Development of Life Cycle Water Footprints for Oil Sands-based Transportation Fuel Production

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Abstract

There is considerable focus on oil sands transportation fuel production. However, most studies focus on greenhouse gas emissions; there is limited work on understanding the life cycle water footprint. This study is an effort to address this gap. The main objective of this study is to develop water demand coefficients of the complete life cycle of oil sands transportation fuel production. Water demand coefficients include consumption and withdrawals, which were estimated for different oil sands unit operations pathways for production in Alberta, Canada. The pathways include three key operations, bitumen extraction, upgrading, and refining. The water consumption coefficients for the complete life cycle range from 2.08-4.19 barrels of water (bbl_W) per barrel of refined oil (bbl_{BUR}) and 2.87-5.16 bbl_W/bbl_{BUR} for water withdrawals coefficients. The lower limit for water demand coefficients is found in refined and upgraded in situ steam assisted gravity drainage recovery and the higher amount in refined and upgraded surface mining recovery. A sensitivity analysis was conducted through Monte Carlo simulations to study the uncertainty of the water demand coefficients. The water consumption coefficient for oil sands

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extraction at a 90% probability was found to be 0.34-2.8 bbl_W/bbl_B, upgrading be 0.87 bbl_W/bbl_U, and refining to be 1.52 bbl_W/bbl_R.

Keywords: Life cycle footprint; water-energy nexus; oil sands; conventional oil; water consumption.

1. Introduction

The demand around the world for petroleum oil as a transportation fuel is increasing. In 2014 total demand was 14.7 million m^3/d (92.43 million bbl/d), in 2015 it was 14.8 million m^3/d (93.34 million bbl/d), and it is expected to reach 15.7 million m^3/d (99.05 million bbl/d) by 2020 [1]. The extra-heavy oil produced in Venezuela as upgraded synthetic crude oil (SCO) [2] and the oil sands produced in Canada as crude bitumen produce the majority of the world's heavy oil with total reserves of about 3000 billion bbl and a production rate of 0.35 million m^3/d (2.2 million bbl/d) in 2008 [3,4]. The province of Alberta in Canada is a hub of crude bitumen and in 2009 produced 0.24 million m^3/d (1.5 million bbl/d) with 55% from surface mining and 45% through in situ operations; production is expected to jump more than 2.6-fold to reach 0.64 million m^3/d (4 million bbl/d) by 2024 [5].

The unit operations of oil sands including extraction, upgrading, and refining results in greenhouse gas (GHG) emissions, which are associated with global warming. The production of transportation fuels from the oil sands consume water and affect the quality of water, land, and air through GHG emissions [3, 6]. Recycling, using more saline water, and developing new technologies that use less water are some of the proposals to alleviate fresh water use in the oil sands industry [7]. Quantitative environmental impacts of the oil sands have been assessed through indicators that reflect the natural resources used and GHG emissions per barrel of bitumen produced, but such assessments are few [8] and would be useful for a comparative assessment of sustainability after being combined with the complete life cycle of transportation fuels produced in the oil sands.

In order for oil sands energy producers to identify which unit operations are the most inefficient in water demand and to improve the associated technology, a sustainability indicator of fresh water used per barrel of oil produced should be considered. In 2005, the amount of fresh water used for injection and thermal activities in the petroleum sector in Alberta, Canada, was estimated 33.9 million m^3, of which 21 million m^3 was from non-saline surface sources and 12.9 million m^3 from non-saline groundwater [9]. Although the total amount of water withdrawals for Alberta's petroleum sector is not higher in its absolute amount compared to other sectors, most of the amount withdrawn is consumed and not returned back to the source. Moreover, most of the water demand in Alberta's oil sands is from a single river basin due to the location of the activities. Water use in Alberta's petroleum sector during 2005 accounted for 8% of the total water allocations in the province, and of this 8%, 92% of the water withdrawn was used and about 65% drawn from the Athabasca River Basin for oil sands mining [9]. Figure 1 shows the geographical locations of oil sands production and river basins in Alberta.

There are a few qualitative analyses of water use in oil sands unit operations [10,11]. Most are focused on bitumen recovery technologies, and the associated impact on quantitative water use to cover a complete life cycle is not considered [12-16]. Most of the published studies on water projections do not consider different pathways of oil sands activities that would take into account the unit operations [9, 17,18].

Oil sands can be recovered in different ways, and the impact on water use is accordingly different, which necessitates structuring production cycles into pathways. The recovery methods of the in situ pathways (steam assisted gravity drainage [SAGD], cyclic steam stimulation [CSS], and primary/EOR extraction) are incorrectly assumed in earlier studies to have the same water consumption coefficient [8]. There is a lack of quantitative studies of water demand through a life cycle analysis that includes detailed oil sands fuel production pathways. This study is aimed at addressing this gap.

The key objectives of this paper are to:

- Develop life cycle water demand coefficients of oil sands-based transportation fuel production pathways.
- Assess the impacts of new technologies on water demand over the complete life cycle of oil sands production activities.
- 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 the production of transportation fuels from the oil sands.

2. Scope and System Boundary

Water demand in this study refers to water consumption and water withdrawals through pre-determined oil sands transportation fuel production pathways. Water consumption is defined as the portion of water withdrawn that could be lost by evaporation or transpiration or consumed by a product or human and not returned to the source [19-21]. Water withdrawals are the diverted water, including consumed and returned amounts, and can be groundwater or surface water. Only fresh water is considered in this study and is defined as water with total dissolved solids of less than 4000 milligrams per litre (mg/L) [22]. The system boundaries taken for the transportation fuel life cycle are extraction, upgrading, and refining processes. Water demand coefficients were developed as unit volume of water (bbl_W) per unit volume of bitumen (bbl_B) during the extraction stage, per unit volume of upgraded bitumen (bbl_U) during the upgrading stage, and per unit volume of refined oil (bbl_R) during the refining stage. For the complete life cycle, the water demand coefficients include all the unit operations involved from the unit volume of water per unit volume of refined oil (bbl_W/bbl_{BUR}). Figure 2 shows the system boundary considered in this study. The concept of presenting water demand coefficients in the form of minimum, maximum, and average or median values is well established in the literature on the water-energy nexus as it relates to power generation [19,20,23-27]. Ali and Kumar [20] conducted a study on the development of water demand coefficients for gas-fired power generation pathways based on this methodology of taking minimum, maximum, and average values for a sensitivity analysis through Monte Carlo simulations. Other literature studies [19, 23-26] present ranges of water demand coefficients without conducting uncertainty analyses of the average or median values with respect to the associated minimum and maximum values. Ou et al. [27] used Monte Carlo simulations for uncertainty analyses of water demand coefficients for power generation technologies based on their own judgement and the minimum, maximum, and median factors developed by Meldrum et al. [26]. Most likely (Mol), minimum (Min), and maximum (Max) water demand coefficients for oil sands pathways were developed in the current study and sensitivity analyses were conducted through Monte Carlo simulations [28-31] to study the uncertainty of the most likely coefficients taken in the analysis.

2.1 Pathway selection

Pathways were structured according to the unit operations and to match the oil sands production profile in Canada as shown in Figure 2. Extraction in the oil sands is done through surface mining and in situ recovery. In situ operations are further divided into three recovery methods: steam-assisted gravity drainage (SAGD), cyclic steam stimulation (CSS), and primary/EOR [32]. Bitumen, a thick, viscous liquid, is produced through both surface and in situ mining.

Synthetic crude oil (SCO) is produced by upgrading bitumen. Upgraders in Alberta currently receive all the bitumen produced by surface mining and some from in situ operations. In the future, a portion of bitumen extracted through surface mining is expected to be removed from Alberta as non-upgraded bitumen [5]. SCO is consumed as diesel and plant fuel, supplied to refineries where it is converted to refined petroleum products (RPPs), or exported. Non-upgraded bitumen produced mainly from in situ operations is either supplied as feedstock to upgraders, removed from Alberta unprocessed, or used as feedstock in refineries [5, 33-36].

Water demand coefficients were developed based on data and the literature on oil sands extraction, bitumen upgrading, and refining.

2.1.1 Oil extraction

Water use for oil sands surface mining extraction is more intensive than all in situ operations [37]. Based on the water demand coefficients derived from the literature [38-40] in order to extract one barrel of bitumen, it is fair to say that surface mining requires on average about five times the amount of water required for in situ operations [41]. The mined components of the oil sands are shovelled, crushed, mixed with warm water to form slurry, and transported by hydro pipeline [42]. Concerns are raised about environmental impacts, especially water shortage and stress on the Athabasca River Basin from oil sands mining operations. New technologies with higher water recycle rates and non-aqueous extractions are examples of efforts to address the intensive use of water in oil sands mining [12].

In situ operations are methods for oil sands extraction by drilling on site. Though the different unit operations for in situ have lower water demand coefficients than does surface mining, Alberta's considerably greater in situ recovery oil production [5, 33-36] requires significant amounts of water. The steam used in SAGD and CSS reduces the viscosity of bitumen, allowing it to be pumped out. The demand for fresh water is reduced drastically due to the greater use of recycled and saline water [6, 43]. The water consumption coefficient for oil sands extraction is dynamic and has improved over time. In 1994, Gleick wrote that 3.6-9.24 bbl_W/bbl_B of water is consumed for tar sands activities in Athabasca, Alberta, which is very high compared to current water consumption coefficients [44]. Foster Creek, Alberta, is one of the largest SAGD projects and one of its main objectives is to improve the water demand coefficient [45].

The main difference between CSS and SAGD is that for CSS, one well is used for both steam injection and oil production, while two separate wells are used for SAGD [32]. Generally, bitumen production from in situ operations is driven by high reserves and slowed by the intensive energy required and higher cost compared to surface mining [43].

The primary technology for oil sands extraction is carried out at the first stage of production and makes use of the natural pressure at the reservoir through the available water or gas. Secondary and tertiary or enhanced oil recovery (EOR) are the next steps of recovery when primary technology is no longer feasible. Alberta Energy [32] considered primary/EOR as one pathway for oil sands extraction, and sometimes EOR is used at the start of production without primary or secondary technologies. EOR is also one of the important unit operations for conventional crude oil extraction [32, 46-49].

2.2.2 Oil sands upgrading

Oil sands upgrading refers to the processing of bitumen to produce SCO, which can be used as feedstock in refineries, in Alberta plants as fuel, or exported [50-52]. Upgrading is done through different conversion processes such as thermal (coking), catalytic, distillation, and hydro-treating [51, 52]. The water demand for upgrading depends mainly on the method, and generally the unit operations with the most intensive water consumption are cooling tower use, gasification, hydrogen production, and coking [50]. In past, there have been efforts to reduce the amount of fresh water taken from the North Saskatchewan River by using treated water for the cooling towers [40].

The advantages of using SCO as feedstock in Alberta's refineries are its low sulphur content and the small amounts of heavy oil produced, and the main disadvantages are the low quality of distillates and the huge amount of aromatics that need to be recovered [5]. In this study, water demand for upgrading is estimated separately from extraction and refining because these processes can be carried out in different geographical locations. For example, oil extraction uses water from the Athabasca River Basin and upgrading the product uses water from North Saskatchewan River Basin [40].

2.2.3 Oil refining

An oil refinery is a facility that converts crude oil or SCO to gasoline or other consumable products such as diesel, jet fuel, asphalt, heating fuel, heavy fuel oil, butane, and propane [53]. Water is used intensively in oil refining processes. It is used in the refinery to desalt crude oil, generate steam, heat fluids, and produce hydrogen, and is also used in cooling systems [49]. The cooling tower in a refinery may use 50% of the total water required [37]. The amount of water demand in a refinery depends mainly on how much water is treated and recycled. Comprehensive research focussed on managing water through recycling and treatment is underway to help alleviate the intensive use of fresh water in the refineries [55-58]. The integration of oil sands upgrading with refining and petrochemical industries in Alberta has been recommended in order to minimize the significant environmental impacts on water, land, and air of establishing separate individual plants [50].

3. Assumptions and input data

Based on earlier estimates [9], the water consumption coefficient in this study is assumed to be 92% of the water withdrawals coefficient, except for the water demand coefficients data derived from the earlier studies that consider the two coefficients separately [50, 54]. Input data for water demand coefficients as shown in Table 1 were developed based on different studies, and the values in barrel of water per barrel of bitumen for the extraction stage (bbl_W/bbl_B), barrel of water per barrel of upgraded oil sands (bbl_W/bbl_U), and barrel of water per barrel of refined oil sands (bbl_W/bbl_R) are used in the analysis of the results.

4. Results and discussion

Figure 3 and 4 show the water demand coefficients for the complete life cycle of oil sands pathways including extraction, upgrading, and refining unit operations based on the most likely values considered in this study. Comparative in situ operations in the oil sands have lower water demand coefficients than surface mining. In situ recovery has lower water demand coefficients due to the efficient use of steam and high recycling rates while surface mining uses hot water for bitumen extraction. Water consumed during the extraction unit operation of surface mining includes amounts discharged to the tailing ponds and not recycled or evaporated, and all the amounts not returned back to the source from where it was withdrawn. The lowest water demand coefficients (2.08 bbl_W/bbl_{BUR} and 2.87 bbl_W/bbl_{BUR} for consumption and withdrawals, respectively) result when oil sands are extracted through SAGD, upgraded, and refined. The highest water demand coefficients (4.19 bbl_W/bbl_{BUR} and 5.16 bbl_W/bbl_{BUR} for consumption and withdrawals, respectively) are found in the surface mining, upgrading, and refining pathway. Upgrading has a lower effect than refining on the water demand coefficient. The developed water demand coefficients for the complete life cycle indicate that each barrel of refined oil extracted through SAGD would save 2.11 barrels of water consumption compared to surface mining recovery. Based on the complete life cycle of SAGD, in situ primary/EOR, and CSS pathways would consume more 0.30 barrel and 0.38 barrel of water for each barrel of refined oil, respectively.

Water demand coefficients obtained for the complete life cycle eases a comparative assessment between pathways, but to estimate the total amounts of water consumed or withdrawn, the coefficients should be disaggregated. Disaggregating water coefficients assists in evaluating water resources based on geographical zones, type of resource, or water quality. For example, an upgrader and a refinery processing the same bitumen could be located in different zones and divert water from different river basins or use surface water and groundwater. Disaggregated water demand coefficients are studied in the next section (in a sensitivity analysis) and an uncertainty analysis of the developed coefficients follows.

5. Sensitivity analysis

The maximum and minimum water demand coefficients detailed in Table 1 were used in a Monte Carlo simulation with the consideration of the averages of what are most likely to happen. A triangle distribution is used through ModelRisk software [28] to give the distribution of probability percentiles for the most likely value compared to the minimum and maximum bounds of water demand coefficients. Triangular distribution was selected in this study due to its simplicity, acceptability, and suitability to the input data which are composed of three parameters [65-67]. These three parameters are assumed the most important determinant for the results rather than the type of probability distribution [68].

Table 2 shows the standard deviation and the distribution of water consumption and water withdrawals coefficients for the main oil sands unit operations at probability percentages of 10% and 90%. All the most likely values taken for the unit operations of water consumption coefficients have a probability higher than 36%. The lowest probability obtained for in situ primary/EOR for the oil sands is 36% due to the high deviation of the consumption coefficient (0.92 bbl_W/bbl_B) derived earlier [49]. The average water demand coefficients for in situ SAGD unit operations taken in the analysis are the most confident values compared to other unit operations and have the highest probability percentages of 64% for a consumption coefficient and 67% for a withdrawals coefficient. The average water withdrawals coefficient for refining unit operations taken in the analysis is the least confident value among the unit operations and has the lowest probability percentage of 28%. This low percentage is due to the significant deviation of the higher withdrawals coefficient 3.7 bbl_W/bbl_R based on CPPI [54].

Figure 5 shows the distribution of water consumption coefficients of the generic unrefined pathways. This group of pathways is mostly affected by the upgrading unit operation, which has a most likely value with a 40% probability (see Table 2). Figure 6 shows the distribution of the water consumption coefficients involved in the refining unit operation. The water consumption coefficients for the complete life cycle of this group would be affected by the most likely value of the refining unit operation, which has a probability of 49%.

Table 3 shows the distribution of water withdrawals for the complete life cycle of oil sands pathways at probability percentages of 10% and 90%. Pathways involving the refining unit operation are affected negatively by the low probability of the most likely value.

6. Conclusions

Water demand coefficients for the complete life cycle of transportation fuels based on oil sands pathways were developed in this paper. Refined oil upgraded through in situ recovery pathways outperformed refined oil through surface mining recovery due to the difference in water use during extraction. Water withdrawals coefficients for the complete life cycle of refined oil from the oil sands is in the range of 2.87- 5.16 bbl_W/bbl_{BUR} with the lower coefficient for a pathway through in situ SAGD and the higher coefficient for surface mining. Extraction stage unit operations are the most sensitive factors for complete life cycle water demand coefficients of the produced fuel. The shifting of oil sands operations from surface mining to in situ would significantly improve the total water demand for transportation fuels produced from oil sands. Water demand coefficients for oil production are dynamic and new recovery technologies can significantly reduce the water required. The results of this study could be used in making decisions and formulating policies related to different liquid fuel production pathways from the oil sands. Surface mining requires more water than SAGD, but for a comprehensive sustainability evaluation of this pathway, it is recommended that other environmental (e.g., GHG emissions) and economic (e.g., cost of production) criteria be integrated with the life cycle water footprint assessed in this study. It is also recommended that more detailed data be reported by oil sands operators including data on water demand, oil production, and technology used for each unit operation. These detailed data would be useful for life cycle assessments and help obtain more accurate results.

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Figure 1: Locations of oil sands production and river basins in Alberta

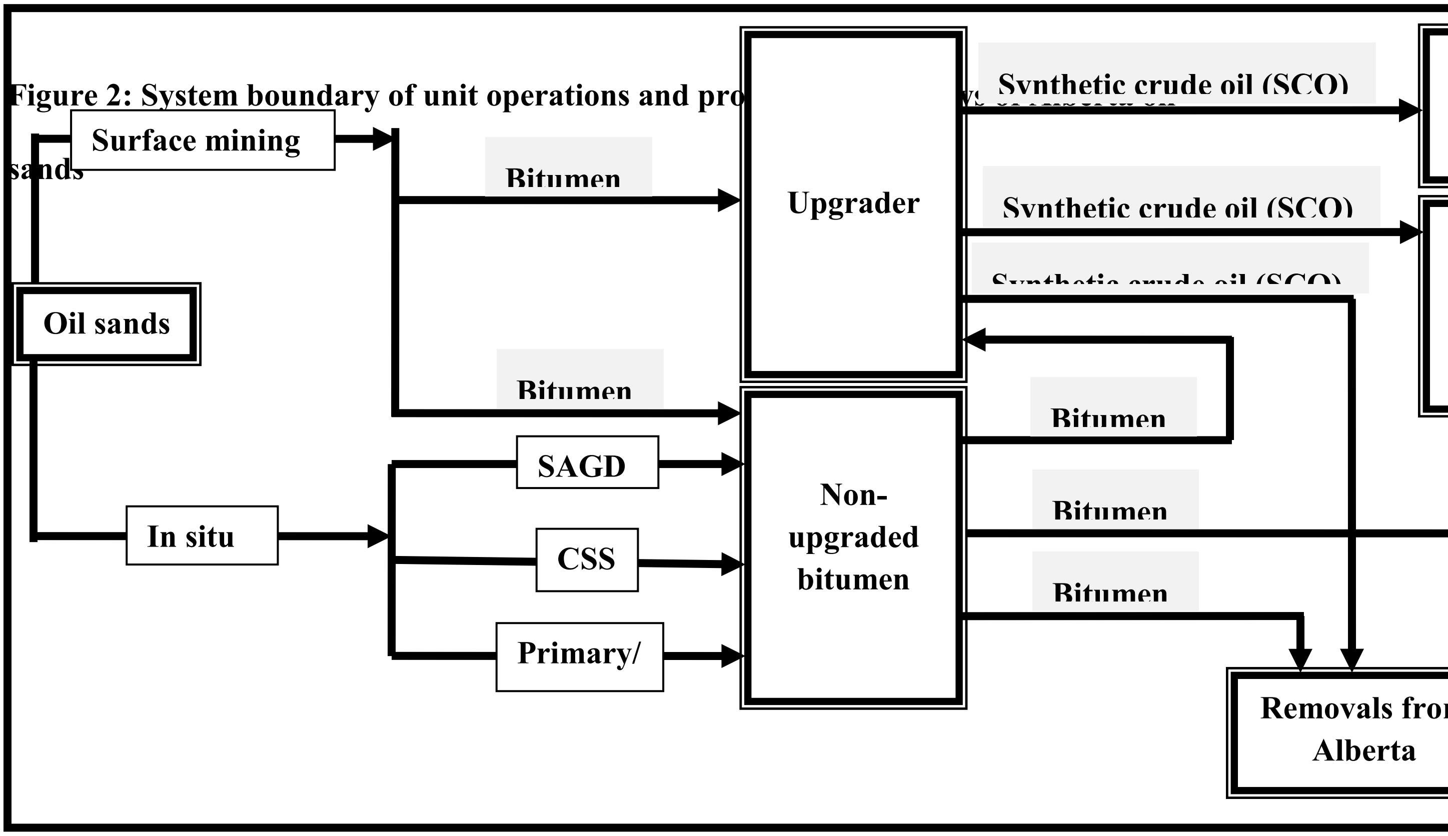

Figure 2: System boundary of unit operations and pro... sands

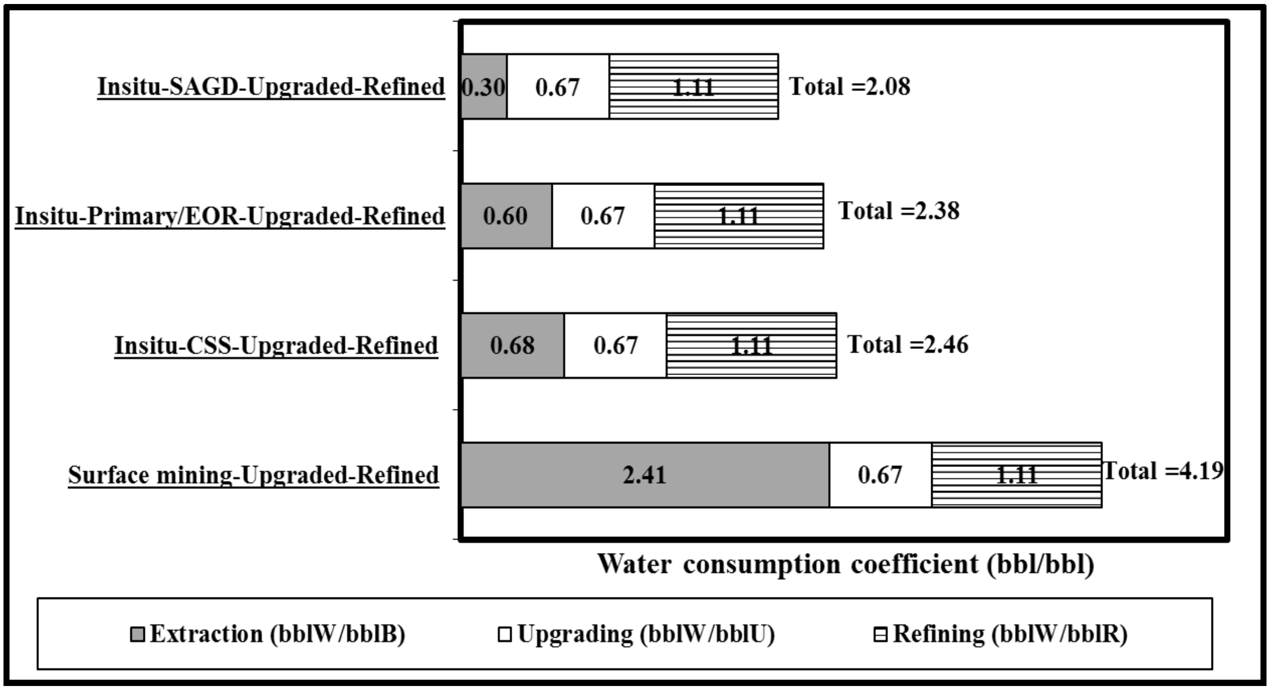

Figure 3: Water consumption coefficients for the complete life cycle of Alberta oil sands

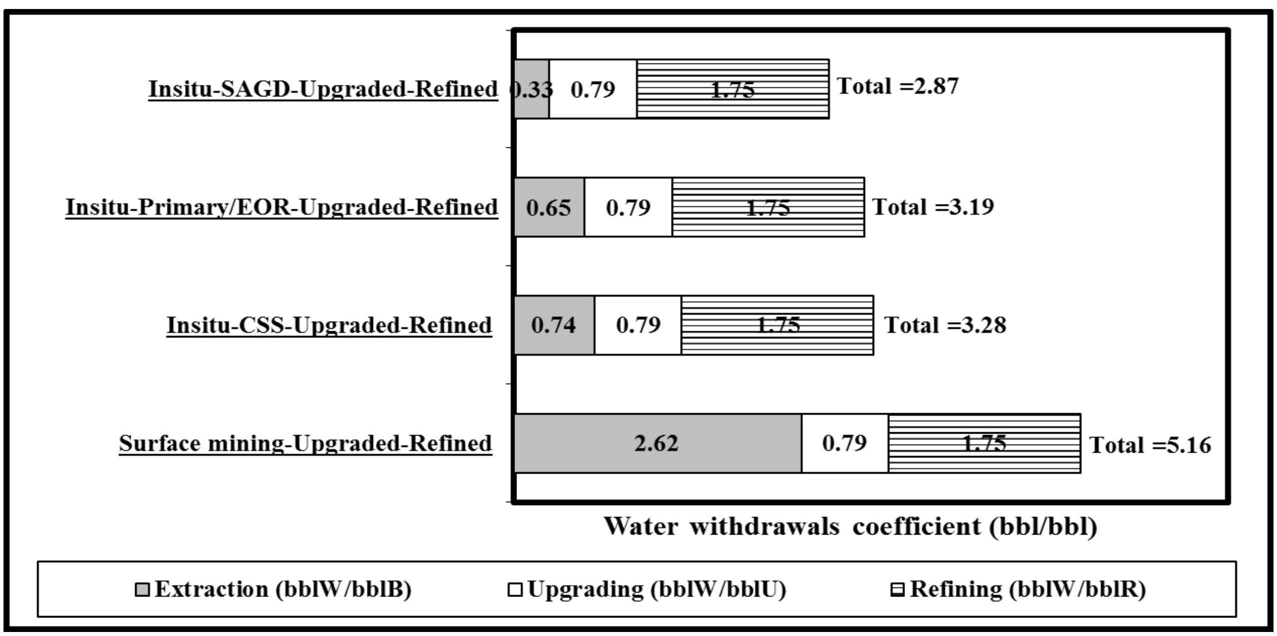

Figure 4: Water withdrawals coefficients for the complete life cycle of Alberta oil sands

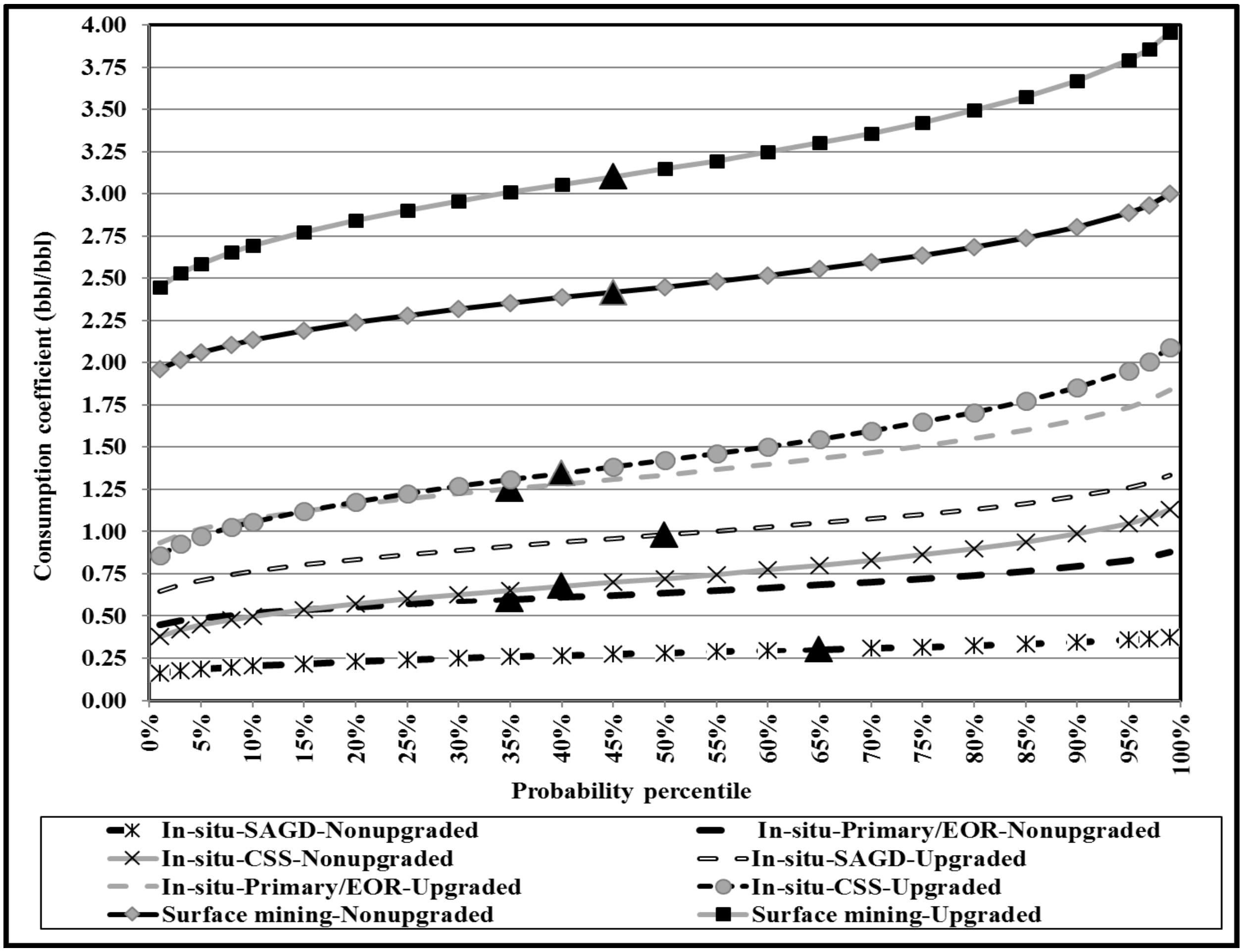

Figure 5: Distribution of water consumption coefficients for unrefined oil sands pathways

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

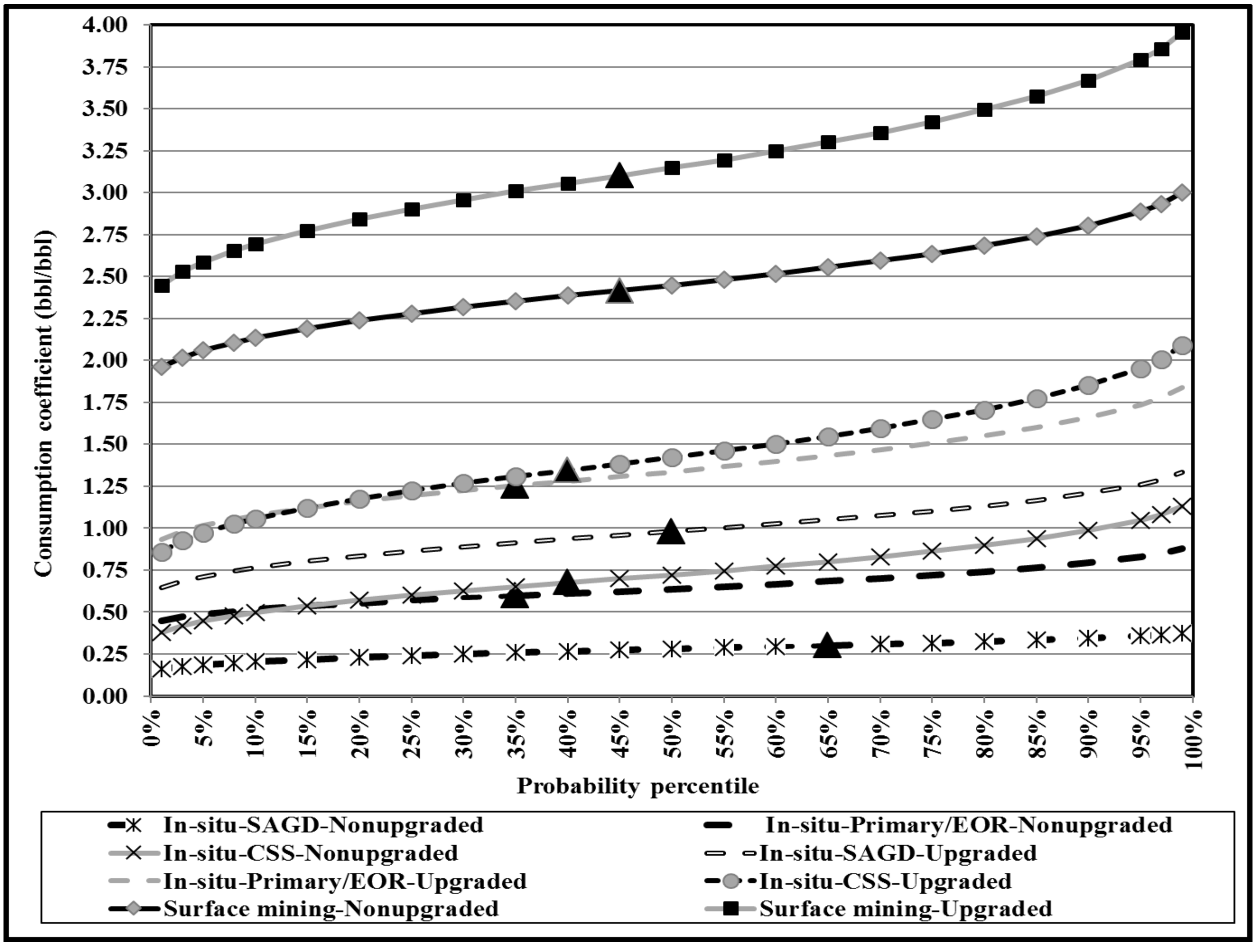

Figure 6: Distribution of water consumption coefficients for refined oil sands pathways

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

Table 1: Ranges for water demand coefficients of oil sands

Unit operation	Water consumption			Water withdrawals			Comments/Sources
	Min	Mol	Max	Min	Mol	Max	
Surface mining of the oil sands (bbl_W/bbl_B)	1.88	2.41	3.12	2.04	2.62	3.39	Min. for consumption and withdrawals are based on average fresh water coefficient reported by Shell Canada in Alberta and covering the period 2008 to 2012 with a range of 1.2-2.4 bbl_W/bbl_B [40]. Max. for consumption and withdrawals are based on average of water withdrawals coefficient in Alberta for the period 2008 to 2012 with a range of 2.8-4.4 bbl_W/bbl_B [59]. Mol. for consumption and withdrawals are based on the average from literature [8, 37- 41, 59, 60].
In situ SAGD for the oil sands (bbl_W/bbl_B)	0.14	0.30	0.39	0.15	0.33	0.42	Min. for consumption and withdrawals are based on average fresh water use coefficient reported by Cenovus Energy in Alberta covering the period 2009 to 2012 with a range of 0.11-0.16 bbl_W/bbl_B. According to CAPP, the 2012 coefficient is 58% lower than the other reported average coefficients for in situ operations in Alberta [61]. Max. for consumption and withdrawals are based on typical net water use with a range of 0.09-1.02 bbl_W/bbl_B published in Table 1 by Donahue [41] for Alberta. Mol. for consumption and withdrawals are based on the average from literature [37, 38, 41, 61].
In situ-CSS	0.32	0.68	1.20	0.35	0.74	1.30	Min. coefficients are

for the oil sands (bbl_W/bbl_B)							according to Imperial Oil Company for operations in Cold Lake, Alberta [18]. Max. ranges are derived from Wu et al. [37]. Mol. for consumption and withdrawals are based on the average from literature [18,37,41].
In situ-Primary/EOR for the oil sands (bbl_W/bbl_B)	0.42	0.60	0.92	0.46	0.65	1.00	Min. coefficients are based on the total fresh water used in Alberta in 2009 [62] divided by the corresponding total conventional crude oil produced in the same year [5, 33-36]. Max. ranges are assumed the same as water coefficients for conventional oil [49]. Mol. for consumption and withdrawals are based on the average from literature [5, 33-36, 59, 62, 63].
Oil sands upgrading (bbl_W/bbl_U)	0.45	0.67	1.00	0.49	0.79	1.09	Min. coefficients are based on average taken from a range published by Donahue [41] indicating that the upgrading of bitumen requires about 0.4-0.5 barrel of fresh water per barrel of SCO produced. Max. are derived from [37] and Mol. coefficients are based on the average from literature [37, 40, 41, 50].
Oil refining (bbl_W/bbl_R)	0.40	1.11	1.85	0.98	1.75	3.70	Min. for consumption is derived from a paper published by the Canadian Petroleum Products Institute (CPPI) [54] that describes historical water use in seventeen Canadian refineries and found that the average water consumption is 400 m^3 of water per 1000 m^3 of crude oil processed.

							Min. for withdrawals is based on the average water consumption index (WCI) for Petrobras refineries in Brazil in 2011 [55]. Max. consumption coefficient is based on the estimate by [57] that the average total is 65 to 90 gallons of water per one barrel of crude oil. Max. withdrawals coefficient is based on the water intake stated by [54]. Mol. coefficients are based on the average from literature [37,54- 57, 64].

Table 2: Distribution and standard deviation of water demand coefficients for the main oil sands unit operations in Alberta

Pathway	**Consumption coefficient**		**Withdrawals coefficient**		**Probability percentile of the most likely value**		**S**
	Probability 10%	Probability 90%	Probability 10%	Probability 90%	Consumption coefficient	Withdrawals coefficient	C c
Surface mining of the oil sands[a]	2.13	2.8	2.32	3.05	44%	44%	
In situ-SAGD for the oil sands[a]	0.20	0.34	0.22	0.37	64%	67%	
In situ-CSS for the oil sands[a]	0.50	0.98	0.54	1.07	41%	41%	
In situ-Primary/EOR for the oil sands[a]	0.51	0.79	0.56	0.86	36%	35%	
Oil sands upgrading[b]	0.56	0.87	0.62	0.96	40%	50%	
Oil refining[c]	0.72	1.52	1.44	2.97	49%	28%	

[a] Coefficients are in bbl_W/bbl_B
[b] Coefficients are in bbl_W/bbl_U
[c] Coefficients are in bbl_W/bbl_R
[d] Standard deviation was calculated based on the all gathered data with respect to the most likely value

Table 3: Distribution of water withdrawals coefficients for Alberta oil sands

Pathway	Withdrawals coefficient		
	Probability 10%	**Probability 90%**	**Probability percentile of the most likely water withdrawals coefficient**
In situ-SAGD-Non-upgraded [a]	0.22	0.37	67%
In situ-Primary/EOR-Non-upgraded [a]	0.56	0.86	35%
In situ-CSS-Non-upgraded [a]	0.54	1.07	41%
In situ-SAGD-Upgraded [b]	0.84	1.33	55%
In situ- Primary/EOR -Upgraded [b]	1.19	1.82	43%
In situ-CSS-Upgraded [b]	1.17	2.03	45%
In situ-SAGD-Non-upgraded-Feedstock to refinery [c]	1.66	3.34	32%
In situ- Primary/EOR -Non-upgraded-Feedstock to refinery [c]	2.00	3.83	29%
In situ-CSS-Non-upgraded-Feedstock to refinery [c]	1.98	4.04	32%
In situ-SAGD-Upgraded-Refined [d]	2.28	4.30	35%
In situ- Primary/EOR -Upgraded-Refined [d]	2.62	4.79	33%
Surface mining-Non-upgraded [a]	2.32	3.05	44%

In situ-CSS-Upgraded-Refined [d]	2.60	5.00	34%
Surface mining-Upgraded [b]	2.94	4.00	46%
Surface mining-Non-upgraded-Feedstock to refinery [c]	3.75	6.02	33%
Surface mining-Upgraded-Refined [d]	4.38	6.98	35%

[a] Coefficients are in bbl_W/bbl_B
[b] Coefficients are in bbl_W/bbl_{BU}
[c] Coefficients are in bbl_W/bbl_{BR}
[d] Coefficients are in bbl_W/bbl_{BUR}

Table 4: Nomenclature

bbl_B	barrel of bitumen
bbl_{BUR}	barrel of upgraded and refined bitumen
bbl/d	barrel per day
bbl_R	barrel of refined product
bbl_U	barrel of upgraded bitumen product
bbl_W	barrel of water

CAPP	Canadian Association of Petroleum Producers
CPPI	Canadian Petroleum Products Institute
CSS	cyclic steam stimulation
EOR	enhanced oil recovery
GHG	greenhouse gas
Max	Maximum water demand coefficient
mg/L	milligrams per litre
Min	Minimum water demand coefficient
MJ	megajoule, unit of energy equal to 10^6 Joule
Mol	most likely value of water demand coefficient
m^3/d	cubic metre per day
NRCAN	National Resources Canada
RPPs	refined petroleum products
SAGD	steam-assisted gravity drainage
SCO	synthetic crude oil
WCI	water consumption index
WCSB	Western Canadian Sedimentary Basin