and either not returned to the source or a lower quality water is returned.

The province of Alberta in Canada is a hub of energy production and in 2005 about 8% of total water allocations were assigned to the petroleum sector. 92% of water withdrawn was consumed and 65% of the water used in the petroleum sector was diverted for oil sands extraction from a single river basin, the Athabasca, which flows close to oil resources. Most (88%) of the total water allocated for the petroleum sector in the Athabasca River Basin is surface water (AENV, 2007). In Alberta, electricity generation plants, refineries, and proposed oil sands upgraders could be located so that they are distributed near different river basins where water use is not a large concern (Hackett et al., 2012; EPCOR, 2004; ATCO, 2016; Griffiths and Dyer, 2008).

Most of the earlier studies conducted on energy sector water demand either focused on a single geographical region (Okadera et al., 2014; Zhang and Anadon, 2013; Grubert et al., 2012), recognized water consumption but not water withdrawals (Okadera et al., 2014; Zhang and Anadon, 2013; Grubert et al., 2012; Gleick, 1994; Wu and Chiu, 2011; Staples, 2013), or covered specific unit operations and not over the complete life cycle (Argaez et al., 2007; AER 2014a). In addition, none of these studies provide a comparative assessment of life cycle water footprints of North American crude oils. In other words, there are few studies on the life cycle water footprint assessment of crude oils and none studies on a comparative life cycle assessment (LCA) of crude oils' water footprint. The authors of this study have conducted complete LCA of water footprints for coal, natural gas, renewable energy-based power generation (Ali and Kumar, 2015, 2016, 2017a), and regression models were developed to determine significant factors affecting thermoelectric power plant water use in the United States (Yang and Dziegielewski, 2007). An early study by the authors included assessment of life cycle water footprint of oil sands (Ali and Kumar, 2017b) but no studies have been done on crude oils. This is a significant gap in the literature, and this paper is aimed at addressing this gap.

The key objectives of this paper are to:

- Develop life cycle water demand coefficients for crude oil produced at five different locations in North America.
- Carry out a comparative LCA of water demand for crude oils.
- Assess the impacts of the re-injection of produced water on water demand over the complete life cycle.
- Assess the impact of different technologies used on the water demand for crude oil production.
- Assess the impact of the water used for refining unit operations on the water demand over the complete life cycle.
- Estimate the uncertainty in the life cycle water footprint for crude oil production at various North American locations.

The second section of this article discusses the methodology followed in the study and the third section gives the background of the five selected oil fields in North America. Assumptions and input data used for the analysis are explained in the fourth section and the obtained results and discussion in the fifth section. The sensitivity analysis and conclusions are presented in the sixth and seventh sections, respectively.

2. Methodology

The life cycle methodology used in this paper covers the unit operations involved in crude oil production. Unit operations have been defined for exploration, drilling, extraction, and refining. The standard steps determined by ISO14040 for LCA were followed in this study (Garofalo et al., 2017) by defining the goal of developing water footprints for different unit operations of conventional oil. The inventory is the quantity of water analysed through demand coefficients per functional unit of conventional oil produced (bbl). Water demand coefficients for crude oil is a term used in this paper to include both water consumption coefficients and water withdrawals coefficients. The water withdrawal (WW) is the total water diverted from a source and includes water consumption (WC) and water returned (WR) to the source. Further details on the life cycle water footprint assessment methodology of energy conversion processes are given in earlier publications by the authors (Ali and Kumar, 2015, 2016, 2017a, 2017b). Five crude oil production regions in North America were selected: three in the U.S. (Alaska North Slope, California's Kern County heavy oil, and Mars), one in Mexico (Maya), and one in Alberta, Canada (Bow River heavy oil). These five regions were selected in this study because they are in line with a previous study on GHG emissions for the same recovery method in North America (Rahman et al., 2014). Figure 1 shows the selected oil production fields on the map of North America. Water demand data for these regions were estimated, and coefficients for unit volume of water per unit volume of oil produced (bbl/bbl) were developed in order to conduct a comparative assessment. The uncertainty in the input parameters was assessed in an extensive sensitivity analysis. The sensitivity analysis was conducted through Monte Carlo simulations (Vose, 2016; Williams et al., 2008; Kullapa and Joe, 2010; Karfopoulos and Anagnostakis, 2010) to evaluate the impact of technology variations on the water demand coefficients for the complete life cycle of crude oil production.

The quality and source of water diverted for the selected five regions may differ, but the developed water demand coefficients in this study are meant to represent benchmarks for similar crude oil production technologies. Only fresh water is considered in this study and it is defined based on information from government agencies such as Alberta Environment (AENV, 2008; AESRD, 2011) that specify water with total dissolved solids (TDS) less than 4000 milligrams per litre (mg/L) is considered fresh water. Beyond this level of water salinity, a diversion license from the Government of Alberta is not required (AESRD, 2011). The raw water could be diverted from the sea with a lower quality than river or groundwater, but when injected for crude oil recovery, sea or produced water has to be treated to a higher quality level considered in the assumed zone of fresh water (less than 4000 mg/L) in this study. The consumption coefficient of fresh water during extraction unit operations was calculated as follows:

$$FW = TWT - PRE * TWP \quad (1)$$

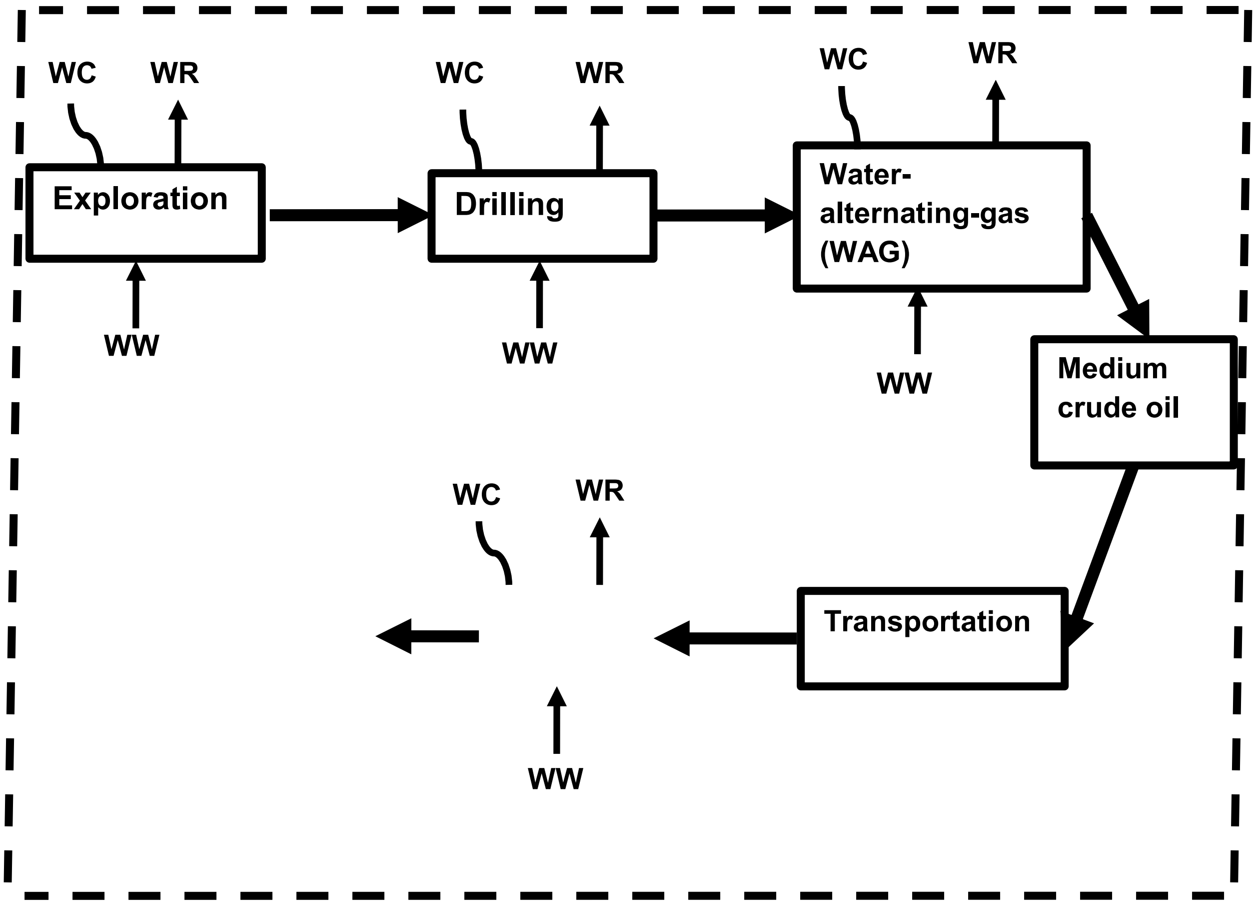
where FW is the consumption coefficient of fresh water (in bbl/bbl), TWT the total water injected (in bbl/bbl), PRE the percentage of produced water re-injected (in %), and TWP the total produced water (in bbl/bbl).

Figure 1: Location of the selected oil production fields in North America

3. Selected oil fields

3.1 Alaska North Slope

Alaska North Slope (ANS) is one of the largest oil producers in the U.S., although production dropped by an average of 3%/year over the thirty-five years preceding 2015 and was 465 thousand bbl/d that year (EIA, 2016b). Prudhoe Bay is the largest oil field in the Alaska North Slope, the largest in the North America, and the twentieth largest in the world; it had a production rate of 271 thousand bbl/d in 2012 (BP, 2012). The medium crude oil produced from Alaska North Slope is sent to refineries through the Trans-Alaska Pipeline System (TAPS) (Sheridan, 2006). The resulting ANS crude is usually loaded into vessels at the Alaska Marine Terminal and sold to customers on the U.S. West Coast (ExxonMobil, 2016). The enhanced oil recovery method most often used in Alaska North Slope is water-alternating-gas injection (WAG) (BP, 2012; ConocoPhillips, 2015). WAG technology has been used extensively in recent years to increase oil productivity (Srivastava and Mahli, 2012; Aghdam et al., 2013; Kulkarni and Rao, 2005). In Alaska North Slope, a miscible injectant is created by mixing compressed produced gas and natural gas liquid (NGL), and the water requirement is met with produced and treated seawater (Kaltenbach et al., 2004). Figure 2 shows the unit operations considered for crude oil production from the Alaska North Slope oil field.

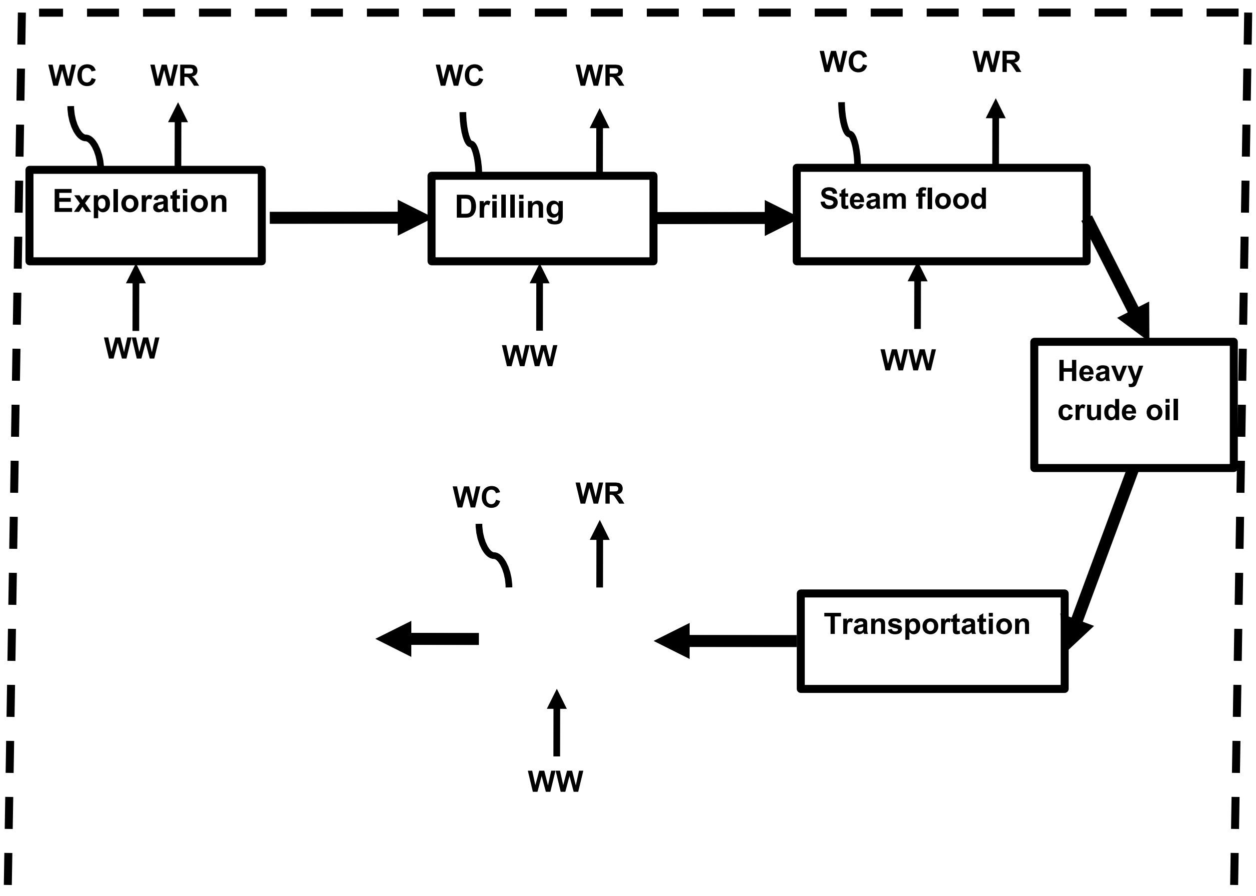


Refining

Figure 2: System boundary and unit operations for the Alaska North slope oil field

3.2 California's Kern County heavy oil

In 2015 California was the third largest oil producer in the U.S. Its production rate in 2015 was 551 thousand bbl/d following a decline since 1980 by an average of 1.7%/year (EIA, 2016c). The largest field in California producing heavy oil (13° API) is Midway-Sunset. In 2012 Midway-Sunset produced 15% of the state's total (Department of Conservation, 2013). Steam flood (thermal enhanced oil recovery) recovery technology is used to melt the heavy oil and increase its pressure, allowing it to be pumped out as a mixture of oil and water (Tennyson, 2005; EPRI, 1999; Schamel, 2001). The heavy oil produced in California is heated or blended with lighter crude oil to ease pipeline transportation to Los Angeles or the Bay area refineries in the U.S. (Sheridan, 2006). Figure 3 shows the unit operations considered for crude oil production from California's Kern County oil field.

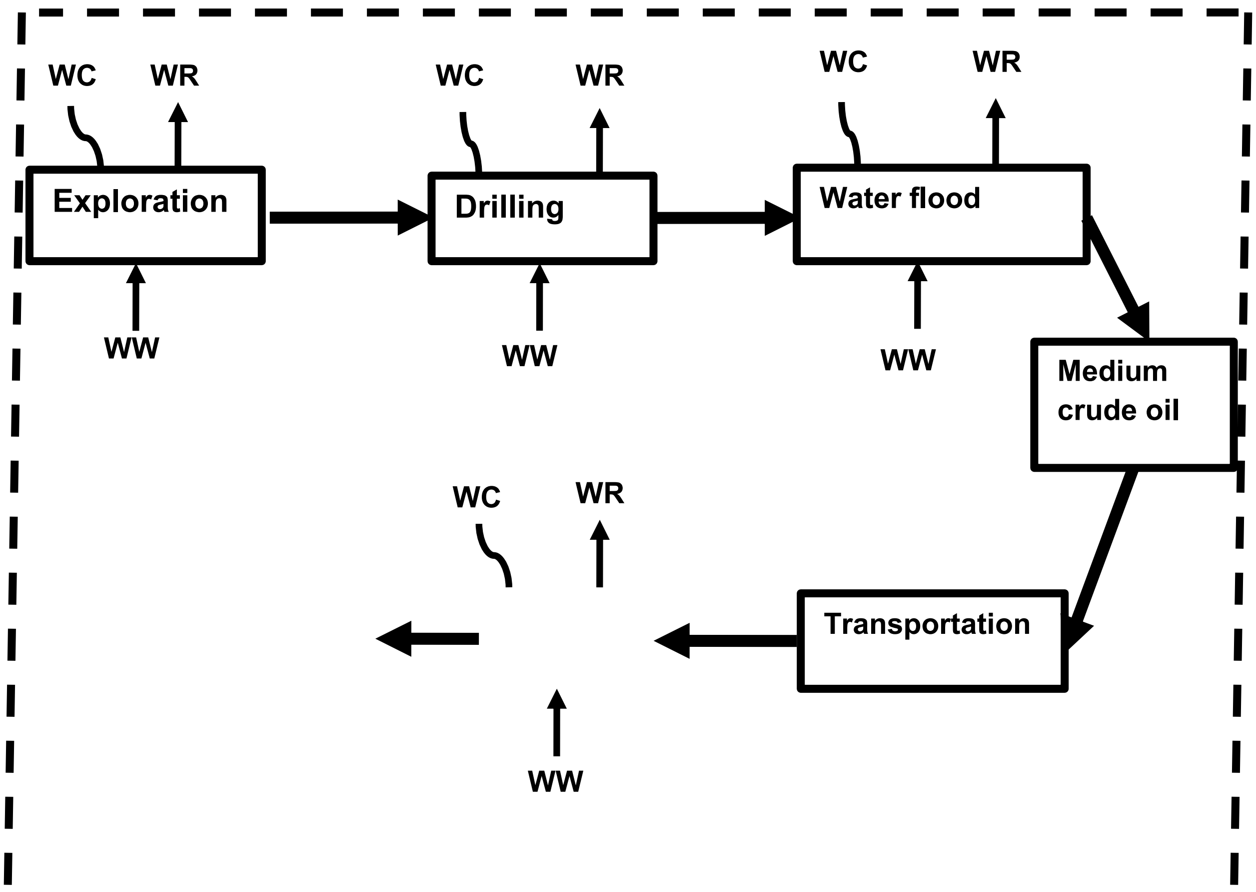


Refining

Figure 3: System boundary and unit operations for California's Kern County oil field

3.3 Mars

Mars is one of the biggest oil fields in the Gulf of Mexico. It is located about 208 kilometers southeast of New Orleans, U.S., and produces 21 thousand bbl/d on average (Offshore Technology, 2016a). Mars blend is a sour medium grade crude oil with an API gravity of 31° (Environment Canada, 1996). Mars crude oil is transported by pipeline to the Louisiana Offshore Oil Port (LOOP) to supply the refining demand (Offshore Technology, 2016a). Water flood is the recovery technology used in the Mars oil field and sea water is used for injection (Weiland et al., 2013). Figure 4 shows the unit operations considered for crude oil production from the Mars oil field.

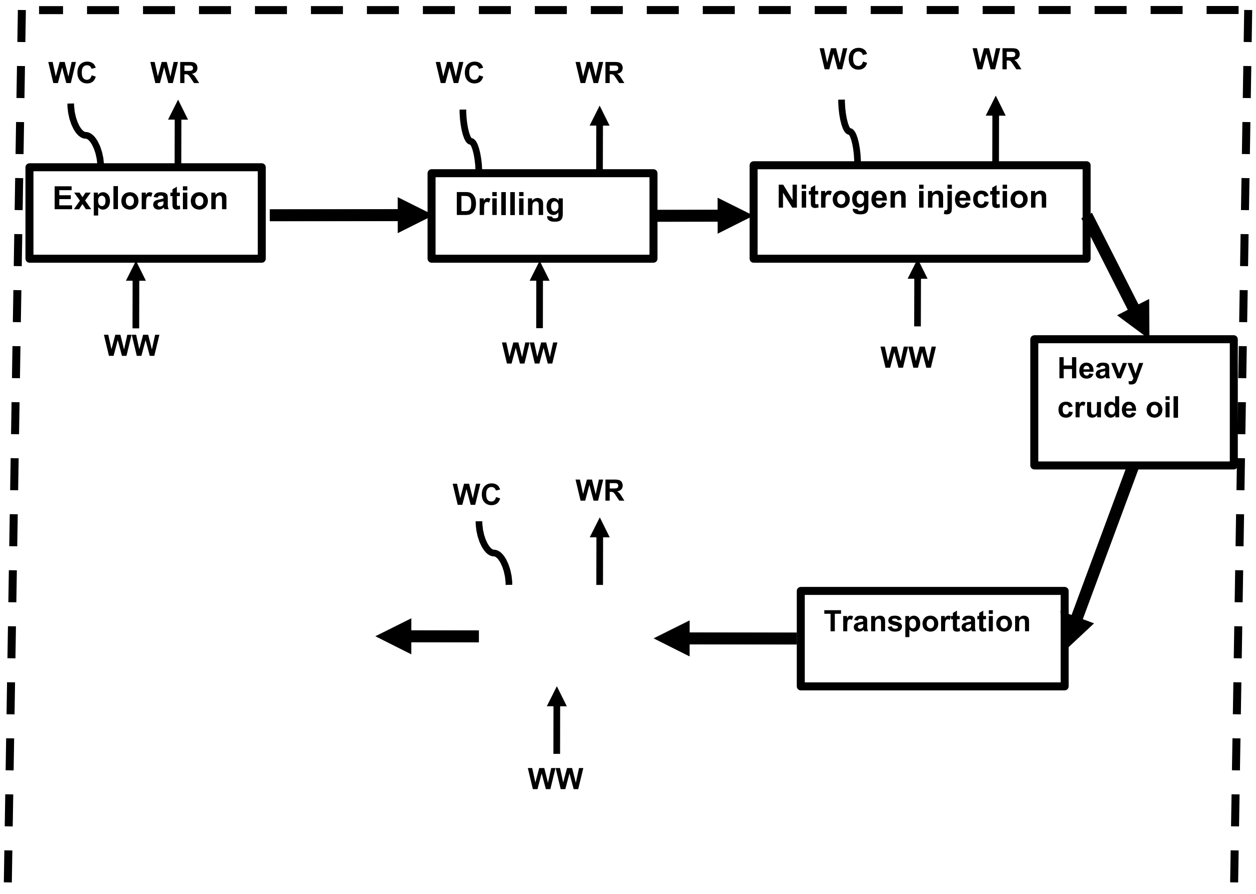


Refining

Figure 4: System boundary and unit operations for Mars oil field

3.4 Maya

Maya is a sour heavy grade oil extracted from the offshore oil fields Ku Maloob Zaap and Cantarell in Mexico (GEO, 2011; Moreno et al., 2014; Morgan et al., 2010). When established thirty years ago, Cantarell, located 100 kilometers from the Yucatan Peninsula in the Gulf of Mexico, was the largest offshore oil field in the world (Offshore Technology, 2016b). Oil production from Cantarell has seen a drastic decline from 2.1 million bbl/d in 2004 to 1.46 million bbl/d (70%) in 2008 (Clemente, 2008) and finally 440 thousand bbl/d (21%) in 2013 (EIA, 2014). To increase production, nitrogen injection technology was introduced (EIA, 2014; Offshore Technology, 2016b; Talwani, 2011). Due to the lack of suitable refineries, most of Mexico's heavy oil is exported as crude (GEO, 2011). The crude oil extracted in the Bay of Campeche is sent through pipelines to Cayo de Arcas and then stored at Dos Bocas. From Dos Bocas some of the oil is exported and some is transported by pipeline to meet internal demand (Offshore Technology, 2016b). Figure 5 shows the unit operations considered for crude oil production from Maya oil field.



Refining

Figure 5: System boundary and unit operations for Maya oil field

3.5 Bow River heavy oil

Bow River conventional heavy crude oil is produced in Alberta, the largest oil-producing province in Canada. In 2013, Alberta's total oil production was 2.7 million bbl/d, of which 78% was from crude bitumen (oil sands) and 22% from conventional crude oil. That same year, 153 thousand bbl/d of conventional heavy oil were produced in Alberta; heavy oil was 26% of the province's conventional crude oil and 6% of its total oil production (AER, 2014b). In 2011, Alberta exported 60% of its crude to the U.S., 22%

remained in the province, 16% went to other Canadian provinces, and 2% went offshore (Alberta Government, 2012). Bow River conventional heavy crude oil has an API gravity of 23°-24°, is sour with 2.75% sulphur content, and is collected from the producer facilities through a network of pipelines in southern Alberta (Crude Quality Inc., 2016). Of Alberta's total initial established heavy crude oil reserves of 2.6 billion bbl, 75% would be recovered by the primary method, 24% by water flood, and 1% by polymer and alkali surfactant polymer (ASP) flooding (AER, 2014b). Figure 6 shows the unit operations considered for conventional heavy crude oil production from Bow River oil field.

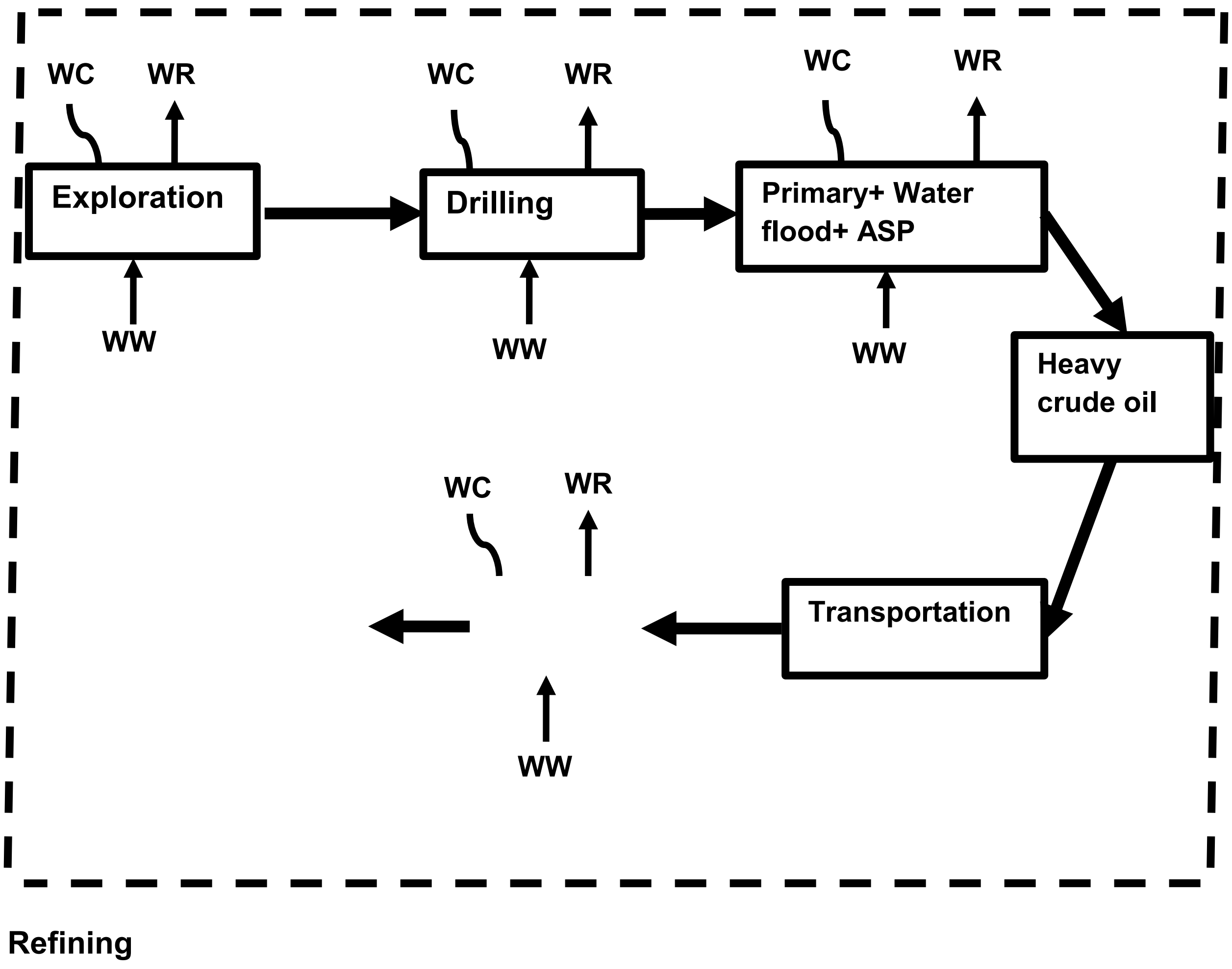


Figure 6: System boundary and unit operations for the Bow River oil field

4. Assumptions and input data

Water demand coefficients for exploration were adapted from Gleick, (1994) and combined with the drilling coefficients. Goodwin et al., (2012) found that the average water consumption for drilling a vertical oil well is 77,000 gallons (1,833 bbl) over the complete production lifetime, and that figure is used in this study along with the total productivity of one well from each oil field (Rahman et al., 2014) to estimate the coefficient in bbl of water per bbl of oil. Coefficients for the total water injected (TWT) and the percentage of produced water re-injected (PRE) to cover all the extraction unit operations were derived from an earlier study (Wu and Chiu, 2011). The coefficients for the total water injected (TWT) were based on the type of recovery technology. and both the percentages of re-injected water (PRE) and the total water produced (TWP) are site-specific. These were based on information from the Petroleum Administration for Defense District (PADD). The percentage of produced water re-injected in the Maya region is assumed to be the same as in Mars (PRE=52%) (Wu and Chiu, 2011). The percentage of produced water re-injected into the Bow River oil field in Canada, however, comes from the fresh water consumption coefficient (FW=0.6 bbl/bbl) average obtained from the literature (CAPP, 2014; AER, 2014b; Cenovus, 2016; CAPP, 2013; CAPP, 2010) and has been adjusted for this study. The coefficient for the total water injected has two parts, one for fresh water and another for produced water. The total amount of water produced (TWP) with the crude oil (Rahman et al., 2014) is used along with the associated percentage (PRE) to estimate the re-injected portion. This is further subtracted from the total coefficient required by the recovery technology to obtain the fresh water coefficient (equation 1). Figure 7 shows the flow of the input data, and more details for drilling and extraction are shown in Table 1.

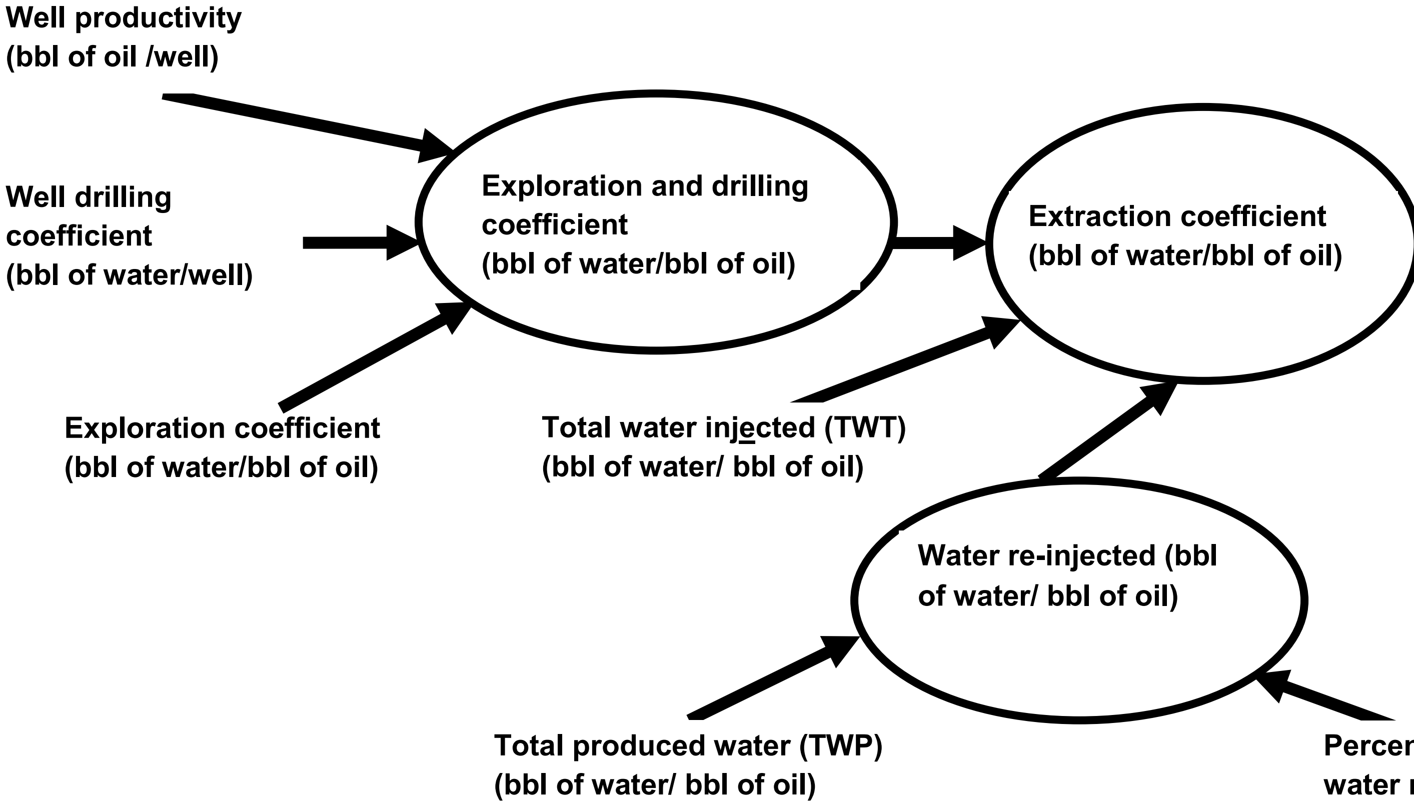


Figure 7: Input data water demand flow for exploration, drilling, and extraction of crude oil

Exploration and drilling water demand coefficients were based on the assumption that withdrawals equal consumption and no water would be returned to the source.

Extraction unit operations were based on the assumption that withdrawals are higher than consumption with water treated and re-injected.

Refining was added to complete the life cycle and was based on the assumption that withdrawals are higher than consumption with water treated and recycled.

The fresh water demand coefficients for the refining unit operations are averages taken from the literature (Wu and Chiu, 2011; CPPI, 2010; Pombo et al., 2013; Souza et al., 2009; Alva-Argaez, 2007; Diepolder, 1992) and included in this study to complete the LCA. Water withdrawals coefficients for the complete life cycle are estimated based on the assumptions that water consumption for exploration and drilling is the same as the associated water withdrawals and that the water consumption for extraction is 92% (AENV, 2007) of the associated water withdrawals. Water demand coefficients for the transportation of crude oil through pipeline are not included in this paper (King and Webber, 2008).

Table 1: Input data for drilling and crude oil extraction

Oil field	Productivity (bbl/well)[a]	Total water consumption for drilling (bbl)[b]	Total water injected (TWT) (bbl/bbl)[c]	Total produced water (TWP) (bbl/bbl)[d]	Percentage of produced water re-injected (PRE) (%)[e]
Alaska North Slope	1,955,733	1,833	8.7	3	76
California's Kern County heavy oil	133,151	1,833	5.4	5.17	76
Mars	533,856	1,833	8.6	5.5	52
Maya	46,800,000	1,833	8.7	3	52
Bow River heavy oil	320,176	1,833	8.6	14.9	53.7

[a] Lifetime productivity from Rahman et al. (2014).
[b] Assumed with average of fresh water consumption for drilling oil well from Goodwin et al., (2012).
[c] Based on the type of the recovery technology (Wu and Chiu, 2011).
[d] Based on the parameter water-to-oil used for energy calculations (Rahman et al., 2014).
[e] Based on the information provided by the PADD (Wu and Chiu, 2011).

5. Results and discussion

Figure 8 shows the fresh water consumption coefficients for the complete life cycle of crude oil from different North American regions. The fresh water consumption range is 1.71- 8.25 bbl/bbl, with the lowest for Bow River heavy oil and the highest for Maya. The

TWT required for Bow River (8.6 bbl/bbl) indicates that the recovery technology used for extraction is the most water-demanding of the complete life cycle unit operations detailed in Figure 6. The produced water is highest in Bow River (14.9 bbl/bbl) and significantly lowers the amount of injected fresh water needed for oil recovery during the extraction unit operations. About 87% of the fresh water consumed for Maya’s crude oil is for the extraction unit operations through nitrogen technology, and the low amount of produced water, along with the smallest percentage re-injected (of the five studied oil fields), meant that this region had the highest fresh water requirement. Based on the complete life cycle, the water consumption coefficient for Alaska North Slope is 9% better than Maya’s due to the 24% increase in the produced water that is re-injected. The amount of water produced, treated, and re-injected, and the recovery technology used as detailed in Figures 2-6 for each oil field are the main factors determining the level of water demand for crude oil production.

The steam flood recovery that is used in California’s Kern County heavy oil requires the least water for injection, yet the same oil field has the highest percentage of produced water re-injected (76%), which means this region has the second lowest water consumption coefficient (2.59 bbl/bbl). Adding water quality and availability factors to this quantitative comparative assessment would give different impacts on water. For example, the fresh water consumption coefficient for Bow River heavy oil is lower in magnitude than the corresponding coefficient for Alaska North Slope, but the quality of water used for Bow River heavy oil is higher because it is diverted from a river with a limited availability compared to the treated seawater used for Alaska North Slope. Low-quality sea water is generally available in abundant amounts compared to high-quality river water, which is usually available in small amounts.

For the complete life cycle, water withdrawals range from 2.41-9.51 bbl/bbl (see Table 2), and based on all studied oil fields, 81% of these figures are consumed and not returned to the source.

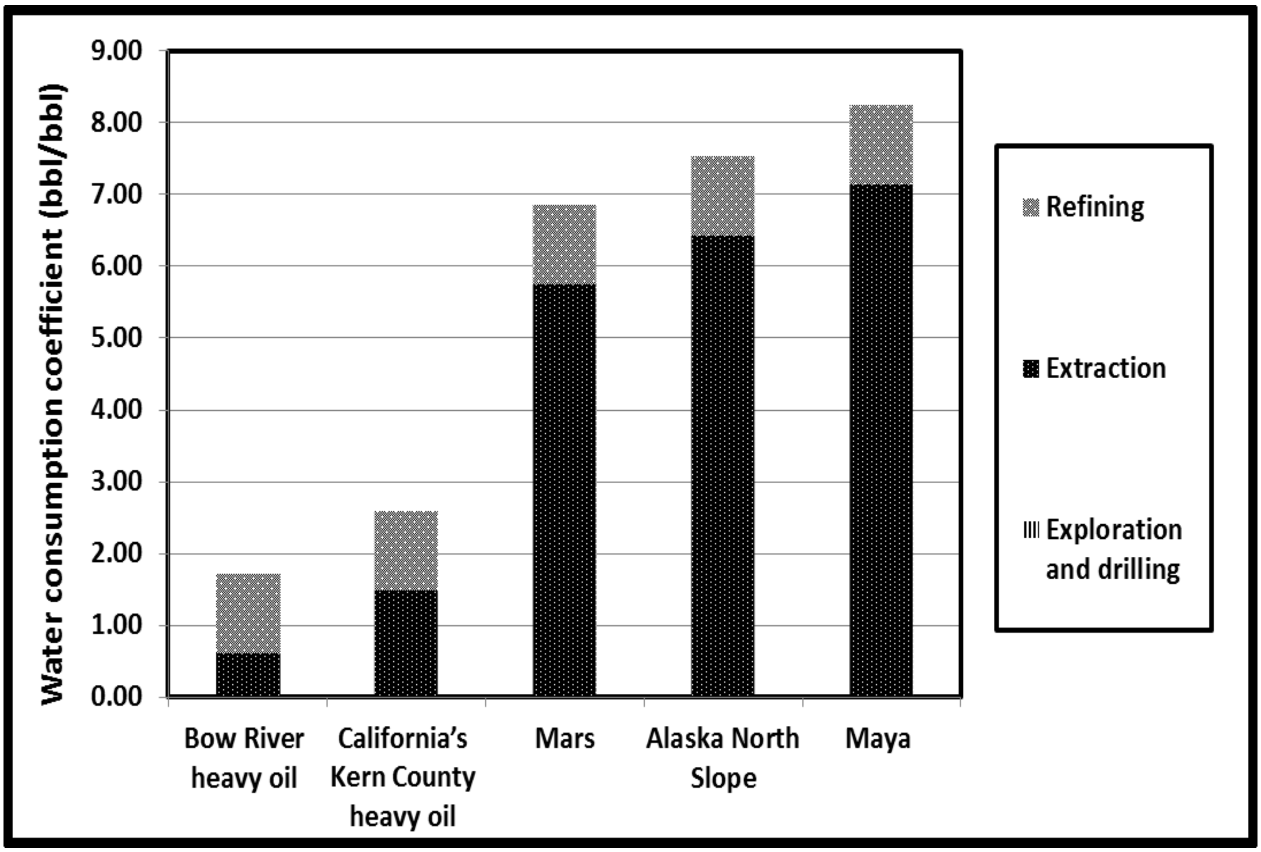


Figure 8: Fresh water consumption coefficients for the life cycle of crude oil

Table 2: Fresh water withdrawals coefficients for the life cycle of crude oil

Process	Exploration and drilling (bbl/bbl)	Extraction (bbl/bbl)	Refining (bbl/bbl)	Total (bbl/bbl)
Bow River heavy oil	0.0061	0.65	1.75	2.41
California's Kern County heavy oil	0.0141	1.60	1.75	3.36
Mars	0.0038	6.24	1.75	7.99
Alaska North Slope	0.0013	6.98	1.75	8.73
Maya	0.0004	7.76	1.75	9.51

6. Sensitivity analysis

Variations in water consumption for the exploration and drilling unit operations have the least impact of all the operations on the total water demand for crude oil. When the total water consumption for drilling is increased ten times over the base case (18,333 bbl/well instead of 1,833 bbl/well), the effect is an average increase of only 1.7% in the total water consumption coefficient of the complete life cycle for the all oil fields studied here.

The extraction unit operation is the most sensitive to water demand (as shown in Table 2), particularly in the percentage of produced water that is re-injected (PRE).

In the base case, the refining unit operation makes up 18-73% of the water withdrawals coefficient and 13-65% of the water consumption coefficient. These sensitivity factors were varied in order to study the effect of variation on the water demand coefficients based on the complete life cycle. PRE and water demand coefficients for refining were varied in Monte Carlo simulations with minimum, maximum, and most likely values as detailed in Table 3 are input to triangular distribution. Minimum PRE is assumed to be at no water produced re-injected (0%) and maximum is assumed at full satisfaction of technology from produced water (100%).

Table 3: Variations of PRE and refining water demand coefficients

Oil field	**Percentage of produced water re-injected (PRE) (%)**	**Probability percentile of the most likely PRE (%)**	**Refining water consumptio n coefficient (bbl/bbl)**	**Probability percentile of the most likely refining water consumption coefficient (%)**	**F v v c (**
	Min. - Most likely value - Max.		**Min. - Most likely value - Max.**		**M - I**
Alaska North Slope	0 – 76 - 100	76	0.40 – 1.11 – 1.85	49[a]	0.
California's Kern County heavy oil	0 – 76 -100	76			
Mars	0 – 52 -100	52			
Maya	0 – 52 - 100	52			
Bow River heavy oil	0 - 53.7-100	53.7			

[a] Derived from the Monte Carlo simulations after taking the corresponding most likely value with Min. and Max. values as input to the triangular distribution.

Figure 9 shows the probability distribution of the water consumption coefficients for the complete life cycle with variable PRE while the refining coefficient remains constant at 1.11 bbl/bbl. The water consumption coefficients for the five oil fields studied ranges from 1.12 to 9.60 bbl/bbl. Maya and Alaska North Slope produce very low volumes of water (the lowest amounts in all the oil fields studied here) and so are the least sensitive to changes in the PRE. For example, when 95% of produced water is re-injected at Alaska North Slope with a 99% probability, the water consumption coefficient (6.96

bbl/bbl) is the same as at Mars when only 50% of produced water is re-injected with a 48% probability.

Bow River heavy oil and California Kern County heavy oil have equal water consumption coefficients at a 25% probability and PREs of 37% and 44%, respectively. When the PRE reaches 58% for Bow River heavy oil with a probability of 62%, the total injection required for extraction would be fully satisfied by the produced water; however, the exploration, drilling, and refining unit operations do not benefit from any of this water and still require a constant amount of water (1.12 bbl/bbl).

Figure 10 shows the probability distribution of the water consumption coefficients for the complete life cycle while the PRE remains constant at the assumed base case values and the water consumption coefficient for the refining unit operation changes through the Monte Carlo distributions. The distribution of the refining consumption coefficient plays a major role in controlling the complete life cycle distribution in this case. The water consumption coefficient for refining unit operations ranges from 0.5 to 1.75 bbl/bbl. The corresponding complete life cycle range is 1.11 – 8.88 bbl/bbl. At a probability of 10%, the complete life cycle range is 1.33 – 7.86 bbl/bbl and at 90% probability, the range is 2.13 – 8.66 bbl/bbl. Figure 11 shows the distribution of water withdrawals coefficients at probability percentiles 10% and 90%. At constant refining coefficient 1.75 bbl/bbl, the water withdrawals coefficient for the complete life cycle range is 1.76- 10.46 bbl/bbl. The highest withdrawals coefficient is for Maya oil field, which is increased 10% at a probability of 10% over the most likely coefficient and decreased by 9% at a probability of 90%. At the variable water withdrawals coefficient for refining, the ranges widen to 2.09 – 10.73 bbl/bbl compared to the base case range of 2.41 – 9.51 bb/bbl.

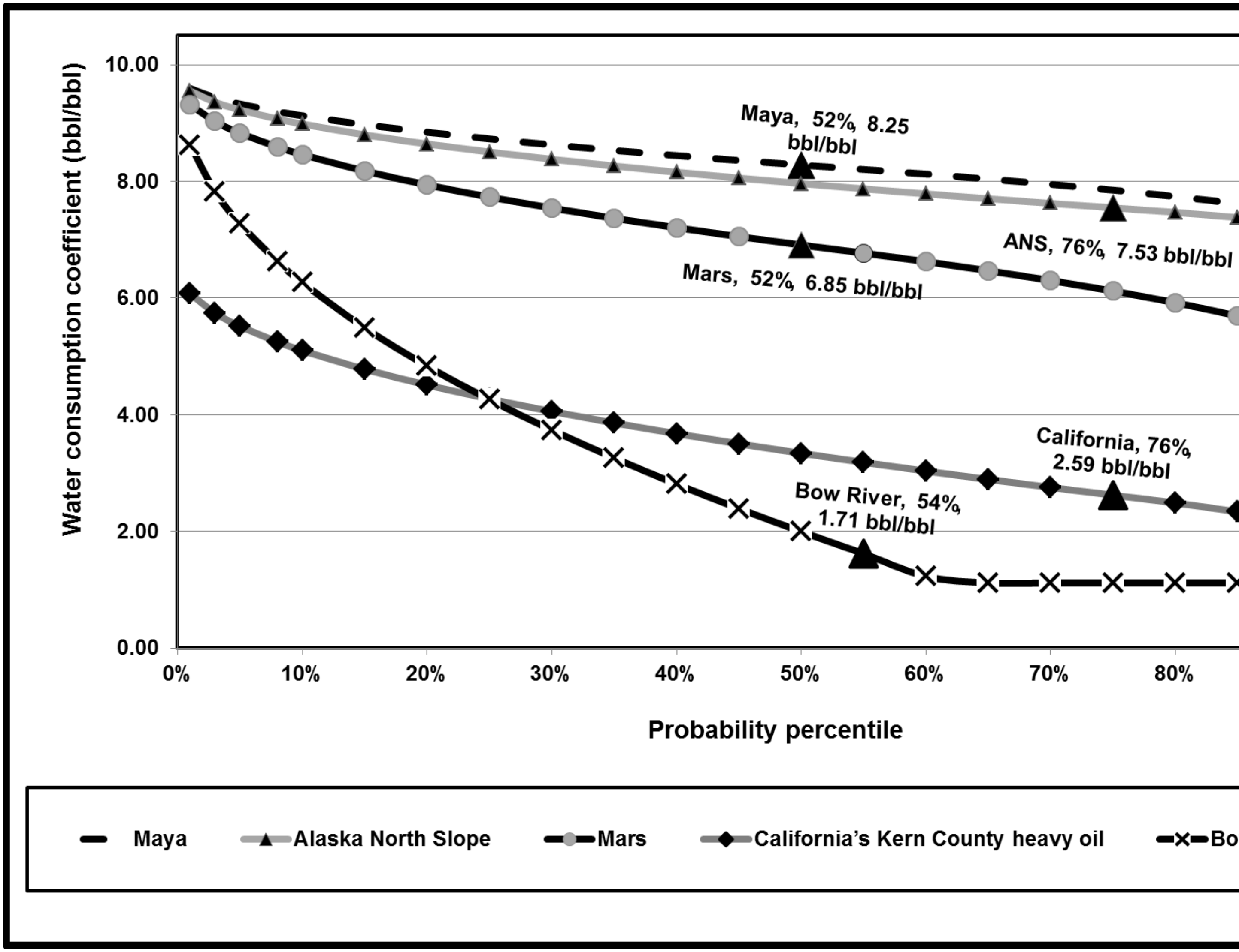


Figure 9: Distribution of complete life cycle water consumptions at a constant refining coefficient

▲ The most likely value and the accompanied probability is shown in the graph for each oil field

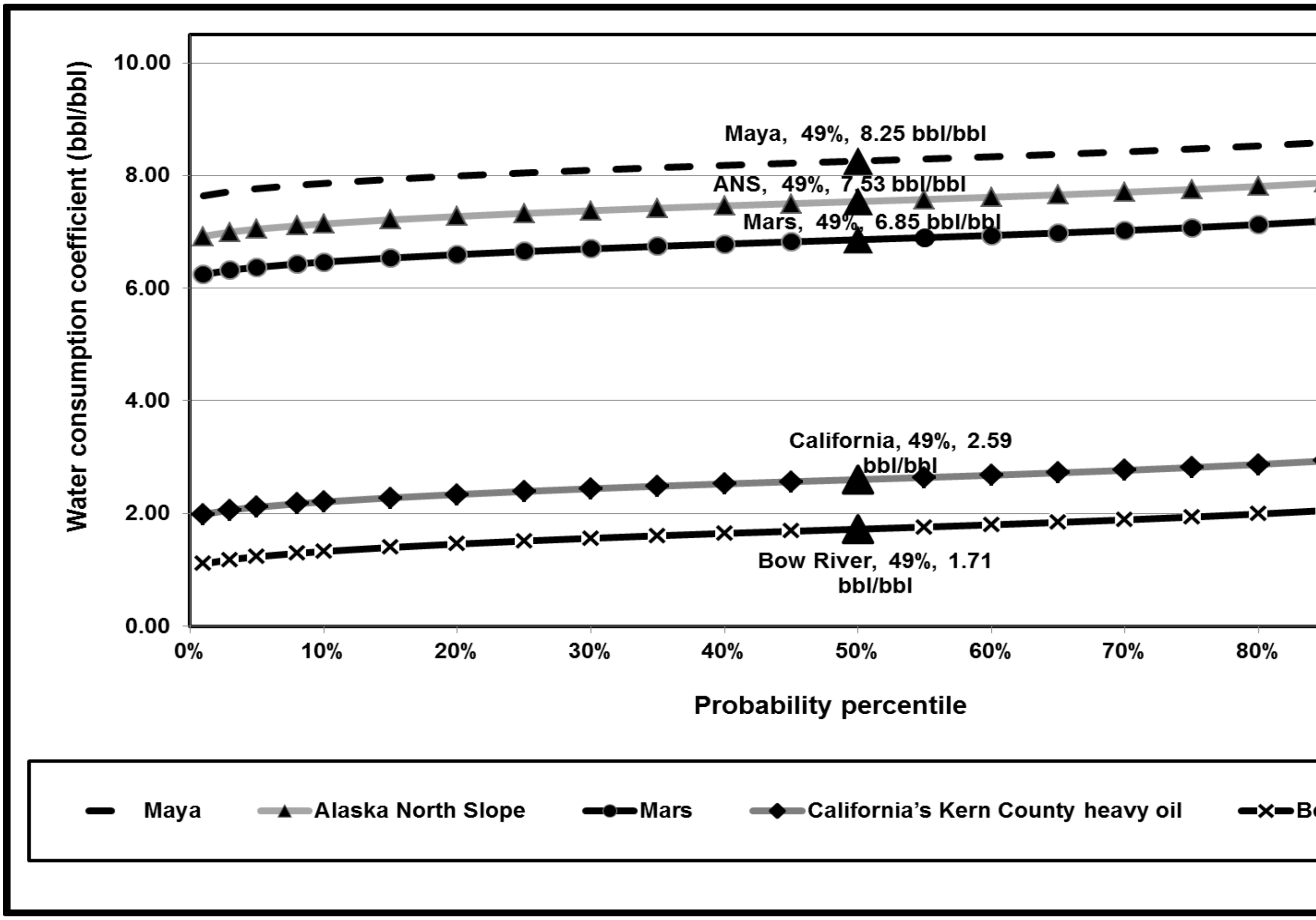


Figure 10: Distribution of complete life cycle water consumptions at a variable refining coefficient

▲ The most likely value and the accompanied probability is shown in the graph for each oil field

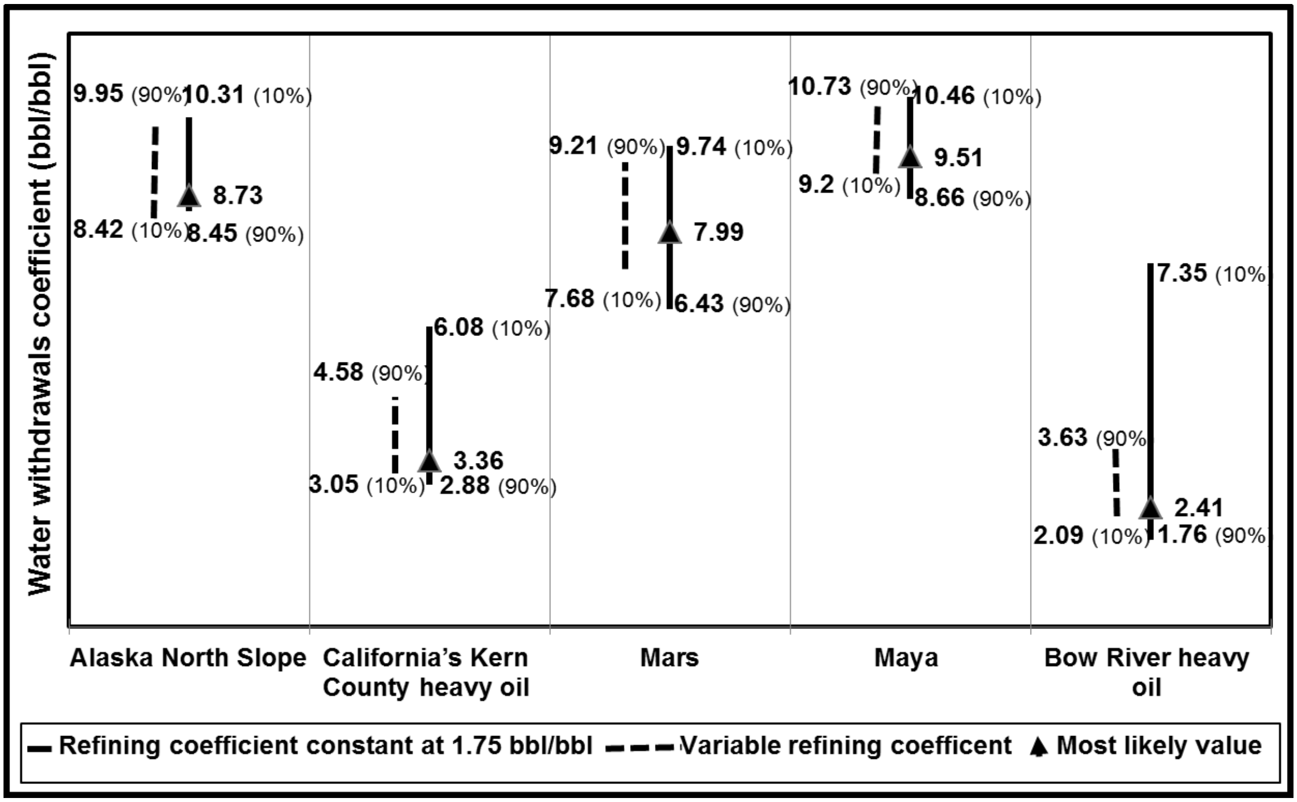


Figure 11: Distribution of water withdrawals coefficients

7. Conclusions

This paper is aimed at developing water demand coefficients for the complete life cycle of fuel from crude oil. The developed water demand coefficients were used as a benchmark for a comparative assessment of five North American oil fields. The water consumption coefficient for the complete life cycle of crude oil is in the range of 1.71-8.25 bbl/bbl. Among the five crude oils assessed here, the lowest life cycle water consumption coefficient is for Bow River heavy oil and the highest for Maya crude oil. The most sensitive unit operation for the water footprint of crude oil is the extraction, especially the type of recovery technology used. Water produced with crude oil can significantly reduce the fresh water demand during extraction unit operations. The technology used to increase the percentage of produced water that is re-injected is another key means of reducing the fresh water requirement. Improving the refining technology so that less water is used can positively affect the water demand for fuels produced from crude oil pathways. Even when maximum use is made of produced water in extraction unit operations, water is required for exploration, drilling, and refining. Exploration and drilling unit operations have lower water demand coefficients than extraction and refining when amortized over the total production from a well. The effect of variable water withdrawals coefficients for refining on the corresponding complete life cycle coefficient is an increase in the base case ranges of 2.41-9.51 bb/bbl to ranges of 2.09-10.73 bbl/bbl.

Water demand for crude oil is a critical metric in determining the environmental footprint of different crude oils and this needs to be taken into account by decision makers when making investment decisions or formulating policies. We recommend that water quality and availability be integrated with this study to give a broader prospective to the comparative assessment. We also recommend that the water demand coefficients developed in this paper for crude oil be integrated in future studies on the impacts on air through GHG emissions, on land, and on the cost of production to have more interdisciplinary views for a better sustainability assessment.

Acknowledgements

The authors are thankful to the NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair Program in Energy and Environmental Systems Engineering and the Cenovus Energy Endowed Chair in Environmental Engineering at the University of

Alberta for financial support for this research. The authors would also like to thank Ms. Astrid Blodgett for editing the paper.

Nomenclature

ANS	Alaska North Slope
API	American Petroleum Institute
ASP	alkali surfactant polymer
bbl/bbl	barrel of water per barrel of oil
bbl/d	barrel per day
bbl/well	barrel per well
FW	consumption coefficient of fresh water (in bbl/bbl)
GHG	greenhouse gas
LCA	life cycle assessment
Loop	Louisiana Offshore Oil Port
NGL	natural gas liquid
PADD	Petroleum Administration for Defense District
PRE	percentage of produced water re-injected (in %)
TAPS	Trans-Alaska Pipeline System
TWP	total water produced (in bbl/bbl)
TWT	total water injected (in bbl/bbl)
U.S.	United States
WAG	water-alternating-gas
WC	water consumption
WR	water returned
WW	water withdrawals

References

AENV, 2007. Current and Future Water Use in Alberta. Prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007). www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf, accessed November 2016.

AENV, 2008. Glossary of Terms Related to Water and Watershed Management in Alberta. 1st edition. Partnerships and Strategies Section, November 2008. Alberta Environment (AENV). https://extranet.gov.ab.ca/env/infocentre/info/library/8043.pdf, accessed November 2016.

AER 2014a. Water and Oil: An Overview of the Use of Water for Enhanced Oil Recovery in Alberta. Alberta Energy Regulator (AER). https://www.aer.ca/documents/applications/WA_WaterOil_UseOfWaterForEnhancedOil Recovery.pdf, accessed November 2016.

AER, 2014b. Alberta's Energy Reserves 2013 and Supply/ Demand Outlook 2014 – 2023. Alberta Energy Regulator (AER). http://www.aer.ca/documents/sts/ST98/ST98-2014.pdf, accessed November 2016.

AESRD, 2011. Focus on Groundwater: Groundwater Management. Alberta Environment and Sustainable Resource Development (AESRD).

http://aep.alberta.ca/about-us/documents/FocusOn-GroundwaterManagement-2014.pdf, accessed November 2016.

Aghdam, K.A., Moghaddas, J.S., Moradi, B., Dabiri, M., and Hassanzadeh, M., 2013. Maximizing the Oil Recovery Through Miscible Water Alternating Gas (WAG) Injection in an Iranian Oil Reservoir. Petroleum Science and Technology 31 (22): 2431-2440.

Alberta Government, 2012. Alberta's Energy Industry: An Overview. http://www.energy.alberta.ca/Org/pdfs/Alberta_Energy_Overview.pdf, accessed November 2016.

Ali, B. and Kumar, A., 2015. Development of Life Cycle Water-Demand Coefficients for Coal-Based Power Generation Technologies. Energy Conversion and Management 90: 247-260.

Ali, B. and Kumar, A., 2016. Development of Life Cycle Water Footprints for Gas-Fired Power Generation Technologies. Energy Conversion and Management 110: 386-396.

Ali B, Kumar A. 2017a. Development of water demand coefficients for power generation from renewable energy technologies. Energy & Conversion Management 143, 470–481.

Ali B, Kumar A. 2017b. Development of life cycle water footprints for oil sands-based transportation fuel production. Energy 131: 41-49.

Alva-Argaez, A., Kokossis, A.C., and Smith, R., 2007. The Design of Water-Using Systems in Petroleum Refining Using a Water-Pinch Decomposition. Chemical Engineering Journal 128: 33-46.

Argaez, A.A., Kokossis, A.C., and Smith, R., 2007. The Design of Water-Using Systems in Petroleum Refining Using a Water-Pinch Decomposition. Chemical Engineering Journal 128: 33-46.

ATCO, 2016. Battle River Generating Station. http://www.atcopower.com/Our-Facilities/Our-Power-Technologies/Coal-Fired-Thermal/Battle-River, accessed November 2016.

BP, 2012. Greater Prudhoe Bay. British Petroleum. http://www.bp.com/content/dam/bp-country/en_us/PDF/prudhoe_bay_2013.pdf, accessed November 2016.

CAPP, 2010. Responsible Canadian Energy Progress Report. For the year ended December 31, 2009. Canadian Association of Petroleum Producers (CAPP). https://issuu.com/capp/docs/rce-oilsands-report/44, accessed November 2016.

CAPP, 2013. Responsible Canadian Energy Progress Report. Canadian Association of Petroleum Producers (CAPP). http://www.capp.ca/~/media/capp/customer-portal/publications/233913.pdf, accessed November 2016.

CAPP, 2014. Responsible Canadian Energy 2014 Progress Report. Canadian Association of Petroleum Producers (CAPP). http://www.capp.ca/~/media/capp/customer-portal/publications/255363.pdf, accessed November 2016.

CAPP, 2016. Crude Oil: Forecast, Markets and Transportation. June 2016. Canadian Association of Petroleum Producers (CAPP). http://www.capp.ca/publications-and-statistics/publications/284950, accessed November 2016.

Cenovus, 2016. Steam-Assisted Gravity Drainage (SAGD). Cenovus Energy. http://www.cenovus.com/operations/oilsands/foster-creek.html, accessed November 2016.

Clemente, J., 2008. Cantarell is not Mexico's Only Oil Production Problem. Pipeline & Gas Journal, August 2008. http://www.peakoil.net/files/Cantarell%20Is%20Not%20Mexico%E2%80%99s%20Only%20Oil%20Production%20Problem.pdf, accessed November 2016.

ConocoPhillips, 2015. Alaska. Factsheet- http://alaska.conocophillips.com/Documents/Fact%20Sheet_Alaska_Spring%202015_FINAL.pdf, accessed November 2016.

CPPI, 2010. Water – A Precious Resource. February 2010. Canadian Petroleum Products Institute (CPPI). http://canadianfuels.ca/userfiles/file/Water%20Primer%20-%20Final%20%28Updated%20with%202010%20data%29.pdf, accessed November 2016.

Crude Quality Inc., 2016. Bow River South (BRS). http://www.crudemonitor.ca/crude.php?acr=BRS, accessed November 2016.

Department of Conservation, 2013. 2012 Preliminary Report of California Oil and Gas Production Statistics. Publication no. PR03. Division of Oil, Gas, and Geothermal Resources. ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2012/PR03_PreAnnual_2012.pdf, accessed November 2016.

Diepolder, P., 1992. Is Zero Discharge Realistic? Hydrocarbon Processing 71 (10): 129-131.

EIA, 2014. Mexico: Overview. U.S. Energy Information Administration (EIA). http://www.eia.gov/beta/international/analysis_includes/countries_long/Mexico/mexico.pdf, accessed November 2016.

EIA, 2016a. How Much Petroleum Does the United States Import and Export? U.S. Energy Information Administration (EIA). http://www.eia.gov/tools/faqs/faq.cfm?id=727&t=6, accessed November 2016.

EIA, 2016b. Alaska North Slope Crude Oil Production. U.S. Energy Information Administration (EIA). http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MANFPAK1&f=A, accessed November 2016.

EIA, 2016c. Crude Oil Production. U.S. Energy Information Administration (EIA). http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm, accessed November 2016.

Environment Canada, 1996. Mars Blend. Emergencies Science and Technology Division. http://www.etc-cte.ec.gc.ca/databases/Oilproperties/pdf/WEB_Mars_Blend.pdf, accessed November 2016.

EPCOR, 2004. 2003 Environmental Report: Genesee Generating Station. http://www.corporateregister.com/a10723/epcor03-env-ca.pdf, accessed November 2016.

EPRI, 1999. Enhanced Oil Recovery Scoping Study. Palo Alto, CA: 1999. TR-113836. http://www.energy.ca.gov/process/pubs/electrotech_opps_tr113836.pdf, accessed November 2016.

ExxonMobil, 2016. Alaskan North Slope (ANS). http://corporate.exxonmobil.com/en/company/worldwide-operations/crude-oils/alaskan-north-slope, accessed November 2016.

Galera, E.S., Allieri, M.A.A, Veneroni, D.L., and Villegas, F.M.R., 2010. Oil Production in Mexico's Highly Diverse Ecosystems: The Importance of Environmental Indicators. International Journal of Oil, Gas and Coal Technology 3 (1): 4-18.

Garofalo, P., D'Andrea, L., Tomaiuolo, M., Venezia, A., and Castrignano, A., 2017. Environmental sustainability of agri-food supply chains in Italy: the case of the whole-peeled tomato production under life cycle assessment methodology. Journal of Food Engineering 200: 1-12.

GEO, 2011. Motley Crude. GEO Estratos S.A. de C.V. http://www.richcarriero.com/pdf/Crude%20Oil%20Varieties%20Mexico.pdf, accessed November 2016.

Glassman, D., Wucker, M., Isaacman, T., and Champilou, C., 2011. The Water Energy Nexus: Adding Water to the Energy Agenda. The World Policy Institute in partnership with EGB Capital. March 2011. http://www.worldpolicy.org/sites/default/files/policy_papers/THE%20WATER-ENERGY%20NEXUS_0.pdf, accessed November 2016.

Gleick, P.H, 1994. Water and Energy. Annual Review of Energy and Environment 19: 267-299.

Goodwin, S., Carlson, K., Douglas, C., Knox, K., 2012. Life Cycle Analysis of Water Use and Intensity of Oil and Gas Recovery in Wattenberg Field, Colo. Oil and Gas Journal 110 (5): 48-58.

Griffiths, M. and Dyer, S., 2008. Up-grader Alley: Oil Sands Fever Strikes Edmonton. http://pubs.pembina.org/reports/Upgrader_Alley-report.pdf, accessed November 2016.

Grubert, E.A., Beach, F.C., and Webber, M.E., 2012. Can Switching Fuels Save Water? A Life Cycle Quantification of Freshwater Consumption for Texas Coal- and Natural Gas-Fired Electricity. Environmental Research Letters 7: 045801.

Hackett, J., Idriss, A., Kause, R., Scott, K., and Tingley, J., 2012. Water Conservation, Efficiency, and Productivity Plan – Electric Power Generation. https://extranet.gov.ab.ca/env/infocentre/info/library/8682.pdf, accessed November 2016.

IEA, 2012. Water for Energy: Is Energy Becoming a Thirstiest Resource? International Energy Agency (IEA). http://www.worldenergyoutlook.org/media/weowebsite/2012/WEO_2012_Water_Excerpt.pdf, accessed November 2016.

Kaltenbach, B., Walsh, C., Foerster, C., Walsh, T., MacDonald, J., Stokes, P., Livesey, C., and Nebesky, W., 2004. North Slope of Alaska Facility Sharing Study. Prepared for Division of Oil & Gas: Alaska Department of Natural Resources. http://www.petroak.com/NorthSlope_Facility_Sharing_Study.pdf, accessed November 2016.

Karfopoulos, K.L. and Anagnostakis, M.J., 2010. Parameters Affecting Full Energy Peak Efficiency Determination During Monte Carlo Simulation. Applied Radiation and Isotopes 68: 1435-1437.

Khoo, H.H, and Tan, R.B.H., 2006. Environmental Impact Evaluation of Conventional Fossil Fuel Production (Oil and Natural Gas) and Enhanced Resource Recovery with Potential CO_2 Sequestration. Energy & Fuels 20: 1914-1924.

King, C.W. and Webber, M.E., 2008. Water Intensity of Transportation. Environmental Science & Technology 42: 7866-72.

King, C.W., Stillwell, A.S., Twomey, K.M., and Webber, M.E., 2013. Coherence Between Water and Energy Policies. Natural Resources Journal 53: 117-215.

Kulkarni, M.M. and Rao, D.N., 2005. Experimental Investigation of Miscible and Immiscible Water-Alternating-Gas (WAG) Process Performance. Journal of Petroleum Science and Engineering 48 (1- 2): 1-20.

McMahon, J.E., and Price, S.K., 2011. Water and Energy Interactions. Annual Review of Environment and Resources 36:163-191.

Vose, 2016. ModelRisk Software. http://www.vosesoftware.com/, accessed November 2016.

Moreno, H.O., Ramirez, J., Minero, F.S., Cuevas, R., and Ancheyta, J., 2014. Hydrocracking of Maya Crude Oil in a Slurry-Phase Batch Reactor. II. Effect of Catalyst Load. Fuel 130: 263–272.

Morgan, T.J., Rodriguez, P.A., George, A., Herod, A.A., and Kandiyoti, R., 2010. Characterization of Maya Crude Oil Maltenes and Asphaltenes in Terms of Structural Parameters Calculated from Nuclear Magnetic Resonance (NMR) Spectroscopy and Laser Desorption-Mass Spectroscopy (LD-MS). Energy Fuels 24: 3977-3989.

Offshore Technology, 2016a. Mars Oil and Gas Field Project, Gulf of Mexico, United States of America. http://www.offshore-technology.com/projects/mars/, accessed November 2016.

Offshore Technology, 2016b. Cantarell Oilfield, Gulf of Mexico, Mexico. http://www.offshore-technology.com/projects/cantarell/, accessed November 2016.

Okadera, T., Chontanawat, J., and Gheewala, S.H., 2014. Water Footprint for Energy Production and Supply in Thailand. Energy 77: 49-56.

OECD, 2008. Key Environmental Indicators. Paris, France, 2008. Organisation for Economic Co-Operation and Development (OECD). http://www.oecd.org/env/indicators-modelling-outlooks/37551205.pdf, accessed November 2016.

Pombo, F., Magrini, A., and Szklo, A., 2013. An Analysis of Water Management in Brazilian Petroleum Refineries Using Rationalization Techniques. Resources, Conservation and Recycling 73:172-179.

Rahman, M.M., Canter, C., and Kumar, A., 2014. Greenhouse Gas Emissions from Recovery of Various North American Conventional Crudes. Energy 74: 607-617.

Sanders, K.T., King, C.W., Stillwell, A.S., and Webber, M.E., 2013. Clean Energy and Water: Assessment of Mexico for Improved Water Services and Renewable Energy. Environment, Development and Sustainability 15:1303–1321.

Schamel, S., 2001. Reactivation of an Idle Lease to Increase Heavy Oil Recovery through Application of Conventional Steam Drive Technology in a Low-Dip Slope and Reservoir in the Midway-Sunset Field, San Jaoquin Basin, California. January 2001. DOE/BC/I4937-12. (OSTI ID: 772932). http://www.osti.gov/scitech/servlets/purl/772932, accessed November 2016.

Sheridan, M., 2006. California Crude Oil Production and Imports. http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF, accessed November 2016.

Soratana, K. and Marriott, J., 2010. Increasing Innovation in Home Energy Efficiency: Monte Carlo Simulation of Potential Improvements. Energy and Buildings 42 (6): 828 – 833.

Souza, A.A., Forgiarini, E., Brandao, H.L., Xavier, M.F., Pessoa, F.L, and Souza, S.M., 2009. Application of Water Source Diagram (WSD) Method for the Reduction of Water Consumption in Petroleum Refineries. Resources, Conservation and Recycling 53:149-154.

Srivastava, J.P. and Mahli, L., 2012. Water-Alternating-Gas (WAG) Injection a Novel EOR Technique for Mature Light Oil Fields - A Laboratory Investigation for GS -5C Sand of Gandhar Field. 9th Biennial International Conference & Exposition on Petroleum Geophysics, Hyderabad 2012. http://www.spgindia.org/spg_2012/spgp109.pdf, accessed November 2016.

Staples, M.D., Olcay, H., Malina, R., Trivedi, P., Pearlson, M.N., Strzepek, K., Paltsev, S.V., Wollersheim, C., and Barrett, S.R.H., 2013. Water Consumption Footprint and Land Requirements of Large-Scale Alternative Diesel and Jet Fuel Production. Environmental Science & Technology 47:12557-12565.

Stillwell, A.S., King, C.W., Webber, M., Duncan, I.J., and Hardberger, A., 2011. The Energy-Water Nexus in Texas. Ecology and Society 16(1): 2. http://www.ecologyandsociety.org/vol16/iss1/art2/, accessed November 2016.

Talwani, M., 2011. Oil and Gas in Mexico: Geology, Production Rates and Reserves. April 29, 2011. http://bakerinstitute.org/files/537/, accessed November 2016.

Tennyson, M.E., 2005. Growth History of Oil Reserves in Major California Oil Fields during the Twentieth Century. U.S. Geological Survey Bulletin 2172–H. http://pubs.usgs.gov/bul/b2172-h/b2172h508.pdf, accessed November 2016.

Weiland, J., Azari, M., Fox, P., and Dorffer, D., 2013. Case History Review of the Application of Pressure Transient Testing and Production Logging in Monitoring the Performance of the Mars Deepwater Gulf of Mexico Field. Reservoir Innovations 2 (2):16-25.

Williams, S.K., Acker, T., Goldberg M., and Greve, M., 2008. Estimating the Economic Benefits of Wind Energy Projects Using Monte Carlo Simulation with Economic Input/Output Analysis. Wind Energy 11 (4): 397-414.

Wu, M. and Chiu, Y., 2011. Consumptive Water Use in the Production of Ethanol and Petroleum Gasoline. Center for Transportation Research, Energy Systems Division, Argonne National Laboratory, December 2008, updated July 2011. ANL/ESD/09-1. https://greet.es.anl.gov/files/consumptive-water, accessed November 2016.

Yang, X. and Dziegielewski, B., 2007. Water Use by Thermoelectric Power Plants in the United States. Journal of the American Water Resources Association (JAWRA) 43(1):160-69.

Zhang, C. and Anadon, L.D., 2013. Life Cycle Water Use of Energy Production and its Environmental Impacts in China. Environmental Science & Technology 47 (24): 14459-14467.