Development of Life Cycle Water Demand Footprints for the Energy Pathways

by

Babkir Ali

A thesis submitted in partial fulfillment of the requirements for the degree of

Doctor of Philosophy
in
Engineering Management

Department of Mechanical Engineering
University of Alberta

Abstract

The water-energy nexus refers to the relationship between water and energy, wherein each one needs the other. This thesis examines that part of the water-energy nexus concerned with water needed for energy production, conversion, and utilization. There has been limited focus on assessing the life cycle water footprints of energy pathways. Such an approach assesses the water requirement for the various unit operations in energy pathways from fuel extraction to its final energy form. A study of the life cycle water footprints of different energy pathways with a focus on minimizing water use could help in policy formation and investment decisions. The main objective of this research is to establish a benchmark for water demand coefficients for energy pathways based on a complete life cycle. The focus is on the assessment of different energy pathways and development of life cycle water demand coefficients through comprehensive modeling. The research includes the evaluation of energy pathways based on both conventional and non-conventional sources of energy, and the energy sources assessed are coal, natural gas, oil, biomass, wind, solar, hydroelectricity, nuclear, and geothermal. The initial focus is on power production. The conversion efficiency of power generation is correlated to developed water demand coefficients to study the effect of a power plant's performance on water use. Coal-based power generation has high water use compared to gas-fired power generation due to differences both in conversion efficiency and the unit operations of fuel extraction. Biomass-based power generation has the highest water demand coefficients over the complete life cycle and wind has the lowest. This study found complete life cycle water consumption coefficients for power generation for coal transported by conventional means to be 0.96 – 3.21 L/kWh and 0.07 – 2.57 L/kWh for gas-fired power plants. Excluding biomass and hydroelectricity pathways, non-conventional energy technology has complete life cycle water consumption coefficients of 0.005

– 4.39 L/kWh. The corresponding range for biomass pathways is 259.6 – 1164.01 L/kWh. Throughout the complete life cycle of a transportation fuel produced from the oil sands in Alberta 2.08 – 4.19 volume of water per volume of oil are consumed, and the corresponding fuel from crude oil extracted from five selected oil fields in North America consumes 1.71 – 8.25 volume of fresh water per volume of oil.

The water demand coefficients developed in this study could be used in making decision regarding selection of water efficient pathways.

Preface

All the data gathering, water demand coefficients developed, and analysis are my original work. Chapter two of this thesis was published as *Ali B, Kumar A. Development of life cycle water-demand coefficients for coal-based power generation technologies. Energy Conversion and Management 2015; 90: 247–260*. Chapter three was published as *Ali B, Kumar A. Development of life cycle water footprints for gas-fired power generation technologies. Energy Conversion and Management 2016; 110: 386–396.* Chapter four was submitted to *Energy Conversion and Management Journal* for publication as *Ali B, Kumar A. Development of water demand coefficients for power generation from renewable energy technologies.* Chapter five was submitted to *Energy Journal* for publication as *Ali B, Kumar A. Development of life cycle water footprints for oil sands-based transportation fuel production.* Chapter six was submitted to *Water Research Journal for publication as Ali B, Kumar A. Development of water demand footprints for crude oil production in North America.* For all these five papers, I was responsible for data collection, the development of the coefficients, analysis, and manuscript structure. Amit Kumar had the supervisory role for the papers and revision.

The water demand coefficients for the fuel stage for switchgrass, corn stover, and wheat straw discussed in chapter four of this thesis were extracted from the paper *Singh S, Kumar A, Ali B. Integration of energy and water consumption factors for biomass conversion pathways. Biofuels, Bioproducts and Biorefining 2011; 5(4): 399-40.* S. Singh was responsible for the data gathering, the development of the coefficients, and the manuscript structure. Amit Kumar supervised the writing of the manuscript, and I assisted in the revision and the structure of the manuscript.

This thesis is dedicated to the souls of my parents Suliman and Elimama and my brother Ismaeal for their kind support to reach this wonderful stage of my life

Acknowledgements

I would like to express my sincere thanks and appreciation to Dr. Amit Kumar for the supervision of this research and his continuous help and guidance in reviewing scientific papers and for his kind support to complete this thesis.

My gratitude is extended to include the supervising committee: Dr. Michael Lipsett, Dr. Evan Davies, Dr. Rajender Gupta, and Dr. Zhigang (Will) Tian who contributed during the candidacy exam to improve this research.

I am also thankful to the NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair Program in Energy and Environmental Systems Engineering and the Cenovus Energy Endowed Chair Program at the University of Alberta for their financial support of this research.

I highly appreciate the efforts from Ms. Astrid Blodgett for editing my papers and this thesis. The thanks are extended to Department of Mechanical Engineering staff Richard Groulx, Gail Dowler, and Teresa Gray for their kind support in administrative and financial issues.

I sincerely thank my colleagues at the Sustainable Energy Research Group for their help and valuable advice in the completion of this research.

Table of Contents

List of Figures

List of Tables

Nomenclature

a	the fraction of heat dissipated as latent heat of evaporation from the closed loop cooling systems
ANS	Alaska North Slope
API	American Petroleum Institute
ASP	alkali surfactant polymer
B.C.	British Colombia, a Province in Canada
bbl/bbl	barrel of water per barrel of oil
bbl/d	barrel per day
bbl/well	barrel per well
bbl_B	barrel of bitumen
bbl_{BUR}	barrel of upgraded and refined bitumen
bbl_R	barrel of refined product
bbl_U	barrel of upgraded bitumen product
bbl_W	barrel of water
BCM	billion cubic metres, equal to 10^9 meters
Billion tonnes	10^9 tonnes
°C	Celsius degree
C	the number of recycling turns of cooling water
CAPP	Canadian Association of Petroleum Producers
CBM	coal-bed methane
CDS	cadmium sulfide

CDTe	cadmium telluride
CHP	combined heat and power
CLP	coal log pipeline, mode of coal transportation
COE	water consumption/withdrawals coefficient in litres of water per m^3 of natural gas for upstream pathways
C-Si	crystalline silicon
CSS	cyclic steam stimulation
DOE	the U.S. Department of Energy
E	evaporative water loss in cubic meter per hour
EGS	enhanced geothermal system
EG-silicon	electronic silicon
EIA	the U.S. Energy Information Administration
EOR	enhanced oil recovery
F1	Water consumption coefficient in litre of water per tonne of coal for upstream pathways
FW	consumption coefficient of fresh water (in bbl/bbl)
GHG	greenhouse gas
GJ	gigajoule, equal to 10^9 Joule
GW	gigawatt, equal to 10^9 Watt
HHV	higher heating value
HR	heat rejection rate from a power plant
IGCC	integrated gasification combined cycle
K1	factor of merit in L/kWh for ranking water demand of coal upstream pathways

K2	factor of merit in L/kWh for ranking water consumption during power generation stage
K3	factor of merit in L/kWh for ranking water withdrawals during power generation stage from coal
kJ	kilojoule, unit of energy equal to 1,000 Joule
km	kilometer, a unit of length in the metric system, equal to 1000 metres
L/kWh	litres of water per kWh of electricity generated
LDV	light duty vehicles
LOOP	Louisiana Offshore Oil Port
M1	factor of merit in L/kWh for ranking water consumption of a non-conventional pathway during the upstream stage
M2	factor of merit in L/kWh for ranking water withdrawals of a non-conventional pathway during the upstream stage
m^3	cubic metre, a unit of volume in the metric system, equal to a volume of a cube with edges one metre
M3	factor of merit in L/kWh for ranking water consumption of a nn-conventional energy pathway using steam cycle during the power generation stage
m^3/d	cubic metre per day
M4	factor of merit in L/kWh for ranking water withdrawals of a non-conventional energy pathway using steam cycle during the power generation stage
M5	factor of merit in L/kWh for ranking water consumption of a non-conventional energy pathway that does not use the steam cycle during the power generation stage

M6	factor of merit in L/kWh for ranking water withdrawals of a non-conventional energy pathway not using the steam cycle during the power generation stage
Max	Maximum water demand coefficient
mg/L	milligrams per litre
MG-silicon	metallurgical grade silicon
Min	minimum water demand coefficient
MJ	megajoule, a unit of energy equal to 10^6 Joule
MJ/kg	megajoule per kilogram
Mol	most likely value of water demand coefficient
MW	megawatt, equal to 10^6 Watt
MWh	megawatt-hour, equal to 10^6 Watt-hour
NGCC	natural gas combined cycle
NGL	natural gas liquid
PADD	Petroleum Administration for Defense District
p-n	positive-negative junction
PRE	percentage of produced water re-injected (in %)
PV	photovoltaic
RPPs	refined petroleum products
SAGD	steam-assisted gravity drainage
SCO	synthetic crude oil
SP	slurry pipeline, mode of coal transportation
TAPS	Trans-Alaska Pipeline System

tcm	trillion cubic meters, equal to 10^{12} cubic metres
tonne	metric system unit of a mass, equal to 1,000 kilograms
TWP	total water produced (in bbl/bbl)
TWT	total water injected (in bbl/bbl)
U.S.	the United States
Us	useful output power from the power plant
WAG	water-alternating-gas
WC	water consumption
WCC	water consumption coefficient in L/kWh during power generation stage
WCI	water consumption index
WCOMP	water consumption coefficient in L/kWh for the complete life cycle of a pathway
WCUP	water consumption coefficient in L/kWh during the upstream stage
WDC	water consumption/withdrawals coefficient in litres of water per kWh generated in upstream pathways
WF	water flow rate per one megawatt (MW) of power output
WR	water returned
WRT	the theoretical make-up water requirements in cubic meter per hour
WW	water withdrawals
WWC	water withdrawals coefficient in L/kWh during power generation stage
WWCOMP	water withdrawals coefficient in L/kWh for the complete life cycle of a pathway
WWUP	water withdrawals coefficient in L/kWh during the upstream stage
ΔT	temperature rise of the cooling water in Fahrenheit (°F)

η	overall conversion efficiency of the power plant from fuel heat content up to the electricity generated
η_{cc}	overall conversion efficiency of an NGCC power plant
η_{cg}	conversion efficiency of a cogeneration gas-fired power plant
η_{max}	maximum conversion efficiency
η_{min}	minimum conversion efficiency
η_{ml}	most likely conversion efficiency
η_{pst}	the conversion efficiency of the portion of the power generated by steam cycle in an NGCC power plant
η_{sc}	conversion efficiency of a single cycle gas-fired power plant
η_{st}	conversion efficiency of a steam cycle gas-fired power plant

Chapter 1

Introduction

1.1 Background

Water and energy are strongly interrelated, as energy production requires water for the extraction, processing, transportation, and generation of power from primary fuels. Water pumping, transportation, treatment, and desalination require energy. This relationship has been extensively investigated by researchers in what is known as the water-energy nexus in the research community [1 - 8]. The water-energy nexus identifies the two-part inter-relationship of “water for energy” and “energy for water” [1, 2].

Water demand in the world has increased three-fold during the last 50 years and is expected to increase by 18% in the next 15 years [9]. Total annual fresh water withdrawal in the world is 3,941 km^3; 70% of this is for agricultural use, 19% for industrial use, and 11% for domestic use [10]. Concern about water demand in the energy sector is high because of the continuous increase in energy demand. A study conducted by the U.S. Energy Information Administration (EIA) [11] estimated that primary energy consumption by 2040 will be 8.9% higher than the 2013 level (from 97.1 to 105.7 quadrillion Btu) and total electricity consumption will grow by 25% from 3.83 to 4.8 billion MWh for the same period. The United Nations World Water Development Report [12] highlighted that about 90% of power generation in the world requires water intensively. Energy outlooks suggested that oil, gas, and coal will be the most demanded fuels in the world by 2040, with a 78% share [13]. Another study reported that the most intensive water users in the energy sector in Canada are the oil and gas industries, thermal electric generators, and hydroelectric power plants [14].

Greenhouse gas (GHG) emissions are a concern, and in order to alleviate the related impact of energy production, various mitigation options have been proposed, such as the use of renewable energy, improving efficiency in energy demand and supply sectors, and the implementation of clean coal production technologies and carbon sequestration technologies [15 – 17]. These proposed mitigation options and their associated economic impacts have been estimated at various levels of detail, but the research to study their impact on water demand is limited. The use of renewable energy can be the best clean technology alternative and may be economical in certain jurisdictions, but when water demand is considered for these mitigation options, the outcome may be different.

1.2 Motivation

To support decision making for appropriate energy planning, the criteria considered should cover quantitative and qualitative assessments of the resources involved. This research is motivated by the need to quantify and evaluate the life cycle water footprint of various energy conversion pathways. System-level assessments of energy conversion pathways in terms of life cycle GHG emissions and techno-economic assessments have been intensively researched [18 - 21]. The water-energy nexus can be introduced to this system-level assessment to add a new dimension and help in comprehensive decision-making focussed on improving sustainability.

The establishment of standard indicators for water demand in the energy sector would ease the comparison of different technology pathways. Through proper indicators, the decision maker could determine which energy pathway should be focussed to optimize water use. Water consumption and water withdrawals coefficients are already established in the water-energy nexus field as standard indicators [22 – 24]. The United States Geological Survey (USGS) has defined water consumption as the portion of water withdrawal not returned to the source; this portion includes water consumed by evaporation, transpiration, and direct consumption by a product or any involved human or livestock. Water withdrawals are defined as the total amount of water that is taken from a surface source or underground for use [22]. The difference between water withdrawals and water consumption is the amount returned to the source. The water coefficients reflect the volume of water consumed or withdrawn in the production of primary fuel or power generation units. Studies conducted to estimate water consumption projections for energy sectors define the water demand coefficient as the amount of water consumed per unit of fuel produced. The unit of fuel produced can be a tonne of coal, a barrel of oil, or a gallon of ethanol [23]. The same approach was followed earlier by the National Energy Technology Laboratory (NETL) [24] to estimate future needs for thermoelectric power generation.

Water demand is one of the essential decision-making factors for developing new energy technologies (e.g., shale gas extraction). New technologies for horizontal drilling and hydraulic fracturing introduced for shale gas extraction in the United States have added abundant resources to natural gas. Hydraulic fracturing associated with production from deep shale gas is a concern because of the large amount of water required [25]. This high concern about water availability is compelling researchers to study new technologies with lower water requirements.

One of the challenges facing the province of Alberta, Canada is how to balance the water-energy nexus. The province is a major producer of primary fuels that have heavy water demand. In 2009, Alberta produced more than 70% of the total crude oil produced in Canada, more than 70% of the total gross natural gas, and more than 50% of the total coal [26]. Most of the petroleum oil production in Alberta is done through extraction from the oil sands, an activity that is projected to increase and has a high demand for water. Canadian Association of Petroleum Producers (CAPP) forecasts that crude oil production from the oil sands is expected to grow from 2.37 mb/d in 2015 to 3.06 mb/d in 2020 and to 3.67 mb/d in 2030 [27]. Concern about the use of fresh water for oil and gas projects is very high in Alberta [28]. The province of Alberta has a significant share in total natural gas production in Canada. Unconventional gas resources are coal-bed methane (CBM) and shale gas, which represent 8% and 0.1% of the total production, respectively. [29]. Alberta, B.C., and Saskatchewan together produce nearly all of Canada's coal. Alberta produces about 25 - 30 million tonnes/year and 70% of the Canadian reserves are available in Alberta [30]. Abundant coal reserves, high production rates, and favorable economics make coal-based power generation more attractive than other sources of electricity.

Most studies conducted in the area of water demand in the energy sector are limited to an incomplete life cycle and include only power generation in their system boundaries; all the unit operations for primary fuels from its extraction to use are not included [31 - 33]. Some studies in this field considered water consumption and not withdrawals [1, 34]. The water demand coefficients developed for earlier studies did not show the impact of conversion efficiency on water use [31 - 34]. There is little research that comparatively assesses conventional and non-conventional sources of energy production. Water demand is investigated in earlier studies independently without broad concepts of integration with economic and GHG factors [35 - 37].

This research is motivated by the aim to fill these gaps. Further details on literature review of water demand for energy sector are given in respective chapters.

1.3 Objectives

The overall aim of this research is to develop water footprints based on the full life cycle for both conventional and non-conventional sources of energy. Development of water coefficients for the complete life cycle based on unit operations and pathways can be used in management, modeling, and forecasting of water demand for the energy sector when combined with production projections. The key contribution of this research is the application of the life cycle assessment (LCA) concept for a comprehensive development of water coefficients for the energy sector and the impact of a power plant's technology and performance on the water demand. There are water demand coefficient estimates for the conversion of fuel to power but there is limited information on the integration of water demand for different upstream and downstream unit operations.

The key objectives of this research are:

- The development of a framework to estimate the life cycle water demand coefficients for the energy pathways.
- The development of life cycle water demand coefficients for the conversion of various conventional and non-conventional sources of energy to electricity.
- The development of life cycle water demand coefficients for petroleum oil production pathways.
- An assessment of the impacts of water demand coefficients on variations in energy production technologies and performance.

- A comparative assessment of the water demands of different pathways involved in the conversion of primary fuels to power.

1.4 Methodology

Water demand coefficients were analyzed by estimating water consumption and water withdrawal coefficients. To cover the complete life cycle of an energy source, the water footprint was developed for all the unit operations from the extraction of primary fuels through to power generation (cradle to grave). For power generation based on non-conventional energy, the complete life cycle included upstream and downstream stages. For petroleum oil, the full life cycle covered extraction, upgrading, and refining unit operations. Further details are given in respective chapters related to the energy source.

The developed footprints trace the unit operations that have intense water use. Coefficients for the upstream stages are estimated as the volume of water per unit of energy input. For power generation pathways, the upstream coefficients are harmonized as litres of water per kWh using the energy input and the conversion efficiency of the power plant. In order to trace the life cycle of energy production, the processes restructured into pathways that include the unit operations of the complete life cycle. Coefficients of water consumption and withdrawals are developed for pathways and used for comparative assessments.

In the base case, the conversion efficiencies of coal, gas, and non-conventional energy power plants are assumed at a certain level. These assumed conversion efficiencies are considered the most likely to develop the water demand coefficient benchmark. Sensitivity analysis is conducted to evaluate the impact of the most uncertain factors on water demand.

1.5 Scope and limitations of the research

The study covers the unit operations in the complete energy sector life cycle: exploration, drilling, stimulation, production, transportation, and power generation. The primary fossil fuels considered are coal, natural gas, and petroleum oil. Power generation includes all existing and new advanced electricity production technologies for both conventional and non-conventional sources of energy.

The scope considers only “water for energy”; the other part of the water-energy nexus, “energy for water,” is not covered in this study. The qualitative impacts of energy sector unit operations on water are beyond the scope of this study.

1.6 Thesis organization

This thesis consists of seven chapters. This thesis has been written in a paper format. The chapters are independent papers and hence some information in chapters might be repeated. The first chapter introduces the background, motivation, objectives, and methodology. The next five chapters are condensed versions of independent papers intended for publication on different energy sector pathways. Chapters two and three describe the development of water demand coefficients for coal and natural gas, respectively. Chapter four is for non-conventional energy technology pathways. Chapters five and six are devoted to oil sands in Alberta and crude oil in North America, respectively. The last chapter outlines conclusions and recommendations for future research work.

References

[1]. Peter H. Gleick. Water and Energy. Annual Review of Energy and Environment 1994; 19:267–299.

[2]. Hardy L, Garrido A, Juana L. Evaluation of Spain's water-energy nexus. International Journal of Water Resources Development 2012; 28(1): 151-170.

[3]. Stillwell AS, King CW, Webber ME, Duncan IJ, Hardberger A. The energy-water nexus in Texas. Ecology and Society 2010; 16(1): 2. Available at: http://www.ecologyandsociety.org/vol16/iss1/art2/ [accessed: 28.08.2016]

[4]. Ku AY, Shapiro AP. The energy-water nexus: water use trends in sustainable energy and opportunities for materials research and development. MRS Bulletin 2012; 37(4): 439-447.

[5]. Glassman D, Wucker M, Isaacman T, Champilou C. The water-energy nexus: adding water to the energy agenda. World Policy, March 2011. Available at: http://www.worldpolicy.org/sites/default/files/policy_papers/THE%20WATER-ENERGY%20NEXUS_0.pdf [accessed: 20.08.2016]

[6]. International Energy Agency (IEA). Water for energy: is energy becoming a thirstiest resources? Excerpt from the World Energy Outlook 2012. Available at: http://www.worldenergyoutlook.org/media/weowebsite/2012/WEO_2012_Water_Excerpt.pdf [accessed: 26.08.2016]

[7]. McMahon JE, Price SK. Water and energy interactions. Annual Review of Environment and Resources. 2011; 36:163-191.

[8]. King CW, Stillwell AS, Twomey KM, Webber ME. Coherence between water and energy policies. Natural Resources Journal 2013; 53: 117 – 215.

[9]. Audrey Maheu. Energy choices and their impacts on demand for water resources: an assessment of current and projected water consumption in global energy production. UNISFERA International Centre Publications. November 2009.

[10]. Pacific Institute. Table 2: Freshwater withdrawal, by country and sector (2010 Update). Available at: http://www.worldwater.org/data.html [accessed: 21.08.2016]

[11]. U.S. Energy Information Administration (EIA). Annual energy outlook 2015 with projections to 2040. DOE/EIA-0383(2015) April 2015. Available at: http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf [accessed: 27.08.2016]

[12]. The United Nations World Water Development Report (WWDR 2014). Water and energy. Available at: http://unesdoc.unesco.org/images/0022/002257/225741e.pdf [accessed: 15.08.2016]

[13] ExxonMobil. The outlook for energy: a view to 2040. Available at: http://cdn.exxonmobil.com/~/media/global/files/outlook-for-energy/2016/2016-outlook-for-energy.pdf [accessed: 27.08.2016]

[14]. Natural Resources Canada. Freshwater: The role and contribution of Natural Resources Canada. Available at: http://www.nrcan.gc.ca/sustainable-development/freshwater/2543#f23 [accessed: 23.08.2016]

[15]. Abdullah MA, Agalgaonkar AP, Muttaqi KM. Climate change mitigation with integration of renewable energy resources in the electricity grid of New South Wales, Australia. Renewable Energy 2014; 66: 305 – 313.

[16]. Davoudpour H, Ahadi MS. The potential for greenhouse gases mitigation in household sector of Iran: cases of price reform/efficiency improvement and scenario for 2000-2010. Energy Policy 2006; 34 (1): 40 – 49.

[17]. Mallah S, Bansal NK. Nuclear and clean coal technology options for sustainable development in India. Energy 2010; 35 (7): 3031 – 3039.

[18]. Sultana A, Kumar A. Ranking of biomass pellets by integration of economical, environmental and technical factors. Biomass and Bio-energy 2012; 39: 344-355.

[19]. Kabir R, Kumar A. Development of net energy ratio and emission factor for biohydrogen production pathways. Bio-resource Technology 2011; 102(19): 8971-8985.

[20]. Sarkar S, Kumar A. Techno-economic assessment of bio-hydrogen production from forest biomass in Western Canada. Transactions of the ASABE 2009; 52(2): 1-12.

[21]. Leighty W, Ogden JM, Yang C. Modeling transitions in the California light-duty vehicles sector to achieve deep reductions in transportation greenhouse gas emissions. Energy Policy 2012; 44: 52-67.

[22]. Kenny JF, Barber NL, Hutson SS, Linsey KS, Lovelace JK, Maupin MA. Estimated use of water in the United States in 2005. U.S. Geological Survey. Circular 1344. Available at: http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf [accessed: 23.08.2016]

[23]. Elcock D. Baseline and projected water demand data for energy and competing water use sectors. Report prepared for U.S Department of Energy. National Energy Technology Laboratory. Argonne National Laboratory. ANL/EVS/TM/08-8. Available at: http://www.acs.org/content/dam/acsorg/policy/acsonthehill/briefings/energywaternexus/11-08-anl-water-demand-for-energy-competing-sectors.pdf [accessed: 28.08.2016]

[24]. National Energy Technology Laboratory (NETL). Estimating freshwater needs to meet future thermoelectric generation requirements. 2011 update. DOE/NETL-2011/1523. Available at: https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Coal/WaterNeeds2011.pdf [accessed: 27.08.2016]

[25]. Matthew E. Mantell. Deep shale natural gas: abundant, affordable, and surprisingly water efficient. 2009 GWPC Water/Energy Sustainability Symposium held in Salt Lake City, Utah, USA,

13-16 September 2009. Available at: http://www.shepstone.net/naturalgasnow/ShaleGasFacts.pdf [accessed: 28.08.2016]

[26]. Energy Statistics Handbook. First quarter 2012. Catalogue No.57-601-X. Available at: http://www.statcan.gc.ca/pub/57-601-x/57-601-x2012001-eng.pdf [accessed: 25.08.2016]

[27]. Canadian Association of Petroleum Producers (CAPP). Crude oil: forecast, markets, & transportation. June 2016. Available at: http://www.capp.ca/publications-and-statistics/publications/284950 [accessed: 26.07.2016]

[28]. Gupta D, Hlidek B. Frac-fluid recycling and water conservation: a case history. SPE Production and Operations 2010; 25 (1): 65-69.

[29]. Government of Alberta. Energy. Natural gas facts. Available at: http://www.energy.alberta.ca/NaturalGas/726.asp [accessed: 20.08.2016]

[30] Government of Alberta. Energy: about coal. Available at: http://www.energy.alberta.ca/coal/645.asp [accessed: 29.08.2016]

[31]. Yang X, Dziegielewski B. Water use by thermoelectric power plants in the United States. Journal of the American Water Resources Association (JAWRA) 2007; 43(1):160-69. DOI: 10.1111/j.1752-1688.2007.00013.x.

[32]. Goldstein R, Smith W. Water & sustainability (Volume 3): U.S. water consumption for power production—The Next Half Century. Palo Alto, CA: EPRI; 2002. 1006786. Available at: http://www.circleofblue.org/waternews/wp-content/uploads/2010/08/EPRI-Volume-3.pdf [accessed 23.08.2016]

[33]. Macknick J, Newmark R, Heath G, Hallett KC. Operational water consumption and withdrawals factors for electricity generating technologies: a review of existing literature. Environmental Research Letters 2012; 7: 045802-12.

[34]. Clark C, Horner R, Harto C. Life cycle water consumption for shale gas and conventional natural gas. Environmental Science & Technology 2013; 47: 11829-36.

[35]. Fulton J, Cooley H. The water footprint of California's energy system, 1990-2012. Environmental Science & Technology 2015; 49 (6): 3314-3321.

[36]. Pacsi AP, Sanders KT, Webber ME, Allen DT. Spatial and temporal impacts on water consumption in Texas from shale gas development and use. ACS Sustainable Chemistry and Engineering 2014; 2(8): 2028-2035.

[37]. Salazar JM, Zitney SE, Diwekar UM. Minimization of water consumption under uncertainty for a pulverized coal power plant. Environmental Science & Technology 2011; 45: 4645–4651.

Chapter 2

Development of Water Demand Coefficients for Coal Pathways[1]

2.1 Introduction

Coal, one of the main fossil fuels, is heavily used around the world predominantly for the generation of electricity. In the reference case (IEO, 2013) conducted by the U.S. Energy Information Administration (EIA) for the period 2010 to 2040, the generation from coal is expected to grow annually by 1.8% and it was contributed by 40% of the electricity generated globally in 2010 [1]; that is, the 1,759 GW generation capacity in 2010 is expected to rise to 2,384 GW by 2020 and this increase is largely due to the anticipated drastic increase in demand for energy in Asian countries [2].

Total electricity generation capacity from coal in 2006 was 314 GW in the U.S. and in Canada was 16 GW [3]. In the same year, Canada burned about 51 million tonnes of coal to generate electricity. The largest coal deposits are found in the Canadian provinces of British Columbia (B.C.), Alberta, and Saskatchewan, and of the 22 mines in operation, 17 of them are in B.C. and Alberta. It is estimated that Canada holds 190 billion tonnes of coal-in-place and 6.6 billion tonnes considered recoverable with current technologies and economic conditions. These 6.6 billion tonnes are expected to last roughly 100 years [4]. The significant market for coal is Asia and coal for electricity generation is heavily imported by China, Japan, and Korea [5]. In Alberta, more than 40% of the total power generation capacity is based on sub-bituminous coal extracted by surface mining [6].

[1] Complete paper was published as *Ali B, Kumar A. Development of life cycle water-demand coefficients for coal-based power generation technologies. Energy Conversion and Management 2015; 90: 247–260.*

However, coal-based power generation is associated with considerable environmental impacts, specifically the consumption of huge amounts of water. In the U.S., total water consumption from coal-based power plants is expected to increase by 21% (from about 3.32 to 4 billion cubic metres [BCM] per year) between 2005 and 2030, and some plants may be vulnerable to water supply-demand conflicts [7]. In Canada, gross water withdrawals during 2009 for thermoelectric power production were 31 BCM and net total consumption was 4.7 BCM [8]. 0.89 BCM was diverted in 2007 for commercial cooling in Alberta [9] and 0.096 BCM was consumed during 2005 [10]. As the demand for energy grows, the water requirement for coal-based power generation will increase.

The amount of water used to generate electricity from coal depends on several factors including the type of coal, the technology used to extract and process coal in its conversion to power, cooling systems, types of reclamation and ash disposal, and the mode of transportation of coal (e.g., through pipelines as slurry). There have been independent studies conducted on water demand related to energy-producing activities as part of the water-energy nexus field [11-13]. Studies have also estimated and projected water demand for power generation with different conversion technologies including coal-based power plants [14-17]. The power generation shift from coal and nuclear-based fuels to natural gas will contribute significantly to decreasing the amount of water consumption in the U.S. This decrease is based on the fact that natural gas combined cycle (NGCC) using cooling towers consume 40% of the water consumption by steam cycle using the same cooling system. This expected decrease is based only on the power generation stage without consideration for the fuel extraction stage [14]. Torcellini et al. [15] have taken 1.8 L/kWh as one aggregate coefficient for consumptive water use in the thermoelectric U.S. power plants without consideration of the technology, fuel, and cooling system used. For example, coal can be converted to power through subcritical pulverized coal power plants [18, 19], supercritical coal power plants [20, 21], or ultra-supercritical coal power plants [22, 23]. Similarly, there are variations in water demand depending on the type of cooling system used by the coal power plants, the location of the power plants, and conversion efficiency of the power plant. A study conducted for eleven river basins in Texas, USA [16] showed a potential reduction in water diversion through utilizing more efficient cooling systems, such as cooling towers and dry cooling. The impact of the power plant's efficiency on the water demand is highlighted by King et al. [17] that improvement of a coal power plant's efficiency from 32% to 40% would reduce the water demand by a range of 5% – 10%. But there is a scarcity of research on the full life cycle water consumption of coal-based power generation that includes all the unit operations involved in power generation from coal. Also, there is very limited research on a comparative assessment of life cycle water consumption that takes into account the variations in unit operations involved in the production of power from coal.

This chapter aims at addressing the gaps identified above and contributes to the full life cycle assessment taking into account the variations of coal mining and transportation modes, the different power generation and cooling technologies, and impact of the conversion efficiency on the water demand for the power plant. The analysis of the impact of conversion efficiency of the power plant on water demand is another significant contribution in the research field of the water-energy nexus.

The overall objective of this chapter is to develop a life cycle water demand paradigm for coal-based power generation. The key objectives of this chapter are to:

- Develop a framework to estimate the life cycle water demand for coal-based power generation including plants with advanced conversion technologies.

- Provide a comparative assessment of the water demand of thirty-six different pathways in the conversion of coal to power; and
- Assess the impacts on water demand from variations in power plant's performance and coal transportation methods.

2.2 Scope and system boundary

Water demand coefficients for the complete life cycle are estimated through pathways developed mainly according to the unit operations for both coal extraction and power generation. Coefficients for coal upstream processes are derived from the literature, through calculations and in discussion with experts as the volume of water required per unit weight of coal. An average water coefficient is developed for each pathway in cubic meters of water per tonne of coal and converted to the equivalent electricity coefficient in litres of water per kWh using the coal energy content and the conversion efficiency for each technology. Power generated from coal is structured in specific pathways (from cradle to grave), and water demand coefficients are developed. Some of the water demand coefficients in the U.S. for specific unit operations were reviewed and used to fill the gap for those pathways not used in coal-based power generation everywhere. Figure 2.1 shows the system boundary and unit operations considered for this chapter.

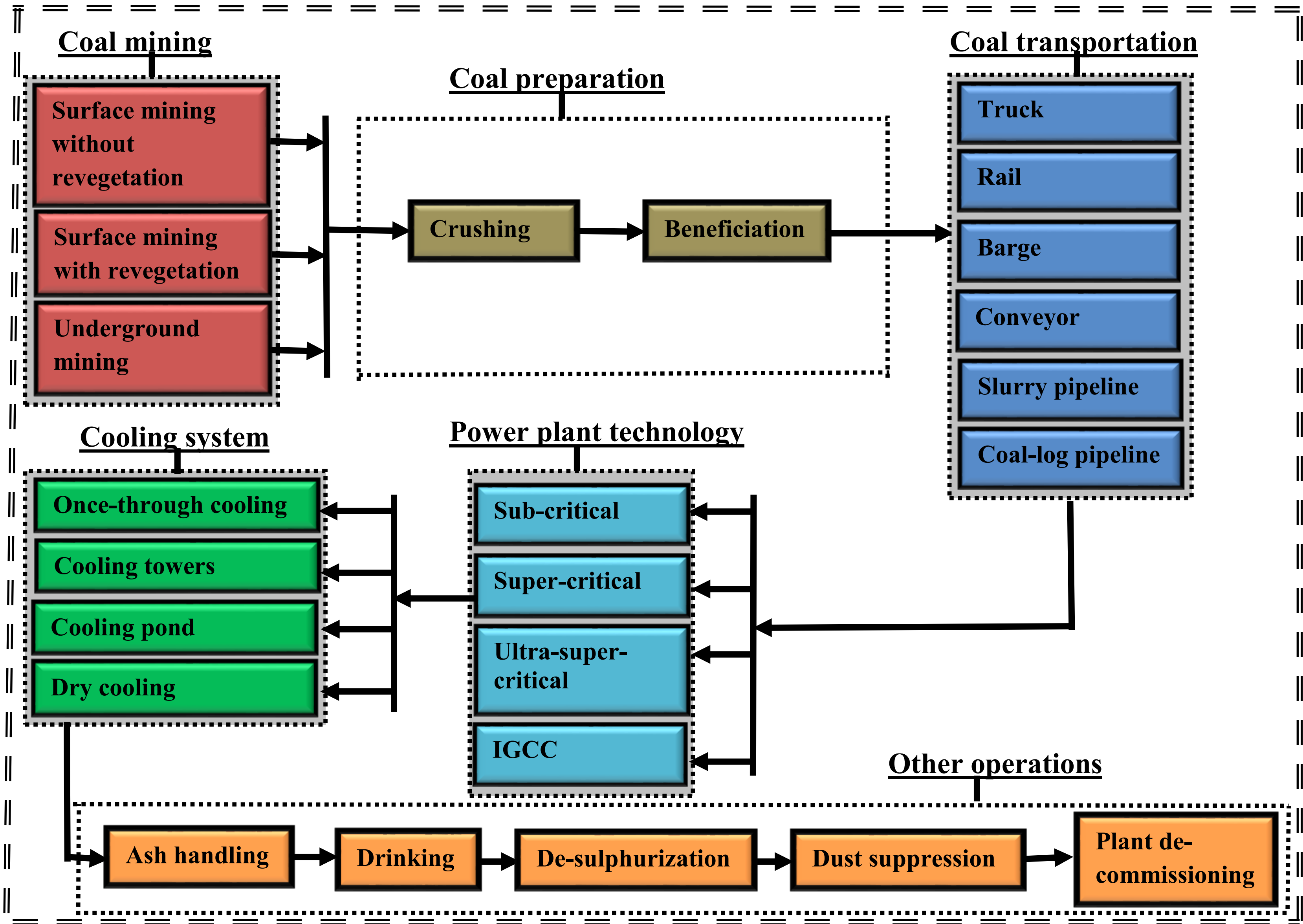

Figure 2.1: System boundary and unit operations for coal-based power generation

2.2.1 Definitions

The water demand coefficients followed in this chapter are derived from an earlier study conducted by Argonne National Laboratory (ANL) [24] and the same terms of water consumption and water withdrawals are being used by the U.S Geological Survey (USGS) [25]. Water demand coefficients for coal-based power plants comprise the water consumed and water withdrawn during the complete life cycle (that is, the mining of coal and its processing, transportation, and conversion to electricity). Each coefficient is expressed as intensity in terms of the amount of water in litres per kWh of electricity generated.

2.2.2 Selection of coal upstream pathways

Coal upstream pathways are disaggregated according to unit operations and their water footprints. Coal extraction pertains to mining, preparation, and transportation. Other operations are added to cover water demand coefficients for coal upstream and electricity generation.

Surface and underground mining are the two common methods of coal mining, and the geology of the coal deposit is the essential factor in determining which method to use [26]. Underground mining can be carried out by room-and-pillar or longwall mining [27]. Surface mining recovers coal closer to the surface and is used for about 80% of coal production in Australia and about 67% in the U.S. [28]. Water demand for coal mining depends mainly on the method followed and whether revegetation is required or not. Operations and equipment used for coal mining methods differ and therefore demand different levels of water.

Coal needs to be crushed and cleaned before being used in power plants as fuel. Coal is prepared by removing impurities, rocks, and some ash-forming materials; this is sometimes referred as coal beneficiation or coal washing [28]. The jig cleaning process, in which coal is separated from the refuse by a pulsating flow of water, is the most common washing method for coarse coal [28, 29].

Coal can be transported by various means, and the method depends mainly on the distance traveled. Coal transportation methods include conventional and unconventional means. The conventional type in this chapter is meant to cover all types of moving vehicles and electric conveyors. Unconventional transportation covers different types of pipeline transport. Thermal coal used for coal-based power plants in Canada needs little transportation, but when coal is exported, it is transported long distances by rail. In Canada, more coal is transported by rail than any other commodity [30]. Pipelines are another way to transport coal, either in a slurry pipeline (SP) or a coal log pipeline (CLP).

Separate water demand coefficients are reserved for other operations resulting from upstream coal mining activities and plant operation activities. These other operations include ash handling, dust suppression, desulphurization, and plant decommissioning [31].

2.2.3 Selection of coal-fired generation pathways

The life cycle assessment in this chapter covers a number of electricity generation processes. The two main factors affecting water footprints in this stage are conversion technology which determines the level of power plant performance and cooling system used.

Coal power plant technology is determined in this chapter according to the boiler operation conditions. The four most common coal power technologies are subcritical pulverized coal, supercritical pulverized coal, ultra-supercritical pulverized coal, and integrated gasification combined cycle (IGCC). Improving the efficiency of coal-based power plants is critical in order to alleviate environmental impacts. Conventional subcritical coal power plants are being replaced by the more advanced and higher efficiency supercritical and ultra-supercritical plants [32, 33].

The cooling system is one of the essential unit operations in a coal power plant. Steam is generated through the boiler and passed to the turbine to generate electricity. The steam expanded from the turbine then has to be condensed to water and pumped back to the boiler to start a new cycle. This condensation of steam to water is carried out through the cooling systems which necessitates passing of cooling medium to remove the heat. This cooling medium can be water as in wet cooling systems or air as in dry cooling systems [34]. Types of cooling systems considered in this chapter are once-through, closed loop cooling (cooling towers and cooling pond), and dry cooling [34- 36]. In the U.S., nearly half (48%) the coal-fired power plants use wet re-circulating cooling systems; 39.1% use once-through systems, 0.2% use dry cooling systems, and 12.7% use cooling pond systems [37].

Theoretically, the heat rejection rate (H_R) through the steam cycle is greater than the useful output power (U_s) for all plants with cycle efficiency (η) less than 50%. This is shown in the following equation [38]:

$$\mathbf{H_R = U_s * ((1/ \eta) - 1)} \qquad \textbf{(2.1)}$$

Cycle efficiency (η) in eq. (2.1) is expressed in decimal fraction. Using this equation, for a coal-fired power plant with a net output of 450 MW and a cycle efficiency of 40%, the heat rejection rate is 675 MW, which is 1.5 times the amount of useful power and has to be removed through a cooling system.

Once-through cooling in coal-based power plants is a system in which water is drawn from a natural source such as a river or a lake, passed through pipes to extract heat from the steam in the power system, and then discharged back to the water source. Heat rejection through evaporation from the mixture is a common process in all once-through cooling systems and water consumption is lower and water withdrawals is higher compared to closed loop cooling systems [38- 40]. Heat rejection requires cooling water to be passed through the condenser. The water flow rate per megawatt (MW) of power output can be calculated as:

$$\mathbf{WF = 1550 * (1 - \eta) / (\Delta T * \eta)} \quad \textbf{(2.2)}$$

where (WF) is the amount of water in m^3/h/MW of generating capacity, (ΔT) the temperature rise of the cooling water in °F, and (η) is the thermodynamic efficiency of the power plant, expressed as a decimal fraction [41].

In closed-loop systems that use cooling towers, water is circulated between the condenser and the cooling tower. A natural water source is used to feed the make-up water and receive the blow-down. The cooling devices can be wet or dry cooling towers, spray ponds, or spray canals and this type of cooling is characterized by higher water consumption and much lower water withdrawals compared to open loop systems [38- 40]. Cooling ponds can be used instead of cooling towers in the closed-loop cooling systems.

In these cooling systems, theoretical make-up water requirements (WRT) in m^3/h can be calculated as follows [42]:

$$\mathbf{WRT = E * (1/ (1- (1/C)))} \quad \textbf{(2.3)}$$

where (C) is the recycling ratio and (E) the evaporative water loss in m^3/h, which for a typical mean water temperature (WT) of 80°F can be calculated as [42]:

$$\mathbf{E = 1.4831 * a * H_R} \quad \textbf{(2.4)}$$

where ‘a’ is the fraction of heat dissipated as latent heat of evaporation (for evaporative towers a = 75% to 85%); and ‘(H_R’) the rate of heat rejection by the plant in MW, which can be calculated from equation (2.1) using ‘U_s’ in MW and (η) the efficiency of the plant expressed as a fraction.

Air is used instead of water in dry cooling systems. There are two methods for dry cooling: direct and indirect [37]. Because air has a lower thermal capacity than water, the plant’s thermal efficiency is reduced and this efficiency loss is proportional to the increase in ambient temperature [43-45]. In addition, dry cooling systems have very high capital and operating costs compared to wet re-circulating cooling systems [45]. In the U.S., most of the new power plants do not use dry cooling due to the associated higher costs and loss in efficiency [46].

2.3 Input data and assumptions

2.3.1 Coal upstream water demand coefficients

Input data are developed through basic thermodynamic calculations, gathered from the literature and determined in consultation with the experts to estimate the water demand coefficient over the life cycle of coal-based power plants. Assumptions for heat content of coal and different conversion efficiencies as shown in Table 2.1 are used to convert water demand coefficients for coal upstream pathways from cubic meter of water per tonne of coal to litres of water per kWh of electricity generated. The average values of water consumptions considered in this chapter for coal upstream pathways are shown in Table 2.2 and for the power generation cycle are shown in Table 2.3. In an earlier study, Gleick [31] published only consumption coefficients without associated withdrawals coefficients. Meldrum et al. [47] reviewed and harmonized a comprehensive data from the literature with the assumption that consumption and withdrawals coefficients are equal for coal fuel cycle. Water withdrawal coefficient for coal upstream life cycle is assumed in this chapter is equal to water consumption coefficient. With this assumption, no water is returned back to the source.

Based on the water consumption results obtained by King and Webber [48] for light duty vehicles (LDV) using petroleum gasoline or diesel and traveling a distance of 1600 km (1000 miles) with a load of 50 tonnes of coal, the average transportation coefficients for water consumption is 0.007 m^3/tonne. The same is considered in this chapter within conventional transportation coefficients.

Table 2.1: Input data and assumptions for characteristics of coal and power plants

Items	Values	Comments/Sources
Heat content of coal (HHV)	22.7 GJ/tonne	Typical average heat content of coal consumed in the U.S. during 2012 [49].
Conversion efficiency (η) of subcritical power plant at HHV of coal	35%	Assumed based on literature [47, 50, 51, 52].
Conversion efficiency (η) of supercritical power plant at HHV of coal	38%	Assumed based on literature [47, 50, 51].
Conversion efficiency (η) of ultra-supercritical power plant at HHV of coal	45%	Assumed based on literature [46, 51, 52].
Conversion efficiency (η) of IGCC power plant at HHV of coal	45%	Assumed based on literature [53, 54, 55].

Table 2.2: Input data and assumptions for estimation of water consumption coefficients of coal upstream pathways

	Average for surface mining (m^3/tonne)	Average for underground mining (m^3/tonne)	Comments/Sources
Mining	0.038	0.257	Gleick's [31] coefficient for surface mining was 0.05 m^3/tonne. Average values for extraction of 0.025 m^3/tonne for surface and 0.226 m^3/tonne for underground mining are derived from a wide range of studies conducted and harmonized by Meldrum et. al. [47] at an efficiency (η) of 34.3% (HHV). For underground mining, the average is taken from the range 0.075 – 0.500 m^3/tonne with the higher value for underground mining with no recycle.
Revegetation	0.075	0.000	Obtained from Gleick [31] as the difference between surface mining with revegetation and without.
Preparation	0.140	0.140	The NETL[56] base case is considered here to include jig cleaning of the coal and landfilling for both surface and underground mining as 0.17 m^3/tonne. Gleick's [31] coefficient of 0.1 m^3/tonne for beneficiation is considered here for preparation of both mining types. An average value of 0.15 m^3/tonne for processing both types of mining is also considered from a wide range of studies conducted and harmonized by Meldrum et. al. [47] at an efficiency (η) of 34.3% (HHV).
Conventional transportation	0.005	0.005	Calculated from King and Webber [48] for transportation by LDV as 0.007 m^3/tonne for both mining types. Transport by train in the range 0.001-0.004 m^3/tonne for both mining types is also included here from Meldrum et.al. [47].
Slurry pipeline transportation	1.161	1.161	Assumption by Kania [57] that coal is crushed and mixed with water to form a slurry of about 50% by dry weight is considered here (1 m^3/tonne). Range for both mining types from Gleick [31] as 1.0-2.125 m^3/tonne for coal power plants in the U.S is also considered. The median value 0.92 m^3/tonne for both types of mining from Meldrum et. al. [47] is added to calculate the average.
Coal-log pipeline transportation	0.333	0.333	The assumption from [58] that coal-to-water mass ratio 3:1 is considered here (0.333 m^3/tonne).
Other operations	2.250	2.250	Assumption from Gleick [31] is considered here to include plant service, potable water requirements, ash handling, and make-up water for boiler and for flue gas desulphurization.

2.3.2 Water demand coefficients for power generation cycle from coal

Table 2.3 shows the input data for water demand coefficients gathered from the literature for the power generation stage. Data on the actual annual amount of water consumption and withdrawals are collected for coal power plants in Alberta [9,10,59 - 63] and combined with power generated [60 - 66] to estimate the water demand coefficients. Capacity factor is assumed at 90% for all coal-fired power plants in Alberta.

Ultra-supercritical water demand coefficients are extrapolated from subcritical and supercritical coefficients using their associated conversion efficiencies. The average of the constants of proportionality (K2 and K3 in equations (2.7) and (2.8) of section 2.5.1 below) are obtained at conversion efficiencies 35% and 38% and with the associated average coefficients from Table 2.3 for subcritical and supercritical, respectively, then the same constants are used to estimate the ultra-supercritical water demand coefficients at conversion efficiency 45%.

Water demand for dry cooling is minimal, and many studies estimate it to be one tenth of the demand of wet re-circulating systems to cover other plant operations such as boiler make-up and drinking [16, 46, 67]. The same assumption is taken for the dry cooling in this chapter as one tenth of cooling towers coefficients.

Table 2.4 shows all the average values considered in this chapter for water demand coefficients of power generation stage and the associated maximum and minimum ranges gathered from the literature.

Table 2.3: Input data for power generation coefficients from coal

Cooling system type	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Comments and sources
Once-through		143.93	Theoretical coefficient calculated from equation (2.2) at η =35% and ΔT=20 °F [41].
	1.20		Derived from Gleick [31] as consumptive use at η =35%.
	1.14	75.76	For the U.S., thermal power plants based on ΔT= 30 °F [14].
	1.14	189.39	For the U.S. thermal power plants based on ΔT=12 °F[14].
	0.51	128.54	Median of subcritical pulverized coal for a wide range of studies harmonized at η =34.3% (HHV) [47].
		112.30	Calculated from actual total water withdrawals and total electricity generation from coal power plants in the U.S. during 2006 [68].
	2.31	94.70	Based on the total water withdrawals for thermoelectric power plants in the U.S. and consumption coefficient calculated as a percentage from the daily withdrawals [69].
	1.8		Calculated from the total amount of water evaporated from thermoelectric power plants per kWh of end-use energy for all of the U.S. [15].
	0.38	98.48	Average values for all coal-fired power plants in the U.S. according to the NETL [7].
	1.17	88.74	Estimated from the actual total annual water demand and electricity generated by 675 MW subcritical Battle River coal-fired power plant in Alberta, Canada, with an assumed capacity factor of 90% [63,70].
	1.52		Average of a range for water use by cooling systems in the Missouri River Basin [71].
	1.24	**116.48**	**Average value assumed in this chapter for subcritical pulverized coal power plants using once-through cooling systems.**
	0.39	88.90	Median of supercritical pulverized coal for a wide range of studies harmonized originally at η =38.4% (HHV) with consumption coefficient range 0.25 – 0.47 L/kWh[47].

Cooling system type	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Comments and sources
	0.39	**88.90**	**Average value assumed in this chapter for supercritical pulverized coal power plants using once-through cooling systems.**
Closed-loop using cooling towers	2.20	2.75	Theoretical coefficients calculated from equations (2.3-2.5) at a = 80%, WT=80°F, η=35%, and C =5 [42].
	2.20	2.45	Theoretical coefficients calculated from equations (2.3-2.5) at a = 80%, WT=80°F, η =35%, and C =10 [42].
	2.60		Derived from Gleick [31] as consumptive use at η =35%.
	1.82	1.89	Based on cooling water demand for the U.S. at the cycle of concentration = 10 [14].
	1.82	2.27	Based on cooling water demand for the U.S. at the cycle of concentration = 5 [14].
	1.69		Typical evaporation from cooling systems for cold climate zone calculated theoretically for a 1000 MW power plant with η =35% and ΔT=18 °F [38].
	2.09		Typical evaporation from cooling systems for hot climate zone calculated theoretically for a 1000MW power plant with η =35% and ΔT=18 °F [38].
	1.70	2.05	Average values for all coal-fired power plants in the U.S. using recirculating cooling systems according to NETL[7].
	1.95	2.43	Median of subcritical pulverized coal for a wide range of studies harmonized at η =34.3% (HHV) [47].
	2.27		Average of a range for water use by cooling systems in the Missouri River Basin [71].
	1.82	2.31	Baseline established by the DOE/NETL [72] for water use by subcritical pulverized coal power plants using wet recirculating cooling systems.
	2.01	**2.31**	**Average value assumed in this chapter for subcritical pulverized coal power plants using the cooling tower.**
	1.61	2.90	Estimated from actual total water demand and electricity generated by a new 450 MW supercritical power plant located at Keephills, Alberta, Canada with an assumed capacity factor of 90% [9,65].

Cooling system type	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Comments and sources
	1.93	2.31	Median of supercritical pulverized coal for a wide range of studies harmonized originally at η =38.4% (HHV) [47].
	1.30	1.48	Proposed supercritical MAXIM power plant to be located near Grande Cache, Alberta, Canada [66].
	1.59	2.08	Baseline established by the DOE/NETL[72] for water use by supercritical pulverized coal power plants using wet recirculating cooling systems.
	1.61	**2.19**	**Average value assumed for supercritical pulverized coal power plants using cooling tower in this chapter.**
	1.14	1.52	Baseline established by the DOE/NETL [72] for water use by IGCC power plants using wet recirculating cooling systems.
	0.93	1.13	Median for a wide range of studies harmonized originally at η =38.5% (HHV) for IGCC [47]. Again re-harmonized here at η =45% (HHV).
	1.04	**1.33**	**Average value assumed for IGCC power plants using cooling tower in this chapter.**
Closed-loop using cooling ponds	1.02	1.14	Based on cooling water demand for the U.S. at C =10 [14].
	1.89	2.27	Based on cooling water demand for the U.S. at C = 5 [14].
	3.38		Calculated as stated by Gleick [31]: 30% higher than the corresponding wet cooling towers.
	2.02	3.25	Estimated from actual total water demand and electricity generated by subcritical coal power plants (Genesee's G1&G2) located in Alberta, Canada [59,64].
	1.47	2.63	Based on the projected evaporation from the cooling pond from the three units (G1, G2, & G3) at Genesee's coal power plants in Alberta, Canada [9].
	1.66	2.37	Estimated from actual water demand and electricity generated by two units (1 & 2) of a 766 MW subcritical Keephills coal power plant located in Alberta, Canada [60]. A capacity factor of 90% is assumed.

Cooling system type	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Comments and sources
	1.04	1.23	Estimated from actual water demand and electricity generated by six units of a 2126 MW subcritical Sundance coal power plant located in Alberta, Canada [61]. A capacity factor of 90% is assumed.
	1.79	3.41	Estimated from actual water demand and electricity generated by two units of subcritical Sheerness coal power plant located in Alberta, Canada [62].
	2.24		Average water consumption for power plants operated by TransAlta in Alberta, Canada. Based on the total MWh generated, operated power plants include 72% from coal and the rest 28% from natural gas, hydro, and wind [73].
	3.03		Average of a range for water use by cooling systems in Missouri River Basin [71].
	1.95	**2.33**	**Average value assumed for subcritical pulverized coal power plants using cooling pond in this chapter.**
	0.88	1.60	Estimated from the expected total water demand and electricity generated by Genesee's supercritical coal power plant (G3) located in Alberta, Canada [9,74,75].
	0.88	**1.60**	**Average value assumed in this chapter for supercritical pulverized coal power plants using cooling ponds.**

Table 2.4: Ranges of consumption and withdrawals coefficients for power generation stage from coal

Pathway	Consumption coefficient (L/kWh)			Withdrawals coefficient (L/kWh)		
	Min.	**Average**	**Max.**	**Min.**	**Average**	**Max.**
Subcritical with once-through cooling	0.38	1.24	2.31	75.76	116.48	189.39
Subcritical with cooling tower	1.69	2.01	2.60	1.89	2.31	2.75
Subcritical with cooling pond	1.02	1.95	3.38	1.14	2.33	3.41
Subcritical with dry cooling	0.17	0.20	0.26	0.19	0.23	0.28
Supercritical with once-through cooling	0.25	0.39	0.47	88.90	88.90	88.90
Supercritical with cooling tower	1.30	1.61	1.93	1.48	2.19	2.90
Supercritical with cooling pond	0.88	0.88	0.88	1.60	1.60	1.60
Supercritical with dry cooling	0.13	0.16	0.19	0.15	0.22	0.29
Ultra-supercritical with cooling tower	1.04	1.26	1.58	1.18	1.58	1.99
Ultra-supercritical with dry cooling	0.10	0.13	0.16	0.12	0.16	0.20
IGCC with cooling tower	0.93	1.04	1.14	1.13	1.33	1.52
IGCC with dry cooling	0.09	0.10	0.11	0.11	0.13	0.15

2.4 Results and discussion

Figure 2.2 shows the results for water consumption coefficients of complete upstream coal processing pathways. The obtained coefficients are affected negatively by slurry pipeline transportation followed by underground mining, and slight effect results from revegetation for surface mining.

Based on the boundary set in this chapter and data gathered from the literature, general water demand coefficients that include consumption and withdrawals were developed for the power generation life cycle and are shown in Figure 2.3. Yang and Dziegielewski [76] found that cooling towers consume on average around 1 L/kWh (0.26 gallon per kWh) more water than the once-through cooling systems. From Figure 2.3, the corresponding difference in average water consumption for subcritical power plants is 0.77 L/kWh (0.20 gallon per kWh) and for supercritical power plants is 1.22 L/kWh (0.32 gallon per kWh). Moreover, Yang and Dziegielewski [76] concluded that on average, more than 150 L/kWh (39.6 gallons per kWh) in withdrawals could be saved if cooling towers replaced once-through cooling systems. The corresponding estimation from Figure 2.3 shows the same difference is 114 L/kWh (30.0 gallons per kWh) for subcritical power plants and 87 L/kWh (23.0 gallon per kWh) for supercritical power plants. The difference between two results is mainly due to the fact that Yang and Dziegielewski [76] based their work on the database of the U.S. thermoelectric power plants burning coal, petroleum, natural gas, and nuclear, while this chapter estimated generic coefficients for coal-based power plants with the consideration for the different generation technologies.

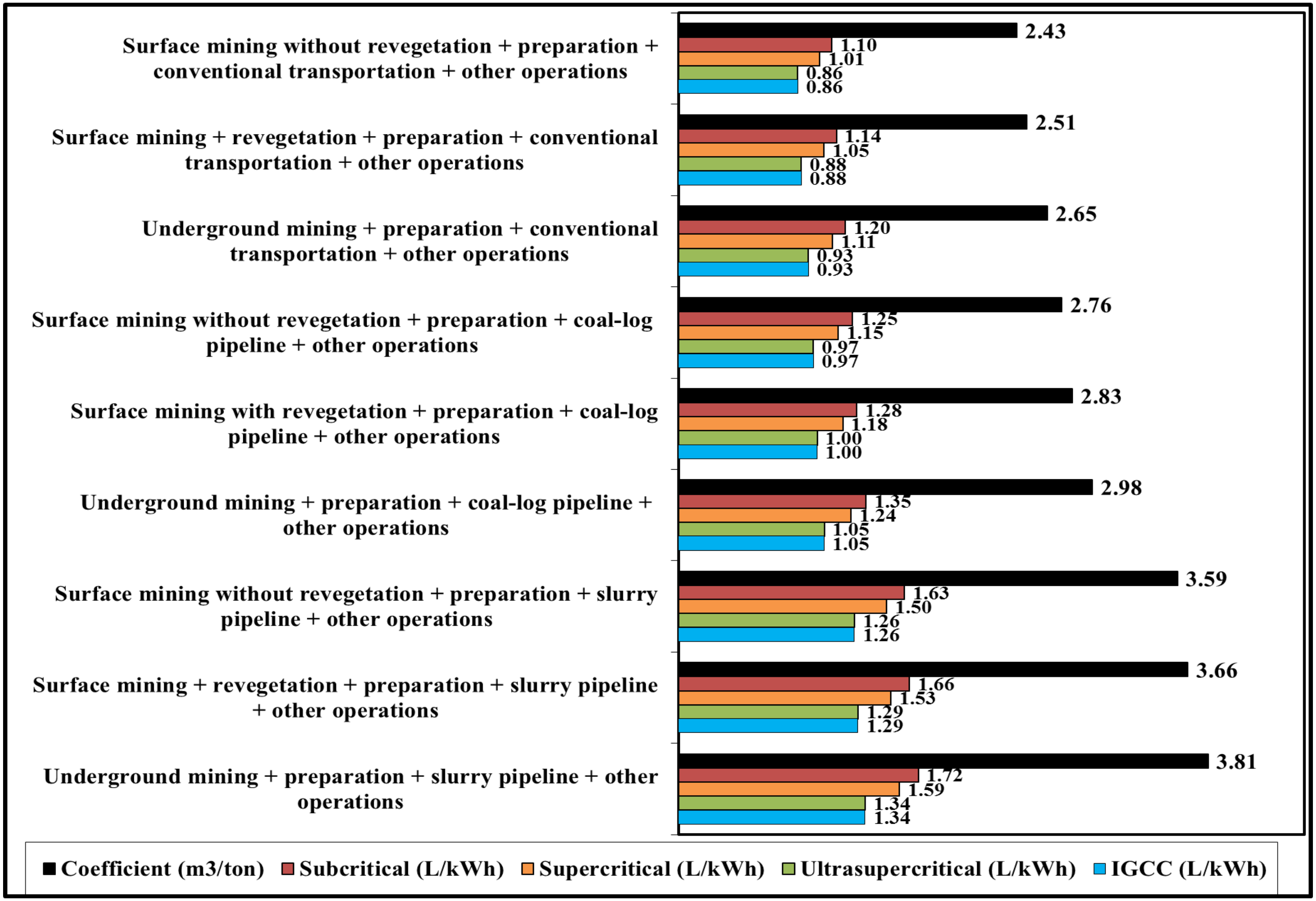

Figure 2.2: Water consumption coefficients for coal upstream stage

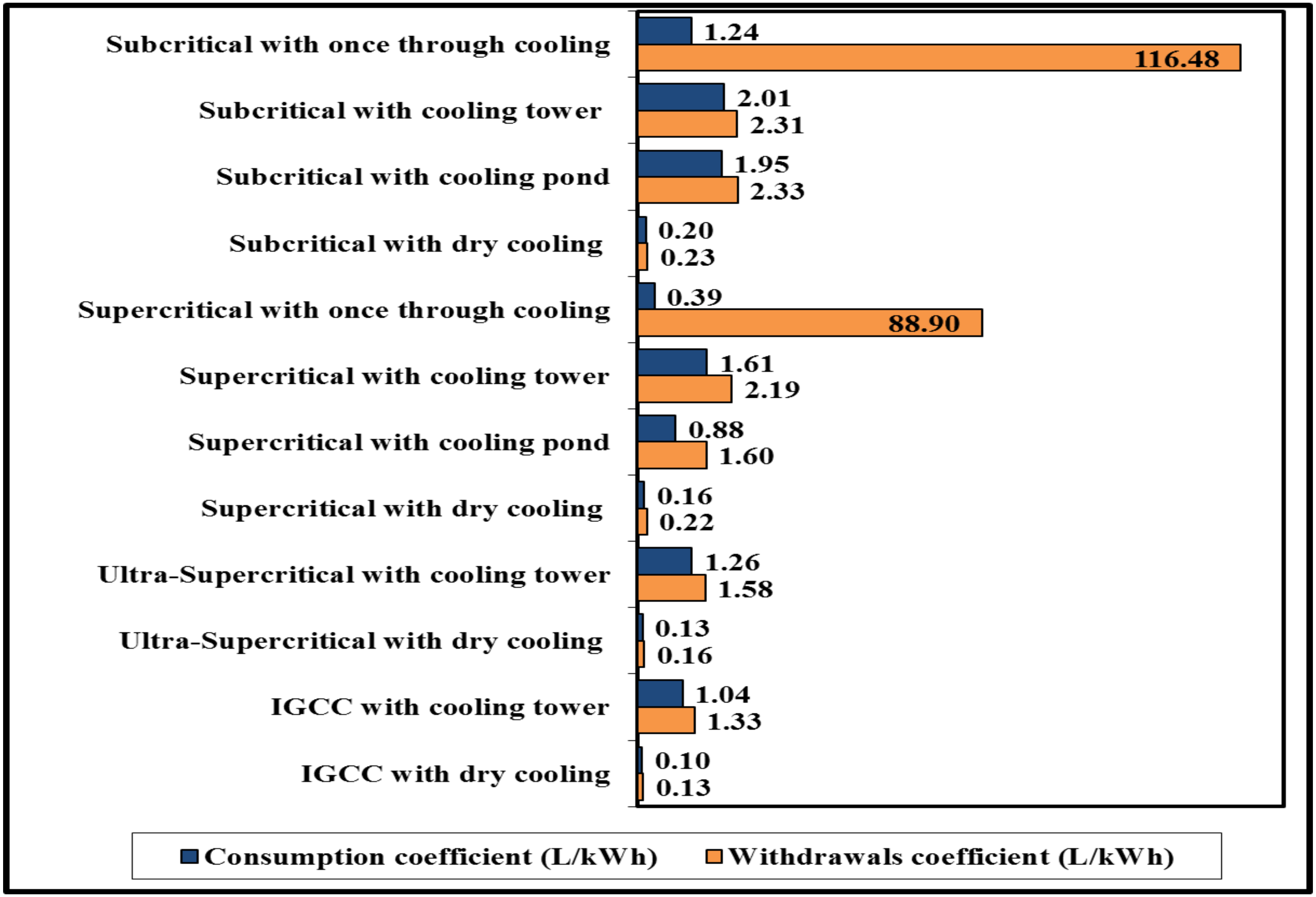

Figure 2.3: Water demand coefficients for the stage of power generation from coal

Coal upstream and power generation stages (Figure 2.2 and Figure 2.3) are combined to give the results shown in Table 2.5. These combined coefficients represent benchmarks for generic water demand coefficients associated with the type of coal mining, power generation technology, and cooling system used. Other conversion efficiencies and unconventional transportation by pipeline are studied in the sensitivity analysis to reflect the impact on water demand coefficient for each pathway.

The lowest water consumption coefficient based on the complete life cycle is obtained through surface mining without revegetating, transporting coal by a conventional method, and using IGCC technology and a dry cooling system. New coal-firing technologies such as IGCC and ultra-supercritical have higher conversion efficiencies and consequently lower water requirements during both the fuel life cycle and power generation stages. Pathways involving IGCC have lower water demand coefficients due to the fact that in combined cycle only about one-third of the electricity generated is by Rankine-cycle and the rest two third is generated by gas turbines which need less water for cooling [9].

Table 2.5: Water demand coefficients for complete life cycle of coal-based power generation pathways

No.	Pathway	Conventional transportation		Coal log pipeline		Coal slurry pipeline	
		Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)
1	Surface mining with revegetation-Subcritical-Once through cooling	2.376	117.616	2.523	117.763	2.899	118.139
2	Surface mining with revegetation-Subcritical-Cooling tower	3.146	3.446	3.293	3.593	3.669	3.969
3	Surface mining with revegetation-Subcritical-Cooling pond	3.086	3.466	3.233	3.613	3.609	3.989
4	Surface mining with revegetation-Subcritical-Dry cooling	1.337	1.367	1.484	1.514	1.860	1.890
5	Surface mining without revegetation-Subcritical-Once through cooling	2.342	117.582	2.489	117.729	2.865	118.105
6	Surface mining without revegetation-Subcritical-Cooling tower	3.112	3.412	3.259	3.559	3.635	3.935
7	Surface mining without revegetation-Subcritical-Cooling pond	3.052	3.432	3.199	3.579	3.575	3.955
8	Surface mining without revegetation-Subcritical-Dry cooling	1.303	1.333	1.450	1.480	1.826	1.856
9	Underground mining-Subcritical-Once through Cooling	2.441	117.681	2.588	117.828	2.965	118.205

No.	Pathway	Conventional transportation		Coal log pipeline		Coal slurry pipeline	
		Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)
10	Underground mining-Subcritical-Cooling tower	3.211	3.511	3.358	3.658	3.735	4.035
11	Underground mining - Subcritical-Cooling pond	3.151	3.531	3.298	3.678	3.675	4.055
12	Underground mining - Subcritical-Dry cooling	1.402	1.432	1.549	1.579	1.926	1.956
13	Surface mining with revegetation-Supercritical-Once through cooling	1.436	89.946	1.572	90.082	1.918	90.428
14	Surface mining with revegetation-Supercritical-Cooling tower	2.656	3.236	2.792	3.372	3.138	3.718
15	Surface mining with revegetation-Supercritical-Cooling pond	1.927	2.648	2.063	2.784	2.409	3.130
16	Surface mining with revegetation-Supercritical-Dry cooling	1.207	1.265	1.343	1.401	1.689	1.747
17	Surface mining without revegetation-Supercritical-Once through cooling	1.405	89.915	1.540	90.050	1.887	90.397
18	Surface mining without revegetation-Supercritical-Cooling tower	2.625	3.205	2.760	3.340	3.107	3.687
19	Surface mining without vegetation-Supercritical-Cooling pond	1.896	2.617	2.031	2.752	2.378	3.099
20	Surface mining without revegetation-Supercritical-Dry cooling	1.176	1.234	1.311	1.369	1.658	1.716

No.	Pathway	Conventional transportation		Coal log pipeline		Coal slurry pipeline	
		Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)
21	Coal-Underground mining-Supercritical-Once through cooling	1.496	90.006	1.632	90.142	1.978	90.488
22	Coal-Underground mining-Supercritical-Cooling tower	2.716	3.296	2.852	3.432	3.198	3.778
23	Underground mining - Supercritical-Cooling pond	1.987	2.708	2.123	2.844	2.469	3.190
24	Underground mining - Supercritical-Dry cooling	1.267	1.325	1.403	1.461	1.749	1.807
25	Surface mining with revegetation-Ultra-supercritical-Cooling tower	2.143	2.463	2.258	2.578	2.550	2.870
26	Surface mining with revegetation-Ultra-supercritical-Dry cooling	1.009	1.041	1.124	1.156	1.416	1.448
27	Surface mining without revegetation-Ultra-supercritical-Cooling tower	2.117	2.437	2.231	2.551	2.524	2.844
28	Surface mining without revegetation-Ultra-supercritical-Dry cooling	0.983	1.015	1.097	1.129	1.390	1.422
29	Underground mining-Ultra-supercritical-Cooling tower	2.194	2.514	2.309	2.629	2.601	2.921
30	Underground mining-Ultra-supercritical-Dry cooling	1.060	1.092	1.175	1.207	1.467	1.499
31	Surface mining with revegetation-IGCC-Cooling tower	1.923	2.213	2.038	2.328	2.330	2.620

No.	Pathway	Conventional transportation		Coal log pipeline		Coal slurry pipeline	
		Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)
32	Surface mining with revegetation-IGCC-Dry cooling	0.987	1.016	1.102	1.131	1.394	1.423
33	Surface mining without revegetation-IGCC-Cooling tower	1.897	2.187	2.011	2.301	2.304	2.594
34	Surface mining without revegetation-IGCC-Dry cooling	0.961	0.990	1.075	1.104	1.368	1.397
35	Underground mining-IGCC-Cooling tower	1.974	2.264	2.089	2.379	2.381	2.671
36	Underground mining-IGCC-Dry cooling	1.038	1.067	1.153	1.182	1.445	1.474

2.5 Sensitivity analysis

2.5.1 Impact of power plant performance

The assumed conversion efficiency of the power plants as detailed in Table 2.1 is changed in the range 20%[50] to 50%[33] to study the impact of the performance on the water-demand coefficients of coal upstream pathways (Figure 2.4). The upper part of Figure 2.4 is dominated by the three pathways using the slurry pipeline as the means of transportation. This indicates that slurry pipeline transportation has the most negative effect on coal upstream pathways. For the pathways with the same unit operations and different only on the type of mining, underground mining has the most negative impact on water demand and affected the ranking. Within pathways using surface mining and with the same mode of transportation, revegetation is the most sensitive factor.

A factor of merit K1 in L/kWh is introduced to rank coal upstream pathways according to the water demand performance. The profile of the curves in Figure 2.4 follows the relationship:

$$\mathbf{WCUP = K1 * (1/ \eta)} \qquad \mathbf{(2.5)}$$

where: WCUP = Water consumption coefficient in L/kWh for coal upstream pathway

$$\mathbf{K1 = 3600}\ \text{(kJ/kWh)}\ \mathbf{*\ F1}\ \text{(L/tonne)}\ \mathbf{/\ H}\ \text{(kJ/tonne)} \qquad \mathbf{(2.6)}$$

where: F1 = Water consumption coefficient in litre of water per tonne of coal for upstream pathway as detailed in Table 2.2.

H = Heat content of coal as given in Table 2.1.

The lower the value of K1 (in L/kWh) is the better its performance is in terms of the water-demand coefficient. K1 values are given in the legend of Figure 2.4 for ranking of each coal upstream pathway.

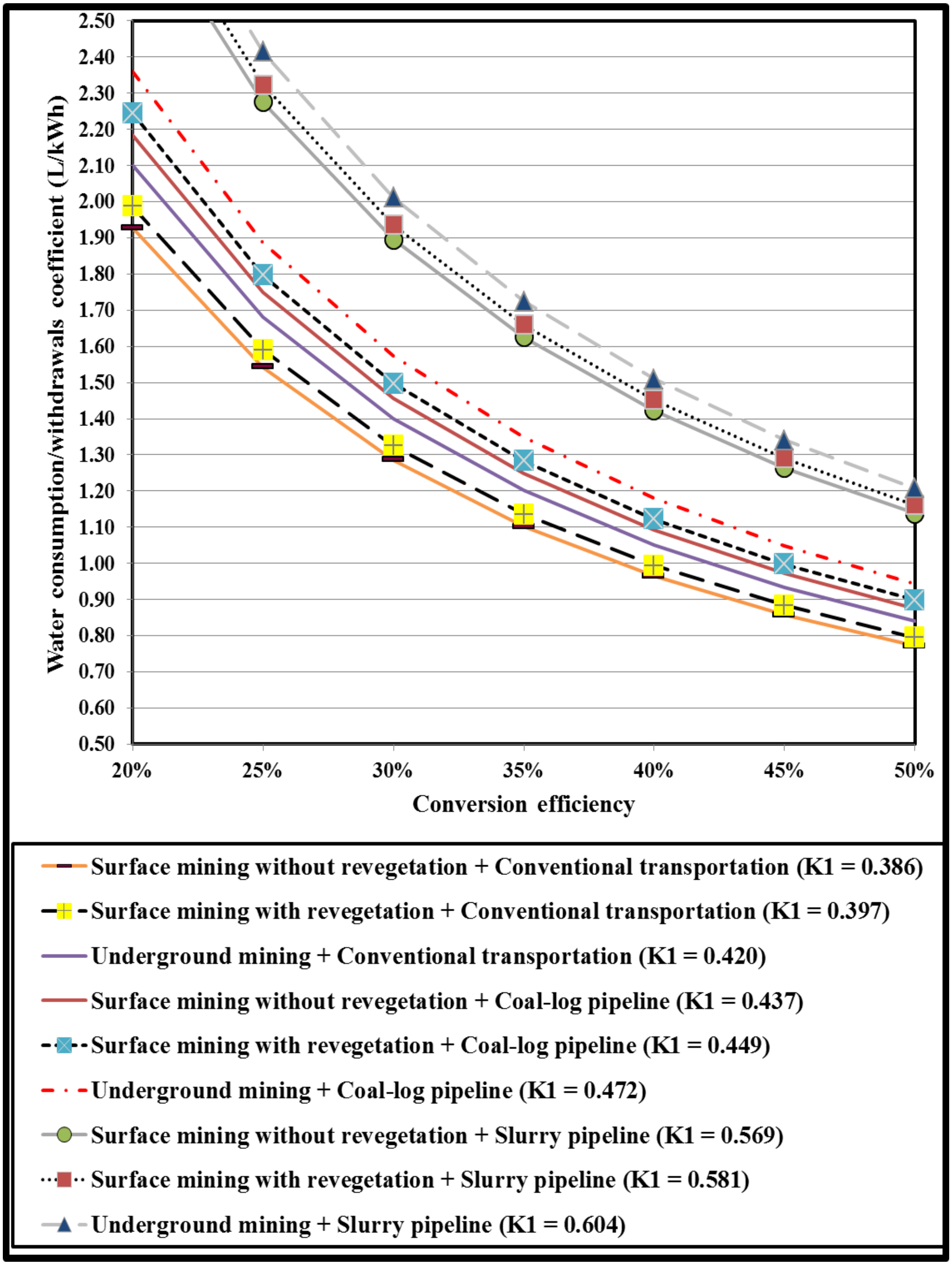

Figure 2.4: Performance curves for coal upstream pathways

The impact of conversion efficiency on water consumption coefficient during the power generation stage is shown in Figure 2.5. The water consumption coefficient (WCC) is correlated to the conversion efficiency (η) according to the associated water cooling type and parameters (included in equations (2.2), (2.3), and (2.4)) other than conversion efficiency terms are considered constants. K2 (in L/kWh) is assumed the constant to represent the factor of merit for water consumption during power generation stage. The value of K2 was determined after taken the average value for water consumption coefficient (WCC) from Table 2.3 with the corresponding conversion (η) efficiency from Table 1:

WCC = K2 *((1/ η) - 1) **(2.7)**

Lower values of K2 indicate the better performance of a pathway in terms of water consumption. From Figure 2.5, dry cooling outperforms followed by once-through cooling and cooling pond. Cooling tower systems have the lowest ranking with the highest value of K2=0.988 L/kWh.

The profile can give an indication to the decision maker whether to use existed conditions of the cooling system and level of performance or to change to better water use conditions. For example, a power plant (A) with 30% efficiency and using once-through cooling system has nearly the same water consumption coefficient of a power plant (B) with cooling tower system and conversion efficiency of 48%.

The water withdrawals coefficient (WWC) performance is shown in Table 2.6 through the same procedure of correlating to conversion efficiency through constant rate K3 (in L/kWh):

WWC = K3 *((1/ η) - 1) **(2.8)**

WWC can play the major role in the result of comparison between two power plants due to the fact that once-through cooling systems have a different negative impact on water withdrawals. The same power plant (A) withdraws more than 100 times the water withdrawals of power plant (B), which will significantly affect the final decision regarding the water use.

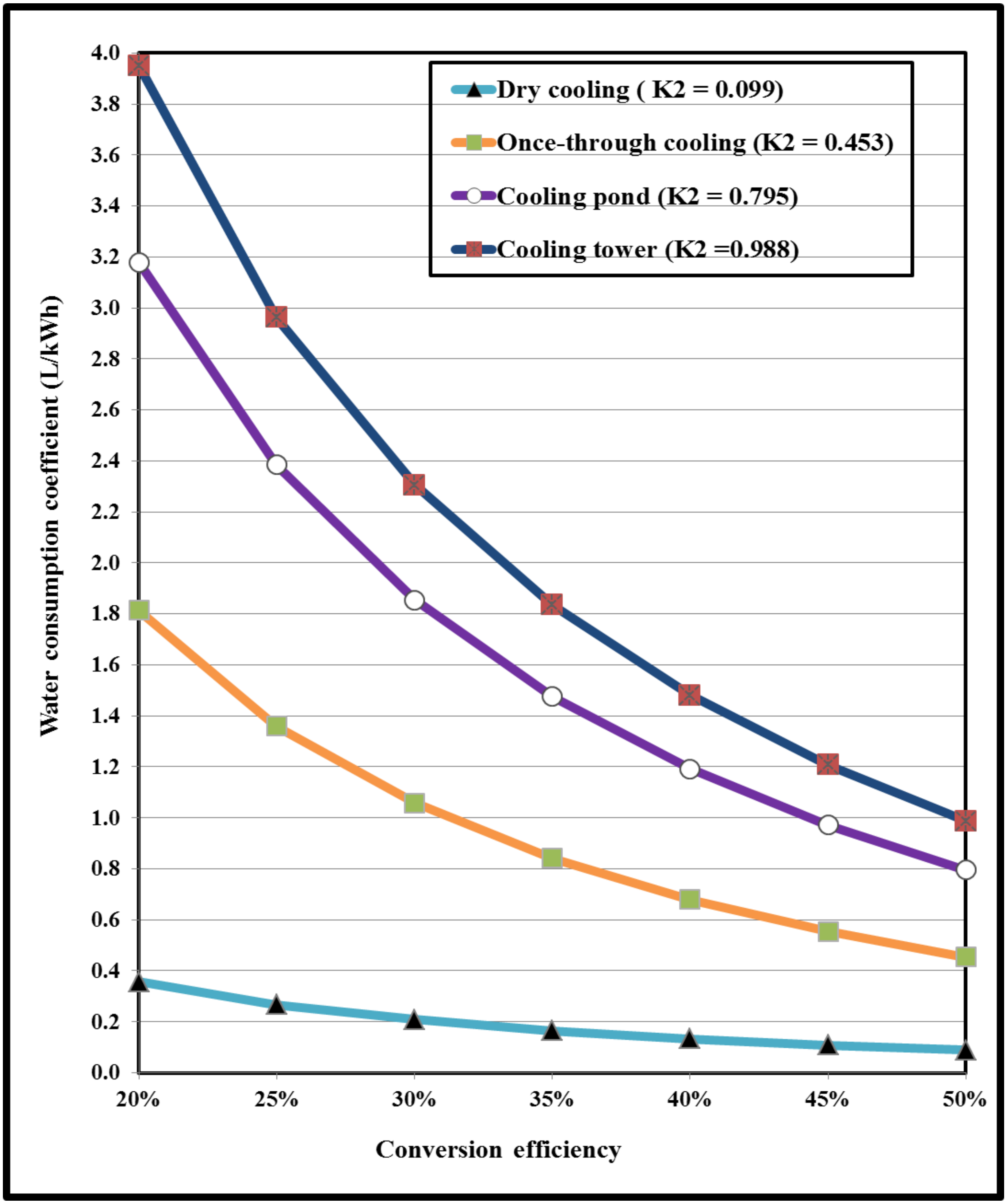

Figure 2.5: Performance curves for water consumption during power generation stage from coal

Table 2.6: Performance of cooling systems in water withdrawals during power generation stage from coal

Conversion efficiency	WWC for once-through cooling systems[a] (L/kWh)	WWC for cooling tower systems[b] (L/kWh)	WWC for cooling pond systems[a] (L/kWh)	WWC for Dry cooling systems[b] (L/kWh)
20%	234.41	4.97	4.47	0.50
25%	175.81	3.73	3.35	0.37
30%	136.74	2.90	2.61	0.29
35%	108.84	2.31	2.08	0.23
40%	87.91	1.86	1.68	0.19
45%	71.63	1.52	1.37	0.15
50%	58.60	1.24	1.12	0.12
K3 (L/kWh)	**58.60**	**1.24**	**1.12**	**0.12**

[a]The factor of merit K3 estimated as an average value from subcritical and supercritical water withdrawals coefficients at η =35% and η=38%, respectively.
[b]The factor of merit K3 estimated as an average value from subcritical, supercritical, ultra-supercritical, and IGCC water withdrawals coefficients at η =35%, η=38%, η=45%, and η=45%, respectively.

To obtain the water consumption coefficient (WCOMP) or withdrawals (WWCOMP) for the complete life cycle of a specific pathway, the two portions related to fuel cycle and power generation cycle can be added to conduct a better comparative assessment between different pathways:

$$\mathbf{WCOMP = K1 *(1/ \eta) + K2 *((1/ \eta) - 1)} \quad \mathbf{(2.9)}$$

$$\mathbf{WWCOMP = K1 *(1/ \eta) + K3 *((1/ \eta) - 1)} \quad \mathbf{(2.10)}$$

Equations (2.9) and (2.10) can be helpful in decision making to save water and compare between the cooling system used and the impact of improving the power plant performance. For example, a pathway using coal from underground mining transported conventionally and with cooling towers would have WCOMP 3.28 L/kWh and WWCOMP 3.79 L/kWh from equations (2.9) and (2.10) at conversion efficiency 33%. To improve the water demand coefficients of this pathway, shifting from cooling towers to cooling pond would give the same improvement results without shifting the cooling systems but instead increasing the conversion efficiency of the power plant to 36%.

2.5.2 Impact of coal transportation mode

To study the effects of unconventional transportation of coal on the water demand coefficients, conventional transportation is replaced by SP and CLP transportation. The effect on the total water demand of shifting from conventional transportation to pipelines depends mainly on the power plant's conversion efficiency. To shift from conventional transportation to SP for all subcritical technologies, 0.52 more L/kWh is consumed. The extra water consumption needed for supercritical, ultra-supercritical, and IGCC are 0.48, 0.41, and 0.41 L/kWh, respectively. To shift from conventional transportation to CLP and using ultra- supercritical or IGCC technology would increase the water consumption coefficient by 0.12 L/kWh.

Other extra values that resulted in the shift from conventional to pipeline transportation (both SP and CLP) are shown in Figure 2.6.

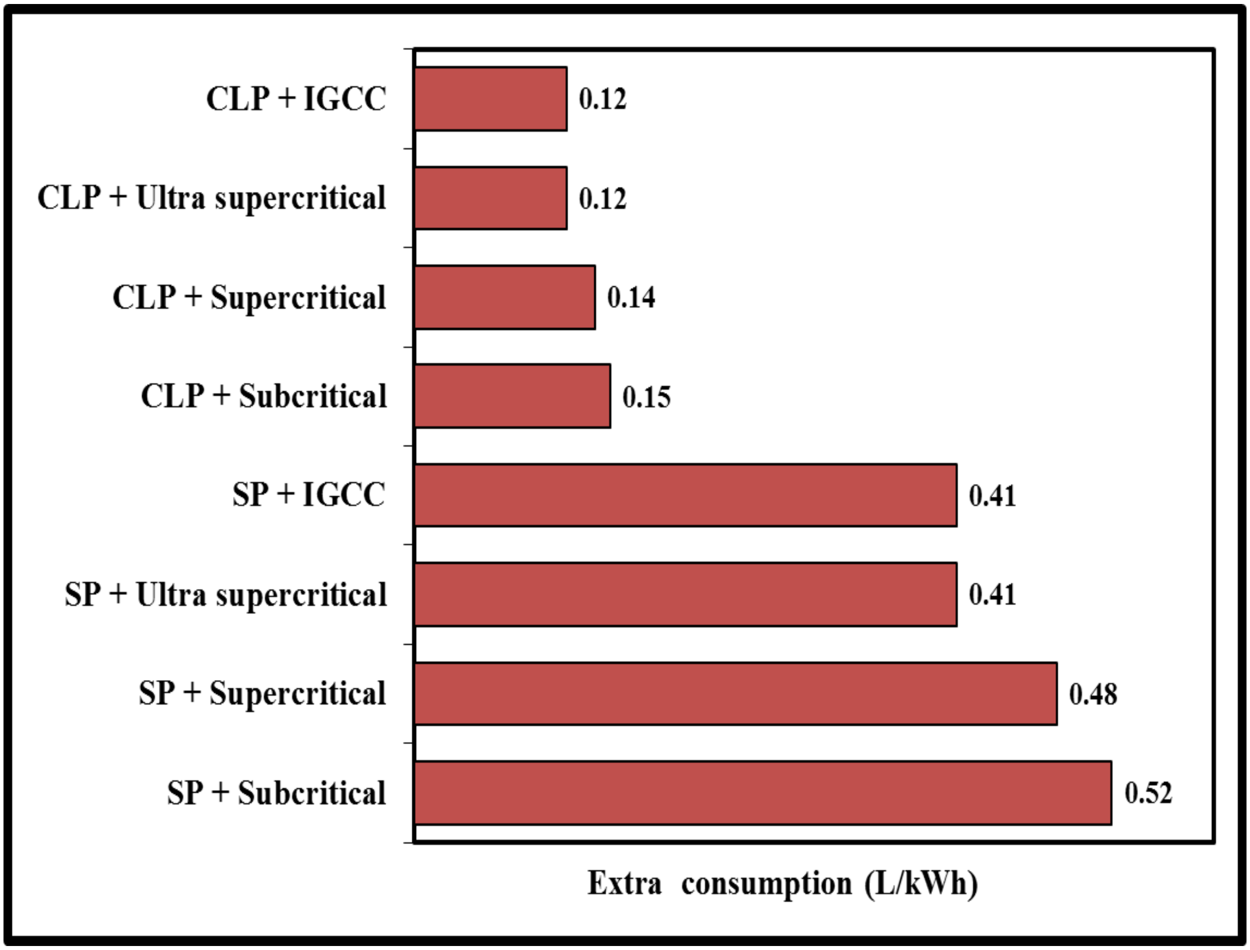

Figure 2.6: Extra water consumption coefficients resulting from changing conventional to pipeline transportation modes of coal

2.6 Conclusions

Water demand during the fuel life cycle is significant and should be taken into account when estimating the water required for the complete life cycle of coal-based power plants. Development of water coefficients for the complete life cycle based on unit operations and pathways can be used in management, modelling, and forecasting of water demand for coal power plants when combined with projections for productionof electricity. Improving the performance of coal-based power plants through new technologies, such as ultra supercritical and IGCC, would reduce water consumption during both electricity generation and the fuel life cycle due to the reduction in fuel used to generate the same amount of energy.

The key contribution of this chapter is the application of life cycle assessment (LCA) concept for comprehensive development of water coefficient for the coal power generation and the impact of power plant's performance on the water demand. There has been an estimation of the water consumption coefficient for only conversion of coal to power but there is very limited information on the integration of the water demand for different upstream and downstream unit operations.

Power generation pathways involving new technologies of integrated gasification combined cycle (IGCC) or ultra supercritical technology with coal transportation by conventional means and using dry cooling systems have the least complete life cycle water-demand coefficients of about 1 L/kWh. The water consumption coefficient over the life cycle of ultra supercritical or IGCC power plants are 0.12 L/kWh higher when conventional transportation of coal is replaced by coal-log pipeline. Similarly, if the conventional method of transportation of coal is replaced by its transportation in the form of a slurry through a pipeline, the consumption coefficient of a subcritical power plant increases by 0.52 L/kWh. Generally, unconventional transportation of coal increases water demand and their impact on total water use depends mainly on the conversion efficiency of the power generation. Dry cooling has the advantage of reducing water demand during power generation, although its application is accompanied with uncertain economic feasibility and technical performance. The scope of this study was focused on the United States and Canada and more regional analysis with recent data on water footprints for coal power generation would be helpful to reflect the new advancements in the technology.

References

[1]. U.S. Energy Information Administration (EIA). International Energy Outlook 2013. DOE/EIA-0484 (2013). July 2013. Available at: http://www.eia.gov/forecasts/ieo/pdf/0484%282013%29.pdf [accessed: 21.7.2015]

[2]. International Power Engineer Magazine. Focus on coal. Available at: http://www.engineerlive.com/Power-Engineer/Focus_on_Coal/Coal-fired_power_plants_capacity_to_grow_by_35_per_cent_in_next_10_years/21600/ [accessed: 28.07.2015]

[3]. National Energy Board (NEB). Energy briefing note: Coal-fired power generation: a perspective. July 2008. Available at: https://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/archive/clfrdpwrgnrtn2008/clfrdpwrgnrtn-eng.pdf [accessed: 29.07.2015]

[4]. Natural Resources Canada. Coal: other information: what is coal?. Available at: http://www.nrcan.gc.ca/mining-materials/markets/commodity-reviews/2012/14377 [accessed: 28.07.2015]

[5] World Coal Association. Uses of coal. Available at: http://www.worldcoal.org/coal/uses-of-coal/ [accessed: 23.07.2015]

[6] Government of Alberta. Energy: about coal. Available at: http://www.energy.alberta.ca/coal/645.asp [accessed: 29.07.2015]

[7]. Elcock D, Kuiper JA. Water vulnerabilities for existing coal-fired power plants. August 2010. DOE/NETL-2010/1429. Available at: http://www.ipd.anl.gov/anlpubs/2010/08/67687.pdf [accessed: 30.07.2015]

[8]. Statistics Canada. Industrial water use. Catalogue no. 16-401-X. 2009 Updated. Available at: http://www.statcan.gc.ca/pub/16-401-x/16-401-x2012001-eng.pdf [accessed: 24.07.2015]

[9]. Griffiths M, Woynillowicz D. Heating up in Alberta: climate change, energy development and water. The Pembina Institute, sustainable energy solutions, February 2009. Available at: http://pubs.pembina.org/reports/heating-up-in-alberta-report.pdf [accessed: 29.07.2015]

[10]. Alberta Environment. Current and future water use in Alberta. Prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007). Available at: www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf [accessed: 24.07.2015]

[11]. Stillwell AS, King CW, Webber ME, Duncan IJ, Hardberger A. The energy-water nexus in Texas. Ecology and Society 2011; 16(1): 2. Available at: http://www.ecologyandsociety.org/vol16/iss1/art2/ [accessed: 21.07.2015]

[12]. King CW, Webber ME. The water intensity of the plugged-in automotive economy. Environmental Science and Technology 2008; 42, 12: 4305-11.

[13]. Audrey Maheu. Energy choices and their impacts on demand for water resources: an assessment of current and projected water consumption in global energy production. UNISFERA International Centre Publications. November 2009.

[14]. Goldstein R, Smith W. Water & sustainability (Volume 3): U.S. water consumption for power production—The Next Half Century. Palo Alto, CA: EPRI; 2002. 1006786. Available at: http://www.circleofblue.org/waternews/wp-content/uploads/2010/08/EPRI-Volume-3.pdf [accessed 24.07.2015]

[15]. Torcellini P, Long N, Judkoff R. Consumptive water use for U.S. power production. Available at: http://www.nrel.gov/docs/fy04osti/35190.pdf [accessed 21.07.2015]

[16]. Stillwell AS, Clayton ME, Webber ME. Technical analysis of a river basin-based model of advanced power plant cooling technologies for mitigating water management challenges. Environmental Research Letters 2011; 6: 034015-26.

[17]. King C, Duncan I, Webber M. Water demand projections for power generation in Texas. Prepared for Texas Water Development Board. Available at: http://www.twdb.texas.gov/publications/reports/contracted_reports/doc/0704830756ThermoelectricWaterProjection.pdf [accessed: 29.07.2015]

[18]. Hermaine Nalbandian. Performance and risks of advanced pulverized-coal plants. Energeia 2009; 20 (1). Available at: http://www.caer.uky.edu/energeia/PDF/vol20_1.pdf [accessed: 21.07.2015]

[19]. National Energy Technology Laboratory (NETL). Subcritical pulverized bituminous coal plant. Available at: http://www.netl.doe.gov/KMD/cds/disk50/PC%20Plant%20Case_Subcritical_051507.pdf [accessed: 27.07.2015]

[20]. Pellegrini LF, Junior SO, Burbanoa JC. Supercritical steam cycles and biomass integrated gasification combined cycles for sugarcane mills. Energy 2010; 35: 1172-1180.

[21]. Paul I. Supercritical coal fired power plants: a technology being successfully deployed in developing countries. Energy Issues 1999; 19. Available at: http://documents.worldbank.org/curated/en/924431468740714825/pdf/multi-page.pdf [accessed: 29.07.2015]

[22]. William LS. The lure of ultra-supercritical: Exploring the future of coal-burning. ENERGYBIZ. September/October 2008. Available at:

http://energycentral.fileburst.com/EnergyBizOnline/2008-5-sep-oct/Tech_Frontier_Ultra-Supercritical.pdf [accessed: 30.07.2015]

[23]. International Energy Agency (IEA). Power generation from coal: measuring and reporting efficiency performance and CO_2 emissions. Available at: http://www.iea.org/publications/freepublications/publication/power_generation_from_coal.pdf [accessed: 30.07.2015]

[24]. Elcock D. Baseline and projected water demand data for energy and competing water use sectors. Report prepared for U.S Department of Energy. National Energy Technology Laboratory. Argonne National Laboratory. ANL/EVS/TM/08-8. Available at: http://www.acs.org/content/dam/acsorg/policy/acsonthehill/briefings/energywaternexus/11-08-anl-water-demand-for-energy-competing-sectors.pdf [accessed: 29.07.2015]

[25]. Kenny JF, Barber NL, Hutson SS, Linsey KS, Lovelace JK, Maupin MA. Estimated use of water in the United States in 2005. U.S. Geological Survey. Circular 1344. Available at: http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf [accessed: 30.07.2015]

[26]. Hermann FW. Types of coal mining. ILO Encyclopaedia of Occupational Health and Safety. Available at: http://www.iloencyclopaedia.org/component/k2/item/596-types-of-coal-mining [accessed: 23.07.2015]

[27]. Mick Barker. Underground coal mining: Understanding of process and techniques. BHP Billiton. Caroona Coal Project. Available at: http://www.bhpbilliton.com/home/society/regulatory/Documents/_coal/nswec/caroona/111205_coal_nswec_caroona_UndergroundCoalMiningPresentation.pdf [accessed: 22.07.2015]

[28]. World Coal Institute. Coal mining. Section two. Available at: http://www.worldcoal.org/bin/pdf/original_pdf_file/underground_and_surface_mining(01_06_2009).pdf [accessed: 29.07.2015]

[29]. Albrecht M, Matoney J. Introduction to coal preparation. Fourth Annual Symposium on Industrial Coal Utilization, DOE, Cincinnati, April 1982. Available at: http://www.albrechts.com/mike/articles/Introduction%20to%20Coal%20Preparation.pdf [accessed: 23.07.2015]

[30]. Coal Association of Canada. Rail, ports & terminals. Available at: http://www.coal.ca/transportation/ [accessed: 29.07.2015]

[31]. Peter H. Gleick. Water and Energy. Annual Review of Energy and Environment 1994; 19:267–299.

[32]. DiPietro P, Krulla K. Improving the efficiency of coal-fired power plants for near term greenhouse gas emissions reductions. National Energy Technology Laboratory (NETL). DOE/NETL -2010/1411. Available at: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2010-1411-ImpEfficCFPPGHGRdctns-0410.pdf [accessed: 22.07.2015]

[33]. International Energy Agency (IEA). Technology roadmap: high-efficiency, low-emissions coal-fired power generation. Available at: http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapHighEfficiencyLowEmissionsCoalFiredPowerGeneration_WEB_Updated_March2013.pdf [accessed: 24.07.2015]

[34]. Union of Concerned Scientists. Clean energy: how it works: water for power plant cooling. Available at: http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-cooling-power-plant.html#sources [accessed: 30.07.2015]

[35]. Merschmann P, Vasquez E, Szklo A, Schaeffer R. Modeling water use demands for thermoelectric power plants with CCS in selected Brazilian water basins. International Journal of Greenhouse Gas Control 2013; 13: 87-101.

[36]. Macknick J, Newmark R, Heath G, Hallett KC. Operational water consumption and withdrawals factors for electricity generating technologies: a review of existing literature. Environmental Research Letters 2012; 7: 045802-12.

[37]. National Energy Technology Laboratory (NETL). Estimating freshwater needs to meet future thermoelectric generation requirements. DOE/NETL-400/2009/1339. September 30, 2009. Available at: http://www.netl.doe.gov/File%20Library/Research/Coal/ewr/water/2009-Water-Needs-Analysis---Final--9-30-2009-.pdf [accessed: 27.07.2015]

[38]. El-Wakil MM. The circulating water system. In: Power plant technology. McGraw-Hill International Editions, Electrical and Mechanical Engineering Series; Singapore,1984, ISBN 0-07-019288-X, page 260-303.

[39]. U.S. Department of Energy. Energy demands on water resources: Report to Congress on the interdependency of energy and water. December 2006. Available at: http://powi.ca/wp-content/uploads/2012/12/Energy-Demands-on-Water-Resources-Report-to-Congress-2006.pdf [accessed: 27.07.2015]

[40]. Electric Power Research Institute. At the power plant. EPRI Journal, summer 2007. California. Available at: http://mydocs.epri.com/docs/CorporateDocuments/EPRI_Journal/2007-Summer/1015362.pdf [accessed: 30.07.2015]

[41] Backus CE, Brown ML. Water requirements for solar energy. In: Gloyna EF, Woodson HH, and Drew HR, editors. Water Management for the Electric Power Industry, Water Resources Symposium #8, Center for Research in Water Resources, The University of Texas at Austin; 1975, 270-279.

[42]. Croley TE, Patel VC, Cheng MS. The water and total optimization of wet and dry-wet cooling towers for electric power plants. Iowa Institute of Hydraulic Research Report No. 163. The University of Iowa, Iowa City, Iowa, January,1975.

[43]. Union of Concerned Scientists. Clean Energy. How it works: water for coal. Available at: http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-coal.html#sources [accessed: 21.07.2015]

[44]. US Department of Energy (DOE). Concentrating solar power commercial application study: Reducing water consumption of concentrating solar power electricity generation Report to Congress. (Washington, DC). Available at: http://www1.eere.energy.gov/solar/pdfs/csp_water_study.pdf [accessed: 21.07.2015]

[45]. Zhai H, Rubin E. Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage. Energy Policy 2010; 38 5653–60.

[46]. World Nuclear Association. Cooling power plants. Available at: http://www.world-nuclear.org/info/cooling_power_plants_inf121.html#_ftn10 [accessed: 29.07.2015]

[47]. Meldrum J, Anderson S, Heath G, Macknick J. Life cycle water use for electricity generation: a review and harmonization of literature estimates. Environmental Research Letters 2013; 8, 015031 (18pp).

[48]. King CW, Webber ME. Water intensity of transportation. Environmental Science and Technology 2008; 42, 7866-72.

[49]. U.S Energy Information Administration (EIA). Frequently asked questions: what is the average heat content of U.S. coal?. Available at: http://www.eia.gov/tools/faqs/faq.cfm?id=72&t=2 [accessed: 21.07.2015]

[50]. Miller D, Chorel M. A Study on the efficiency of Alberta's electrical supply system. project # CASA-EEEC-02-04. For Clean Air Strategic Alliance (CASA). October 2004. Available at: http://www.hme.ca/reports/CASA_Report_--_The_Efficiency_of_Alberta's_Electrical_Supply_System_EEEC-02-04.pdf [accessed: 27.07.2015]

[51]. Berkley M, Cruz E, Vatanakul M, Hynes R, Stickler A. Innovation avenues for coal derived power essential for the future. XXIst World Energy Congress, Montreal, September 12-16, 2010. Available at: http://www.indiaenergycongress.in/montreal/library/pdf/290.pdf [accessed: 27.07.2015]

[52]. Weitzel PS. Steam generator for advanced ultra-supercritical power plants 700 to 760C. ASME 2011 Power Conference, Denver, Colorado, U.S.A., July 12-14, 2011. Available at: http://www.babcock.com/library/documents/br-1852.pdf [accessed: 29.07.2015]

[53]. Matthias Fripp. Life-cycle greenhouse gas emissions from clean coal, clean gas and wind generators. Prepared for NextEra Energy Resources. Juno Beach, Florida. April 30, 2009. Available at: http://www.academia.edu/567349/Life-Cycle_Greenhouse_Gas_Emissions_From_Clean_Coal_Clean_Gas_and_Wind_Generators [accessed: 22.07.2015]

[54]. Wong R, Whittingham E. A comparison of combustion technologies for electricity generation. 2006 Update including a discussion in carbon capture and storage in Ontario context. Available at: http://pubs.pembina.org/reports/Combustion_CCS_Final.pdf [accessed: 22.07.2015]

[55]. Davison J. Performance and costs of power plants with capture and storage of CO_2. Energy 2007; 32, 1163-1176.

[56]. Spath PL, Mann MK, Kerr DR. Life cycle assessment of coal-fired power production. NREL/TP-570-2511. Available at: http://www.nrel.gov/docs/fy99osti/25119.pdf [accessed: 25.07.2015]

[57]. Kania JJ. Economics of coal transport by slurry pipeline versus unit train: a Case study. Energy economics 1984; 6, 2: 131-138.

[58]. Liu H, Marrero TR. Coal log pipeline technology: an overview. Powder Technology 1997; 94: 217-222.

[59]. EPCOR. 2003 Generating report: Genesee generating station (2004). Available at: http://www.corporateregister.com/a10723/epcor03-env-ca.pdf [accessed: 28.07.2015]

[60]. TransAlta. Report on annual water use diversion – 2009: Water supply from North Saskatchewan River to Keephills Generating Plant Interim License No. 11986, TransAlta, Keephills File 320-851.6.

[61]. TransAlta. 2009 Annual water use and return report: Water supply from North Saskatchewan River to Sundance generating plant License No. 146161 and 12086 (amendment No. 00037698-00-05), TransAlta, File No. 12245-A.

[62]. Martz LW, Bruneau JF, Rolfe JT. Climate change and water. SSRB Final technical report. Final Report April 2007. Available at: http://www.parc.ca/ssrb/SSRB_Final_Report.pdf [accessed: 25.07.2015]

[63]. Thompson J, Taylo P. Thermal power water use, needs, impacts & management. Available at:

http://www.battleriverwatershed.ca/sites/default/files/pdfs/forums/Water%20%26%20Power%20Generation.pdf [accessed: 29.07.2015]

[64]. Kindzierski W. Technical communications, CIV E 240 presentation. Department of Civil and Environmental Engineering. Available at: http://www.energyquest4nanticoke.ca/gen3c.pdf [accessed: 21.07.2015]

[65]. TransAlta Website. Facilities in development: Keephills-3. Available at: http://www.transalta.com/facilities/facilities-development/keephills-3 [accessed: 29.07.2015]

[66]. MAXIM Power Corp. Proposed HR Milner expansion project: public disclosure document. November 2007. Available at: http://esrd.alberta.ca/lands-forests/land-industrial/programs-and-services/environmental-assessment/documents/MaximPower_Milner_PDD.pdf [accessed: 25.07.2015]

[67]. Power Technology. Kogan Creek coal-fired power station, Queensland, Australia. key data. Available at: http://www.power-technology.com/projects/kogan/ [accessed: 29.07.2015]

[68]. Sovacool BK, Sovacool KE. Identifying future electricity–water tradeoffs in the United States. Energy Policy 2009; 37, 2763–73.

[69]. Hoffmann J, Feeley T, Carney B. DOE/NETL's Power plant water management R&D program—responding to emerging issues. Presentation at the 8th Electric Utilities Environmental Conference, Tucson, AZ, January 24-26, 2005. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/PPWaterMgt-EUEC-2005.pdf [accessed: 22.07.2015]

[70]. ATCO Website: Battle River coal-fired generating station. Available at: http://www.atcopower.com/Our-Facilities/Our-Power-Technologies/Coal-Fired-Thermal/Battle-River [accessed: 29.07.2015]

[71]. Georgianna TD, Haynes KE. Competition for water resources: coal and agriculture in the Yellowstone Basin. Economic Geography 1981; 57, 3, 225-37 Published by: Clark University.

[72]. Ciferno JP, Munson RK, Murphy JT, Lash BS. Determining carbon capture and sequestration's water demands. U.S. Department of Energy, National Energy Technology Laboratory and Leonardo Technologies Inc. Available at: http://www.powermag.com/determining-carbon-capture-and-sequestrations-water-demands/ [accessed: 28.07.2015]

[73]. TransAlta Website. The numbers. Available at: http://www.transalta.com/2009rs/our-performance/the-numbers/?phpMyAdmin=0ExjgFujJyNsQzdiavXlDMNMWD6 [accessed: 28.07.2015]

[74]. TransAlta Website. Plants in operation: Genesee 3. Available at: http://www.transalta.com/facilities/plants-operation/genesee-3 [accessed: 28.07.2015]

[75]. Acton J, Suzuki Y, Shimogori Y. 495-MW Capacity Genesee phase 3 project: The first supercritical pressure coal-fired boiler in Canada. Available at: http://www.hitachipowersystems.us/supportingdocs/forbus/hpsa/technical_papers/EP2005.pdf [accessed: 30.07.2015]

[76]. Yang X, Dziegielewski B. Water use by thermoelectric power plants in the United States. Journal of the American Water Resources Association (JAWRA) 2007; 43(1):160-69. DOI: 10.1111/j.1752-1688.2007.00013.x.

Chapter 3

Development of Water Demand Coefficients for Natural Gas Pathways[2]

3.1 Introduction

It is expected that natural gas production and demand will increase due to the diversity of its applications, well-established technologies of extraction and conversion, cost competitiveness, and attractiveness to environmentalists as a cleaner fuel than other fossil fuels. Natural gas with a lower carbon content emits less GHG compared to coal and oil on combustion. The water footprints for power generation from natural gas can be evaluated through the life cycle assessment (LCA) which is considered as a useful tool in the research community to conduct a comparative analysis of the environmental impacts [1].

In 2013 the production potential of natural gas in Alberta was 6.69 trillion cubic meters (tcm); the remaining established reserves were 0.96 tcm, total production was 0.096 tcm, including 0.048 tcm used locally, and the remaining 0.048 tcm was exported to other Canadian provinces and the U.S. Other unconventional gas resources in Alberta are coal-bed methane (CBM) and shale gas [2]. The production potential represents the ultimate recoverable natural gas in Alberta and the remaining established reserves represent the initial natural gas left after cumulative production.

Shale gas is one of the unconventional sources that have started to contribute significantly to the production of natural gas, and one of the largest shale gas resources in the U.S. is the Marcellus

---

[2] Complete paper was published as *Ali B, Kumar A. Development of life cycle water footprints for gas-fired power generation technologies. Energy Conversion and Management 2016; 110: 386–396.*

Shale with estimated reserves of 42.4 tcm [3]. Researchers, policymakers, and the public have raised concerns about the extraction of this unconventional gas and its environmental impact on water [3-5]. The annual natural gas production in Canada is expected to reach 0.21 tcm by 2025, and 40% of this production will be from unconventional gas [6].

Water use for electricity generation has been raised as a key issue and some power plants have been forced to shut down or reduce generation due to the water shortage [7,8].

The generation of power through natural gas is expected to increase because of its availability and its ability to compete with other fossil fuels and renewable sources of energy. It has been expected that by 2035 natural gas will overcome coal as the most used source for electricity generation in the world. [9]. Natural gas is also used for cooking, space heating, transportation, hydrogen production, and petrochemical industries, where it is converted to heat or used as a feedstock.

The unit operations associated with natural gas are those related to primary fuel extraction and processing. The impact on the water demand varies according to the natural gas source and the technologies used for processing and transportation. The type of technology and cooling system used for power generation from natural gas are essential unit operations in determining the amount of water required. Electricity can be generated from natural gas without the use of steam through a single cycle while combined cycle (NGCC), cogeneration, and the steam cycle necessitate the use of water for steam make-up and cooling [10-12].

Most studies carried out in the water-energy nexus consider only the power generation stage [13-15] without taking into account the fuel cycle, some recognize only water consumption without considering intensive water withdrawals for power generation stage [16-18], and comprehensive studies, including fuel life cycle water demand through detailed pathways, are scarce. Other than that, the broad effects of boundaries, technologies, and power plant's performance on the variability of water demand coefficients have not been captured through sensitivity analysis in earlier studies [19]. There has been a study on life cycle water demand on power generation from coal [20]. Grubert et al. [21] addressed natural gas and coal power generation through complete life cycle for the specific geographical boundary (Texas) and for a specific technology (NGCC).

One of the motivations to estimate water demand for the first stage of primary fuel extraction is due to the fact that the geographical location of natural gas resources is not controlled by humans, unlike the locations of power plants, which of necessity have to be located near a water source.

The aim of this chapter is to develop a life cycle water demand benchmark for power generation from natural gas. The key objectives of this chapter are to:

- Develop and estimate the life cycle water demand for gas-fired power generation including plants with advanced conversion technologies.
- Provide a comparative assessment of the water demand of twenty-six different pathways in the conversion of natural gas to power. Pathways were structured to cover the full life cycle based on the unit operations of the gas source, power generation technology, and cooling system used.
- Assess the impacts on the complete life cycle water demand coefficients from using minimum, maximum, and average coefficients of the different unit operations.

3.2 Scope and system boundary

Water demand coefficients include water consumption and water withdrawals as considered in chapter two and defined by the U.S Geological Survey (USGS) [22] are followed in this chapter. Natural gas is consumed either in power generation pathways or for heat and other applications. Effects on water demand due to conversion to heat and applications of natural gas other than power generation are not covered in this chapter, except in the case of cogeneration technology. Each pathway of electricity generation from natural gas consists of a number of unit operations. This includes unit operations for the production of natural gas, its processing, transportation and utilization of power production. Upstream pathways are divided according to the type of natural gas source. Power generation pathways are branched according to the unit operations that affect the water footprint significantly.

In this chapter, data were developed, gathered from the literature and harmonized at the assumed conversion efficiency for each technology. In the base case, average values for the data are used to represent water demand coefficients for the various upstream and downstream unit operations involved in power generation from natural gas. These developed water demand coefficients for each unit operations are used to estimate the complete life cycle water demand coefficient of gas-fired power generation. Only fresh water was considered in this chapter. A comprehensive sensitivity analysis is carried out in order to study the uncertainty of using average values in the base case on the complete life cycle water demand coefficients. The average data are taken as the most likely in Monte Carlo simulations model with the consideration of the minimum and maximum values. The unit operations and system boundary considered for this chapter are shown in Figure 3.1.

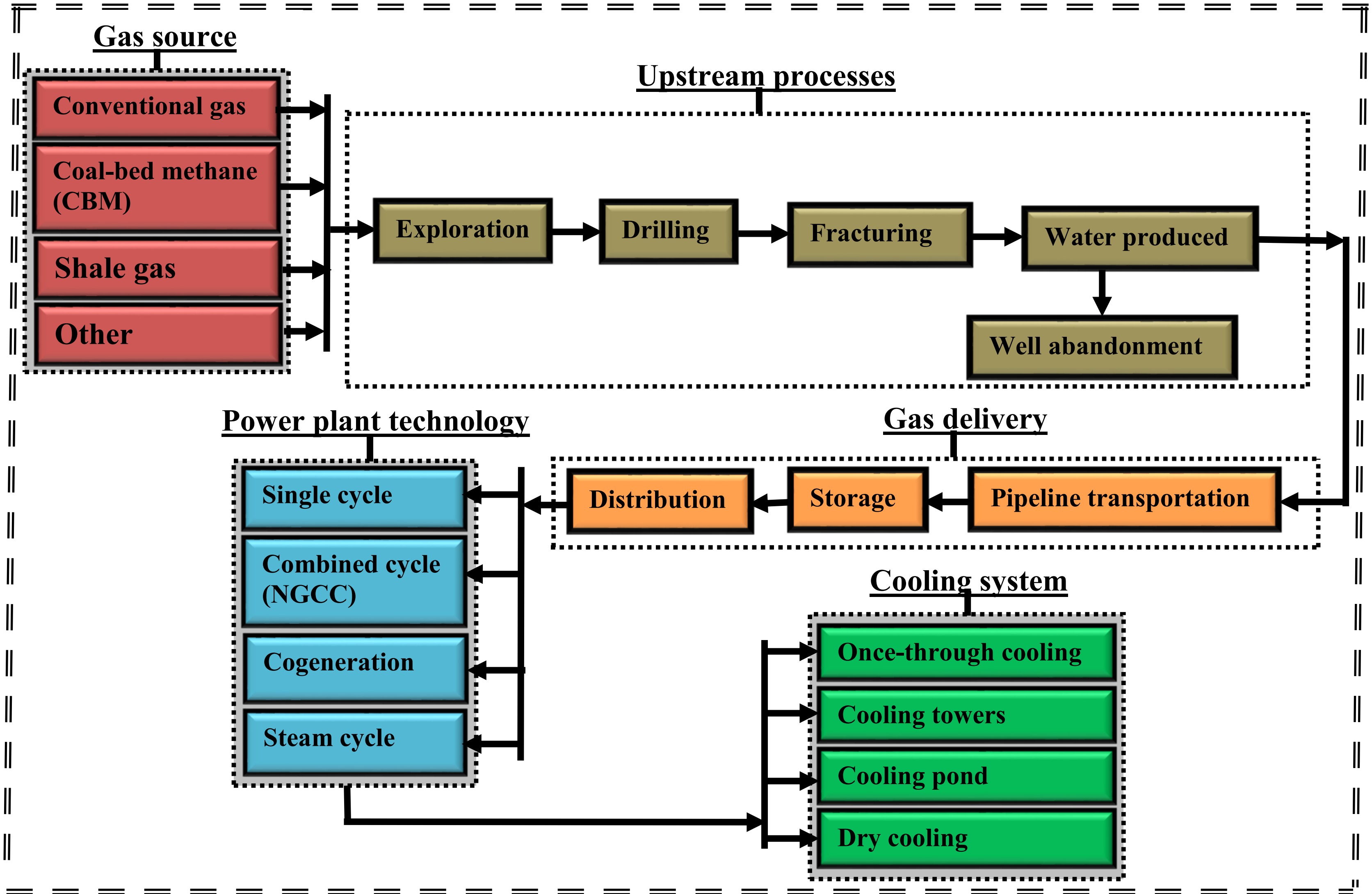

Figure 3.1: System boundary and unit operations for gas-fired power generation

3.2.1 Selection of gas-fired power generation pathways

Gas-fired power generation pathways are branched according to the technology and cooling system used. Technologies used to generate power from natural gas are single cycle, steam cycle, NGCC, and cogeneration. The same four types of cooling systems investigated in chapter two for coal power plants are considered in this chapter for gas-fired power generation.

Gas-fired power plants with single cycle work on the principle of the Brayton cycle by burning a mixture of pressurized air and fuel in a chamber. The exhaust gasses are expanded in the turbine, which spins to generate electricity and drive the compressor [10]. When the gas turbine reaches a high temperature, it needs to be cooled to improve the conversion efficiency. Wet compression, the injection of water into the compressor inlet, is one of the technologies used to improve the performance of gas turbine power plants [23]. Other technologies used to improve performance are evaporative cooling, fogging, mechanical cooling, absorption chillers, and thermal energy storage [23-26].

Gas-fired power plants can use steam as the working fluid, and the simplest, most practical plant using steam is based on the Rankine cycle. In this cycle, the boiler is fired by natural gas to generate steam that is supplied to the turbine to spin and generate electricity at a low conversion efficiency in the range of 33% to 35% [11]. The steam, after expanding in the turbine, is passed to the condenser and pumped back as water to the boiler [27]. The condensation of steam into water necessitates wet or dry cooling systems.

The efficiency of the single gas turbine can be improved significantly by incorporating the principles of the Rankine cycle [11] in combined cycle (NGCC) power plants. The exhaust gasses from the gas turbine are supplied to the heat recovery steam generator, which is a combination of the Brayton and Rankine cycles [28]. This combination of high and low-temperature cycles in the gas and steam turbines, respectively, make this technology one of the most effective in energy conversion [25]. Water is required both for the cooling systems used during the steam cycle and to improve performance in the gas turbine.

Cogeneration or combined heat and power (CHP) refers to the simultaneous production of electricity and thermal power from one source of energy [12]. This thermal power can be used for heating or cooling in different sectors such as industrial, commercial, or residential. The combined efficiency of the cogeneration power plant is higher than the efficiency of a single application for an electricity generation plant. Adding cogeneration to an existing electricity generation power plant can improve conversion efficiency from 45% to 80% [12, 29]. The major fuel used for cogeneration in the U.S. is natural gas [30], and district heating, of great concern to researchers, is one of the promising applications of cogeneration in which space heating and electricity generation are combined [30-32]. Cogeneration based on NGCC technology is considered in this chapter to be a significant improvement on plant performance.

3.2.2 Selection of natural gas upstream pathways

The upstream unit operations for the extraction of natural gas considered in this chapter includes processes and delivery. Processes have stages of exploration, drilling (drilling mud and casing), fracturing (stimulation), water produced (production), and well abandonment [33,34]. Delivery unit operations include gas transportation, through pipelines, storage, and distribution. Each stage in the system boundary has its own impact on the water footprints of the complete life cycle. The selection of upstream pathways for water footprints depends mainly on the type of natural gas resource, since the unit operation and equipment used may differ according to the type of natural gas. In this chapter, upstream pathways are initiated from resource types and include conventional, CBM, and shale gas. Other types of natural gas resources such as deep, tight, geo-pressurized, and Methane hydrates [35] are not considered in this chapter due to the limited data available for water footprints in these pathways.

The conversion efficiency (η) and higher heating value (HHV) in (MJ/m^3) are used to estimate the water demand coefficients (WDC) (includes water consumption and water withdrawals in L/kWh) for the upstream stage with respect to the unit of power to be generated:

$$\mathbf{WDC = 3600*COE/\ (HHV\ *\eta)} \tag{3.1}$$

In equation (3.1): 1 kWh = 3600 kJ is used for conversion and COE is the upstream water demand coefficient (water consumption and water withdrawals) in litres of water per cubic meter of gas (L/m^3).

3.3 Input data and assumptions

Table 3.1 shows the assumptions taken in this chapter for higher heating value (HHV) of natural gas and conversion efficiencies for different technologies of gas-fired power plants. Table 3.2 shows the minimum, maximum, and average water demand coefficients for the upstream stage and the assumptions of Table 3.1 are used to convert the average coefficients from L/m^3 to L/kWh using equation (3.1) for the analysis of the base case. The water consumption coefficient for gas upstream pathways is assumed to be equal to the water withdrawals coefficient [19], which indicates that no water is returned to the source after being diverted. The minimum water demand coefficients for the upstream stage are all assumed with no fresh water is consumed/ withdrawn and the required amount is fully satisfied from the produced water.

Table 3.1: Assumptions for natural gas and power plant characteristics

Items	Values	Comments/Sources
Higher heating value (HHV) of natural gas	38.2 MJ/m^3	Typical average heat content of natural gas delivered to consumers in the U.S. based on the period 2003-2011 [36]
Conversion efficiency of a single cycle power plant at HHV (η_{sc})	40%	Assumed based on literature [17,37,38]
Conversion efficiency of an NGCC power plant at HHV (η_{cc})	60%	Assumed based on literature [38-41]
Conversion efficiency of a cogeneration power plant at HHV (η_{cg})	75%	Assumed based on literature [12,19,37,42]
Conversion efficiency of a steam power plant at HHV (η_{st})	33%	Assumed based on literature [17,37,42]

Table 3.2: Ranges for water demand coefficients of natural gas upstream pathways

Pathway	Conventional gas (L/m^3)			Shale gas (L/m^3)			Coal bed methane (CBM) (L/m^3)			Comments/Sources
	Min.	**Average**	**Max.**	**Min.**	**Average**	**Max.**	**Min.**	**Average**	**Max.**	
Exploration	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	Assumed based on literature [16, 17, 19, 33].
Drilling	0.000	0.045	0.068	0.000	0.045	0.068	0.000	0.045	0.068	Assumed based on literature [17, 19,33,43].
Extraction	0.000	0.003	0.01	0.000	0.534	1.048	0.000	0.007	0.01	Assumed based on literature [16, 17, 19, 33, 43]. Hydraulic fracturing is included in this stage.
Processing	0.000	0.194	0.278	0.000	0.194	0.278	0.000	0.194	0.278	Assumed based on literature [16, 17, 19, 33] and the processing is the same for different types of gas sources.
Transport	0.000	0.115	0.139	0.000	0.115	0.139	0.000	0.115	0.139	Assumed based on literature [16, 17, 19, 33] and the transport is the same for the different types of gas sources.
Total	**0.000**	**0.357**	**0.495**	**0.000**	**0.888**	**1.533**	**0.000**	**0.361**	**0.495**	These ranges are to be used for the sensitivity analysis of the upstream stage.

The conversion efficiency of a natural gas combined cycle (NGCC) power plant (η_{cc}) is assumed to be 60%, for a single cycle (η_{sc}) 40%, and for the steam cycle (η_{st}) 33%. The assumed conversion efficiencies are related and should satisfy the following governing equation [44]:

$$\eta_{cc} = \eta_{sc} + \eta_{st} - \eta_{sc} * \eta_{st} \qquad (3.2)$$

With these conversion efficiencies, a gas turbine would generate two-thirds and a steam turbine would generate the remaining one-third of the total generated by an NGCC power plant [45]. Input data for the power generation stage as shown in Table 3.3 were gathered from literature and harmonized at the assumed conversion efficiency values.

Table 3.3: Input data for water demand coefficients during the power generation stage of gas-fired power plants

Cooling system type	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Comments and sources
Single cycle	0.04	0.04	Mentioned as "other use" to include water for gas turbine cooling, equipment washing, emission treatment, etc., by the U.S. DOE [46]. The withdrawals coefficient is assumed to be equal to the consumption coefficient.
	0.16	1.34	Median taken from Meldrum et al. [19], with a range 0.16-1.06 L/kWh for the consumption, and harmonized at η_{sc} =40%.
	0.14	0.14	Derived from Clark et al. [17] and harmonized at η_{sc} =40%.The withdrawals coefficient is assumed to be equal to the consumption coefficient.
	0.00	0.00	Mentioned as zero [47] or not specified in some studies [13, 14, 16, 43] and assumed to be zero in this chapter.
	0.09	**0.38**	**Average value used for the analysis in this chapter for single cycle.**
Steam cycle with once-through cooling	1.14	75.76	For U.S. thermal power plants based on ΔT= 30 °F (from Goldstein and Smith [14]).
	1.14	189.39	For U.S. thermal power plants based on ΔT=12 °F (from Goldstein and Smith [14]).
	1.57	157.35	Theoretical withdrawals coefficient calculated at η_{st} =33% and ΔT=20 °F [20] and consumption coefficient assumed to be 1% of the withdrawals (from Goldstein and Smith [14]).
	1.10	136.36	Median taken from Meldrum et al. [19] with the consumption range 0.72 – 1.55 L/kWh.
	0.91	132.58	Median taken from Macknick et al. [13] with the consumption range 0.36 – 1.10 L/kWh and withdrawals range 37.88 – 227.27 L/kWh.
	1.17	**138.29**	**Average value used for the analysis in this chapter for steam cycle using once-through cooling systems.**

Cooling system type	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Comments and sources
Steam cycle with closed-loop using cooling tower	1.82	1.89	Based on cooling water demand for the U.S. at a cycle of concentration =10 (from Goldstein and Smith [14]).
	1.82	2.27	Based on cooling water demand for the U.S. at a cycle of concentration = 5 (from Goldstein and Smith [14]).
	1.85	2.11	Typical evaporation from cooling systems for cold climate zones calculated theoretically for a 1000 MW power plant with η_{st} =33% and ΔT=18 °F [48]. Withdrawals coefficient calculated theoretically at a recycling turns =7[20].
	2.28	2.61	Typical evaporation from cooling systems for hot climate zones calculated theoretically for a 1000 MW power plant with η_{st} =33% and ΔT=18 °F [48]. Withdrawals coefficient calculated theoretically at a recycling turns =7[20].
	2.41	3.01	Theoretical coefficients calculated at a = 80%, WT=80°F, η_{st} =33%, and C =5 [20].
	2.41	2.68	Theoretical coefficients calculated from equations 3-5 at a = 80%, WT=80°F, η_{st} =33%, and C =10 [20].
	2.77	4.55	Median taken from Meldrum et al. [19] with the consumption range 2.12 – 4.17 L/kWh.
	2.13	2.43	Average used by [17] for analysis and harmonized at η_{st} =33%. Withdrawals coefficient calculated theoretically at a recycling turns =7[20].
	3.13	4.56	Median taken from Macknick et al. [13] with consumption range 2.51 – 4.43 L/kWh and withdrawals range 3.60 – 5.53 L/kWh.
	2.58	2.69	Estimated coefficients for Texas, U.S. [49].
	2.32	**2.88**	**Average value used for the analysis in this chapter for steam cycle using cooling tower systems.**

Cooling system type	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Comments and sources
Steam cycle with closed-loop using cooling pond	1.02	1.14	Based on cooling water demand for the U.S. at a cycle of concentration =10 (from Goldstein and Smith [14]).
	1.89	2.27	Based on cooling water demand for the U.S. at a cycle of concentration = 5 (from Goldstein and Smith [14]).
	1.02	1.71	Median for consumption coefficient taken from [19] and withdrawals coefficient calculated as average (from Goldstein and Smith [14]).
	3.09	3.81	Calculated as stated by Gleick [16]: 30% higher than the corresponding wet cooling towers.
	1.76	**2.23**	**Average value used for the analysis in this chapter for steam cycle using cooling pond systems.**
NGCC with once-through cooling	0.44	43.27	Based on the assumption that two-thirds of the total generation are from gas turbines and one-third from steam turbines.
	0.38	28.41	For U.S. thermal power plants based on ΔT= 30 °F (from Goldstein and Smith [14]).
	0.38	75.76	For U.S. thermal power plants based on ΔT=12 °F (from Goldstein and Smith [14]).
	0.22	15.71	Median value from Meldrum et al. [19] and harmonized at η_{cc} =60%[20].
	0.36	**40.79**	**Average value used for the analysis in this chapter for the NGCC cycle using once-through cooling systems.**
NGCC with closed-loop using cooling tower	0.85	1.23	Based on the assumption that two-thirds of the total generation are from gas turbines and one-third from steam turbines.
	0.41	0.64	Median value from Meldrum et al. [19] with consumption range 0.13 – 0.57 L/kWh, withdrawals range 0.47 – 1.52 L/kWh, and harmonized at η_{cc} =60%[20].

Cooling system type	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)	Comments and sources
	0.24		Derived from Clark et al. [17] and harmonized at η_{cc} =60%.
	0.78	0.97	Median taken from Macknick et al. [13] with the consumption range 0.49 – 1.14 L/kWh.
	0.87	0.98	Estimated coefficients for Texas, U.S. [49].
	0.63	**0.96**	**Average value used for the analysis in this chapter for the NGCC cycle using cooling tower systems.**
NGCC with closed loop using cooling pond	0.65	1.00	Based on the assumption that two-thirds of the total generation are from gas turbines and one-third from steam turbines.
	0.46		Median taken from Meldrum et al. [19] and harmonized at η_{cc} =60%[20].
	0.87	1.17	Calculated as stated by Gleick [16]: 30% higher than the corresponding wet cooling towers.
	0.66	**1.09**	**Average value used for the analysis in this chapter for NGCC using cooling pond systems.**

Table 3.4 gives the maximum and minimum ranges as well as the considered average values for water demand coefficients of the power generation stage. Cogeneration pathways are extrapolated from the related NGCC pathways with the conversion efficiency (η_{cg}) extended to 75%. The increase in the conversion efficiency of cogeneration technology is assumed to be from the steam cycle portion (η_{pst}), with its constant, single cycle performance at η_{sc}=40%.

The same assumption taken in chapter two for dry cooling that the total water demand is about one-tenth of wet re-circulating systems [50-52] is followed in this chapter.

Table 3.4: Ranges of water demand coefficients for the power generation stage from natural gas[a]

Pathway	Consumption coefficient (L/kWh)			Withdrawals coefficient (L/kWh)		
	Min.	**Average**	**Max.**	**Min.**	**Average**	**Max.**
Single cycle	0.00	0.09	1.06	0.00	0.38	1.34
Steam cycle with once-through cooling	0.36	1.17	1.57	37.88	138.29	227.27
Steam cycle with cooling tower	1.82	2.32	4.43	1.89	2.88	5.53
Steam cycle with cooling pond	1.02	1.76	3.09	1.14	2.23	3.81
Steam cycle with dry cooling	0.00	0.23	0.44	0.00	0.29	0.55
NGCC with once-through cooling	0.08[b]	0.36	0.44	15.71	40.79	75.76
NGCC with cooling tower	0.13	0.63	1.14	0.47	0.96	1.52
NGCC with cooling pond	0.46	0.66	0.87	1.00	1.09	1.17
NGCC with dry cooling	0.00	0.06	0.11	0.00	0.10	0.15
Cogeneration with once-through cooling	0.09	0.19	0.21	5.78	14.62	26.94
Cogeneration with cooling tower	0.1	0.28	0.46	0.41	0.58	0.78
Cogeneration with cooling pond	0.22	0.29	0.36	0.60	0.63	0.66
Cogeneration with dry cooling	0.00	0.03	0.05	0.00	0.06	0.08

[a]Ranges are based and abstracted from Table 3.3.
[b]Taken from Macknick et al. [13]
All minimum coefficients for dry cooling pathways are assumed with 0.00 L/kWh and
Ranges for cogeneration pathways are extrapolated from NGCC pathways

3.4 Results and discussion

3 .4.1 Water demand for the upstream stage

Equation (3.1), Table 3.1, and Table 3.2 were used to obtain the water demand coefficients for natural gas upstream processes as shown in Figure 3.2. The water footprint of this stage is determined mainly by the gas source and the performance of the power generation technology. The source affects the water demand through the unit operations, and the technology impacts the water demand through the amount of gas used to generate a specific unit of power. A considerable amount of water is required for hydraulic fracturing in the case of shale gas [17, 33], and a huge amount of water is produced during the extraction of coal-bed methane (CBM) [33, 53]. The amount of water required during the upstream stage does not depend only on the amount of water produced, but on the portion of that water recycled and re-injected, which has to be of a certain quality [54]. The more efficient power generation technology would consume less energy to produce a specific unit of power and consequently would use less natural gas and water. In this early stage of the gas production life cycle, a pathway through a CBM source using steam cycle would have a very close water demand coefficient (0.10 L/kWh) to a different pathway through a shale gas source using cogeneration (0.11 L/kWh). Although the two pathways have different gas sources, the final type of power generation technology with higher conversion efficiency would compensate for the extra water used during the fuel extraction stage. Pathways from the same power generation technology and using conventional gas or CBM have nearly the same water demand coefficient.

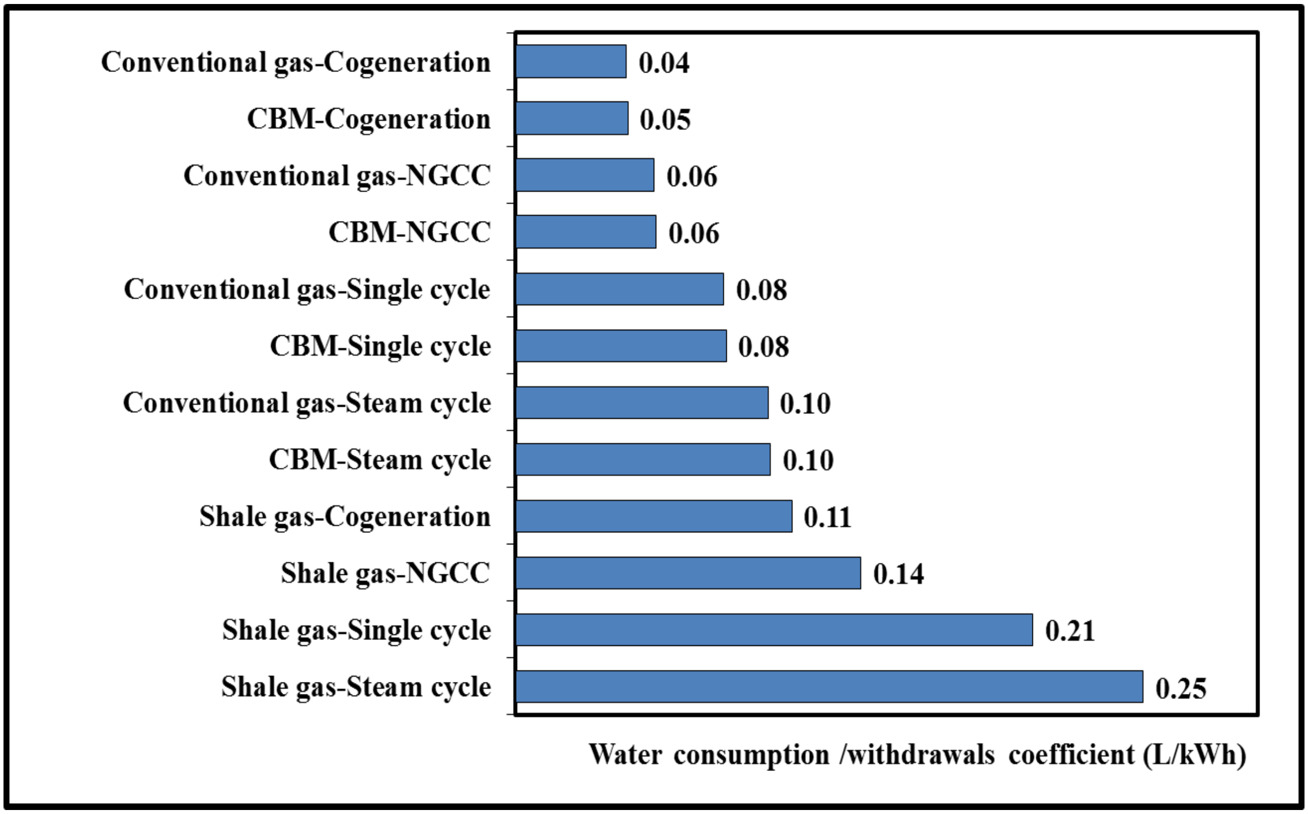

Figure 3.2: Water demand coefficients for the upstream stage of natural gas extraction

3.4.2 Water demand for the power generation stage

Figure 3.3 shows the water consumption and water withdrawals coefficients for the second stage of the power generation life cycle based on the average data shown in Table 3.4. The effect of the minimum and maximum values would be studied in the sensitivity analysis section. Besides the power generation technology, the most important water demand factor in this stage is the cooling system type. Dry cooling systems have very low water demand coefficients. Single-cycle power plants have low water demand coefficients in this stage because no condenser or steam is used. The conversion efficiency of the power generation technology in this second stage determines the level of water demand. The conversion efficiency of the power plant is important, and it affects the two stages of the life cycle (natural gas upstream stage and power generation stage).

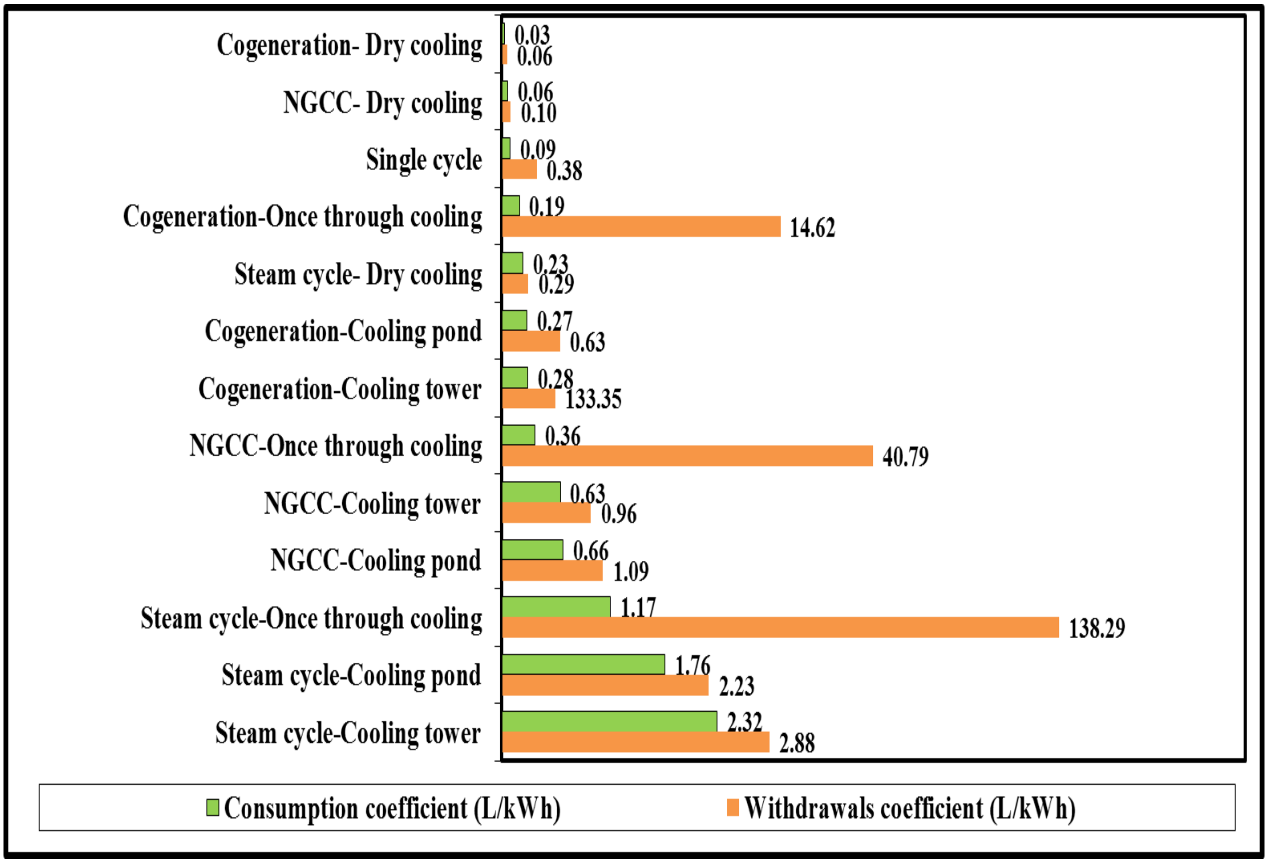

Figure 3.3: Water demand coefficients for the stage of power generation from natural gas

3.4.3 Water demand coefficients for the complete life cycle

Two stages of fuel extraction and power generation from natural gas, as detailed in Figures 3.2 and 3.3, are combined in Table 3.5 to give the water demand coefficients over the complete life cycle (because of the closeness of values for the natural gas and CBM are presented together in one line in Table 3.5). These combined coefficients represent benchmarks for generic water demand coefficients associated with the type of natural gas source, power generation technology, and cooling system.

The lowest water demand coefficients (0.07 L/kWh for consumption and 0.10 for withdrawals) are achieved through the pathway that uses conventional gas to generate power through cogeneration and dry cooling. These lowest coefficients are achieved due to the low water requirement for conventional gas and dry cooling, along with the highest conversion efficiency of cogeneration technology. The highest water consumption coefficient (2.57 L/kWh) is seen in the pathway that uses shale gas with a steam cycle and cooling tower. Ninety percent of this full life cycle-based coefficient is from the power generation stage and 10% from the gas upstream stage. Improving this technology's conversion efficiency is a solution to the intensive consumption of water in this pathway. A further improvement in NGCC technology efficiency would decrease the same highest water consumption coefficient by 70% to 0.77 L/kWh, and even this last coefficient could be improved 49% further to reach 0.39 L/kWh through cogeneration technology, so the total reduction in water consumption over the complete life cycle would be 85% (from 2.57 L/kWh to 0.39 L/kWh).

The once-through cooling system has the greatest impact on the water withdrawals coefficient, and, when considering the complete life cycle, all pathways using once-through cooling have more than 99% of water withdrawn during the power generation stage. On average and for the complete life cycle of all pathways that use once-through cooling systems, 1.26% of the water withdrawn is consumed. Based on the all developed pathways, water consumed for the power generation stage averaged 73% of the total life cycle consumption and the remaining 27% was consumed during the upstream fuel extraction stage. For water withdrawal, 85% is the average for the power generation stage and 15% for the upstream fuel extraction stage.

Table 3.5: Water demand coefficients for the complete life cycle of gas-fired power generation pathways

No.	Pathway	Consumption coefficient (L/kWh)	Withdrawals coefficient (L/kWh)
1	Conventional gas/CBM-Single cycle	0.17	0.46
2	Shale gas-Single cycle	0.30	0.59
3	Conventional gas/CBM-Steam cycle-Once-through	1.27	138.39
4	Conventional gas/CBM-Steam cycle-Cooling tower	2.42	2.98
5	Conventional gas/CBM-Steam cycle-Cooling pond	1.86	2.33
6	Conventional gas/CBM-Steam cycle-Dry cooling	0.33	0.39
7	Shale gas-Steam cycle-Once-through cooling	1.42	138.54
8	Shale gas-Steam cycle-Cooling tower	2.57	3.13
9	Shale gas-Steam cycle-Cooling pond	2.01	2.48
10	Shale gas-Steam cycle-Dry cooling	0.49	0.54
11	Conventional gas/CBM-NGCC-Once-through	0.42	40.85
12	Conventional gas/CBM-NGCC-Cooling tower	0.69	1.02
13	Conventional gas/CBM-NGCC-Cooling pond	0.72	1.15
14	Conventional gas/CBM-NGCC-Dry cooling	0.12	0.15
15	Shale gas-NGCC-Once-through cooling	0.50	40.93
16	Shale gas-NGCC-Cooling tower	0.77	1.10
17	Shale gas-NGCC-Cooling pond	0.80	1.23
18	Shale gas-NGCC-Dry cooling	0.20	0.24
19	Conventional gas/CBM-Cogeneration-Once-through	0.23	14.66
20	Conventional gas/CBM-Cogeneration-Cooling tower	0.32	0.62
21	Conventional gas/CBM-Cogeneration-Cooling pond	0.31	0.67
22	Conventional gas/CBM-Cogeneration-Dry cooling	0.07	0.10
23	Shale gas-Cogeneration-Once-through cooling	0.30	14.73
24	Shale gas-Cogeneration-Cooling tower	0.39	0.69
25	Shale gas-Cogeneration-Cooling pond	0.38	0.74
26	Shale gas-Cogeneration-Dry cooling	0.14	0.17

3.5 Sensitivity analysis

The average values of water demand coefficients assumed for the base case are taken as input with the associated minimum and maximum ranges in a model using Monte Carlo simulations to study the uncertainty of the obtained results. Triangle distribution is used through ModelRisk software [55] and the inputs for the upstream stage are based on Table 3.2 data and for the power generation stage are based on Table 3.4 data.

3.5.1 Upstream stage

Figure 3.4 shows the distribution of the probability percentiles results from Monte Carlo simulations for the water demand coefficients during the upstream stage. The considered average values for conventional gas (0.357 L/m^3), for CBM (0.361 L/m^3), and for shale gas (0.888 L/m^3) have probability percentiles of 72%, 73%, and 58%, respectively. The low probability for shale gas due to the wide variability in the gathered data and that the technology is still under development. The taken average values in the base case for conventional gas and CBM during the upstream stage are more certain and the range between minimum and maximum is narrower than the shale gas case.

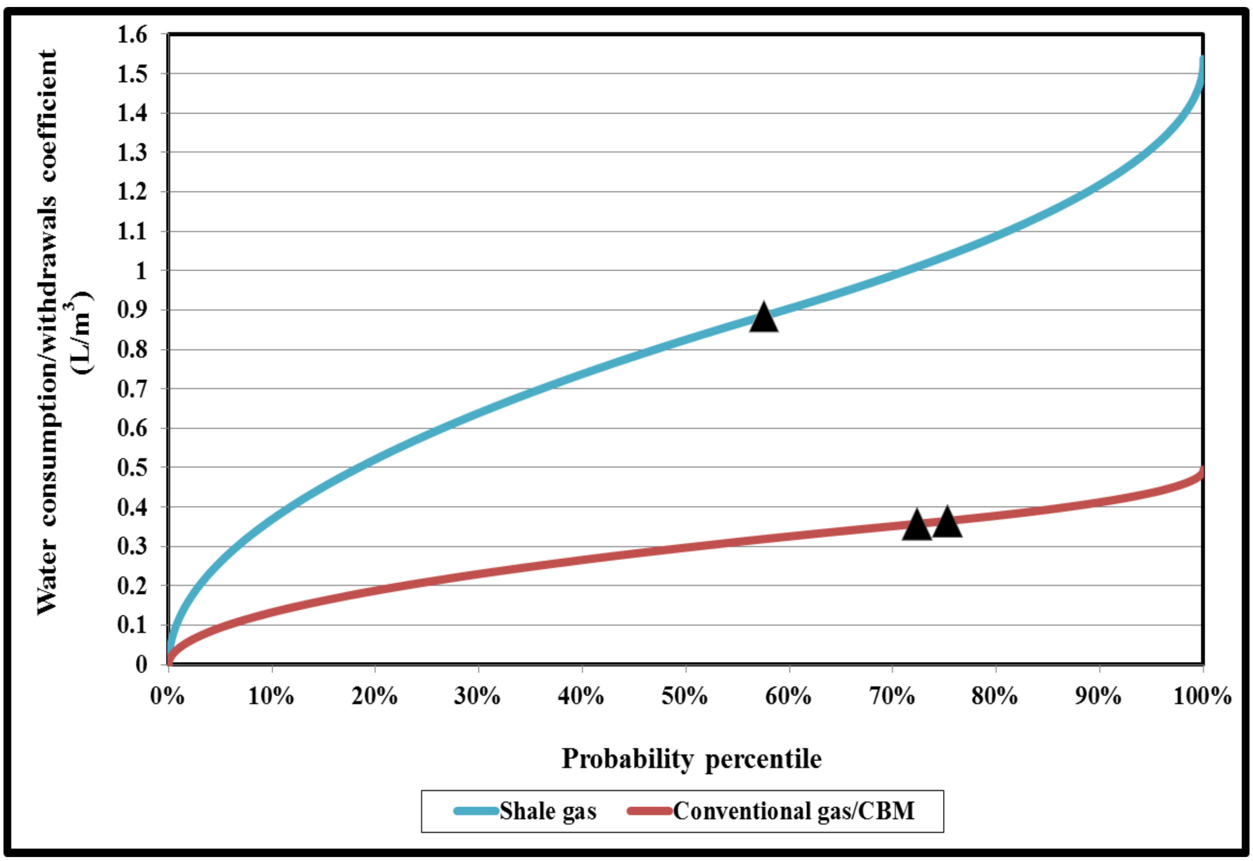

Figure 3.4: Distribution of water demand coefficients for natural gas upstream stage
▲ The most likely value and the accompanied probability is shown in graph for each gas source

3.5.2 Power generation stage

Distributions of water consumption coefficients during the power generation stage are shown in Figure 3.5 for pathways involving dry cooling, Figure 3.6 for pathways through NGCC, cogeneration, and single cycle and Figure 3.7 for steam cycle technology pathways. The lowest probability for the most likely value (0.09 L/kWh) is 9% for the consumption coefficient of single cycle. This most likely value has been taken closer to the minimum value (0.00 L/kWh) compared to the maximum (1.06 L/kWh) which is derived from Meldrum et al. [19] and led to this low probability. The most likely water consumption coefficient of cogeneration with once-through cooling (0.19 L/kWh) has been calculated from the gathered data and resulted in the highest probability percentile of 83%.

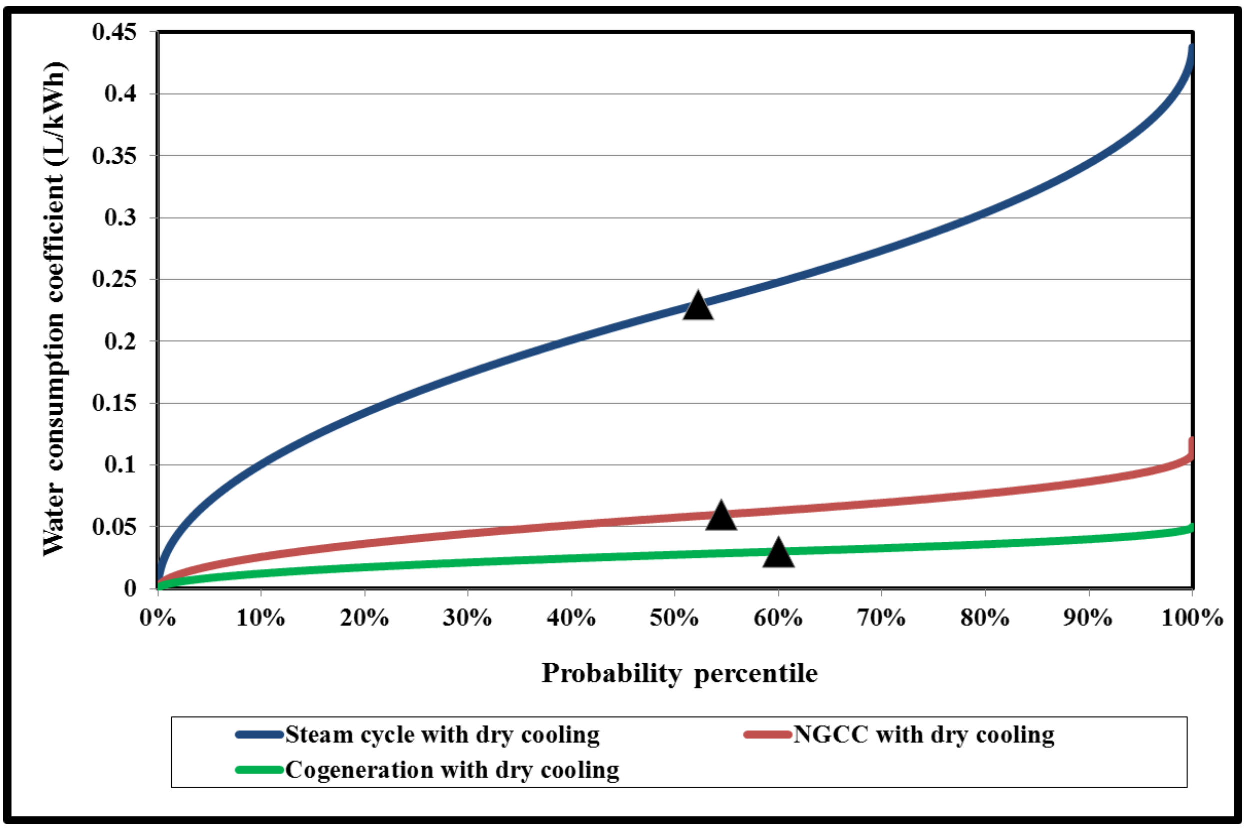

Figure 3.5: Distribution of water consumption coefficients for pathways through dry cooling during the power generation stage from natural gas

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

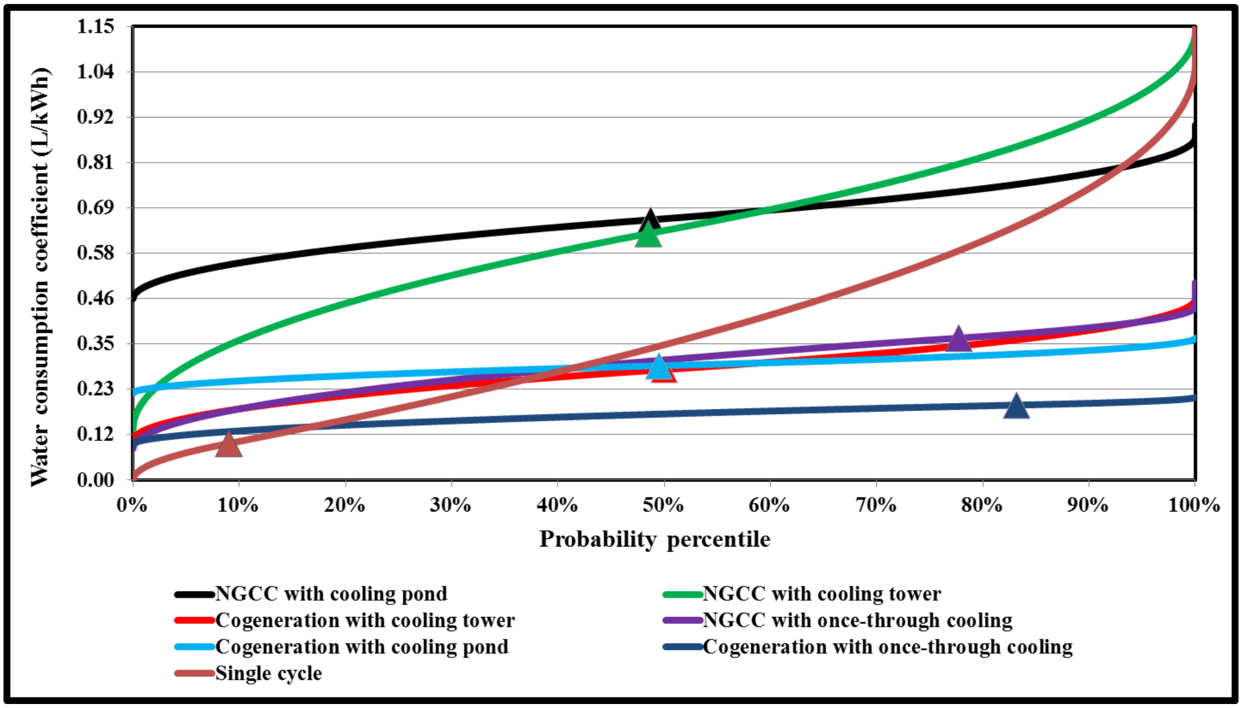

Figure 3.6: Distribution of water consumption coefficients for pathways through NGCC, cogeneration, and single cycle during the power generation stage from natural gas

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

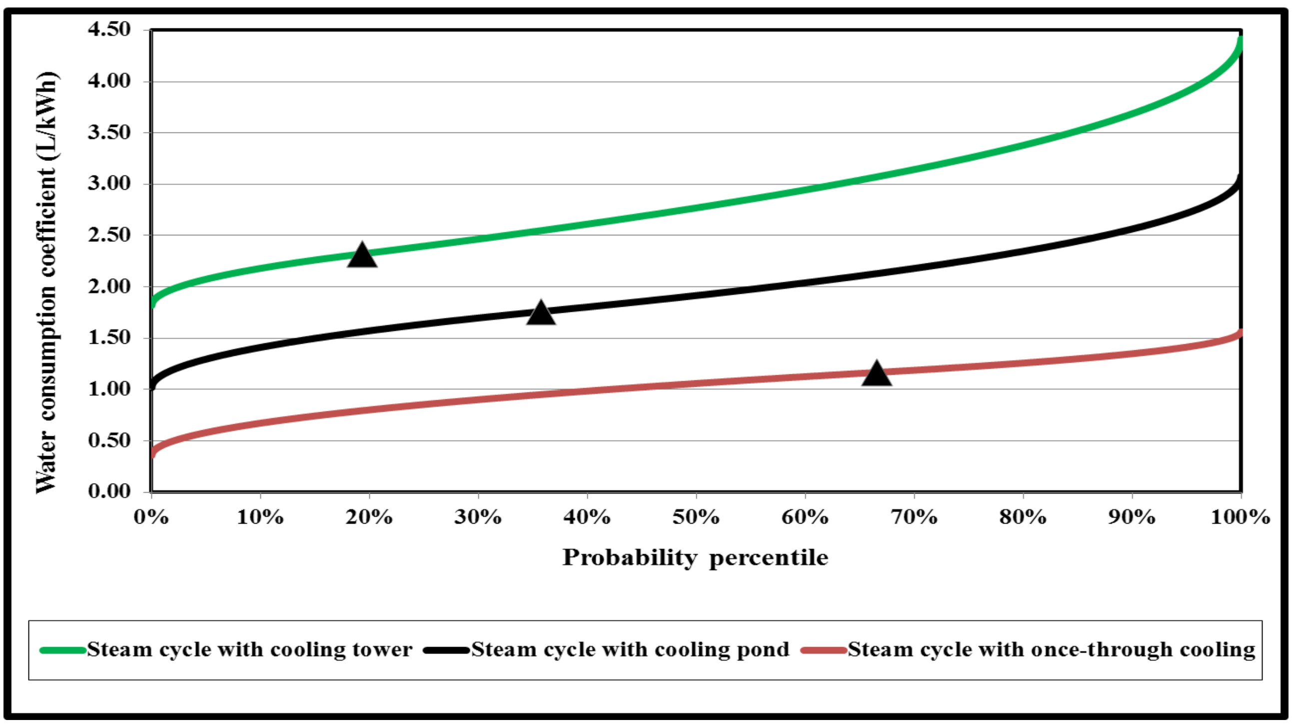

Figure 3.7: Distribution of water consumption coefficients for pathways through steam cycle during the power generation stage from natural gas

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

Table 3.6 shows the distribution of water withdrawals coefficients during the power generation stage at probability 10%, 90%, and the probability percentile of the most likely value (average) taken in the base case. The lowest probability 27% is obtained for the steam cycle with cooling tower. Water withdrawals coefficient for the single cycle has a probability of 28% and its probability is affected as in the consumption coefficient by the very high maximum value (1.34 L/kWh). The base case water withdrawals coefficient for cogeneration with dry cooling has the highest certainty with probability 75%.

Table 3.6: Distribution of water withdrawals coefficients during the power generation stage from natural gas

Pathway	**Water withdrawals coefficient (L/kWh) at probability 10%**	**Water withdrawals coefficient (L/kWh) at probability 90%**	**Probability percentile of the most likely water withdrawals coefficient (%)**
Single cycle	0.23	0.98	28
Steam cycle with once-through cooling	81.44	186.10	53
Steam cycle with cooling tower	2.49	4.55	27
Steam cycle with cooling pond	1.68	3.16	41
Steam cycle with dry cooling	0.13	0.43	53
NGCC with once-through cooling	28.02	61.20	42
NGCC with cooling tower	0.70	1.28	46
NGCC with cooling pond	1.04	1.13	53
NGCC with dry cooling	0.04	0.12	67
Cogeneration with once-through cooling	10.10	21.81	42
Cogeneration with cooling tower	0.49	0.69	46
Cogeneration with cooling pond	0.61	0.65	50
Cogeneration with dry cooling	0.02	0.07	75

3.6 Conclusions

The conversion efficiency of a gas-fired power plant has a significant effect on water demand. The conversion efficiency affects both upstream gas extraction and power generation. The higher water demand from specific types of gas sources can be compensated for with efficient power generation technology. The cooling system used is also essential in determining the level of water required. Dry cooling could improve water demand performance, though there are uncertainties related to economic feasibility and overall conversion efficiency. Water demand is higher during power generation from natural gas than during the fuel extraction stage. Water withdrawals coefficients during power generation for gas-fired power plants using once-through cooling systems are higher than for plants using other cooling systems. With once-through cooling systems, a smaller percentage of withdrawn water is consumed. The water consumption coefficient for the complete life cycle of gas-fired power generation pathways ranged between 0.07 to 2.57 L/kWh, the corresponding water withdrawals ranged between 0.10 to 3.13 L/kWh for closed loop cooling systems, and 14.66 to 138.54 L/kWh for once-through cooling systems.

References

[1]. Ozbilen A, Dincer I, Rosen MA. A comparative life cycle analysis of hydrogen production via thermochemical water splitting using a Cu-Cl cycle. International Journal of Hydrogen Energy 2011; 36: 11321-11327.

[2]. Government of Alberta. Energy: natural gas. Available at: http://www.energy.alberta.ca/NaturalGas/727.asp [accessed: 04.07.2015]

[3]. Dale A, Khanna V, Vidic R, Bilec M. Process based life-cycle assessment of natural gas from the Marcellus Shale. Environmental Science and Technology 2013; 47: 5459−66.

[4]. Vandecasteele I, Rivero IM, Sala S, Baranzelli C, Barranco R, Batelaan O, Lavalle C. Impact of shale gas development on water resources: a case study in Northern Poland. Environmental Management 2015; 55:1285–1299.

[5]. National Energy Technology Laboratory (NETL). Modern shale gas development in the United States: a primer. April 2009. Available at: http://energy.gov/sites/prod/files/2013/03/f0/ShaleGasPrimer_Online_4-2009.pdf [accessed: 03.07.2015]

[6]. Petroleum Technology Alliance Canada (PTAC), Canadian Society for Unconventional Gas (CSUR) and National Energy Board (NEB). Filling the gap : unconventional gas technology roadmap. Petroleum Technology Alliance Canada, 2006. Available at: www.ptac.org/attachments/1510/download [accessed: 02.07.2015]

[7]. Dodder RS. A review of water use in the U.S. electric power sector: insights from systems-level perspectives. Current Opinion in Chemical Engineering 2014, 5:7–14.

[8]. National Energy Technology Laboratory (NETL). Impact of drought on U.S: steam electric power plant cooling water intakes and related water resource management issues. DOE/NETL-2009/1364. Pittsburgh, PA, April 2009. Available at: http://www.circleofblue.org/waternews/wp-

content/uploads/2010/08/Impact-of-Drought-on-Steam-Electric-Power-Plant-Cooling-Water-Intakes.pdf [accessed: 02.07.2015]

[9]. U.S. Energy Information Administration (EIA). Annual energy outlook 2014. DOE/EIA-0383(2014) April 2014. Available at: http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf [accessed: 03.07.2015]

[10]. Crow I, Shippen K. Electricity generation. In: Snow D. Plant engineer's reference book. ISBN 0 7506 4452 4.Butterworth-Heinemann, Linacre House, Jordan Hill, Oxford OX2 8D. A division of Reed Educational and Professional Publishing Ltd.; 2001, p. 22/3-22/19.

[11]. NaturalGas.org. Electric generation using natural gas. Available at: http://naturalgas.org/overview/uses-electrical/ [accessed: 14.07.2015]

[12]. Shipley A, Hampson A, Hedman B, Garland P, Bautista P. Combined heat and power: effective energy solutions for a sustainable future. Oak Ridge National Laboratory (ORNL), 2008. ORNL/TM-2008/224. Available at: http://info.ornl.gov/sites/publications/files/Pub13655.pdf [accessed: 14.07.2015]

[13]. Macknick J, Newmark R, Heath G, Hallett K. Operational water consumption and withdrawal factors for electricity generating technologies: a review of existing literature. Environmental Research Letters 2012; 7: 045802 (10pp).

[14]. Goldstein R, Smith W. Water & Sustainability (Volume 3): U.S. Water Consumption for Power Production—The Next Half Century, EPRI, Palo Alto, CA: 2002. 1006786. Available at: http://www.circleofblue.org/waternews/wp-content/uploads/2010/08/EPRI-Volume-3.pdf [accessed: 14.07.2015]

[15]. Yang X, Dziegielewski B. Water use by thermoelectric power plants in the United States. Journal of the American Water Resources Association (JAWRA) 2007; 43(1):160-69. DOI: 10.1111/j.1752-1688.2007.00013.x.

[16]. Peter H. Gleick. Water and Energy. Annual Review of Energy and Environment 1994; 19:267–299.

[17].Clark C, Horner R, Harto C. Life cycle water consumption for shale gas and conventional natural gas. Environmental Science and Technology 2013; 47: 11829-36.

[18]. Okadera T, Chontanawat J, Gheewala SH. Water footprint for energy production and supply in Thailand. Energy 2014; 77: 49-56.

[19]. Meldrum J, Anderson S, Heath G, Macknick J. Life cycle water use for electricity generation: a review and harmonization of literature estimates. Environmental Research Letters 2013; 8, 015031 (18pp).

[20]. Ali B, Kumar A. Development of life cycle water-demand coefficients for coal-based power generation technologies. Energy Conversion and Management 2015; 90: 247–260.

[21]. Grubert E, Beach F, Webber M. Can switching fuels save water? a life cycle quantification of freshwater consumption for Texas coal- and natural gas-fired electricity. Environmental Research Letters 2012; 7: 045801 (11pp).

[22]. Kenny JF, Barber NL, Hutson SS, Linsey KS, Lovelace JK, Maupin MA. Estimated use of water in the United States in 2005. U.S. Geological Survey. Circular 1344. Available at: http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf [accessed 02.07.2015]

[23]. Bracco S, Pierfederici A, Trucco T. The wet compression technology for gas turbine power plants: thermodynamic model. Applied Thermal Engineering 2007; 27:699–704.

[24]. Popli S, Rodgers P, Eveloy V. Gas turbine efficiency enhancement using waste heat powered absorption chillers in the oil and gas industry. Applied Thermal Engineering 2013; 50: 918-931.

[25]. Mahto D, Pal S. Thermodynamics and thermo-economic analysis of simple combined cycle with inlet fogging. Applied Thermal Engineering 2013; 51: 413-424.

[26]. Gureev V, Mats E, Ivanova V, Gureev M, Malyshkin D, Agalakov Y. Processing feasibilities of enhancing the GTE-based electric power plant efficiency. Russian Aeronautics (Iz.VUZ) 2013; 56, (1):179–184.

[27]. Carvill J, Cullum R. Power units and transmission. In: Smith E. Mechanical engineer's reference book. ISBN 0 7506 4218 1.Butterworth-Heinemann, Linacre House, Jordan Hill, Oxford OX2 8D. A division of Reed Educational and Professional Publishing Ltd.; 2000, p. 10/3-10/49.

[28]. Ibrahim T, Rahman M. Study on effective parameter of the triple-pressure reheat combined cycle performance. Thermal Science 2013; 17(2): 497-508.

[29]. International Energy Agency (IEA). Combined heat and power: evaluating the benefits of greater global investment. Available at: https://www.iea.org/publications/freepublications/publication/chp_report.pdf [accessed: 12.07.2015]

[30]. Gils H, Cofala J, Wagner F, Schopp W. GIS-based assessment of the district heating potential in the USA. Energy 2013; 58: 318-329.

[31]. Munster M, Morthorst P, Larsen H, Bregnbæk L, Werling J, Lindboe H, Ravn H. The role of district heating in the future Danish energy system. Energy 2012; 48: 47-55.

[32]. Nielsen S, Molle B. GIS based analysis of future district heating potential in Denmark. Energy 2013; 57: 458-468.

[33]. Grubert E, Kitasei S. How energy choices affect fresh water supplies: a comparison of U.S. coal and natural gas. Worldwatch Institute. Natural Gas and Sustainable Energy Initiative. (November 2010). Available at: http://www.worldwatch.org/system/files/BP2.pdf [accessed: 09.07.2015]

[34]. Mary Griffiths. Protecting water, producing gas. The Pembina Institute, 2007. Drayton Valley, AB. Available at: www.pembina.org/pub/1434 [accessed: 15.07.2015]

[35]. NaturalGas.org. Unconventional natural gas resources. Available at: http://naturalgas.org/overview/unconventional-ng-resources/ [accessed: 12.07.2015]

[36]. U.S Energy Information Administration (EIA). U.S. heat content of natural gas deliveries to consumers. Available at: http://www.eia.gov/dnav/ng/hist/nga_epg0_vgth_nus_btucfa.htm [accessed: 13.07.2015]

[37]. Miller D, Chorel M. A study on the efficiency of Alberta's electrical supply system. Project # CASA-EEEC-02-04. For Clean Air Strategic Alliance (CASA). October 2004. Available at: http://www.hme.ca/reports/CASA_Report_--_The_Efficiency_of_Alberta's_Electrical_Supply_System_EEEC-02-04.pdf [accessed: 10.07.2015]

[38]. International Energy Agency (IEA). Gas-fired power. Energy Technology Systems Analysis Programme (ETSAP). Available at: http://www.iea-etsap.org/web/e-techds/pdf/e02-gas_fired_power-gs-ad-gct.pdf [accessed: 13.07.2015]

[39]. Then O, Sanders C, Viereck D, Ladwig M. Emsland KA26 power plant: high efficiency with flexibility. Article in: Modern Power Systems; March 2008; 28 (3): p13.

[40]. Ishikawa M, Terauchi M, Komort T, Yasuraoka J. Development of high efficiency gas turbine combined cycle power plant. Mitsubishi Heavy Industries, Ltd. Technical Review 2008; 45 (1): 15-17. Available at: http://www.mhi.co.jp/technology/review/pdf/e451/e451015.pdf [accessed: 11.07.2015]

[41]. Chase D, Kehoe P. GE Combined-cycle product line and performance. GE Power Systems, GER-3574G. Available at: http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger3574g.pdf [accessed: 08.07.2015]

[42]. Center for Climate and Energy Solutions. Cogeneration/Combined heat and power (CHP). Available at: http://www.c2es.org/technology/factsheet/CogenerationCHP#_edn4 [accessed: 07.07.2015]

[43]. Mielke E, Anadon L, Narayanamurti V. Water consumption of energy resource extraction, processing, and conversion. Energy Technology Innovation Policy Research Group. Belfer Center for Science and International Affairs, 2010. Available at: http://belfercenter.ksg.harvard.edu/files/ETIP-DP-2010-15-final-4.pdf [accessed: 15.07.2015]

[44]. Langston L, Opdyke G. Introduction to gas turbines for non-engineers. Global Gas Turbine News 1997; 37 (2) Available at: http://files.asme.org/IGTI/Knowledge/Articles/13051.pdf [accessed: 12.07.2015]

[45]. Griffiths M, Woynillowicz D. Heating up in Alberta: climate change, energy development and water. The Pembina Institute, February 2009. Available at: http://pubs.pembina.org/reports/heating-up-in-alberta-report.pdf [accessed: 13.07.2015]

[46]. U.S. Department of Energy. Energy demands on water resources. Report to Congress on the independency of energy and water. Available at: http://powi.ca/wp-content/uploads/2012/12/Energy-Demands-on-Water-Resources-Report-to-Congress-2006.pdf [accessed: 14.07.2015]

[47]. Union of Concerned Scientists. How it works: water for natural gas. Available at: http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-natural-gas.html#sources [accessed: 27.07.2015]

[48]. El-Wakil MM. The circulating water system. In: Power plant technology, Chapter seven: ISBN 0-07-019288-X. McGraw-Hill International Editions, Electrical and Mechanical Engineering Series; Singapore;1984, p. 260-303.

[49]. Scanlon B, Reedy R, Duncan I, Mullican W, Young M. Controls on water use for thermoelectric generation: Case study Texas, U.S. Environmental Science and Technology 2013; 47:11326-34.

[50]. Stillwell AS, Clayton ME, Webber ME. Technical analysis of a river basin-based model of advanced power plant cooling technologies for mitigating water management challenges. Environmental Research Letters 2011; 6: 034015-26.

[51]. Union of Concerned Scientists. How it works: water for power plant cooling. Available at: http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-cooling-power-plant.html#sources [accessed: 11.07.2015]

[52]. Power Technology. Kogan Creek coal-fired power station, Queensland, Australia: key data. Available at: http://www.power-technology.com/projects/kogan/ [accessed: 12.07.2015]

[53]. Griffiths M, Baker CS. Unconventional gas: the environmental challenges of coalbed methane development in Alberta. Pembina Institute, June 2003. Available at: pubs.pembina.org/reports/CBM_Final_April2006D.pdf [accessed: 20.07.2015]

[54]. Wu M, Chiu Y. Consumptive water use in the production of ethanol and petroleum gasoline-2011 update. Center for Transportation Research, Energy Systems Division, Argonne National Laboratory, December 2008, updated July 2011. ANL/ESD/09-1 Update. Available at: https://greet.es.anl.gov/files/consumptive-water [accessed: 29.10.2016]

[55]. Vose. ModelRisk Software. Available at: http://www.vosesoftware.com/ [accessed: 05.07.2015]

Chapter 4

Development of Water Demand Coefficients for Power Generation from Non-conventional Energy Technologies[3]

4.1 Introduction

Natural resource use needs to be balanced with electricity demand in such a way that an acceptable level of sustainability is maintained. Most of the focus to this point has been on the mitigation of greenhouse gas (GHG) emissions, and water use in electricity production has received little attention. As part of maintaining a sustainable balance, the quantity and quality of water, a precious natural resource, have to be managed. Renewable energy technologies are proposed as a critical aspect of the water, energy, and food nexus [1]. There is evidence around the world showing how water availability has played a key role in decisions related to power generation. For example, following the 2006 - 2007 drought in the U.S. and in France in 2003, some coal and nuclear power plants were shut down or are now operating at reduced capacity [2]. The contribution to electricity generation from renewable energy is expected to increase in the U.S. from 13% of the total energy in 2013 to 18% by 2040 [3].

Electricity generation consumes considerable amounts of water during the generation of power during cooling, steam cycle, make-up, cleaning, and fuel life cycle activities. In 2005, thermoelectric power plants withdrew 41% of the total fresh water required in the U.S. with a consumption rate of 3%, and the water use for some renewable energy sources may exceed that of conventional technologies [4]. Thermoelectric power plants in Canada, including nuclear,

[3]Complete paper was submitted to *Energy Conversion and Management Journal* as *Ali B, Kumar A. Development of water demand coefficients for power generation from renewable energy technologies. (submitted, in-review).*

withdrew about 27.8 million m^3 of water in 2005, or 66% of the total water withdrawals, and in the same year hydroelectric power used more than 100 times that amount [5]. Renewable energy has been proposed as a clean, alternative solution to conventional resources from a GHG mitigation point of view [6-9].

The use of water for renewable energy has been studied earlier [10-15]. Most of these studies were conducted with a focus on the power generation stage and not on life cycle water consumption. Moreover, most of these studies do not assess the effects of conversion efficiencies on water demand coefficients. Water demand coefficients include the water consumption coefficient and the water withdrawals coefficient for each pathway. Water consumption is the amount of water consumed by the unit operations of the process and not returned back to the source, while water withdrawals include water returned to the source apart from consumption [16, 17]. Since renewable technologies are still at various stages of development and demonstration, there needs to be a life cycle approach to understand the full impacts of the technologies. In addition, there is good potential for conversion efficiency improvement in the power generation technologies, and the potential can be better understood by assessing their impacts. There is little research that comparatively assesses life cycle water consumption coefficients for different non-conventional energy pathways. Tan and Zhi [18] highlighted the lack of studies on the water-energy nexus for solar, wind, and geothermal technologies and recommended future research be conducted in this field. This chapter is an effort to fill that gap.

The main objectives of this chapter are to:

- Develop water demand coefficients for non-conventional energy technologies over the full life cycle.

- Comparatively, assess the upstream and power generation stages of the water demand coefficients for various non-conventional energy technologies.
- Comparatively, assess the water demand of sixty different pathways in the conversion of non-conventional energy to power; and
- Assess the impact of conversion efficiency on water use for non-conventional energy pathways through a comprehensive uncertainty analysis.

4.2 Scope and system boundary

Pathways were structured specific to non-conventional energy sources (see Figure 4.1) to include renewable and nuclear energy pathways. The main unit operations considered for water demand coefficients during the entire life cycle are fuel extraction (if any), conversion technology for power generation, and the cooling system (if any; shown by the dotted line in Figure 4.1). For the base case, the specific conversion efficiency of power plants was assumed and impacts of variations were studied later in the sensitivity analysis. This base case conversion efficiency was taken as the most likely value in a model executed through Monte Carlo simulations [19-22]. The most likely value is bound by minimum and maximum efficiencies to study the uncertainty of the assumed values [16].

Two sets of water demand coefficients were developed and further harmonized at certain conversion efficiencies. The first set of developed coefficients covers the full life cycle of the pathway and the second set is limited to unit operations for power generation. The conversion efficiency was varied in the sensitivity analysis to study the effect of power plant performance on the water demand coefficient levels.

The water consumption coefficient (WCUP) and the water withdrawals coefficient (WWUP) in the upstream stage included irrigation water and are correlated to the conversion efficiency (η) through the factors of merit M1 and M2, respectively, as follows (as conducted in chapter two [17]):

$$\mathbf{WCUP = M1 * (1/\eta)} \tag{4.1}$$

$$\mathbf{WWUP = M2 * (1/\eta)} \tag{4.2}$$

Factors of merit are constant coefficients in L/kWh assigned to differentiate between the water demand coefficients of pathways from the same set. The lower the factor of merit, the better the performance of a pathway with respect to the water demand coefficient.

There are two types of correlations between water demand coefficients and conversion efficiencies (η) identified in this chapter for the power generation stage. The first type includes all non-conventional energy technologies that use a steam cycle to generate electricity (thermoelectric). These technologies cover all biomass, nuclear, solar-thermal, and geothermal pathways and are governed by the factors of merit M3 for the water consumption coefficient (WCC) and M4 for the water withdrawals coefficient (WWC) (based on chapter two [17]), as follows:

$$\mathbf{WCC = M3 *((1/\eta) - 1)} \tag{4.3}$$

$$\mathbf{WWC = M4 *((1/\eta) - 1)} \tag{4.4}$$

The second set of factors of merit, M5 and M6, is assigned to the rest of the technologies (wind, hydroelectricity, and solar-photovoltaic) to correlate the conversion efficiency (η) to the water consumption coefficient (WCC) and water withdrawals coefficient (WWC), respectively, as follows:

$$\mathbf{WCC = M5 *(1/\eta)} \tag{4.5}$$

$$\mathbf{WWC = M6*(1/\eta)} \tag{4.6}$$

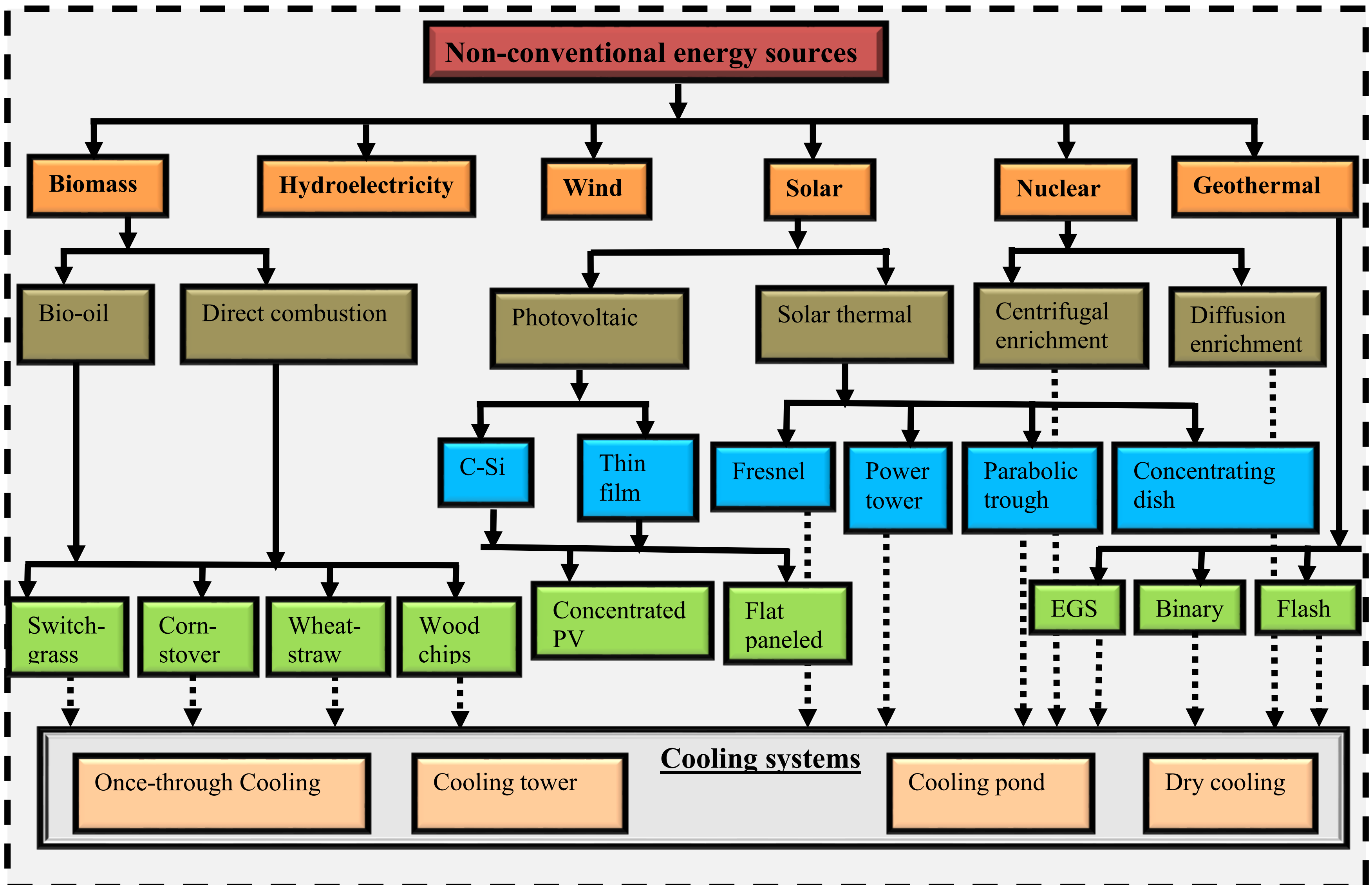

Figure 4.1: Non-conventional energy pathways

----Dashed lines show pathways with cooling systems

4.3 Pathways Selection

Six types of power generation from non-conventional energy sources were selected: biomass, hydroelectricity, wind, solar, geothermal, and nuclear. Biomass and nuclear are the principle non-conventional sources considered in this study. Cooling systems (once-through, cooling tower, cooling pond, and dry cooling) were considered for the biomass, solar-thermal, nuclear, and geothermal power generation pathways [23, 24]. Hybrid cooling was considered for the solar-thermal pathways (power tower and parabolic trough) as well as the geothermal energy-based pathways using binary technology [11].

4.3.1 Biomass pathways

Biomass pathways were subdivided by fuel into direct or bio-oil combustion of one of four feedstocks (switchgrass, corn stover, wheat straw, and wood chips) [12, 25]. Direct combustion burns biomass feedstock in a boiler to produce steam, and power is generated in a Rankine cycle. The power generation unit operations in this case are similar to those for coal-fired power generation. In the other combustion method, bio-oil is produced through pyrolysis and combusted as fuel to generate power. The agricultural stage for the both considered biomass technologies (direct combustion and bio-oil combustion) and the conversion stage for bio-oil pathways were added to the upstream unit operations. Further details can be found in earlier studies [12, 25].

Other pathways of biomass-based power generation such as gasification [26] and co-firing [27] are not considered in this chapter due to the limited availability of data related to the water demand footprint for these pathways.

4.3.2 Nuclear pathways

Nuclear energy is one of the most cost-effective energy sources [28]. Nuclear fuel pathways consider fuel enrichment by diffusion or centrifugally [6, 11]. Most nuclear power plants use uranium U-235 after enriching from the 0.7% content in the natural raw uranium (the remaining 99.3% is U-238) up to the range 3%-5%. Raw uranium is ground into powder and converted to uranium hexafluoride (UF_6) gas. U-238 is heavier than U-235, which helps in the enrichment process. In gaseous diffusion enrichment, UF_6 is passed through a vessel wall with holes. U-235 passes through the holes faster than U-238 due to the difference in weight. The gas collected through the low-pressure passage is enriched U-235. The centrifugal process is through cylinders rotating at a high speed to create centrifugal force. This force moves the U-238 towards the wall of the cylinder and the U-235 is collected in the centre of the cylinder. Laser enrichment is a technology used to enrich uranium but is not available commercially [29, 30]. The upstream stage of nuclear power generation includes extraction, grinding, conversion to UF_6, enrichment, and plant construction. The power generation stage includes cooling systems, steam make-up, fuel disposal, and power plant construction and decommissioning.

4.3.3 Solar pathways

Solar energy power generation technologies include solar-thermal and photovoltaic. Solar-thermal technologies include power tower, parabolic trough, Fresnel lens, and dish systems [31, 32]. Photovoltaic systems can be made by thin film or crystalline silicon (C-Si) and the modes of operation are flat paneled or concentrated photovoltaic (PV).

The solar-thermal technology generates power through concentrating sun rays to heat a medium fluid that rotates a turbine and a generator. The shape of solar collectors varies depending on the technology. The power tower has heliostats to reflect the incoming sun rays into a tower carrying the central receiver. The concentrated sun rays heat the fluid in the central receiver and the kinetic energy of this fluid is converted to mechanical and electric energy through the turbine and the generator. Parabolic trough technology focuses the sun's rays on a linear receiver (pipe) to heat the fluid and generate power. In Fresnel lens technology, curved mirrors reflect the sun's rays onto a linear receiver to generate power. A parabolic dish concentrates the sun's rays on a focal point (a receiver and a Sterling engine) to generate power [33, 34].

A thin film photovoltaic module has two semiconductors, cadmium telluride (CDTe or $CuInSe_2$) and cadmium sulfide (CDS), which make up a p-n junction. CDTe and CDS are deposited in thin layers onto a transparent glass panel. After the p-n junctions have been connected in a series, another glass panel is added to the top to cover and protect the module [35]. A crystalline silicon (C-Si) module is manufactured by purifying silica sand into metallurgical grade silicon (MG-silicon) and then to electronic silicon (EG-silicon). The silicon is melted and cast in molds into polycrystalline blocks to produce multi-silicon wafers. The Czochralski process is used to produce mono-silicon wafers. Photovoltaic cells are produced after the silicon ingots have been cut into columns according to the size of the required wafer. Etching, doping, screen printing, coating, and testing are the main steps involved in finalizing the product. The cells are connected by string and silver points on the top and bottom and covered on both sides by ethyl-vinyl acetate layers. Transparent glass is added to the top and Tedlar film on the bottom as protective covers. Under heating and high-pressure conditions, a sandwich panel is produced after the edges have been finished and the connections insulated. An aluminium frame is added to support the manufactured photovoltaic panel. Laminated panels do not need this frame [36].

The operation of solar-thermal technologies needs water for cooling, and the water demand for materials extraction, manufacturing, and construction of the systems is included in the upstream stage.

Photovoltaic power generation requires minimal water during operation, for panel washing, and no cooling system is needed.

4.3.4 Wind and hydroelectricity pathways

Wind is created by the difference in ambient temperature initiated from the sun's heat. Wind turbines are mounted on a tower to convert the kinetic energy of wind into mechanical and then electric energy through a generator [37]. The main components of a wind plant are the tower, the turbine, and the generator. A wind energy plant can be as small as a few kilowatts to over 10 MW, depending on the application, and a farm could be designed with several units to increase power capacity from a location [38]. Wind energy is one of the fastest-growing power generation technologies around the world [38, 39]. Power generation operations from wind energy do not require cooling systems, and minimal water is required (for cleaning the turbines and for construction during the upstream stage).

Hydroelectricity originates from moving water, which converts kinetic energy to mechanical energy through a turbine and then to electric energy through a generator. Some hydropower plants are located in the running stream of water (run-of-river), and for high power production scales, dams are constructed to increase the height (head) of the falling water. Reservoirs are constructed with dams to store water for other uses and to help control the amount of running water through the penstock to the turbine [40]. In 2008 more than 16% of the total power generated in the world was from hydroelectricity [41]. Hydroelectricity operations consume significant amounts of water through evaporation from the reservoir. Water demand during the upstream stage is for hydropower plant construction.

4.3.5 Geothermal pathways

Geothermal pathways include binary, flash, and enhanced geothermal system (EGS) technologies. The binary technology operates at a low temperature (85°C - 175°C) and uses geothermal liquid to heat through the exchanger an intermediate working fluid (such as isobutene) at a boiling point that is lower still. The kinetic energy of the heated working fluid is converted to mechanical energy to rotate the turbine, which is coupled to the electric generator, for power generation [42, 43]. Geothermal flash is the most common geothermal power generation technology; in this system, a mixture of water and steam produced from the reservoir is flashed in a separate tank at low pressure. The steam is separated and used to generate electricity; the water not flashed is returned to the geothermal reservoir through an injection well [42-45]. In EGS technology, water as a working fluid is circulated in a closed loop through the injection well to rocks and pumped out through a production well. Circulated water is heated to the steam phase to run the turbine and generate power [46]. The cooling system is the most critical unit operation determining the level of water demand during the power generation stage of geothermal pathways.

4.4 Input data and assumptions

We developed water demand coefficients for the various unit operations and integrated them to estimate the overall life cycle water footprint. The estimates were further harmonized at the most likely conversion efficiencies assumed in the base case. Table 4.1 shows the most likely, minimum, and maximum efficiencies considered in this chapter.

Coefficients for the power generation stage from biomass pathways were derived from chapter two [17]. The complete life cycle water demand coefficients for agricultural biomass feedstocks (switchgrass, corn stover, and wheat straw) were estimated after taking into account fuel production stage data taken from an earlier study [12]. Forest biomass-based power was estimated based on Canadian pine tree characteristics [47-49]. Table 4.2 shows the input data used to develop water demand coefficients for biomass pathways. Input data for nuclear pathways are shown in Table 4.3; solar-thermal and geothermal pathways are shown in Table 4.4; and Table 4.5 gives input data for photovoltaic, wind, and hydroelectricity pathways.

Table 4.1: Assumed conversion efficiencies of non-conventional energy technologies

Items	Minimum conversion efficiency (η_{min})	Most likely conversion efficiency (η_{ml})	Maximum conversion efficiency (η_{max})	Source
Biomass power plant	20%	33%	40%	According to the DOE, small capacity plants have low efficiency (20%) and with new techniques would reach over 40% [50]. η_{ml} is assumed based on a study by Singh et al. [12]. Direct combustion and bio-oil pathways were assumed to have the same range of conversion efficiency.
Nuclear power plant	30%	33%	36%	Based on the comprehensive review conducted by Warner and Heath [51] for nuclear power plants, which showed that boiler water reactors have lower efficiency than pressurized water reactors. η_{ml} is assumed as the average value.
Solar-thermal power tower	7%	20%	25%	η_{min} is based on historical data [52], η_{ml} on the review by Meldrum et al. [11], and η_{max} on the expected improvement of the technology after 2025 [32].
Solar-thermal parabolic trough	10%	15%	25%	
Solar-thermal Fresnel lens	10%	11%	25%	Based on under- construction plants and expected technology improvement after 2025 [32].
Solar-thermal concentrating dish	15%	22%	25%	
Solar photovoltaic system	4%	13%	22%	η_{min} and η_{max} are taken from a study assessing sustainability indicators [53], and the average value is considered for η_{ml}.
Wind power plant	24%	39%	54%	
Hydroelectricity power plant	82%	90%	98%	η_{ml} is considered according to [53, 54] and η_{min}, η_{max} were respectively assumed -8% and +8% compared to η_{ml}. η_{max} is extended from 95% [55] to 98% to accommodate for the expected technology improvement [41].

Items	Minimum conversion efficiency (η_{min})	Most likely conversion efficiency (η_{ml})	Maximum conversion efficiency (η_{max})	Source
Geothermal with binary technology	1%	8%	16.3%	η_{min} is the actual efficiency of the Chena Hot Springs power plant with an average operation temperature 73°C [56]. η_{ml} is based on a power plant with an operating temperature of 180°C [57]. η_{max} is based on the upper-end efficiency of a Miravalles Unit 5 power plant in Costa Rica [58].
Geothermal with flash technology	5%	11%	20%	η_{min} and η_{max} are based on the correlations developed by Moon and Zarrouk [56] and η_{ml} on a power plant operating at 180 °C [57].
Geothermal with EGS technology	7%	9%	12%	η_{ml} is based on the average from global efficiency ranges of 7.4%-10.4% and η_{max} derived from ten case studies [59].

Table 4.2: Input data for water demand coefficients of biomass pathways

Pathway	Upstream stage (L/kWh)	Power generation stage (L/kWh)[e]							
		Once- through cooling		Cooling tower		Cooling pond		Dry cooling	
	WCUP/ WWUP [a]	WCC	WWC	WCC	WWC	WCC	WWC	WCC	WWC
Wood chips- Direct combustion	622.45[b]	1.36	127.34	2.20	2.53	2.13	2.55	0.22	0.25
Wood chips- Bio-oil	1161.81[c]								
Corn stover- Direct combustion	259.38[d]								
Corn stover- Bio-oil	326.59[d]								
Wheat straw- Direct combustion	318.30[d]								
Wheat straw- Bio-oil	465.80[d]								
Switchgrass-Direct combustion	672.13[d]								
Switchgrass-Bio-oil	823.67[d]								

[a] WCUP and WWUp are assumed equal and no water returned to the same source where it was taken.
[b] Estimated water footprint for Canadian pine = 1.141 m^3 of water per kg of wood [47, 48] with 20 MJ/kg HHV for wood [49], and conversion efficiency (η_{ml}) 33%.
[c] Estimated water footprint for Canadian pine = 1.141 m^3 of water per kg of wood [47, 48] with 17.9 MJ/kg HHV for bio-oil; the yield is 0.599 kg of bio-oil per kg of dry wood [49] and conversion efficiency (η_{ml}) of 33%.
[d] Based on water consumption coefficients developed in Singh et al. [12].
[e] Subcritical water demand coefficients developed earlier (at a conversion efficiency of 35%) [17] were used to estimate these coefficients through Equation 4.3.

Table 4.3: Input data for water demand coefficients of nuclear pathways[a]

Pathway	Upstream stage (L/kWh)	Power generation stage (L/kWh)							
		Once- through cooling		Cooling tower		Cooling pond		Dry cooling	
	WCUP/ WWUP	WCC	WWC	WCC	WWC	WCC	WWC	WCC	WWC
Nuclear-Centrifugal enrichment	0.21	1.52	178.03	2.73	4.17	2.31	4.17	0.27	0.42
Nuclear-Diffusion enrichment	0.33/0.53								

[a] Coefficients were based on the median values of statistics revision from the literature [11] and assumed at the same conversion efficiency (η_{ml}) of 33%.

Table 4.4: Input data for water demand coefficients of solar-thermal and geothermal pathways [a]

Pathway	Upstream stage (L/kWh)	Power generation stage (L/kWh)					
		Cooling tower		Hybrid cooling		Dry cooling	
	WCUP/ WWUP	WCC	WWC	WCC	WWC	WCC	WWC
Solar thermal- Power tower	0.61	3.07	3.07	0.64	0.64	0.10	0.10
Solar thermal- Parabolic trough	0.61	3.37	3.64	1.29	1.29	0.30	0.30
Solar thermal- Fresnel	0.61	3.79[b]	3.79[b]	-	-	0.38[c]	0.38[c]
Solar thermal- Concentrating dish	0.61	0.02[d]					
Geothermal-Binary	0.01	-	-	1.74	1.74	1.10	1.10
Geothermal-Flash	0.01	0.06 [b]	0.06 [b]	-	-	-	-
Geothermal-EGS	0.01	-	-	-	-	1.93	1.93

[a] Coefficients were based on the median values of statistics revision from the literature [11] and assumed at the same conversion efficiency η_{ml} detailed in Table 4.1.
[b] Assumed with a cooling tower of equal consumption and withdrawals coefficients [60].
[c] Estimated with the assumption of 10% from the associated cooling tower coefficients.
[d] No cooling system is needed and coefficients were assumed for other water uses such as washing.

Table 4.5: Input data for water demand coefficients of photovoltaic, wind, and hydroelectricity pathways [a]

Pathway	Upstream stage (L/kWh)		Power generation stage (L/kWh)			
			Flat panel		Concentrated PV	
	WCUP	WWUP	WCC	WWC	WCC	WWC
Crystalline silicone	0.31	0.36	0.02	0.02	0.11	0.11
Thin film	0.02	0.07				
	WCUP	WWUP	WCC		WWC	
Wind	0.0004	0.098	0.0049		0.0057	
Hydroelectricity [b]	0.00	0.00	68.18		68.18	

[a] Coefficients were based on the median values of statistics revision from the literature [11] and assumed at the same conversion efficiency η_{ml} detailed in Table 4.1.
[b] Water demand coefficients were developed considering the national average rate of evaporation from reservoirs in the U.S [61]. Upstream water demand coefficients were not considered.

4.5 Results and discussion

Table 4.6 shows the developed generic water demand coefficients for 60 different non-conventional energy pathways based on the most likely conversion efficiencies (see Table 4.1) and after combining the input data from Tables 4.2 through 4.5. Based on the complete life cycle of non-conventional energy pathways, biomass-based power generation has the most negative impact on water demand. This is because the complete life cycle includes the high water requirement in the agriculture stage. Power generation from the combustion of bio-oil produced from wood chip feedstock has the highest water demand coefficients; power generation from wind energy has the lowest.

When we consider power generation alone, the hydroelectricity pathway has the highest water consumption coefficient due to the large amount of water that evaporates in the reservoir. Due to the nature of once-through cooling systems, the associated water withdrawals are generally large, and nuclear-based power generation with this cooling system technology has the highest water withdrawal coefficient. Despite the lower conversion efficiency of nuclear power plants, the steam cycle has a major part in this high water withdrawal coefficient. The cooling system also affects the water demand for power generation. In terms of the complete life cycle, the water consumption coefficient for nuclear energy through diffusion enrichment using a cooling tower (3.06 L/kWh) can be improved by 14% (2.64 L/kWh) if the cooling system is replaced by a cooling pond and can be improved further by 30% (1.84 L/kWh) if the pond is replaced by once-through cooling and by 33% (to 0.6 L/kWh) through dry cooling. This low coefficient (0.6 L/kWh) achieved through dry cooling is very close to the corresponding water consumption coefficient of a concentrating dish (0.63 L/kWh). The proper choice of a cooling system in this example during power generation compensates for the water consumption during the fuel cycle.

Table 4.6: Base case water demand coefficients for power generation from non-conventional energy pathways

NO.	Pathway	Complete life cycle		Power generation only	
		Water Consumption coefficient (L/kWh)	Water Withdrawals coefficient (L/kWh)	Water Consumption coefficient (L/kWh)	Water Withdrawals coefficient (L/kWh)
1	Biomass-Wood chips-Direct combustion-Once-through cooling	623.81	749.79	1.36	127.34
2	Biomass-Wood chips-Direct combustion-Cooling tower	624.65	624.98	2.20	2.53
3	Biomass-Wood chips-Direct combustion-Cooling pond	624.58	625.00	2.13	2.55
4	Biomass-Wood chips-Direct combustion-Dry cooling	622.67	622.70	0.22	0.25
5	Biomass-Wood chips-Bio-oil-Once-through cooling	1163.17	1289.15	1.36	127.34
6	Biomass-Wood chips-Bio-oil-Cooling tower	1164.01	1164.34	2.20	2.53
7	Biomass-Wood chips-Bio-oil-Cooling pond	1163.94	1164.36	2.13	2.55
8	Biomass-Wood chips-Bio-oil-Dry cooling	1162.03	1162.06	0.22	0.25
9	Biomass-Corn stover-Direct combustion-Once-through cooling	260.74	386.72	1.36	127.34
10	Biomass-Corn stover-Direct combustion-Cooling tower	261.58	261.91	2.20	2.53
11	Biomass-Corn stover-Direct combustion-Cooling pond	261.51	261.93	2.13	2.55
12	Biomass-Corn stover-Direct combustion-Dry cooling	259.60	259.63	0.22	0.25
13	Biomass-Corn stover-Bio-oil-Once-through cooling	327.92	453.90	1.36	127.34
14	Biomass-Corn stover-Bio-oil-Cooling tower	328.76	329.09	2.20	2.53
15	Biomass-Corn stover-Bio-oil-Cooling pond	328.69	329.11	2.13	2.55
16	Biomass-Corn stover-Bio-oil-Dry cooling	326.78	326.81	0.22	0.25
17	Biomass-Wheat straw-Direct combustion-Once-through cooling	319.66	445.64	1.36	127.34
18	Biomass-Wheat straw-Direct combustion-Cooling tower	320.50	320.83	2.20	2.53
19	Biomass-Wheat straw-Direct combustion-Cooling pond	320.43	320.85	2.13	2.55
20	Biomass-Wheat straw-Direct combustion-Dry cooling	318.52	318.55	0.22	0.25

NO.	Pathway	Complete life cycle		Power generation only	
		Water Consumption coefficient (L/kWh)	Water Withdrawals coefficient (L/kWh)	Water Consumption coefficient (L/kWh)	Water Withdrawals coefficient (L/kWh)
21	Biomass-Wheat straw-Bio-oil-Once-through cooling	467.16	593.14	1.36	127.34
22	Biomass-Wheat straw-Bio-oil-Cooling tower	468.00	468.33	2.20	2.53
23	Biomass-Wheat straw-Bio-oil-Cooling pond	467.93	468.35	2.13	2.55
24	Biomass-Wheat straw-Bio-oil-Dry cooling	466.02	466.05	0.22	0.25
25	Biomass-Switchgrass-Direct combustion-Once-through cooling	673.49	799.47	1.36	127.34
26	Biomass-Switchgrass-Direct combustion-Cooling tower	674.33	674.66	2.20	2.53
27	Biomass-Switchgrass-Direct combustion-Cooling pond	674.26	674.68	2.13	2.55
28	Biomass-Switchgrass-Direct combustion-Dry cooling	672.35	672.38	0.22	0.25
29	Biomass-Switchgrass-Bio-oil-Once-through cooling	825.03	951.01	1.36	127.34
30	Biomass-Switchgrass-Bio-oil-Cooling tower	825.87	826.20	2.20	2.53
31	Biomass-Switchgrass-Bio-oil-Cooling pond	825.80	826.22	2.13	2.55
32	Biomass-Switchgrass-Bio-oil-Dry cooling	823.89	823.92	0.22	0.25
33	Nuclear-Centrifugal enrichment-Once-through cooling	1.73	178.24	1.52	178.03
34	Nuclear-Centrifugal enrichment-Cooling tower	2.94	4.38	2.73	4.17
35	Nuclear-Centrifugal enrichment-Cooling pond	2.52	4.38	2.31	4.17
36	Nuclear-Centrifugal enrichment-Dry cooling	0.48	0.63	0.27	0.42
37	Nuclear-Diffusion enrichment-Once-through cooling	1.84	178.56	1.52	178.03
38	Nuclear-Diffusion enrichment-Cooling tower	3.06	4.70	2.73	4.17
39	Nuclear-Diffusion enrichment-Cooling pond	2.64	4.70	2.31	4.17
40	Nuclear-Diffusion enrichment-Dry cooling	0.60	0.95	0.27	0.42
41	Solar thermal-Power tower-Cooling tower	3.67	3.67	3.07	3.07
42	Solar thermal-Power tower-Hybrid cooling	1.25	1.25	0.64	0.64

NO.	Pathway	Complete life cycle		Power generation only	
		Water Consumption coefficient (L/kWh)	Water Withdrawals coefficient (L/kWh)	Water Consumption coefficient (L/kWh)	Water Withdrawals coefficient (L/kWh)
43	Solar thermal-Power tower-Dry cooling	0.70	0.70	0.10	0.10
44	Solar thermal-Parabolic trough-Cooling tower	3.98	3.98	3.37	3.37
45	Solar thermal-Parabolic trough-Hybrid cooling	1.89	1.89	1.29	1.29
46	Solar thermal-Parabolic trough-Dry cooling	0.90	0.90	0.30	0.30
47	Solar thermal-Fresnel-Cooling tower	4.39	4.39	3.79	3.79
48	Solar thermal-Fresnel-Dry cooling	0.98	0.98	0.38	0.38
49	Solar thermal-Concentrating dish	0.63	0.63	0.02	0.02
50	Solar-Photovoltaic-Crystalline Silicon (C-Si)-Flat paneled	0.33	0.38	0.02	0.02
51	Solar-Photovoltaic-Crystalline Silicon (C-Si)-Concentrated PV	0.42	0.47	0.11	0.11
52	Solar-Photovoltaic-Thin film-Flat paneled	0.05	0.09	0.02	0.02
53	Solar-Photovoltaic-Thin film-Concentrated PV	0.14	0.18	0.11	0.11
54	Wind	0.005	0.104	0.005	0.006
55	Hydroelectricity	68.182	68.182	68.182	68.182
56	Geothermal-Binary-Hybrid cooling	1.75	1.75	1.74	1.74
57	Geothermal-Binary-Dry cooling	1.11	1.11	1.10	1.10
58	Geothermal-Flash-Cooling tower	0.06	0.07	0.06	0.06
59	Geothermal-Flash-Dry cooling	0.05	0.08	0.04	0.07
60	Geothermal-Enhanced geothermal system (EGS)-Binary-Dry cooling	1.94	1.94	1.93	1.93

4.6 Sensitivity analysis

The assumed conversion efficiencies detailed in Table 4.1 were used as inputs to ModelRisk [19] to study the impact of uncertainty in power plant performance on the water demand coefficients through Monte Carlo simulations. Figure 4.2 shows the probability percentile of each conversion efficiency considered for the base case compared to the maximum and minimum values.

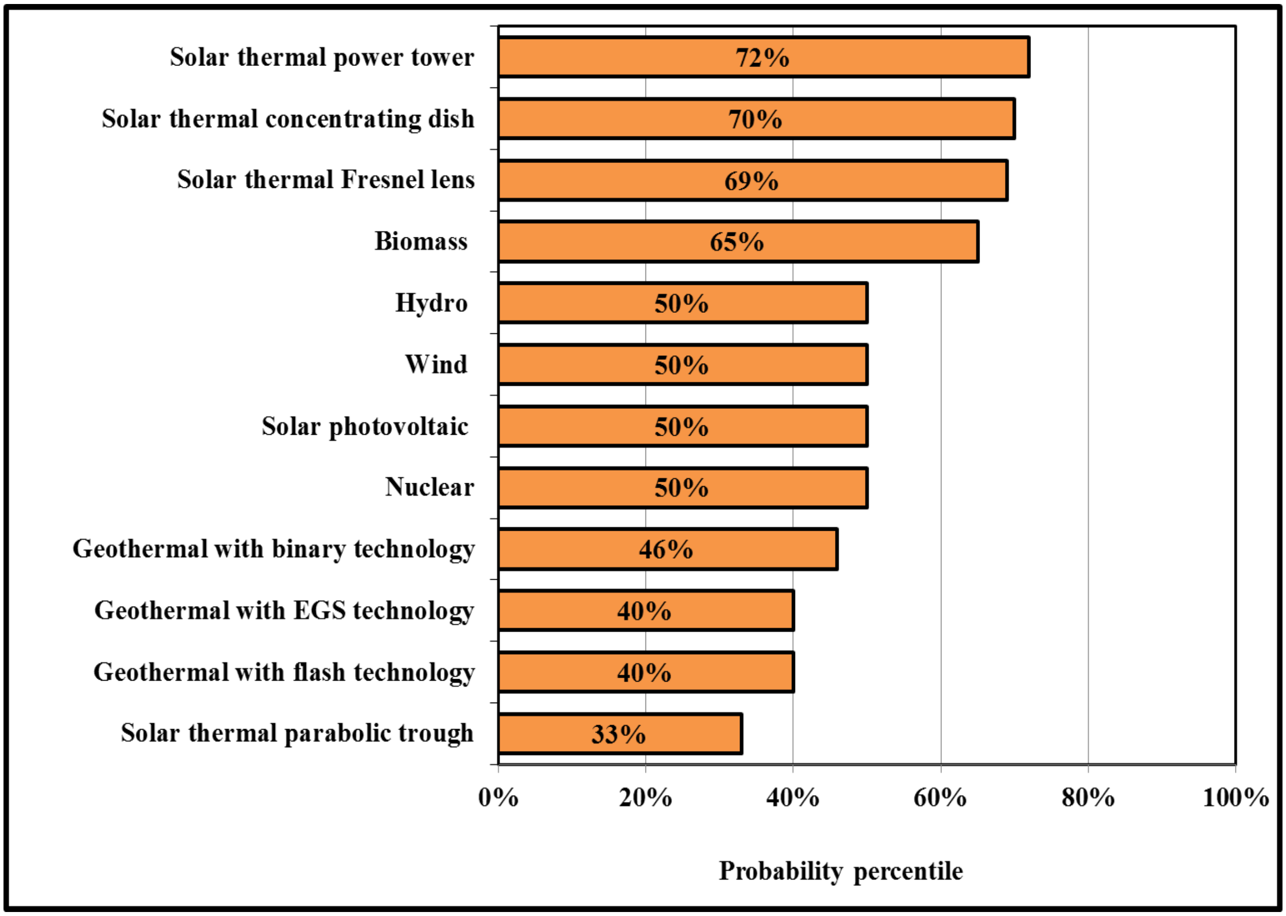

Figure 4.2: Probability percentiles of the most likely conversion efficiencies of non-conventional energy technologies

Performance profiles are developed theoretically through equations to correlate conversion efficiency to water demand coefficients [17, 62]. The effect is studied separately for the two stages of primary fuel extraction or construction (upstream stage) and for the power generation stage.

4.6.1 Upstream stage

The distribution of WCUPs at probabilities of 10% and 90% is shown in Table 4.7 for pathways with different M1 and M2 values. The corresponding distribution of pathways with the same M1 and M2 values is shown in Table 4.8. When a pathway has the same M1 and M2 value, this indicates that the WWUP is the same as the WCUP, and no water is returned to the source. Wind energy takes the lead here, followed by geothermal, solar, and nuclear. Water demand coefficients for wind energy are always less than 0.15 L/kWh under all probability percentiles as shown from the output of the Monte Carlo simulation in Table 4.7. Water demand coefficients during the upstream stage are lower for these technologies due to the fact that either no fuel is required or very low water is needed, as in the case of nuclear power, and only materials and construction consume water.

The WWUPs for biomass upstream pathways are all assumed to be equal to the corresponding WCUPs (M1=M2). The intensive water used in the production stage of the biomass feedstock gives them the highest WCUPs of all the non-conventinal energy pathways.

Table 4.7: WCUP and WWUP distributions for the upstream stage of non-conventional energy pathways with different values for M1 and M2

Pathway	Values (L/kWh) at probability 10%[c]		Values (L/kWh) at probability 90%[c]		Factor of merit (L/kWh)	
	WCUP	WWUP	WCUP	WWUP	M1[a]	M2[b]
Nuclear-Diffusion enrichment	0.35	0.56	0.31	0.50	0.11	0.175
Solar-Photovoltaic-C-Si	0.0032	0.58	0.0072	0.26	0.04	0.047
Solar-Photovoltaic-Thin film	0.037	0.11	0.016	0.049	0.003	0.009
Wind	0.00005	0.1251	0.00003	0.0812	0.00001	0.038

[a] Calculated using Equation 4.1, the conversion efficiencies (η_{ml}) from Table 4.1, and the corresponding WCUPs from input tables (Tables 4.2 to 4.5).
[b] Calculated using Equation 4.2, the conversion efficiencies (η_{ml}) from Table 4.1, and the corresponding WWUPs from input tables (Tables 4.2 to 4.5).
[c] M1 and M2 were used with Equations 4.1 and 4.2, respectively, to calculate the WCUP and the WWUP using a Monte Carlo probability triangular distribution of conversion efficiency.

Table 4.8: WCUP and WWUP distributions for the upstream stage of non-conventional energy pathways with the same M1 and M2

Pathway	WCUP/WWUP (L/kWh) at probability 10% [b]	WCUP/WWUP (L/kWh) at probability 90% [b]	Factor of merit M1 = M2[a] (L/kWh)
Nuclear-Centrifugal enrichment	0.22	0.20	0.07
Solar thermal-Power tower	1.02	0.55	0.12
Solar thermal-Parabolic trough	0.71	0.43	0.09
Solar thermal-Fresnel	0.78	0.56	0.07
Solar thermal-Concentrating dish	0.76	0.57	0.13
Geothermal-Binary	0.02	0.006	0.0008
Geothermal-Flash	0.01	0.007	0.0011
Geothermal-EGS	0.01	0.008	0.0009
Wood chips-Direct combustion	818.36	566.49	205.41
Wood chips-Bio-oil	1527.45	1057.36	383.40
Corn stover-Direct combustion	341.06	236.07	85.60
Corn stover-Bio-oil	429.38	297.23	107.77
Wheat straw-Direct combustion	418.49	289.69	105.04
Wheat straw-Bio-oil	612.41	423.92	153.71
Switchgrass-Direct combustion	883.68	611.70	221.80
Switchgrass-Bio-oil	1082.91	749.62	271.81

[a] Calculated using Equation 4.1, the conversion efficiencies (η_{ml}) from Table 4.1, and the corresponding WCUPs from input tables (Tables 4.2 to 4.5).
[b] M1 was used with Equation 4.1 to calculate the WCUP/WWUP using a Monte Carlo probability triangular distribution of conversion efficiency.

4.6.2 Power generation stage

Table 4.9 shows the water demand coefficients for the power generation stage at probability percentiles of 10% and 90%, besides the factors of merit. Of all the non-conventional energy technologies, wind energy still has the lowest water demand coefficients during power generation. Nuclear energy with a once-through cooling system has the highest impact on water withdrawals during the power generation stage (165.30 and 192.10 L/kWh at 10% and 90% probabilities, respectively). Biomass pathways outperform in water demand coefficients during the power generation stage compared to nuclear energy pathways.

Factors of merit are constants relating water demand coefficients to the conversion efficiency of the power plants (see equations 4.1- 4.6). These constant factors are useful comparison tools for pathways following the same track. For example, the biomass power generation stage with a cooling tower has an M3 of 1.08 L/kWh while the same pathway based on nuclear energy has an M3 of 1.34 L/kWh, which indicates that at the same conversion efficiency, this biomass pathway always performs better than the corresponding nuclear pathway.

Table 4.9: WCUP and WWUP distributions for the power generation stage of non-conventional energy pathways

Pathway	WCC (L/kWh) at probability 10%[e]	WCC (L/kWh) at probability 90%[e]	WWC (L/kWh) at probability 10%[f]	WWC (L/kWh) at probability 90%[f]	Factor of merit (L/kWh)			
					M3[a]	M4[b]	M5[c]	M6[d]
Biomass-Once through cooling	1.99	1.17	187.16	110.25	0.67	62.72	-	-
Biomass-Cooling tower	3.23	1.90	3.71	2.19	1.08	1.24	-	-
Biomass-Cooling pond	3.13	1.85	3.74	2.21	1.05	1.25	-	-
Biomass-Dry cooling	0.32	0.19	0.37	0.22	0.11	0.12	-	-
Nuclear-Once through cooling	1.63	1.41	192.10	165.30	0.75	87.69	-	-
Nuclear-Cooling tower	2.94	2.53	4.50	3.87	1.34	2.05	-	-
Nuclear-Cooling pond	2.49	2.15	4.50	3.87	1.14	2.05	-	-
Nuclear-Dry cooling	0.29	0.25	0.45	0.39	0.13	0.21	-	-
Geothermal-Flash-Dry cooling	0.06	0.03	0.10	0.04	0.005	0.008	-	-
Solar thermal-Power tower-Cooling tower	5.71	2.72	5.71	2.72	0.77	0.77	-	-
Solar thermal-Power tower-Hybrid cooling	1.20	0.57	1.20	0.57	0.16	0.16	-	-
Solar thermal-Power tower-Dry cooling	0.18	0.09	0.18	0.09	0.02	0.02	-	-
Solar thermal-Parabolic trough-Cooling tower	4.07	2.22	4.07	2.22	0.59	0.59	-	-
Solar thermal-Parabolic trough-Hybrid cooling	1.56	0.85	1.56	0.85	0.23	0.23	-	-
Solar thermal-Parabolic trough-Dry cooling	0.36	0.19	0.36	0.19	0.05	0.05	-	-
Solar thermal-Fresnel-Cooling tower	5.00	3.47	5.00	3.47	0.47	0.47	-	-
Solar thermal-Fresnel-Dry cooling	0.50	0.35	0.50	0.35	0.05	0.05	-	-

Pathway	**WCC (L/kWh) at probability 10%[e]**	**WCC (L/kWh) at probability 90%[e]**	**WWC (L/kWh) at probability 10%[f]**	**WWC (L/kWh) at probability 90%[f]**	**Factor of merit (L/kWh)**			
					M3[a]	**M4[b]**	**M5[c]**	**M6[d]**
Geothermal-Binary-Hybrid cooling	3.40	1.04	3.40	1.04	0.15	0.15	-	-
Geothermal-Binary-Dry cooling	2.14	0.65	2.14	0.65	0.10	0.10	-	-
Geothermal-Flash-Cooling tower	0.08	0.04	0.08	0.04	0.007	0.007	-	-
Geothermal-EGS-Binary-Dry cooling	2.20	1.58	2.20	1.58	0.19	0.19	-	-
Solar thermal-Concentrating dish	0.02	0.018	0.02	0.018	-	-	0.004	0.004
Solar-Photovoltaic-Flat paneled	0.04	0.02	0.04	0.02	-	-	0.003	0.003
Solar-Photovoltaic-Concentrated PV	0.18	0.08	0.18	0.08	-	-	0.015	0.015
Wind	0.006	0.004	0.007	0.005	-	-	0.002	0.002
Hydroelectricity	71.70	65.00	71.70	65.00	-	-	61.36	61.36

[a] Calculated using Equation 4.3, the conversion efficiencies (η_{ml}) from Table 4.1, and the corresponding WCCs from the input tables (Tables 4.2 to 4.5).
[b] Calculated using Equation 4.4, the conversion efficiencies (η_{ml}) from Table 4.1, and the corresponding WCCs from the input tables (Tables 4.2 to 4.5).
[c] Calculated using Equation 4.5, the conversion efficiencies (η_{ml}) from Table 4.1, and the corresponding WCCs from the input tables (Tables 4.2 to 4.5).
[d] Calculated using Equation 4.6, the conversion efficiencies (η_{ml}) from Table 4.1, and the corresponding WCCs from the input tables (Tables 4.2 to 4.5).
[e] M3 and M5 were used with Equations 4.3 and 4.5, respectively, to calculate the WCCs using a Monte Carlo probability triangular distribution of conversion efficiency.
[f] M4 and M6 were used with Equations 4.4 and 4.6, respectively, to calculate the WCCs using a Monte Carlo probability triangular distribution of conversion efficiency.

4.7 Conclusions

Sixty pathways of power generation from non-conventional energy were developed along with water demand coefficients for each pathway to cover water consumption and water withdrawals coefficients at the base case conversion efficiency. The effects of conversion efficiency variation on the water demand coefficients were studied through a comprehensive uncertainty analysis. Wind energy has the most positive impact on water demand and can alleviate the intensive water required to generate power. The highest water withdrawals coefficient during the power generation stage is from nuclear energy with a once-through cooling system and is 165.30 at a probability of 90% and 192.10 L/kWh at a probability of 10%. Direct combustion of corn stover has the lowest water demand coefficient (about 260 L/kWh for consumption and 260 – 387 L/kWh for withdrawals) among all the biomass pathways. The water required to irrigate crops grown for biomass negatively affects the water demand for biomass technology pathways. Considering the complete life cycle, dry cooling during power generation that can effectively compensate for the intensive water use during the fuel cycle. The lower conversion efficiencies of nuclear energy and solar-thermal pathways compared to other thermoelectric technologies negatively impacts the water demand coefficients. Improving conversion efficiency is one of the essential factors to consider when studying the level of water demand for a certain technology. The mostly likely conversion efficiencies selected for the base case in this study had the probability range of 33% - 72% based on the maximum and minimum ranges. Studies of water demand for power generation technologies have to be integrated with other environmental, economic, and social aspects in order to make decisions for sustainable development.

References

[1]. The International Renewable Energy Agency (IRENA). Renewable energy in the water, energy & food nexus. Available at: http://www.irena.org/DocumentDownloads/Publications/IRENA_Water_Energy_Food_Nexus_2015.pdf [accessed 13.11.2016]

[2]. National Energy Technology Laboratory (NETL). Impact of drought on U.S. steam electric power plant cooling water intakes and related water resource management issues. DOE/NETL-2009/1364. Pittsburgh, PA. Available at: https://www.netl.doe.gov/File%20Library/Research/Coal/ewr/water/final-drought-impacts.pdf [accessed: 12.11.2016]

[3]. U.S. Energy Information Administration (EIA). Annual energy outlook 2015 with projections to 2040. DOE/EIA-0383(2015). Available at: http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf [accessed: 07.11.2016]

[4]. Macknick J. Water impacts of the electricity sector. American Solar Energy Society, World Renewable Energy Forum. National Renewable Energy Laboratory (NREL). Available at: http://www.nrel.gov/docs/fy12osti/55028.pdf [accessed: 08.11.2016]

[5]. Statistics Canada. Section 3: the demand for water in Canada. Available at: http://www.statcan.gc.ca/pub/16-201-x/2010000/part-partie3-eng.htm [accessed: 09.11.2016]

[6]. Hondo H. Life cycle GHG emission analysis of power generation systems: Japanese case. Energy 2005; 30: 2042–2056.

[7]. World Nuclear Association (WNA). Comparison of lifecycle greenhouse gas emissions of various electricity generation sources. Available at: http://www.world-nuclear.org/uploadedFiles/org/WNA/Publications/Working_Group_Reports/comparison_of_lifecycle.pdf [accessed: 08.11.2016]

[8]. Spath PL, Mann MK. Biomass power and conventional fossil systems with and without CO_2 sequestration – comparing the energy balance, greenhouse gas emissions and economics. Prepared under Task No. BB04.4010. NREL/TP-510-32575. Available at: http://www.nrel.gov/docs/fy04osti/32575.pdf [accessed: 06.11.2016]

[9]. Lechon Y, Rua C, Saez R. Life cycle environmental impacts of electricity production by solar thermal power plants in Spain. Journal of Solar Energy Engineering 2008; 130: 021012-1-7.

[10]. Goldstein R, Smith W. Water & sustainability (Volume 3): U.S. water consumption for power production—The Next Half Century. Palo Alto, CA: EPRI;1006786. Available at: http://www.circleofblue.org/wp-content/uploads/2010/08/EPRI-Volume-3.pdf [accessed 04.11.2016]

[11]. Meldrum J, Anderson SN, Heath G, Macknick, J. Life cycle water use for electricity generation: a review and harmonization of literature estimates. Environmental Research Letters 2013; 8: 015031 (18pp).

[12]. Singh S, Kumar A, Ali B. Integration of energy and water consumption factors for biomass conversion pathways. Biofuels, Bioproducts and Biorefining 2011; 5(4): 399-409.

[13]. Gleick PH. Water and Energy. Annual Review of Energy and Environment 1994; 19:267–299.

[14]. Webber ME. The water intensity of the transitional hydrogen economy. Environmental Research Letters 2007; 2: 034007 (7pp).

[15]. Onat N, Bayar H. The sustainability indicators of power production systems. Renewable and Sustainable Energy Reviews 2010; 14: 3108–3115.

[16]. Ali B, Kumar A. Development of life cycle water footprints for gas-fired power generation technologies. Energy Conversion and Management 2016; 110: 386–396.

[17]. Ali B, Kumar A. Development of life cycle water-demand coefficients for coal-based power generation technologies. Energy Conversion and Management 2015; 90: 247–260.

[18]. Tan C, Zhi Q. The energy-water nexus: a literature review of the dependence of energy on water. Energy Procedia 2016; 88: 277 – 284.

[19]. ModelRisk Software. Available at: http://www.vosesoftware.com/ [accessed: 10.11.2016]

[20]. Williams SK, Acker T, Goldberg M, Greve M. Estimating the economic benefits of wind energy projects using Monte Carlo simulation with economic input/output analysis. Wind Energy 2008; 11 (4): 397 – 414.

[21]. Kullapa S, Marriott J. Increasing innovation in home energy efficiency: Monte Carlo simulation of potential improvements. Energy and Buildings 2010; 42 (6): 828 – 833.

[22]. Karfopoulos KL, Anagnostakis MJ. Parameters affecting full energy peak efficiency determination during Monte Carlo simulation. Applied Radiation and Isotopes 2010; 68: 1435-1437.

[23]. World Nuclear Association (WNA). Cooling power plants. Available at: http://www.world-nuclear.org/info/Current-and-Future-Generation/Cooling-Power-Plants/ [accessed: 12.11.2016]

[24]. Union of Concerned Scientists. How it works: water for power plant cooling. Available at: http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-cooling-power-plant.html#.VjmMPvldVMQ [accessed: 13.11.2016]

[25]. Singh S, Kumar A. Development of water requirement factors for biomass conversion pathways. Bioresource Technology 2011; 102(2), 1316-1328.

[26]. Garcia SG, Lacoste C, Aicher T, Feijoo G, Lijo, L, Moreira MT. Environmental sustainability of bark valorisation into biofoam and syngas. Journal of Cleaner Production 2016; 125: 33-43.

[27]. Fogarasi S, Cormos CC. Technico-economic assessment of coal and sawdust co-firing power generation with CO_2 capture. Journal of Cleaner Production 2015; 103: 140-148.

[28]. Cohen BL. Breeder reactors: a renewable energy source. American Journal of Physics 1983; 51(1). Available at: http://large.stanford.edu/publications/power/references/docs/pad11983cohen.pdf [accessed: 09.11.2016]

[29]. The United States Natural Regulatory Commission (U.S.NRC). Uranium enrichment. Available at: http://www.nrc.gov/docs/ML0313/ML031330159.pdf [accessed: 13.11.2016]

[30]. World Nuclear Association (WNA). Uranium enrichment. Available at: http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/conversion-enrichment-and-fabrication/uranium-enrichment.aspx [accessed: 13.11.2016]

[31]. U.S. Department of Energy (DOE). Concentrating solar power commercial application study: reducing water consumption of concentrating solar power electricity generation. Report to Congress. Available at: http://www1.eere.energy.gov/solar/pdfs/csp_water_study.pdf [accessed: 07.11.2016]

[32]. A.T. Kearney Inc. Solar thermal electricity 2025. Clean electricity on demand: attractive STE cost stabilize energy production. June 2010. Available at: http://www.promes.cnrs.fr/uploads/pdfs/documentation/2010-Solar%20thermal%20electricity%202025%20ESTELA.pdf [accessed: 08.11.2016]

[33]. International Energy Agency (IEA). Technology roadmap: solar thermal electricity. Available at: https://www.iea.org/publications/freepublications/publication/technologyroadmapsolarthermalelectricity_2014edition.pdf [accessed 04.11.2016]

[34]. Ali B. Simulation of a solar concentrating dish for steam generation. International Journal of Sustainable Energy 2003; 23 (3):129-141.

[35]. Raugei M, Bargigli S, Ulgiati S. Life cycle assessment and energy pay-back time of advanced photovoltaic modules: CdTe and CIS compared to poly-Si. Energy 2007; 32:1310–1318.

[36]. Peng J, Lu L, Yang H. Review on life cycle assessment of energy payback and greenhouse gas emission of solar photovoltaic systems. Renewable and Sustainable Energy Reviews 2013; 19: 255–274.

[37]. U.S. Department of Energy (DOE). Small wind electric systems: a U.S. consumer's guide. Energy Efficiency and Renewable Energy. Available at: http://www.nrel.gov/docs/fy07osti/42005.pdf [accessed: 13.11.2016]

[38]. Weis T, Doukas A, Anderson K, Howell G. Landowners' guide to wind energy in Alberta. Pembina Institute. Available at: https://www.pembina.org/reports/alberta-landowners-guide-web.pdf [accessed: 12.11.2016]

[39]. U.S. Department of Energy (DOE). 20% wind energy by 2030: increasing wind energy's contribution to U.S. electricity supply. DOE/GO-102008-2567. Available at: http://www.nrel.gov/docs/fy08osti/41869.pdf [accessed: 12.11.2016]

[40]. U.S. Department of the Interior, Bureau of Reclamation (USBR). Hydroelectric power. Available at: https://www.usbr.gov/power/edu/pamphlet.pdf [accessed: 11.11.2016]

[41]. International Energy Agency (IEA). Renewable energy essentials: hydropower. Available at: http://www.iea.org/publications/freepublications/publication/hydropower_essentials.pdf [accessed 12.11.2016]

[42]. Younas U, Khan B, Ali SM, Arshad CM, Farid U, Zeb K, Rehman F, Mehmood Y, Vaccaro A. Pakistan geothermal renewable energy potential for electric power generation: a survey. Renewable and Sustainable Energy Reviews 2016; 63: 398–413.

[43]. Kagel A, Bates D, Gawell K. A guide to geothermal energy and the environment. Geothermal Energy Association. Available at: http://geo-energy.org/reports/environmental%20guide.pdf [accessed: 12.11.2016]

[44]. Ahmed I, Rashid A. Study of geothermal energy resources of Pakistan for electric power generation. Energy Sources 2010; Part A, 32:826–838.

[45]. Ezzat MF, Dincer I. Energy and exergy analyses of a new geothermal–solar energy based system. Solar Energy 2016; 134: 95–106.

[46]. Massachusetts Institute of Technology (MIT). The future of geothermal energy: impact of enhanced geothermal systems (EGS) on the United States in the 21st century. Available at: http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf [accessed: 08.11.2016]

[47]. Oel PRO, Hoekstra AY. Towards quantification of the water footprint of paper: a first estimate of its consumptive component. Water Resources Management 2012; 26:733–749.

[48]. The Engineering ToolBox. Wood densities. Available at: http://www.engineeringtoolbox.com/wood-density-d_40.html [accessed: 07.11.2016]

[49]. Ringer M, Putsche V, Scahill J. Large-scale pyrolysis oil production: a technology assessment and economic analysis. Technical Report NREL/TP-510-37779. Available at: http://www.nrel.gov/docs/fy07osti/37779.pdf [accessed: 13.11.2016]

[50]. Boundy B, Diegel SW, Wright L, Davis SC. Biomass energy data book: edition 4. U.S Department of Energy (DOE), ORNL/TM-2011/446. Available at: http://info.ornl.gov/sites/publications/files/Pub33120.pdf [accessed: 12.11.2016]

[51]. Warner ES, Heath GA. Life cycle greenhouse gas emissions of nuclear electricity generation: systematic review and harmonization. Journal of Industrial Ecology 2012; 16 (No.S1):S73:S92. DOI: 10.1111/j.1530-9290.2012.00472.x.

[52]. National Energy Technology Laboratory (NETL). Assessment of parabolic trough and power tower solar technology cost and performance forecasts. Sargent & Lundy LLC Consulting Group Chicago, Illinois. Available at: http://www.nrel.gov/docs/fy04osti/34440.pdf [accessed: 12.11.2016]

[53]. Evans A, Strezov V, Evans TJ. Assessment of sustainability indicators for renewable energy technologies. Renewable and Sustainable Energy Reviews 2009; 13: 1082–1088.

[54]. U.S. Energy Information Administration (EIA). Annual energy review 2011: alternatives for estimating energy consumption. Available at: http://www.eia.gov/totalenergy/data/annual/pdf/sec17.pdf [accessed: 07.11.2016]

[55]. Eurelectric. Hydropower: supporting a power system in transition. Available at: http://www.eurelectric.org/media/180752/hydropower-final-lr-2015-2120-0003-01-e.pdf [accessed: 11.11.2016]

[56]. Moon H, Zarrouk SJ. Efficiency of geothermal power plants: a worldwide review. New Zealand Geothermal Workshop 2012 Proceedings, 19 - 21 November 2012, Auckland, New Zealand. Available at: http://www.geothermal-energy.org/pdf/IGAstandard/NZGW/2012/46654final00097.pdf [accessed 11.11.2016]

[57]. Bertani R. Level of typical efficiencies for electricity generation of geothermal plants. EGEC. Available at: http://egec.info/wp-content/uploads/2011/08/12-TP-GEOELEC-Pisa-Bertani.pdf [accessed 11.11.2016]

[58]. DiPippo R. Ideal thermal efficiency for geothermal binary plants. Geothermics 2007; 36: 276–285.

[59]. Lacirignola M, Blanc I. Environmental analysis of practical design options for enhanced geothermal systems (EGS) through life-cycle assessment. Renewable Energy 2013; 50: 901-914.

[60]. Macknick J, Newmark R, Heath G, Hallett KC. Operational water consumption and withdrawals factors for electricity generating technologies: a review of existing literature. Environmental Research Letters 2012; 7: 045802-12.

[61]. Torcellini P, Long N, Judkoff R. Consumptive water use for U.S. power production. Available at: http://www.nrel.gov/docs/fy04osti/35190.pdf [accessed: 13.11.2016]

[62]. Yang X, Dziegielewski B. Water use by thermoelectric power plants in the United States. Journal of the American Water Resources Association (JAWRA) 2007; 43(1):160-69. DOI: 10.1111 ⁄ j.1752-1688.2007.00013.x.

Chapter 5

Development of Water Demand Footprints for Oil Sands in Alberta[4]

5.1 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

---

[4] Complete paper was submitted to *Energy Journal* as *Ali B, Kumar A*. *Development of life cycle water footprints for oil sands-based transportation fuel production. (submitted, in-review).*

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 5.1 shows the geographical locations of oil sands production and river basins in Alberta.

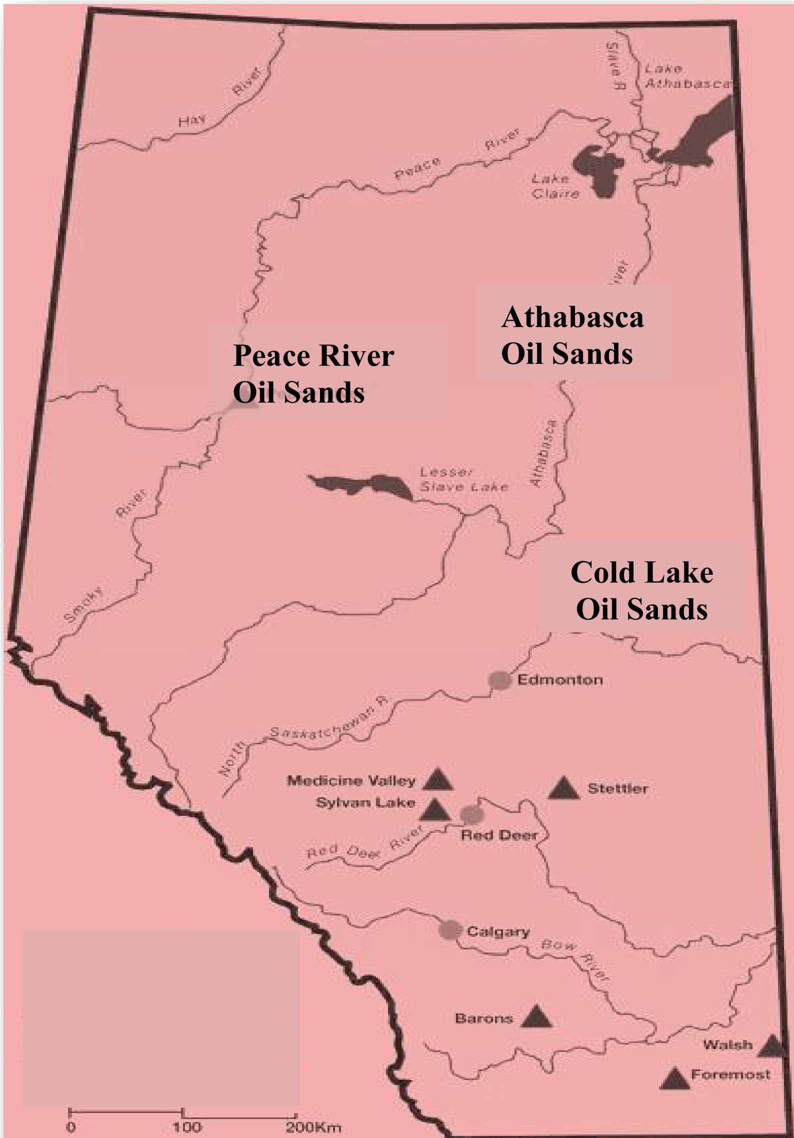

Figure 5.1: Locations of oil sands production and river basins in Alberta

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 chapter is aimed at addressing this gap.

The key objectives of this chapter 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.

5.2 Scope and system boundary

Water demand in this chapter 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 5.2 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 the 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 chapter and sensitivity analyses were conducted through Monte Carlo simulations [28-31] to study the uncertainty of the most likely coefficients taken in the analysis.

5.2.1 Pathways selection

Pathways were structured according to the unit operations and to match the oil sands production profile in Canada as shown in Figure 5.2. 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 processing.

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 [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.

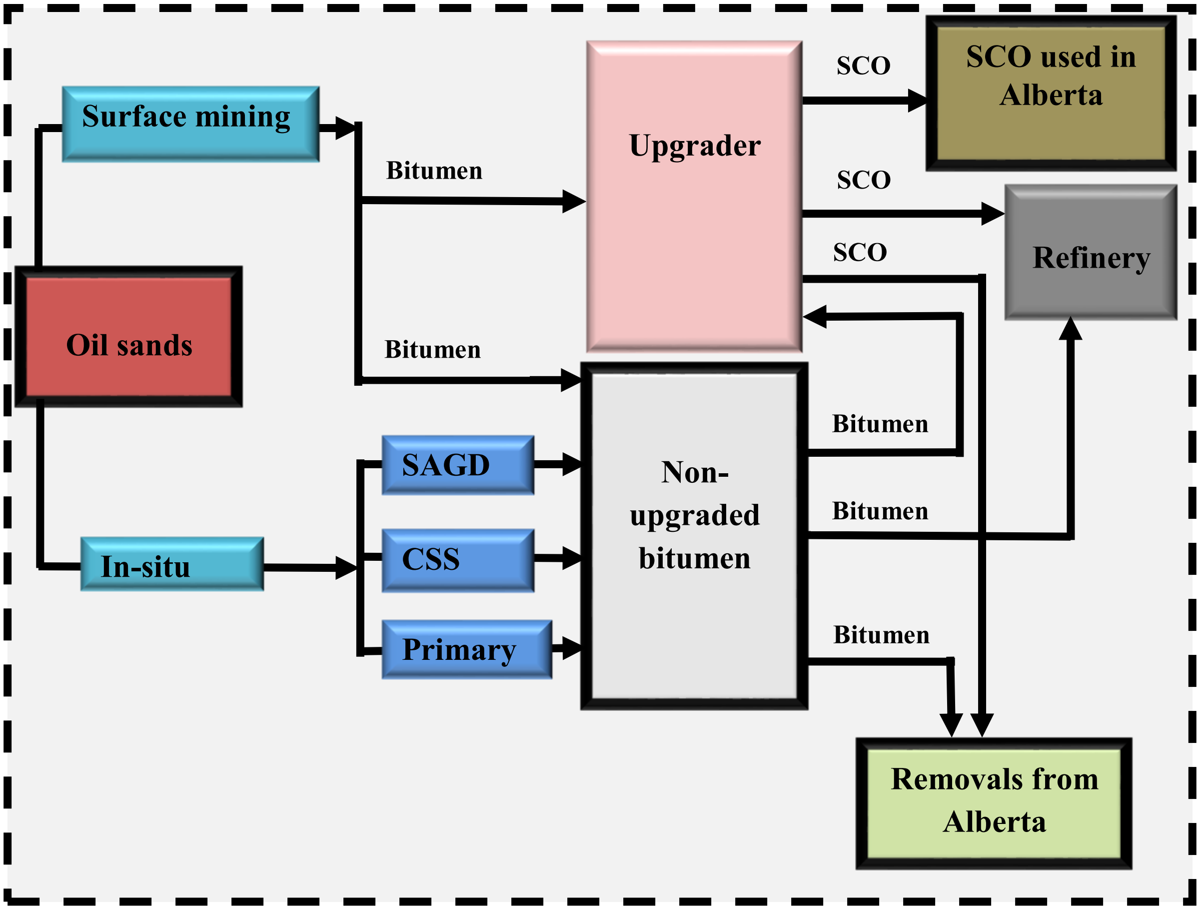

Figure 5.2: System boundary of unit operations and production pathways of Alberta oil sands

5.2.2 Oil sands 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 more than two times the amount of water required for in situ operations [41]. Pembina Institute [8] estimated the average water use intensity by in situ operations at 1.1 bbl_W/bbl_B compared to 2.1 bbl_W/bbl_B for the surface mining. The mined components of the oil sands are shovelled, crushed, mixed with warm water to form a slurry, and transported by hydro-transport 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 transportation fuel based on oil sands is dynamic and has improved over time. In 1994, Gleick wrote that 3.6-9.24 bbl_W/bbl_U 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 in situ extraction is carried out at the first stage of production and makes use 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 after primary technology becomes infeasible. 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].

5.2.3 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 chapter, water demand for upgrading is estimated separately from extraction and refining because these processes can be carried out in different geographical locations. For example, Shell Company uses water from Muskeg River for surface mining operations and upgrading the product in Scotford upgrader uses water from North Saskatchewan River Basin [40].

5.2.4 Oil sands 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. The 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].

5.3 Input data and assumptions

Based on earlier estimates [9], the water consumption coefficient in this chapter 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 5.1 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.

Table 5.1: 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 for the oil sands (bbl_W/bbl_B)	0.32	0.68	1.20	0.35	0.74	1.30	Min. coefficients are 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].

Unit operation	Water consumption			Water withdrawals			Comments/Sources
	Min	Mol	Max	Min	Mol	Max	
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 Fuels Association [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].

5.4 Results and discussion

Figure 5.3 and 5.4 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 chapter. Comparative in situ operations in the oil sands has 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, respectively. Disaggregated water demand coefficients are studied in the next section (in a sensitivity analysis), and an uncertainty analysis of the developed coefficients follows.

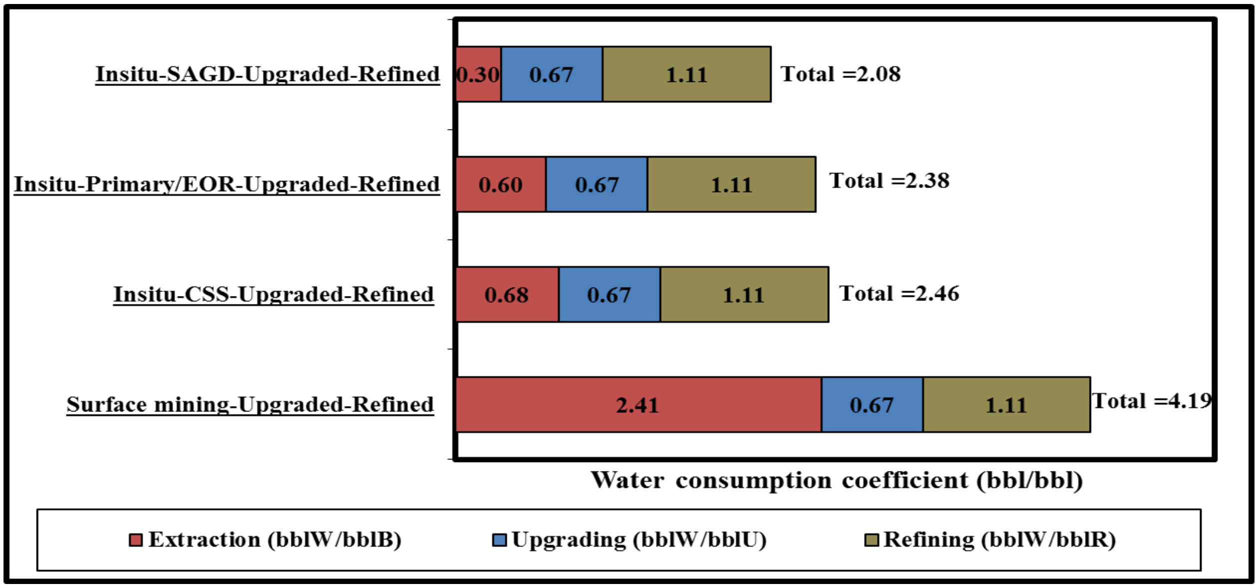

Figure 5.3: Water consumption coefficients for the complete life cycle of Alberta oil sands

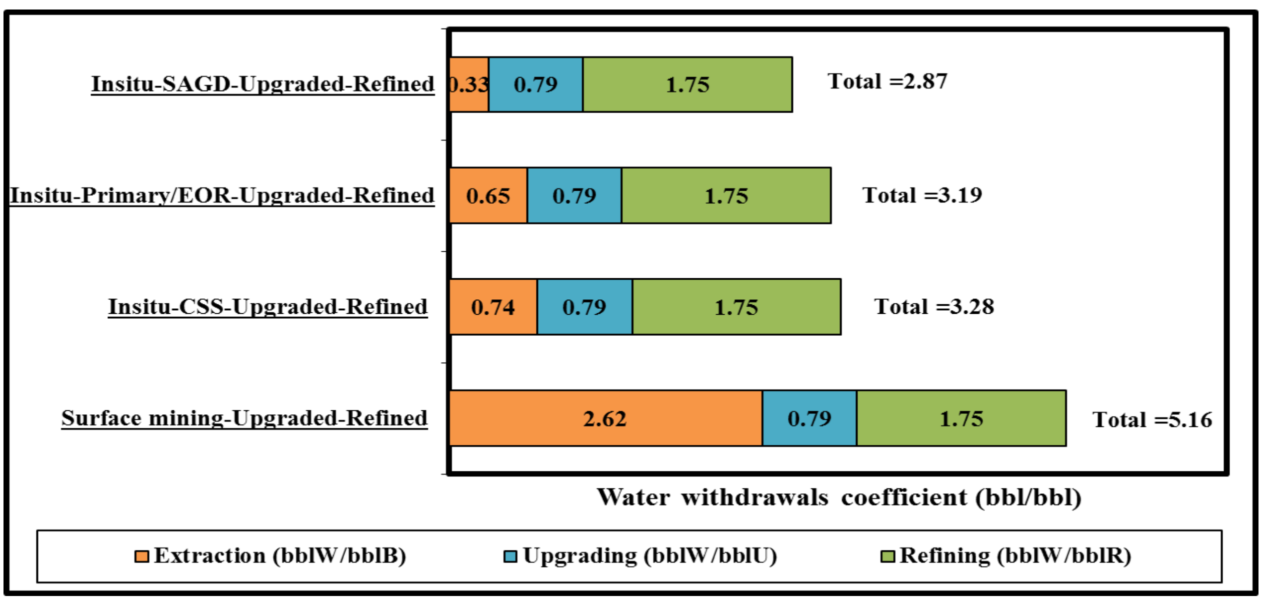

Figure 5.4: Water withdrawals coefficients for the complete life cycle of Alberta oil sands

5.5 Sensitivity analysis

The maximum and minimum water demand coefficients detailed in Table 5.1 were used in a Monte Carlo simulation with the consideration of the averages of what are most likely to happen. 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.

Table 5.2 shows 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] from the other gathered data. The average water demand coefficients for in situ SAGD unit operations taken in the analysis are the most certain 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 certain 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 Canadian Fuels Association [54].

Figure 5.5 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 5.2). Figure 5.6 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 5.3 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.

Table 5.2: Distribution of water demand coefficients for the main oil sands unit operations

Pathway	Consumption coefficient		Withdrawals coefficient		Probability percentile of the most likely value	
	Probability 10%	Probability 90%	Probability 10%	Probability 90%	Consumption coefficient	Withdrawals coefficient
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 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

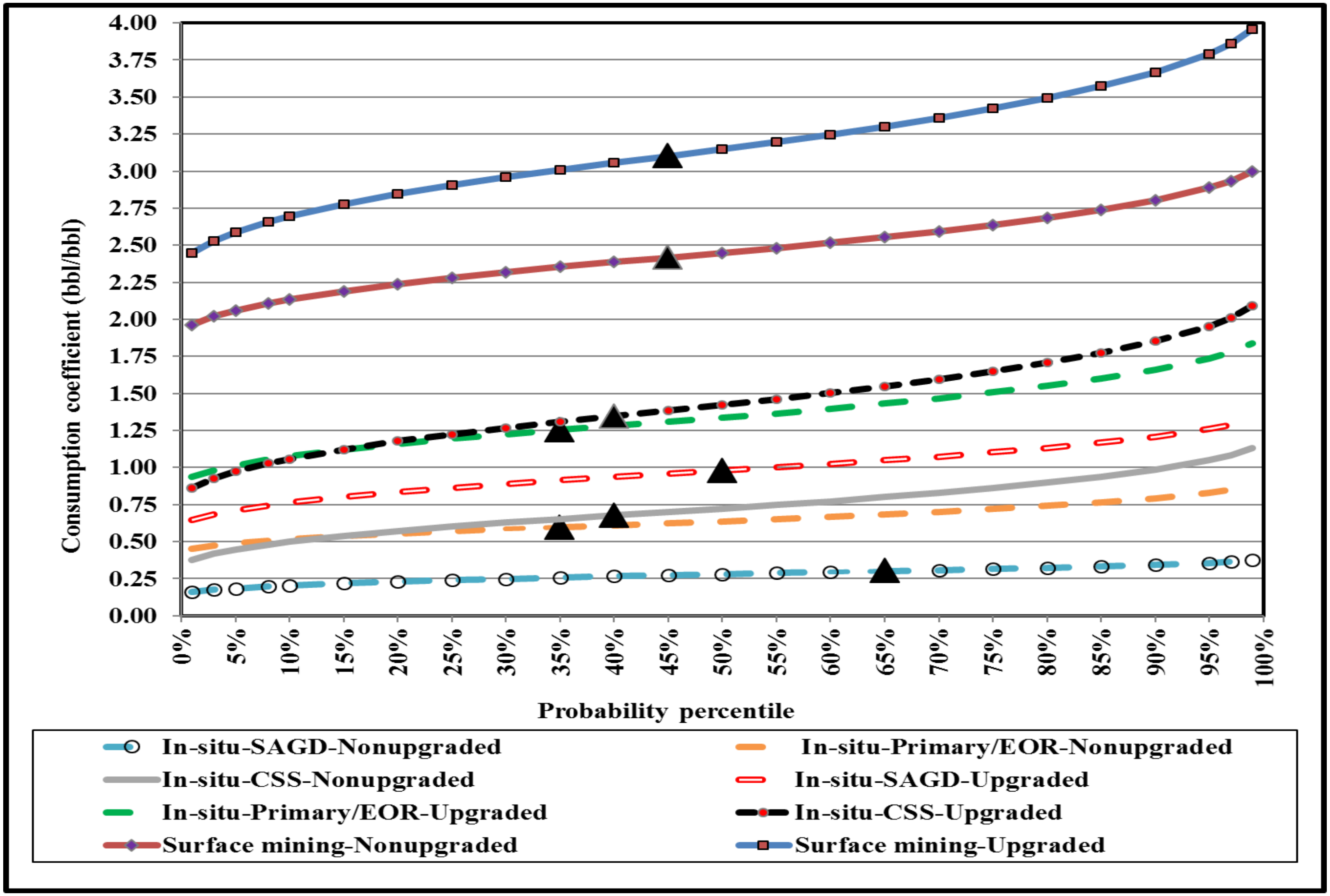

Figure 5.5: Distribution of water consumption coefficients for unrefined oil sands pathways

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

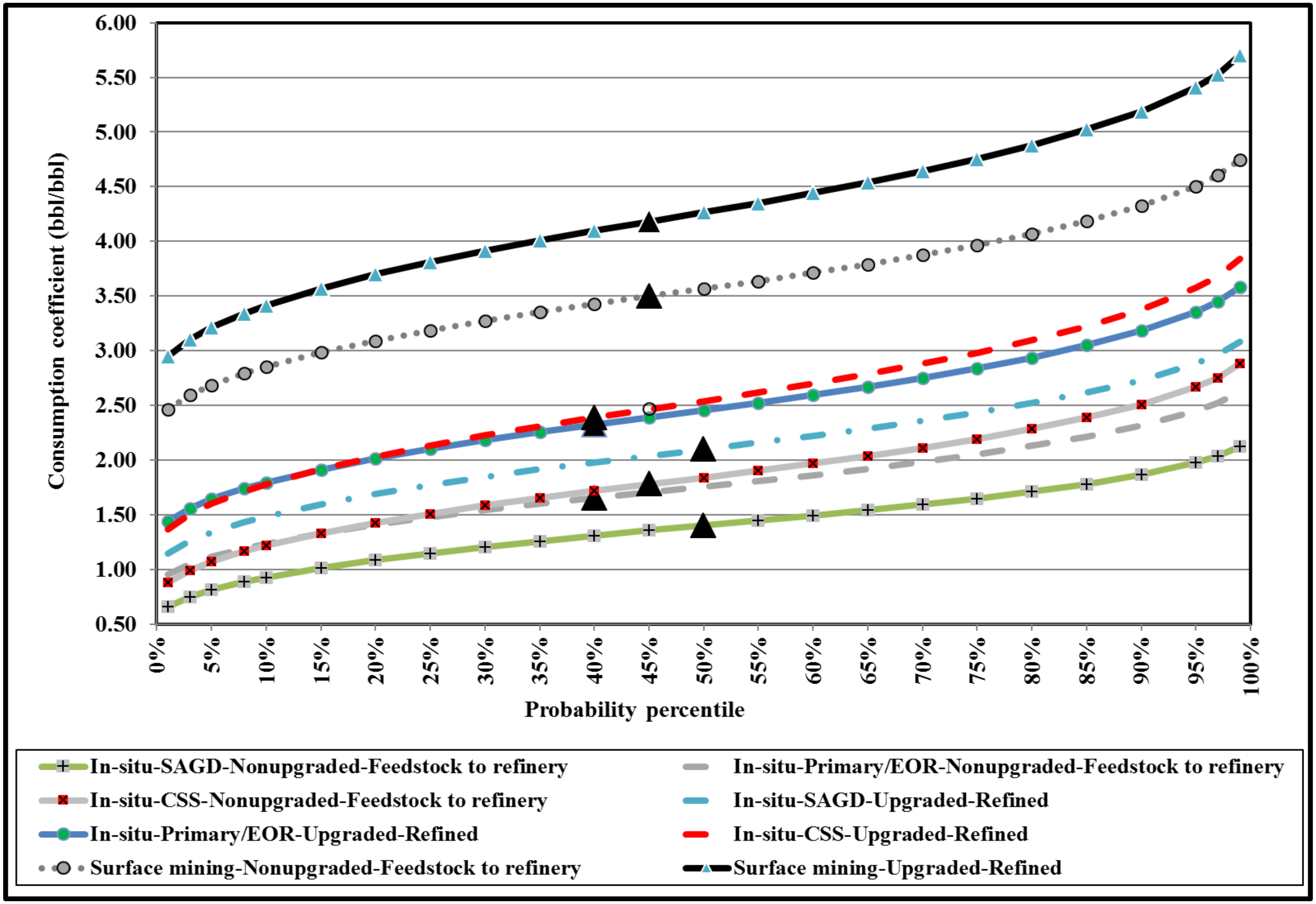

Figure 5.6: Distribution of water consumption coefficients for refined oil sands pathways

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

Table 5.3: Distribution of water withdrawals coefficients for 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-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-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-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--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}

5.6 Conclusions

Water demand coefficients for the complete life cycle of transportation fuels based on oil sands pathways were developed in this chapter. 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 chapter could be used in making decisions and formulating policies related to different liquid fuel production pathways from the oil sands. Surface mining has negative impacts on water, but for a comprehensive sustainability evaluation of this pathway, it is recommended that other environmental and economic impacts such as GHG emissions and production be integrated with this study. It is also recommended that more detailed data be reported by the 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.

References

[1]. International Energy Agency (IEA). Oil: medium-term market report 2015. Available at: https://www.iea.org/publications/freepublications/publication/MTOMR_2015_Final.pdf [accessed: 13.06.2016]

[2]. U.S. Energy Information Administration (EIA). Country analysis brief: Venezuela. Available at: http://www.eia.gov/beta/international/analysis_includes/countries_long/Venezuela/venezuela.pdf [accessed: 13.06.2016]

[3]. TOTAL S.A. Extra-heavy oils & oil sands: the challenges of development. Available at: http://www.total.com/sites/default/files/atoms/file/brochure-eho-en [accessed: 13.06.2016]

[4]. Desseault MB. Comparing Venezuelan and Canadian heavy oil and tar sands. Canadian International Petroleum Conference, Calgary, Alberta, Canada, June 12–14, 2001, Canadian Institute of Mining, Metallurgy, and Petroleum, Proceedings, Paper 2001–061.

[5]. Alberta Energy Regulator (AER). Alberta's energy reserves 2014 and supply/demand outlook 2015-2024. ST98-2015. ISSN 1910-4235. Available at: http://www.aer.ca/documents/sts/ST98/ST98-2015.pdf [accessed: 30.05.2016]

[6]. Government of Alberta. Energy. Available at: http://www.energy.alberta.ca/OilSands/791.asp [accessed: 15.05.2016]

[7]. Canadian Association of Petroleum Producers (CAPP). Optimal water management. Available at: http://www.capp.ca/responsible-development/water/optimal-water-management [accessed: 15.05.2016]

[8]. Pembina Institute Publications. Mining vs in situ. Fact sheet. Available at: http://pubs.pembina.org/reports/mining-vs-in situ.pdf [accessed: 29.06.2016]

[9]. Alberta Environment (AENV). Current and future water use in Alberta. Prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007). Available at: www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf [accessed: 28.06.2016]

[10]. Zubot W, MacKinnon MD, Ayala PC, Smith DW, Gamal El-Din M. Petroleum coke adsorption as a water management option for oil sands process-affected water. Science of the Total Environment 2012; 427–428: 364-372.

[11]. Chalaturnyk RJ, Scott JD, Ozum B. Management of oil sands tailings. Petroleum Science and Technology 2002; 20: 9-10:1025-1046.

[12]. Harjai SK, Flury C, Masliyah J, Drelich J, Xu Z. Robust aqueous-nonaqueous hybrid process for bitumen extraction from mineable Athabasca oil sands. Energy Fuels 2012; 26: 2920-2927.

[13]. Hofmann H, Babadagli T, Zimmermann G. Hot water generation for oil sands processing from enhanced geothermal systems: Process simulation for different hydraulic fracturing scenarios. Applied Energy 2014; 113: 524-547.

[14]. Zhao DW, Wang J, Gates ID. Thermal recovery strategies for thin heavy oil reservoirs. Fuel 2014; 117: 431-441.

[15]. Al-Otoom A, Allawzi M, Al-Omari N, Al-Hsienat E. Bitumen recovery from Jordanian oil sand by froth flotation using petroleum cycles oil cuts. Energy 2010; 35: 4217-4225.

[16]. Hong PA, Cha Z, Zhao X, Cheng CJ, Duyvesteyn W. Extraction of bitumen from oil sands with hot water and pressure cycles. Fuel Processing Technology 2013; 106: 460-467.

[17]. Grant J, Angen E, Dyer S. Forecasting the impacts of oilsands expansion. Pembina Institute, June 2013. Available at: http://www.pembina.org/pub/2455 [accessed: 20.06.2016]

[18]. Lunn S. Water use in Canada's oil-sands industry: the facts. SPE Economics and Management 2013; 5(1): 17-27.

[19]. Ali B, Kumar A. Development of life cycle water-demand coefficients for coal-based power generation technologies. Energy Conversion and Management 2015; 90: 247-260.

[20]. Ali B, Kumar A. Development of life cycle water footprints for gas-fired power generation technologies. Energy Conversion and Management 2016; 110: 386-396.

[21]. Kenny JF, Barber NL, Hutson SS, Linsey KS, Lovelace JK, Maupin MA. Estimated use of water in the United States in 2005. U.S. Geological Survey. Circular 1344. Available at: http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf [accessed: 20.05.2016]

[22]. Alberta Environment (AENV). Glossary of terms related to water and watershed management in Alberta. 1st edition. Partnerships and Strategies Section, November 2008. Available at: http://environment.gov.ab.ca/info/library/8043.pdf [accessed: 20.06.2016]

[23]. Macknick J, Newmark R, Heath G, Hallett K. Operational water consumption and withdrawal factors for electricity generating technologies: a review of existing literature. Environmental Research Letters 2012; 7: 045802 (10pp).

[24]. Goldstein R, Smith W. Water & Sustainability (Volume 3): U.S. Water Consumption for Power Production—The Next Half Century, EPRI, Palo Alto, CA: 2002. 1006786. Available at: http://www.circleofblue.org/wp-content/uploads/2010/08/EPRI-Volume-3.pdf [accessed: 12.12.2016]

[25]. U.S. Department of Energy. Energy demands on water resources. Report to Congress on the independency of energy and water. Available at: http://powi.ca/wp-content/uploads/2012/12/Energy-Demands-on-Water-Resources-Report-to-Congress-2006.pdf [accessed: 12.12.2016]

[26]. Meldrum J, Anderson SN, Heath G, Macknick, J. Life cycle water use for electricity generation: a review and harmonization of literature estimates. Environmental Research Letters 2013; 8: 015031 (18pp).

[27]. Ou Y, Zhai H, Rubin ES. Life cycle water use of coal- and natural-gas-fired power plants with and without carbon capture and storage. International Journal of Greenhouse Gas Control 2016; 44: 249–261.

[28]. Vose. ModelRisk Software. Available at: http://www.vosesoftware.com/ [accessed: 20.05.2016]

[29]. Williams SK, Acker T, Goldberg M, Greve M. Estimating the economic benefits of wind energy projects using Monte Carlo simulation with economic input/output analysis. Wind Energy 2008; 11 (4): 397-414.

[30]. Kullapa S, Joe M. Increasing innovation in home energy efficiency: Monte Carlo simulation of potential improvements. Energy and Buildings 2010; 42 (6): 828-833.

[31]. Karfopoulos KL, Anagnostakis MJ. Parameters affecting full energy peak efficiency determination during Monte Carlo simulation. Applied Radiation and Isotopes 2010; 68: 1435-1437.

[32]. Alberta Energy. Oil sands production profile: 2004-2014. Energy Technical Services, Resource Development Policy Division, January 31, 2016. Available at: http://www.energy.alberta.ca/Org/pdfs/InitiativeOSPP.pdf [accessed: 25.05.2016]

[33]. Alberta Energy Regulator (AER). Alberta's energy reserves 2008 and supply/demand outlook 2009-2018. ST98-2009. ISSN 1910-4235. Available at: http://www.aer.ca/documents/sts/ST98/st98-2009.pdf [accessed: 26.06.2016]

[34]. Alberta Energy Regulator (AER). Alberta's energy reserves 2009 and supply/demand outlook 2010-2019. ST98-2010. ISSN 1910-4235. Available at: http://www.aer.ca/documents/sts/ST98/st98_2010.pdf [accessed: 26.06.2016]

[35]. Alberta Energy Regulator (AER). Alberta's energy reserves 2010 and supply/demand outlook 2011-2020. ST98-2011. ISSN 1910-4235. Available at: http://www.aer.ca/documents/sts/ST98/st98-2011.pdf [accessed: 26.06.2016]

[36]. Alberta Energy Regulator (AER). Alberta's energy reserves 2011 and supply/demand outlook 2012-2021. ST98-2012. ISSN 1910-4235. Available at: http://www.aer.ca/documents/sts/ST98/ST98-2012.pdf [accessed: 26.06.2016]

[37]. Wu M, Chiu Y. Consumptive water use in the production of ethanol and petroleum gasoline-2011 update. Center for Transportation Research, Energy Systems Division, Argonne National Laboratory, December 2008, updated July 2011. ANL/ESD/09-1. Available at: https://greet.es.anl.gov/files/consumptive-water [accessed: 15.11.2016]

[38]. Suncor Energy. 2013 Report on sustainability. Available at: http://sustainability.suncor.com/2013/en/environment/water.aspx?__utma=1.1910911359.1369248968.1369248968.1369248968.1&__utmb=1.2.10.1379622632&__utmc=1&__utmx=-&__utmz=1.1369248968.1.1.utmcsr=google|utmccn=%28organic%29|utmcmd=organic|utmctr=%28not%20provided%29&__utmv=-&__utmk=236633089 [accessed: 20.05.2016]

[39]. Syncrude Canada Ltd. Are the oil sands being responsibly developed? Available at: http://syncrudesustainability.com/2011/media/pdf/Sycrude%202010-11%20CSR%20Report.pdf [accessed: 28.05.2016]

[40]. Shell Canada. Oil sands performance report 2012. Available at: http://s04.static-shell.com/content/dam/shell-new/local/country/can/downloads/pdf/oil-sands/oil-sands-performance-report-2012.pdf [accessed: 20.05.2016]

[41]. Donahue W. In situ oil sands – get ready for massive water demands in northern and central Alberta. Water Matters. August 2010. Available at: http://www.water-matters.org/story/401 [accessed: 20.05.2016]

[42]. Gray M, Xu Z, Masliyah J. Physics in the oil sands of Alberta. Physics Today 2009; 62 (3): 31-35.

[43]. Regional Aquatics Monitoring Program (RAMP). In Situ methods used in the oil sands. Available at: http://www.ramp-alberta.org/resources/development/history/insitu.aspx [accessed: 20.05.2016]

[44]. Gleick PH. Water and Energy. Annual Review of Energy and Environment 1994; 19:267–299.

[45]. Cenovus Energy. Steam-assisted gravity drainage (SAGD). Available at: http://www.cenovus.com/operations/technology/sagd.html [accessed: 22.05.2016]

[46]. Galas C, Clements A, Jaafar E, Jeje O. Potential of EOR in Alberta oil pools. Phase 1 report. Prepared by Sproule for the Energy Resources Conservation Board (ERCB) (June 2011). Available at: http://www.ags.gov.ab.ca/publications/pdf_downloads/ercb-eor-report1.pdf [accessed: 22.05.2016]

[47]. Galas C, Clements A, Jaafar E, Jeje O. Holst D, Holst R. Identification of enhanced oil recovery potential in Alberta. Phase 2 final report. Prepared by Sproule for Energy Resources Conservation Board (ERCB) (March 31, 2012). Available at:

http://www.ags.gov.ab.ca/publications/pdf_downloads/ercb-eor-report2.pdf [accessed: 22.05.2016]

[48]. Alberta Government. Alberta oil and gas industry: Quarterly update. Winter 2013. Available at: http://albertacanada.com/files/albertacanada/OilGas_QuarterlyUpdate_Winter2013.pdf [accessed: 20.05.2016]

[49]. Peachey B. Strategic needs for energy related water use technologies. Water and the EnergyINet. New Paradigm Engineering Ltd. Available at: http://www.assembly.ab.ca/lao/library/egovdocs/2005/aleri/154945.pdf [accessed: 20.05.2016]

[50]. Griffiths M, Dyer S. Up-grader alley: Oil sands fever strikes Edmonton. June 2008. Available at: http://pubs.pembina.org/reports/Upgrader_Alley-report.pdf [accessed: 29.05.2016]

[51]. Oil Sands Discovery Centre (OSDC). Facts about Alberta's oil sands and its industry. Available at: http://history.alberta.ca/oilsands/resources/docs/facts_sheets09.pdf [accessed: 28.05.2016]

[52]. Regional Aquatics Monitoring Program (RAMP). Upgrading of the oil sands. Available at: http://www.ramp-alberta.org/resources/development/history/upgrading.aspx [accessed: 27.05.2016]

[53]. Chevron Canada. How does an oil refinery work? Available at: http://www.chevron.ca/operations/refining/refineryworks.asp [accessed: 20.05.2016]

[54]. Canadian Fuels Association. Water – a precious resource. February 2010. Available at: http://canadianfuels.ca/userfiles/file/Water%20Primer%20-%20Final%20%28Updated%20with%202010%20data%29.pdf [accessed: 20.05.2016]

[55]. Pombo F, Magrini A, Szklo A. An analysis of water management in Brazilian petroleum refineries using rationalization techniques. Resources, Conservation and Recycling 2013; 73:172-179.

[56]. Souza AA, Forgiarini E, Brandao HL, Xavier MF, Pessoa FL, Souza SM. Application of water source diagram (WSD) method for the reduction of water consumption in petroleum refineries. Resources, Conservation and Recycling 2009; 53:149-154.

[57]. Alva-Argaez A, Kokossis AC, Smith R. The design of water-using systems in petroleum refining using a water-pinch decomposition. Chemical Engineering Journal 2007; 128: 33–46.

[58]. Anze M, Alves RM, Nascimento CA. Optimization of water use in oil refinery. AICHE Annual Meeting. Available at: http://aiche.confex.com/aiche/2010/webprogrampreliminary/Paper201402.html [accessed: 20.05.2016]

[59]. Canadian Association of Petroleum Producers (CAPP). 2013 Responsible Canadian energy progress report. Available at: http://www.capp.ca/~/media/capp/customer-portal/publications/233913.pdf [accessed: 16.11.2016]

[60]. Natural Resources Canada (NRCAN). Oil sands: water management. Available at: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/eneene/pubpub/pdf/os2015/14-0704-Oil-Sands-Water-Management_access_eng.pdf [accessed: 20.05.2016]

[61]. Cenovus Energy. 2012 Corporate responsibility report. Available at: http://www.cenovus.com/reports/2012-corporate-responsibility/ [accessed: 10.05.2016]

[62]. Canadian Association of Petroleum Producers (CAPP). Responsible Canadian energy progress report. For the year ended December 31, 2009. Available at: https://issuu.com/capp/docs/rce-oilsands-report/44 [accessed: 16.11.2016]

[63]. Canadian Association of Petroleum Producers (CAPP). The 2010 responsible Canadian energy progress report. Available at: http://www.capp.ca/media/news-releases/canadian-oil-and-gas-industry-releases-2010-responsible-canadian-energy-progress-report [accessed: 16.11.2016]

[64]. Diepolder P. Is zero discharge realistic? Hydrocarbon Processing 1992, 71 (10): 129-131.

Chapter 6

Development of Water Demand Footprints for Crude Oil Production in North America[5]

6.1 Introduction

Petroleum oil is one of the largest sources of energy and its extraction has environmental impacts on air, water, and land [1]. 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 [2,3]. 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 key players in the crude oil production in North America [4-6]. The U.S. is the largest consumer of oil products in the world and in 2012 consumed 18.6 million bbl/d. That country produced 60% of this consumption and imported 40% of it. The largest oil supplier to the U.S. in 2015 is Canada (40% of the total imports) and Mexico is the fourth largest (8%) after Venezuela (9%) [7]. 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 [8]. 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 [9].

[5] Complete paper was submitted to *Water Research Journal as Ali B, Kumar A***.** *Life cycle water demand coefficients for crude oil production from five North American locations. (submitted, in-review).*

The concern about the use of water for energy is high all over the world [10-13], 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 the water withdrawn is consumed and either not returned to the source or a lower quality water is returned. For example, in Alberta, Canada, in 2005 only 8% of 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 petroleum sector in Athabasca River Basin is surface water [14]. 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 [15-18].

Most of the earlier studies conducted on energy sector water demand either focused on a single geographical region [19-21], recognized water consumption but not water withdrawals [19-24], or covered specific unit operations and not over the complete life cycle [25,26]. 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 of crude oils' water footprint. There have been studies conducted on complete life cycle assessments of water footprints for coal and natural gas-based power generation [27, 28]; and regression models were developed to determine significant factors affecting water use of thermoelectric power plants in the United States [29], but none have been conducted for crude oils. This is a significant gap in the literature, and this chapter is aimed at addressing this gap.

The key objectives of this chapter are to:

- Develop life cycle water demand coefficients for crude oil produced at five different locations in North America.
- Carry out a comparative life cycle assessment 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 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.

6.2 Scope and system boundary

The life cycle methodology used in this chapter covers the unit operations involved in crude oil production. Unit operations have been defined for exploration, drilling, extraction, and refining. Water demand coefficients for crude oil are represented in this chapter by 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 [27, 28]. 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)

[30]. Figure 6.1 shows the selected oil production fields on the map of North America. Water demand data for these regions were estimated, and coefficients for a 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 [31– 34] to evaluate the impact of technology variations on the water demand coefficients for the complete life cycle of crude oil production.

6.2.1 Water quality

Water quality and source for the selected five regions may differ, but the developed water demand coefficients in this chapter are meant to represent a benchmark for the similar crude oil production technologies. Only fresh water is considered in this chapter and it is defined based on information from government agencies such as Alberta Environment [35, 36] 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 [36]. The raw water could be diverted from 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 within the assumed zone of fresh water (less than 4000 mg/L) in this chapter. The consumption coefficient of fresh water during extraction unit operations was calculated as follows:

$$\mathbf{FW = TWT - PRE * TWP} \qquad \mathbf{(6.1)}$$

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).

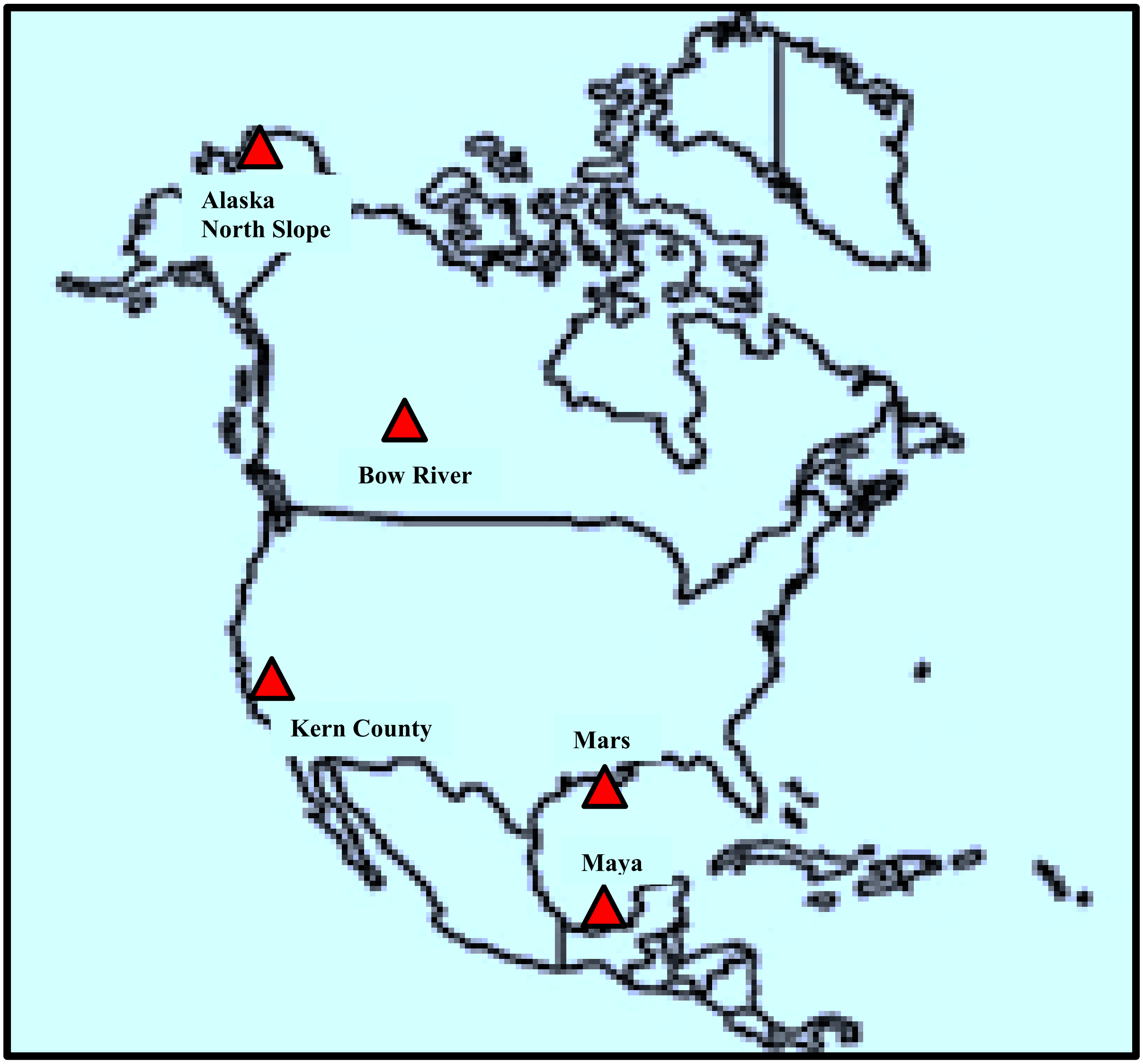

Figure 6.1: Location of the selected oil production fields in North America

6.3 Selected oil fields

6.3.1 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 [37]. 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 [38]. The medium crude oil produced from Alaska North Slope is sent to refineries through the Trans-Alaska Pipeline System (TAPS) [39]. The resulting ANS crude is usually loaded into vessels at the Alaska Marine Terminal and sold to customers on the U.S. West Coast [40]. The enhanced oil recovery method most often used in Alaska North Slope is water-alternating-gas injection (WAG) [38, 41]. WAG technology has been used extensively in recent years to increase oil productivity [42-44]. 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 [45]. Figure 6.2 shows the unit operations considered for crude oil production from the Alaska North Slope oil field.

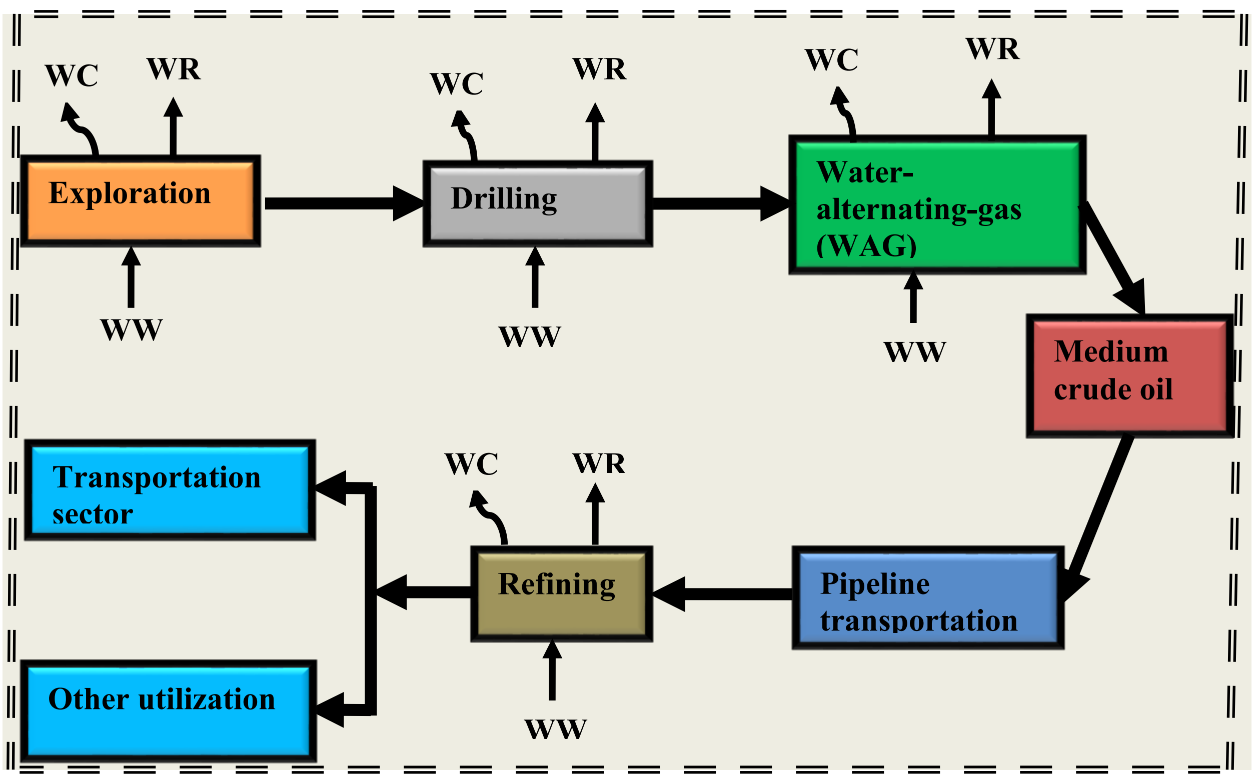

Figure 6.2: System boundary and unit operations for the Alaska North slope oil field

6.3.2 California's Kern County heavy oil

In 2013 California was the third-largest oil producer in the U.S. Its production rate in 2013 was 545 thousand bbl/d following a decline since 1986 by an average of 2.4%/year [46]. The largest field in California producing heavy oil (13° API) is Midway-Sunset. In 2012 Midway-Sunset produced 15% of the state's total [47]. 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 [48-50]. 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. [39]. Figure 6.3 shows the unit operations considered for crude oil production from California's Kern County oil field.

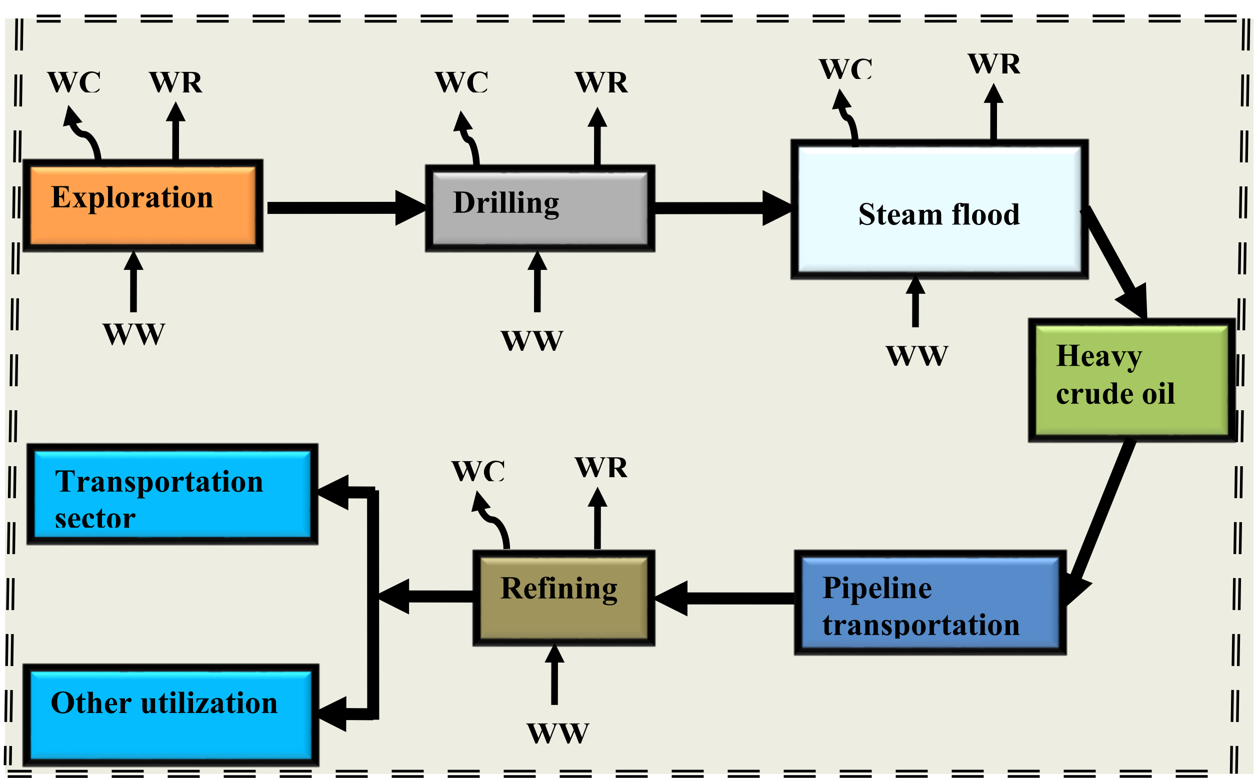

Figure 6.3: System boundary and unit operations for California's Kern County oil field

6.3.3 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 [51]. Mars blend is a sour medium grade crude oil with an API gravity of 31° [52]. Mars crude oil is transported by pipeline to the Louisiana Offshore Oil Port (LOOP) to supply the refining demand [51]. Water flood is the recovery technology used in the Mars oil field and sea water is used for injection [53]. Figure 6.4 shows the unit operations considered for crude oil production from the Mars oil field.

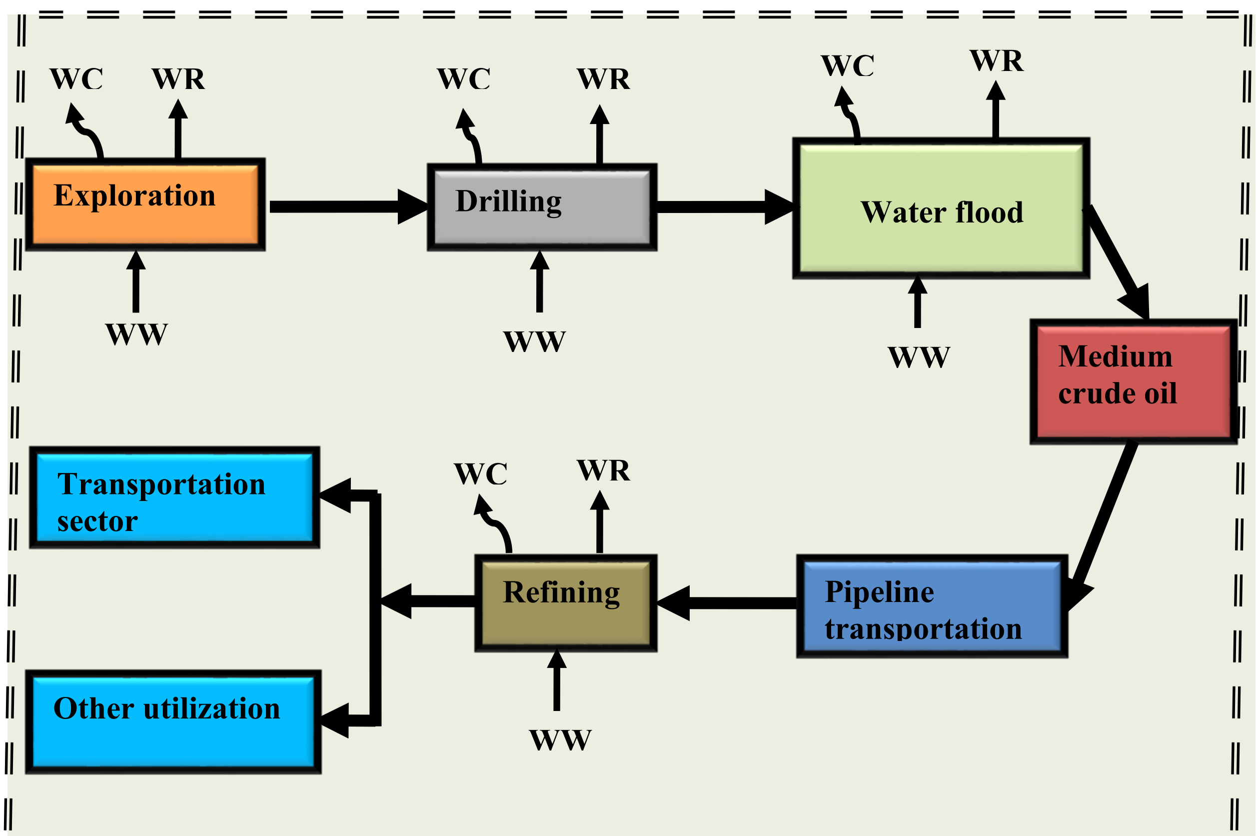

Figure 6.4: System boundary and unit operations for Mars oil field

6.3.4 Maya

Maya is a sour heavy grade oil extracted from the offshore oil fields Ku Maloob Zaap and Cantarell in Mexico [54-56]. 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 [57]. 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 [58] and finally 440 thousand bbl/d (21%) in 2013 [9]. To increase production, nitrogen injection technology was introduced [9, 57, 59]. Due to the lack of suitable refineries, most of Mexico's heavy oil is exported as crude [54]. 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 [57]. Figure 6.5 shows the unit operations considered for crude oil production from Maya oil field.

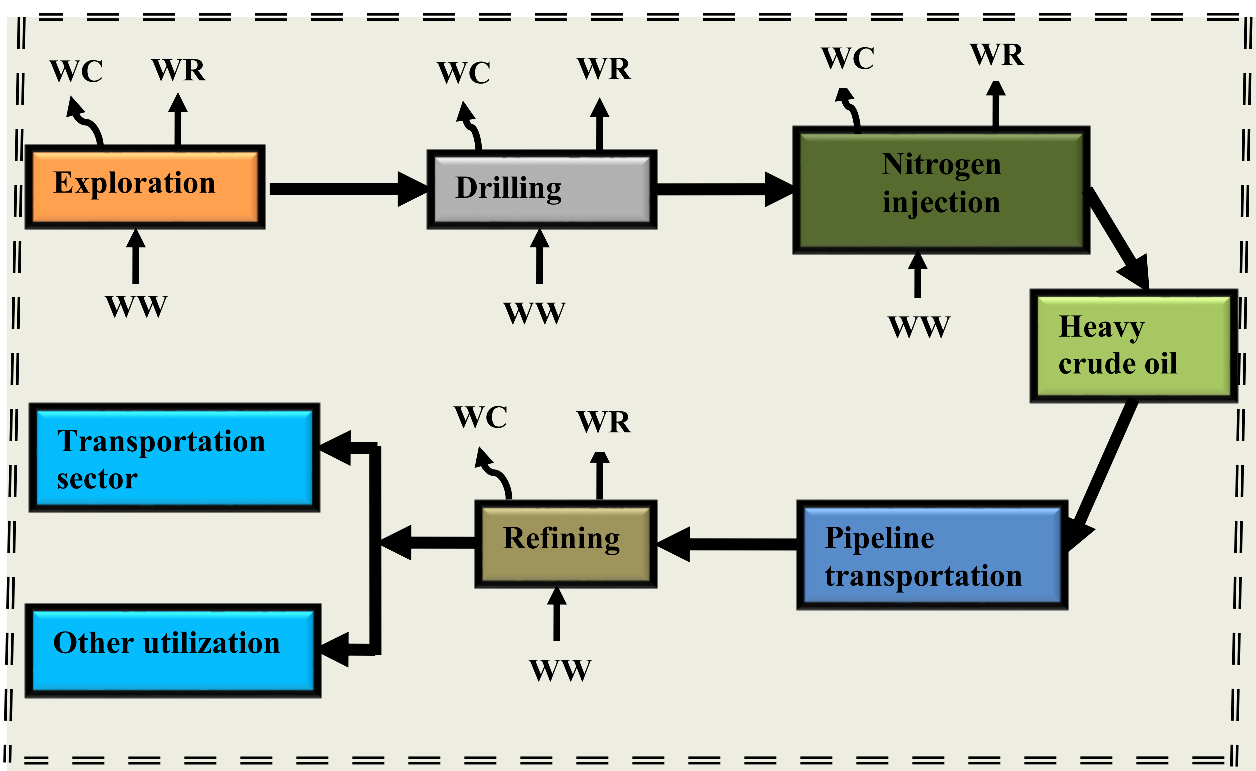

Figure 6.5: System boundary and unit operations for Maya oil field

6.3.5 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 the 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 [60]. 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 [61]. 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 [62]. 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 [60]. Figure 6.6 shows the unit operations considered for conventional heavy crude oil production from Bow River oil field.

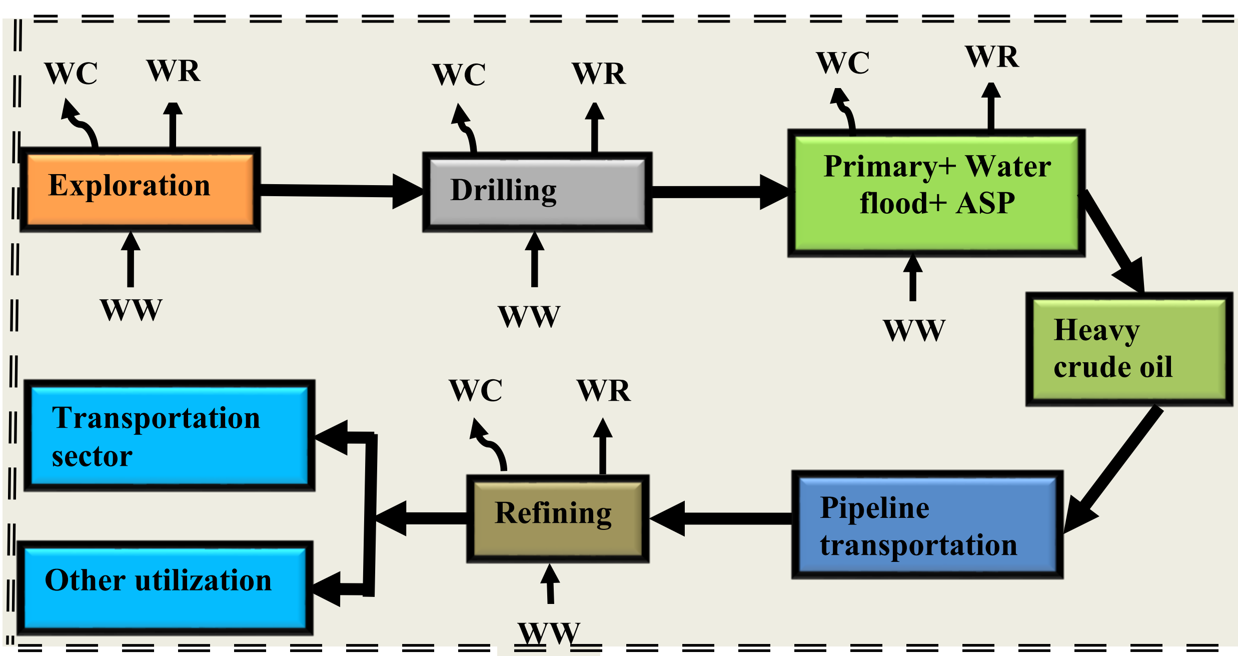

Figure 6.6: System boundary and unit operations for Bow River oil field

6.4 Input data and assumptions

Water demand coefficients for exploration were adapted from Gleick [22] and combined with the drilling coefficients. Goodwin et al. [63] found that the average water consumption for drilling a vertical oil well is 77,000 gallons (1,833 bbl), and that figure is used in this chapter along with the total productivity of one well from each oil field [30] 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 [23]. The coefficients for the total water injected (TWT) were based on the type of recovery technology and the percentages of re-injected water (PRE) accordingly. 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%) [23]. 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 [5,60,64-66] and has been adjusted for this chapter. 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 [30] 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 6.1). Figure 6.7 shows the flow of the input data, and more details for drilling and extraction are shown in Table 6.1.

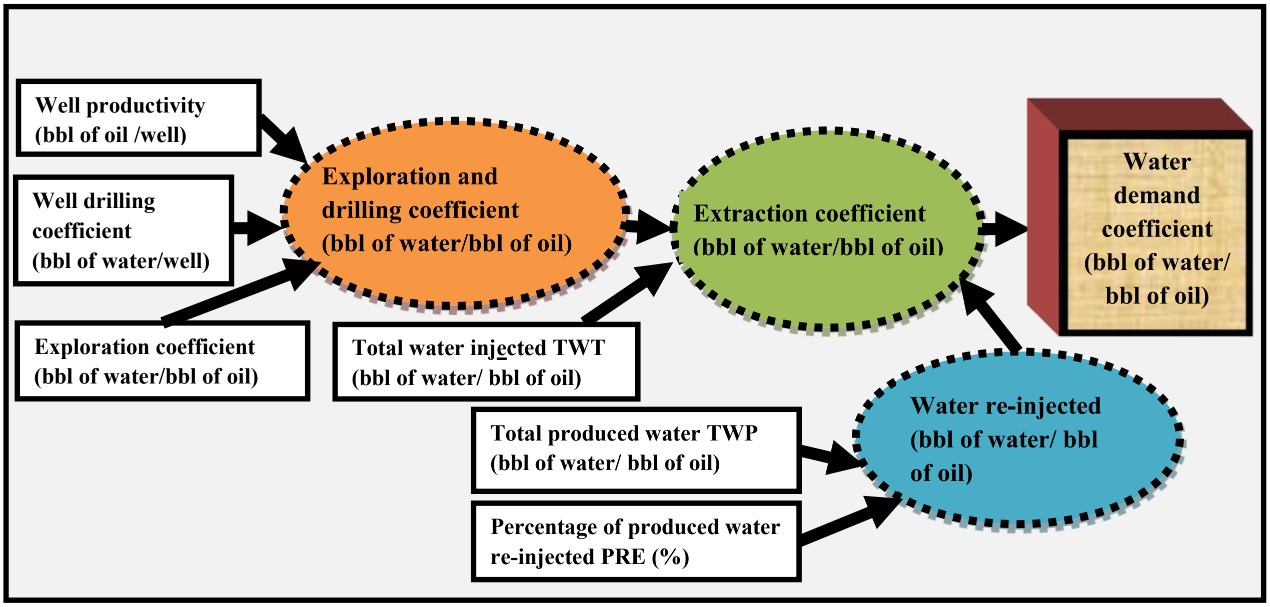

Figure 6.7: Input data water demand flow for exploration, drilling, and extraction of crude oil

The fresh water demand coefficients for the refining unit operations are averages taken from the literature [23, 67 - 71] and included in this chapter to complete the life cycle assessment. 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% [14] of the associated water withdrawals. Water demand coefficients for the transportation of crude oil through the pipeline are not included in this chapter [72].

Table 6.1: Input data for drilling and crude oil extraction

Oil field	Productivity (million 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	1.96	1,833	8.7	3	76
California's Kern County heavy oil	0.13	1,833	5.4	5.17	76
Mars	0.53	1,833	8.6	5.5	52
Maya	46.80	1,833	8.7	3	52
Bow River heavy oil	0.32	1,833	8.6	14.9	53.7

[a] Lifetime productivity from Rahman et al. [30].
[b] Assumed with an average of water consumption for drilling oil well from Goodwin et al. [63].
[c] Based on the type of the recovery technology [23].
[d] Based on the parameter water-to-oil used for energy calculations [30].
[e] Based on the information provided by the PADD [23].

6.5 Results and discussion

Figure 6.8 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 produced water is highest in Bow River (14.9 bbl/bbl) and significantly lowers the amount of injected fresh water needed for oil recovery. About 87% of the fresh water consumed for Maya's crude oil is for the extraction unit operations, 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 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.

For the complete life cycle, water withdrawals range from 2.41-9.51 bbl/bbl (see Table 6.2), and based on all studied oil fields, 81% of these figures are consumed and not returned to the source. Based on the complete life cycle, water withdrawals coefficients are higher than water consumption coefficients due to the difference during extraction and refining unit operations while they were assumed equal during exploration and drilling unit operations.

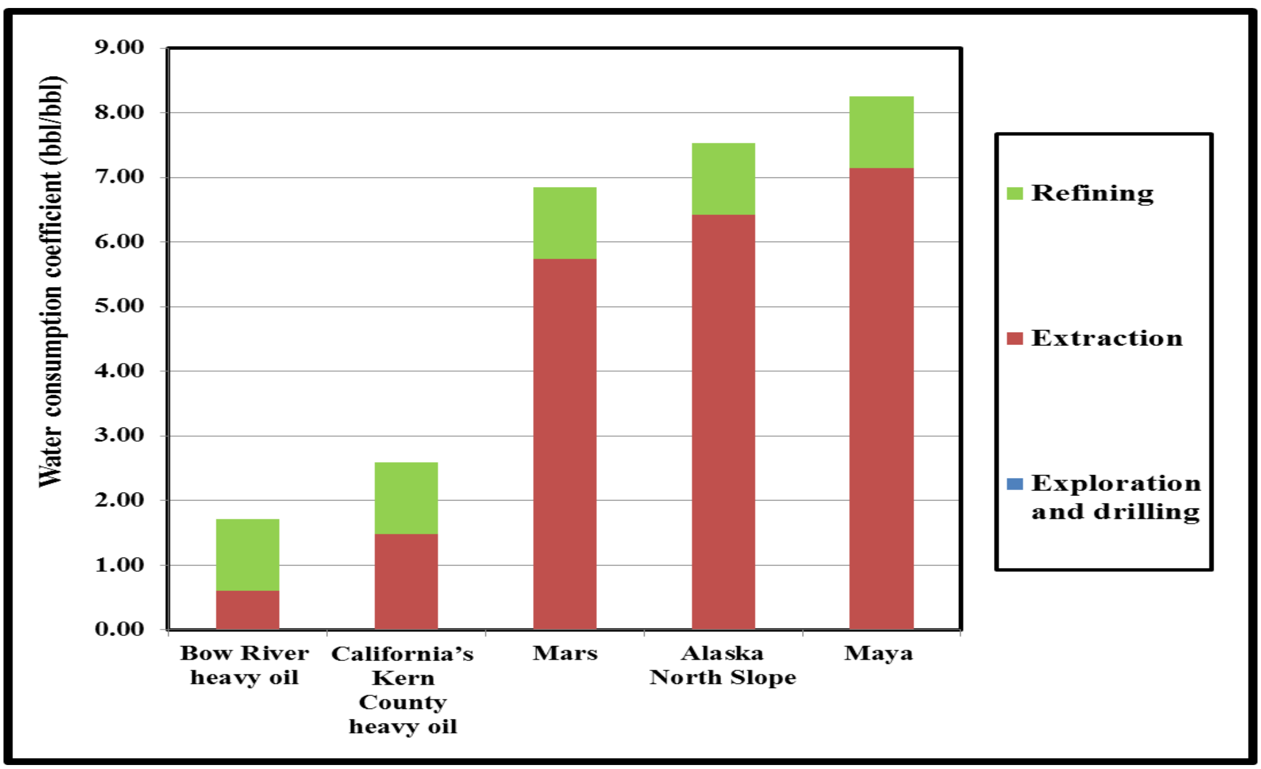

Figure 6.8: Water consumption coefficients for the life cycle of crude oil

Table 6.2: 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
ANS	0.0013	6.98	1.75	8.73
Maya	0.0004	7.76	1.75	9.51

6.6 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 all oil fields studied here.

The extraction unit operation is the most sensitive to water demand (as shown in Table 6.2), 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 6.3. Minimum PRE is assumed to be at no water produced re-injected (0%) and the maximum is assumed at full satisfaction of technology from produced water (100%).

Table 6.3: Variations of PRE and refining water demand coefficients

<table>
<tr><th>Oil field</th><th>Percentage of produced water re-injected (PRE) (%)</th><th>Probability percentile of the most likely PRE (%)</th><th>Refining water consumption coefficient (bbl/bbl)</th><th>Probability percentile of the most likely refining water consumption coefficient (%)</th><th>Refining water withdrawals coefficient (bbl/bbl)</th><th>Probability percentile of the most likely refining water withdrawals coefficient (%)</th></tr>
<tr><td></td><td>Min. - Most likely - Max.</td><td></td><td>Min. - Mos likely - Max.</td><td></td><td>Min. - Most likely - Max.</td><td></td></tr>
<tr><td>Alaska North Slope</td><td>0 – 76 - 100</td><td>76</td><td rowspan="5">0.40 – 1.11 – 1.85</td><td rowspan="5">49</td><td rowspan="5">0.98 – 1.75 – 3.70</td><td rowspan="5">28</td></tr>
<tr><td>California’s Kern County heavy oil</td><td>0 – 76 -100</td><td>76</td></tr>
<tr><td>Mars</td><td>0 – 52 -100</td><td>52</td></tr>
<tr><td>Maya</td><td>0 – 52 - 100</td><td>52</td></tr>
<tr><td>Bow River heavy oil</td><td>0 - 53.7-100</td><td>53.7</td></tr>
</table>

Figure 6.9 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 as shown in Figure 6.9).

Figure 6.10 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 change 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 6.11 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 bbl/bbl.

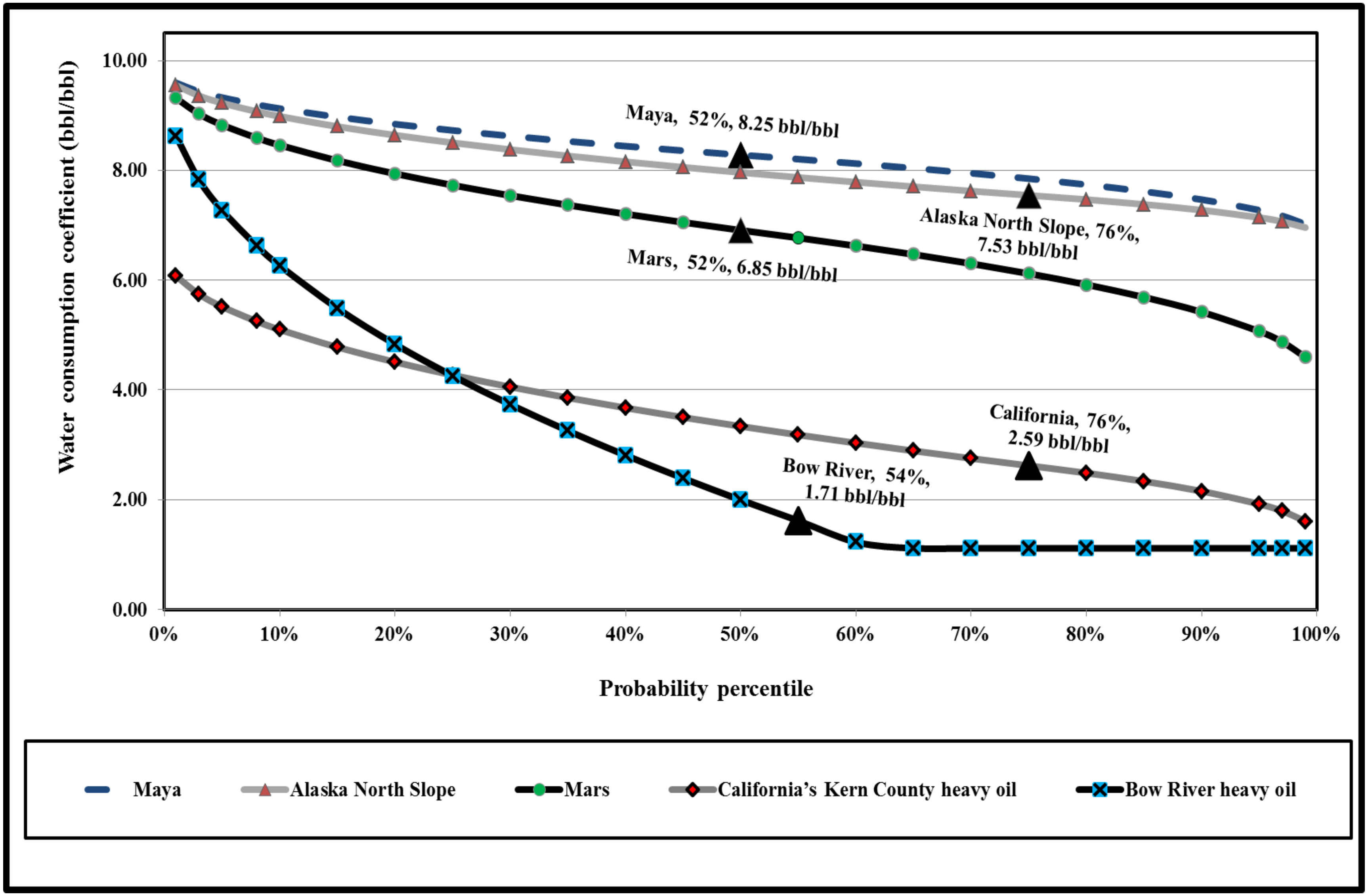

Figure 6.9: Distribution of complete life cycle water consumptions at a constant refining coefficient

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

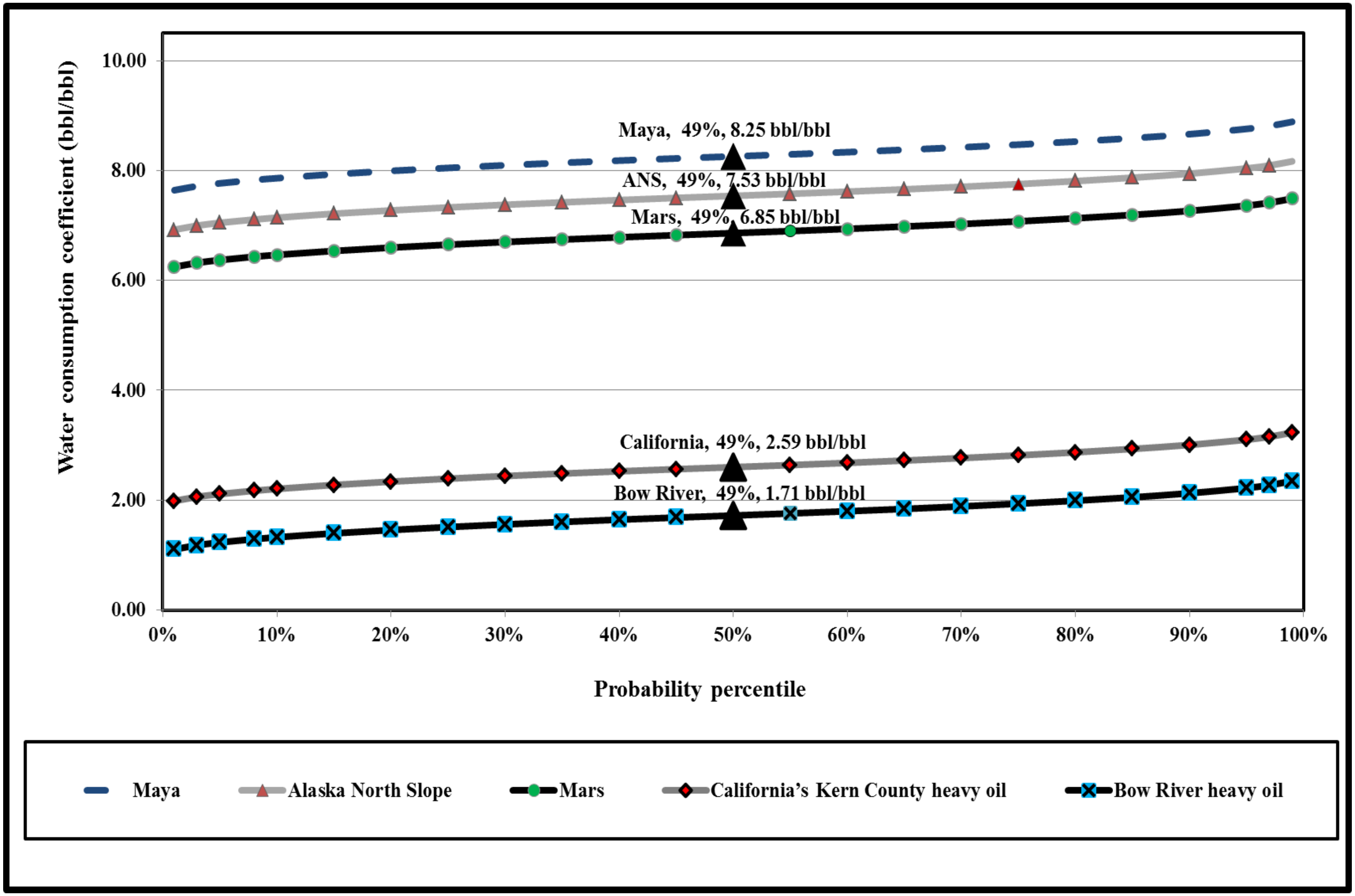

Figure 6.10: Distribution of complete life cycle water consumptions at a variable refining coefficient

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

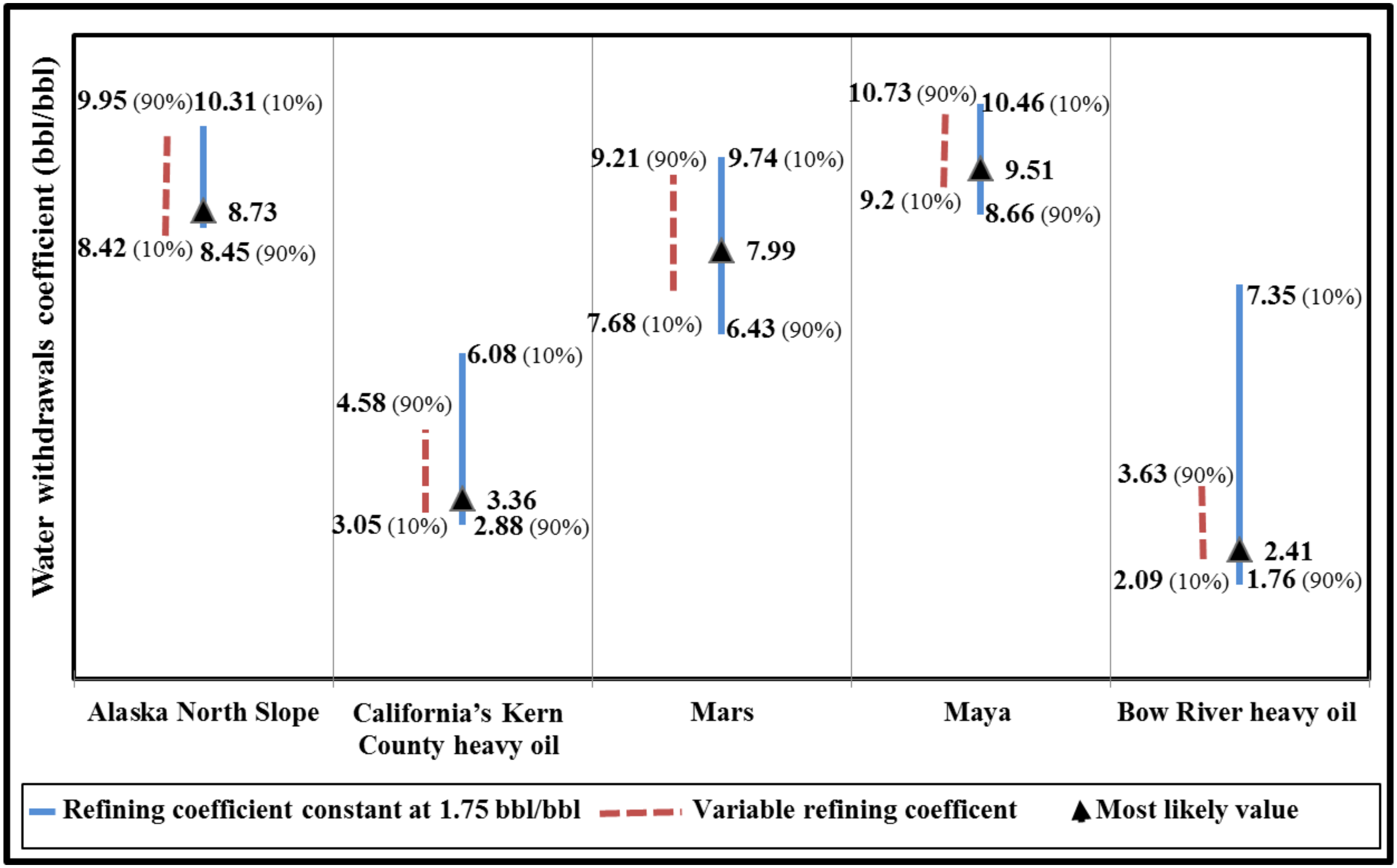

Figure 6.11: Distribution of water withdrawals coefficients for crude oil

6.7 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.

Among the five crude oils assessed here, the lowest life cycle water consumption coefficient is for Bow River heavy oil and the highest is 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. Water quality and availability are recommended to be integrated with this study to give broader prospective of comparative assessment.

References

[1]. Khoo HH, Tan RBH. Environmental impact evaluation of conventional fossil fuel production (oil and natural gas) and enhanced resource recovery with potential CO_2 Sequestration. Energy & Fuels 2006; 20: 1914-1924.

[2]. Organisation for Economic Co-Operation and Development (OECD). Key environmental indicators. Paris, France, 2008. Available at: http://www.oecd.org/env/indicators-modelling-outlooks/37551205.pdf [accessed: 14.11.2016]

[3]. Galera ES, Allieri MAA, Veneroni DL, Villegas FMR. Oil production in Mexico's highly diverse ecosystems: the importance of environmental indicators. International Journal of Oil, Gas and Coal Technology 2010; 3 (1): 4-18.

[4]. Stillwell AS, King C.W, Webber M, Duncan IJ, Hardberger A. The energy-water nexus in Texas. Ecology and Society 2011; 16(1): 2. Available at: http://www.ecologyandsociety.org/vol16/iss1/art2/ [accessed: 11.11.2016]

[5]. Canadian Association of Petroleum Producers (CAPP). Responsible Canadian Energy 2014 Progress Report. Available at: http://www.capp.ca/~/media/capp/customer-portal/publications/255363.pdf [accessed: 12.11.2016]

[6]. Sanders KT, King CW, Stillwell AS, Webber ME. Clean energy and water: assessment of Mexico for improved water services and renewable energy. Environment, Development and Sustainability 2013; 15:1303–1321. DOI 10.1007/s10668-013-9441-5.

[7]. U.S. Energy Information Administration (EIA). Energy in brief: how dependent are we on foreign oil? Available at: http://www.eia.gov/energy_in_brief/article/foreign_oil_dependence.cfm [accessed: 14.11.2016]

[8]. Canadian Association of Petroleum Producers (CAPP). Crude oil: forecast, markets and transportation. June 2016. Available at: http://www.capp.ca/publications-and-statistics/publications/284950 [accessed: 16.11.2016]

[9]. U.S. Energy Information Administration (EIA). Mexico: overview. April 24, 2014. Available at: http://www.eia.gov/beta/international/analysis_includes/countries_long/Mexico/mexico.pdf [accessed: 13.11.2016]

[10]. International Energy Agency (IEA). Water for energy: is energy becoming a thirstiest resource? Excerpt from the World Energy Outlook 2012. Available at: http://www.worldenergyoutlook.org/media/weowebsite/2012/WEO_2012_Water_Excerpt.pdf [accessed: 14.11.2016]

[11]. McMahon J.E, Price S.K. Water and energy interactions. Annual Review of Environment and Resources 2011; 36:163-191.

[12]. King CW, Stillwell AS, Twomey KM, Webber ME. Coherence between water and energy policies. Natural Resources Journal 2013; 53: 117-215.

[13]. Glassman D, Wucker M, Isaacman T, Champilou C. The water energy nexus: adding water to the energy agenda. The World Policy Institute in partnership with EGB Capital. March 2011. Available at: http://www.worldpolicy.org/sites/default/files/policy_papers/THE%20WATER-ENERGY%20NEXUS_0.pdf [accessed: 13.11.2016]

[14]. Alberta Environment (AENV). Current and future water use in Alberta. Prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007). Available at: www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf [accessed: 11.11.2016]

[15]. Hackett J, Idriss A, Kause R, Scott K, Tingley J. Water conservation, efficiency, and productivity plan – electric power generation. August 2012. Available at: https://extranet.gov.ab.ca/env/infocentre/info/library/8682.pdf [accessed: 10.11.2016]

[16]. EPCOR. 2003 Generating report: Genesee generating station (2004). Available at: http://www.corporateregister.com/a10723/epcor03-env-ca.pdf [accessed: 08.11.2016]

[17]. ATCO Power. Battle River coal-fired generating station. Available at: http://www.atcopower.com/Our-Facilities/Our-Power-Technologies/Coal-Fired-Thermal/Battle-River [accessed: 12.11.2016]

[18]. Griffiths M, Dyer S. Up-grader alley: Oil sands fever strikes Edmonton. June 2008. Available at: http://pubs.pembina.org/reports/Upgrader_Alley-report.pdf [accessed: 09.11.2016]

[19]. Okadera T, Chontanawat J, Gheewala SH. Water footprint for energy production and supply in Thailand. Energy 2014; 77: 49-56.

[20]. Zhang C, Anadon LD. Life cycle water use of energy production and its environmental impacts in China. Environmental Science & Technology 2013; 47 (24): 14459-14467.

[21]. Grubert EA, Beach FC, Webber ME. Can switching fuels save water? a life cycle quantification of freshwater consumption for Texas coal- and natural gas-fired electricity. Environmental Research Letters 2012; 7: 045801.

[22]. Gleick PH. Water and Energy. Annual Review of Energy and Environment 1994; 19:267-299.

[23]. Wu M, Chiu Y. Consumptive water use in the production of ethanol and petroleum gasoline-2011 update. Center for Transportation Research, Energy Systems Division, Argonne National Laboratory, December 2008, updated July 2011. ANL/ESD/09-1 Available at: https://greet.es.anl.gov/files/consumptive-water [accessed: 15.11.2016]

[24]. Staples MD, Olcay H, Malina R, Trivedi P, Pearlson MN, Strzepek K, Paltsev SV, Wollersheim C, Barrett SRH. Water consumption footprint and land requirements of large-scale alternative diesel and jet fuel production. Environmental Science & Technology 2013; 47:12557-12565.

[25]. Argaez A.A, Kokossis AC, Smith R. The design of water-using systems in petroleum refining using a water-pinch decomposition. Chemical Engineering Journal 2007; 128: 33-46.

[26]. Alberta Energy Regulator (AER). Water and oil: an overview of the use of water for enhanced oil recovery in Alberta. March 2014. Available at: https://www.aer.ca/documents/applications/WA_WaterOil_UseOfWaterForEnhancedOilRecovery.pdf [accessed: 29.07.2015]

[27]. Ali B, Kumar A. Development of life cycle water-demand coefficients for coal-based power generation technologies. Energy Conversion and Management 2015; 90: 247-260.

[28]. Ali B, Kumar A. Development of life cycle water footprints for gas-fired power generation technologies. Energy Conversion and Management 2016; 110: 386-396.

[29]. Yang X, Dziegielewski B. Water use by thermoelectric power plants in the United States. Journal of the American Water Resources Association (JAWRA) 2007; 43(1):160-69.

[30]. Rahman M.M, Canter C, Kumar A. Greenhouse gas emissions from recovery of various North American conventional crudes. Energy 2014; 74: 607-617.

[31]. ModelRisk Software. Available at: http://www.vosesoftware.com/ [accessed: 14.11.2016]

[32]. Williams SK, Acker T, Goldberg M, Greve M. Estimating the economic benefits of wind energy projects using Monte Carlo simulation with economic input/output analysis. Wind Energy 2008; 11 (4): 397-414.

[33]. Kullapa S, Joe M. Increasing innovation in home energy efficiency: Monte Carlo simulation of potential improvements. Energy and Buildings 2010; 42 (6): 828 – 833

[34]. Karfopoulos KL, Anagnostakis MJ. Parameters affecting full energy peak efficiency determination during Monte Carlo simulation. Applied Radiation and Isotopes 2010; 68: 1435-1437.

[35]. Alberta Environment (AENV). Glossary of terms related to water and watershed management in Alberta. 1st edition. Partnerships and Strategies Section, November 2008. Available at: https://extranet.gov.ab.ca/env/infocentre/info/library/8043.pdf [accessed: 13.11.2016]

[36]. Government of Alberta. Focus on groundwater: groundwater management. Available at: http://aep.alberta.ca/about-us/documents/FocusOn-GroundwaterManagement-2014.pdf [accessed: 13.11.2016]

[37]. U.S. Energy Information Administration (EIA). Alaska North Slope crude oil production. Available at: http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MANFPAK1&f=A [accessed: 14.11.2016]

[38]. BP in Alaska. Greater Prudhoe Bay. Available at: http://www.bp.com/content/dam/bp-country/en_us/PDF/prudhoe_bay_2013.pdf [accessed: 14.11.2016]

[39]. Sheridan M. California crude oil production and imports. Available at: http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF [accessed: 11.11.2016]

[40]. ExxonMobil: Refining and Supply. About Alaskan North Slope (ANS). Available at: http://www.exxonmobil.com/crudeoil/about_crudes_ans.aspx [accessed: 11.11.2016]

[41]. ConocoPhillips Alaska. Factsheet- March 2015: Alaska. Available at: http://alaska.conocophillips.com/Documents/Fact%20Sheet_Alaska_Spring%202015_FINAL.pdf [accessed: 12.11.2016]

[42]. Srivastava JP, Mahli L. 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. Available at: http://www.spgindia.org/spg_2012/spgp109.pdf [accessed: 10.11.2016]

[43]. Aghdam KA, Moghaddas JS, Moradi B, Dabiri M, Hassanzadeh M. Maximizing the oil recovery through miscible water alternating gas (WAG) injection in an Iranian oil reservoir. Petroleum Science and Technology 2013; 31 (22): 2431-2440.

[44]. Kulkarni MM, Rao DN. Experimental investigation of miscible and immiscible water-alternating-gas (WAG) process performance. Journal of Petroleum Science and Engineering 2005; 48 (1- 2): 1-20.

[45]. Kaltenbach B, Walsh C, Foerster C, Walsh T, MacDonald J, Stokes P, Livesey C, Nebesky W. North Slope of Alaska facility sharing study. Prepared for Division of Oil & Gas: Alaska Department of Natural Resources. Available at: http://www.petroak.com/NorthSlope_Facility_Sharing_Study.pdf [accessed: 13.11.2016]

[46]. U.S. Energy Information Administration (EIA). Crude oil production. Available at: http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm [accessed: 09.11.2016]

[47]. Department of Conservation: Division of Oil, Gas, and Geothermal Resources. 2012 Preliminary report of California oil and gas production statistics. Issued April 2013. Publication no. PR03. Available at: ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2012/PR03_PreAnnual_2012.pdf [accessed: 12.11.2016]

[48]. Tennyson M.E. Growth history of oil reserves in major California oil fields during the twentieth century. U.S. Geological Survey Bulletin 2172–H. Available at: http://pubs.usgs.gov/bul/b2172-h/b2172h508.pdf [accessed: 11.11.2016]

[49]. EPRI. Enhanced oil recovery scoping study. Palo Alto, CA: 1999. TR-113836. Available at: http://www.energy.ca.gov/process/pubs/electrotech_opps_tr113836.pdf [accessed: 14.11.2016]

[50]. Schamel S. 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). Available at: http://www.osti.gov/scitech/servlets/purl/772932 [accessed: 07.11.2016]

[51]. Offshore Technology. Mars oil and gas field project, Gulf of Mexico, United States of America. Available at: http://www.offshore-technology.com/projects/mars/ [accessed: 11.11.2016]

[52]. Environment Canada: Emergencies Science and Technology Division. Mars blend. Available at: http://www.etc-cte.ec.gc.ca/databases/Oilproperties/pdf/WEB_Mars_Blend.pdf [accessed: 09.11.2016]

[53]. Weiland J, Azari M, Fox P, Dorffer D. 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 2013; 2(2):16-25.

[54]. GEO Estratos S.A. de C.V. Motley crude. Available at; http://www.richcarriero.com/pdf/Crude%20Oil%20Varieties%20Mexico.pdf [accessed: 13.11.2016]

[55]. Moreno H.O, Ramirez J, Minero FS, Cuevas R, Ancheyta J. Hydrocracking of Maya crude oil in a slurry-phase batch reactor. II. Effect of catalyst load. Fuel 2014; 130: 263–272

[56]. Morgan TJ, Rodriguez PA, George A, Herod AA, Kandiyoti R. 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 2010; 24: 3977-3989.

[57]. Offshore Technology. Cantarell oilfield, Gulf of Mexico, Mexico. Available at: http://www.offshore-technology.com/projects/cantarell/ [accessed: 09.11.2016]

[58]. Clemente J. Cantarell is not Mexico’s only oil production problem. Pipeline & Gas Journal, August 2008. Available at:

http://www.peakoil.net/files/Cantarell%20Is%20Not%20Mexico%E2%80%99s%20Only%20Oil%20Production%20Problem.pdf [accessed: 11.11.2016]

[59]. Talwani M. Oil and gas in Mexico: geology, production rates and reserves. April 29, 2011. Available at: http://bakerinstitute.org/files/537/ [accessed: 11.11.2016]

[60]. Alberta Energy Regulator (AER). Alberta's energy reserves 2013 and supply/ demand outlook 2014 – 2023. Available at: http://www.aer.ca/documents/sts/ST98/ST98-2014.pdf [accessed: 09.11.2016]

[61]. Alberta Government. Alberta's energy industry: An overview. Available at: http://www.energy.alberta.ca/Org/pdfs/Alberta_Energy_Overview.pdf [accessed: 06.11.2016]

[62]. Crude Quality Inc.: Crude Monitor. Bow River South (BRS). Available at: http://www.crudemonitor.ca/crude.php?acr=BRS [accessed: 13.11.2016]

[63]. Goodwin S, Carlson K, Douglas C, Knox K. Life cycle analysis of water use and intensity of oil and gas recovery in Wattenberg field, Colo. Oil and Gas Journal May 7, 2012; 110 (5): 48-58.

[64]. Cenovus Energy. Steam-assisted gravity drainage (SAGD). Available at: http://www.cenovus.com/operations/oilsands/foster-creek.html [accessed: 09.11.2016]

[65]. Canadian Association of Petroleum Producers (CAPP). 2013 Responsible Canadian energy progress report. Available at: http://www.capp.ca/~/media/capp/customer-portal/publications/233913.pdf [accessed: 16.11.2016]

[66]. Canadian Association of Petroleum Producers (CAPP). Responsible Canadian energy progress report. For the year ended December 31, 2009. Available at: https://issuu.com/capp/docs/rce-oilsands-report/44 [accessed: 16.11.2016]

[67]. Canadian Fuels Association. Water – a precious resource. February 2010. Available at: http://canadianfuels.ca/userfiles/file/Water%20Primer%20-%20Final%20%28Updated%20with%202010%20data%29.pdf [accessed: 20.07.2015] [68].

Pombo F, Magrini A, Szklo A. An analysis of water management in Brazilian petroleum refineries using rationalization techniques. Resources, Conservation and Recycling 2013; 73:172-179.

[69]. Souza A.A, Forgiarini E, Brandao HL, Xavier MF, Pessoa FL, Souza SM. Application of water source diagram (WSD) method for the reduction of water consumption in petroleum refineries. Resources, Conservation and Recycling 2009; 53:149-154.

[70]. Alva-Argaez A, Kokossis AC, Smith R. The design of water-using systems in petroleum refining using a water-pinch decomposition. Chemical Engineering Journal 2007; 128: 33-46.

[71]. Diepolder P. Is zero discharge realistic? Hydrocarbon Processing; 1992, 71 (10): 129-131.

[72]. King CW, Webber ME. Water intensity of transportation. Environmental Science & Technology 2008; 42: 7866-72.

Chapter 7

Conclusions and Recommendations for Future Research

7.1 Conclusions

Life cycle water demand footprints were developed in this study for power generation, oil sands, and crude oil in five North American locations. The developed water footprints included water consumption and water withdrawals coefficients based on the complete life cycle for each pathway. Power generation pathways studied are fossil-fuel based (36 pathways for coal and 26 pathways for gas) and non-conventional energy technologies (60 pathways). Uncertainty analysis was conducted through Monte Carlo simulations to study the impact of different operation conditions on the developed water demand coefficients.

Figure 7.1 shows the ranges of water demand coefficients developed in this study for power generation pathways.

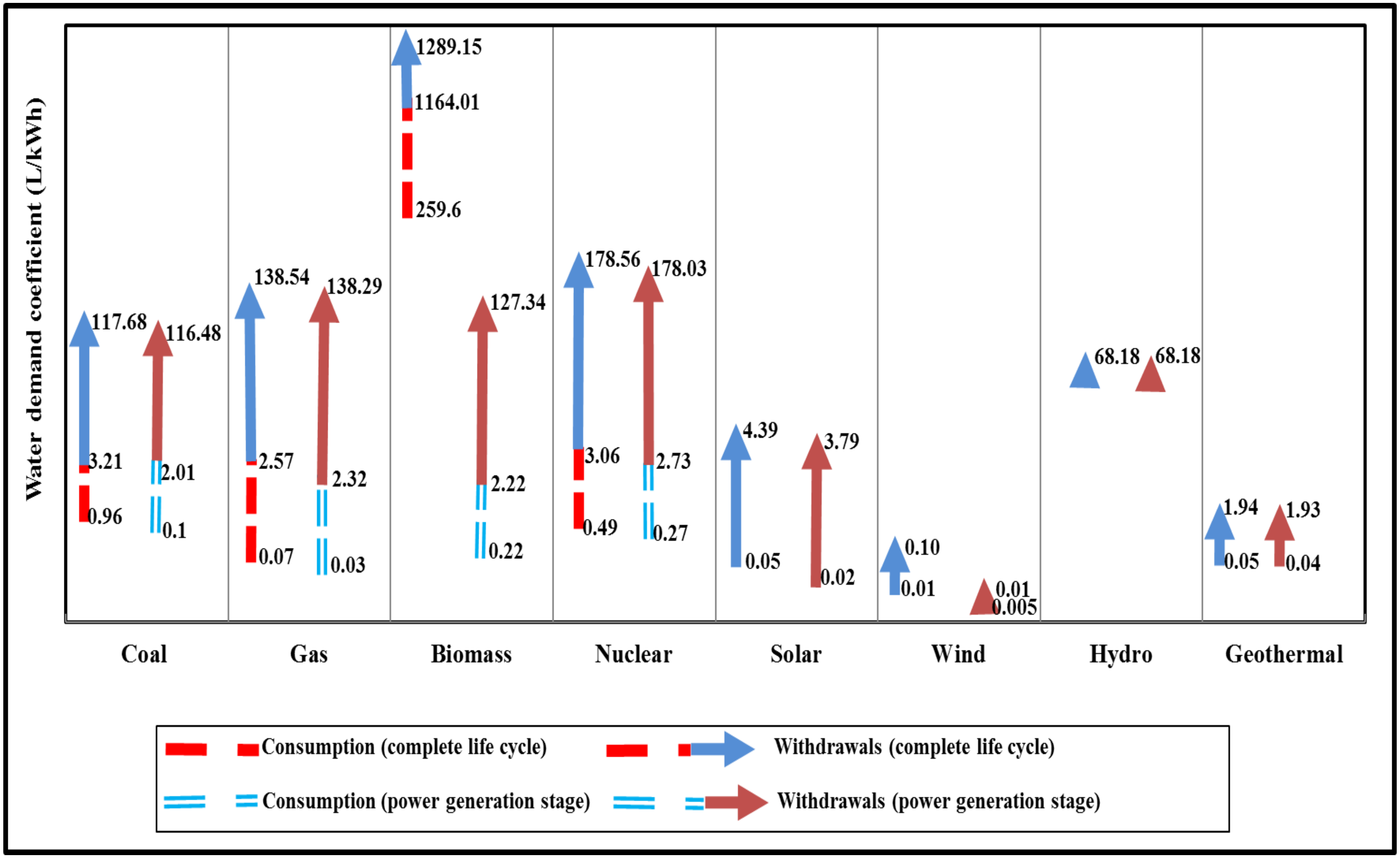

Figure 7.1: Ranges of water demand coefficients for power generation pathways

Water demand during the fuel life cycle is significant and should be taken into account when estimating the water required for the complete life cycle of coal-based power plants. Improving the performance of coal-based power plants through new technologies, such as ultra-supercritical and integrated gasification combined cycle (IGCC), would reduce water consumption during both power generation and the fuel life cycle due to the reduction in fuel used to generate the same amount of energy.

Power generation pathways involving new technologies of IGCC or ultra-supercritical technology with coal transportation by conventional means and using dry cooling systems have the lowest complete life cycle water-demand coefficients of about 1 L/kWh. Consumption coefficients over the life cycle of ultra-supercritical or IGCC power plants are 0.12 L/kWh higher when conventional transportation of coal is replaced by coal-log pipeline. If coal is transported in the slurry through a pipeline, the consumption coefficient of a subcritical power plant increases by 0.52 L/kWh. Generally, unconventional transportation of coal increases water demand and the impact on total water use depends mainly on the conversion efficiency of the power generation.

The conversion efficiency of a gas-fired power plant has a significant effect on water demand. The conversion efficiency affects both upstream gas extraction and power generation. The higher water demand from specific types of gas sources can be compensated with efficient power generation technology. The cooling system used is also essential in determining the level of water required. Dry cooling could improve water demand performance, though there are uncertainties related to economic feasibility and overall conversion efficiency. Water demand is higher during power generation from natural gas than during the fuel extraction stage. Water withdrawals coefficients during power generation for gas-fired power plants using once-through cooling systems are higher than for plants using other cooling systems. With once-through cooling systems, a smaller percentage of withdrawn water is consumed. The water consumption coefficient based on the complete life cycle for gas-fired power generation are 0.07 – 2.57 L/kWh, with the lowest coefficient for conventional gas or coal bed methane (CBM) through cogeneration technology and dry cooling and the highest coefficient for shale gas use through steam cycle technology and cooling tower systems.

Wind energy has the most positive impact on water demand and can be used to alleviate the high water requirement for power generation. Direct combustion of corn stover to generate electricity has the lowest water demand coefficient among the biomass technologies. The water required to irrigate crops grown for biomass negatively affects the water demand for these pathways. The lower conversion efficiency of nuclear energy and solar thermal pathways compared to other thermoelectric technologies negatively impacts the water demand coefficients. Some renewable power generation technologies can be more flexible in improving conversion efficiency. Improving conversion efficiency is one of the essential factors to consider when studying water demand for a certain technology.

Water demand coefficients for the complete life cycle of transportation fuel extracted from oil sands indicated that in-situ recovery outperforms in the water use compared to the surface mining. Water consumption coefficients for transportation fuel based on oil sands are in the range 2.08-4.19 barrel of water per barrel of refined oil (bbl/bbl) and 2.87 – 5.16 bbl/bbl for water withdrawals coefficients with the lower bound through SAGD and upper bound through surface mining recovery. Water demand coefficients for transportation fuel production are dynamic and the new oil sands recovery technologies can play a major role in water conservation.

The range of water demand based on the complete life cycle of transportation fuel extracted from oil sands (2.08- 4.19 bbl/bbl for consumption and 2.87 – 5.16 bbl/bbl for withdrawals) is found to be in the entire range of crude oil-based fuel from the selected oil fields in North America (1.71- 8.25 bbl/bbl for consumption and 2.41 – 9.51 bbl/bbl for withdrawals). Water demand for the complete life cycle of transportation fuel from three studied oil fields Mars, Alaska North Slope, and Maya exceeded the corresponding water demand for oil sands-based fuel. Technology improvement in two areas to increase the percentage of produced water re-injected and to reduce water use in refining unit operations are the essential factors in water conservation for transportation fuel production. Even when the maximum amount of produced water is used for extraction, water is still 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. Figure 7.2 shows the ranges of water demand coefficients developed in this study for oil sands and crude oil with variable coefficients of refining unit operation.

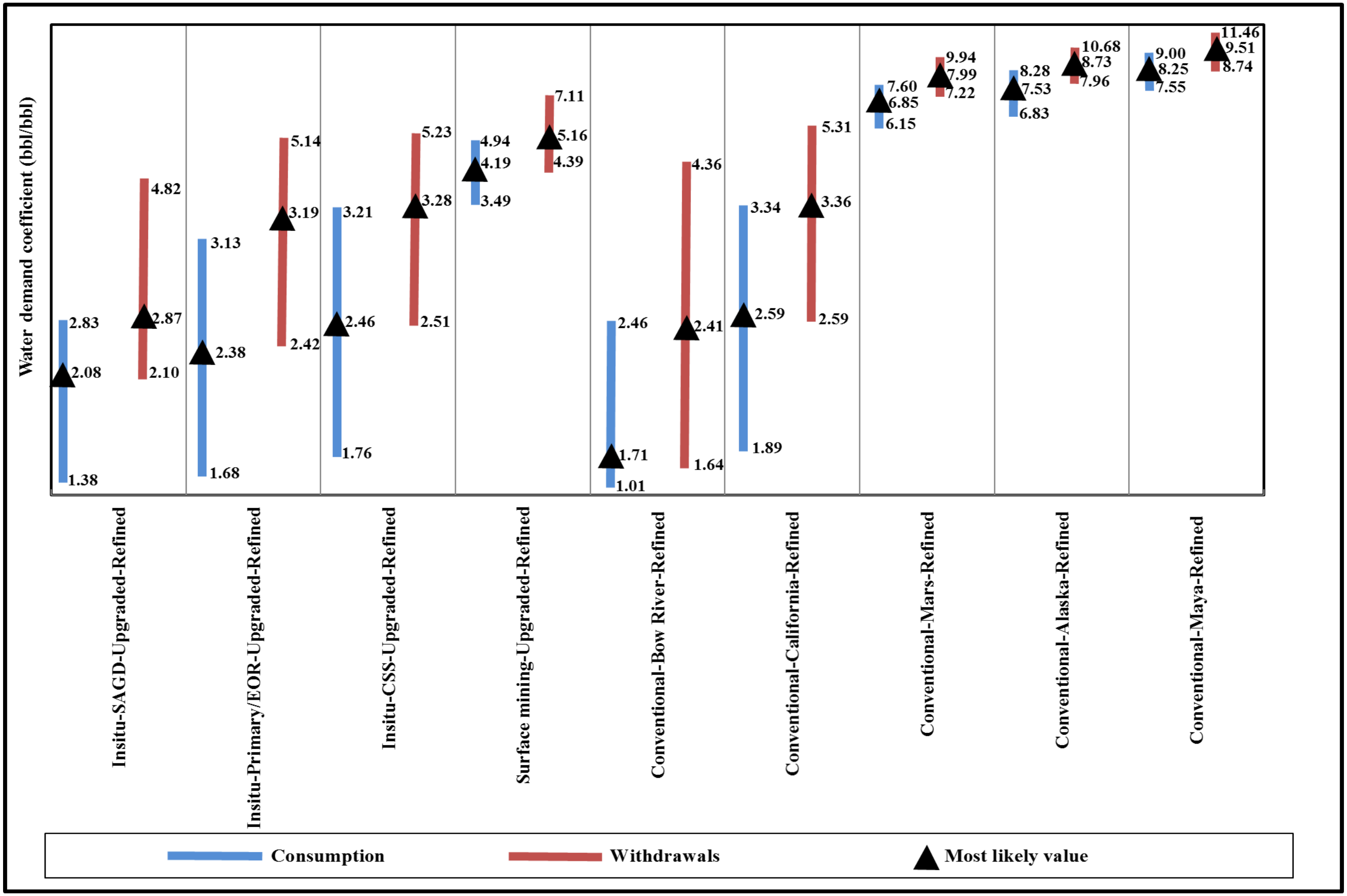

Figure 7.2: Ranges of water demand coefficients for oil sands and crude oil with variable refining coefficients

7.2 Recommendations for future research

7.2.1 Development of forecasting models

The water consumption and water withdrawals coefficients developed in this study are recommended for forecasting the corresponding water amounts required for each pathway. The forecasting is to cover the complete life cycle stages of primary fuel and power generation unit operations. The projections of primary fuel produced or power generated from specific pathways have to be combined with the associated water coefficient to obtain the required amount of water over a specified time horizon and for a specific jurisdiction or river basin. The variation of water demand coefficients due to the advanced technologies or performance improvement over the specified time horizon should be taken into account for more accurate forecasting.

A model to forecast water demand in different sectors has already been developed by the Stockholm Environment Institute (SEI) through the Water Evaluation and Planning (WEAP) [1] software. One of the limitations of WEAP is that it lacks built-in water demand coefficients. The developed water demand coefficients from this study could be a significant contribution in the field of water forecasting for the energy sector if integrated with WEAP capabilities.

Unit operations may use water from different geographical zones or with different qualities and to differentiate between these in the forecasting model, pathways have to be structured accordingly. For example, differentiation may be required between surface water and groundwater or between saline and fresh water. Models should also consider geographical zones through water basins or based on specific jurisdiction.

7.2.2 Cost of conserved water for power generation

The cost of conserved water (CCW) can be introduced to integrate economic indicator and water demand indicators for power generation developed in in this study. An Economic indicator is represented by the levelized cost of electricity (LCOE) for each pathway. The LCOE is directly proportional to the ratio between the costs (capital and operating costs after both brought to the present value) and the amount of the power generated over the complete lifetime of the power plant [2 - 4]. The CCW in $ per m^3 of water saved is a concept has been used by the DOE/NETL [5] to compare dry cooling and wet recirculating cooling systems and was also applied by Ku and Shapiro [6] to compare alternate power generation technologies and a baseline pulverized coal power plant using a cooling tower

A similar concept of the CCW has been used by researchers for GHG emissions assessment through the calculation of the abatement cost [7 - 9].

7.2.3 Optimization of power generation pathways

It is recommended that the water demand coefficients developed in this study be integrated with other factors to select optimal power generation pathways in a certain jurisdiction. The optimization is done by integrating the impacts on water, air, land, and the cost of production. The integration of the some of these factors is introduced by International Atomic Energy Agency (IAEA) and covers climate, land, energy, and water strategies (CLEWS). The CLEWS approach is based on the concept that these factors cannot be dealt independently and cannot be met sustainably without trade-offs [10]. In order to obtain the optimal sustainable pathway, the solution should consider environmental, social, and economic views. Water is essential in these three areas [11]. Since the social view cannot easily be quantified, only environmental and economic factors are covered in this recommended study. The World Summit, held in 2005, specified the three main components of sustainable development to include economic and social development, besides the mitigation of environmental impacts. The outcome of the summit considered protecting and managing natural resources as one of the main objectives and a major requirement for sustainable development [12].

Some earlier studies assessed the sustainability of power generation [13 - 16]. Evans et al. [13] selected a range of sustainability indicators to assess renewable energy technologies. The indicators used were the price of generated electricity, full life cycle greenhouse gas (GHG) emissions, availability of renewable sources, energy conversion efficiency, land requirement, water consumption, and social impacts. Onat and Bayar [14] analyzed the sustainability of electrical energy production through assigning indicators for unit energy cost, CO_2 emissions, availability, efficiency, fresh water consumption, land use, and social influences. The indicators are summed up and electricity generation technologies are ranked accordingly. Ribeiro et al. [15] used logic models to assess the electricity generation in Portugal. The logic models are developed with the aid of literature reviews and interviews with experts. The limitations of ranking and logic models are that the results could be subjective and would not show how much electricity has to be generated from each pathway within the optimum boundary. Abdullah et al. [16] optimized electricity generation from renewable energy by minimizing cost and GHG emissions. This study followed a multi-objective optimization technique for sustainability and included the uncertainty in availability of renewable energy.

Some other earlier studies were conducted to develop energy optimization models using linear programming, set cost related matters as the objective function, and have resources as constraints [13, 14]. The same concept could be adopted here in this recommended study by setting the cost of power generation the objective function to be minimized. The constraints of the linear programming model to be represented by the available natural resources (water and land), electricity demand, and total GHG emissions (air).

Special programs such as LINDO, LINGO, and LP solver in the field of operations research are available to give solutions to such linear programming models [17].

The output from this recommended model would determine how much power to generate from each pathway and the intervals for the introduced coefficients and constraints at the optimal region. These intervals can be used to conduct a sensitivity analysis to study the effect of changing the most likely uncertain factors. The model can be set as system dynamics and cover a certain period of time determined by the user in a certain geographical zone.

References

[1]. Stockholm Environment Institute (SEI). Water Evaluation and Planning (WEAP). Available at: http://www.weap21.org/ [accessed 02.08.2016]

[2]. Fraunhofer Institute for Solar Energy Systems ISE. Levelized cost of electricity: renewable energy technologies. November 2013. Available at: http://www.ise.fraunhofer.de/en/publications/veroeffentlichungen-pdf-dateien-en/studien-und-konzeptpapiere/study-levelized-cost-of-electricity-renewable-energies.pdf [accessed: 24.08.2016]

[3]. Nease J, Adams TA. Coal-fuelled systems for peaking power with 100% CO_2 capture through integration of solid oxide fuel cells with compressed air energy storage. Journal of Power Sources 2014; 251: 92 -107.

[4]. Larsson S, Fantazzini D, Davidsson S, Kullander S, Hook M. Reviewing electricity production cost assessments. Renewable and Sustainable Energy Reviews 2014; 30:170–183.

[5]. National Energy Technology Laboratory (NETL). Existing plants, emissions and capture – setting water-energy R&D program goals. DOE/NETL-2009/1372. Available at: http://www.circleofblue.org/waternews/wp-content/uploads/2010/08/NETL-Existing-Plants-Emissions-and-Caputre-Setting-Water-Energy-Rd-Goals.pdf [accessed: 14.08.2016]

[6]. Ku AY, Shapiro AP. The energy–water nexus: water use trends in sustainable energy and opportunities for materials research and development. MRS Bulletin 2012; 37: 439 – 447.

[7]. Kesicki F. What are the key drivers of MAC curves? a partial-equilibrium modelling approach for the UK. Energy Policy 2013; 58: 142 – 151.

[8]. Alqahtani BJ, Echeverri DP. Integrated solar combined cycle power plants: paving the way for thermal solar. Applied Energy 2016; 169: 927–936.

[9]. Morris J, Paltsev S, Reilly J. Marginal abatement costs and marginal welfare costs for greenhouse gas emissions reductions: results from the EPPA Model. MIT Joint Program on the Science and Policy of Global Change, Cambridge, MA, USA. Available at: http://globalchange.mit.edu/files/document/MITJPSPGC_Rpt164.pdf [accessed: 14.08.2016]

[10]. Rogner HH. CLEWS: climate land energy and water strategies: a case study. International Atomic Energy Agency (IAEA). Available at: http://www.iaea.org/OurWork/ST/NE/Pess/csd17/csd-17_clew_2009_holger.pdf [accessed 21.08.2016]

[11]. The United Nations World Water Development Report (WWDR 2015). Water for a sustainable world. Available at: http://unesdoc.unesco.org/images/0023/002318/231823E.pdf [accessed 15.08.2016]

[12].United Nations General Assembly (2005). 2005 World Summit Outcome. Resolution A/60/1 Adopted by the General Assembly on September 15, 2005. Available at: http://data.unaids.org/Topics/UniversalAccess/worldsummitoutcome_resolution_24oct2005_en.pdf [accessed 18.08.2016]

[13]. Evans A, Strezov V, Evans TJ. Assessment of sustainability indicators for renewable energy technologies. Renewable and Sustainable Energy Reviews 2009; 13: 1082–1088.

[14]. Onat N, Bayar H. The sustainability indicators of power production systems. Renewable and Sustainable Energy Reviews 2010; 14: 3108–3115.

[15]. Ribeiro F, Ferreira P, Araujo M. Sustainability assessment of electricity production using a logic models approach. Renewable and Sustainable Energy Reviews 2013; 28: 215–223.

[16]. Abdullah MA, Muttaqi KM, Agalgaonkar AP. Sustainable energy system design with distributed renewable resources considering economic, environmental and uncertainty aspects. Renewable Energy 2015; 78: 165-172.

[17]. Winston WL, Goldberg JB. Operations research: applications and algorithms. Fourth edition. Publisher: Curt Hinrichs. ISBN-13: 978-0534-38058-8.

Bibliography

Abdullah, M.A., Agalgaonkar, A.P., and Muttaqi, K.M. (2014). ***"Climate change mitigation with integration of renewable energy resources in the electricity grid of New South Wales, Australia."*** Renewable Energy, 66: 305 – 313.

Abdullah, M.A., Muttaqi K.M., and Agalgaonkar A.P. (2015). ***"Sustainable energy system design with distributed renewable resources considering economic, environmental and uncertainty aspects."*** Renewable Energy, 78: 165-172.

Acton, J., Suzuki, Y., and Shimogori, Y. (2005). ***495-MW Capacity Genesee phase 3 project: the first supercritical pressure coal-fired boiler in Canada.*** Available from http://www.hitachipowersystems.us/supportingdocs/forbus/hpsa/technical_papers/EP2005.pdf. Accessed: August, 2016.

AENV (2008). Alberta Environment (AENV). ***Glossary of terms related to water and watershed management in Alberta.*** 1st edition. Partnerships and Strategies Section, November 2008. Available from https://www.ualberta.ca/-/media/ualberta/faculties-and-programs/centres-institutes/water-initiative/waterterminology.pdf. Accessed: August, 2016.

AENV (2007). Alberta Environment. ***Current and future water use in Alberta.*** Prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007). Available from www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf. Accessed: August, 2016.

AER (2015). Alberta Energy Regulator (AER). ***Alberta's energy reserves 2014 and supply/demand outlook 2015-2024.*** ST98-2015. ISSN 1910-4235. Available from http://www.aer.ca/documents/sts/ST98/ST98-2015.pdf. Accessed: August, 2016.

AER (2014a). Alberta Energy Regulator (AER). ***Alberta's energy reserves 2013 and supply/ demand outlook 2014 – 2023.*** Available from http://www.aer.ca/documents/sts/ST98/ST98-2014.pdf. Accessed: August, 2016.

AER (2014b). Alberta Energy Regulator (AER). ***Water and oil: an overview of the use of water for enhanced oil recovery in Alberta.*** Available from https://www.aer.ca/documents/applications/WA_WaterOil_UseOfWaterForEnhancedOilRecovery.pdf. Accessed: August, 2016.

AER (2012). Alberta Energy Regulator (AER). ***Alberta's energy reserves 2011 and supply/demand outlook 2012-2021.*** ST98-2012. ISSN 1910-4235. Available from http://www.aer.ca/documents/sts/ST98/ST98-2012.pdf. Accessed: August, 2015.

AER (2011). Alberta Energy Regulator (AER). ***Alberta's energy reserves 2010 and supply/demand outlook 2011-2020.*** ST98-2011. ISSN 1910-4235. Available from http://www.aer.ca/documents/sts/ST98/st98-2011.pdf. Accessed: August, 2016.

AER (2010). Alberta Energy Regulator (AER). ***Alberta's energy reserves 2009 and supply/demand outlook 2010-2019.*** ST98-2010. ISSN 1910-4235. Available from http://www.aer.ca/documents/sts/ST98/st98_2010.pdf. Accessed: August, 2016.

AER (2009). Alberta Energy Regulator (AER). ***Alberta's energy reserves 2008 and supply/demand outlook 2009-2018.*** ST98-2009. ISSN 1910-4235. Available from http://www.aer.ca/documents/sts/ST98/st98-2009.pdf. Accessed: August, 2016.

AESRD (2011). Alberta Environment and Sustainable Resource Development (AESRD).Government of Alberta. ***Focus on groundwater: groundwater management.*** Available from http://aep.alberta.ca/about-us/documents/FocusOn-GroundwaterManagement-2014.pdf. Accessed: August, 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.

Ahmed, I. and Rashid, A. (2010). ***"Study of geothermal energy resources of Pakistan for electric power generation."*** Energy Sources, Part A, 32:826–838

Alberta Energy (2015a). Government of Alberta. ***About coal.*** Available from http://www.energy.alberta.ca/coal/645.asp. Accessed: August, 2016.

Alberta Energy (2015b). Government of Alberta. ***About oil sands: facts and statistics.*** Available from http://www.energy.alberta.ca/OilSands/791.asp. Accessed: August, 2016.

Alberta Energy (2015c).Government of Alberta. ***Natural Gas.*** Available from http://www.energy.alberta.ca/NaturalGas/727.asp. Accessed: August, 2016.

Alberta Energy (2015d). Government of Alberta. ***Natural gas facts.*** Available from http://www.energy.alberta.ca/NaturalGas/726.asp. Accessed: August, 2016.

Alberta Government (2013). ***Alberta oil and gas industry: quarterly update.*** Winter 2013. Available from http://albertacanada.com/files/albertacanada/OilGas_QuarterlyUpdate_Winter2013.pdf. Accessed: August, 2016.

Alberta Government (2012). ***Alberta's energy industry: an overview.*** Available from http://www.energy.alberta.ca/Org/pdfs/Alberta_Energy_Overview.pdf. Accessed: August, 2016.

Albrecht, M. and Matoney, J. (1982). ***Introduction to coal preparation.*** Fourth Annual Symposium on Industrial Coal Utilization, DOE, Cincinnati, April 1982. Available from http://www.albrechts.com/mike/articles/Introduction%20to%20Coal%20Preparation.pdf. Accessed: August, 2016.

Ali, B., Kumar, A. (2016). ***"Development of life cycle water footprints for gas-fired power generation technologies."*** Energy Conversion and Management, 110: 386- 396.

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. (2003). ***"Simulation of a solar concentrating dish for steam generation."*** International Journal of Sustainable Energy 23 (3):129-141

Al-Otoom, A., Allawzi, M., Al-Omari, N., and Al-Hsienat, E. (2010). ***"Bitumen recovery from Jordanian oil sand by froth flotation using petroleum cycles oil cuts."*** Energy, 35: 4217- 4225.

Alqahtani, B.J and Echeverri, D.P. (2016). ***"Integrated solar combined cycle power plants: paving the way for thermal solar."*** Applied Energy, 169: 927–936

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.

Anze, M., Alves, R.M., and Nascimento, C.A. (2010). ***Optimization of water use in oil refinery.*** AICHE Annual Meeting, Salt Lake City, UT, United States, November 7-12, 2010. Available from http://aiche.confex.com/aiche/2010/webprogrampreliminary/Paper201402.html. Accessed: August, 2016.

ATCO (2015). ***Battle River coal-fired generating station.*** Available from http://www.atcopower.com/Our-Facilities/Our-Power-Technologies/Coal-Fired-Thermal/Battle-River. Accessed: August, 2016.

A.T. Kearney Inc. (2010). ***Solar thermal electricity 2025: clean electricity on demand: attractive STE cost stabilize energy production.*** June 2010. Available from http://www.promes.cnrs.fr/uploads/pdfs/documentation/2010-Solar%20thermal%20electricity%202025%20ESTELA.pdf. Accessed: August, 2016.

Backus, C.E. and Brown, M.L. (1975). ***Water requirements for solar energy.*** In: Gloyna EF, Woodson HH, and Drew HR, editors. Water Management for the Electric Power Industry, Water Resources Symposium #8, Center for Research in Water Resources, The University of Texas at Austin, 1975, 270-279.

Barker, M. (2011). ***Underground coal mining: understanding of process and techniques.*** BHP Billiton. Caroona Coal Project. Available from http://www.bhpbilliton.com/~/media/bhp/documents/society/regulatory/_coal/nswec/caroona-coal-project/111205_coal_nswec_caroona_undergroundcoalminingpresentation.pdf?la=en. Accessed: August, 2016.

Berkley, M., Cruz, E., Vatanakul, M., Hynes, R., and Stickler, A. (2010). ***Innovation avenues for coal derived power essential for the future.*** XXIst World Energy Congress, Montreal, September

12-16, 2010. Available from http://www.indiaenergycongress.in/montreal/library/pdf/290.pdf. Accessed: August, 2016.

Bertani, R. (2010). ***Level of typical efficiencies for electricity generation of geothermal plants.*** EGEC. ETP Geothermal, Pisa, 10.06.2010. Available from http://egec.info/wp-content/uploads/2011/08/12-TP-GEOELEC-Pisa-Bertani.pdf. Accessed: August, 2016.

BP in Alaska (2013). ***Greater Prudhoe Bay.*** Available from http://www.bp.com/content/dam/bp-country/en_us/PDF/prudhoe_bay_2013.pdf. Accessed: August, 2016.

Bracco, S., Pierfederici, A., and Trucco, T. (2007). ***"The wet compression technology for gas turbine power plants: thermodynamic model."*** Applied Thermal Engineering, 27:699–704.

Canadian Fuels Association (2010). ***Water – a precious resource.*** February 2010. Available from http://canadianfuels.ca/userfiles/file/Water%20Primer%20-%20Final%20%28Updated%20with%202010%20data%29.pdf. Accessed: July, 2015.

CAPP (2015a). Canadian Association of Petroleum Producers (CAPP). ***Crude oil: forecast, markets, & transportation.*** June 2016. Available from http://www.capp.ca/publications-and-statistics/publications/284950. Accessed: July, 2015.

CAPP (2015b). Canadian Association of Petroleum Producers (CAPP). ***Optimal water management.*** Available from http://www.capp.ca/responsible-development/water/optimal-water-management. Accessed: August, 2016.

CAPP (2014). Canadian Association of Petroleum Producers (CAPP). ***Responsible Canadian energy 2014 progress report.*** Available from http://www.capp.ca/~/media/capp/customer-portal/publications/255363.pdf. Accessed: August, 2016.

CAPP (2012). Canadian Association of Petroleum Producers (CAPP). ***2013 Responsible Canadian energy progress report.*** Available from http://www.capp.ca/~/media/capp/customer-portal/publications/233913.pdf. Accessed: July, 2016.

CAPP (2011). Canadian Association of Petroleum Producers (CAPP). ***Water use in Canada's oil sands.*** July 2011. 2011-0015.

CAPP (2010). Canadian Association of Petroleum Producers (CAPP). ***The 2010 responsible Canadian energy progress report.*** Available from www.capp.ca/~/media/capp/customer-portal/publications/200577.pdf. Accessed: July, 2015.

CAPP (2009). Canadian Association of Petroleum Producers (CAPP). ***Responsible Canadian energy progress report.*** For the year ended December 31, 2009.

Carvill, J. and Cullum, R. (2000). ***Power units and transmission. In: Smith E. Mechanical engineer's reference book.*** ISBN 0 7506 4218 1.Butterworth-Heinemann, Linacre House, Jordan

Hill, Oxford OX2 8D. A division of Reed Educational and Professional Publishing Ltd.; 2000, p. 10/3-10/49.

Cenovus Energy Inc. (2015). ***Steam-assisted gravity drainage (SAGD).*** Available from http://www.cenovus.com/operations/technology/sagd.html. Accessed: July, 2015.
Cenovus Energy Inc. (2012). ***Corporate responsibility report.*** Available from http://www.cenovus.com/reports/2012-corporate-responsibility/. Accessed: August, 2016.

Chalaturnyk, R.J., Scott, J.D., and Ozum, B. (2002). ***"Management of oil sands tailings."*** Petroleum Science and Technology, 20: 9-10:1025-1046.

Chase, D. and Kehoe P. (2000). ***GE combined-cycle product line and performance.*** GE Power Systems, GER-3574G. Available from http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger3574g.pdf. Accessed: July, 2015.

Chevron Canada (2015). ***How does an oil refinery work?*** Available from http://www.chevron.ca/operations/refining/refineryworks.asp. Accessed: August, 2016.

Ciferno, J.P., Munson, R.K., Murphy, J.T., and Lash, B.S. (2014). ***Determining carbon capture and sequestration's water demands.*** U.S. Department of Energy, National Energy Technology Laboratory and Leonardo Technologies Inc. Available from http://www.powermag.com/determining-carbon-capture-and-sequestrations-water-demands/. Accessed: August, 2016.

Clark, C., Horner, R., and Harto, C. (2013). ***"Life cycle water consumption for shale gas and conventional natural gas."*** Environmental Science & Technology, 47: 11829-36.

Clemente, J. (2008***). Cantarell is not Mexico's only oil production problem.*** Pipeline & Gas Journal, August 2008. Available from http://www.peakoil.net/files/Cantarell%20Is%20Not%20Mexico%E2%80%99s%20Only%20Oil%20Production%20Problem.pdf. Accessed: August, 2016.

Coal Association of Canada (2015). ***Rail, ports & terminals.*** Available from http://www.coal.ca/transportation/. Accessed: August, 2016.

Cohen, B.L. (1983). ***"Breeder reactors: a renewable energy source."*** American Journal of Physics, 51:75

ConocoPhillips Alaska (2015). ***Factsheet: Alaska.*** Available from http://alaska.conocophillips.com/Documents/Fact%20Sheet_Alaska_Spring%202015_FINAL.pdf. Accessed: August, 2016.

Croley, T.E., Patel, V.C., and Cheng, M.S. (1975). ***The water and total optimization of wet and dry-wet cooling towers for electric power plants.*** Iowa Institute of Hydraulic Research Report No. 163. The University of Iowa, Iowa City, Iowa, January,1975.

Crow, I. and Shippen, K. ***Electricity generation. In: Snow D. Plant engineer's reference book.*** ISBN 0 7506 4452 4.Butterworth-Heinemann, Linacre House, Jordan Hill, Oxford OX2 8D. A division of Reed Educational and Professional Publishing Ltd.; 2001, p. 22/3-22/19.

Crude Quality Inc. (2015). ***Bow River South (BRS).*** Available from http://www.crudemonitor.ca/crude.php?acr=BRS. Accessed: August, 2016.

Dale, A., Khanna, V., Vidic, R., and Bilec, M. (2013). ***"Process based life-cycle assessment of natural gas from the Marcellus Shale."*** Environmental Science & Technology, 47: 5459−66.

Davison, J. (2007). ***"Performance and costs of power plants with capture and storage of CO_2."*** Energy, 32, 1163-1176.

Davoudpour, H. and Ahadi, M.S. (2006). ***"The potential for greenhouse gases mitigation in household sector of Iran: cases of price reform/efficiency improvement and scenario for 2000-2010."*** Energy Policy, 34 (1): 40 – 49.

Department of Conservation: Division of Oil, Gas, and Geothermal Resources (2013). ***2012 Preliminary report of California oil and gas production statistics.*** Issued April 2013. Publication no. PR03. Available from ftp://ftp.consrv.ca.gov/pub/oil/annual_reports/2012/PR03_PreAnnual_2012.pdf. Accessed: August, 2016.

Desseault M.B. (2001). ***Comparing Venezuelan and Canadian heavy oil and tar sands.*** Canadian International Petroleum Conference, Calgary, Alberta, Canada, June 12–14, 2001, Canadian Institute of Mining, Metallurgy, and Petroleum, Proceedings, Paper 2001–061, 20 p.

Diepolder, P. (1992). ***"Is zero discharge realistic?"*** Hydrocarbon Processing, 71 (10): 129-131.

DiPietro, P. and Krulla, K. (2010). ***Improving the efficiency of coal-fired power plants for near term greenhouse gas emissions reductions.*** National Energy Technology Laboratory (NETL). DOE/NETL -2010/1411. Available from http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2010-1411-ImpEfficCFPPGHGRdctns-0410.pdf. Accessed: August, 2016.

DiPippo, R. (2007). ***"Ideal thermal efficiency for geothermal binary plants."*** Geothermics, 36: 276–285.

Dodder, R.S. (2014). ***"A review of water use in the U.S. electric power sector: insights from systems-level perspectives."*** Current Opinion in Chemical Engineering, 5:7–14.

DOE (2011). ***Biomass power overview.*** Available from: http://cta.ornl.gov/bedb/biopower/Biopower_Overview.pdf. Accessed: August, 2016.

DOE (2009). US Department of Energy (DOE). ***Concentrating solar power commercial application study: reducing water consumption of concentrating solar power electricity generation***. Report to Congress. (Washington, DC). Available from http://www1.eere.energy.gov/solar/pdfs/csp_water_study.pdf. Accessed: August, 2016.

DOE (2008). ***20% wind energy by 2030: increasing wind energy's contribution to U.S. electricity supply.*** DOE/GO-102008-2567. Available from: http://www.nrel.gov/docs/fy08osti/41869.pdf. Accessed: August, 2016.

DOE (2007). U.S. Department of Energy (DOE). ***Small wind electric systems: a U.S. consumer's guide.*** Energy Efficiency and Renewable Energy. Available from: http://www.nrel.gov/docs/fy07osti/42005.pdf. Accessed: August, 2016.

DOE (2006). U.S. Department of Energy (DOE). ***Energy demands on water resources: report to Congress on the interdependency of energy and water.*** December 2006. Available from http://powi.ca/wp-content/uploads/2012/12/Energy-Demands-on-Water-Resources-Report-to-Congress-2006.pdf. Accessed: August, 2016.

Donahue, W. (2010). ***In situ oil sands – get ready for massive water demands in northern and central Alberta.*** Water Matters. August 2010. Available from http://www.water-matters.org/story/401. Accessed: August, 2016.

EIA (2015a). U.S. Energy Information Administration (EIA). ***Alaska North Slope crude oil production.*** Available from http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MANFPAK1&f=A. Accessed: August, 2016.

EIA (2015b). U.S. Energy Information Administration (EIA). ***Annual energy outlook 2015 with projections to 2040.*** DOE/EIA-0383(2015) April 2015. Available from http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf. Accessed: August, 2016.

EIA (2015c). U.S. Energy Information Administration (EIA). ***Country analysis brief: Venezuela.*** Available from http://www.eia.gov/beta/international/analysis_includes/countries_long/Venezuela/venezuela.pdf. Accessed: August, 2016.

EIA (2015d). U.S. Energy Information Administration (EIA). ***Crude oil production.*** Available from http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm. Accessed: August, 2016.

EIA (2015e). U.S Energy Information Administration (EIA). ***Frequently asked questions: what is the average heat content of U.S. coal?.*** Available from http://www.eia.gov/tools/faqs/faq.cfm?id=72&t=2. Accessed: August, 2016.

EIA (2015f). U.S Energy Information Administration (EIA). ***U.S. heat content of natural gas deliveries to consumers.*** Available from http://www.eia.gov/dnav/ng/hist/nga_epg0_vgth_nus_btucfa.htm. Accessed: August, 2016.

EIA (2014a). U.S. Energy Information Administration (EIA). ***Annual energy outlook 2014.*** DOE/EIA-0383(2014) April 2014. Available from http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf. Accessed: August, 2016.

EIA (2014b). U.S. Energy Information Administration (EIA). ***Mexico: overview.*** April 24, 2014. Available from http://www.eia.gov/beta/international/analysis_includes/countries_long/Mexico/mexico.pdf. Accessed: August, 2016.

EIA (2013a). U.S. Energy Information Administration (EIA). ***Energy in brief: how dependent are we on foreign oil?.*** Available from http://www.eia.gov/energy_in_brief/article/foreign_oil_dependence.cfm. Accessed: August, 2016.

EIA (2013b). U.S. Energy Information Administration (EIA). ***International Energy Outlook 2013.*** DOE/EIA-0484 (2013). July 2013. Available from http://www.eia.gov/forecasts/ieo/pdf/0484%282013%29.pdf. Accessed: August, 2016.

EIA (2011). U.S. Energy Information Administration (EIA). ***Annual energy review 2011: alternatives for estimating energy consumption.*** Available from: http://www.eia.gov/totalenergy/data/annual/pdf/sec17.pdf. Accessed: August, 2016.

Elcock, D. and Kuiper, J.A. (2010). ***Water vulnerabilities for existing coal-fired power plants.*** August 2010. DOE/NETL-2010/1429. Available from http://www.ipd.anl.gov/anlpubs/2010/08/67687.pdf. Accessed: August, 2016.

Elcock, D. (2008). ***Baseline and projected water demand data for energy and competing water use sectors.*** Report prepared for U.S Department of Energy. National Energy Technology Laboratory. Argonne National Laboratory. ANL/EVS/TM/08-8. Available from http://www.acs.org/content/dam/acsorg/policy/acsonthehill/briefings/energywaternexus/11-08-anl-water-demand-for-energy-competing-sectors.pdf. Accessed: August, 2016.

El-Wakil, M.M. (1984). ***The circulating water system. In: Power plant technology.*** McGraw-Hill International Editions, Electrical and Mechanical Engineering Series; Singapore,1984, ISBN 0-07-019288-X, page 260-303.

Engineerlive (2013). ***Focus on coal: coal-fired power plants capacity to grow by 35 per cent in next 10 years.*** International Power Engineer Magazine, 21st February 2013. Available from http://www.engineerlive.com/Power-Engineer/Focus_on_Coal/Coal-fired_power_plants_capacity_to_grow_by_35_per_cent_in_next_10_years/21600/. Accessed: August, 2016.

Environment Canada (2015). Emergencies Science and Technology Division. ***Mars blend.*** Available from http://www.etc-cte.ec.gc.ca/databases/Oilproperties/pdf/WEB_Mars_Blend.pdf. Accessed: August, 2016.

EPCOR (2003). ***Genesee Generating Station: annual environmental report.*** Available from http://www.corporateregister.com/a10723/epcor03-env-ca.pdf. Accessed: August, 2016.

EPRI (2007). Electric Power Research Institute (EPRI). ***At the power plant.*** EPRI Journal, summer 2007. California. Available from http://mydocs.epri.com/docs/CorporateDocuments/EPRI_Journal/2007-Summer/1015362.pdf. Accessed: August, 2016.

EPRI (1999). ***Enhanced oil recovery scoping study.*** Palo Alto, CA: 1999. TR-113836. Available from http://www.energy.ca.gov/process/pubs/electrotech_opps_tr113836.pdf. Accessed: August, 2016.

EURELECTRIC (2015). ***Hydropower: supporting a power system in transition.*** Available from: http://www.eurelectric.org/media/180752/hydropower-final-lr-2015-2120-0003-01-e.pdf. Accessed: August, 2016.

Evans, A., Strezov, V., and Evans, T.J. (2009). ***"Assessment of sustainability indicators for renewable energy technologies."*** Renewable and Sustainable Energy Reviews, 13: 1082–1088.

ExxonMobil (2015). ***The outlook for energy: a view to 2040.*** Available from http://cdn.exxonmobil.com/~/media/global/files/outlook-for-energy/2016/2016-outlook-for-energy.pdf. Accessed: August, 2016.

ExxonMobil (2013). Refining and Supply. ***About Alaskan North Slope (ANS).*** Available from http://www.exxonmobil.com/crudeoil/about_crudes_ans.aspx. Accessed: August, 2016.

Ezzat, M.F., Dincer, I. (2016). ***"Energy and exergy analyses of a new geothermal–solar energy based system."*** Solar Energy, 134: 95–106

Fogarasi, S., Cormos, C.C. (2015). ***"Technico-economic assessment of coal and sawdust co-firing power generation with CO2 capture."*** Journal of Cleaner Production, 103: 140-148

Fripp, M. (2009). ***Life-cycle greenhouse gas emissions from clean coal, clean gas and wind generators.*** Prepared for NextEra Energy Resources. Juno Beach, Florida. April 30, 2009. Available from http://www.academia.edu/567349/Life-Cycle_Greenhouse_Gas_Emissions_From_Clean_Coal_Clean_Gas_and_Wind_Generators. Accessed: August, 2016.

Fulton, J. and Cooley, H. (2015). ***"The water footprint of Californias energy system, 1990-2012."*** Environmental Science & Technology, 49 (6): 3314-3321.

Galas, C., Clements, A., Jaafar, E., and Jeje, O. (2011). ***Potential of EOR in Alberta oil pools.*** Phase 1 report. Prepared by Sproule for the Energy Resources Conservation Board (ERCB) (June 2011). Available from https://www.aer.ca/documents/reports/ercb-eor-report1.pdf. Accessed: August, 2016.

Galas, C., Clements, A., Jaafar, E., Jeje, O., Holst, D., and Holst, R. (2012). ***Identification of enhanced oil recovery potential in Alberta.*** Phase 2 final report. Prepared by Sproule for Energy Resources Conservation Board (ERCB) (March 31, 2012). Available from http://aer.ca/documents/reports/ercb-eor-report2.pdf. Accessed: August, 2016.

Galera, E.S., Allier,i 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

Garcia, S.G., Lacoste, C., Aicher, T., Feijoo, G., Lijo, L., and Moreira, M.T. (2016). ***"Environmental sustainability of bark valorisation into biofoam and syngas."*** Journal of Cleaner Production, 125: 33-43

GEO Estratos S.A. de C.V. (2011). ***Motley crude.*** Available from http://www.richcarriero.com/pdf/Crude%20Oil%20Varieties%20Mexico.pdf. Accessed: August, 2016.

Georgianna, T.D. and Haynes, K.E. (1981). ***"Competition for water resources: coal and agriculture in the Yellowstone Basin."*** Economic Geography, 57, 3, 225-37 Published by: Clark University.

Gils, H., Cofala, J., Wagner, F., and Schopp, W. (2013). ***"GIS-based assessment of the district heating potential in the USA."*** Energy, 58: 318-329.

Glassman, D., Wucker, M., Isaacman, T., and Champilou, C. (2011). ***The water-energy nexus: adding water to the energy agenda.*** World Policy, March 2011. Available from http://www.worldpolicy.org/sites/default/files/policy_papers/THE%20WATER-ENERGY%20NEXUS_0.pdf. Accessed: August, 2016.

Gleick, P.H. (1994). ***"Water and Energy."*** Annual Review of Energy and Environment, 19:267–299.

Goldstein, R. and Smith, W. (2002). ***Water & sustainability (Volume 3): U.S. water consumption for power production—The Next Half Century.*** Palo Alto, CA: EPRI; 2002. 1006786. Available from http://www.circleofblue.org/waternews/wp-content/uploads/2010/08/EPRI-Volume-3.pdf. Accessed: August, 2016.

Goodwin, S., Carlson, K., Douglas, C., and 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.

Grant, J., Angen, E., and Dyer, S. (2013). ***Forecasting the impacts of oilsands expansion.*** Pembina Institute, June 2013. Available from http://www.pembina.org/pub/2455. Accessed: August, 2016.

Gray, M., Xu, Z. and Masliyah, J. (2009). ***"Physics in the oil sands of Alberta."*** Physics Today, 62 (3): 31−35.

Griffiths, M. and Baker, C.S. (2003). ***Unconventional gas: the environmental challenges of coalbed methane development in Alberta.*** Pembina Institute, June 2003. Available from pubs.pembina.org/reports/CBM_Final_April2006D.pdf. Accessed: August, 2016.

Griffiths, M. and Dyer, S. (2008). ***Up-grader alley: oil sands fever strikes Edmonton.*** June 2008. Available from http://pubs.pembina.org/reports/Upgrader_Alley-report.pdf. Accessed: August, 2016.

Griffiths, M. and Woynillowicz, D. (2009). ***Heating up in Alberta: climate change, energy development and water.*** The Pembina Institute, February 2009. Available from http://pubs.pembina.org/reports/heating-up-in-alberta-report.pdf. Accessed: August, 2016.

Griffiths, M. (2007). ***Protecting water, producing gas.*** The Pembina Institute, 2007. Drayton Valley, AB. Available from www.pembina.org/pub/1434. Accessed: August, 2016.

Grubert, E. and Kitasei, S. (2010). ***How energy choices affect fresh water supplies: a comparison of U.S. coal and natural gas.*** Worldwatch Institute. Natural Gas and Sustainable Energy Initiative. (November 2010). Available from http://www.worldwatch.org/system/files/BP2.pdf. Accessed: August, 2016.

Grubert, E., Beach, F., and Webber, M. (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 (11pp).

Gupta, D. and Hlidek, B. (2010). ***"Frac-fluid recycling and water conservation: a case history."*** SPE Production and Operations, 25 (1): 65-69.

Gureev, V., Mats, E., Ivanova, V., Gureev, M., Malyshkin, D., and Agalakov, Y. (2013). ***"Processing feasibilities of enhancing the GTE-based electric power plant efficiency."*** Russian Aeronautics (Iz.VUZ), 56, (1):179–184.

Hackett, J., Idriss, A., Kause, R., Scott, K., and Tingley, J. (2012). ***Water conservation, efficiency, and productivity plan – electric power generation.*** August 2012. Available from https://extranet.gov.ab.ca/env/infocentre/info/library/8682.pdf. Accessed: August, 2016.

Hardy, L., Garrido, A., and Juana, L. (2012). ***"Evaluation of Spain's water-energy nexus."*** International Journal of Water Resources Development, 28(1): 151-170.

Harjai, S.K., Flury, C., Masliyah, J., Drelich, J., and Xu, Z. (2012). ***"Robust aqueous−nonaqueous hybrid process for bitumen extraction from mineable Athabasca oil sands."*** Energy Fuels, 26: 2920−2927.

Hermann, F.W. ***Types of coal mining.*** ILO Encyclopaedia of Occupational Health and Safety. Available from http://www.iloencyclopaedia.org/component/k2/item/596-types-of-coal-mining. Accessed: August, 2016.

Hoffmann, J., Feeley, T., and Carney B. (2005). ***DOE/NETL's Power plant water management R&D program—responding to emerging issues.*** Presentation at the 8th Electric Utilities Environmental Conference, Tucson, AZ, January 24-26, 2005. Available from http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/PPWaterMgt-EUEC-2005.pdf. Accessed: August, 2016.

Hofmann, H., Babadagli, T., and Zimmermann, G. (2014). ***"Hot water generation for oil sands processing from enhanced geothermal systems: process simulation for different hydraulic fracturing scenarios."*** Applied Energy, 113: 524–547.

Holly, C., Mader, M., and Toor, J. (2016). ***Oil sands production profile.*** Alberta Energy, Government of Alberta, January 31, 2016. Available from http://www.energy.alberta.ca/Org/pdfs/InitiativeOSPP.pdf. Accessed: August, 2016.

Hondo, H. (2005). ***"Life cycle GHG emission analysis of power generation systems: Japanese case."*** Energy, 30: 2042–2056.

Hong, P.A., Cha, Z., Zhao, X., Cheng, C.J., and Duyvesteyn, W. (2013). ***"Extraction of bitumen from oil sands with hot water and pressure cycles."*** Fuel Processing Technology, 106: 460-467.

Ibrahim, T. and Rahman, M. (2013). ***"Study on effective parameter of the triple-pressure reheat combined cycle performance."*** Thermal Science, 17(2): 497-508.

IEA (2015). International Energy Agency (IEA). ***Oil: medium-term market report 2015.*** Available from: https://www.iea.org/publications/freepublications/publication/MTOMR_2015_Final.pdf. Accessed: August, 2016.

IEA (2012a). International Energy Agency (IEA). ***Technology roadmap: high-efficiency, low-emissions coal-fired power generation.*** Available from http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapHighEfficiencyLowEmissionsCoalFiredPowerGeneration_WEB_Updated_March2013.pdf. Accessed: August, 2016.

IEA (2012b). International Energy Agency (IEA). ***Water for energy: is energy becoming a thirstiest resource? excerpt from the World Energy Outlook 2012.*** Available from http://www.worldenergyoutlook.org/media/weowebsite/2012/WEO_2012_Water_Excerpt.pdf. Accessed: August, 2016.

IEA (2010a). International Energy Agency (IEA). ***Gas-fired power.*** Energy Technology Systems Analysis Programme (ETSAP). Available from http://www.iea-etsap.org/web/e-techds/pdf/e02-gas_fired_power-gs-ad-gct.pdf. Accessed: August, 2016.

IEA (2010b). International Energy Agency (IEA). ***Power generation from coal: measuring and reporting efficiency performance and CO_2 emissions.*** Available from http://www.iea.org/publications/freepublications/publication/power_generation_from_coal.pdf. Accessed: August, 2016.

IEA (2010c). International Energy Agency (IEA). ***Renewable energy essentials: hydropower.*** Available from: http://www.iea.org/publications/freepublications/publication/hydropower_essentials.pdf. Accessed: August, 2016.

IEA (2008). International Energy Agency (IEA). ***Combined heat and power: evaluating the benefits of greater global investment.*** Available from https://www.iea.org/publications/freepublications/publication/chp_report.pdf. accessed: August, 2016.

IRENA, 2015. International Renewable Energy Agency (IRENA). ***Renewable energy in the water, energy & food nexus.*** Available from: http://www.irena.org/DocumentDownloads/Publications/IRENA_Water_Energy_Food_Nexus_2015.pdf. Accessed: August, 2016.

ISE (2013). Fraunhofer Institute for Solar Energy Systems (ISE). ***Levelized cost of electricity: renewable energy technologies.*** November 2013. Available from http://www.ise.fraunhofer.de/en/publications/veroeffentlichungen-pdf-dateien-en/studien-und-konzeptpapiere/study-levelized-cost-of-electricity-renewable-energies.pdf. Accessed: August, 2016.

Ishikawa, M., Terauchi, M., Komort, T., and Yasuraoka, J. (2008). ***"Development of high efficiency gas turbine combined cycle power plant."*** Mitsubishi Heavy Industries, Ltd. Technical Review, 45 (1): 15-17. Available from http://www.mhi.co.jp/technology/review/pdf/e451/e451015.pdf. Accessed: August, 2016.

Kabir, R. and Kumar, A. (2011). ***"Development of net energy ratio and emission factor for biohydrogen production pathways."*** Bio-resource Technology, 102(19): 8971-8985.

Kagel, A., Bates, D., and Gawell, K. (2007). ***A guide to geothermal energy and the environment.*** Geothermal Energy Association. Available from http://geo-energy.org/reports/environmental%20guide.pdf. Accessed: August, 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. Available from http://www.petroak.com/NorthSlope_Facility_Sharing_Study.pdf. Accessed: August, 2016.

Kania, J.J. (1984). ***"Economics of coal transport by slurry pipeline versus unit train: a case study."*** Energy Economics, 6, (2): 131-138.

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.

Kenny, J.F., Barber, N.L., Hutson, S.S., Linsey, K.S., Lovelace, J.K., and Maupin, M.A. (2009). ***Estimated use of water in the United States in 2005.*** U.S. Geological Survey. Circular 1344. Available from http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf. Accessed: August, 2016.

Kesicki, F. (2013). ***"What are the key drivers of MAC curves? a partial-equilibrium modelling approach for the UK."*** Energy Policy, 58: 142 – 151.

Khoo, H.H., 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.

Kindzierski, W. (2007). ***EPCOR Genesee Generating Station Phase 3.*** Technical communications, CIV E 240 Presentation. Department of Civil and Environmental Engineering. Available from http://www.energyquest4nanticoke.ca/gen3c.pdf. Accessed: August, 2016.

King, C.W. and Webber, M.E. (2008a). ***"The water intensity of the plugged-in automotive economy."*** Environmental Science & Technology, 42, 12: 4305-11.

King, C.W., Duncan, I., and Webber, M. (2008b). ***Water demand projections for power generation in Texas.*** Prepared for Texas Water Development Board, August 31, 2008. Available from http://www.twdb.texas.gov/publications/reports/contracted_reports/doc/0704830756ThermoelectricWaterProjection.pdf. Accessed: August, 2016.

King, C.W. and Webber, M.E. (2008c). **"Water intensity of transportation."** Environmental Science & Technology, 42, 7866-7872.

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.

Ku, A.Y. and Shapiro, A.P. (2012). ***"The energy-water nexus: water use trends in sustainable energy and opportunities for materials research and development."*** MRS Bulletin, 37(4): 439-447.

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.

Kullapa, S. and Joe, M. (2010). ***"Increasing innovation in home energy efficiency: Monte Carlo simulation of potential improvements."*** Energy and Buildings, 42 (6): 828 – 833.

Lacirignola, M. and Blanc, I. (2013). ***"Environmental analysis of practical design options for enhanced geothermal systems (EGS) through life-cycle assessment."*** Renewable Energy, 50: 901-914.

Langston, L. and Opdyke, G. (1997). ***"Introduction to gas turbines for non-engineers."*** Global Gas Turbine News, 37 (2) Available from http://files.asme.org/IGTI/Knowledge/Articles/13051.pdf. Accessed: August, 2016.

Larsson, S., Fantazzini, D., Davidsson, S., Kullander, S., and Hook, M. (2014). ***"Reviewing electricity production cost assessments."*** Renewable and Sustainable Energy Reviews, 30:170–183.

Lechon, Y., Rua, C., and Saez, R. (2008). "***Life cycle environmental impacts of electricity production by solar thermal power plants in Spain."*** Journal of Solar Energy Engineering, 130:021012-1-7.

Leighty, W., Ogden, J.M., and Yang, C. (2012). ***"Modeling transitions in the California light-duty vehicles sector to achieve deep reductions in transportation greenhouse gas emissions."*** Energy Policy, 44: 52-67.

Liu, H. and Marrero, T.R. (1997). ***"Coal log pipeline technology: an overview."*** Powder Technology, 94: 217-222.

Lunn, S. (2012). ***Water use in Canada's oil-sands industry: the facts.*** Imperial Oil Resources. SPE/APPEA International Conference on Health, Safety, and Environment in Oil and Gas Exploration and Production, Perth, Australia, 11-13 September, 2012.

Macknick, J., Newmark, R., Heath, G., and Hallett, K.C. (2012). ***"Operational water consumption and withdrawals factors for electricity generating technologies: a review of existing literature."*** Environmental Research Letters, 7: 045802-12.

Macknick, J. (2012). ***Water impacts of the electricity sector.*** American Solar Energy Society, World Renewable Energy Forum. May 14, 2012. National Renewable Energy Laboratory (NREL). Available from http://www.nrel.gov/docs/fy12osti/55028.pdf. Accessed: August, 2016.

Maheu, M. (2009). ***"Energy choices and their impacts on demand for water resources: an assessment of current and projected water consumption in global energy production."*** UNISFERA International Centre Publications, November 2009.

Mahto, D. and Pal, S. (2013). ***"Thermodynamics and thermo-economic analysis of simple combined cycle with inlet fogging."*** Applied Thermal Engineering, 51: 413-424.

Mallah, S. and Bansal, N.K. (2010). ***"Nuclear and clean coal technology options for sustainable development in India."*** Energy, 35 (7): 3031 – 3039.

Mantell, M.E. (2010). ***Deep shale natural gas: abundant, affordable, and surprisingly water efficient.*** 2009 GWPC Water/Energy Sustainability Symposium held in Salt Lake City, Utah, USA, 13-16 September 2009. Available from http://www.shepstone.net/naturalgasnow/ShaleGasFacts.pdf. Accessed: August, 2016.

Martz, L.W., Bruneau, J.F., and Rolfe, J.T. (2007). ***Climate change and water.*** SSRB Final technical report. Final Report April 2007. Available from http://www.parc.ca/ssrb/SSRB_Final_Report.pdf. Accessed: August, 2016.

MAXIM Power Corp. (2007). ***Proposed HR Milner expansion project: public disclosure document.*** November 2007. Available from http://esrd.alberta.ca/lands-forests/land-industrial/programs-and-services/environmental-assessment/documents/MaximPower_Milner_PDD.pdf. Accessed: August, 2016.

McMahon, J.E. and Price, S.K. (2011) ***"Water and energy interactions."*** Annual Review of Environment and Resources, 36:163-191.

Meldrum, J., Anderson, S., Heath, G., and Macknick, J. (2013). ***"Life cycle water use for electricity generation: a review and harmonization of literature estimates.*** Environmental Research Letters, 8: 015031 (18pp).

Merschmann, P., Vasquez, E., Szklo, A., and Schaeffer, R. (2013). ***"Modeling water use demands for thermoelectric power plants with CCS in selected Brazilian water basins."*** International Journal of Greenhouse Gas Control, 13: 87-101.

Mielke, E., Anadon, L., and Narayanamurti, V. (2010). ***Water consumption of energy resource extraction, processing, and conversion.*** Energy Technology Innovation Policy Research Group. Belfer Center for Science and International Affairs, 2010. Available from http://belfercenter.ksg.harvard.edu/files/ETIP-DP-2010-15-final-4.pdf. Accessed: August, 2016.

Miller, D. and Chorel, M. (2004). ***A study on the efficiency of Alberta's electrical supply system.*** project # CASA-EEEC-02-04. For Clean Air Strategic Alliance (CASA). October 2004. Available from http://www.hme.ca/reports/CASA_Report_--_The_Efficiency_of_Alberta's_Electrical_Supply_System_EEEC-02-04.pdf. Accessed: August, 2016.

MIT (2006). Massachusetts Institute of Technology (MIT). ***The future of geothermal energy: impact of enhanced geothermal systems (EGS) on the United States in the 21st century.*** Available from http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf. Accessed: August, 2016.

Moon, H. and Zarrouk, S.J. (2012). ***Efficiency of geothermal power plants: a worldwide review.*** New Zealand Geothermal Workshop 2012 Proceedings, 19 - 21 November 2012, Auckland, New Zealand. Available from http://www.geothermal-energy.org/pdf/IGAstandard/NZGW/2012/46654final00097.pdf. Accessed: August, 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. DOI:10.1021/ef100320t.

Morris, J., Paltsev, S., and Reilly, J. (2008). ***Marginal abatement costs and marginal welfare costs for greenhouse gas emissions reductions: results from the EPPA Model.*** MIT Joint Program on the Science and Policy of Global Change, Cambridge, MA, USA. Available from http://globalchange.mit.edu/files/document/MITJPSPGC_Rpt164.pdf. Accessed: August, 2016.

Munster, M., Morthorst, P., Larsen, H., Bregnbæk, L., Werling, J., Lindboe, H., and Ravn, H. (2012). ***"The role of district heating in the future Danish energy system."*** Energy, 48: 47-55.

Nalbandian, H. (2009). ***"Performance and risks of advanced pulverized-coal plants."*** Energeia, 20 (1). Available from http://www.caer.uky.edu/energeia/PDF/vol20_1.pdf. Accessed: August, 2016.

NATGAS (2013a). NaturalGas.org. ***Electric generation using natural gas.*** Available from http://naturalgas.org/overview/uses-electrical/. Accessed: August, 2016.

NATGAS (2013b). NaturalGas.org. ***Unconventional natural gas resources.*** Available from http://naturalgas.org/overview/unconventional-ng-resources/. Accessed: August, 2016.

Nease, J. and Adams, T.A. (2014). ***"Coal-fuelled systems for peaking power with 100% CO_2 capture through integration of solid oxide fuel cells with compressed air energy storage."*** Journal of Power Sources, 251: 92 -107.

NEB (2008). National Energy Board (NEB). ***Energy briefing note: coal-fired power generation: a pperspective.*** July 2008. Available from https://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/archive/clfrdpwrgnrtn2008/clfrdpwrgnrtn-eng.pdf. Accessed: August, 2016.

NETL (2011b). National Energy Technology Laboratory (NETL). ***Estimating freshwater needs to meet future thermoelectric generation requirements.*** 2011 update. DOE/NETL-2011/1523. Available from https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Coal/WaterNeeds2011.pdf. Accessed: August, 2016.

NETL (2009a). National Energy Technology Laboratory (NETL). ***Estimating freshwater needs to meet future thermoelectric generation requirements.*** DOE/NETL-400/2009/1339. September 30, 2009. Available from http://www.netl.doe.gov/File%20Library/Research/Coal/ewr/water/2009-Water-Needs-Analysis---Final--9-30-2009-.pdf. Accessed: August, 2016.

NETL (2009b). National Energy Technology Laboratory (NETL). ***Existing plants, emissions and capture – setting water-energy R&D program goals.*** DOE/NETL-2009/1372. Available from http://www.circleofblue.org/waternews/wp-content/uploads/2010/08/NETL-Existing-Plants-Emissions-and-Caputre-Setting-Water-Energy-Rd-Goals.pdf. Accessed: August, 2016.

NETL (2009c). National Energy Technology Laboratory (NETL). ***Impact of drought on U.S. steam electric power plant cooling water intakes and related water resource management issues.*** DOE/NETL-2009/1364. Pittsburgh, PA, April 2009. Available from http://www.circleofblue.org/waternews/wp-content/uploads/2010/08/Impact-of-Drought-on-Steam-Electric-Power-Plant-Cooling-Water-Intakes.pdf. Accessed: August, 2016.

NETL (2009d). National Energy Technology Laboratory (NETL). ***Modern shale gas development in the United States: a primer.*** April 2009. Available from http://energy.gov/sites/prod/files/2013/03/f0/ShaleGasPrimer_Online_4-2009.pdf. Accessed: August, 2016.

NETL (2007). National Energy Technology Laboratory (NETL). ***Subcritical pulverized bituminous coal plant.*** Available from http://www.netl.doe.gov/KMD/cds/disk50/PC%20Plant%20Case_Subcritical_051507.pdf. Accessed: August, 2016.

Nielsen, S., and Molle, B. (2013). ***"GIS based analysis of future district heating potential in Denmark."*** Energy, 57: 458-468.

NRCAN (2015). Natural Resources Canada (NRCAN). ***Coal: other information: what is coal?.*** Available from http://www.nrcan.gc.ca/mining-materials/markets/commodity-reviews/2012/14377. Accessed: August, 2016.

NRCAN (2013a). Natural Resources Canada (NRCAN). ***Freshwater: the role and contribution of Natural Resources Canada.*** Available from http://www.nrcan.gc.ca/sustainable-development/freshwater/2543#f23. Accessed: August, 2016.

NRCAN (2013b). Natural Resources Canada (NRCAN). ***Oil sands: water management.*** Available from https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/pdf/eneene/pubpub/pdf/os2015/14-0704-Oil-Sands-Water-Management_access_eng.pdf. Accessed: August, 2016.

NREL (2003). National Renewable Energy Laboratory (NREL). ***Assessment of parabolic trough and power tower solar technology cost and performance forecasts.*** Sargent & Lundy LLC Consulting Group Chicago, Illinois. NREL/SR-550-34440, October 2003. Available from http://www.nrel.gov/docs/fy04osti/34440.pdf. Accessed: August, 2016.

OECD (2008). Organisation for Economic Co-Operation and Development (OECD). ***Key environmental indicators.*** Paris, France, 2008. Available from http://www.oecd.org/env/indicators-modelling-outlooks/37551205.pdf. Accessed: August, 2016.

Oel, P.R.O. and Hoekstra, A.Y. (2012). ***"Towards quantification of the water footprint of paper: a first estimate of its consumptive component."*** Water Resources Management, 26:733–749

Offshore Technology (2015a). ***Cantarell oilfield, Gulf of Mexico, Mexico.*** Available from http://www.offshore-technology.com/projects/cantarell/. Accessed: August, 2016.

Offshore Technology (2015b). ***Mars oil and gas field project, Gulf of Mexico, United States of America.*** Available from http://www.offshore-technology.com/projects/mars/. Accessed: August, 2016.

Okadera, T., Chontanawat, J., and Gheewala, S.H. (2014). ***"Water footprint for energy production and supply in Thailand."*** Energy, 77: 49-56.

Onat, N. and Bayar, H. (2010). ***"The sustainability indicators of power production systems."*** Renewable and Sustainable Energy Reviews, 14: 3108–3115.

OSDC (2011). Oil Sands Discovery Centre (OSDC). ***Facts about Alberta's oil sands and its industry.*** Available from http://history.alberta.ca/oilsands/docs/facts_sheets09.pdf. Accessed: August, 2016.

Ou, Y., Zhai, H., and Rubin, E.S. (2016). ***"Life cycle water use of coal- and natural-gas-fired power plants with and without carbon capture and storage."*** International Journal of Greenhouse Gas Control, 44: 249–261.

Ozbilen, A., Dincer, I., and Rosen, M.A. (2011). ***"A comparative life cycle analysis of hydrogen production via thermochemical water splitting using a Cu-Cl cycle."*** International Journal of Hydrogen Energy, 36: 11321-11327.

Pacific Institute (2010). ***Table 2: Freshwater withdrawal, by country and sector (2010 Update).*** Available from http://www.worldwater.org/data.html. Accessed: August, 2016.

Pacsi, A.P., Sanders, K.T., Webber, M.E., and Allen, D.T. (2014). ***"Spatial and temporal impacts on water consumption in Texas from shale gas development and use."*** ACS Sustainable Chemistry and Engineering, 2(8): 2028-2035.

Paul, I. (1999). ***"Supercritical coal fired power plants: a technology being successfully deployed in developing countries."*** Energy Issues, 19. Available from http://documents.worldbank.org/curated/en/924431468740714825/pdf/multi-page.pdf. Accessed: August, 2016.

Peachey, B. (2005). ***Strategic needs for energy related water use technologies.*** Water and the EnergyINet. New Paradigm Engineering Ltd. Available from http://www.assembly.ab.ca/lao/library/egovdocs/2005/aleri/154945.pdf. Accessed: August, 2016.

Pellegrini, L.F., Junior, S.O., and Burbanoa, J.C. (2010). ***"Supercritical steam cycles and biomass integrated gasification combined cycles for sugarcane mills."*** Energy, 35: 1172-1180.

Pembina Institute (2010). ***Mining vs in situ: fact sheet.*** Available from http://pubs.pembina.org/reports/mining-vs-in-situ.pdf. Accessed: August, 2016.

Peng, J., Lu, L., and Yang, H. (2013). ***"Review on life cycle assessment of energy payback and greenhouse gas emission of solar photovoltaic systems."*** Renewable and Sustainable Energy Reviews, 19: 255–274

PEW Center (2011). Global Climate Change. ***Cogeneration/Combined heat and power (CHP).*** Available from http://www.c2es.org/docUploads/CogenerationCHP.pdf. Accessed: August, 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.

Popli, S., Rodgers, P., and Eveloy, V. (2013). ***"Gas turbine efficiency enhancement using waste heat powered absorption chillers in the oil and gas industry."*** Applied Thermal Engineering, 50: 918-931.

Power Technology (2015). ***Kogan Creek coal-fired power station, Queensland, Australia.*** key data. Available from http://www.power-technology.com/projects/kogan/. Accessed: August, 2016.

PTAC (2006). Petroleum Technology Alliance Canada (PTAC). ***Filling the gap : unconventional gas technology roadmap.*** Petroleum Technology Alliance Canada, 2006. Available from www.ptac.org/attachments/1510/download. Accessed: August, 2016.

Rahman, M.M., Canter, C., and Kumar, A. (2014). ***"Greenhouse gas emissions from recovery of various North American conventional crudes."*** Energy, 74: 607 – 617.

RAMP (2015a). Regional Aquatics Monitoring Program (RAMP). ***In Situ methods used in the oil sands.*** Available from http://www.ramp-alberta.org/resources/development/history/insitu.aspx. Accessed: August, 2016.

RAMP (2015b). Regional Aquatics Monitoring Program (RAMP). ***Upgrading of the oil sands.*** Available from http://www.ramp-alberta.org/resources/development/history/upgrading.aspx. Accessed: August, 2016.

Raugei, M., Bargigli, S., and Ulgiati, S. (2007). ***"Life cycle assessment and energy pay-back time of advanced photovoltaic modules: CdTe and CIS compared to poly-Si."*** Energy 32:1310–1318

Ribeiro, F., Ferreira, P., and Araujo, M. (2013). ***"Sustainability assessment of electricity production using a logic models approach."*** Renewable and Sustainable Energy Reviews, 28: 215–223.

Ringer, M., Putsche, V., and Scahill, J. (2006). ***Large-scale pyrolysis oil production: a technology assessment and economic analysis.*** Technical Report NREL/TP-510-37779 November 2006. Available from http://www.nrel.gov/docs/fy07osti/37779.pdf. Accessed August, 2016.

Rogner, H.H. (2009). ***CLEWS: Climate land energy and water strategies: a case study.*** International Atomic Energy Agency (IAEA). Available from http://www.iaea.org/OurWork/ST/NE/Pess/csd17/csd-17_clew_2009_holger.pdf. Accessed: August, 2016.

Salazar, J.M., Zitney, S.E., and Diwekar, U.M. (2011). ***"Minimization of water consumption under uncertainty for a pulverized coal power plant."*** Environmental Science & Technology, 45: 4645–4651.

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. DOI 10.1007/s10668-013-9441-5.

Sarkar, S. and Kumar, A. (2009). ***"Techno-economic assessment of bio-hydrogen production from forest biomass in Western Canada."*** Transactions of the ASABE, 52(2): 1-12.

Scanlon, B., Reedy, R., Duncan, I., Mullican, W., and Young, M. (2013). ***"Controls on water use for thermoelectric generation: case study Texas, U.S."*** Environmental Science & Technology, 47:11326-34.

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). Available from http://www.osti.gov/scitech/servlets/purl/772932. Accessed: August, 2016.

SEI (2015). Stockholm Environment Institute (SEI). ***Water Evaluation and Planning (WEAP).*** Available from http://www.weap21.org/. Accessed: August, 2016.

Shell Canada (2012). ***Oil sands performance report 2012.*** Available from http://s04.static-shell.com/content/dam/shell-new/local/country/can/downloads/pdf/oil-sands/oil-sands-performance-report-2012.pdf. Accessed: August, 2016.

Sheridan, M. (2006). ***California crude oil production and imports.*** Available from http://www.energy.ca.gov/2006publications/CEC-600-2006-006/CEC-600-2006-006.PDF. Accessed: August, 2016.

Shipley, A., Hampson, A., Hedman, B., Garland, P., and Bautista, P. (2008). ***Combined heat and power: effective energy solutions for a sustainable future.*** Oak Ridge National Laboratory (ORNL). ORNL/TM-2008/224. Available from http://info.ornl.gov/sites/publications/files/Pub13655.pdf. Accessed: August, 2016.

Singh, S. and Kumar, A. (2011). ***"Development of water requirement factors for biomass conversion pathways."*** Bioresource Technology, 102(2): 1316-1328.

Singh, S., Kumar, A., and Ali, B. (2011). ***"Integration of energy and water consumption factors for biomass conversion pathways."*** Biofuels, Bioproducts and Biorefining, 5(4): 399-409.

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.

Sovacool, B.K. and Sovacool, K.E. (2009). ***"Identifying future electricity–water tradeoffs in the United States."*** Energy Policy, 37, 2763–73.

Spath, P.L. and Mann, M.K. (2004). ***Biomass power and conventional fossil systems with and without CO_2 sequestration – comparing the energy balance, greenhouse gas emissions and economics.*** Prepared under Task No. BB04.4010. NREL/TP-510-32575. January 2004. Available from http://www.nrel.gov/docs/fy04osti/32575.pdf. Accessed: August, 2016.

Spath, P.L., Mann, M.K., and Kerr, D.R. (1999). ***Life cycle assessment of coal-fired power production.*** NREL/TP-570-2511. Available from http://www.nrel.gov/docs/fy99osti/25119.pdf. Accessed: August, 2016.

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. Available from http://www.spgindia.org/spg_2012/spgp109.pdf. Accessed: August, 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.

Statistics Canada (2013). ***Section 3: the demand for water in Canada.*** Available from http://www.statcan.gc.ca/pub/16-201-x/2010000/part-partie3-eng.htm. Accessed: August, 2016.

Statistics Canada (2012). ***Energy Statistics Handbook: first quarter 2012.*** Catalogue No.57-601-X. Available from http://www.statcan.gc.ca/pub/57-601-x/57-601-x2012001-eng.pdf. Accessed: August, 2016.

Statistics Canada (2009). ***Industrial water use.*** Catalogue no. 16-401-X. 2009 Updated. Available from http://www.statcan.gc.ca/pub/16-401-x/16-401-x2012001-eng.pdf. Accessed: August, 2016.

Stillwell, A.S., Clayton, M.E., and Webber, M.E. (2011). ***"Technical analysis of a river basin-based model of advanced power plant cooling technologies for mitigating water management challenges."*** Environmental Research Letters, 6: 034015-26.

Stillwell, A.S, King, C.W., Webber, M.E., Duncan, I.J., and Hardberger, A. (2010). ***"The energy-water nexus in Texas."*** Ecology and Society, 16(1): 2. Available from http://www.ecologyandsociety.org/vol16/iss1/art2/. Accessed: August, 2016.

Sultana, A. and Kumar, A. (2012). ***"Ranking of biomass pellets by integration of economical, environmental and technical factors."*** Biomass and Bio-energy, 39: 344-355.

Suncor Energy (2013). ***2013 Report on sustainability.*** Available from http://sustainability.suncor.com/2013/en/environment/water.aspx?__utma=1.1910911359.1369248968.1369248968.1369248968.1&__utmb=1.2.10.1379622632&__utmc=1&__utmx=-&__utmz=1.1369248968.1.1.utmcsr=google|utmccn=%28organic%29|utmcmd=organic|utmctr=%28not%20provided%29&__utmv=-&__utmk=236633089. Accessed: August, 2016.

Syncrude Canada Ltd (2010). ***Are the oil sands being responsibly developed?*** Available from http://syncrudesustainability.com/2011/media/pdf/Sycrude%202010-11%20CSR%20Report.pdf. Accessed: August, 2016.

Talwani, M. (2011). ***Oil and gas in Mexico: geology, production rates and reserves.*** April 29, 2011. Available from http://bakerinstitute.org/files/537/. Accessed: August, 2016.

Tan, C. and Zhi, Q. (2016). "***The energy-water nexus: a literature review of the dependence of energy on water."*** Energy Procedia, 88: 277 – 284.

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. Available from http://pubs.usgs.gov/bul/b2172-h/b2172h508.pdf. Accessed: August, 2016.

The Engineering ToolBox (2015). ***Wood densities.*** Available from http://www.engineeringtoolbox.com/wood-density-d_40.html. Accessed: August, 2016.

Then, O., Sanders, C., Viereck, D., and Ladwig, M. (2008). ***"Emsland KA26 power plant: high efficiency with flexibility."*** Article in: Modern Power Systems, March 2008; 28 (3): p13.

Thompson, J. and Taylo, P. (2005). ***Thermal power water use, needs, impacts & management.*** Available from http://www.battleriverwatershed.ca/sites/default/files/pdfs/forums/Water%20%26%20Power%20Generation.pdf. Accessed: August, 2016.

Torcellini, P., Long, N., and Judkoff, R. (2003). ***Consumptive water use for U.S. power production.*** Available from http://www.nrel.gov/docs/fy04osti/35190.pdf. Accessed: August, 2016.

TOTAL (2012). ***Extra-heavy oils & oil sands: the challenges of development***. Available from http://www.total.com/sites/default/files/atoms/file/brochure-eho-en. Accessed: August, 2016.

TransAlta (2014). ***Facilities in development: Keephills-3.*** Available from http://www.transalta.com/facilities/facilities-development/keephills-3. Accessed: August, 2016.

TransAlta (2011). ***Plants in operation: Genesee 3.*** Available from http://www.transalta.com/facilities/plants-operation/genesee-3. Accessed: August, 2016.

TransAlta (2009a). ***Annual water use and return report: water supply from North Saskatchewan River to Sundance generating plant***. License No. 146161 and 12086 (amendment No. 00037698-00-05), TransAlta, File No. 12245-A.

TransAlta (2009b). ***Report on annual water use diversion – 2009: Water supply from North Saskatchewan River to Keephills Generating Plant.*** Interim License No. 11986, TransAlta, Keephills File 320-851.6.

TransAlta (2009c). ***The numbers.*** Available from http://www.transalta.com/2009rs/our-performance/the-numbers/?phpMyAdmin=0ExjgFujJyNsQzdiavXlDMNMWD6. Accessed: August, 2016.

Union of Concerned Scientists. (2015a). ***Clean energy. how it works: water for coal.*** Available from http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-coal.html#sources. Accessed: August, 2016.

Union of Concerned Scientists (2015b). ***How it works: water for natural gas.*** Available from http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-natural-gas.html#sources. Accessed: August, 2016.

Union of Concerned Scientists. (2015c). ***Clean energy: how it works: water for power plant cooling.*** Available from http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-cooling-power-plant.html#sources. Accessed: August, 2016.

United Nations General Assembly (2005). ***2005 World Summit Outcome.*** Resolution A/60/1 Adopted by the General Assembly on September 15, 2005. Available from http://data.unaids.org/Topics/UniversalAccess/worldsummitoutcome_resolution_24oct2005_en.pdf. Accessed: August, 2016.

USBR (2005). U.S. Department of the Interior, Bureau of Reclamation, Power Resources Office (USBR). ***Hydroelectric power.*** Available from https://www.usbr.gov/power/edu/pamphlet.pdf. Accessed: August, 2016.

U.S.NRC (2016). ***Uranium enrichment.*** Available from http://www.nrc.gov/docs/ML0313/ML031330159.pdf. Accessed: August, 2016.

Vandecasteele, I., Rivero, I.M., Sala, S., Baranzelli, C., Barranco, R., Batelaan, O., and Lavalle, C. (2015). ***"Impact of shale gas development on water resources: a case study in Northern Poland."*** Environmental Management, 55:1285–1299.

Vose (2013). ***ModelRisk Software.*** Available from http://www.vosesoftware.com/. Accessed: August, 2016.

Warner, E.S. and Heath, G.A. (2012). "***Life cycle greenhouse gas emissions of nuclear electricity generation: systematic review and harmonization."*** Journal of Industrial Ecology, 16 (No.S1): S73:S92. DOI: 10.1111/j.1530-9290.2012.00472.x.

WCA (2015b). World Coal Association (WCA). ***Uses of coal.*** Available from http://www.worldcoal.org/coal/uses-of-coal/. Accessed: August, 2016.

WCI (2005). World Coal Institute (WCI). ***The coal resource: a comprehensive overview of coal.*** Available from http://www.worldcoal.org/bin/pdf/original_pdf_file/underground_and_surface_mining(01_06_2009).pdf. Accessed: July, 2015.

Webber, M.E. (2007). ***"The water intensity of the transitional hydrogen economy."*** Environmental Research Letters, 2: 034007 (7pp).

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.

Weis, T., Doukas, A., Anderson, K., and Howell, G. (2010). ***Landowners' guide to wind energy in Alberta.*** Pembina Institute. Available from https://www.pembina.org/reports/alberta-landowners-guide-web.pdf. Accessed: August, 2016.

Weitzel, P.S. (2011). ***Steam generator for advanced ultra-supercritical power plants 700 to 760C.*** ASME 2011 Power Conference, Denver, Colorado, U.S.A., July 12-14, 2011. Available from http://www.babcock.com/library/documents/br-1852.pdf. Accessed: August, 2016.

William, L.S. (2008). ***The lure of ultra-supercritical: exploring the future of coal-burning.*** ENERGYBIZ. September/October 2008. Available from http://energycentral.fileburst.com/EnergyBizOnline/2008-5-sep-oct/Tech_Frontier_Ultra-Supercritical.pdf. Accessed: August, 2016.

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.

Winston, W.L. and Goldberg, J.B. (2004). ***Operations research: applications and algorithms.*** Fourth edition. Publisher: Curt Hinrichs. ISBN-13: 978-0534-38058-8.

WNA (2016). World Nuclear Association (WNA). **Uranium enrichment.** Available from http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/conversion-enrichment-and-fabrication/uranium-enrichment.aspx. Accessed: August, 2016.

WNA (2015). World Nuclear Association (WNA). ***Cooling power plants.*** Available from: http://www.world-nuclear.org/info/cooling_power_plants_inf121.html#_ftn10. Accessed: August, 2016.

WNA (2011). World Nuclear Association (WNA). ***Comparison of lifecycle greenhouse gas emissions of various electricity generation sources.*** Available from http://www.world-nuclear.org/uploadedFiles/org/WNA/Publications/Working_Group_Reports/comparison_of_lifecycle.pdf. Accessed: August, 2016.

Wong, R. and Whittingham, E. (2006). ***A comparison of combustion technologies for electricity generation.*** 2006 Update including a discussion in carbon capture and storage in Ontario context. Available from http://pubs.pembina.org/reports/Combustion_CCS_Final.pdf. Accessed: August, 2016.

Wu, M., and Chiu, Y. (2011). ***Consumptive water use in the production of ethanol and petroleum gasoline-2011 update.*** Center for Transportation Research, Energy Systems Division, Argonne National Laboratory, December 2008, updated July 2011. ANL/ESD/09-1 Update. Available from https://greet.es.anl.gov/files/consumptive-water Accessed: August, 2016.

WWDR (2015).The United Nations World Water Development Report (WWDR). ***Water for a sustainable world.*** Available from http://unesdoc.unesco.org/images/0023/002318/231823E.pdf. Accessed: August, 2016.

WWDR (2014). The United Nations World Water Development Report (WWDR). ***Water and energy.*** Available from http://unesdoc.unesco.org/images/0022/002257/225741e.pdf. Accessed: August, 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):160-169. DOI: 10.1111/j.1752-1688.2007.00013.x.

Younas, U., Khan, B., Ali, S.M., Arshad, C.M., Farid, U., Zeb, K., Rehman, F., Mehmood, Y., and Vaccaro, A. (2016). ***"Pakistan geothermal renewable energy potential for electric power generation: a survey".*** Renewable and Sustainable Energy Reviews, 63: 398–413

Zhai, H. and Rubin, E. (2010). ***"Performance and cost of wet and dry cooling systems for pulverized coal power plants with and without carbon capture and storage."*** Energy Policy, 38 5653–5660.

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.

Zhao, D.W., Wang, J., and Gates, I.D. (2014). ***"Thermal recovery strategies for thin heavy oil reservoirs."*** Fuel, 117: 431–441.

Zubot, W., MacKinnon, M.D., Ayala, P.C., Smith, D.W., and Gamal El-Din, M. (2012). ***"Petroleum coke adsorption as a water management option for oil sands process-affected water."*** Science of the Total Environment, 427–428: 364–372.