University of Alberta

Analysis of the cost effectiveness of alternative policies and technologies to manage water extractions by the oil sands sector along the lower Athabasca River

by

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To my family:

Mum, Dad, Jeremy and Rebecca

Abstract

The Lower Athabasca Water Management Framework limits water extractions by the oil sands industry near Fort McMurray, Alberta. To increase water-use efficiency and minimise the cost of water restrictions, several policy and technology options were developed and assessed using quantitative and qualitative methods. Selected options were the policies of water trade and pricing with refund, and the technologies of storage, and consolidated tailings and increased recycling. Options were designed based on year 2020 demand and assessed relative to prior allocation. Using linear programming and static optimisation, it is shown that an off-stream storage sized to avoid water restrictions, in combination with efficient water allocation (e.g. water trade), is most cost-effective, although provides no ongoing incentive to increase water-use efficiency. Only the policy options provide equal incentives across firms to increase efficiency. To achieve both objectives of increased water-use efficiency and minimised costs, a combined policy and technology approach is recommended.

Acknowledgements

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Hydrological data and other background information were obtained from a number of sources. Alberta Environment, in particular, Preston McEachern, Tom Tang, and Carmen de la Chevrotière, were most helpful, while correspondence with several others in industry and academia assisted in my understanding of the topic.

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List of Symbols and Abbreviations

bbl	Barrel, equivalent to 0.1589873 m^3
GAMS	General Algebraic Modeling System
GL	Gigalitre, equivalent to 1 000 000 m^3, or approximately 811 acre feet
M	Million
ML	Megalitre, equivalent to 1 000 m^3, approximately 0.811 acre feet, or one (1) cubic decametre (dam^3)
NPV	Net Present Value
PV	Present Value
SAGD	Steam Assisted Gravity Drainage
WMF	Water Management Framework. Refers to Phase 1 (in particular) of the Lower Athabasca Water Management Framework.
Yr	Year

1. Introduction

1.1 Context

The Athabasca River basin in northern Alberta provides a relatively unique situation for water resource management. The lower portion of the basin is home to the Athabasca oil sands deposit that, along with two similar deposits nearby (Peace River and Cold Lake), is estimated to comprise the world's second-largest reserves of oil after Saudi Arabia (Alberta Department of Energy [2007], Anon [2007]). Flow in the Athabasca River is highly variable across years and over the course of each year, and drops to its lowest levels in winter while covered by ice. This natural, variable pattern of streamflows, combined with relatively constant water extraction by oil sands surface-mining operations near Fort McMurray, indicates that the greatest loss of aquatic habitat values due to water extraction (in terms of wetted area and total dissolved oxygen) is likely to be sustained during winter. While water is recycled by industry, water from several surface-mining operations is stored in large tailings ponds that have associated environmental risks. Downstream of the Oil Sands are the wetlands of the Peace-Athabasca Delta, the world's largest boreal delta, that provide important habitat particularly for birds (Environment Canada, 2001) and form part of the traditional use area of the local Aboriginal population. Surface mining of oil sands creates significant revenue and employment in Alberta, however the environmental impact of this activity - including its water use - has generated considerable public concern (The Strategic Counsel, 2007).

Current and planned oil-sands mining operations are located along a 125 km (approx.) length of the Athabasca River downstream of Fort McMurray. Water licences for the mining operations are issued following a review of individual project applications via an environmental impact assessment process. The licences specify an annual volume that may be extracted directly from the Athabasca River along with a maximum instantaneous rate of extraction. Annual limits on extraction from other water sources (groundwater, surface run-off, tributaries to the Athabasca River) are also specified. Restrictions on the instantaneous rate of total industrial extractions taken directly from the Athabasca River, based on weekly flow conditions, were introduced in February 2007 as part of Phase 1 of the Lower Athabasca Water Management Framework (Alberta Environment and Fisheries and Oceans Canada, 2007). A long-term plan for the implementation of the framework is yet to be developed, and is likely to be addressed within a refined version of the framework (Phase 2) that is due to be implemented by September 30th, 2010 (Alberta Environment and Fisheries and Oceans Canada, 2007).

This research project was developed with a broad vision to assist in the long-term implementation of the Lower Athabasca Water Management Framework. It follows the initial review of water availability in the lower Athabasca River by Schindler et al. (2007) and the preliminary analysis of water-use options by Adamowicz (2007)[1]. Contained herein is a relatively unique analysis of selected water policies and technologies, and their interaction, set within a river basin whose water use is dominated by a low number of large industrial firms producing similar output. The uniqueness of this study arises from the focus on water use by industrial firms, a user group that is relatively understudied (Renzetti, 2002), and the analysis of a broad range and combination of policy options (prior allocation, water trade, and water pricing with refund) and technical options (storage, and consolidated tailings and increased water recycling) to reduce water-use and to share restricted water supplies in a cost-effective manner. Background material collated as part of the study is likely to be the most comprehensive analysis to date of projected water availability in the Oil Sands. The analysis of a pricing with refund scheme, a policy option based on a Swedish scheme to manage NO_x emissions (Sterner and Höglund Isaksson, 2006), is a unique contribution of this study. To the best of our knowledge this approach has not been examined in terms of its application to the management of water use.

By analysis of cost effectiveness, and the use of linear programming to optimise water allocation (where applicable), it is shown that all policy and technology options considered outperform the base case of prior allocation. Shared off-stream storage is shown to reduce the financial impact of water restrictions at least cost, though once constructed the option may remove incentives to increase water-use efficiency, and there are additional concerns regarding uncertain technical feasibility and ecological impact. The cost effectiveness of storage stems from its ability to avoid shortfalls in supply altogether. In contrast, the policy options of water trade and a pricing with refund scheme are shown to provide a cost-effective reaction to water scarcity by reallocating

[1] The findings of both studies were jointly presented at the workshop: "Running Out of Steam? Oil Sands Development and Water Use in the Athabasca-River Watershed: Science and Market-Based Solutions", held at the University of Alberta on May 10th, 2007.

water to where it can obtain the highest net value. Though the analysis was static rather than dynamic in nature, it is recognised that a distinct benefit of the policy options is their ability to manage demand by providing incentives to increase water-use efficiency across all firms. This incentive is driven by market prices that reflect the shadow value of water associated with industrial uses, in the case of water trade, or refunded charges that provide a direct incentive to increase water-use efficiency, in the case of a pricing with refund scheme. Overall, it is shown that a combined approach that employs both a change in policy and technology (note that a technology change may be in response to a policy change) would minimise the costs of potential water restrictions while simultaneously providing incentives to increase water-use efficiency, when compared to the current situation of restrictions in order of licence seniority.

1.2 Purpose

The key government policy related to this study, the Lower Athabasca Water Management Framework (herein referred to as the WMF), was prepared with an aim to balance the needs of environmental and industrial uses, and encourage improvements in water-use efficiency, while minimising risks to the aquatic ecosystem during relatively sensitive periods (Alberta Environment and Fisheries and Oceans Canada, 2007). Background information on environmental values and the potential impact of water extractions in the lower Athabasca River basin is provided in Appendix A. The WMF has the following objectives for the current Phase 1 and pending Phase 2 (Alberta Environment and Department of Fisheries and Oceans Canada, 2007:7):

1. *To provide a high level of protection of the aquatic ecosystem over the long-term*
2. *To provide the incentive to develop cooperative management options for water in the Athabasca River*
3. *To provide the incentive for achieving more efficient water use*
4. *To provide a reliable supply of good quality water*
5. *To ensure water use restrictions are realistic and the framework is straightforward to administer.*

The objectives numbered 1, 4 and 5 are addressed by the water restriction policy of the WMF (refer to Section 1.4 for details). Objectives 2 and 3 are expected to be addressed within Phase 2 of the WMF. If a standard approach is followed of first determining the preferred option(s) based on economic efficiency, then determining cost-sharing arrangements, it follows that Objective 2 (loosely related to cost sharing) should be addressed after preferred policy and technical options are identified to meet Objective 3 (increased efficiency).

The purpose of this study, related principally to Objective 3 of the WMF, is as follows:

To develop and evaluate selected policies and technologies to increase water-use efficiency and respond to the water restriction policy of the Lower Athabasca Water Management Framework (Phase 1) in a cost-effective manner.

Due to data limitations the study does not conduct a benefit cost analysis of the WMF but rather examines the cost effectiveness of policy and technology options developed in response to the WMF. Although linked, these two forms of analysis are distinctly different. The policy option of water trade, and the technology options combined with water trade, create incentives that reflect the shadow value of the resource when water extraction is limited by the WMF. Where the shadow value of the resource is apparent, this encourages cost-effective reductions in water use and the allocation of scarce water supplies in a manner that maximises production. The shadow value in this case is the opportunity cost of water that would otherwise be used to produce additional oil by the next most-efficient producer with spare capacity. Note, however, that the opportunity costs of water use related to social and environmental factors are not explicitly considered, and so the analysis is one of cost effectiveness rather than economic efficiency.

The purpose of this study is similar to the goals for water management described in several government publications related to the WMF. The 1999 Regional Sustainable Development Strategy for the Athabasca Oil Sands Area (RSDS) allows for economic development while addressing environmental needs and sustainability in the use of natural resources (Alberta Environment, 1999), and cites the policy direction that "environmental decisions will take into account economic impacts, and economic decisions will reflect environmental impacts" (Alberta Government, 1999:4). The strategic plan (2005 to 2010) of the Department of Fisheries and Oceans Canada mentions the strategic context of sustainable development related to the "efficient and environmentally responsible use" (Department of Fisheries and Oceans Canada, 2005) of scarce resources, and the integration of environmental, economic, and social considerations to inform decisions.

Other non-governmental organisations and experts have offered alternative goals for water management in the region. The Pembina Institute advocates the specific policy of passing the full cost of water use, including non-use values, onto industrial water consumers to encourage firms to consider all factors when privately determining the worth of options that may impact upon water use (Griffiths et al., 2006). The Institute also recommends greater encouragement of innovation and use of best available technologies, and suggests a user-fee system for fresh water consumption with revenues used to finance water research and development (Griffiths et al., 2006). In contrast, Rogers (2006) considers water use in the Oil Sands from an operational perspective, and outlines four best practice goals for water management, as follows (Rogers, 2006:28):

- *To limit the amount of water withdrawn from the Athabasca River overall and during sensitive time periods*
- *To limit the amount of tailings water to be stored as free water*
- *To limit the corrosion, scaling and fouling of the recycled water*
- *To limit any adverse impact on oil sands processing when using the recycled water.*

1.3 Objectives for assessment

Related to the purpose of this study are the specific objectives for the assessment of options. The focus of the quantitative assessment presented in this document will be solely on the relative cost-effectiveness of the options. In addition, a qualitative assessment of the options will be conducted from a broader perspective to provide a practical, rounded evaluation. Table 1-1 lists selected criteria for the qualitative evaluation of options from an environmental policy perspective, adapted from criteria presented in Common (1995). The criteria are similar to that used by Adamowicz (2007 [in turn based on Olewiler (2007)]).

- **Table 1-1 Criteria for the qualitative evaluation of options, adapted from Common (1995)**

Criteria		Description and related evaluation questions
A	Dependability	Degree of assurance that the option will achieve the environmental goal. Secondary environmental impacts (e.g. water quality, greenhouse gas production, risks related to tailings storage) should also be considered.
B	Finance	Does the option generate revenues that may be used to finance the administration of the option, or does it require funds from government?
C	Economic efficiency	Consideration of overall costs to society. Does the use of the option lead to an efficient (least cost) outcome? Given existing technologies, are there avoidable costs associated with the option? Consideration of adverse selection and other market failures.
D	Informational requirements	How much of what kinds of information is needed to be able to implement the option effectively?
E	Monitoring and enforcement	Monitoring is needed to judge compliance, and enforcement arises when non-compliance is detected. Are the monitoring requirements feasible, and can these be provided at a reasonable cost?
F	Permanence	Does the effectiveness of the option depend on circumstances that may change, such as the level of background streamflows or oil prices?
G	Flexibility	Does the option have the capability to continue with changing economic circumstances? Or, would modifications be required as circumstances change? (And can modifications be handled easily?)
H	Equity	How are the benefits and costs of the option distributed across firms and/or individuals?
I	Dynamic incentives	Does the option encourage the adoption of new, environmentally beneficial technologies, or the retention of existing technology?
J	Continuing incentives	Does the option provide the incentive to create environmental benefits of a fixed amount, or to maximise environmental benefits?
K	Political considerations	Political practicality of option. Includes consideration of political feasibility, direct stakeholder acceptance, and broad public acceptance.

1.4 Lower Athabasca Water Management Framework

The WMF limits total water extractions sourced directly from the Athabasca River based on available scientific information concerning in-stream flow needs, and is being developed in two phases. The interim Phase 1 framework classifies the weekly flow conditions of the lower Athabasca River as either green, yellow or red, with corresponding progressive limits on total allowable extraction (Table 1-2). The framework allows for climate change, albeit retrospectively, due to the flow and habitat area thresholds that define the weekly flow conditions being specified in percentile terms (rather than absolute) along with proportional restrictions on water extraction. Phase 2 is expected to revise the framework using a method that balances environmental, social and economic factors, while incorporating additional data and stakeholder views (Alberta Environment and Fisheries and Oceans Canada, 2007). In contrast to Phase 1, Phase 2 may include an ecosystem base flow below which extractions are not permitted (Alberta Environment and Fisheries and Oceans Canada, 2007).

- **Table 1-2 Lower Athabasca Water Management Framework, Phase 1 [a]**

Flow Condition / Season [b]	**Environmental implication**	**Management action**
Green When river flow is above the Cautionary Threshold (CT) [c] – maximum of HDA80 [d] or Q90 [e]	Flows are sufficient – impacts to aquatic ecosystem are negligible	All licensees operate normally and operate within the conditions of their licences Maximum cumulative withdrawal is 15% of instantaneous flow Not likely to result in impacts to fish habitat, not likely to require Fisheries Act authorisation
Yellow When river flow is below the CT – maximum of HDA80 or Q90 but above Q95	Natural low flows occurring Assume aquatic ecosystem may experience stress from a 15% withdrawal	Total cumulative diversion rate is 10% of the average of the HDA80 and Q95 Maximum cumulative withdrawals: Winter [f] = 15 m^3/s Spawning = 5% of the HDA80 flow or 34 m^3/s, whichever is less Summer = 34 m^3/s Recent and new licences will include conditions that mandate incremental reductions Likely to result in impacts to fish habitat and may require a Fisheries Act authorisation
Red When river flow is below Q95 i.e. "Potential Sustainability Threshold" [g]	Natural low flows may limit habitat availability Increased duration and frequency of habitat loss due to water withdrawals should be minimised	Mandatory reductions and use of storage Total cumulative diversion rate is 5.2% of historical median flow in each week Maximum cumulative withdrawals: Winter = 15 m^3/s Spawning = 5% of the HDA80 flow or 34 m^3/s, whichever is less Summer = 34 m^3/s Applies to all licences in a variety of ways Likely to result in impacts to fish habitat and may require a Fisheries Act authorisation

Refer to notes and definitions on the following page.

Notes and definitions to Table 1-2:

a. Source: Table 1, Alberta Environment and Fisheries and Oceans Canada (2007).

b. Flow condition is determined by the background flow less extraction.

c. Cautionary Threshold is based on: (i) Q90, the "min. flow required for maintenance of riparian vegetation" (Alberta Environment and Fisheries and Oceans Canada, 2007:33) as found for the South Saskatchewan River, and (ii) the highest HDA80 value for the range of aquatic species for which data were available.

d. HDA80 refers to the flow level that corresponds to 80% habitat area exceedance i.e., the flow level at which the habitat area is available at least 80% of the time. See Appendix B.1 for habitat area rating table.

e. Q90 refers to 90% flow exceedance i.e., the Q90 flow is equalled or exceeded 90% of the time. Similarly for Q95.

f. Winter is from week 44 (late October) through to week 15 (early April) of the following year. Summer is from week 16 (April) to week 43 (October). The fish spawning period is specified from week 16 through to week 24 (April to early June).

g. Potential Sustainability Threshold (PST) defines the point at which the impacts of extraction "are potentially significant and long-term, depending on duration and frequency (of) withdrawals" (Alberta Environment and Fisheries and Oceans Canada, 2007:35-36).

While a long-term plan for sharing water is forthcoming, industry representatives devised the Oil Sands Mining Water Management Agreement for the 2007-2008 season (Athabasca Regional Issues Working Group, 2007). This agreement covers the first period of implementation of the framework for the four surface-mining companies in operation: Suncor, Syncrude, Albian Sands and Canadian Natural Resources Ltd (CNRL). The agreement outlines the maximum rates of water extraction allowed by each company during red and yellow flow conditions over the low-flow weeks of the year when water extraction limits (Table 1-2) may become binding. This agreement is described in detail in Appendix B.2.

1.5 Research approach

At a broad level, the research was undertaken in three distinct stages: (i) quantification of the risk of water shortage, (ii) gathering of information on policy and technical options available to increase water-use efficiency and manage the risk of water supply shortfalls, and (iii) quantitative and qualitative evaluation of options.

In the first stage, background data on flows and water use were collected and analysed to determine whether the water-use limits of the WMF would be reached and the potential severity of restrictions. Information collected included streamflows, licensed water-use, historic water extractions, and projected future extractions. The potential impact of climate change on flow was investigated by reviewing previous studies. This literature review indicated that the period of record of streamflows is likely to have been relatively wet, and that an artificial flow scenario representing drier climatic conditions may be more appropriate than the historic record for the base analysis of options. Following on from this review it was decided that four background flow scenarios (in total) would be analysed for consideration of sensitivity of results to flow. The information collected was then used to develop a spreadsheet model to calculate the flow and habitat area thresholds of the WMF (Table 1-2), and estimate the impact on water availability, for each of the background flow scenarios.

In the second stage, the characteristics of industrial water-use were reviewed to assist in the development of options. This included a review of on-site options to reduce water use, and off-site options to store and then release water at times of water scarcity to avoid triggering the restrictions of the WMF. Four main options were selected for analysis: water trade, water pricing with refund, water storage, and use of consolidated tailings technology combined with increased water recycling. These options can be loosely grouped into policy options (water rights trading, and water pricing with refund) and technical options (storage, and consolidated tailings and increased recycling) that cover aspects of physical supply and demand reduction technologies. Two combined options were also analysed that involved combining the technical options with the economically-optimised allocations produced by the policy options; that is, (i) water storage and allocations under water trade or water pricing with refund, and (ii) consolidated tailings and increased water recycling combined with allocations under water trade or water pricing with refund. The basis for the analysis of options was the current policy of water restrictions under the prior allocation (i.e., first-in-time first-in-right) system. As part of this base case, it was assumed that mining operations do not have ready access to alternative water supplies or more water-efficient production methods, and that restrictions would immediately result in reduced oil production in direct proportion to the degree of restriction of each company.

In the third and final stage, static models were developed to evaluate the policy options and provide the foundation for evaluating the technical options. These models, developed using linear programming, optimised water allocations in each week of a 47-

year sequence of background flows. The options were compared in terms of their cost effectiveness relative to the base case using net present values. The options were also qualitatively evaluated in terms of their performance against the policy criteria listed in Table 1-1. Finally, the sensitivity of net present values was analysed by considering three alternative background flow scenarios and two alternative oil price scenarios (selected based on the wide fluctuation of oil prices in 2008).

1.6 Document structure

This document is structured in a similar order to the research approach (Section 1.5). First, Section 2 provides background information related to water supply, water demands and water-use characteristics. Section 2 also includes background technical details of the consolidated tailings and increased recycling option, a summary of available cost estimates for water storage, a brief overview of pertinent economic theory, a listing of relevant economic factors for the application of market-based options in the Oil Sands, and a literature review of market-based policy instruments for environmental management. In Section 3, the method of analysis is presented, including a full description of the options. Results are summarised in Section 4; the implications of which are discussed in Section 5. Finally, a summary of the overall findings of the study and recommendations for further analysis are provided in Section 6.

Detailed background and method information (e.g. programming code of the models) is provided in the Appendix, along with additional results including those of the sensitivity analysis.

2. Background

2.1 Water management and water supply availability

2.1.1 Water licences

Water licences in Alberta are issued under the provincial *Water Act 1996* and are administered by Alberta Environment. As well as direct extraction from the Athabasca River, licences are required for the diversion of surface runoff and surface runoff that is tributary to the Athabasca River, and extraction of groundwater. The licences specify the source of supply, the fixed annual volume able to be diverted from each source, and the maximum instantaneous rate of withdrawal from licensed works that access the Athabasca River. The licences may also limit the months when water extraction may occur. All major licences for oil sands activities are able to be modified to address unforeseen environmental concerns[2].

The *Water Act* (*s30 [2]*) stipulates that during times of scarcity water will be allocated according to the principle of prior allocation, i.e., allocation is in order of licensed date of priority (based on the submission date of the original licence application), and those holding a water licence with an earlier date are able to obtain their full licensed volume before the next in order is granted access. This form of allocation is commonly referred to as "first-in-time, first-in-right", and in practice works similar to the prior appropriation rights system during times of shortage (Percy, 2004). The Act allows water transfers subject to conditions that include no adverse effects to other water users (such as effects on the security of supply) or to the aquatic environment.

Licensed allocation, licensed water-use and actual water-use, as well as other terms such as water right and entitlement, can have different meanings in different water management regions. In Alberta, the term "licensed allocation" refers to the total volume able to be extracted i.e., the sum of consumptive and non-consumptive volumes, whereas "licensed water-use" refers to consumptive use only i.e., licensed allocation minus

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[2] For example, Suncor's primary licence states that the licence is subject to "modification to ensure the most beneficial use of the water in the public interest" (Alberta Environment, 1987:3), and that a minimum base flow may be specified such that "the licensee shall be required to cease or reduce any further diversion during periods when the residual flow falls below the rate designated" (Alberta Environment, 1987:3).

licensed return flow. “Actual water-use” refers to the volume of consumptive use that actually occurs. (Allocation is also used throughout this report in its literal sense.)

The majority of licensed water-use in the Athabasca Basin is held by seven licensees. Table 2-1 provides details on existing and approved licensed water-use in the Oil Sands for each company and compares licensed use to the historic range of annual flow in the Athabasca River. Further information on licences in the Athabasca River basin, including those specific to the petroleum industry and for water sources other than direct from the Athabasca River, is provided in Appendix C.1.

- **Table 2-1 Approved licences for water use sourced from the Athabasca River for oil sands mining [a]**

Project / Company	Status	Annual licensed water-use, GL	Annual licensed water-use, m^3/s	Max. instantaneous pumping rate, m^3/s	Licensed water-use as % of Min. Annual Flow [h]	Licensed water-use as % of Median Annual Flow [h]	Licensed water-use as % of Max. Annual Flow [h]
Suncor[b]	Existing	62.825	1.99	3.790	0.55	0.33	0.19
Syncrude	Existing	61.675	1.96	4.163	0.54	0.32	0.19
Athabasca Oil Sands Project (AOSP), Albian Sands [c]	Existing	55.100	1.75	2.220	0.48	0.29	0.17
Fort Hills Demonstration Plant, Petro-Canada	Existing	0.271	0.01	0.030	0.00	0.00	0.00
Joslyn SAGD (Steam Assisted Gravity Drainage), Total E&P Canada Ltd.	Existing	0.177	0.01	0.020	0.00	0.00	0.00
Total existing		**180.048**	**5.71**	**10.22**	**1.56**	**0.94**	**0.55**
Jackpine Phase I, Shell [c, d]	Approved	63.500	2.01	1.950	0.55	0.33	0.20
Horizon, CNRL [e]	Approved	79.320	2.52	3.100	0.69	0.41	0.24
Fort Hills Project, Petro-Canada [f]	Approved	39.000	1.24	1.237	0.34	0.20	0.12
Kearl, Imperial [g]	Approved	80.000	2.54	4.600	0.70	0.42	0.25
Total approved		**261.820**	**8.30**	**10.89**	**2.28**	**1.36**	**0.81**
Total existing & approved		**441.868**	**14.01**	**21.11**	**3.84**	**2.30**	**1.36**

Notes to Table 2-1:

a. Source: Alberta Environment (pers. comm., Preston McEachern, 10/12/2007), with adjustments based on licence specifications. Estimated timing of projects yet to be constructed reflects information available in 2007 and is subject to change.

b. Of Suncor's licences, one minor licence of 3 GL per annum (priority 2003-04-23-001) allows water to be diverted only between May 1st and October 31st in each year.

c. Shell Jackpine and Albian Sands share an intake with a combined maximum pumping rate of 4.17 m^3/s or 1.8% of river flow under the Fisheries Act, whichever is lower.

d. Jackpine Phase I licence: 63.5 GL for Stage 1 (from 2010 up to approx. 2017), 35.3 GL for Stage 2. Note that maximum pumping rate shown is 4.17 m^3/s less original licensed maximum of 2.22 m^3/s for Albian Sands AOS project.

e. CNRL Horizon licence: 79.32 GL for Phases 1 and 2 (up to approx. 2009); 55.82 GL for Phase 3 (approx. 2010 to 2011), and 51.02 GL for the steady-state stage (after approx. 2011).

f. No maximum instantaneous rate specified, rate shown is average rate.

g. Kearl (Imperial) licence approved on 19th December 2007. Licensed water-use shown is the maximum licensed water-use, issued for Stage C. Licensed water-use is 50 GL for Stage A (one train of production [each train equal to approx. 100,000 bbl/day], approx. 2010-2017), 65 GL for Stage B (two trains of production, approx. 2018-2030), 80 GL for Stage C and 45 GL for Stage D (three trains of production, then operation moving to in-pit mode, approx. 2031-2054), and 70 GL for Stage E (three trains of production, and filling of end pit lakes, approx. 2055-2065). Note: estimates of project timing are based on Alberta Environment estimates made prior to licence approval, with adjustments, and may not concur with other forecasts (e.g. Dunbar [2008]).

h. Minimum, median and maximum annual flow based on annual flow in the Athabasca River below Fort McMurray (07DA001) from 1958 to 2004.

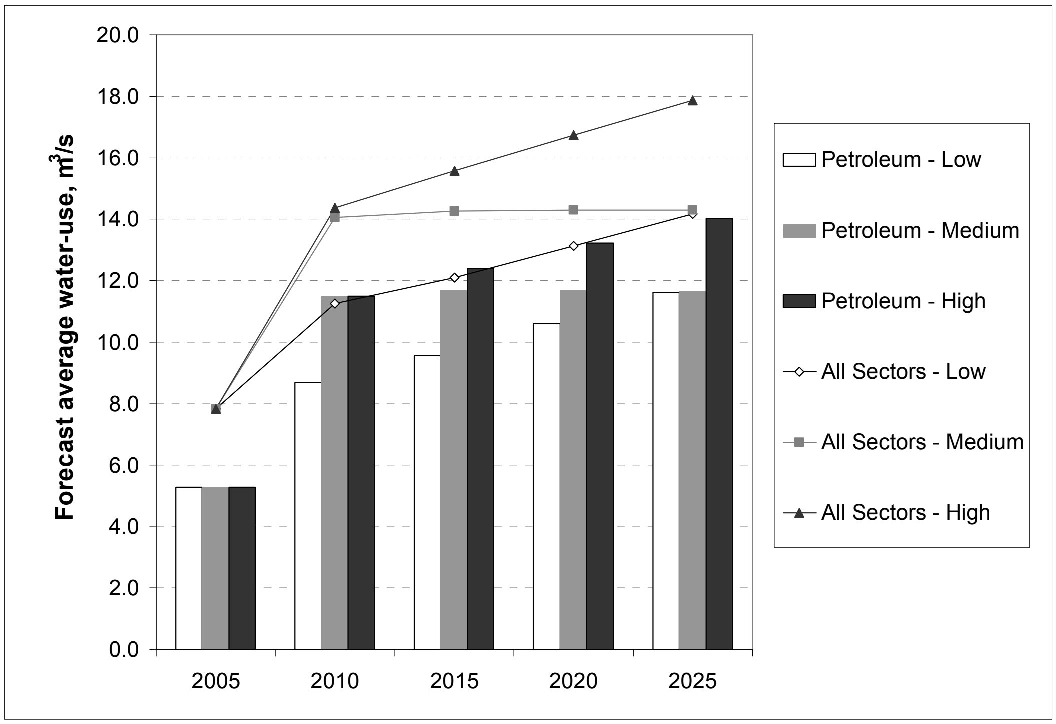
2.1.2 Historic water-use and future projections

In Alberta, actual water-use is typically considerably lower than licensed water-use. Data for the petroleum sector in the Athabasca basin reflect this tendency, with actual water-use for 2005 estimated to comprise 35.5% of licensed water-use from surface-water sources, and 24% of licensed groundwater use (Alberta Environment, 2007). The water supply infrastructure for oil sands surface-mines is managed by the licensees, and no external fees are charged for water use.

Charts of historic water extraction by company for surface mining of oil sands, in terms of annual extraction and proportion of licensed water-use, are provided in Appendix C.2. Information on historic water-use efficiency, in terms of water extracted from the Athabasca River per unit of oil production, is provided in Appendix C.3.

Actual use of surface water by the petroleum sector has been forecast to increase over the period 2005 to 2025 by 120% under a low to medium growth scenario, and by 165%

under a high growth scenario (Alberta Environment, 2007). Predictions for the Athabasca basin are shown in Figure 2-1. The forecasts "reflect a 'business-as-usual' case that ties water use to economic…growth and assumes that companies will improve their operating efficiencies as they have done in the recent past" (Alberta Environment, 2007:14). The forecasts were based on consultation with large licence holders and production outlooks by the Alberta Energy and Utilities Board (2006) and the Canadian Association of Petroleum Producers (2006).



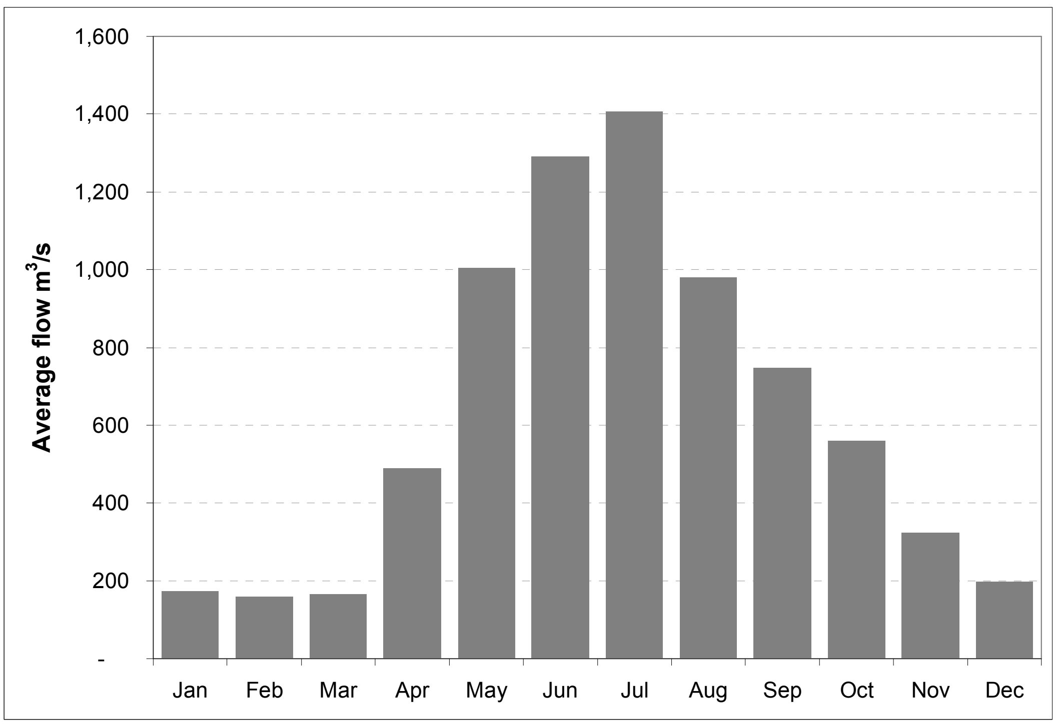
- **Figure 2-1 Forecast low, medium and high growth scenarios of actual water-use of surface water in the Athabasca basin, m^3/s, 2005 to 2025 (Source: Alberta Environment [2007], Table 11-36 to Table 11-38)**

Assuming no change in mean annual discharge (e.g. no climate change) and forecast increases under the high growth scenario (Alberta Environment, 2007), water extractions in the Athabasca River basin from all sources and sectors are expected to grow from 1.4% of the mean annual flow to approximately 3.2% over the 2005 to 2025 period.

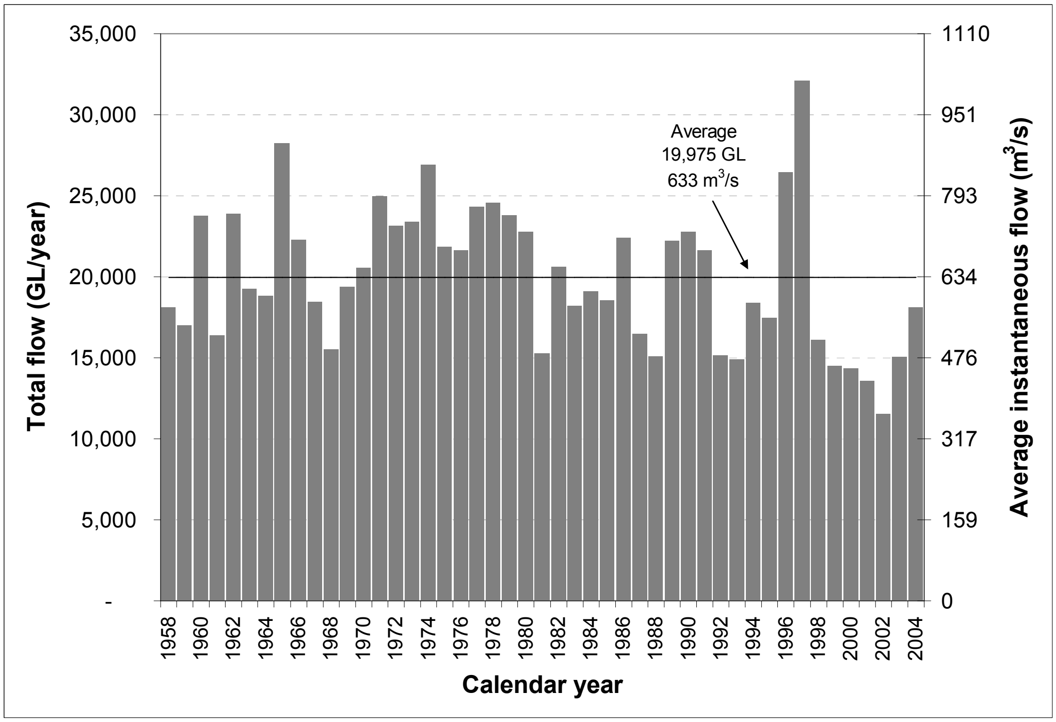
2.1.3 Historic streamflows

Flow information for the lower Athabasca River was provided by Alberta Environment for the 47-year period from January 1st, 1958 to December 31st, 2004. This information was in the form of monitored continuous flow and modelled daily background flow (that excludes extractions by oil-sands mining operations). A detailed description of flow information, along with the contribution of the lower tributaries and a brief description of the basin, is provided in Appendix D.

The flow in the Athabasca River is unregulated i.e., unaltered by man-made structures that regulate flow, and water use is relatively minor in comparison to the average flow. Thus the pattern of flow in the Athabasca River retains much of its natural fluctuations, with significant intra-annual (Figure 2-2) and inter-annual variability (Figure 2-3).



- **Figure 2-2 Average monthly flow (m^3/s) in the Athabasca River below Fort McMurray (WSC gauge no. 07DA001), 1958 to 2004**



- **Figure 2-3 Annual modelled background flow in the lower Athabasca River, for the reach just downstream of the confluence with the Steepbank River (Reach 4), 1958 to 2004**

2.1.4 Potential impact of climate change

Climate change is an important consideration for future water management in the lower Athabasca basin, particularly given that recent streamflow conditions (most notably in 2002) have been well below average (Figure 2-3). The cautionary and potential sustainability thresholds of the WMF (Table 1-2) are based on habitat area and flow percentiles (e.g. HDA80, Q90 and Q95) calculated over the length of flow record, and so changes in flow as a result of climate change would eventually result in updated thresholds that are moderated by earlier data. Given that water licences are specified in absolute volumes and rates of flow, rather than as proportions of annual, weekly or instantaneous flow (with the exception of the Albian Sands and Shell Jackpine developments), both the frequency of green, yellow and red flow conditions of the WMF and the proportional level of supply shortfalls due to restriction will change with climate change.

A review of previous studies (Appendix E) was used to guide the selection of a number of climate change scenarios of background flow. These studies include the calculation of trends in streamflow in the Athabasca River using historic data (Golder Associates [2005], Schindler and Donahue [2006], Burn et al. [2004]), as well as the use of climate-based modelling to predict future changes in Athabasca streamflows (Bruce and Tin [2006], Toth et al. [2006], Schindler et al. [2007]). However, the cyclical effects of medium-term influences - in particular the Pacific Decadal Oscillation - make it difficult to conclusively detect and explain trends particularly in flow data sets that span less than 50-years (Rood et al., 2005), as is the case in the lower Athabasca; while climate-based modelling has similar issues (Wang and Schimel, 2003) and has been shown to produce variable results (Rood et al., 2005). Tree ring analysis (Case and MacDonald, 2003) and paleolimnological studies (Wolfe et al., 2006), that provide an indirect analysis of long-term streamflows, indicate that past conditions have been highly variable and drier than over the period of recorded flow. Tree ring data for the adjacent North Saskatchewan basin, spanning 1 113 years, indicates that flows were 8.6% higher in the 20th Century than the estimated long-term mean, with similar results found for the South Saskatchewan and Saskatchewan basins (Case and MacDonald, 2003). Given the long period of analysis, this result for the North Saskatchewan basin was used as the basis for setting flow scenarios in the Athabasca River for use in this study.

2.1.5 Water supply availability

Various scenarios of background flows and licensed extractions were modelled to analyse the frequency of green, yellow, and red flow conditions of the WMF and the characteristics of supply shortfalls when the extraction limits of the WMF (Table 1-2) become binding. Provided below is a summary of the water supply analysis that is presented in detail in Appendix F[3].

Four background flow scenarios were selected to analyse water supply availability. A decline in the historic average flow of 10% was selected for the base-case scenario (rounded upwards from 8.6% for conservative reasons), while the historic flow record was considered the wet scenario, and for symmetry a 20% reduction in flow was

[3] A version of Appendix F has been accepted for publication. Mannix, A. E., Dridi, C. and W. L. Adamowicz. 2009. Water Availability in the Oil Sands under projections of increasing demands and a changing climate: An assessment of the Lower Athabasca Water Management Framework (Phase 1). *Canadian Water Resources Journal*.

considered the dry scenario. The base case was broadly based on the results of the tree-ring analysis by Case and MacDonald (2003) for the adjacent North Saskatchewan basin. To further test the resilience of the framework, an extreme climate change scenario ("ext. dry") of a 50% reduction in flow was included for interest. These proportions were applied across all weeks of the historic flow record (January 1st, 1958 to December 31st, 2004).

Scenarios of industrial water demand were developed based on licensed water-use, and current and forecast water-use information. Water demand was assumed to be constant given the relatively constant water-use of mine site utilities across seasons (Rogers, 2006). Four demand scenarios for water extraction from the Athabasca River were selected, as follows:

1. Water demand of 2.5 m^3/s (or 78 GL/year), based on the average rate of net industrial water-use extracted direct from the Athabasca River in 2006 (refer to Appendix C.2 for source information).

2. Water demand of 5.7 m^3/s (or 180 GL/year), based on the existing average rate of licensed extraction (Table 2-1).

3. Water demand of 11.6 m^3/s (or 366 GL/year), based on the Alberta Environment (2007) forecast of actual surface-water use in the Athabasca basin by the petroleum sector in 2025, under low and medium growth scenarios (Figure 2-1).

4. Water demand of 14.0 m^3/s (or 442 GL/year), based on the Alberta Environment (2007) forecast of actual surface-water use in the Athabasca basin by the petroleum sector in 2025, under a high growth scenario (Figure 2-1). This scenario is also the approved average licensed rate of extraction (Table 2-1).

Each demand scenario was analysed in conjunction with the base-case flow scenario. For other flow scenarios, constant demands of 14 m^3/s were assumed.

Results of modelled supply shortfalls are shown in Table 2-2 for the base case flow scenario (10% reduction in historic flows) and all demand scenarios. Results of supply shortfalls for the 14.0 m^3/s demand scenario along with the range of background flow scenarios, are shown in Table 2-3. Charts of frequency of binding flow conditions and severity of supply shortfalls, for the 14.0 m^3/s demand scenario combined with the base case flow scenario, are provided in Figure 2-4, Figure 2-5 and Figure 2-6.

The results indicate that the average frequency of water restrictions may increase from zero to six weeks per year by 2025 (based on long-run assumptions, including that future flows are 10% lower than the historic record). Binding flow conditions of the WMF are likely to occur only during the low flow, ice-cover period (Figure 2-5), and may cause shortfalls that reach up to 6.6 m^3/s, or almost 50% of demand under the high growth forecast, by 2025 (Table 2-3 and Figure 2-6). Using trial and error it was found that water demand would need to be below 7.5 m^3/s during low-flow periods to avoid restrictions under the base-case flow scenario.

- **Table 2-2 Summary statistics of modelled supply shortfalls under the WMF for various water demands and base case flow scenario**

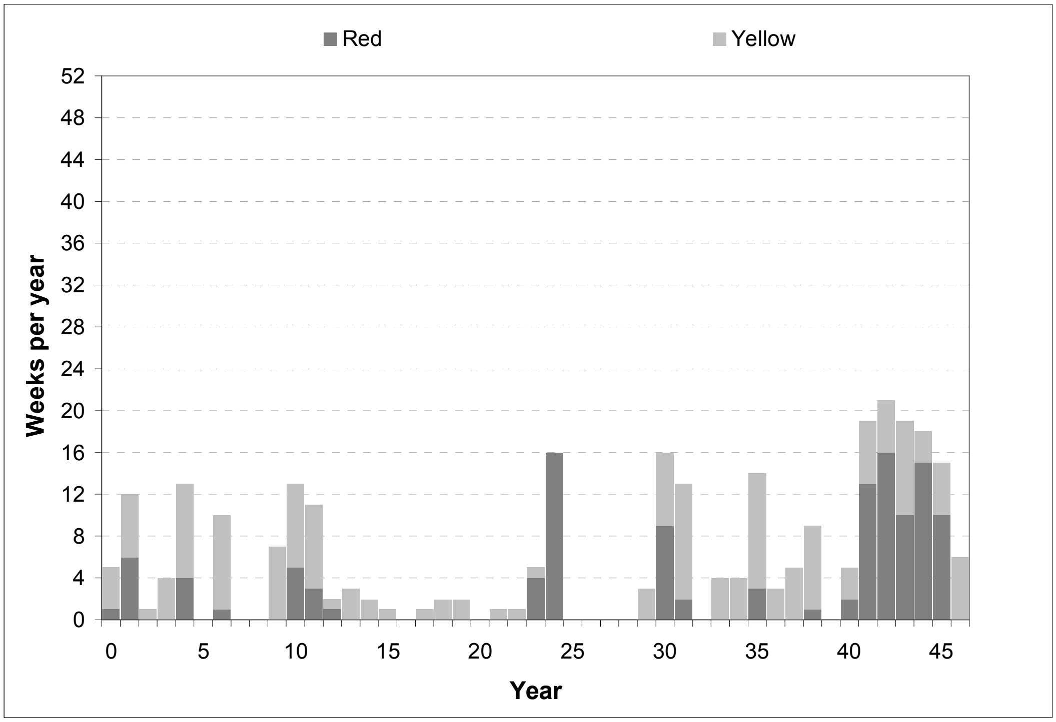
Shortfall statistic	**Water demand, m^3/s**			
	2.5	**5.7**	**11.6**	**14.0**
Peak shortfall, m^3/s	0	0	4.2	6.6
Longest shortfall event				
No. weeks	-	-	20	21
Average weekly shortfall, m^3/s	-	-	3.0	5.2
Total shortfall, GL	-	-	35.8	66.6
Annual shortfall, % total demand				
Average	0	0	2	3
Median	0	0	0	1
Standard deviation	0	0	3	4
Maximum	0	0	8	14
Minimum	0	0	0	0
Annual no. of weeks of shortfall				
Average	0	0	4	6
Median	0	0	1	4
Standard deviation	0	0	6	6
Maximum	0	0	18	21
Minimum	0	0	0	0
Annual average weekly shortfall, % total demand [a]				
Average	-	-	16	23
Median	-	-	15	24
Standard deviation	-	-	9	9
Maximum	-	-	28	40
Minimum	-	-	2	8

a. Calculation of annual average weekly shortfall only includes weeks within the year when a shortfall occurs. Years without shortfall not included.

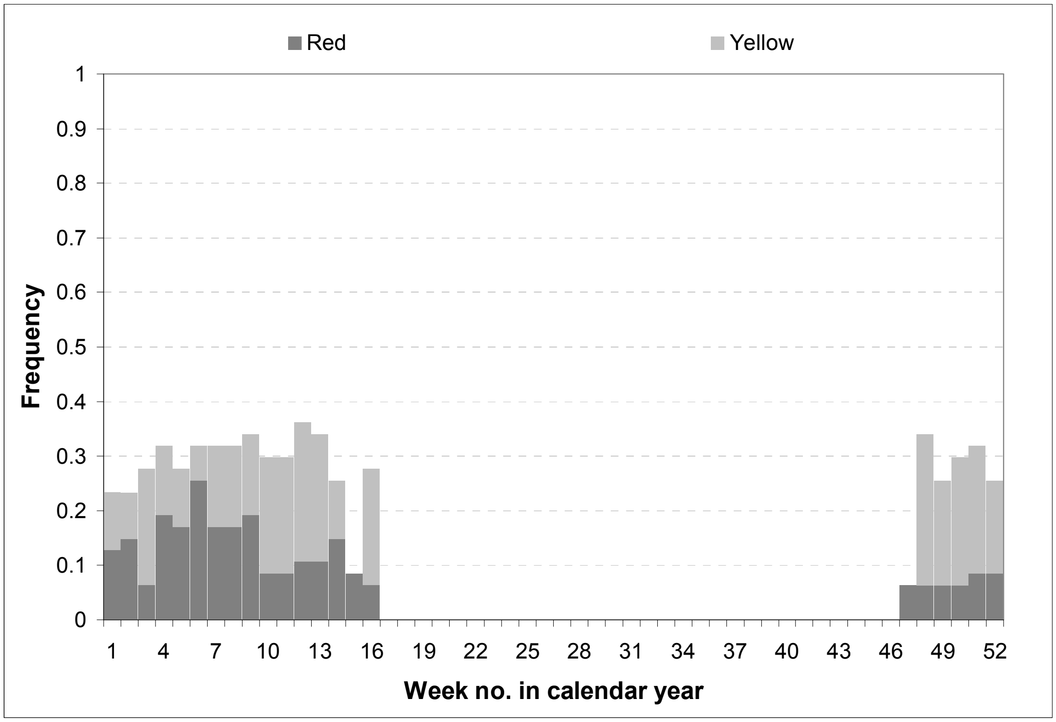
- **Table 2-3 Summary statistics of modelled supply shortfalls under the WMF for various flow scenarios and constant 14.0 m^3/s demand (approved average licensed water-use)**

Shortfall statistic	Flow scenario			
	Wet	Base Case	Dry	Ext. Dry
Peak shortfall, m^3/s	5.8	6.6	7.4	9.9
Longest shortfall event				
No. weeks	20	21	23	28
Average weekly shortfall, m^3/s	4.5	5.2	5.8	7.8
Total shortfall, GL	54.9	66.6	80.1	131.3
Annual shortfall, % total demand				
Average	2	3	5	11
Median	0	1	2	10
Standard deviation	3	4	5	9
Maximum	11	14	17	29
Minimum	0	0	0	0
Annual no. of weeks of shortfall				
Average	5	6	7	14
Median	3	4	4	14
Standard deviation	6	6	7	7
Maximum	19	21	23	28
Minimum	0	0	0	0
Annual average weekly shortfall, % total demand [a]				
Average	17	23	30	37
Median	19	24	31	40
Standard deviation	10	9	10	19
Maximum	34	40	46	66
Minimum	3	8	6	1

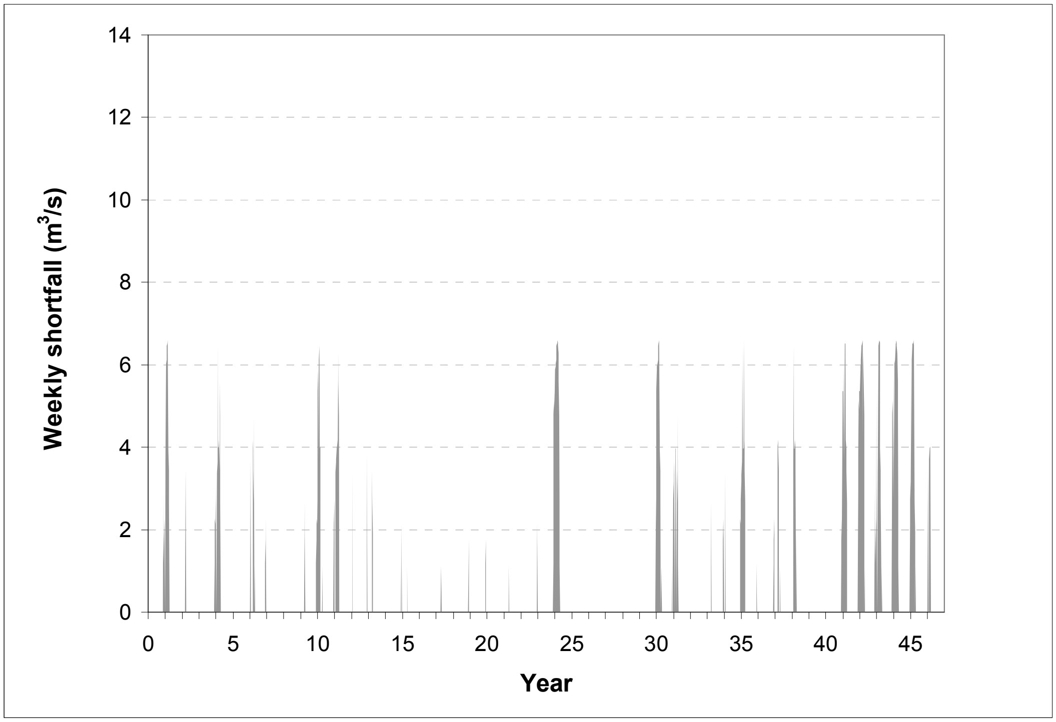
a. Calculation of annual average weekly shortfall only includes weeks within the year when a shortfall occurs. Years without shortfall not included.



▪ **Figure 2-4 Annual frequency of modelled binding flow conditions under the WMF for the base case flow scenario and 14.0 m^3/s demand (approved average licensed water-use)**



- **Figure 2-5 Weekly average frequency of modelled binding flow conditions under the WMF for the base case flow scenario and 14.0 m^3/s demand (approved average licensed water-use)**



▪ **Figure 2-6 Modelled supply shortfalls under the WMF for the base case flow scenario and 14.0 m^3/s demand (approved average licensed water-use)**

2.2 Storage options

Storage is a supply-side technical option that may be used to avoid the restrictions of the WMF, and may be in the form of either an off-stream or on-stream storage. In the case of an off-stream storage, this may be filled by extractions from the Athabasca River during times when there is excess water available. Off-stream storage might be constructed upstream of the surface mines, or as individual storages located on-site (similar to tailings ponds). On-stream storage would require dam construction along a tributary of the Athabasca River that is gradually filled by run-off from the catchment upstream of the dam site. To avoid shortfalls, water would be released from storage during times of binding restrictions and conveyed to surface mines via the Athabasca River or, in the case of on-site storage, by pipeline.

The costs of several off-stream and on-stream storage options to supply surface-mining operations in the Lower Athabasca basin were estimated in a "pre-conceptual" study by Golder Associates (2004). Storage volume was set at 80 GL, or the equivalent of four months' storage for four surface-mines that each divert 1.9 m^3/s of water on average. In addition to costs, the study compared potential regulatory issues and social impacts of each option. Results for each option are listed in Table 2-4.

- **Table 2-4 Estimated costs and issues associated with 80 GL storage options to supply oil sands surface-mines based on pre-conceptual analysis by Golder Associates (2004)**

Option	Storage type	Capital cost, $ M	Operation and maintenance, $ M	Issues
Athabasca	Off-stream	37.0	1.11	Geotechnical feasibility
Gordon Lake	On-stream	29.8	0.93	Disturbance to lake, regulatory/stakeholder opposition, insufficient catchment area, downstream flow impacts, winter icing
Buffalo Lake	On-stream	30.6	0.95	Disturbance to lake, regulatory/stakeholder opposition, insufficient catchment area, downstream flow impacts, winter icing
McMillan Lake	Off-stream	42.6	1.06	Disturbance to lake
Near Agnes Lake	Off-stream	212.6	1.02	High cost

A further option of on-site storage with a capacity of 20 GL was also investigated. This option was estimated to cost between $2 to $3 per m^3 of storage capacity, indicating an overall capital cost of up to $60 M (Golder Associates, 2004). If this volume were instead stored as free water within tailings ponds, the cost is estimated to be in the order of $2 per m^3 for the earthworks required to raise the height of a tailings dam (Golder Associates, 2004).

Storage that is shared among mining operations provides significant returns to scale. Among the shared storage options, based on multi-criteria analysis the Athabasca off-stream storage was identified as the preferred choice (Golder Associates, 2004). The capital cost components of this preferred option are listed in Table 2-5.

- **Table 2-5 Estimated capital costs of Athabasca 80 GL off-stream storage to supply oil sands surface-mines. Pre-conceptual analysis by Golder Associates (2004).**

Item	**Capital cost, $ M**
Roads and bridges	3.32
Pump, inlet and outlet	10.91
Dam and spillway	18.51
Planning and design	4.27
Total	**37.01**

2.3 Characteristics of water use by surface mines

This section describes the characteristics of industrial water-use for oil sands surface-mining operations, used for the conceptual development of the consolidated tailings and increased water recycling option. Other forms of mining, in particular thermal in-situ methods such as Steam Assisted Gravity Drainage (SAGD), were not considered, given these forms typically require much smaller volumes of water obtained from sources other than direct from the Athabasca River (Appendix C.1).

2.3.1 Water-use processes and preferred sources of water

Water is used by surface mining operations for a range of on-site processes. A number of water sources are available that provide differing levels of reliability of supply and quality. The Athabasca River has a relatively reliable supply of high quality water, and is generally preferred to other alternatives (Rogers, 2006). The use of water for surface mining and the potential for increased water-use efficiency is documented in the summary report, *Surface Oil Sands Water Management* (Rogers, 2006), prepared for the Cumulative Environmental Management Association (CEMA). Relevant information from this report is summarised below.

Surface-mining operations may undertake some or all of the following activities: (i) mining the oil sand, (ii) transporting the oil sand to extraction facilities, (iii) bitumen extraction, (iv) upgrading the bitumen, and (v) operation of utilities (Rogers, 2006). Mining the oil sand first requires removal of the surface soils above the oil sands deposit, including muskeg (1-3 metres thick, drained before removal), waterlogged soil, and overburden. Mining is mostly undertaken using massive shovels, that dump the oil sand in trucks for transport to a central transfer station. The material is then sent to an extraction plant via conveyor belt or hydro-transport, a relatively new method that facilitates mixing and separation and involves the mixing with water (or in some cases caustic soda) to form a slurry which is then pumped via pipeline. In the extraction plant, the bitumen is separated from the sand, clay and water with an aim to recover the greatest fraction of bitumen and remove waste material as tailings. During the initial separation phase, heat from the addition of hot water reduces the viscosity of the bitumen, and mixing with caustic soda assists separation. The slurry is then filtered and pumped into separation vessels, with diluent added (e.g. naptha or paraffin) to improve separation. Separated bitumen floats to the surface for collection, the diluent is recycled, and the remaining clay, sand, water, and unrecovered bitumen is pumped via pipe to tailings facilities (comprising sand banks and settling ponds). The upgrading process converts the raw bitumen from a heavy oil to a lighter crude oil, while removing impurities including nitrogen, sulphur and carbon. The upgraded oil is then transported via pipeline to a refinery.

After the tailings are disposed to the ponds, the coarse sands settle and water fills the voids between the sand grains. After approximately six months, 30% (by weight) of the fine sands and clays settle to the bottom as mature fine tailings, with the rest remaining suspended in solution (Rogers, 2006). About 30% of the process wastewater is tied up in the long-term storage of tailings (Davies and Scott, 2006), while the remainder is "free water" available for recycling. A certain amount of free water, freeboard, is needed to protect the settled mature fine tailings from becoming re-suspended due to wind and wave action (once disturbed, resettlement of mature fine tailings requires about three days before free water can again be reused). The depth of freeboard required - about three metres - may be relaxed slightly during ice-cover in winter (Rogers, 2006).

The tailings ponds play a key role in water recycling. A large oil-sands operation requires about 250 GL per year of water, most of which is sourced from the free water stored in tailings ponds (Davies and Scott, 2006). To maximise wastewater recycling, half the annual volume of water needed for bitumen extraction must be stored as free water in the tailings ponds; if there is insufficient stored water then additional water must be extracted from the River, while if there is excess water then additional storage must be constructed (Rogers, 2006).

For each process described, water is required of a certain quality that meets the requirements of the process and limits the damage to equipment associated with corrosion, fouling and scaling (Rogers, 2006). Selection of the source of water and level of treatment is based on the quantity and quality objectives of the individual activity. Operators can opt to use water from either the Athabasca River or other surface-water sources including tributaries, groundwater, on-site precipitation (i.e., rain and snow melt, available from around May to October, that by regulation must be retained if in contact with oil sands), or connate water (i.e., pore water trapped within the mined oil-sands material [approx. 5% content]); with this choice based on cost, technical considerations, and water licence conditions (Rogers, 2006). Water is also available from muskeg removal, although water from this source does not contact the oil sands and so is generally drained to the river (Rogers, 2006). Groundwater is available from mine dewatering and licensed pumping, with its use dependent on the quality of the source aquifer and the methods available for water treatment. In general, water from the Athabasca River is preferred by operators as its quality and quantity are predictable (and so is suitable for continuous operations), and the river is located within a reasonable distance (Rogers, 2006).

Improvements in water-use efficiency are possible given mature operations are not limited in their supply of free water, and extraction from the river may only be required for certain utility purposes (Rogers, 2006). To ensure that water savings are genuine, improvements for particular processes need to be undertaken while ensuring no corresponding increase in the use of river water to top-up the free water inventory (Rogers, 2006). The use of river water is relatively cheap as it requires less treatment, and so the methods available to improve water-use efficiency are expected to impose additional costs. A summary of the range of uses of water for surface-mining operations, along with use objectives linked to water quality requirements, disposal and potential conservation methods, is provided in Table 2-6.

- **Table 2-6 Common water uses of surface-mining operations and potential conservation methods, based on Rogers (2006)**

Activity	Water use & objectives	Typical water source & treatment	Disposal	Water conservation methods
Mining	Road maintenance; dust control	Free water from tailings facilities	Evaporation	
Transport	Hydro-transport; create slurry	Free water from tailings if sufficient volume available and low suspended solids, otherwise river water	Removed during extraction process to tailings ponds	Use of corrosion-resistant materials and scale inhibitors to avoid use of river water
Bitumen extraction	Hot water to extract bitumen; must not corrode, foul or scale-up equipment	Free water from tailings. If insufficient volume available or high suspended solids (requiring expensive treatment), then use of river water. Water heated by using it to cool other processes, with additional heat received from condensed steam.	Tailings ponds	Hydro-transport (rather than steam injection of oil-sand material in tumblers) lowers demand for steam and boiler feedwater (and reduces wastewater sent to tailings facilities). Use of corrosion-resistant materials and scale inhibitors to avoid use of river water.
Utilities	Potable use; fit for human consumption	River water or groundwater. Treatment to remove colour, organic material, suspended material, viruses and bacteria via clarification and filtration, then addition of chlorine or other technology.	Treated then disposed to either tailings ponds or Athabasca River	
	Cooling water make-up (less water needed in colder months). Must not cause scaling, fouling or corrosion of equipment.	Treated river water. Water cooled via evaporation then reused in process.	Concentrated dissolved solids removed in blowdown sent to tailings ponds	Recovery of blowdown, operation of cooling towers at higher cycles of salt concentration. Use of more corrosion-resistant materials, application of protective coatings, use of sacrificial anodes or chemical treatment.
	Washing plant and equipment	River water	Tailings ponds	Recycling of rinse waters

Activity	Water use & objectives	Typical water source & treatment	Disposal	Water conservation methods
	Fire emergency use	River water, stored separately on-site	Not specified	
	Steam production for power generation, heating, driving motors, and hydrogen production. Extra water needed in colder months. Must not cause scaling, fouling or corrosion of equipment.	Treated river water free of dissolved solids. Pre-treatment (e.g. clarification and filtration), then dissolved solids removed by ion exchange (use of resins that require periodic regeneration) or reverse osmosis (~75% recovery rate of water treated, remainder disposed to tailings facilities).	Evaporation Wastewater from water treatment process (reverse osmosis) disposed to tailings ponds	Recovery and reuse of boiler blowdown, electrical (rather than steam) heating of pipes that carry fluids
	Gland water, to pump material around plant for processes; must be reliable source without causing damage to pumps	Not specified	Not specified	Use mechanical seals on pumps, use wastewater as gland water
Tailings ponds	Recycle water and storage of tailings; prevent re-suspension of mature fine tailings (using freeboard allowance) and minimise costs	Includes water originally contained within the oil sand (connate water), and wastewater from the bitumen extraction process. Other inputs received from precipitation (snow and rain) in contact with oil sands, groundwater that is diverted from mine dewatering, wastewater from utility operations (potable water, cooling water, boiler feedwater, fire water and gland water), and direct inputs from the Athabasca River.	Outflows from wastewater recycling, evaporation and potentially seepage. Pore water between coarse sand particles and water that forms sludge with mature fine tailings (vol. depends on fines within mineral deposit) is effectively trapped from future reuse.	Consolidated tailings produces less sludge volume and so requires less freeboard. Technique requires addition of chemicals (e.g. gypsum) to tailings discharged following the extraction process. The subsequent increased calcium and bicarbonate alkalinity of free water causes equipment scaling and reduced bitumen recovery, and so requires additional treatment e.g. softening using lime or caustic soda, and use of a scale inhibitor. Dry tailings technologies e.g. Bitmin.

2.3.2 Typical on-site water balance

The typical on-site water balance provides source information for determining the potential for increased water recycling and its associated cost.

Allen (2008) estimates a water balance for a hypothetical oil sands surface-mine producing 200 000 barrels per day and assuming no treatment of tailings. The water balance (Table 2-7), shown in adjusted units of GL per annum, indicates that surface mines recycle a significant proportion of their water use during the extraction process. The flow rates of the water balance are expected to differ among operations due to differences in ore content, extraction and upgrading methods, and tailings treatment (Allen, 2008).

Rogers (2006) estimates the variation in water use for similar processes across surface-mining operations (Table 2-8). The information presented is similar to that in Table 2-7, although Rogers (2006) includes a category for river water that is directly transferred to tailings ponds, and provides estimates of evaporation, net precipitation and treated sewage discharge. Rogers (2006) notes that the variation among operations is primarily due to different levels of production; combined with secondary factors that include the maturity of operations, the efficiency of the operator's processes (related to the date of installation), product quality, and differences in the quality of available water (e.g. groundwater).

- **Table 2-7 Estimated water balance for a hypothetical oil sands mine, based on Allen (2008). Assumptions include: production rate of 200 000 barrels per day, ratio of river water extraction to oil production of 4.6:1, no use of consolidated tailings.**

Item	Mass, tonnes per hour	Volume, GL per annum[A]	% of total inflow/ outflow
Inflows			
Water to utilities			
Pumped water from river	6 082	53.3	90
Water to bitumen extraction process			
Recycled water from utilities	5 778	50.6	86
Free water from tailings ponds	6 364	55.7	95
Connate water	651	5.7	10
Water to tailings			
Water from extraction process	11 514	100.9	171
Water from froth treatment	1 215	10.6	18
Total inflow (water pumped from river plus connate water)	6 733	59.0	100
Outflows			
Tailings to free water (to be recycled)	6 364	55.7	95
Tailings disposal			
Mature fine tailings	4 336	38.0	64
Beach	2 029	17.8	30
Net evaporation, or change in storage of free water held in tailings (estimated by balance)[B]	368	3.2	5
Total outflow (tailings disposal plus evaporation)	6 733	59.0	100

Notes: A. Volume conversion assumes a temperature of 4 °C.

B. Evaporation is noted by Allen (2008), however a quantitative estimate of evaporation or net evaporation (i.e., evaporation minus precipitation) is not included in the original balance. If actual net evaporation is less than the balancing figure shown, this would indicate an increase in the volume stored in tailings ponds over time.

- **Table 2-8 Range of water use for oil sands operation (based on Rogers [2006:13])**

Item	Volume, GL/yr	Comments
River water to river water storage	35 – 125	Dependent on size and age of operations
River water to tailings facilities (inc. recycling)	10 – 100	Mature operations use less water
River water to utilities and upgrading	25 – 65	More water used if upgrader is present
Evaporation	10 – 20	Represents the only major loss in the water balance of an operation. More evaporation occurs from plants with cooling towers.
Net precipitation	2 – 15	More precipitation as disturbed area increases
Sewage waste	0 – 1	Treated, then retained or discharged to river
Utilities/upgrading wastewater to tailings	25 – 100	Total volume from river water storage to utilities/upgrading less losses from evaporation and hydrogen production

2.4 Potential recovery of water and costs of consolidated tailings

Based on Section 2.2, the key to reducing extractions from the Athabasca River and improving water-use efficiency is to maximise the reuse of free water stored in tailings facilities, and to minimise the volume of water used for the long-term storage of tailings. The typical water balance (Table 2-7) indicates that half the water discharged as tailings (during the bitumen extraction process) may represent an additional volume available for recycling. If it is assumed that the water used to dispose of sand/beach (Table 2-7) is not able to be recycled, then this leaves only the mature fine tailings as a significant source for recovering water losses.

Consolidated tailings, also known as composite tailings or non-segregated tailings, converts mature fine tailings from a sludge to a more consolidated form, so that less water is consumed during the tailings disposal process. Consolidated tailings may be formed by the addition of lime (CaO) or gypsum ($CaSO_4$), or other treatment method

(Matthews et al., 2000). Syncrude has previously selected gypsum for use in consolidated tailings and, in 2000, had plans for over 50% of tailings discharged from the extraction process to be treated (MacKinnon et al., 2000). Gypsum dosage rates are in the order of 1000 to 1200 grams per m^3 (Matthews et al., 2000).

Mackinnon et al. (2000) report the composition of tailings before and after consolidation (Table 2-9). Following treatment, over a period of days to weeks approximately 50% of the initial water content of the tailings is released, and a further 20 to 30% may eventually become available under containment (MacKinnon et al., 2000). Combining these figures with the example of a 200 000 bbl/d surface mine (Table 2-7), full implementation of consolidated tailings may reduce water outflows associated with mature fine tailings by 73%, in this case from 38.0 GL per year to 10.1 GL per year (i.e., 27.9 GL per year recovered).

- **Table 2-9 Predicted composition of tailings associated with consolidated tailings (CT) method (Source: MacKinnon et al. [2000:444])**

Stage	% weight solids	Volume, % volume			Available water, % of total water
		Solids fraction	Water content	Release water	
Initial stage	60	36	64	0	0
Rapid CT deposit densification	75	36	32	32	50
Final CT deposit densification	82	36	17	15	73

There are a number of options for utilising the water recovered from the implementation of consolidated tailings. The water could be treated and released back to the river, although this is currently not allowed under environmental regulations and water treatment may be prohibitively expensive[4]. An alternative option is to recycle the recovered water for use as process water for bitumen extraction (in the same manner that free water stored in tailings ponds is recycled), combined with the use of recycled water for utilities purposes.

[4] See Allen (2008) for a review of potential water treatment objectives.

Examination of the typical water balance (Table 2-7) indicates that, in order for the consolidated tailings option to lead to a maximum reduction in water extraction from the Athabasca River, a reduction in water outflows from the utilities process would be required that is equal to the volume of recovered water from consolidated tailings[5]. If the water-use efficiency of utilities is considered constant, to reduce water outflows from the utilities process would in turn require that water discharged from the utilities be treated then reused for utilities purposes. Based on the water balance for the hypothetical mine presented in Table 2-7, to gain the full river benefit associated with implementation of the consolidated tailings option would require that 27.9 GL per year (38.0 GL minus 10.1 GL) of utilities water be recycled for utilities purposes. To recycle water for utilities purposes, it is assumed that pre-treatment would be required to reduce the salt content and avoid corrosion of equipment and other associated costs (e.g. increased maintenance and accelerated capital replacement).

Water treatment by reverse osmosis is a standard procedure to remove salts from water. Using a membrane, the salts are separated into a brine concentrate[6] leaving a stream of fresh water. RosTek Associates et al. (2003) estimate the cost of a range of desalting technologies in U.S. dollars (1999 dollar value), with reverse osmosis found to be the most cost-effective (regardless of plant size). The costs of reverse osmosis, along with design time estimates, are reproduced below (Table 2-10) for the treatment of brackish water with a total dissolved solids (TDS) content of 2 500 mg/L.

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[5] This statement assumes that other factors that may influence the water balance are held constant (e.g. volume of water required for bitumen extraction).

[6] The saline byproduct of reverse osmosis could be disposed via injection into a deep saline aquifer. Similar to the case of disposal of high-saline basal water (Rogers, 2006), disposal via this method may require technology development and acceptance from government regulators.

- **Table 2-10 Estimated capital and operation costs, and duration of design and construction, for reverse osmosis treatment (2 500 mg/l feedwater), measured in 1999 U.S. dollars (Source: tables and interpolation of figures presented in RosTek Associates et al. [2003])**

Item	**Plant size (m^3/d)[A] for reverse osmosis treatment**				
	3 785	**18 925**	**30 000**	**37 850**	**189 250**
Capital cost[B], \$ per m^3 per day	1 220	530	480	460	230
Operating cost[B], \$ per m^3	0.40	0.23	0.18	0.18	0.08
Design time, months	3	4	6	9	12
Construction time, months	6	9	12	15	18

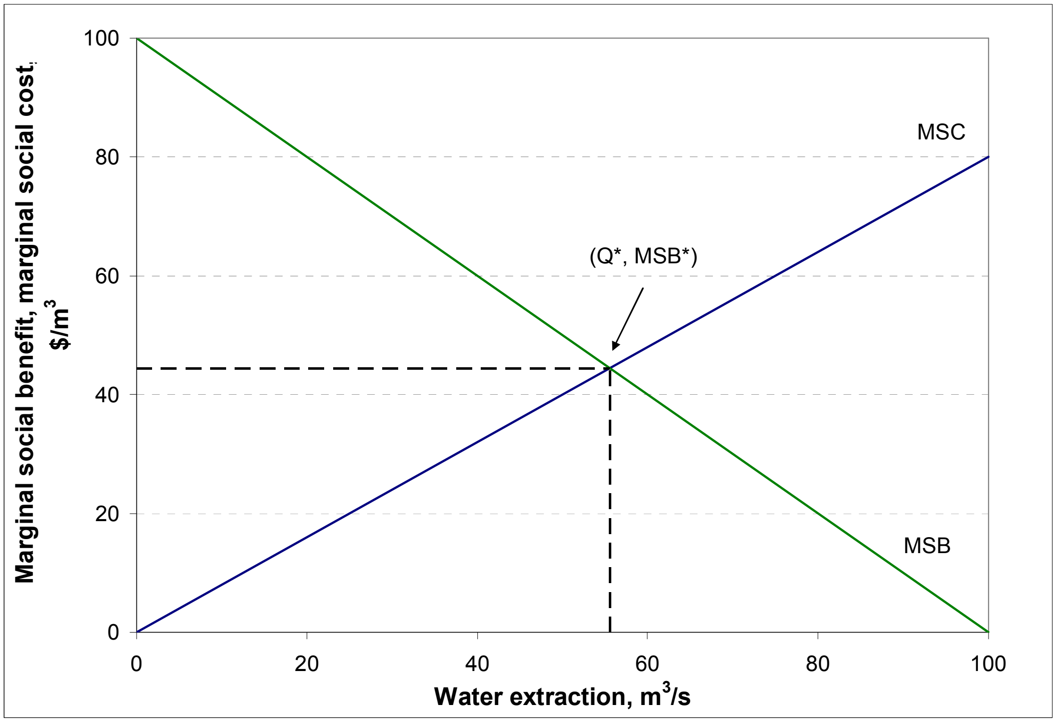
Notes: A. Plant size refers to output (product water) capacity

B. Costs assume that water treatment facility is operational 85% of the time

2.5 Review of economic theory and literature

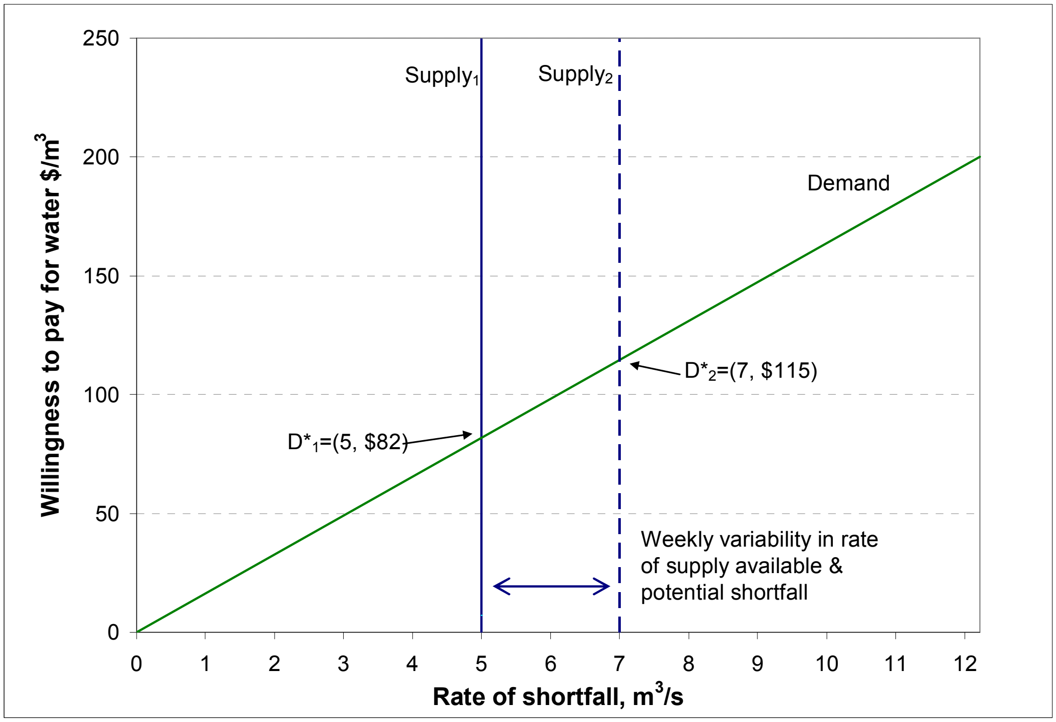
2.5.1 Optimal water allocation

In theory, a socially optimal allocation of water will occur when the marginal social benefits (MSB) of water extraction equal its marginal social costs (MSC). In this valuation context, the term "social" broadly refers to all use and non-use values (environmental, social and economic) arising from water extraction. Social benefits include the economic benefits of production arising from industrial water-use. Social costs include those associated with the impacts of water extraction to the downstream environment. In the case of the lower Athabasca River, the social costs of water extraction may include those associated with altered downstream flow variability, total dissolved oxygen content of flow, and other indicators of water quality (Appendix A). Non-use values may also be present (e.g. those associated with the environmental quality of the Peace-Athabasca Delta [Appendix A]) that may be affected by water extractions. Figure 2-7 provides a hypothetical illustration of the relationship between MSB and MSC of water extraction, and the optimal level of water allocation.



▪ **Figure 2-7 Hypothetical depiction of marginal social benefits and costs of water extraction, and optimal level of water allocation (Q*)**

The WMF sets a limit on total water extraction on a weekly basis. For a given water supply used to produce a single good (e.g. oil), if it is assumed that the water supply limit is set at the social optimum and is below that for profit maximisation, producers face equal costs of production, and assuming no other externalities associated with production, then economic efficiency occurs when water is allocated so that production is maximised. An example of the form of the supply and demand curves that may be applicable to the lower Athabasca basin is provided in Figure 2-8. Note that the horizontal axis in Figure 2-8 depicts quantity in the form of quantity of shortfall, rather than quantity supplied, with the demand curve being equal to (or at least a subset of) the MSB of water extraction. For the lower Athabasca River, estimation of the position of the supply curve is based on the analysis of water availability under the WMF (Section 2.1.5).



- **Figure 2-8 Illustrative (hypothetical) example of relationship between shortfall of supply and demand for water in an unregulated river system with a weekly variable cap on water extraction**

2.5.2 Project evaluation and analysis of cost effectiveness

Two methods are often used to evaluate and compare alternative options: net present value (NPV) and benefit-cost ratio. Both require selection of an appropriate discount rate to allow future benefits and costs to be evaluated using a common benchmark in time. NPV has the advantage that it depicts the relative size of net value that may then be used to compare the results of other options where similar estimation methods are used. A typical formula for calculation of NPV is depicted below:

$$NPV = \sum_{t=0}^{n} \frac{B_t - C_t}{(1+r)^t}$$

Where:

n = time period for consideration of benefits and costs

t = time

B_t = Benefit of option (e.g. reduction in costs) in each period relative to base case.

r = Discount rate

C_t = Cost of option in each period relative to base case.

For the analysis of cost effectiveness, the benefits and costs of the options for the calculation of NPV are measured in terms of financial impacts using discounted cash flows.

2.5.3 Industrial water demand characteristics

The shape of the water demand relationship for oil-sands mining operations will have an important influence on the NPV of the options. Renzetti (2002) provides a detailed review of econometric and linear programming studies of industrial water demands, including for self-supplied firms, and found that industrial water demands have been relatively understudied - particularly in the case of the mining sector. Provided below is a brief summary of relevant studies.

Dupont and Renzetti (2001) was the single study cited by Renzetti (2002) on the water demands of the mining sector. For mines operating in Ontario in 1991, the study estimated a price elasticity of intake water demand of -0.744 based on the use of an instrumental variable as a proxy for water price, and annual water-use and output data. Dupont and Renzetti (2001) also analysed data for Canadian manufacturing firms over 1981 to 1991, and found that although actual water-use is limited by licensed water-use, water use can be considered to be a variable input to production. Water extractions were found to be a substitute for capital, labour and energy; while water reuse was found to be a substitute for labour and a compliment to energy and capital (Dupont and Renzetti, 2001). Own price elasticities for water extraction (intake) and water reuse were in the order of -0.8 for both cooling and steam production, while cross-price elasticities for water intake and recirculation were found to be much greater for process uses than for cooling or steam production (Dupont and Renzetti, 2001). Technological change was found to favour increased water extraction and decreased water recycling (Dupont and Renzetti, 2001). Using an extension of the same data series, Renzetti and Bruneau (2007) found that Canadian manufacturing firms appear to decide whether to recycle water on an ongoing basis. Their econometric analysis indicated that, in cases where water recycling occurs, additional recycling may be encouraged by higher intake costs and (where applicable) higher marginal costs of water treatment prior to discharge, e.g. associated with stricter wastewater quality requirements for discharge (Renzetti and Bruneau, 2007).

Linear programming studies of industrial water use are also available. The linear programming models typically use input demand equations that are piece-wise continuous, with kinks that represent the point of adoption of an alternative technology (Renzetti, 2002). If water-saving options are limited, the results of linear programming models may indicate that small changes in the price of water extraction may not produce a change in water use (Renzetti, 2002). Stone and Whittington (1984, in Renzetti [2002]) study the water use of a Polish thermal power plant using a detailed engineering process model, and found that price elasticities of water demand over a range of water prices reflect the viability and availability of feasible conservation options. They found low price elasticities of demand (approx. -0.02) at both very low prices, when many options were not financially viable, and at very high water prices, when there were few alternatives left; with a mid-range elasticity (-0.56) found at mid-range water prices.

It is unknown whether the previous studies of industrial water demands may be applicable to the mining industry and oil-sands mining. Allen (2006) reviews emerging water treatment technologies for potential application to the oil sands industry, and includes a detailed list of unit costs of water treatment estimated by previous studies. Combined with an engineering process model of on-site water use, information on the costs and water-use implications of various technologies could be used to estimate price elasticities of water demand in the Oil Sands (e.g. similar to the study by Stone and Whittington [1984] in Renzetti [2002]). It is unknown whether such information has been collated or is publicly available.

Given the unique characteristics of oil sands mining, technology development and technology incentives would strongly influence the shape of the long-run demand curve for water. In the short run, demand may be particularly inelastic. If water extractions were to cease at short notice, Syncrude has estimated that short-run conservation measures may allow continued operation for “a few days”, with free water inventory from tailings ponds allowing operation for approximately 30-days prior to shutdown (Matte, 2004). Relatively new operations may be unable to generate this level of free water inventory. It is conceivable that water demands may be similar to those found by Stone and Whittington (1984, in Renzetti [2002]) given there have been few incentives to conserve water to date, and achieving large reductions in water use may require a complete overhaul of operations.

2.5.4 Selection and design of economic instruments

In a recent presentation on the design of markets to manage water allocations, Young (2008) highlighted the importance of selecting a separate policy instrument to address each policy goal. This was based on Tinbergen's principle, that the number of policy instruments must at least number the independent targets to be attained to enable a particular outcome to be achieved (Tinbergen, 1952), accompanied by Mundell's principle of effective market classification (Mundell, 1960), which advises that "policies should be paired with the objectives on which they have the most influence" (Mundell, 1968:239) to enable a dynamic system to be steered directly toward a stable solution. In this study, the dual goals of cost-effective implementation of water restrictions under the WMF and increased water-use efficiency (Section 1.2) have some dependency but are not equal. Water restrictions may not occur for some time (Section 2.1.5), while there may be current potential for increased water-use efficiency that may be economically efficient if all social benefits of reduced water use were considered. In addition, other policy objectives listed in Table 1-1 - particularly those related to technology - may not be adequately covered by the two primary goals of the study. This suggests that more than one policy instrument may be necessary.

A fundamental consideration for the design of economic instruments is whether to employ a price-based or quantity-based instrument (or a hybrid of some form). The WMF effectively caps quantity across different ranges of the flow duration curve calculated for each week of the year (e.g. Appendix D.4 provides a flow duration curve calculated across all data points), however in theory it is possible that a price instrument may achieve the same quantity outcome. In cases where the quantity limit may not be reached, a price instrument has the advantage that it retains the potential to reflect the shadow value of water use.

Weitzman (1974) explains the relative advantages of each type of instrument for regulating the production of a single good (e.g. an environmental good), and for regulating the production of either multiple goods or a single good produced by multiple entities, in cases where there is uncertainty in the benefits and costs of production. A key finding was that the relative non-linearity of benefits versus costs influences the risk associated with the selection of either instrument (Weitzman, 1974). Summarised by Nordhaus (2007:37), "if costs are highly nonlinear compared to benefits, then price-type regulation is more efficient; conversely, if the benefits are highly nonlinear while the costs are close to linear, then quantity-type regulation is more efficient". It was also found that with more firms producing similar output there is a greater advantage of using price instruments rather than quantities (Weitzman, 1974).

In addition to the choice of instrument, uncertainties related to the benefits and costs of water conservation are particularly important in determining the optimal level of environmental protection. If the loss of environmental values is irreversible, there is an option value associated with the uncertainty of benefits to future generations - indicating that the level of protection should be set higher than otherwise (Pindyck, 2007). Conversely, improvements in water-use efficiency are likely to require investment in long-term changes to industry operations. The presence of irreversible sunk costs, when benefits are uncertain, indicates that the level of conservation should be set lower than otherwise (Pindyck, 2007).

Other policy factors may also influence instrument selection. Public acceptability is likely to be higher for systems designed to reduce an environmental harm in a cost-effective manner, compared to those schemes that allow the (cost-effective) maintenance of present levels of an environmentally harmful activity (Stavins, 2003). If the instrument generates revenues for government, such as in the case of a charge for water extraction, how the revenue is used (e.g. increased public spending or reducing other taxes) may affect the overall merit of the policy when indirect or general equilibrium impacts are taken into account (Sterner [2003], Fischer and Newell [2007]).

Optimal setting of prices for price-based instruments may be difficult. For efficiency, prices should be set on an annual basis such that the marginal costs of abatement, e.g. reduced water extraction, should equal the present value of marginal damages, e.g. arising from water use (Parry and Pizer, 2007). In the case of the lower Athabasca, which has flows that continually fluctuate, the impact of a unit of water extraction would vary across seasons and years. As optimal prices may be difficult to determine, a quantity instrument may be more precise and easier to develop in practice (Sterner, 2003).

The number of market participants is particularly important in the case of quantity-based instruments. Quantity-based instruments create artificial scarcities, monopolies, or rents, and are more susceptible to corrupt activities than price-based instruments - even in developed countries (Nordhaus, 2007). With few market participants, thin markets may result in significant market distortion, very limited trading, and strategic behaviour by firms (Sterner, 2003). Price-based instruments fix prices and provide certainty to firms, whereas trading systems may produce volatile prices for licences, which in turn may lead to reduced investment in abatement technology and additional costs for risk-averse firms (Parry and Pizer, 2007). Price volatility may be a particular issue for short-term water trading in an unregulated river basin, given unpredictable flow, fixed licensed water-use, and inelastic demand in the short run.

Hybrid schemes provide a method for dealing with the shortcomings of price-based and quantity-based instruments. In cases of increasing marginal damages, hybrid instruments are particularly attractive where marginal damages have wide variation across the range of total environmental harm (in the case of the Athabasca River, this may be associated with the range in the proportion of water extracted) and have significant uncertainty (Roberts and Spence, 1976). Licences can be used to avoid a high level of environmental harm, while charges provide an ongoing incentive to reduce environmental harm and may provide a greater level of abatement (e.g. water conservation) than that required by licences in the case where abatement costs are low (Roberts and Spence, 1976). One particular form of hybrid scheme allows licences to be traded and imposes a fixed penalty when water extraction is greater than licence conditions; the fixed penalty protects participants against volatile market prices (Roberts and Spence, 1976).

Sterner and Höglund Isaksson (2006) highlight the symmetry between price and quantity-based instruments and advise that the choices available for instrument selection depend on the property rights to the natural resource (Table 2-11). In the case of water licences in the lower Athabasca basin, existing industry has prior rights although the degree of ownership is not entirely clear. Water trade is allowed subject to approval, however licences that are not actively used may be cancelled. Licences may be amended to ensure "the most beneficial use of the water in the public interest" (Alberta Environment, 1987), and if so this in turn may lead to compensation under the *Water Act* (*s158*). Given that direct payments to the oil sands industry to reduce water use (whether using a quantity or price instrument) is likely to be incongruous with public sentiments, this suggests that rights are at most intermediary with some prior appropriation. The quantity instruments available (Table 2-11) are well established. Price instruments for an intermediate rights situation are fairly novel in practice, and are discussed in more detail below.

- **Table 2-11 Rights to the environment and selection of policy instruments (Sterner and Höglund Isaksson, 2006:96)**

Holder of ownership rights to the environment	**Type of instrument**	
	Quantity	**Price**
Society	Auctioned Permits	Tax
Intermediate (State grants rights in proportion to output)	Permits output allocated to cover some share of permits needed	Total or partial refunding of charges i.e. Refunded Emission Payment (REP)
Intermediate (Firms have some "prior appropriation" rights)	Grandfathered permits to cover some share of permits needed	Tax-subsidy i.e. Tax with Allowances (TWA)
Polluter	Free permits with buyback from state to correspond with abatement	Pure subsidy

One price instrument that may be applicable in the case of intermediate rights to the environment is a tax with allowance or charge-subsidy scheme (Table 2-11). This type of instrument sets a baseline right to each firm for the resource. If the effluent level (or, in this case, water extraction) of a firm is above the baseline then a charge is imposed, if instead it is below the baseline then a fixed payment is provided (Mumy [1980] in Pezzey [1992]). New firms have no baseline rights, and pay for their entire consumption. Pezzey (1992) demonstrates that this scheme creates the same outcomes as a tax, and is symmetric to a permit market in which permits are initially allocated (e.g. grandfathered) and government either rents permits back or offers additional permits depending on the optimal level of effluent (or water extraction).

The alternative price instrument applicable in cases of intermediate rights is the refunded emission payment scheme. In Sweden, a refunded emission payment scheme exists to regulate the emission of nitrogen oxides (NO_x) from large industry. Described by Sterner and Höglund Isaksson (2006), the Swedish scheme sets an unusually high charge for emission of nitrogen oxides with the revenues collected then refunded in proportion to output (based on a measure of energy produced by each firm). The choice of scheme was influenced by the variance in abatement costs among polluters, familiarity in the use of charges rather than tradeable permits among policymakers, and practical issues including the high costs of monitoring (that restricted the scheme to 200 large polluters) and polluter resistance (Höglund Isaksson [2005], Sterner and Höglund Isaksson [2006]). Refunded payments are likely to be more politically attractive for managing water extractions in the lower Athabasca basin than a direct charge (without refund). Compared to a tax with allowance, the refunded emission payment does not assume a baseline level of rights, and so may be relatively favourable for new firms (Sterner and Höglund Isaksson, 2006). Over a five year period of implementation it was found that technology improvement had reduced abatement costs for the Swedish firms, with many of the abatement activities carried out at very low to zero cost (Höglund Isaksson, 2005).

Refunded emission payments are variable rather than fixed (i.e., net payment depends on performance in relation to the refund measure and that of other scheme participants), and do not provide the same outcomes as a pure charge or tax with allowance scheme. In theory, under perfect competition any degree of refunding would lead to distortions as a higher level of output than otherwise is encouraged by the refund (Gersbach and Requate, 2004). Imperfect competition may also result in suboptimal outcomes, with weaker incentives for abatement in the case of low competition or oligopolies with large output shares (Sterner and Höglund Isaksson, 2006). In addition to sufficient competition, to achieve an equivalent outcome as a Pigouvian tax the scheme requires technology development to be external to the targeted plants (i.e., exogenous), otherwise there is a risk of reduced innovation - particularly in cases of indistinct technology that is unable to be protected by patents, such as learning from other's experiences (Höglund Isaksson, 2005).

The provision of incentives for technological progress (innovation and adoption) differ depending on policy instrument selection (e.g. Fischer and Newell, 2007), and the effect of technological progress on market outcomes in turn differs depending on the policy instrument. If environmental charges (e.g. water prices) are constant, then exogenous technological progress produces a higher than optimal level of abatement; whereas if the policy of an environmental cap (e.g. associated with water trade) is constant, then exogenous technological progress will result in a less than optimal level of abatement and a fall in the market price of licences (Sterner [2003], Stavins and Whitehead [1992]). Which method produces the greatest loss is an empirical matter, although if damages are estimated to increase with time, e.g. with increased population, income, and/or knowledge, then the price-based instrument is preferable (Sterner, 2003).

Private investment in research and development may lead to benefits to others when information is shared, yet this benefit may be external to the investment decision and the knowledge gained may not be publicly disseminated. Jaffe et al. (2005) discuss the relationship between market failures associated with innovation and diffusion of new technologies (leading to market under-provision), and activities that create environmental externalities (leading to market over-provision, e.g. instream flow impacts). A lack of investment in new, environmentally-beneficial technology may be due to a weak environmental policy, positive knowledge and adoption spillovers, or incomplete information (Jaffe et al., 2005). To deal with both forms of market failure (i.e., environment and technology), environmental regulation should be the main policy focus, while taking care to avoid policies that favour a particular technology at the expense of further innovation (Jaffe et al., 2005). To provide incentives for technology, public-private partnerships that allow market forces to influence the choice of technology may be particularly effective (Jaffe et al., 2005).

An applied study that ties the analysis of market-based instruments and incentives for new technology is provided by Fischer and Newell (2007). They model the effects of six policies designed to reduce the greenhouse gas emissions of a perfectly competitive energy sector. The policies assessed included a production subsidy for implementation of a new technology, and subsidies for research and development. They found that while emissions pricing provided the primary incentive to reduce emissions, an optimum (and much cheaper) portfolio consisted of three policies to address three externalities: (i) emissions, addressed by emissions pricing, (ii) research and development spillovers, addressed by an R&D subsidy, and (iii) learning spillovers, addressed by a subsidy for production that uses new technology (in this case, a renewable generation subsidy). The R&D subsidy was found to be a "no regrets" policy (Fischer and Newell, 2007:40) that outperformed the emissions pricing option when very low levels of abatement were required.

Investment in new technology is likely to be key for increasing the water-use efficiency of oil-sands mining operations. Breakthrough technology (a form not considered by Fischer and Newell [2007]), that may produce large reductions in water use over the long term, may be particularly important. Forms of breakthrough technology that are still at an experimental stage may already be available in the oil sands. Potential technologies in this realm include dry tailings technology (Bitmin Resources Inc., 2007) for surface-mining operations, and toe to heel air injection (THAI) for in-situ mining (Petrobank Energy and Resources Ltd). Due to learning spillover effects, where not all the potential learning benefits gained during production and use of a new technology accrue to their investors, it is likely that the market would under-provide this form of endogenous technological innovation without policy intervention. Encouraging output via output-support subsidies, as analysed by Fischer and Newell (2007), can encourage innovation and may be particularly applicable where technology has been developed (such as in the case of the oil sands) but is yet to be adequately tested in practice. Incentives for the provision of information would form part of this policy.

2.5.5 Market characteristics and policy considerations

There are a number of market factors particular to water use by mining operations in the lower Athabasca River basin that may reduce the effectiveness of the options (particularly the policy options) to manage water-use in practice. Issues and associated risks are summarised in Table 2-12.

- **Table 2-12 Issues and risks associated with a potential market for water use in the lower Athabasca River basin**

Issue	Description	Market inefficiency risk
Low number of water users, water use is less than full allocation	The majority of licensed water-use is issued to seven surface-mining operations (Table 2-1). Licences issued in excess of requirements, with historic water-use being significantly less than full allocation (Appendix C.2).	Collusion and low, sub-optimal level of trading (in case of policy of water trade) resulting in market prices that do not reflect marginal costs
Barriers to new entrants	Water trading has not been developed given that no formal cap on *annual* extractions has been announced, and water transfers on a seasonal or shorter timeframe (e.g. weekly) have not been enabled. Applications for new water licences are evaluated individually through an environmental impact assessment process. New licensees have less certainty of supply under the prior allocation system. It is uncertain whether water management agreements (e.g. Appendix B) or other alternatives for sharing scarce water supplies will be available in the future.	Reduced competition for water resource, less than optimal level of production.
Asymmetric information	Information on the costs to conserve water may be accessible to mining operators but is not available to government regulators.	Inefficient policy design e.g. sub-optimal price or cap on quantity
Asymmetric power	The oil sands industry provides substantial revenues to the government of Alberta, and may have a considerable indirect influence on policy.	Effective industry lobbying against the adoption of preferred policy
Technology development and dissemination	Technology is particularly important given the unique nature of the resource and extraction methods. In 2006, there was no collaborative water research being undertaken by the oil sands industry (Rogers, 2006).	Private under-provision of technology
Unequal time horizons	Improvements in water-use efficiency are likely to be long-term in nature, with investment in long-lived infrastructure and low flexibility in the short run. This long timescale is in contrast to the management of water use on a weekly basis under the WMF.	Inaccurate financial assessment of long-run investment options to improve water-use efficiency
Uncertainty in benefits and costs of water conservation	Uncertainty in the benefits and costs of water conservation, and the relative slope of marginal values with reduced water-use. Benefits of water conservation may change over time with change in real income and relative scarcity of environmental values. Similarly, costs may change over time with change in technology.	Sub-optimal choice of policy instrument

Issue	Description	Market inefficiency risk
Licences allow extraction from multiple, linked water sources	Water licences for mining operations include water sourced from groundwater and tributaries (Appendix C.1). Uncontrolled switching of water sources in response to restrictions may continue to impact flows in the Athabasca River (Appendix A.3, Appendix D.6).	Undermining of cap on weekly water-use (in place under the WMF)

This concludes the discussion of economic instruments and the outline of the background material. As outlined in the following section, the background information was used to formulate the method for defining the policy and technical options and the setting (e.g. streamflows, demands) used to evaluate the selected options in terms of their ability to increase water-use efficiency and to respond to the water restriction policy of the WMF. The background themes related to the selection and design of economic instruments (price versus quantity instruments, technology implications), and the particular market issues related to industry along the lower Athabasca River, are revisited in the discussion of results (Section 5).

3. Methods

3.1 Selected options for assessment

Four main options were selected for analysis:

1. Water trade
2. Water pricing with refund
3. Water storage, and
4. Consolidated tailings technology and increased water recycling.

These options can be loosely grouped into policy or demand management options (water trade, and water pricing with refund scheme) and technical or supply management options (storage, and consolidated tailings and increased recycling). Two combined options were also analysed that involved combining the technical options (water storage and consolidated tailings) with economically-optimised allocations produced by the policy options (principally water trade, otherwise a pricing with refund scheme under certain set prices); that is, (i) water storage combined with economically-optimal allocations, and (ii) consolidated tailings and increased water recycling combined with economically-optimal allocations. The technical options were selected based on the available background information (Sections 2.2 and 2.4). Water trade was selected given that licence transfers and agreements to assign water are allowed under Alberta's *Water Act 1996*, and water trading has been utilised in several other regions of the world (e.g. Australia, several western regions of the United States, Chile). Selection of the water pricing with refund option was based on the successful use of refunded emission payments to manage industrial NO_x emissions in Sweden (Sterner and Höglund Isaksson, 2006), and a desire to investigate a relatively innovative method for managing water-use that may be more politically feasible than water pricing alone. The analysis was restricted to four key options, however other options may be applicable that were not covered in this assessment. In the case of new technology, further analysis was hampered by a lack of publicly-available information (e.g. capital and operation costs, water-efficiency benefits, production impacts etc.).

The assessment of the relative benefits and costs of the options requires the definition of a common baseline or base case, often defined as the most likely scenario without additional policy intervention. During the first season of implementation of the WMF (2007-08), the Oil Sands Mining Water Management Agreement was devised for sharing scarce water supplies (Appendix B.2). The alternative without an industry agreement would be water restrictions under the prior allocation (i.e., first-in-time first-in-right) system. Given there is no guarantee that water management agreements may be negotiated in the future, allocation of scarce water supplies using the prior allocation system was considered the most appropriate base case. The adopted base case assumes that mining operations do not have ready access to alternative water supplies or more water-efficient production methods (i.e., no access to storage, no use of consolidated tailings technology), and that restrictions would immediately result in reduced oil production in direct proportion to the degree of water restriction of each company.

3.2 General evaluation method and key assumptions

3.2.1 General evaluation approach

The cost effectiveness of the options was evaluated according to net present value (NPV, Section 2.5.2) relative to the base case, calculated over a standard zero to 20-year period using a discount rate of 8%. The selected discount rate of 8% is recommended for the analysis of regulatory interventions in Canada (Treasury Board of Canada Secretariat, 2007), based on an empirical analysis by Jenkins and Kuo (2007)[7]. All costs and benefits were estimated in Canadian dollars equivalent to 2007 price levels. The evaluation assumes perfect competition, no market failure, and a constant level of technology (with the exception of the analysis of technical options). In general, the method assumes a worst-case scenario of a short-run response by industry to water restrictions and linear production functions, that in turn favour the adoption of the various options.

While the focus of the quantitative assessment was solely on the relative cost-effectiveness of the options, qualitative assessment from a broad perspective was conducted to provide a practical, rounded evaluation. A brief response to each of the

[7] The social discount rate was determined based on a weighted average of (i) the rate of return on alternative, postponed investments by the domestic private-sector, (ii) the rate of interest (net of tax) on domestic savings by those in the domestic private-sector that forgo consumption, and (iii) the marginal cost of foreign capital inflows obtained from foreign savers (Jenkins and Kuo [2007], Treasury Board of Canada Secretariat [2007]).

qualitative criteria and related policy questions (Table 1-1) was provided relative to the base case.

3.2.2 Background flow and water availability

A weekly model of background flow and water availability (Appendix F) was used in the evaluation of options. The model spans 47-years of weekly flow (measured in terms of average weekly flow in m^3/s) based on the historic flow record (Section 2.1.3). The model allows the user to input a background flow scenario that proportionally adjusts streamflows uniformly across all weeks and years, then updates the flow and habitat thresholds of the WMF (Table 1-2) and recalculates water availability. The model provides an input time series of available water supply to the linear programming models of the base case and policy options used to determine water allocations for each mining operation (explained further in Section 3.2.5).

A decline in the historic average flow of 10% was selected for the background flow (Sections 2.1.4 and 2.1.5).

3.2.3 Licensed water demands and production

Water shortfalls are not anticipated to occur for the selected background flow scenario until water demands rise above 7.5 m^3/s (Section 2.1.5). This is well above the average rate of licensed water-use of 5.7 m^3/s (Table 2-1), and thrice the rate of actual water-use of 2.5 m^3/s recorded in 2006 (Section 2.1.5). Thus to evaluate the options for the case when there may be a significant risk of water restrictions required selection of a forecast water demand scenario.

In August 2008, Strategy West Inc. (Dunbar, 2008) prepared a summary of existing and proposed mining projects in the Athabasca Oil Sands. The scheduled start-up dates for new projects spanned up to 2018. This information was combined with licence information to depict production and licensed water-use that may occur by the year 2020 (approximately) for use in evaluating the options. Only those mines for which water licence information was available (Table 2-1) were included in the analysis[8]. Given the analysis is based on a forecast scenario using estimated rather than actual information, throughout the results presentation the mining operations are referred to generically (i.e., Firm 1, 2, 3 etc.) rather than directly by name.

The seniority of licences and assumed production and water demands for use in the option evaluation are listed in Table 3-1. The water demand and production estimates (Table 3-1) are likely to be fairly conservative given they represent a forecast of year 2020 conditions, with a number of projects yet to commence operation. Production was assumed to be equal to the forecast capacity of each mining project as listed by Dunbar (2008). Licensed water-use or the available water supply (whichever is lower) was assumed to be utilised to its full extent, with actual water-use equal to average licensed water-use when supply is not limiting. It was assumed that the currently-held water licences (Table 2-1) will continue to apply, with no additional licences granted. For staged water licences (CNRL Horizon project, Shell Jackpine project, and Imperial Kearl project), demands equal to the licensed water-use that corresponds to the forecast production stage by the year 2020 were assumed. Water demand was assumed to be equal across all weeks based on relatively constant water-use by utilities across seasons (Rogers, 2006). Finally, it was assumed that the mines source all water from the Athabasca River, with no switching of water sources occurring in response to restrictions.

[8] Three mining ventures for which production forecasts were available, the Albian Sands Pierre River project, the Synenco Northern Lights project, and the UTS Teck/Cominco Frontier and Equinox projects, were excluded from the analysis given that water licences direct from the Athabasca River were not registered for inclusion in Table 2-1 (this may be due to pending licence application or because direct water extraction is not required). These projects are expected to produce a total of approximately 425,000 bbl/d by 2018 (Dunbar, 2008).

- **Table 3-1 Water-use and seniority of licences, and estimated production and water demand by company (~year 2020) used in the analysis of options**

Mining operation (company and/or project)	Licences		Production and water demand assumptions for options analysis ~ year 2020		
	Licensed average water-use, m^3/s	Relative seniority rank (1=most senior)	Oil production, m^3/day	Oil production, bbl/day	Water demand, m^3/s
Total E&P Canada, Joslyn project	0.006	10	16 000	100 000	0.006
CNRL, Horizon project[A]	1.618	8	92 000	577 000	1.618
Syncrude	1.917	2			
	0.039	3	94 000	593 000	1.956
Shell, Jackpine project[A]	1.119	7	48 000	300 000	1.119
Suncor	0.978	1			
	0.919	4			
	0.095	9	70 000	441 000	1.992
Albian Sands, A.O.S. project	1.747	5	43 000	270 000	1.747
Petro-Canada, Fort Hills project	1.245	6	30 000	190 000	1.245
Imperial, Kearl project	2.537	11	48 000	300 000	2.537
Total	**12.22**		**441 000**	**2 771 000**	**12.22**

Notes: A. Table information takes into account that the licensed water-use of CNRL Horizon and Shell Jackpine for the year 2020 is expected to be lower than their current licensed water-use (Table 2-1).

3.2.4 Operating revenue and cost of water restriction

Oil prices have fluctuated dramatically in the latter half of 2008. For the base case it was assumed that oil production revenue equates to $70 (Canadian) per barrel, or

\$440 per m^3. Total operating costs of Syncrude were \$26.46 per barrel in 2006 (Syncrude Canada, 2007), or approximately \$166 per m^3 of oil production. Due to an absence of publicly available information, the cost of production at each mine was assumed to be equal to the 2006 total operating cost of Syncrude. Thus all mines were assumed to receive a net revenue of \$43.50 per barrel, or \$274 per m^3, of oil production.

The base case and policy options assume a short-run response to water shortfalls in the form of reduced production. It was assumed that all mines would operate at full capacity over the 20-year period of analysis (i.e., constant production at the levels listed in Table 3-1, from the year 2020 to 2040), such that lost production due to water restrictions is not regained by increased production at a later date. Production functions were assumed to be linear, with average water-use per unit of production equal to marginal water-use. Similarly, operation costs were assumed to vary with the level of production, with average operating costs equal to marginal operating costs i.e., reduced oil production is estimated to cost \$43.50 per barrel or \$274 per m^3. This estimate may represent a minimum bound of the cost of reduced production in the short run given some operating costs would not be variable over a short period, and operations are likely to demonstrate some degree of positive economies of scale. Conversely, the cost of water restrictions may be lowered for some operations given that there may be potential to increase water-use efficiency using methods separate to the selected options (e.g. Table 2-6), and mature operations may have short-term access to free water inventory within tailings ponds (Matte, 2004).

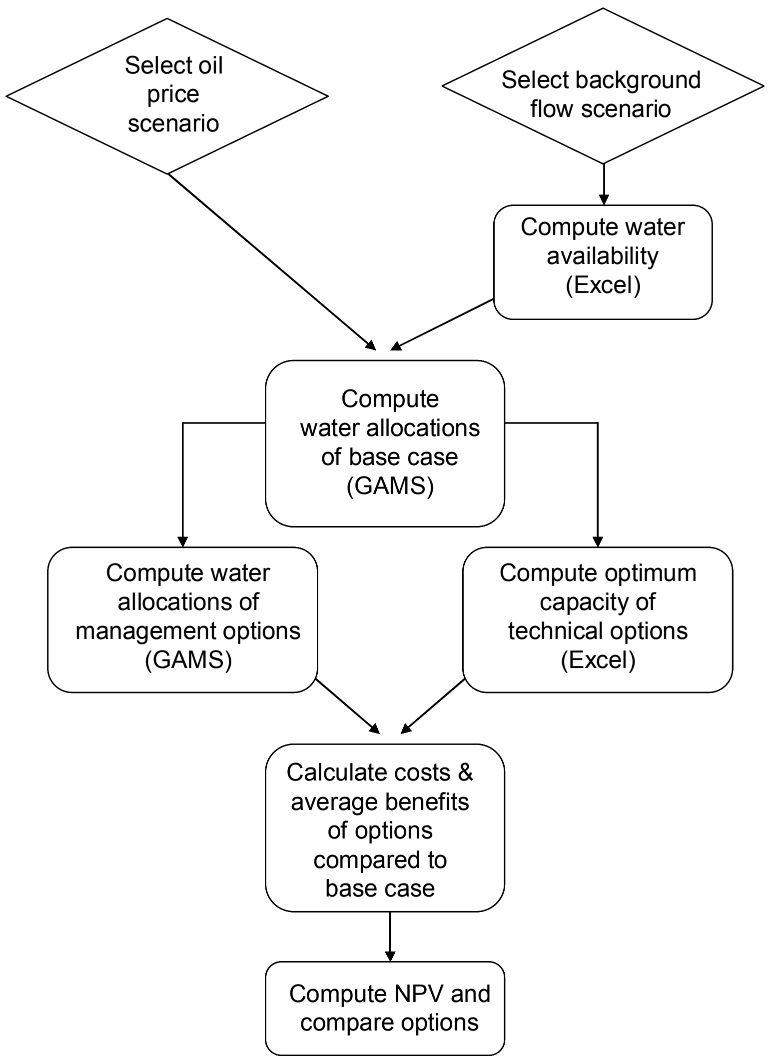
3.2.5 Model conceptualisation

The policy options and base case were evaluated using linear programming models solved using the General Algebraic Modeling System (GAMS) software package. The models provide a static optimisation of water allocation for each week of input streamflows (i.e., 47 years or 2444 weeks in total). A fixed level of technology was assumed, with no inducement of innovation.

A flow chart of the option evaluation process is shown in Figure 3-1.

The weekly time-step of the models was selected to reflect the weekly basis of the restriction policy of the WMF (Table 1-2). The models did not require consideration of spatial effects due to the minimal influence of tributaries (Appendix D.6) over the low-flow winter period when restrictions are most likely (Figure 2-5), and due to the time period for winter streamflows to pass by the licensees being less than the weekly model time-step (Appendix D.7).

Modelling of the policy options was complicated by the fact that some licensees hold several licences (Table 3-1), such that no unique production level and water-use efficiency were able to be assigned to each licence. This was handled by modelling water allocations for the policy options on a firm (or licensee) basis.



- **Figure 3-1 Flow chart of calculation of option net present value relative to base case**

3.2.6 Evaluation of cost effectiveness

The cost effectiveness of each option was evaluated based on its impact on total net revenue as a result of water allocation, and capital and operation and maintenance costs (where applicable), relative to the base case. Rather than relying on a particular sequence of weekly streamflows, the calculation of the impact on total net revenue utilised the results of the linear programming models to compare the *average* net revenue of the option and the base case. The average calculation is based on the average instantaneous net revenue over the 47-year sequence of weekly streamflows. The average instantaneous change in net revenue was then summed across all licensees and converted to an annual measure to describe the impact of the option on the total net revenue for each year of the 20-year analysis of NPV. The general formula used for the calculation of cost effectiveness and a description of each component is provided below.

$$NPV = \sum_{t=0}^{n} \frac{B_t - C_t}{(1+r)^t}$$

Where:

n	=	Time period for consideration of benefits and costs, equal to 20 years.
t	=	Time, in years.
B_t	=	Increase in annual net revenue arising from change in water allocation relative to the base case. Calculated using the change in average instantaneous net revenue ($ per second, average over the 47-year weekly modelling period) across all licensees then converted to an annual measure ($ per year, B). In the case of the policy options, benefits are equal across all years (i.e., $B_t = B$); in the case of the technology options, benefits are zero until the option is fully constructed, whereupon benefits are equal (B) across all remaining periods.
r	=	Discount rate, equal to 8%.
C_t	=	Cost of option across all licensees. Costs are registered in the time period in which they are incurred. Costs are relative to the base case and

include both capital and operating costs. Costs were only applied to the technology options, and were assumed to be zero ($C_t = 0$) for the policy options.

Capital and operation and maintenance costs of the technical options were based on interpolation of cost estimates developed by other studies, while administrative costs for all options (relative to the base case) were assumed to be insignificant. In the case of consolidated tailings and increased recycling, the selection of the optimum capacity and estimated cost-effectiveness assumed foresight that the water available in each year of the 20-year analysis of NPV would be equal to the average water availability (calculated over the 47-year sequence of weekly streamflows). Sequencing is important, however, in the case of storage (due to its stock nature) and so for this option the selection of capacity was based on the background flow pattern of the 47-year period of modelled flows. Initial calculations indicated that the optimum storage capacity would be similar or equal to the minimum capacity able to provide full protection against water restrictions. Following this, the evaluation of cost effectiveness of storage was based on the ability to avoid the average annual shortfalls of the base case scenario, combined with associated capital and operation and maintenance costs.

3.2.7 Sensitivity analysis

Sensitivity of the relative NPV of the options was analysed by calculating the impacts of a number of alternative background flow and oil price scenarios. Along with a base case of a 10% reduction in historic flows (Section 3.2.1), the sensitivity analysis considered the potential impact of climate change by selecting three background flow scenarios: a wet scenario equal to the historic flow record, a dry scenario equal to a 20% reduction in historic flows, and an extreme dry scenario of a 50% reduction in historic flows (Sections 2.1.4 and 2.1.5). In addition to a base price of $70 per barrel, to reflect the recent wide fluctuation in oil prices the sensitivity analysis considered a low oil price of $30 per barrel, and a high price of $110 per barrel.

3.3 Restrictions under prior allocation (base case)

Restrictions under prior allocation were modelled by assigning a prioritisation rank to each licence (Table 3-1) and allocating the available water in order of licence seniority. While this option does not require the use of economic optimisation techniques, an optimisation model was developed using GAMS (Appendix G.1) for ease in generating output of a similar format to the results of the policy options.

Prior allocation was modelled by assigning a progressive bonus to more senior licences[9], as outlined by the following equations:

Objective: Maximise $$\sum_{i=1}^{n}\left[(n+1-s_i)^M . \sum_{k=1}^{K} l_{i,k}.w_{i,k}\right]$$

Subject to:

Total water availability constraint $$\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k} \le W$$

Average diversion constraint for individual licences $$\sum_{k=1}^{K} l_{i,k}.w_{i,k} \le Q_{mean,i}$$

Instantaneous diversion constraint for each licensed works $$\sum_{i=1}^{n} l_{i,k}.w_{i,k} \le Q_{\max,k}$$

Where:

i = set of individual licences, where: $i = 1, \dots, n$.

k = set of individual licensed works to divert water directly from the Athabasca River, where: $k = 1, \dots, K$. Note that each licence, *i*, is accessed from a single point of diversion, *k*; while a point of diversion, *k*, may supply multiple licences, *i*.

s_i = seniority of individual licence, *i*, ranked from most senior (1) to least senior (n).

[9] Progressive bonus is represented by the term: $(n+1-s_i)^M$ in the objective function.

M	=	a positive real number, for use as the exponent of the seniority term $(n+1-s_i)$ within the objective function, that is sufficiently high in value to ensure that differences in the volume allocated to each water licence ($w_{i,k}$, constrained by $Q_{mean,i}$ and $Q_{\max,k}$) does not interfere with the prior allocation order. In this case, *M* was selected to equal 10.
$[l_{i,k}]_{n\times K}$	=	binary matrix, where $l_{i,k}$ is equal to one (1) when licence, *i*, corresponds to licensed works, *k*, otherwise zero (0). In this case, due to simplifying assumptions $[l_{i,k}]_{n\times K}$ is equal to the identity matrix.
$w_{i,k}$	=	water (m^3/s) allocated to individual licence, *i*, to be diverted at licensed works, *k*.
W	=	total water available for extraction (m^3/s) according to WMF conditions.
$Q_{mean,i}$	=	Average water diversion (m^3/s) allowed under individual licence, *i*, based on the average of the annual maximum licensed water-use (i.e., assumption of constant water extraction).
$Q_{\max,k}$	=	Maximum instantaneous water diversion (m^3/s) allowed using licensed works, *k*.

In practice, the model code was simplified by assuming that each licensed works, *k*, may be used exclusively by a single licence, *i* (allowing the matrix $[l_{i,k}]_{n\times K}$ to form the identity matrix)[10].

[10] This assumption required the instantaneous diversion limit of the diversion works shared by Albian Sands (A.O.S. project) and Shell (Jackpine project) to be split between the two operations, with 2.22 m^3/s of the total limit of 4.17 m^3/s provided to Albian Sands based on the conditions of their original, higher seniority licence.

3.4 Water trade

Water trade was modelled in GAMS (Appendix G.2) by allowing trade to allocate water to its most efficient use, such that oil production was maximised for a given water supply. Trade was modelled in the form of short-term (weekly) water transfers. Water-use efficiency was estimated for each mining operation based on the capacity of oil production per unit of licensed water-use (as forecast for the year 2020).

The model of water trade is described by the following equations:

Objective: Maximise

$$\sum_{j=1}^{m}\left[a\ .e_j \cdot \sum_{i=1}^{n}\sum_{k=1}^{\mathrm{K}} b_{i,j}.w_{i,k}\right]$$

Subject to:

Total water availability constraint

$$\sum_{i=1}^{n}\sum_{k=1}^{\mathrm{K}} l_{i,k}.w_{i,k} \le W$$

Average diversion constraint across licences

$$\sum_{i=1}^{n}\sum_{k=1}^{\mathrm{K}} l_{i,k}.w_{i,k} \le \sum_{i=1}^{n} Q_{mean,i}$$

Instantaneous diversion constraint across licensed works

$$\sum_{i=1}^{n}\sum_{k=1}^{\mathrm{K}} l_{i,k}.w_{i,k} \le \sum_{k=1}^{\mathrm{K}} Q_{\max,k}$$

Production constraint for individual mining operation

$$e_j \cdot \sum_{i=1}^{n}\sum_{k=1}^{\mathrm{K}} b_{i,j}.w_{i,k} \le Y_{\max,j}$$

Where:

a = net revenue i.e., revenue minus variable cost, per unit of oil production ($/m^3)

i = set of individual licences, where: $i = 1, \ldots, n$.

j = set of individual mining operations (company and/or project), where: $j = 1, \ldots, m$.

k = set of individual licensed works to divert water directly from the Athabasca River, where: $k = 1, \ldots, \mathrm{K}$. Note that each licence, i, is accessed from a single point of diversion, *k*; while a point of diversion, *k*, may supply multiple licences, *i*.

$[b_{i,j}]_{n\times m}$ = binary upper triangular matrix, where $b_{i,j}$ is equal to one (1) when licence, *i*, corresponds to mining operation, *j*, otherwise zero (0).

$[l_{i,k}]_{n\times \mathrm{K}}$ = binary matrix, where $l_{i,k}$ is equal to one (1) when licence, *i*, corresponds to licensed works, *k*, otherwise zero (0). In this case, due to simplifying assumptions $[l_{i,k}]_{n\times \mathrm{K}}$ is equal to the identity matrix.

e_j = water-use efficiency (m^3 of oil produced per m^3 of water use) of individual mining operation, *j*, estimated based on a fixed rate equal to

$$\frac{\sum_{i=1}^{n} b_{i,j} . Q_{mean,i}}{Y_{\max,j}}$$

$w_{i,k}$ = water (m^3/s) allocated to individual licence, *i*, to be diverted at licensed works, *k*.

W = total water available for extraction (m^3/s) according to WMF conditions.

$Q_{mean,i}$ = Average water diversion (m^3/s) allowed under individual licence, *i*, based on the average of the annual maximum licensed water-use (i.e., assumption of constant water extraction).

$Q_{\max,k}$ = Maximum instantaneous water diversion (m^3/s) allowed using licensed works, *k*.

$Y_{\max,j}$ = Oil production capacity (m^3/s) for individual mining operation, *j*.

The model calculates the allocation of water per mining operation ($\sum_{i=1}^{n}\sum_{k=1}^{\mathrm{K}} b_{i,j}.w_{i,k}$) that provides an economically optimal solution. The units of each parameter and variable are provided in the above definition for clarity, however the equations as specified are dimensionless. In practice, the model code was simplified by assuming that each licensed works, *k*, may be used exclusively by a single licence, *i* (allowing the matrix $[l_{i,k}]_{n\times \mathrm{K}}$ to form the identity matrix), and the maximum instantaneous water diversion was specified for each mining operation rather than licensed works (i.e., $Q_{\max,j}$ rather than $Q_{\max,k}$).

The model assumes that licences are divisible to suit the water requirements of each mining operation. The model also assumes that there are no physical barriers to water trade (e.g. diversion infrastructure is able to accommodate trade), as represented by the aggregate form of the instantaneous diversion constraint, and there are no other forms of transaction costs. In contrast to the prior allocation model (Section 3.3), the model for water trade does not explicitly recognise the priority ranking of each licence. For a given water supply (W), if it is assumed that licensed volumes are perfectly divisible then licence priority would have no effect on the allocation outcome as modelled.

3.5 Pricing with refund

The pricing with refund scheme was modelled similar to the refunded emission payment scheme described by Sterner and Höglund Isaksson (2006). In this scheme, producers are subject to volumetric charges for water obtained from the Athabasca River, with the collected payments then returned to industry on the basis of market share of oil production.

The pricing with refund model, modelled using GAMS (Appendix G.3), is described by the following equations:

Objective:

Maximise

$$\sum_{j=1}^{m}\left[a\,.e_j.\left(\sum_{i=1}^{n}\sum_{k=1}^{\mathrm{K}} b_{i,j}.w_{i,k}\right) - p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{\mathrm{K}} b_{i,j}.w_{i,k}\right) + p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{\mathrm{K}} l_{i,k}.w_{i,k}\right).\frac{q_j}{\left(\sum_{j=1}^{m} q_j\right)}\right]$$

Subject to:

Total water availability constraint
$$\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k} \leq W$$

Average diversion constraint across licences
$$\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k} \leq \sum_{i=1}^{n} Q_{mean,i}$$

Instantaneous diversion constraint across licensed works
$$\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k} \leq \sum_{k=1}^{K} Q_{\max,k}$$

Production constraint for individual mining operation
$$e_j \cdot \sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k} \leq Y_{\max,j}$$

Where:

a = net revenue i.e., revenue minus variable cost, per unit of oil production ($/m[3]).

i = set of individual licences, where: $i = 1, \dots , n$.

j = set of mining operations (company and/or project), where: $j = 1, \dots , m$.

k = set of individual licensed works to divert water directly from the Athabasca River, where: $k = 1, \dots , K$. Note that each licence, *i*, is accessed from a single point of diversion, *k*; while a point of diversion, *k*, may supply multiple licences, *i*.

$[b_{i,j}]_{n\times m}$ = binary upper triangular matrix, where $b_{i,j}$ is equal to one (1) when licence, *i*, corresponds to mining operation, *j*, otherwise zero (0).

$[l_{i,k}]_{n\times K}$ = binary matrix, where $l_{i,k}$ is equal to one (1) when licence, *i*, corresponds to licensed works, *k*, otherwise zero (0). In this case, due to simplifying assumptions $[l_{i,k}]_{n\times K}$ is equal to the identity matrix.

e_j = water-use efficiency (m^3 of oil produced per m^3 of water use) of individual mining operation, j, estimated based on a fixed rate equal to

$$\frac{\sum_{i=1}^{n} b_{i,j}.Q_{mean,i}}{Y_{\max,j}}$$

p_w = price charged per m^3 of water allocated for diversion.

$w_{i,k}$ = water (m^3/s) allocated to individual licence, i, to be diverted at licensed works, k.

q_j = production of oil (m^3/s) by individual mining operation, j, equal to

$$e_j.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)$$

W = total water available for extraction (m^3/s) according to WMF conditions.

$Q_{mean,i}$ = Average water diversion (m^3/s) allowed under individual licence, i, based on the average of the annual maximum licensed water-use (i.e., assumption of constant water extraction).

$Q_{\max,k}$ = Maximum instantaneous water diversion (m^3/s) allowed using licensed works, k.

$Y_{\max,j}$ = Oil production capacity (m^3/s) for individual mining operation, j.

The objective function consists of three parts, explained as follows:

Net revenue associated with oil production: $$a\ .e_j.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)$$

Charge for water use: $$p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)$$

Refund of water charges in proportion to quantity of oil production:

$$p_w \cdot \left(\sum_{i=1}^{n} \sum_{k=1}^{K} l_{i,k} . w_{i,k} \right) \cdot \frac{q_j}{\left(\sum_{j=1}^{m} q_j \right)}$$

Due to the circular reference to total production within the objective function, a starting total production level is provided within the model (based on optimum efficiency for the given volume of water available), with total production then recalculated for each successive price loop (explained further below).

Similar to the model of water trade, the model calculates the allocation of water per mining operation ($\sum_{i=1}^{n} \sum_{k=1}^{K} b_{i,j} . w_{i,k}$) that provides an economically optimal solution. As before, the model code was simplified by assuming that each licensed works, *k*, may be used exclusively for a single licence, *i* (allowing the matrix $[l_{i,k}]_{n \times K}$ to form the identity matrix).

Above a certain price for water (p_w), the quantity of water demand will fall as less efficient producers are presented with a net charge for water that is above the net revenue received for oil production. During times of restriction, the pricing with refund model first allocates water among companies based on efficiency. The model then calculates the threshold water price (i.e., $p_{w,\max}$) able to be set before the price becomes so high that the next least-efficient company (among those provided with a water allocation) ceases to produce. Using GAMS, a loop statement was inserted to calculate this threshold price (to the nearest \$10 per m^3) while checking that the quantity of production remains at the optimal level based on the available water supply. Given the incremental nature of the price estimation, the model will estimate a price that is either equal to or just below the true upper bound.

If water trade is not allowed to occur simultaneously with a pricing with refund scheme, then the model as depicted ignores licence seniority and assumes equal priority of licences. The model does apply, however, to the prior allocation system if water trading is allowed and water licences are perfectly divisible[11].

Under perfect competition, output inducement beyond an efficient level is expected by a refunding scheme (Gersbach and Requate, 2004). Given the model used in this analysis is static and optimises water allocation across all mining operations (while also incorporating production constraints and fixed water-use efficiencies), the model does not allow individual mining operations the ability to influence their share of output above an economically efficient level, thus output inducement effects are ignored.

3.6 Storage

Storage is a supply-side option that may be used to avoid the restrictions of the WMF. As outlined in the background material (Section 2.2) there are a number of different forms of storage that might be applicable. Although the technical feasibility of this option (e.g. geotechnical feasibility, operation when the river is covered by ice, operation during extremely cold conditions) requires further investigation, the established practice of reuse of free water obtained from tailings ponds provides a general indication that the option has technical potential.

To estimate the anticipated water restrictions associated with different storage capacities, a basic model depicting the water balance of an off-stream storage was created in Excel. For a given water demand (Table 3-1) and storage capacity, the model calculates the volume of water held in storage on a weekly basis over the 47-year period of background flows. Drawdown of storage was allowed to avoid restrictions, and refilling (up to capacity) occurred whenever excess supply was available (according to the extraction limits of the WMF [Table 1-2]) [12]. Storage drawn down to a zero volume while the

[11] The model output of the price with refund scheme includes the calculation of the market price of water. This calculation is not presented in the results given its residual nature when the price of water is near the threshold (the market price equals zero when the true threshold is a multiple of $10).

[12] In practice, the refilling of a storage combined with the average licensed extraction would be constrained by the licensed maximum instantaneous rate of extraction. This constraint was not modelled, although is not expected to significantly affect the results (due to the licensed maximum instantaneous rate being 50% greater than the average licensed rate of extraction [Table 2-1]).

extraction limits of the WMF were binding indicated that restrictions would occur for the given storage capacity. The model did not consider precipitation or evaporation (i.e., net precipitation was assumed to equal zero), nor local catchment effects associated with surface run-off and groundwater.

The cost estimates for the Athabasca off-stream storage option (Table 2-5) prepared by Golder Associates (2004) for an 80 GL storage capacity were manipulated to estimate the costs of storages of varying capacity. It was assumed that the cost of roads and bridges, pump, inlet and outlet, and planning and design do not vary with scale and so were considered fixed ($18.5 M). For the costs of the dam and spillway, these were assumed to involve a fixed cost component, arbitrarily set at 50% of the original cost estimate for the 80 GL dam ($9.25 M), plus a variable component depending on the size of the dam. The premise of this method is that the peak water requirement of the storage options (providing full supply to four companies) that affects the sizing of the pump, inlet and outlet is likely to be similar regardless of the background flow scenario, while the size of the dam and spillway would determine the overall supply reliability and so would be variable above an assumed minimum cost. Operation and maintenance costs were assumed to be independent of storage size.

Based on the cost estimation method described, a preliminary analysis of costs versus reliability of supply found that the optimum capacity of a shared off-stream storage would be approximately equal to the minimum capacity able to provide full protection against water restrictions. Following this, for all background flow and oil price scenarios considered, the storage capacity was designed to provide complete protection against restrictions using the water balance model[13]. This method assumes perfect foresight of the background flow pattern over the 47-year period of modelled flows.

For the alternative case of on-site storage, Golder Associates (2004) provide an approximate indication of the costs of on-site storage for surface-mining operations of $2 to $3 per m^3, or $60 M for a 20 GL storage. The size requirements and costs of individual storages were considered in this study, however the storage capacities in some

[13] In the case of low oil prices of $30 per barrel, the optimal capacity of storage might be less than the assumed capacity of full protection against water restrictions. This possibility was not investigated for the sensitivity analysis (i.e., the maximum capacity was assumed).

cases far exceeded the design volume of the original cost estimate (20 GL), and so detailed results for the on-site storages option were omitted for accuracy reasons[14].

The costs presented in Golder Associates (2004) were assumed to be based on 2003 prices. An inflation rate between 2003 and 2007 of 42% was assumed, based on interpolation of the non-residential building construction price index for industrial structures in Edmonton, Alberta (Statistics Canada). Design and construction of the shared storage was assumed to require three years.

3.7 Consolidated tailings and increased water recycling

The feasibility and optimum capacity of consolidated tailings and increased water recycling were evaluated separately for each surface-mining operation. It was assumed that consolidated tailings could be implemented on either a continuous basis, leading to a constant reduction in water extractions from the Athabasca River, or on a partial or intermittent basis, leading to a reduction in the demand for water from the Athabasca River only during times of water restriction. The results of both sub-options are presented. For each surface-mining operation, the optimal degree of implementation (to the nearest 10%) was evaluated by comparison of NPV.

As discussed in Section 2.4, for the consolidated tailings option to have a maximum impact on reducing the demand for water sourced from the Athabasca River, the option is likely to require the recycling of water discharged from utilities for reuse by utilities, with reverse osmosis likely to be the cheapest method of water treatment to enable reuse. Due to the water losses of reverse osmosis treatment, the reduction in water extraction from the Athabasca River is not equal to the volume of water recovered from tailings following consolidation. Figure 3-2 presents a conceptual flow diagram for the calculation of the reduction in water extractions from the Athabasca River as a result of consolidated tailings implementation. In this study, a water recovery rate for reverse osmosis treatment (i.e., volume of output divided by volume of input) of 80% is assumed, based on an estimated range of between 60 to 85% recovery for brackish water treatment (Mickley [1995] in RosTek Associates et al. [2003]). Assuming that the treatment

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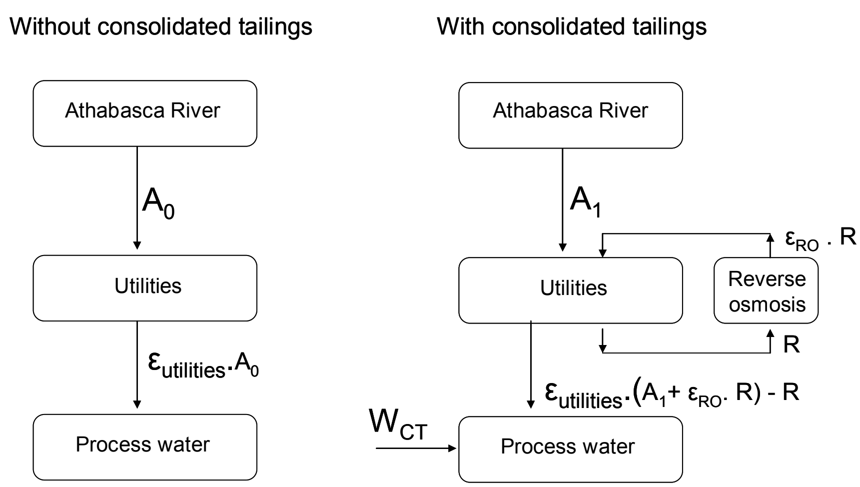
[14] As expected, it was found that the total cost of multiple, on-site storages was greater than the cost of a single, shared storage.

facility is operational 85% of the time (RosTek Associates et al., 2003), the volumetric efficiency of water treatment of reverse osmosis is estimated to be 68%. Based on these assumptions and the equations listed in Figure 3-2, the proportional volume of water recovered from tailings and the corresponding maximum reduction in use of river water associated with this option (for partial implementation calculated for each 10% increment) is provided in Table 3-2.



Utilities water requirement: $A_0 = A_1 + \varepsilon_{RO}.R$

Process water requirement: $\varepsilon_{utilities}.A_0 = \varepsilon_{utilities}.(A_1 + \varepsilon_{RO}.R) - R + W_{CT}$

Solutions: $A_0 - A_1 = \varepsilon_{RO}.R$ & $R = W_{CT}$

Symbols:

A_0 , A_1	Athabasca River extractions (0 – without consolidated tailings [CT] 1 – with CT)
$\varepsilon_{utilities}$	Water efficiency of utilities ($\varepsilon_{utilities} < 1$)
ε_{RO}	Water treatment efficiency of reverse osmosis ($\varepsilon_{RO} < 1$)
R	Volume of water treated by reverse osmosis
W_{CT}	Volume of water recovered by CT

▪ **Figure 3-2 Conceptual diagram of selected water balance components of a typical surface-mining operation from river to processing stage, comparison of with and without use of consolidated tailings and increased recycling option**

- **Table 3-2 Estimated water recovered from tailings, and reduction in water extractions from the Athabasca River, as a result of varying degrees of implementation of consolidated tailings and increased recycling option**

% Implementation of Consolidated Tailings	% Volume of water recovered from tailings	% Reduction in water extracted from the Athabasca River
10	7	4
20	15	7
30	22	11
40	29	14
50	37	18
60	44	21
70	51	25
80	59	28
90	66	32
100	73	36

For each 10% level of implementation, the cost information for reverse osmosis presented in Table 2-10 (based on RosTek Associates et al. [2003]) was linearly interpolated to estimate the capital and operation costs of the option for each surface-mining operation. Corresponding estimates of the duration of design and construction (Table 2-10) were also applied. To convert the cost information into a form applicable for this study, the following assumptions were made:

- U.S. dollar exchange rate for Canadian dollars of 0.6793, based on the exchange rate as of 30th June 1999.
- Construction price inflation between 1999 and 2007 of 65%, based on interpolation of the non-residential building construction price index for industrial structures in Edmonton, Alberta (Statistics Canada).
- Operation cost inflation between 1999 and 2007 of 40%, based on equal weighting of construction price inflation and average hourly earnings for hourly-paid employees in the oil and gas sector (Statistics Canada).

Treatment of tailings with gypsum was assumed to be at a rate of 1000 grams per m^3 (Section 2.4). Given a cost of gypsum of $107 per ton[15], the cost of treatment was estimated to be $0.11 per m^3 of tailings.

A number of costs and benefits were not considered in the analysis. These include the potential costs associated with reuse of water recovered from treated tailings, that may have a relatively high salt (e.g. Ca^{2+}) content, for use in the bitumen extraction process; use of the recovered water without further treatment may reduce the recovery efficiency of bitumen extraction (Chalaturnyk et al., 2004)[16] and impose other costs related to scaling of process equipment and corrosion of susceptible materials (MacKinnon et al., 2000). Another cost not considered was the cost of discharge of the brine by-product of reverse osmosis treatment. Benefits not considered include the reduced costs of containment of mature fine tailings, which may be in the order of the on-site storage estimates mentioned in Section 2.2. There would also be indirect economic benefits associated with reduced environmental risk of tailings disposal that were not estimated as part of the quantitative assessment.

[15] Pers. comm., Tracey Dawson, Heemskirk Canada, 17/10/2008.

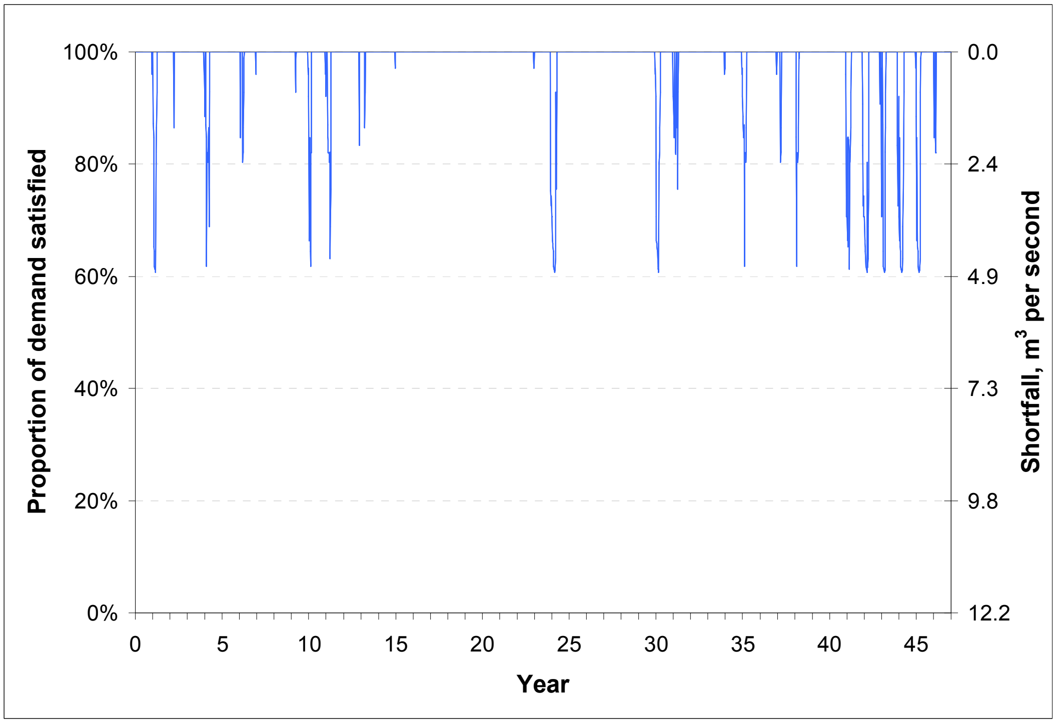
[16] Note, however, that at one site it was found that the clay content within the reuse water attracted calcium ions such that conventional treatment was not required (Davies and Scott, 2006).

4. Results

4.1 Water availability

Water availability for the base case scenario of background flow (-10% historic) and demand (~2020) is displayed in Figure 4-1 over the 47-year modelling period[17]. As shown, supply shortfalls occur in a similar pattern to the charts of water availability displayed previously (Section 2.1.5, Figure 2-6), although the shortfalls are lower in magnitude due to a lower modelled demand (12.22 m^3/s rather than 14.0 m^3/s). Peak shortfalls were approximately 40% of demand. Summary statistics of the frequency, duration and magnitude of shortfalls are provided in Appendix I.1.1. Sensitivity analysis of background flows (Appendix I.1.1) indicates that a 10% change in flow would result in a 14 to 17% change in magnitude of the peak shortfall.

[17] Note that the Year axis (Figure 4-1) is based on modelled information, and does not directly correspond to a particular year of record. Water demand was static and was based on an estimate of licensed water-use for the year 2020 (approximately). Background flows over the 47-year period were based on modelling and adjustment of streamflow data collected from 1958 to 2004 (refer to Sections 2.1.3 to 2.1.5).



- **Figure 4-1 Proportion of demand that is able to be supplied (%) and the rate of shortfall (m^3 per second), base case scenario of background flows**

4.2 Value of water use by mining operation

The estimated water-use efficiency and value of water use for each mining operation are provided in Table 4-1. These estimates are dependent on water use and production assumptions (Section 3.2.3), and so firms are referred to generically by number (in order of estimated water-use efficiency) rather than by name. Water-use efficiency was measured by forecast capacity of oil production and licensed water-use for water taken directly from the Athabasca River, with no consideration of whether water is also used for oil refinement (in addition to bitumen extraction) or is supplemented by other sources. The calculation of the shadow value per unit (m^3) of water use was based on the efficiency of water use (m^3 of oil production per unit of water use) multiplied by the net revenue of oil production ($ per m^3 of oil produced). Both measures are sensitive to oil price (Appendix I.2.1).

The results (Table 4-1) indicate the heterogeneity across companies that is important for the estimation of benefits of the policy options. Water-use efficiency was found to vary between 0.03 to 4.55 units of water per unit of oil production. Based on the method adopted, the age of design of operations does not appear to be an explanatory factor of water-use efficiency. Of the licensees, Firm 1 is clearly the most water-efficient based on the efficiency measure selected. This firm uses SAGD technology and is the only in situ (rather than surface) mining operation among those considered.

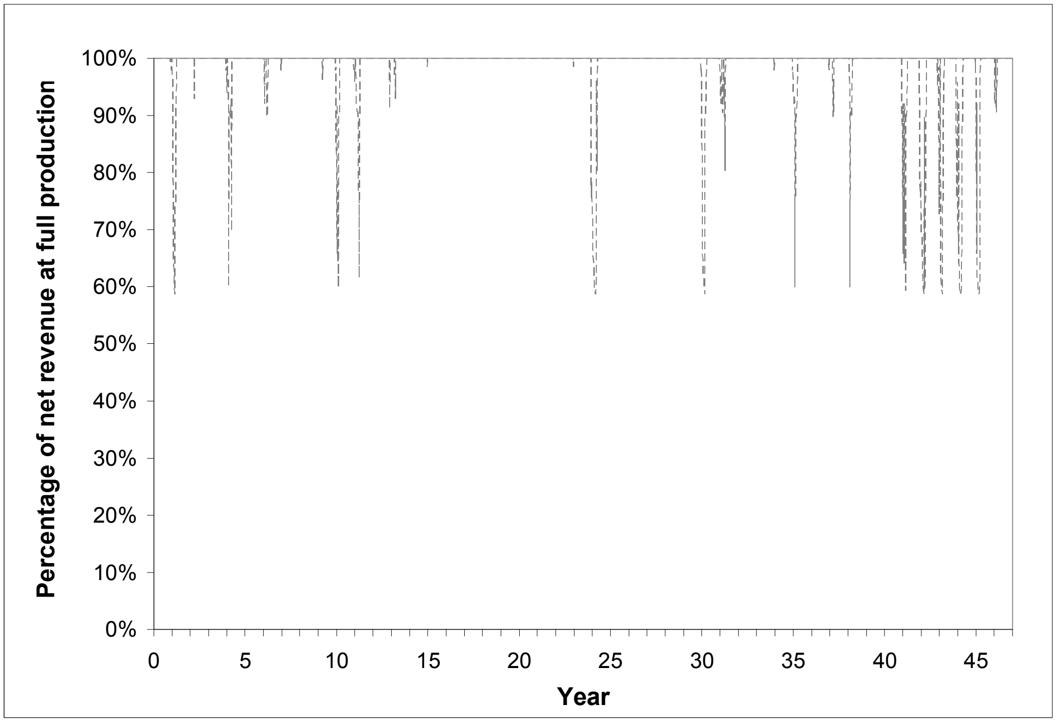
- **Table 4-1 Estimated water-use efficiency (m^3 oil produced per m^3 water) and shadow value of water use (\$ per m^3 and \$ per bbl), by mining operation**

Mining operation	Water-use efficiency, m^3 oil produced per m^3 of water extracted from the Athabasca River	Shadow value of water use	
		\$ per m^3 of water use	\$ per barrel of water use
Firm 1	32.84	8 998	1 431
Firm 2	0.66	180	29
Firm 3	0.56	153	24
Firm 4	0.49	135	21
Firm 5	0.41	112	18
Firm 6	0.28	78	12
Firm 7	0.28	77	12
Firm 8	0.22	60	9
Median	**0.45**	**123**	**20**

4.3 Restrictions under prior allocation (base case)

Results for the base case scenario of restrictions under prior allocation are provided in Figure 4-2 and Table 4-2. As previously outlined (Section 3.2.4), this scenario assumes a short-run response to water restrictions of reduced production. A comparison of the revenue and water-use efficiency of each mining operation, displayed in Figure 4-3, shows that the two most efficient operations are among those exposed to water restrictions due to the lower seniority of their licences. The net revenue associated with the base case is sensitive to the level of background streamflows (Table 4-2, Appendix I.1.3).

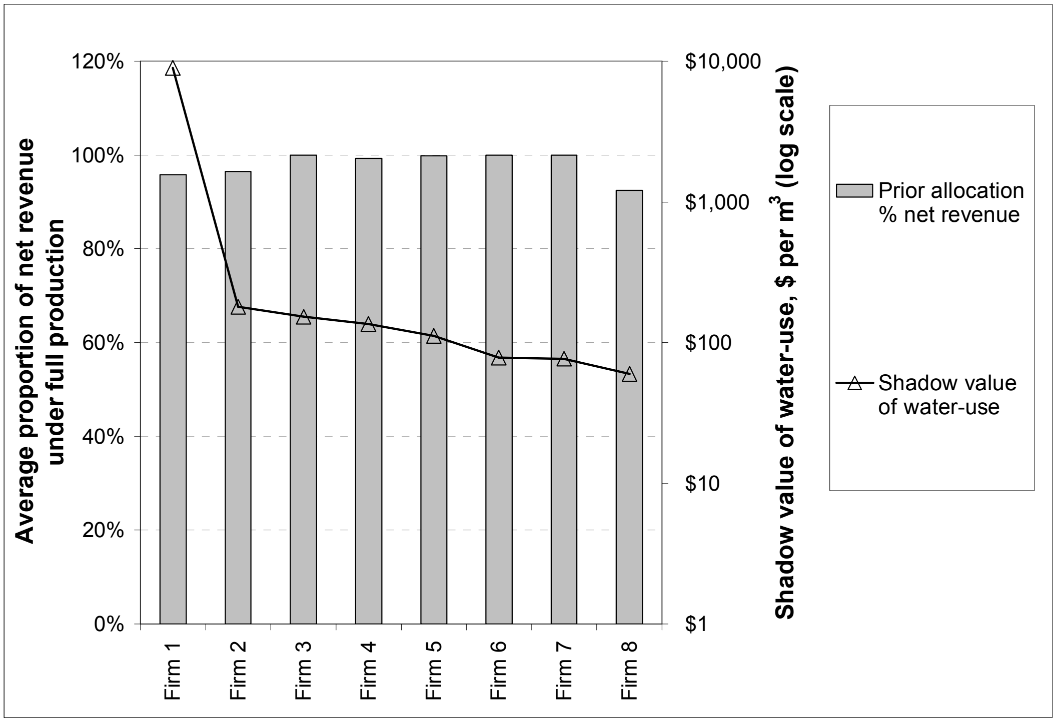
Given the base case is the benchmark from which to measure the value of the options, this scenario has no measure of cost effectiveness and a comparative qualitative analysis is not applicable (by definition). Qualitative comments can, however, be made regarding the general merits and risks associated with the base case. As prior allocation favours senior licensees and forms the basis of water allocations in Alberta, its continuation is likely to be politically favourable. In contrast, the base case may not reflect public sentiments given it does not offer incentives to increase water-use efficiency beyond the limits of the WMF, nor to improve the water-use technology of each operation following its design and licence approval, and the water use of senior licensees (who manage the largest tailings facilities) would continue virtually unabated. Prior allocation effectively forms a barrier to the entry of new mining operations (raising both efficiency and equity issues), who are more exposed to water restrictions and their potential cost. Licensees may be particularly exposed to changes in their water supply risk associated with changes in background streamflows e.g., due to climate change (Section 2.1.5), as mitigation would be limited to on-site measures. In addition, water management agreements (e.g., Appendix B.2) may become increasingly difficult to negotiate as demands increase; accordingly there may be strong incentives for junior licensees to lobby for relaxation of restrictions if faced with unexpected shortfalls in supply.



- **Figure 4-2 Proportion (%) of net revenue under full production associated with short run response to water shortfalls (i.e., reduced production), restrictions under prior allocation (base case)**

- **Table 4-2 Results summary of cost effectiveness of restrictions under prior allocation (base case) and sensitivity to background flows**

Item	Background flow scenario			
	Wet	Base Case	Dry	Extreme Dry
Average net revenue as a proportion of that under full production, %	98.97	**98.20**	97.06	91.53
Annual value of cost savings (related to water allocation), $ M	-	**-**	-	-
Present value of cost savings, $ M	-	**-**	-	-
Present value of costs (capital, operation and maintenance), $ M	-	**-**	-	-
Net present value, $ M	-	**-**	-	-



- **Figure 4-3 Average net revenue as a proportion of that under full production by mining operation associated with a short run response to water shortfalls (i.e., reduced production). Water allocations under base case of prior allocation. Shadow value of water use is shown on the secondary axis (log scale).**

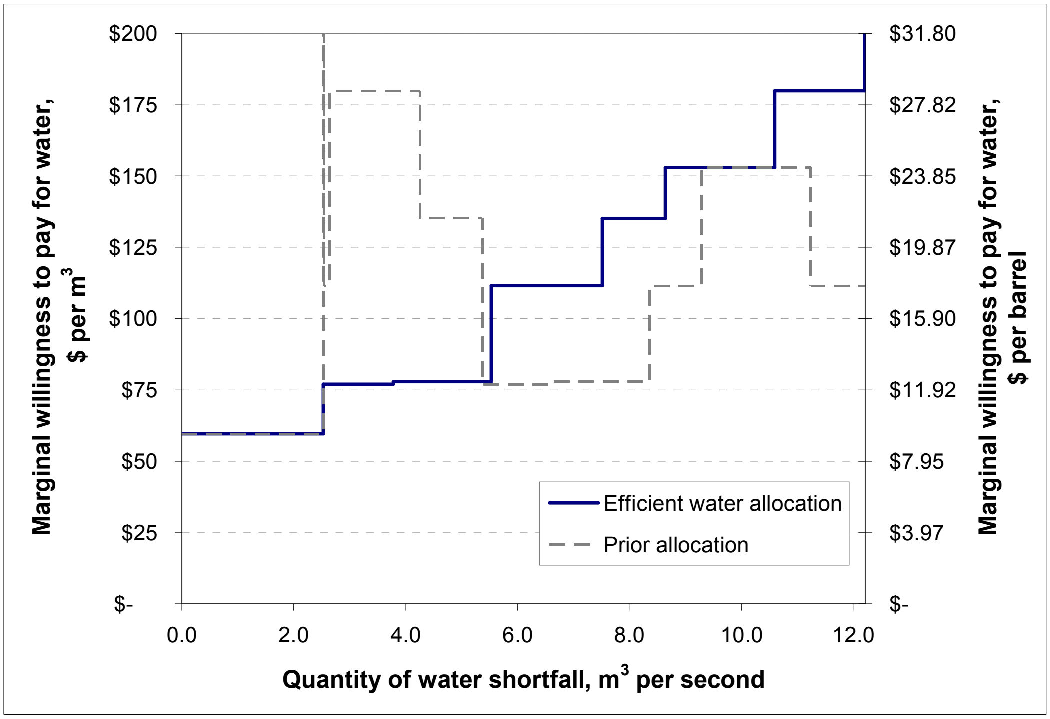
4.4 Water trade

The willingness to pay for water over the full range of possible shortfalls is displayed in Table 4-3 and Figure 4-4. The degree of willingness to pay is highly sensitive to the price of oil (Appendix I.2.1, Figure 4-5). Figure 4-4 and Figure 4-5 appear as step functions due to the assumption that production functions are linear for each mining operation, and that there is a unique, fixed water-use efficiency for each operation (Table 4-1). The information on willingness to pay combined with the modelled shortfalls (Figure 4-1) produces a time series of the market price for water (Figure 4-6).

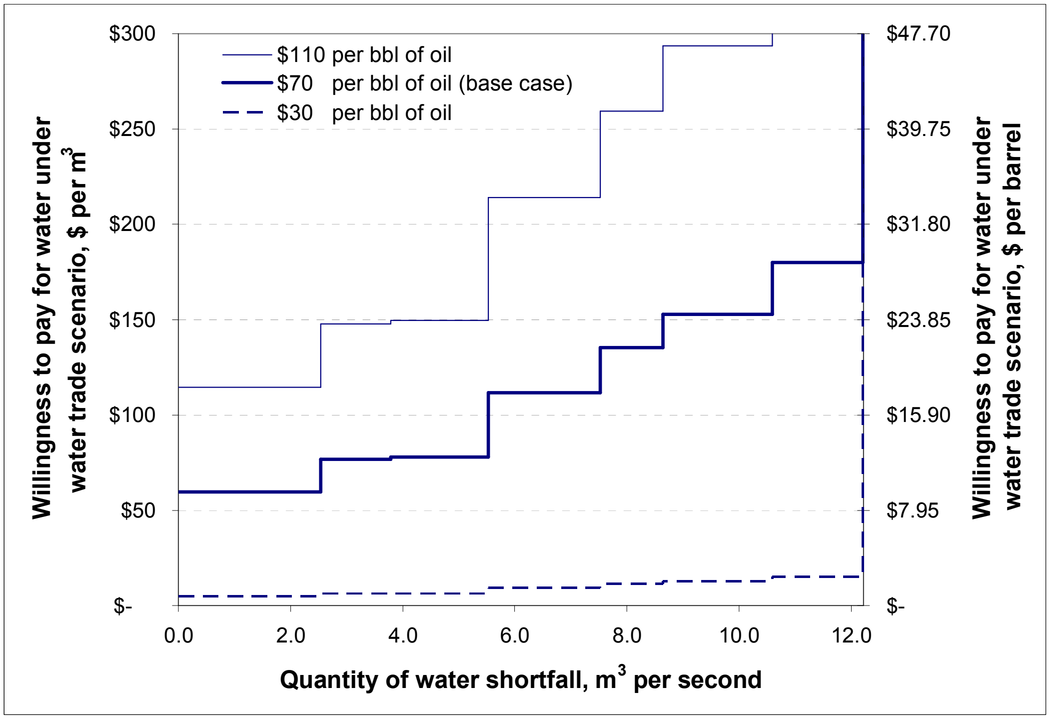
The reduction in the cost of shortfalls under water trade compared to the base case is illustrated by a time series of net revenue as a proportion of that under full production (Figure 4-7). The estimated average reduction in costs of water trade, equivalent to 0.61% of net revenue under full production (or $270 M per year), has a NPV over 20-years of approximately $2 900 M (Table 4-4, Table 4-5). A comparison of average production revenue and water-use efficiency of each mining operation, shown in Figure 4-8, illustrates that the most efficient operations are not subject to water shortfalls and reduced production due to the ability to trade with their less-efficient counterparts. Qualitative comments are provided in Table 4-6.

- **Table 4-3 Willingness to pay for water, dollars per m^3 and dollars per barrel, with water trade and a short run response to water shortfalls (i.e., reduced production), for each level of severity of water shortfall**

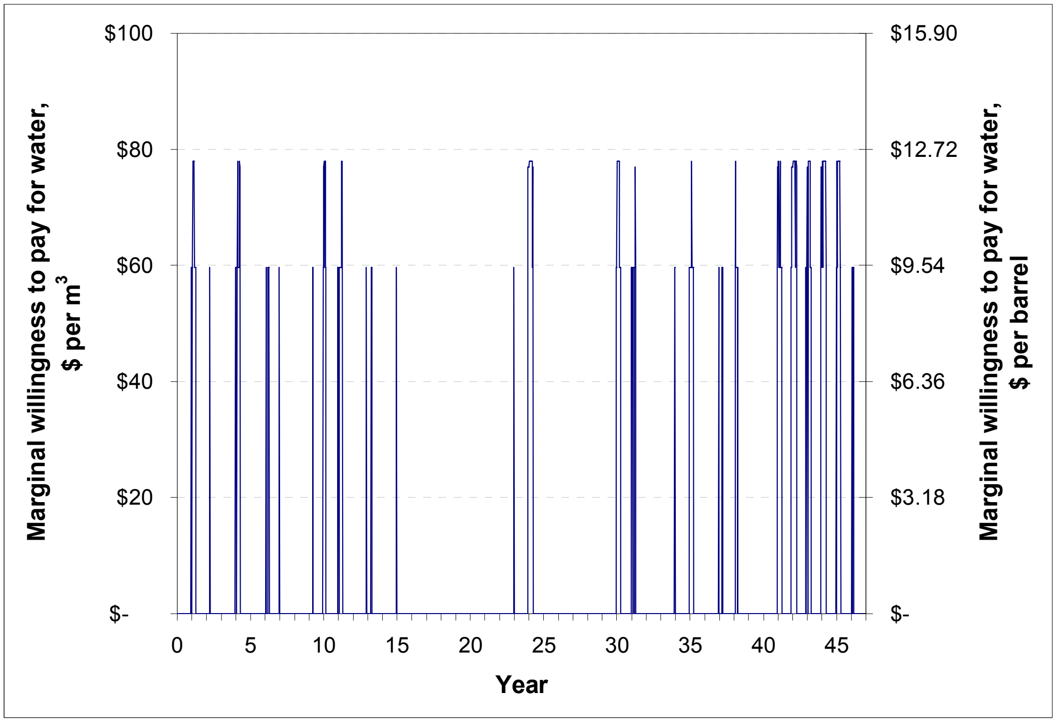
Water shortfall, m^3/s	Willingness to pay for water		Mining operation with equivalent shadow value of water use
	$/$m^3$	$/bbl (water)	
0.00 to 2.54	60	9	Firm 8
2.54 to 3.78	77	12	Firm 7
3.78 to 5.53	78	12	Firm 6
5.53 to 7.52	112	18	Firm 5
7.52 to 8.64	135	21	Firm 4
8.64 to 10.60	153	24	Firm 3
10.60 to 12.21	180	29	Firm 2
12.21 to 12.22	8 998	1 431	Firm 1



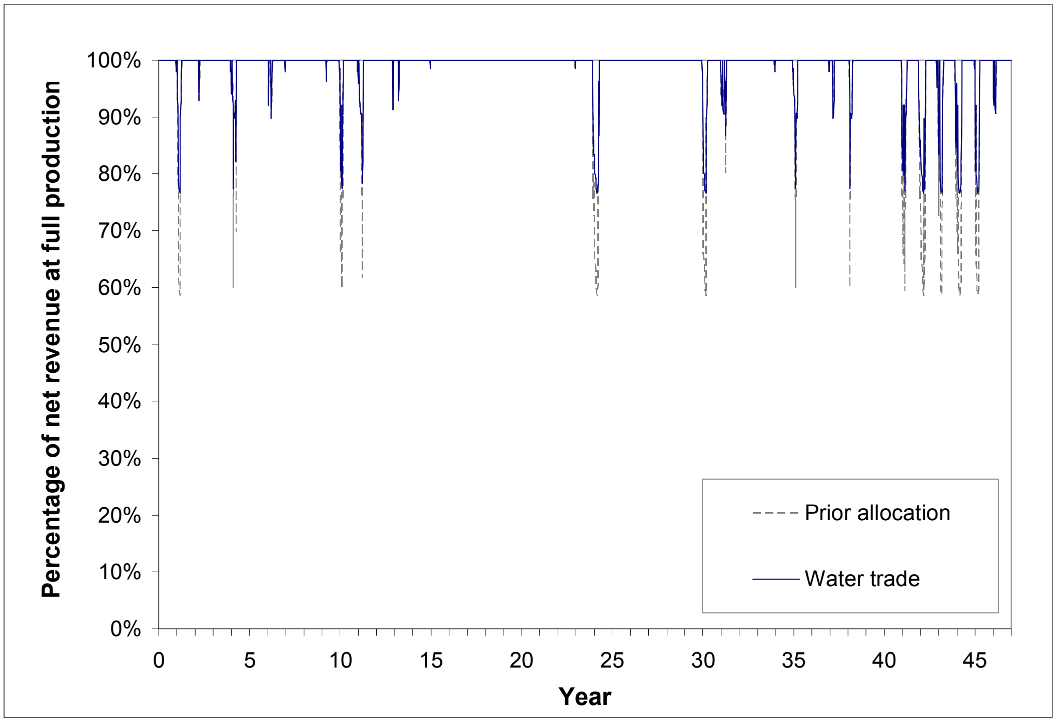
- **Figure 4-4 Marginal willingness to pay for water, dollars per m^3 and dollars per barrel, efficient allocation under water trade versus prior allocation. Assumes a short run response to water shortfalls (i.e., reduced production).**



- **Figure 4-5 Willingness to pay for water and sensitivity to oil price, dollars per m^3 and dollars per barrel, with water trade and a short run response to water shortfalls (i.e., reduced production)**



▪ **Figure 4-6 Marginal willingness to pay for water, dollars per m^3 and dollars per barrel, with water trade and a short run response to water shortfalls (i.e., reduced production)**



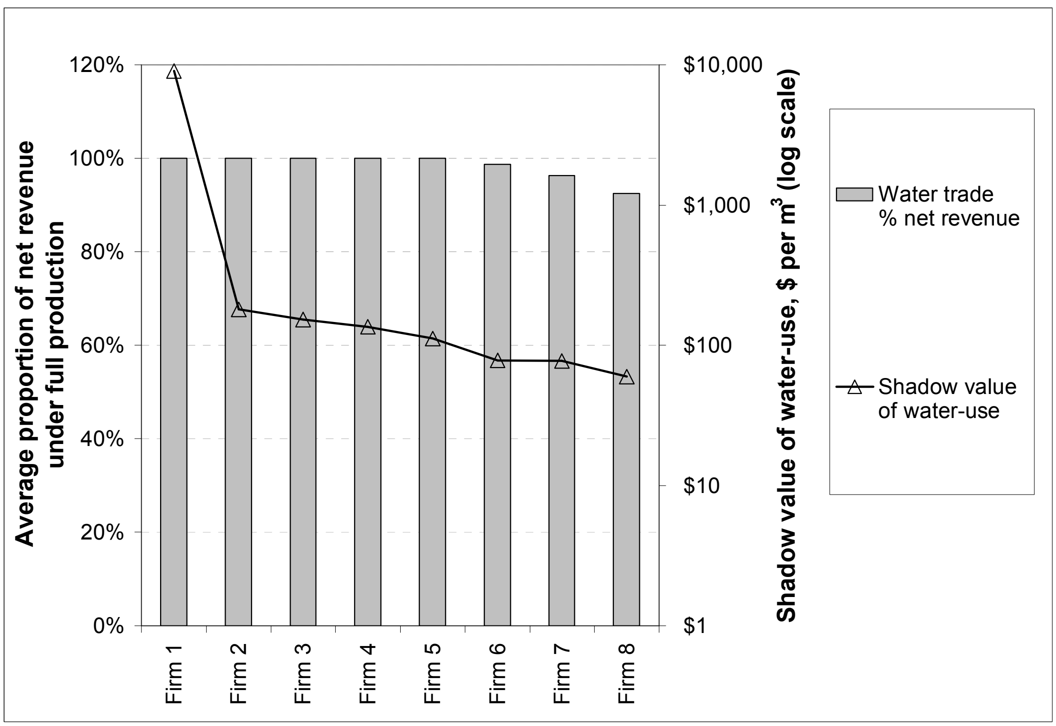
- **Figure 4-7 Proportion (%) of net revenue under full production associated with a short run response to water shortfalls (i.e., reduced production), water trade compared to prior allocation (base case)**

- **Table 4-4 Results summary of cost effectiveness of water trade and sensitivity to background flows**

Item	**Background flow scenario**			
	Wet	**Base Case**	**Dry**	**Extreme Dry**
Average net revenue as a proportion of that under full production, %	99.30	**98.81**	98.15	94.08
Annual value of cost savings (related to water allocation), $ M	140	**270**	480	1 120
Present value of cost savings, $ M	1 500	**2 900**	5 200	12 100
Net present value, $ M	1 500	**2 900**	5 200	12 100

- **Table 4-5 Results summary of cost effectiveness of water trade and sensitivity to oil price**

Item	Oil price scenario ($ per bbl)		
	$30	**$70, Base Case**	**$110**
Average net revenue as a proportion of that under full production, %	98.81	**98.81**	98.81
Annual value of cost savings (related to water allocation), $ M	20	**270**	510
Present value of cost savings, $ M	200	**2 900**	5 500
Net present value, $ M	200	**2 900**	5 500



- **Figure 4-8 Average net revenue as a proportion of that under full production by mining operation associated with a short run response to water shortfalls (i.e., reduced production) and water allocations under water trade. Shadow value of water use is shown on the secondary axis (log scale).**

- **Table 4-6 Qualitative evaluation of water trade**

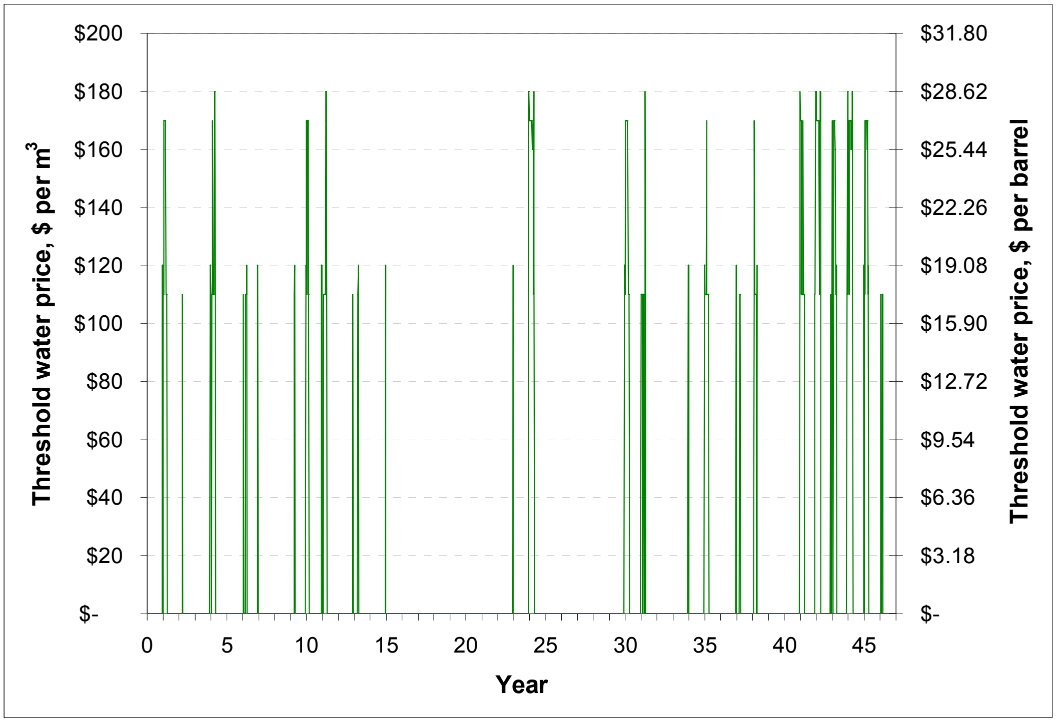
Criteria		Evaluation comments
A	Dependability	Assuming adequate monitoring and enforcement, and full use of licences, the direct environmental outcome of water trade would be no different to the base case (as market cap would be the water-use limits of the WMF). Water trade provides equal incentives for each operation to increase water-use efficiency in response to water scarcity (rather than the uneven incentives of the base case), and so may lead to reduced indirect impacts of water stored in tailings ponds.
B	Finance	Administration costs expected to be similar to the base case. Revenues could be collected from an administrative charge on water transfers.
C	Economic efficiency	Has potential to provide a more efficient response to restrictions under the WMF. Although a lack of competition may inhibit trading activity, any trades that occur would be expected to result in a more efficient situation than the base case.
D	Informational requirements	Information on instantaneous water-use is required to ensure legitimate transfers. Advance notice of a forecast water scarcity may allow on-site options to be investigated by affected mines, reducing the need for water trade.
E	Monitoring and enforcement	Cost of monitoring instantaneous water-use. In addition, higher levels of monitoring and enforcement of all impacts to Athabasca River flow would be required, given water restrictions and market value of water may encourage uncontrolled switches in water sources.
F	Permanence	Cost-effectiveness may change with background streamflows, level of demand, and oil price, however the *relative* cost-effectiveness is comparatively stable.
G	Flexibility	Option is highly adaptable to changes in economic circumstances assuming these are reflected by changes in the market price of water; there is potential for volatile prices due to fluctuations in oil price and streamflow (excessive prices could be avoided with the use of a hybrid quantity-price limit scheme, e.g. Roberts and Spence [1976]), and for other issues associated with imperfect competition.
H	Equity	Distribution of benefits depends on the initial water allocation that is then able to be traded. Firms with secure licences obtained at no cost, and current opportunities to reduce water-use at relatively low cost, would gain from the option. Water trade has the potential to allow new entrants, and provides equal incentives for improved technology.
I	Dynamic incentives	With water scarcity (i.e., an active market for water trade), option encourages adoption of new technology.
J	Continuing incentives	Similar to the base case, water trade creates environmental benefits of a fixed amount under the WMF.

Criteria		Evaluation comments
K	Political considerations	General public distrust of markets for natural resources (particularly water), although option may gain popularity if public informed of water-use efficiency implications (particularly related to tailings ponds). Likely to be accepted by mining operators given potential for financial gain, perhaps with greater support than for the base case. Option may have implications for other basins in Alberta.

4.5 Pricing with refund

As modelled, the pricing with refund scheme produces the same revenue (Figure 4-12) and NPV (Table 4-7 and Table 4-8) as water trade. The difference between the two policy options relates to the price of water: the threshold price able to be charged while maintaining water use, when collected charges are refunded, is much higher than the marginal willingness to pay for water without refund (Figure 4-9 compared to Figure 4-6). This in turn implies that the incentives for the adoption of new technologies that increase water-use efficiency would be greater under a pricing with refund scheme. Charts of the price comparison between water trade and a pricing with refund scheme are displayed in Appendix H. The prices associated with both options were found to be highly dependent on the oil price (appendices I.2.1 and I.2.2), however the proportional difference in prices remained similar (i.e., threshold prices under the price with refund system remained significantly higher than the marginal willingness to pay under water trade). A comparison of water-use efficiency and revenue of each mining operation under the pricing with refund scheme, shown in Figure 4-13, illustrates that the most efficient operations are rewarded by receiving refunds in excess of their water charges, while their less-efficient counterparts are penalised. Qualitative comments are listed in Table 4-9.

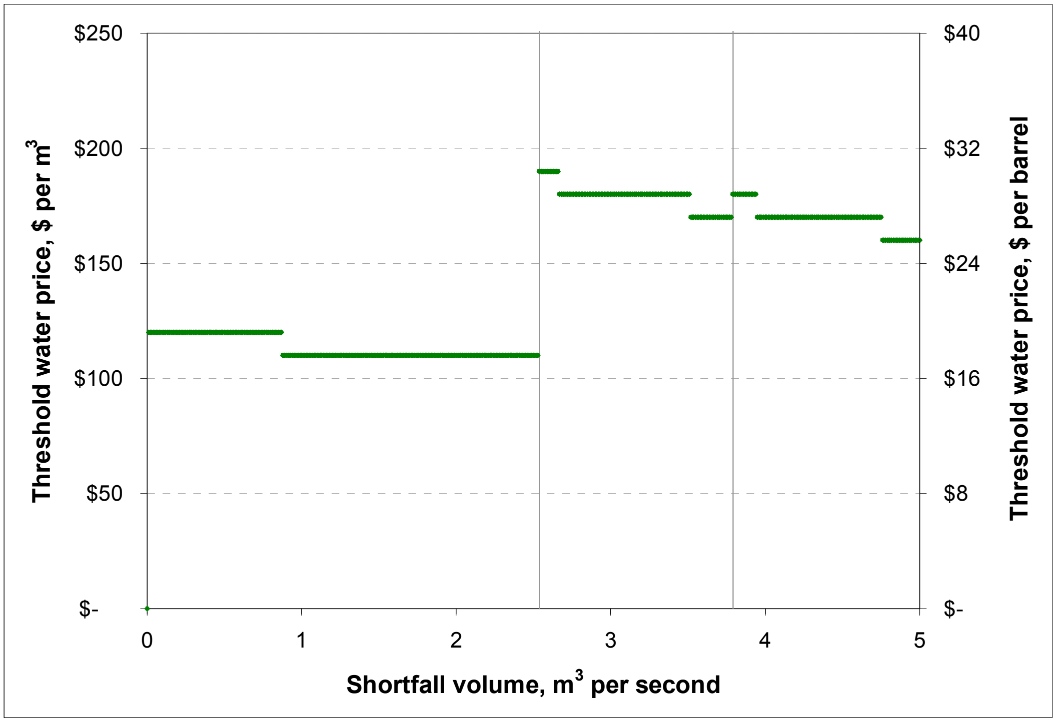
Interpretation of the threshold prices shown in Figure 4-9 may not be obvious. At each point in time, if water prices are set higher than the threshold depicted then water use would be expected to be below the available supply and the pricing with refund scheme would be independently effective at enforcing the restrictions of the WMF. If the water price is set lower than the threshold, then the pricing with refund scheme may not induce water-use within the limits of the WMF, and a back-stop policy - such as a cap and water trade (or prior allocation) - would be required. The lower the set water price below the threshold modelled price, the higher the marginal price of water that may be revealed in a concurrent water market.



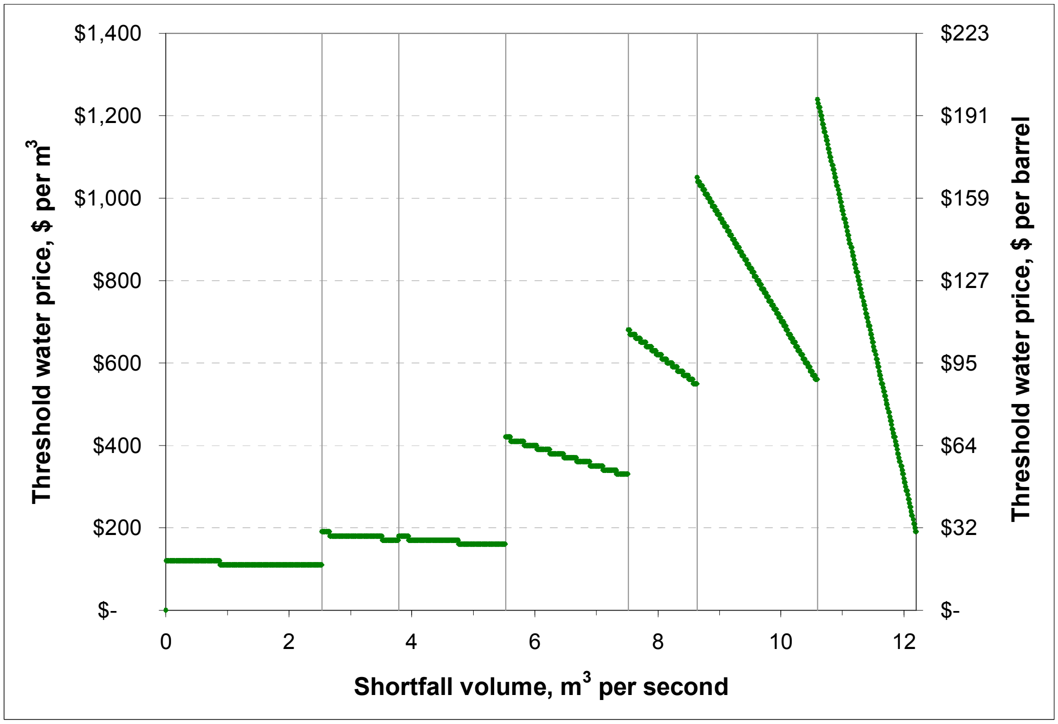
- **Figure 4-9 Threshold price for water ($ per m^3 and $ per barrel) able to be sustained under the pricing with refund scheme while maximising use of available water supplies. Short run response to water shortfalls (i.e., reduced production).**

Threshold prices able to be charged by a price with refund scheme over the range of supply shortfalls are depicted in Figure 4-10 (for the range of shortfalls modelled) and Figure 4-11 (over the full range of possible shortfalls). For each degree of supply shortfall or volume of restriction, the charts depict the upper limit on the price that may be charged for water before the price becomes so high that the demand for water is reduced. The vertical lines in Figure 4-10 and Figure 4-11 represent the volumes at which the next least-efficient mining operation no longer demands water due to excessive cost. Between these vertical lines, the number of mining operations extracting water remains the same. Prices in both figures appear in the form of a discontinuous step function (particularly in Figure 4-10) due to the model providing output prices as a multiple of $10 (see Section 3.5 for further explanation), and the input supply shortfall being in increments of 0.01 m^3/s.

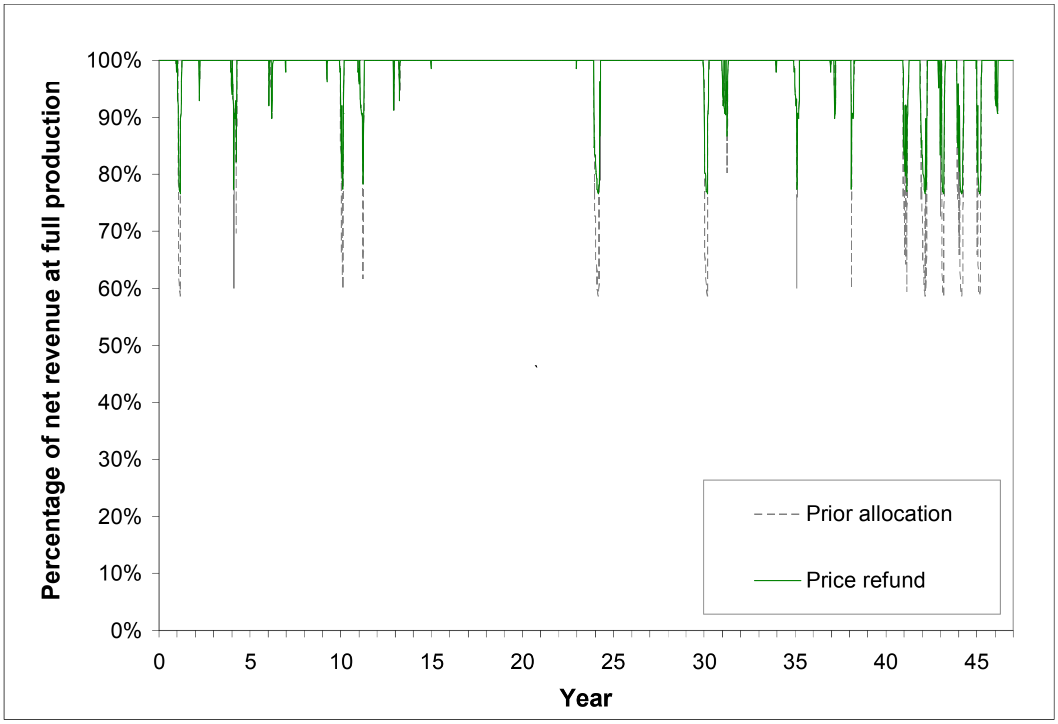
Over each interval in which the number of mines extracting water remains steady (i.e., between the vertical lines shown in Figure 4-10 and Figure 4-11), the threshold price declines with increasing water scarcity because the least-efficient mining operation receives a lower volume of water, and due to its lower water-use efficiency it receives a disproportionally lower share of the refund; in turn this means it is less able to withstand the effects of the scheme on its profitability. As the volume of water declines further, so that one less mine is extracting water, the threshold price jumps as the least-efficient firm naturally has a higher water-use efficiency than that of the previous order and so can withstand a higher price threshold. The slope of the threshold price, when the number of mines extracting water is constant, becomes steeper with a decreasing number of operating mines; this increasingly negative gradient is associated with the increased efficiency of the remaining mines and the greater proportional impact that a decrease by one unit of water has on the total water supply as water becomes more scarce. The characteristics of a negative slope of prices with increasing water scarcity, greater price instability with water scarcity, and price instability with oil price, have important implications for the ability of this option to manage shortfalls in the case of linear production. The relationship between the threshold price level, oil price, firm water-use efficiency and water availability is depicted mathematically in Appendix H.2.



- **Figure 4-10 Threshold price for water ($ per m^3 and $ per barrel) able to be sustained in the short run under the pricing with refund scheme while maximising the use of available water supplies, 0 to 5 m^3/s range of water shortfalls.**



- **Figure 4-11 Threshold price for water (\$ per m^3 and \$ per barrel) able to be sustained in the short run under the pricing with refund scheme while maximising the use of available water supplies, shown for each possible level of water shortfall.**



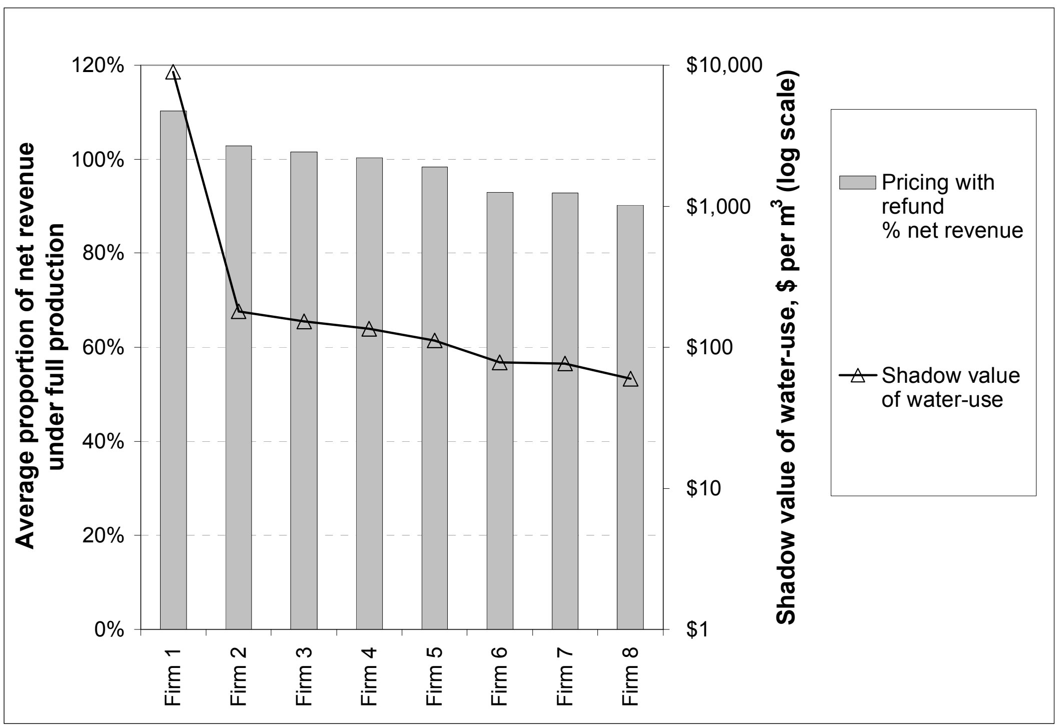
- **Figure 4-12 Proportion (%) of net revenue under full production associated with a short run response to water shortfalls (i.e., reduced production), pricing with refund scheme compared to prior allocation (base case)**

- **Table 4-7 Results summary of cost effectiveness of pricing with refund scheme and sensitivity to background flows**

Item	**Background flow scenario**			
	Wet	**Base Case**	**Dry**	**Extreme Dry**
Average net revenue as a proportion of that under full production, %	99.30	**98.81**	98.15	94.08
Annual value of cost savings (related to water allocation), $ M	140	**270**	480	1 120
Present value of cost savings, $ M	1 500	**2 900**	5 200	12 100
Net present value, $ M	1 500	**2 900**	5 200	12 100

- **Table 4-8 Results summary of cost effectiveness of pricing with refund scheme and sensitivity to oil price**

Item	Oil price scenario ($ per bbl)		
	$30	**$70, Base Case**	**$110**
Average net revenue as a proportion of that under full production, %	98.81	**98.81**	98.81
Annual value of cost savings (related to water allocation), $ M	20	**270**	510
Present value of cost savings, $ M	200	**2 900**	5 500
Net present value, $ M	200	**2 900**	5 500



- **Figure 4-13 Average net revenue as a proportion of that under full production by mining operation associated with a short run response to water shortfalls (i.e., reduced production). Water allocations under pricing with refund option. Shadow value of water use is shown on the secondary axis (log scale).**

- **Table 4-9 Qualitative evaluation of water pricing with refund**

Criteria		Evaluation comments
A	Dependability	Used independently, this option may not be practical for ensuring water use is within the limits of the WMF (i.e., cap and water trade or restriction under prior allocation may also be required). The option maximises the incentive to increase water-use efficiency across all mining operations, and so has important indirect impacts related to the potential reduced size of tailings facilities.
B	Finance	Administration costs would be relatively high. A proportion of the revenues from the scheme could be used to fund administration, with refund of the remainder to mining operations on the basis of output.
C	Economic efficiency	Option has the potential to provide a more efficient response to the WMF, although may induce higher-than-optimal levels of output.
D	Informational requirements	Significant issue of asymmetric information for setting appropriate water prices: requires information on operation costs and revenues.
E	Monitoring and enforcement	Cost of monitoring of water use and corresponding production. Production would be difficult to accurately monitor on a short-term (weekly) basis. Monitoring costs may be minimal in comparison to benefits of option. The prospect of obtaining valuable refunds may encourage uncontrolled switches in water sources while continuing to impact flow in the River; the monitoring and enforcement of all impacts would be required (similar to water trade).
F	Permanence	Set water prices need to be responsive to market conditions. Threshold price able to be charged for water use depends on oil price (refer Appendix I.2.2) and may be difficult to set in practice.
G	Flexibility	Requires price to fluctuate with changes in oil price (Appendix I.2.2) and level of shortfall. The set water price is susceptible to market factors e.g., the threshold water price becomes more volatile when water scarcity increases.
H	Equity	Mines that have a relatively high water-use efficiency will gain from this option, while the least water-efficient mines will face costs. Equity of option partly depends on initial water allocation and ability to trade. Option may be able to accommodate new entrants when combined with water trade.
I	Dynamic incentives	Continuously rewards licensees for seeking improvements in water-use efficiency relative to other mining operations. Provides strong incentives for endogenous innovation, implementation of exogenous technology (if available), and suppression of spillover effects associated with indistinct technology gains by individual firms.
J	Continuing incentives	Depends on magnitude of water price. May encourage increases in water-use efficiency and reduced water-use beyond that required by WMF restrictions.

Criteria		Evaluation comments
K	Political considerations	Likely to be acceptable to the public if they are informed of the details and the scheme's limited application to the Oil Sands. Likely to divide direct stakeholders, given option will create winners and losers. The option would be more politically feasible than assigning a water price without a commensurate refund scheme, although its preference relative to the base case is unclear.

4.6 Storage

Storage was modelled in the form of a single off-stream storage that, once constructed, completely avoids water restrictions across all mining operations over the model period. The share of stored water required by each firm, listed in Table 4-10, is dependent on whether the option is combined with efficient water allocations (e.g. storage with water trade). For example, in the case of Firm 6, this firm holds relatively senior licences yet its water use is relatively inefficient, and so if a water market were established it may be more profitable for Firm 6 to sell its high-priority licences and opt for licences with a lower priority, then contribute to the costs of storage construction in the near-term to safeguard its production revenues. Production would only be at risk while the storage is being constructed. Depending on cost-sharing arrangements, the combined option (e.g. storage with water trade) may alter the equity implications of the option.

- **Table 4-10 Share of storage, by mining operation**

Mining operation (company and/or project)	Storage capacity requirement to avoid shortfalls, % volume of shared storage	
	Storage only	Storage combined with optimal allocations
Firm 1	0.1	0
Firm 2	22.0	0
Firm 3	0	0
Firm 4	3.5	0
Firm 5	1.6	0
Firm 6	0	8.8
Firm 7	0	18.3
Firm 8	72.9	72.9

The required storage size to avoid supply shortfalls is estimated to be 45 GL[18], providing a NPV of approximately \$ 6 300 M (Table 4-11). As modelled, the combined option would provide the additional benefit of efficient water allocations during the three years required to construct the storage. Storage was found to have considerable benefit compared to other options as it enables supply shortfalls to be completely avoided rather than redistributed, as in the case of the policy options. The cost of storage was estimated to be relatively stable over the various capacities designed to account for each background flow condition (Table 4-11), while its cost effectiveness varies depending on how often the storage would be accessed (Table 4-11) and the oil price (Table 4-12). Qualitative comments on the option are listed in Table 4-13.

[18] As a comparison, St. Mary Reservoir in southern Alberta has a capacity of 370 GL (Alberta Environment).

- **Table 4-11 Cost effectiveness of shared off-stream storage and sensitivity to background flows**

Item	Background flow scenario			
	Wet	**Base Case**	**Dry**	**Ext. Dry**
Average shortfall volume (prior to storage), m^3/s	0.16	**0.27**	0.39	1.07
Storage capacity required to avoid shortfalls, GL	32	**45**	57	103
Capital cost of shared storage, $ M	42	**45**	48	58
Operation cost of shared storage, $ M per year	1.6	**1.6**	1.6	1.6
Present value of costs, $ M	52	**54**	57	66
Present value of costs, $ per m^3 of average annual shortfall avoided	10.50	**6.30**	4.60	2.0
Annualised cost, $ per m^3 of average annual shortfall avoided	1.00	**0.60**	0.40	0.20
Annual value of reduced shortfalls, $ M				
Storage only (once constructed)	450	**790**	1 290	3 730
Incremental effect of storage following optimal water allocation (e.g. via water trade)	310	**530**	810	2 610
Storage combined with optimal water allocation (total)	450	**790**	1 290	3 730
Net present value, $ M				
Storage only	3 600	**6 300**	10 300	29 900
Incremental effect of storage following optimal water allocation (e.g. via water trade)	2 400	**4 200**	6 500	20 900
Storage combined with optimal water allocation (total)	4 000	**7 100**	11 700	33 000

- **Table 4-12 Cost effectiveness of shared off-stream storage and sensitivity to oil price**

Item	Oil price scenario ($ per barrel)		
	$ 30	**$70, Base Case**	**$110**
Average shortfall volume (prior to storage), m^3/s		**0.27**	
Storage capacity required to avoid shortfalls, GL		**45**	
Capital cost of shared storage, $ M		**45**	
Operation cost of shared storage, $ M per year		**1.6**	
Present value of costs, $ M		**54**	
Present value of costs, $ per m^3 of average annual shortfall avoided		**6.30**	
Annualised cost, $ per m^3 of average annual shortfall avoided		**0.60**	
Annual value of reduced shortfalls, $ M			
Storage only (once constructed)	60	**790**	1 520
Incremental effect of storage following optimal water allocation (e.g. via water trade)	40	**530**	1 010
Storage combined with optimal water allocation (total)	60	**790**	1 520
Net present value, $ M			
Storage only	500	**6 300**	12 100
Incremental effect of storage following optimal water allocation (e.g. via water trade)	300	**4 200**	8 000
Storage combined with optimal water allocation (total)	520	**7 100**	13 600

- **Table 4-13 Qualitative evaluation of shared off-stream storage**

Criteria		Evaluation comments
A	Dependability	If constructed to ensure no future restrictions, the option is effective in managing net water extractions to within the limits of the WMF. However, the option provides minimal incentives to increase water-use efficiency. Construction and operation of storage may have secondary environmental impacts (e.g. flow variability, instream habitat, loss of habitat within storage footprint).
B	Finance	No significant costs to government above the base case if the cost of storage is shared among industry. (Due to largely private benefits there is unlikely to be a compelling case for government contributions.)
C	Economic efficiency	Provides the most efficient outcome based on the analysis of cost effectiveness, although does not encourage improvements in water-use efficiency. A shared off-stream storage is expected to be less expensive than individual on-site storages.
D	Informational requirements	Information required on environmental and other impacts of dam construction prior to approval. Selection of design capacity requires adequate forecasts of background flows and demand. Technical feasibility issues need to be resolved.
E	Monitoring & enforcement	Monitoring required to ensure storage releases are the same volume as extractions during times when demands would otherwise be restricted.
F	Permanence	Storage design capacity depends on accuracy of forecast streamflows and water demands (e.g. start-up of new operations would be dependent on oil prices).
G	Flexibility	Modifications to storage size may be difficult once constructed. Relatively low operation costs. With sufficient water demands the storage would continue to be used in response to binding flow conditions under the WMF.
H	Equity	Depends on cost-sharing arrangements and whether the option is implemented in conjunction with trade. Potential for cost sharing between relatively junior licensees if no trade, or between the least water-efficient licensees with water trade (licensees may also gain from the sale of senior water licences in this case). Without water trade, the option is unlikely to provide direct benefits to senior licensees.
I	Dynamic incentives	Once storage is constructed, option does not encourage innovation or adoption of water-efficient technology (unless unforeseen increases in demand create competition for limited storage space). Similar to base case.
J	Continuing incentives	Similar to the base case, option creates environmental benefits of a fixed amount under the WMF, although excess storage could be used at relatively low cost to reduce the ecological impacts of water extractions at other times (e.g. red, non-binding flow conditions of the WMF).

Criteria		Evaluation comments
K	Political considerations	Storage approval and construction is typically politically divisive. Storage would be favoured by direct stakeholders (mining operations) due to its relatively low cost. May not be acceptable to the public due to environmental impacts, and inability of option to encourage increased water-use efficiency.

4.7 Consolidated tailings and increased water recycling

The potential water savings of consolidated tailings and increased water recycling (based on the analysis method and specifications outlined in Section 3.7) are listed by company in Table 4-14. Unlike storage, this option does not offer full protection against water supply shortfalls due to its limited ability to recover water. The estimated degree of implementation (to the nearest 10%), relative benefit, average cost per m^3 of average annual shortfall reduction, and NPV by company are presented in Table 4-15. Incremental effects of the option when combined with optimal water allocations (e.g. via water trade) are listed in Table 4-16. The cost-effectiveness of the option and its sensitivity to background flow and oil prices are presented in Table 4-17 and Table 4-18. Qualitative comments are listed in Table 4-19.

In the combined case with optimal allocations (e.g. via water trade), only the three least water-efficient operations face potential water restrictions once water is reallocated. The combined case produces a more cost-effective outcome overall (Table 4-17 and Table 4-18) due mainly to its ability to redirect water to the most water-efficient operations when shortfalls are beyond the water recovery capacity of treatment facilities. The combined option also produces a slightly lower average cost per unit of water recovered (see annualised costs in Table 4-16 compared to Table 4-15) due to economies of scale for water treatment. In the case of a low oil price of $30 per barrel, the continuous operation of consolidated tailings and increased recycling is not viable for any company (regardless of level of restriction), while the option under intermittent operation is viable for only two companies when water is allocated based on the prior allocation system, and for only one company following water trade between operations. Note that the presentation of results following Table 4-18 assume intermittent rather than continuous operation of water treatment (as required to reduce shortfalls) due to its lower cost.

- **Table 4-14 Estimated maximum water savings associated with consolidated tailings and increased water recycling, by mining operation**

Mining operation (company and/or project)	Average licensed water-use, m^3/s	Maximum reduction in extractions from the Athabasca River associated with consolidated tailings and reverse osmosis, m^3/s
Firm 1	0.006	Not applicable (SAGD project)
Firm 2	1.62	0.58
Firm 3	1.96	0.70
Firm 4	1.12	0.40
Firm 5	1.99	0.71
Firm 6	1.75	0.62
Firm 7	1.25	0.44
Firm 8	2.54	0.90
Total	**12.22**	**4.35**

- **Table 4-15 Net present value of consolidated tailings and increased water recycling, by mining operation**

Mining operation (company and/or project)	% implement-ation of option	PV of reduced shortfalls, $ M	Constant operation		Intermittent operation	
			Annualised cost, $ per m^3/yr of average reduction in shortfalls	NPV, $ M	Annualised cost, $ per m^3/yr of average reduction in shortfalls	NPV, $ M
Firm 1	0	-	-	-	-	-
Firm 2	100	1 170	32	920	9	1 090
Firm 3	0	-	-	-	-	-
Firm 4	100	280	72	100	20	230
Firm 5	20	140	63	50	18	110
Firm 6	0	-	-	-	-	-
Firm 7	0	-	-	-	-	-
Firm 8	100	1 390	12	1 030	4	1 280
Total		**3 000**	**22**	**2 100**	**6**	**2 700**

- **Table 4-16 Incremental net present value of consolidated tailings and increased water recycling option, combined with optimal allocations (e.g. following water trade), by mining operation.**

Mining operation (company and/or project)	% implement-ation of option	PV of reduced shortfalls, $ M	Constant operation		Intermittent operation	
			Annualised cost, $ per m^3/yr of average reduction in shortfalls	NPV, $ M	Annualised cost, $ per m^3/yr of average reduction in shortfalls	NPV, $ M
Firm 1	0	-	-	-	-	-
Firm 2	0	-	-	-	-	-
Firm 3	0	-	-	-	-	-
Firm 4	0	-	-	-	-	-
Firm 5	0	-	-	-	-	-
Firm 6	100	360	47	90	13	280
Firm 7	100	400	32	200	9	340
Firm 8	100	1 390	12	1 030	4	1 280
Total		**2 100**	**20**	**1 300**	**6**	**1 900**

- **Table 4-17 Cost effectiveness of consolidated tailings and sensitivity to background flows**

Item	Background flow scenario			
	Wet	Base Case	Dry	Ext. Dry
Consolidated tailings (restrictions under prior allocation)				
PV of reduced shortfalls, $ M	1 900	**3 000**	4 600	12 200
NPV, $ M				
Constant operation	1 200	**2 100**	3 700	10 900
Intermittent operation	1 700	**2 700**	4 400	11 800
Consolidated tailings combined with optimal allocations				
PV of reduced shortfalls, $ M	2 800	**5 000**	8 200	21 600
NPV, $ M				
Constant operation	2 300	**4 200**	7 400	20 300
Intermittent operation	2 700	**4 800**	8 000	21 200

- **Table 4-18 Cost effectiveness of consolidated tailings and sensitivity to oil price**

Item	Oil price scenario ($ per barrel)		
	$ 30	$70, Base Case	$110
Consolidated tailings (restrictions under prior allocation)			
PV of reduced shortfalls, $ M	210	**3 000**	5 700
NPV, $ M			
Constant operation	-	**2 100**	4 800
Intermittent operation	30	**2 700**	5 400
Consolidated tailings combined with optimal allocations			
PV of reduced shortfalls, $ M	340	**5 000**	9 600
NPV, $ M			
Constant operation	230	**4 200**	8 800
Intermittent operation	240	**4 800**	9 400

- **Table 4-19 Qualitative evaluation of consolidated tailings and increased water recycling**

Criteria		Evaluation comments
A	Dependability	Provides only partial assurance that water restrictions will be avoided given limitations on water savings, and so requires prior allocation or cap and water trade to ensure water-use is within the limits of the WMF. Secondary environmental impact of increased energy consumption (greenhouse gas emissions) and secondary environmental benefit of reduced size of tailings ponds.
B	Finance	No significant difference to base case, given option is expected to be implemented privately by mines (if financially viable).
C	Economic efficiency	Option provides a medium reduction in costs compared to the base case, particularly if implemented with a scheme that induces optimal allocations (e.g. water trade), although is higher in costs compared to storage.
D	Informational requirements	Further information required on production risk associated with recycling of recovered water from tailings consolidation for use in bitumen extraction process. Approved method is required for long-term disposal of saline water from reverse osmosis treatment process.
E	Monitoring and enforcement	No additional environmental monitoring expected (assuming reuse rather than discharge of recovered water). Additional process monitoring may be required by mining operations to provide an ongoing check of quality of reuse water and corresponding bitumen extraction rates.
F	Permanence	Permanence of option depends on government policy on greenhouse gas emissions: economic risk that cost of increased greenhouse gas emissions will be greater than cost of water use and tailings disposal. Degree of implementation of option depends on oil price (Appendix I.2.3).
G	Flexibility	May be negatively affected by low oil prices and high operation costs - mines may opt to temporarily shut down tailings treatment and reverse osmosis to save costs during times of low oil prices.
H	Equity	Equity depends on whether water trade is allowed and method of initial water allocation. Option implemented by junior licensees if no trade, or implemented by least water-efficient licensees with water trade. Without trade, no direct benefits would be expected for senior licensees (similar equity outcome as base case).
I	Dynamic incentives	Option assumes a fixed technology. High operation costs may create a continuing incentive to seek further innovation to minimise costs.
J	Continuing incentives	Similar to base case, creates environmental benefits of a fixed amount in terms of reduced water-use. Provides additional long-term environmental benefits associated with site remediation and reduced risk of tailings storage.

Criteria		Evaluation comments
K	Political considerations	Potentially acceptable to broader public given anticipated reduction in size of tailings ponds, although may be opposition to increased energy requirements. May not be acceptable to mining operations due to production risk and relatively high cost compared to storage option.

4.8 Results summary

Results of the quantitative analysis are summarised in Table 4-20 and Figure 4-14. Among the options considered and based on the analysis method (Section 3), it was found that storage combined with optimal water allocation was the most efficient at reducing the overall costs of water restrictions under the WMF. This was due to its ability to completely avoid shortfalls (rather than redistribute) and its low operation costs. As storage was assumed to require three years to construct, the combined option of storage in addition to optimal allocations (e.g. by combining storage with water trade) is anticipated to further reduce costs compared to storage alone.

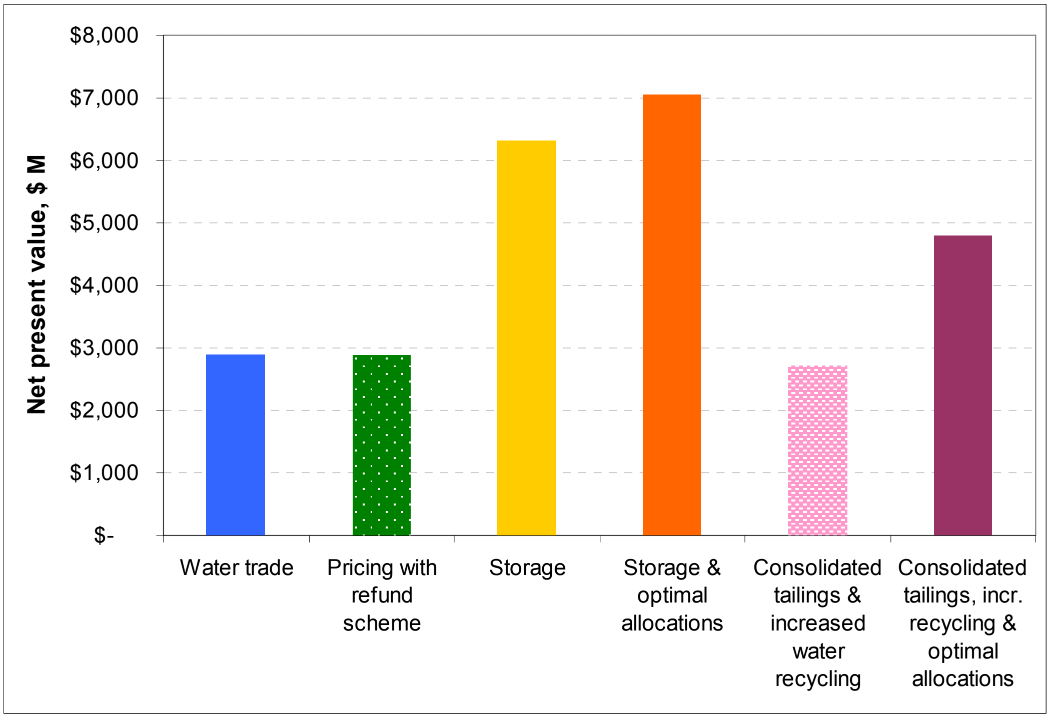
If storage is not feasible for technical or other reasons, it was found that policies to reallocate water so that production is optimised (by water trade, or by using a price with refund scheme where water prices are set at threshold levels, or a combination of both), or consolidated tailings under a continued policy of prior allocation, provide similar benefits - although the options are most cost effective when implemented as a combined technology and policy approach. This combined approach of consolidated tailings and increased recycling technology and an optimal water allocation policy provides cost savings associated with economies of scale (due to a reduced number of water treatment plants required - from five to three) and minimisation of impacts of water restrictions when shortfalls are above the maximum capacity of the technology.

Importantly, the results of the qualitative assessment note that an off-stream storage sized to eliminate water restrictions would provide little to no incentive to increase water-use efficiency. This option essentially removes the supply-side influence that signals water scarcity, creating a shift of the supply curve past the maximum quantity demanded across all periods that would otherwise be considered water scarce. In comparison, use of consolidated tailings and increased recycling technology increases water-use efficiency, creating a shift of the demand curve toward a lower quantity of water demanded. This shift is insufficient for protection against water restrictions in all periods, and so there may be a continued incentive to seek further increases in efficiency under this particular technology option. Water trade, assuming no market distortions, would encourage increased water-use efficiency to an efficient level, that may include other forms of technological change than the two technology options modelled. Water pricing with refund would also encourage increased water-use efficiency with an open choice of technology, though efficiency increases may be higher than optimal due to potential output-inducement effects (note, however, that output inducement was not modelled in this analysis).

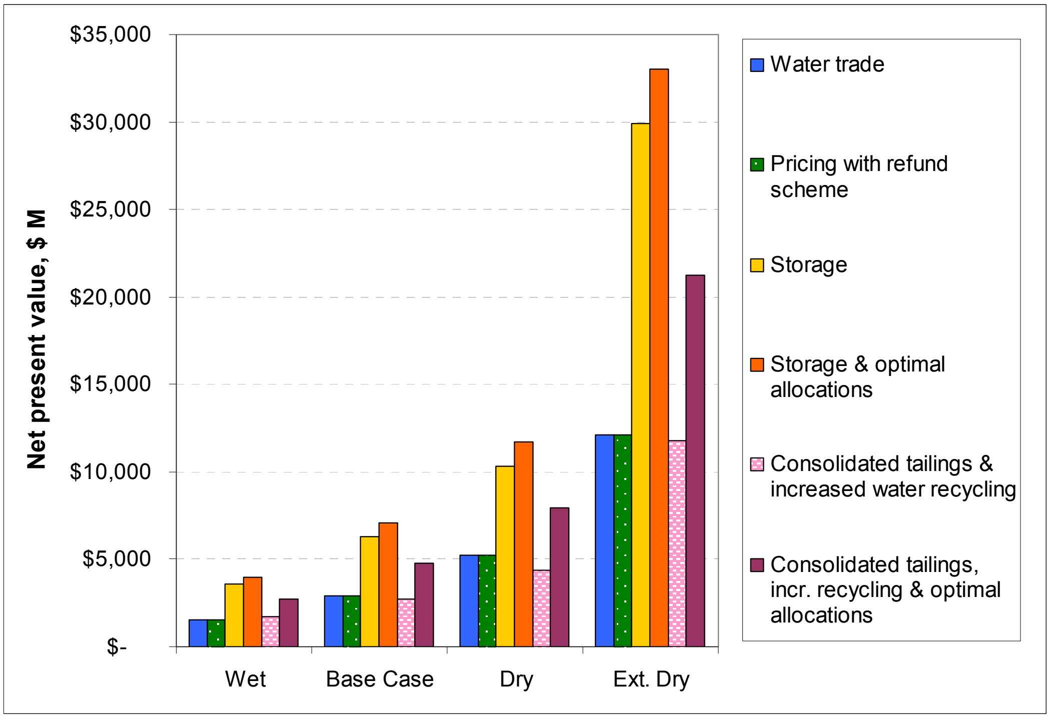
Although the overall cost-effectiveness of the options varied considerably with changes in background streamflow and oil price, in general it was found that the relative performance of the options was not affected by changes in either variable, and that all options provide a saving in costs compared to the base case of prior allocation and a short-run response to water restrictions (Figure 4-15, Figure 4-16, Appendix I). An exception occurs at very low oil prices, when the policy options (water trade, pricing with refund) significantly outperform the technology of consolidated tailings and increased recycling (as revenue may fall below operating costs inclusive of water treatment for this technology).

- **Table 4-20 Summary of net present value of options, $ M**

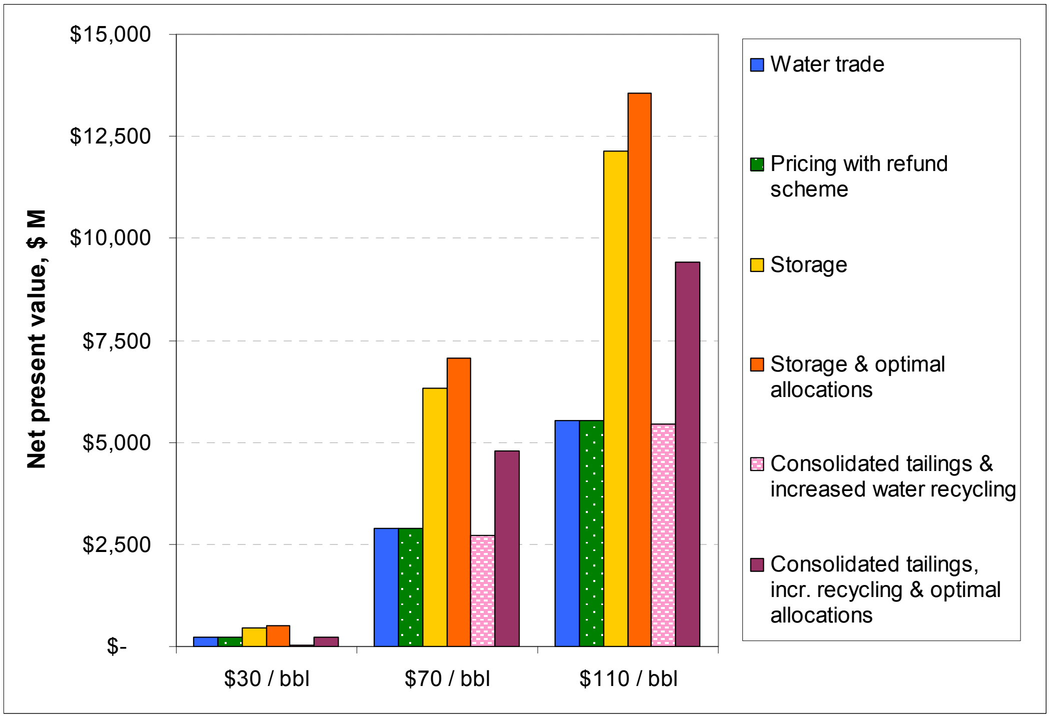
Option	PV of costs (capital, operation and maintenance)	PV of reduced costs associated with shortfalls	NPV
Policy options			
Restrictions under prior allocation (base case)	-	-	-
Water trade	-	2 900	2 900
Pricing with refund scheme	-	2 900	2 900
Technical and combined technical and policy options			
Storage	50	6 400	6 300
Storage combined with optimal allocations (e.g. following water trade)			
Incremental effect of storage	50	4 200	4 200
Total for combined option	50	7 100	7 100
Consolidated tailings and increased water recycling (intermittent operation)	250	3 000	2 700
Consolidated tailings and increased water recycling (intermittent operation) combined with optimal allocations			
Incremental effect of tailings treatment and recycling	240	2 100	1 900
Total for combined option	240	5 000	4 800



▪ **Figure 4-14 Comparison of net present value of options, $ M**

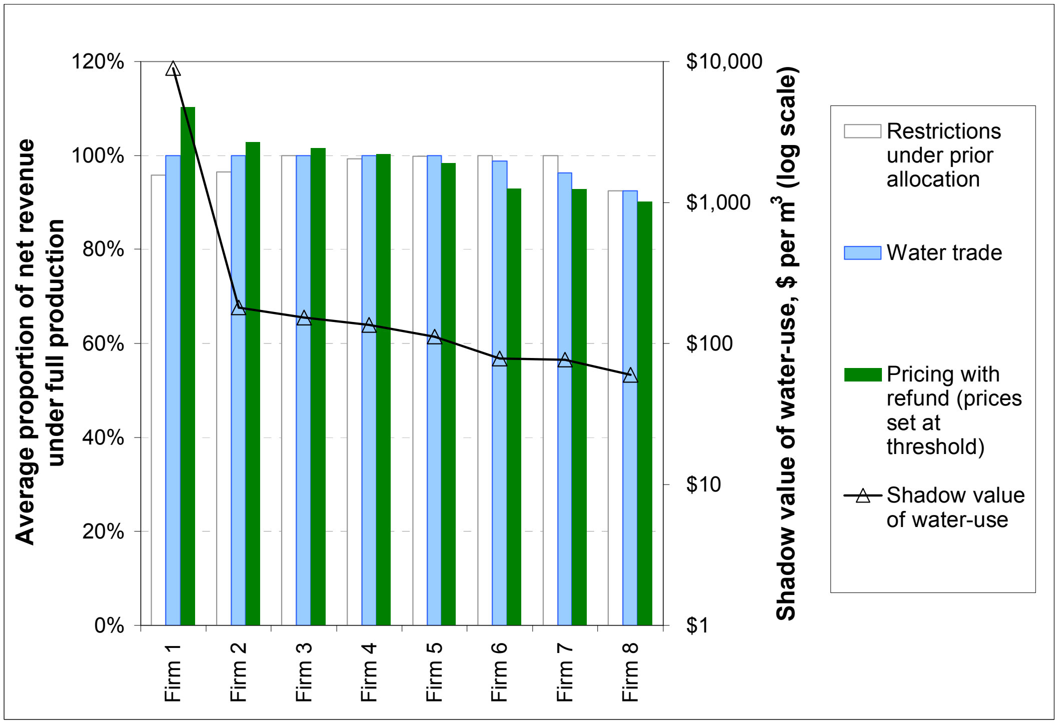


▪ **Figure 4-15 Sensitivity of net present value of options to background streamflows, $ M (refer to Appendix I.1.3 for numerical results)**



- **Figure 4-16 Sensitivity of net present value of options to oil price, $ M (refer to Appendix I.2.4 for numerical results)**

The equity implications of the policy options compared to the base case is indicated by Figure 4-17 (refer to Appendix I.1.3 for similar figures depicting sensitivity to background flows). As shown, the base case of prior allocation protects relatively senior licensees from restriction, while water trade reallocates water so that the production revenue of relatively water-efficient operations is protected. The pricing with refund scheme maximises the incentive to improve water-use efficiency relative to other operations by rewarding the most efficient operations (by providing refunds in excess of water charges) and penalising others (by imposing water charges in excess of refunds). Under this scheme, the maximum revenue that a firm can receive beyond production revenue is capped at the total value of receipts for water-use multiplied by the proportion of output of the firm compared to the total output across the industry. When background flows drop below that of the base case, the disparity in production revenues becomes greater (Appendix I.1.3) - particularly for the price with refund scheme. Water trade provides the opportunity for realisable gains from the sale of licences, the equity implications of which depend on the method of initial allocation, and the price of sale compared to willingness to pay/accept of the transacting parties.



- **Figure 4-17 Comparison of policy options in terms of average net revenue as a proportion of that under full production by mining operation associated with short run response to water shortfalls (i.e., reduced production). Shadow value of water use is shown on the secondary axis (log scale).**

5. Discussion

The range of characteristics and issues associated with water management in the lower Athabasca basin are relatively unique: the basin has a small number of large water demands; oil-sands extraction and processing requires niche technology; capital requirements are typically long-lived and costly, and are likely to be relatively inflexible for reaction to the weekly, variable cap imposed on water extraction (a component of the Lower Athabasca Water Management Framework); and the unregulated streamflows of the river are linked to a system of high value wetlands, located downstream of industry within the Peace-Athabasca Delta. In Alberta, scarce water is allocated to licensees in order based on the original date of licence application; those holding licences marked with an earlier date of application (i.e., senior licensees) receive priority, and may be supplied in full before the next in order may access the water supply. This ordering system is known as prior allocation, which in practice allocates scarce water in a similar style as the United States doctrine of prior appropriation (Percy, 2004).

The purpose of this study was to develop and evaluate selected policies and technologies to increase the water-use efficiency of industry in the Oil Sands, and to respond to water restrictions in a cost-effective manner. Based on linear optimisation in each weekly period of a 47-year simulation, and assumptions that include a static level of water demand (set at the approximate level of licensed water-use in the year 2020), linear production functions and perfect competition, this study has shown that water storage combined with efficient water allocation (so that the value of production is maximised, e.g. via water trade) provides the most cost-effective response to water restrictions among the options considered. However, this option provides little incentive to increase water-use efficiency once the storage is built, and so fails to meet a key goal of the Lower Athabasca Water Management Framework (WMF).

It was revealed that a price with refund scheme, that maximises the charge for water while maintaining the total water demand at levels that equal the available supply, and refunds collections to industry based on share of total output, maximises the incentives to increase water-use efficiency by rewarding the most efficient operations and penalising the least efficient. This scheme would be more favourable from a political perspective than an equivalent direct charge on water use, although may have practical issues in terms of price setting and monitoring of production - particularly if implemented to match the weekly time step of the WMF. It is recommended that an annual version of the scheme be further investigated as part of a mix of measures designed to meet the multiple objectives of this study i.e., the dual objectives of increased water-use efficiency and a cost-effective response to restrictions. The results are discussed below with regards to water supply availability, conceptualisation of the options, and results interpretation and policy recommendations. This is then followed by a brief review of analysis limitations, and general comments regarding water policy and management in the Athabasca basin.

5.1 Water supply availability

The WMF defines the conditions for signaling water scarcity among industry in the Oil Sands. The current level of water demand appears to be below that which may trigger the limits of the WMF (based on an average water-use of 2.5 m^3/s in 2006), however there is the risk of significant water restrictions if approved developments proceed and the licences issued to date become fully utilised (Section 2.1.5). As the extraction limits of the WMF are set as a proportion of the background flow, and water licences are defined in terms of fixed volumes and rates of extraction[19], if the WMF limits do become binding this was shown to be more likely in relatively dry years (Figure 2-4) during the winter period (Figure 2-5), while the risk of restrictions is not equal across years given dry years tend to occur in succession. A decline in background flows relative to historic conditions would increase water scarcity in three forms: restriction events would be more frequent, restrictions would be longer in duration, and restrictions would be more severe with shortfalls affecting a greater proportion of the demand (Table 2-3). For the WMF to effectively limit the impacts of water use, the use of other sources of water that may reduce freshwater inflows to the Athabasca River (e.g. groundwater and surface water from tributaries) should be taken into account to avoid uncontrolled switching of water sources by industry.

The analysis of options required a plausible forecast of background flows in the lower Athabasca River i.e., flow without oil-sands extractions. The annual flow has been low in recent years (Figure 2-3), however this appears to coincide with cyclical climatic

[19] The licensed shared intake of Shell Jackpine and Albian Sands A.O.S.P. has additional water-use limits based on background flow conditions (see Table 2-1).

influences associated with the Pacific Decadal Oscillation (see Rood et al. [2005]). Regardless of the cause of the recent dry period, paleoclimatological studies of tree rings in nearby basins (Case and MacDonald [2003]), reinforced by similar studies (Sauchyn and Skinner, 2001) and the findings of sediment analysis (Wolfe et al., 2006), indicate that nearby basins have at times been subject to more prolonged and severe droughts than in recent years, and that the average flow over the long term is lower than that of the historic flow record. Consequently, the base case for this analysis assumed that background streamflows were 10% less than historic streamflows over the analysis period (1958 to 2004).

Note that the proportional change in flow of the base case and the sensitivity analyses was applied equally across all weeks of the analysis period, whereas greater reductions in flow have been observed in the summer. For example, a declining trend in streamflows of 0.2% per year has been observed in the Athabasca River at Jasper, while winter streamflows appear to be slightly increasing (Rood et al., 2008); further, winter streamflows may continue to increase with climate change (Toth et al., 2006) along with an associated shorter season of ice-cover (Beltaos et al., 2006). These observations and predictions indicate a declining risk of water restrictions under the WMF. A base case that considers these inter-annual influences on streamflow could be investigated as an extension to this study. In addition, it is of interest to note that the apparent streamflow influence of the PDO has a period of approximately 50-years (Rood et al., 2005), providing an indication of when low streamflow conditions may recur. Further consideration of this pattern may assist in medium-term planning related to water availability.

To avoid restrictions under the base level of background flows, it was found that the total demand during low-flow periods would need to be below 7.5 m^3/s (Section 2.1.5 and Appendix F) i.e., three times the average rate of water use in 2006 and almost 50% lower than the average extraction limit allowed under current approved licences (Table 2-1). To obtain this rate on average without supply augmentation, while reaching the production forecast of approximately 2.3 million barrels of crude oil per day from surface mines by 2020 (Canadian Association of Petroleum Producers, 2006), would require an average water-use of 0.29 m^3 per barrel of crude oil production, which is approximately 25% less than recent reported use (Appendix C.3). While several planned oil-sands developments are expected to use less than this rate, the rate is substantially lower than that reported for a number of existing and proposed surface-mining operations (Dyer et al., 2008).

In order to depict a situation of water scarcity, a demand scenario of 12.22 m^3/s was selected for the base case. This rate of demand is equivalent to the approximate level of average licensed water-use by the year 2020. The base case demand scenario relied on several major assumptions: that no further licences are approved after 2007 (Table 2-1), that industry production occurs as per a recent forecast (Dunbar, 2008), and that there is full utilisation of water licences and productive capacity. Based on the demand and background flows selected for the base case, on average it was found that the extraction limits of the WMF would be binding for 5 weeks per year (6 weeks std. dev.), causing the total supply to industry to be restricted by 16% (10% std. dev.). Peak shortfalls were 4.8 m^3/s, or 39% of demand (Appendix I.1.1). The longest restriction event was found to last 20 consecutive weeks and restricted supply across industry by 30% or 44.8 GL in total.

5.2 Option conceptualisation

From a simple economic perspective, the weekly water supply can be represented by a vertical supply line that shifts according to water availability (Figure 2-8). Water scarcity, that occurs when the limits of the WMF become binding, is represented by an intersection between the supply line and the weekly demand curve, which in turn signals an associated equilibrium willingness-to-pay for water. Assuming perfect market conditions, if the equilibrium willingness-to-pay for water were charged for water use - with the price able to fluctuate on a weekly basis - this in turn would lead to the quantity demanded by oil-sands operations equaling the available water supply. Alternatively, if water trade were available on a weekly basis, under perfect market conditions the market price would be expected to equal the equilibrium willingness-to-pay for water, and the quantity demanded would equal the quantity supplied. As water is available free of charge in Alberta and weekly water trading is not available, involuntary restrictions would be required to curtail demand.

The purpose of this study was to develop and evaluate selected policies and technologies to increase the water-use efficiency of oil-sands operations and to promote a cost-effective response to water restrictions under the WMF. Possible options to reduce the likelihood of water scarcity under the WMF include: (i) supply-side actions, which would result in a positive shift of the supply curve toward an increase in the quantity of water supplied, or (ii) demand-side actions, which increase water-use efficiency and would result in a negative shift of the demand curve or change in slope toward a decrease in the quantity of water demanded. In this study, potential supply-side and demand-side actions were termed "technology" options. These technology options were assumed to require time for design and construction prior to being effective in reducing water scarcity. Possible options to mitigate the consequences of water scarcity under the WMF include policies that reallocate the water supply to reduce the overall cost of water restrictions. These policy options were assumed to have an immediate effect. In this analysis, selected options for quantitative and qualitative assessment were the policy options of water trade and a pricing with refund scheme, and the technology options of storage, and consolidated tailings and increased recycling. Combined policy and technology options (economically-efficient allocations followed by implementation of the technology) were also analysed. All options were assessed relative to the base case of water restrictions in order of prior allocation, for which production is assumed to be temporarily curtailed by those firms who experience a supply shortfall.

The policy of prior allocation, whereby junior licensees are first to be restricted (regardless of their water-use efficiency), structures the water demand curve such that the willingness-to-pay per unit of water does not monotonically decrease with an increase in the quantity supplied. In effect, the policy options derive their benefits by reconfiguring water demands so that the inverse water demand function exhibits an orderly decrease with quantity. When water is scarce, the policy options reallocate the water supply from those firms whose water licences are relatively junior (i.e., recently approved) to those firms who produce the highest value per unit of water use.

Heterogeneity in the water-use efficiency among firms is a significant influence on the slope of the water demand function and hence the cost-effectiveness of the policy options. The greater the degree of heterogeneity, the steeper the slope of the water demand function and the greater the expected benefits associated with the policy options. Heterogeneity in water-use efficiency among oil-sands operations stems from differences in scale, maturity and design, quality of output, and quality of alternative sources of available water inputs such as groundwater (Rogers, 2006). For the purposes of the quantitative component of this study, firm heterogeneity was based on average licensed water-use and associated forecast production levels (Table 3-1). A major source of heterogeneity in this study was the type of mining activity: there is one Steam Assisted Gravity Drainage (SAGD) operation with a relatively junior water licence, while all other operations are less water-efficient surface mines. If the SAGD operation was excluded from the analysis then this would lower heterogeneity, though the overall cost-effectiveness of the policy options would not be substantially affected given the SAGD operation had the lowest level of forecast production.

An important impact of the policy options is the provision of incentives that encourage actions that reduce the risk of restrictions (e.g. measures that increase water-use efficiency), and so while having benefits in the short run in terms of reducing the consequences of water scarcity, they may also indirectly encourage decreases in the likelihood and/or consequences of water scarcity in the medium to long term. The policy options apply these incentives either indirectly, via the market price (water trade), or directly via the price of water charges and anticipated refunds (price with refund scheme), and provide equal encouragement across firms. The potential impact of these incentives was not modelled; only the short-run benefits associated with the reconfiguration of the demand curve were considered. Thus the analysis may considerably underestimate the benefits of both policy options in terms of the potential indirect impacts on supply and demand that arise from the provision of incentives.

The two technology options reduce the risk of restrictions in distinctly different ways. Storage reconfigures the temporal pattern of water supply at a relatively low cost, by shifting the weekly supply curve so that it no longer intersects the demand curve; while consolidated tailings and increased water recycling introduces a substitute water source and increases water-use efficiency (creating a shift in the demand curve toward reduced levels of demand), so that the impact on production for those firms at risk of restriction is less severe than otherwise. Both technology options require sufficient time for design and construction, and so after the decision to proceed with the technology a firm may still be exposed to weekly water restrictions in the short period before the technology is accessible. If storage is combined with economically-efficient allocations (e.g. that may be associated with the policy options), then the cost of potential restrictions during the storage design and construction period is reduced. If consolidated tailings and increased recycling is combined with economically-efficient allocations, then the firms at risk of water restriction during the design and construction period, and who continue to be at risk once the option is in operation (given the limited ability to recover water from tailings and water treatment), shifts from the junior licensees to those with relatively less-efficient production - in this case, those with a relatively high water-use per unit of oil production.

Importantly, both options of storage and consolidated tailings and increased recycling have technical feasibility issues that require further investigation. In the case of consolidated tailings and increased recycling, this option was assumed to only be operated on a weekly basis when a firm is faced with water restriction, and to have a limited ability to protect against shortfalls i.e., water would be still required from the Athabasca River (albeit in smaller quantities). It is conceivable, however, that the option could also be operated to assist in providing water to other firms who may face water scarcity, e.g. via water trade. In addition, rather than having a limited ability to protect against shortfalls, the tailings ponds of mature operations could be utilised as a form of on-site storage, with tailings treated and water reused (following treatment using reverse osmosis) on an as-needs basis in order to fully satisfy a firm's water demand. Further investigation of these possibilities would require detailed information on costs for each individual operation.

5.3 Interpretation of results

It was shown that all options analysed produced cost savings relative to the base case of restrictions according to prior allocation. A major finding was the high cost of unexpected water shortages, which in turn contributed to the favourability of the options. Based on an oil price of $70 per barrel and a cost of production of $26.50 per barrel, a short run response to water restrictions of reduced production is estimated to cost in the order of at least $60 per m^3 of water (Table 4-3, Figure 4-4, Figure 4-6), which is equivalent to $60 000 per ML or above $48 000 per acre foot. These figures suggest that, without additional measures taken by industry to conserve water, the water-use limits of the WMF (when binding) imply a marginal value of water that would be one of the highest in the world[20].

[20] As a comparison, water prices for seasonal irrigation allocations in the Goulburn irrigation district in Australia (comprising of horticulture, dairy, and mixed farming enterprises) during severe drought conditions peaked at $1 000 per ML (Appendix J) or slightly above $800 per acre foot.

Storage combined with either of the policy options was found to provide the maximum cost saving of $270 million per year during storage construction, and $790 million per year (or 1.8% of the estimated net revenue when production is not limited by water availability) thereafter. The cost savings for the policy options were estimated to be $270 million per year across industry (or the equivalent of 0.6% of the estimated net revenue received when the water supply is sufficient), while consolidated tailings and increased recycling provided similar savings. There were major differences, however, in the ability of the options to increase, or to promote an increase in, water-use efficiency relative to the base case of restrictions according to prior allocation.

The background information highlighted the range of potential opportunities available to increase water-use efficiency among existing operations (Table 2-6). Each would have an associated cost and would likely require some form of financial incentives to encourage their implementation on a voluntary basis. The options assessed in this study have marked differences in terms of their ability to provide this incentive. The base case of prior allocation has a strong inhibiting effect on the implementation of new technology. For those operations with senior licences, who are highly unlikely to experience water restrictions, there is currently no material incentive to increase water-use efficiency. (However, there is an indirect incentive associated with avoiding the need to apply for additional water licences to allow operations to expand; there may also be an incentive if agreements to assign water [allowed under the *Water Act*] involved monetary compensation.) Storage would stifle technology improvements given that it eliminates water scarcity, and could in effect promote a lower level of water-use efficiency than the base case. Conversely, consolidated tailings and increased recycling directly increases water-use efficiency among those firms for which it is financially viable e.g., junior licensees in the non-combined option. (Consolidated tailings also has the benefits of reduced environmental risks associated with tailings ponds, at a potential cost of increased greenhouse gas emissions.) Only the policy options, however, are capable of conveying incentives across all firms to increase water-use efficiency.

Among the two policies considered, the pricing with refund scheme was found to maximise the level of incentives; the scheme can be designed so that firms face a higher per unit cost of water use in comparison to the marginal willingness-to-pay revealed in a water market, and are rewarded with payments per unit of output relative to the total output of industry. However, the pricing with refund scheme has practical issues associated with designing an appropriate pricing structure and information asymmetry (i.e., to effectively set prices for the scheme requires an understanding of firm profitability), as well as determining an appropriate timescale for output measurement (this would need to be longer than the weekly time step of the WMF), and the scheme is likely to discourage the sharing of indistinct technology developments (that would not be covered by patents) among firms. Equity among firms may also be an issue, given the distribution of rewards and penalties is regardless of licence seniority and the prior expectations of investors. Note, however, that the maximum penalty of the scheme would be similar to that of an equivalent direct charge on water use (set based on the marginal cost of supply shortfalls to industry), while other firms would either receive a net gain or would pay a comparatively lower net charge. Though equity impacts would be unavoidable, the impact could be lessened by the provision of advance notice of the scheme and graduated prices.

Although a pricing with refund scheme may not be practical as a direct tool for managing water scarcity on a weekly basis, the scheme may be more preferable for application over a longer time step as part of a mix of instruments (so that other measures are able to address its shortcomings). Prices under the scheme could be lower than the maximum levels possible in order to improve practicality at the cost of decreased incentives. The analysis of the scheme could be extended by further research regarding its ability to induce technology, including when prices are set at levels that are lower than the maximum price threshold, and consideration of the potential for market failures that include strategic behaviour, induced output, and spillovers associated with endogenous, indistinct technology, although data availability will be an issue.

Water trade also provides incentives for increases in water-use efficiency, though incentives are indirect and may be hampered by a limited level of trading and limited access to market information. In addition to the small number of firms, trading activity may be lower than in other water markets due to water-use infrastructure that is typically long lived. Modifications to technology to increase water-use efficiency are likely to be more costly for existing operations compared to those still under design. This is distinctly different from water markets that involve the irrigation sector. For example, markets for seasonal water allocations in Australia are active and create considerable economic benefits (Peterson et al., 2004) due in part to the flexibility of mixed farming enterprises to seasonally adjust their demands in response to water availability and market prices (e.g. Appels et al., 2004).

Allowing water trade in the Oil Sands with so few licensees may result in strategic behaviour. For example, senior licensees could restrict the supply of transfers that in turn would inflate the market price. Another potential source of market imperfection is a lack of market information; without specific regulations, the price paid for transfers is unlikely to be transparent (the public is unlikely to favour the payment of large sums for water, particularly in the Oil Sands, and so information may not be disclosed voluntarily due to fear of negative publicity). These forms of market imperfections may reduce the incentives for increased water-use efficiency that would otherwise be associated with water trade. In the case that water trade is short-listed as a preferred option, then it is recommended that further study be undertaken to address the potential sources of market failure, and to examine the forms of trading instruments and markets (e.g. trading period, trade of licensed water-use or capacity share, differentiation of security of supply of licences, starting allocations) that may enable efficient investment in the long-lived technology that is particular to the Oil Sands.

It may be possible to implement a pricing scheme and the ability to trade water simultaneously. If water trading were allowed in conjunction with a pricing with refund scheme, then reallocation of licensed water-use could occur at much lower market prices, and market information (if transparent) would potentially have less impact on public sentiments. The potential interaction between a price with refund scheme, and water trading under the water-use cap of the WMF, is analogous to the discussion by Weitzman (1974) of the optimal choice between price versus quantity instruments under uncertainty. A pricing with refund scheme appears more amenable to implementation when a higher number of mines are in operation and when water shortfalls are low, which may coincide with a situation in which the private costs of reduced water-use may be relatively non-linear in comparison to the public benefits. Conversely, during red binding flow conditions of the WMF, which may coincide with times when the public benefits of reduced water-use may be relatively nonlinear compared to costs, quantity regulation (e.g., the WMF cap combined with prior allocation or, more preferably, with water trade) may be an appropriate safeguard in addition to a pricing with refund scheme. While a weekly pricing with refund scheme would be impractical, an annual scheme that reflects the shadow value of water use across all flow conditions of the WMF (red, yellow, and green) may have potential, particularly if water trade were also available as part of a hybrid policy.

5.4 A suggested policy approach

A fundamental basis for effective policy design is the designation of a separate policy instrument to address each separate policy goal (based on Tinbergen's principle [Tinbergen, 1952]). Providing the incentive for increased water-use efficiency is separate (though not entirely independent) to the objective of reducing the costs of water restrictions. Thus it may be appropriate to use several instruments to manage water use in the lower Athabasca basin, that could meet the goals of the WMF at a lower cost compared to a single instrument (e.g. as found by Fischer and Newell [2007] when comparing policies to address climate change). This may take the form of a price instrument, to improve water-use efficiency across all periods; a quantity instrument, to provide for the cost-effective reallocation of water during restriction periods of the WMF (that may in turn induce storage construction); and separate policies to address research and development, and the implementation of existing innovative technologies[21].

The background literature reviewed in this study (Section 2.5.4) is able to assist in determining the options that may be best-suited to achieve the two objectives of this study i.e., (i) to increase the water-use efficiency of oil-sands operations, and (ii) to promote a cost-effective response to water restrictions under the WMF. To address market failures related to both the environment and technology, Jaffe et al. (2005) advise that environmental regulation should be the main policy focus while taking care to avoid policies that favour a particular technology at the expense of further innovation. To enable efficient and effective control of outcomes, Mundell (1960) advises to assign policies to those in which they have the most influence. Based on this advice, it is clear that a pricing with refund scheme would be best suited to provide incentives for increases in water-use efficiency (and so would address objective (i)); while a combination of storage and water trade would be best suited to minimise the short run and long run costs associated with water restrictions, while enabling water to be reallocated under the cap of

[21] Likewise, reduced size of tailings ponds, and reduced greenhouse gas emissions, are separate policy goals that may in turn be addressed by separate policies.

the WMF (and so would address objective (ii)). In the event that a shared storage is not technically feasible to be operated during the winter months, or may be incorrectly sized to avoid all possible shortfalls, water trade provides a fallback option to reduce the costs of water restriction. Consolidated tailings and increased recycling is a particular technology that if imposed creates issues of technology entrenchment that in turn may inhibit further innovation, and so its implementation should be at the discretion of firms rather than enforced by government standards[22]. As demonstrated in the results of the combined options, the incentives associated with the WMF and the policy options may be sufficient to induce the take-up of technology without further intervention. Finally, in outlining the above selection, it is assumed that the preferred mix of options are designed to address market imperfections so that the potential effect of these imperfections on market outcomes is insignificant.

5.5 Limitations

The modelling perspective and assumptions of this analysis have the potential to alter the relative cost-effectiveness of the options. This includes the static perspective (rather than dynamic), and assumptions of linear production functions, fixed operating costs per barrel across industry, a short-run response to water restrictions and, particularly in the case of the policy options, a fixed level of technology, an absence of substitutes for water, and perfect competition. The implications of these factors are discussed below.

The relative cost-effectiveness of the options is influenced by the static perspective of the analysis and the design of the base case. The static perspective assumes that water scarcity is present from the outset and is based on a constant year 2020 level of demand, and there is no prior implementation of the technology options. Without implementation of the technology options, firms are assumed to respond to supply shortfalls using the expensive, short-run approach of reducing production. In reality, however, decisions are made in a dynamic environment, where there is some warning of the risks to water supply prior to 2020, and there may be advance plans to increase water-use efficiency and/or reduce the costs of potential restrictions. There appears to be considerable lead time for

[22] This recommendation relates to the purposes of water management only, and does not consider the potential benefits associated with reduced size of tailings ponds.

risk management given the under-utilisation of existing licences and the current low risk of water scarcity under the WMF.

For example, a number of planned surface-mining operations include the design of large on-site water storages in order to prepare for restrictions in supply from the Athabasca River. The CNRL Horizon mining operation has a storage design of 2 000 ML (AECOM), that appears to offer 2 weeks' supply (based on full utilisation of average licensed water-use in 2020), and Imperial Kearl reports plans for a storage capable of supplying water over a 3-month period in the case of severe restrictions (Imperial Oil, 2006). These storages would significantly lower the potential cost of restrictions under the base case, and so would lower the relative cost-effectiveness of the options[23]. Thus under a dynamic investment framework with technological change, this would alter the base case such that the relative advantage of the options may prove to be less than modelled in this study.

The assumption of full utilisation of average licensed water-use does not appear realistic for active licences (Appendix C.3)[24]. If usage were less than the average licensed water-use assumed in this study, this would buffer the impacts of minor restriction events and would reduce the costs associated with the base case; this indicates that the benefits of the options may be overestimated, though the relative performance of the options is unlikely to be affected. In contrast, note that licensees are entitled to extract their licensed maximum rate of water use even when the water supply is scarce (provided they have sufficient seniority), and could possibly take advantage of this arrangement to engage in strategic behaviour - particularly in the application of the policy options. Thus, the results of this analysis may overestimate the impacts of water restrictions, in the case of under-utilisation of average licensed water-use, and underestimate the impacts of water

[23] Individual storages are clearly technically feasible though are likely to be more expensive than a single, shared storage (Section 2.2). However, the staging of investments in small on-site storages would lower the cost difference and may be worth further investigation.

[24] Note, however, that earlier licences were not staged to account for variations in the water supply needs over the life cycle of a mining operation, and so provided a large buffer once high start-up water demands had been supplied and operations were sufficiently mature (Appendix C.2). Recently issued licences specify multiple stages of water-use limits, and so are expected to be utilised to a comparatively greater extent.

restrictions, in the case of full utilisation of maximum licensed water-use when water is scarce.

The assumption of linearity may also impact the net benefits of the options, particularly when an operation is only partially affected by water restrictions. Linear demands assume that the marginal benefit of water use is equal to its average benefit i.e., constant returns to water-use, and create an industry water demand function that is discontinuous (Figure 4-4). In reality, the actual shape of the demand function for water is unknown to regulators, and it could instead display properties of decreasing marginal returns to water-use resulting in a smoother industry demand function. If marginal returns are decreasing rather than constant, then the cost of water restrictions may be overestimated although the relative cost-effectiveness of the options is unlikely to change. The assumption of linear demand has a dramatic impact, however, on the threshold prices able to be charged for maximising incentives under a pricing with refund scheme (Figure 4-11). In practice, if linear demand were a reasonable assumption, then constant water prices could be devised over each range of shortfall (e.g. see Appendix H.3), similar to increasing block tariffs, to lower price volatility and the potential for perverse incentives.

Perfect competition is a major assumption that affects the potential benefits of the policy options. With only eight firms in the analysis, each with differing levels of licence seniority, a potential market for water use is unlikely to be perfectly competitive. Imperfect competition is common to many markets; the important question is whether the degree of imperfection is sufficient to alter the relative cost-effectiveness of the options. If weekly water trading were possible the market is likely to be "thin" and the number of transfers could be lower than optimal. Market prices and corresponding incentives may be inconsistent and may not reflect the true marginal value of water use. With suboptimal levels of trading, imperfect competition would lower the cost effectiveness of water trade relative to the base case. However, any transfer that does occur is expected to reduce the overall costs of restriction, and so imperfect competition may not affect the assessment of relative performance of the options, provided that senior licensees do not artificially increase their demand when water is scarce (this type of behaviour could be minimised by carefully designed trading rules, and could be affected by implementation of a concurrent pricing with refund scheme). In the case of the pricing with refund scheme, even under conditions of perfect competition the scheme is expected to distort market outcomes by inducing a higher than optimal level of output (Gersbach and

Requate, 2004). While this may not seem a concern, a scheme that operates on a weekly basis may create weekly output fluctuations that may lower the scheme's effectiveness, suggesting that a longer time step for the basis of refunds (e.g. annual) may be more appropriate. It is recommended that the potential for strategic behaviour and the range of possible impacts of imperfect competition be further investigated.

Finally, this analysis assumed that all operations receive $70 per barrel of oil produced, and face equal operating costs of $26.50 per barrel. Variability in prices received or operating costs across the operations would increase heterogeneity and therefore increase the benefits associated with the policy options. The sensitivity analysis of oil price (low price scenario of $30 per barrel, high price scenario of $110 per barrel) indicated that fluctuations in oil price do not affect the relative cost-effectiveness of the options, except in the case of low oil prices for consolidated tailings and increased recycling (when revenues may drop below operating costs).

5.6 Policy implications

Given the analysis was focused on a future scenario, it is worth questioning the potential consequences of deferring decisions related to water management along the lower Athabasca River until there is sufficient demand to create the risks to production modelled in this study. In other words, what might happen between now and the year 2020 if the water management response is "business-as-usual"?

Currently the only option available to reduce the potential impact of water restrictions via water reallocation is the use of agreements to assign water (available under the *Water Act*). These are devised ahead of time, and would not be practical to implement on a weekly, separate basis as modelled by this study. An agreement to assign water across firms was reached for the first season of implementation of the WMF (Appendix B.2). This agreement appeared to reallocate water that would otherwise not be utilised by senior licensees. If necessary, junior licensees were to rely upon private water storage, such that water restrictions if triggered would result in a similar water allocation as the default policy of prior allocation. Agreements to assign water may be more difficult to reach in the future, particularly if they represent an actual restriction of the licensed water-use of senior licensees (i.e., a restriction of average licensed use in addition to maximum licensed use), and there is the risk that market power will result in less water sharing than optimal. In turn this may lead to junior licensees comparatively over-investing in water saving technologies and/or storage to deal with potential shortfalls. In the worst-case scenario, unexpected shortfalls in supply could occur (given the unregulated nature of streamflows), and if these occur when agreements to assign water either haven't been reached or represent less-than-optimal water sharing, this may reduce production by more than is necessary and possibly result in temporary shutdowns. Thus there is the potential for considerable financial impacts, particularly to junior licensees.

Under Alberta's current system of prior allocation, there are effectively no ongoing incentives for existing mining operations to develop and implement technology to reduce water-use. New mines may alter the design of their operations in response to forecast water shortages, although once built these operations similarly face no further incentives to implement new technology to reduce water-use (assuming there is no change in the background level of streamflows, and no expansions in operation). Each operation has an equal impact per unit of water extraction on the downstream environment, yet prior allocation provides unequal incentives to reduce water-use when water is scarce. Given these undesirable effects, the policy of prior allocation when water is scarce appears worthy of reconsideration. It is recommended that this policy be analysed in comparison to a system of equal share of licensed water-use based on the available water supply (e.g., similar to that applied in parts of the Murray-Darling Basin, Australia), taking into account factors such as the incentives for water-use efficiency, the potential costs of market imperfections in the case of water trade, barriers to new entrants, investment risk and consideration of sunk costs; as well as factors particular to the Oil Sands that include rigid technology with costly refurbishment, and endogenous technology development.

Regardless of the method of initial water allocation, if there is a desire to see ongoing increases in water-use efficiency among existing operations, while also minimising the cost of improvements, then flexible incentives are required. The provision of flexible incentives may be particularly important in the Oil Sands given that endogenous technology is likely to be the main driver of improvements in water-use efficiency (given the unique nature of the resource and extraction methods). This study reviewed two policy options for the provision of flexible incentives, water trade and a pricing with refund scheme, that have the potential to be implemented in unison for maximum effect.

An issue not considered in this study is the optimal setting of water-use limits. As discussed in the background (Section 2.5.1), an economically optimal policy (that takes into consideration all use and non-use values) would select water-use limits at which the marginal benefits of water use for instream purposes equal the marginal costs of an additional unit of water savings. However, this approach is difficult without the estimation of economic, social and environmental values using a common unit, e.g. dollars. Alternatively, using the results of this study the question of valuation can be reversed. That is, if environmental and social values were able to be converted into dollars, is it realistic to consider that the marginal environmental and social benefits of instream flows in the lower Athabasca River are in the order of \$60 per m^3? This value appears significantly higher than the marginal values suggested by water markets within other parts of the world (refer to Appendix J for an Australian example).

The setting of appropriate water-use limits raises the question as to whether water allocation should be managed to minimise potential impacts to river systems, and the environment is in effect considered the most important value among environmental, social and economic considerations; or whether a lower level of environmental quality of river systems may be accepted given the considerable financial gains and potential economic benefits associated with water use for production (in this case, oil production). This choice ultimately rests with the citizens of Alberta. Regardless of value preferences, the potential trade-offs involved in setting an appropriate water-use limit may be reduced by the options analysed in this study. Flexible incentives to increase water-use efficiency can be enabled under a functioning water market and/or provided in the form of a pricing with refund scheme. Changing the inter-temporal pattern of net water-use, in the form of off-stream storage, may also lower the potential environmental and economic impacts. If the latter option of storage is preferred, implementation should occur in conjunction with flexible incentives to increase water-use efficiency in order to lower the overall impacts of water use in the Oil Sands.

6. Conclusions and recommendations

6.1 Summary of main findings

The purpose of this study was to develop and evaluate selected policies and technologies to increase water-use efficiency and respond to water restrictions in a cost-effective manner. Six options in total were analysed: two policy options of water trade and a pricing with refund scheme, two technology options of storage, and consolidated tailings and increased recycling, and two combined policy and technology options (economically-efficient allocations followed by implementation of either technology option). The options were assessed relative to the base case of water restrictions that are assigned in order of prior allocation.

By undertaking a detailed assessment of water supply in the lower Athabasca River, it is shown that there is a relatively low risk of the WMF limiting water-use in the short run. If the future flow in the lower Athabasca River is assumed to be slightly lower than the historic record (i.e., 10% less than the weekly average flow from 1958 to 2004), water demands may not be at risk of restriction until actual water-use nears 7.5 m^3/s. This threshold is well above recent records of actual water-use (2.5 m^3/s in 2006), although is well below the average licensed water-use (14.0 m^3/s, Table 2-1).

A demand scenario equivalent to the year 2020 (approximately) was selected for the base case in order to depict a situation of water scarcity. Assuming linear production functions and water-use of 12.2 m^3/s, it is shown that an off-stream storage sized to avoid water restrictions, in combination with efficient water allocations (to minimise the cost of restrictions during storage design and construction), provides the most cost-effective response to water restrictions where the industry reaction would otherwise be a short-run response of reduced oil production. However, storage eliminates water scarcity and so is unable to provide ongoing incentives to increase water-use efficiency. The alternative technology of consolidated tailings was shown to be less cost-effective than storage, although has the advantages of actively increasing water-use efficiency along with indirect benefits associated with a reduced size of tailings ponds. For consolidated tailings technology to lead to reduced extractions from the Athabasca River, increased water recycling is required that in turn may create increased greenhouse gas emissions. Thus there is a potential trade-off between water use and climate change impacts. Both technology options require confirmation of their technical feasibility.

By enabling water to be redistributed to its highest value, it is shown that the policy options of water trade and a pricing with refund scheme also reduce the costs of water restrictions - particularly when combined with the technology options. The two policy options analysed were the only options capable of promoting increases in water-use efficiency across all operations. It is shown that a pricing with refund scheme has the potential to maximise incentives for improved water-use efficiency, although for practicality its implementation may be more suited to a hybrid scheme in conjunction with a quantity-based instrument. Due to the small number of firms and the potential for endogenous technology spillovers, it is recommended that the risk of market failures associated with the policy options be investigated.

Although related, the two objectives of this study of minimising the cost of water restrictions and increasing water-use efficiency are distinctly separate. To successfully achieve both objectives requires at least two separate instruments (Tinbergen, 1952), with each preferably assigned to the objective that it is best able to influence (Mundell, 1960). It is shown that the combined policy and technology options are most effective at reducing the costs of restrictions, and with additional refinement a combined or hybrid scheme may be designed to both minimise costs and create incentives for increased water-use efficiency.

6.2 Recommendations for further study

This study uncovered additional questions and topics worthy of further investigation. In particular, it became clear during the course of the research that technology to increase water-use efficiency, and the provision of incentives to implement technology, are particularly important. This is associated with the unique nature of oil sands and the methods for oil extraction, and the importance of endogenous technology development and spillover effects associated with learning by doing.

Additional research could be directed toward the sensitivity of the modelling assumptions and the investigation of other options. For example, consideration of the adoption of technology under a dynamic investment framework would be ideal, though is likely to be hampered by limited data. In particular, it would be of interest to investigate the implications of investment choices when water-using technology is typically long lived and costly, and under what conditions (if any) would prior allocation without trade lead to efficient technology investment. Consideration of the implications of uncertainty in benefits and costs, related to Weitzman (1974), is also recommended.

The potential impacts of market failure and the ability to minimise these impacts need to be addressed in order to make an informed judgement of the policy options. This includes market failure related to technology and strategic behaviour. If water trade is a preferred option then it is recommended that further study be carried out to examine the forms of markets (e.g. timeframe over which the quantity cap is applied, forms of trading instruments, specification of property rights etc.) that may lead to an efficient investment in technology. For a pricing with refund scheme, it is recommended that an annual scheme that reflects the shadow value of water use across all flow conditions of the WMF (red, yellow, and green) be investigated, possibly as part of a hybrid scheme. Other potential combined options may include forms of support for the implementation of new technologies and dissemination of lessons learnt.

While this study addresses the cost effectiveness of the response by industry to the water-use limits of the WMF, the economic efficiency of these limits has not been evaluated. This evaluation would assist in integrating the range of goals for water management in the Oil Sands (Section 1.2) by providing information on non-use values associated with water use, including social and environmental values. Provided a reasonable method can be devised, the valuation of the provision of instream flows may be worthwhile for comparison with the costs associated with reducing water-use.

7. Bibliography

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Appendix A Ecological considerations

A.1 Overview and key issues

The Athabasca River is the longest, unregulated river (i.e. flow unaltered by man-made structures such as dams) in Alberta. A relatively low proportion of its total annual flow is extracted, and so overall its natural flow variability has remained relatively preserved - particularly when compared to basins located to its south in the province.

Notwithstanding the immediate in-stream habitat it provides, the Athabasca River has particular ecological importance due to its shared role in replenishing the wetlands of the Peace-Athabasca Delta, located at the outlets of the Peace, Athabasca and Birch rivers. The Peace-Athabasca Delta is listed under the Ramsar Convention on Wetlands of International Importance and forms part of the UNESCO World Heritage-listed Wood Buffalo National Park. Reasons for its Ramsar designation include its status as the world's largest boreal delta, its relatively undisturbed nature, and its importance as habitat for birds, including the endangered Whooping Crane, and bison.

In 1996, the Northern River Basins Study (NRBS) analysed the cumulative environmental issues in the Peace, Athabasca and Slave Rivers (Wrona et al., 1996). The broad study area of the NRBS is likely to have facilitated a balanced analysis of environmental issues within the contributing basins, although some conclusions may now be outdated given the rapid expansion of industry in the Oil Sands. Over the length of the Athabasca River, the discharge of contaminants and health implications were the predominant concerns recommended for action in the NRBS. Specific to the reach downstream of Fort McMurray to the Peace-Athabasca Delta, the cumulative impacts assessment of the NRBS listed the following key management considerations (Wrona et al., 1996:57):

- *Pollution prevention in light of downstream interests and cumulative effects*
- *Naturally occurring hydrocarbons and metals*
- *Nutrient management*
- *Health of aquatic life*
- *Long term management of oil sands tailing ponds, oil sands operational emissions and expanding operations*

- *Spill response: timely response in reporting of municipal and industrial spills to downstream interests*
- *Wetland drainage and deforestation effects*
- *Tainted fish and drinking water*.

The NRBS considered changes to the hydrologic regime to be of "minimal concern" (Wrona et al., 1996:51) throughout the length of the Athabasca River, while action was recommended on this indicator for the Peace River basin downstream of the Bennett Dam. Due to its flow variability, the Athabasca River is subject to natural marked changes in water quality that are compounded by the use of the waterway to discharge treated effluent (Wrona et al., 1996). In particular, low flows in winter "limit the capacity of the river to dilute both natural and man-made inputs" (MacLock et al., 1997:9). Concern was raised regarding low dissolved oxygen levels in the Athabasca River downstream of Whitecourt to the Grand Rapids (located upstream of Fort McMurray), with action recommended to address declining levels along this reach from downstream of the confluence with the Pembina River. The addition of nutrients to the Athabasca River was of similar concern, with the NRBS recommending that action be taken to reduce nutrients discharged from paper and pulp mills and municipal sources between the towns of Hinton and Whitecourt.

More recently, Schindler et al. (2007) raise concerns about the ecological impact of increasing water extractions in the lower Athabasca River, with a particular focus on two main issues: (i) the impact on flow variability, both in-stream and the associated downstream effects on the Peace-Athabasca Delta; and (ii) the impact on fish habitat, given that dissolved oxygen concentration has been measured at low levels in winter that may be detrimental to fish species, and further extractions will reduce the total amount of dissolved oxygen available. These issues are further discussed below, followed by additional points regarding water quality.

A.2 Flow variability

The Peace-Athabasca Delta has relatively complex hydrology owing to its three river deltas, a low hydraulic gradient, and its interconnected channels, lakes and ephemeral wetlands. Many of the 1 000+ small lakes and wetlands that exist within the delta

(Jaques, 1989 in Peters et al., 2006) are perched above the floodplain and depend on large, intermittent floods to replenish water lost primarily due to evaporation (Peters et al., 2006a).

Although the rate of water extraction for oil-sands mining appears very low compared to peak flows in the Athabasca River, Schindler et al. (2007) are concerned that water extraction during these peak periods may be detrimental given that the floodplain is flat and highly sensitive to differences in water depth. They mention the wide range of flood frequencies found within the delta, with some wetlands experiencing flooding on an almost annual basis while others rarely, and that the most common frequency occurs between these two extremes. This wide range of flood variability provides "a diversity of successional stages and habitat characteristics that support the high diversity of wildlife in the area" (Schindler et al., 2007:10).

Analysis of flood events since the late 1950s (when hydrometric records first became available), including modelling of natural flows in the Peace River to remove the effects of regulation, has demonstrated that overbank flooding of the Peace Delta is likely to only occur due to the backwater effects of ice jams, while flooding of the Athabasca Delta may occur as a result of ice jams or high summer flows (Peters et al., 2006). In general, the extent of flooding in the Peace-Athabasca Delta depends on factors that include the type of flood (ice jam or open water), the antecedent water levels, and the flow volume and duration during the flood. Given all major floods recorded in the Peace-Athabasca Delta were due to ice jams, and ice jams are likely to be the only form of flooding capable of recharging the higher-elevation perimeter of the delta (Peters et al., 2006), the conditions that influence the frequency and magnitude of ice-jam floods are of key interest.

Ice-jam floods in the lower Peace River have recently been studied by Beltaos et al. (2006). They found that ice break-up, which usually occurs in late April or early May, must be mechanical in nature rather than thermal to result in major flooding[25]. Once this necessary precondition is met, spring flow must be of sufficient volume and duration to cause overbank flooding in the area of interest. By analysing previous flood events,

[25] "Thermal" ice break-up refers to ice separation associated with warmer temperatures and melting ice, while "mechanical" ice break-up refers to ice instability and break-up due to hydraulic influences e.g. rapid increase in flow while river is covered in ice.

Beltaos et al. (2006) found that ice jams created by mechanical break-up appear more likely the lower the level of river ice formation, and the higher the spring flow. They advise that a lower ice-cover stage could be achieved by ensuring low flows throughout winter, or possibly (though not tested) in the short period prior to ice break-up (Andres, 2003, in Beltaos et al., 2006). Low flows during the period of freeze-up is another potential approach. Flow could then be surcharged in spring if a mechanical ice-jam appears likely, e.g. based on factors such as snowpack conditions and ice-cover thickness. These two approaches are recommended by Beltaos et al. (2006) to be used in combination, and were studied for the Peace River given that the flow is regulated and so strategic regulation may be possible.

For the lower Athabasca River and delta, high spring flows leading to an ice-jam flood are largely the result of high runoff due to snowmelt in the tributaries within the mid to lower regions (foothill and plains) of the basin i.e. all tributaries from the Pembina River downstream (Peters and Prowse, 2006). Spring floods are more likely the larger the snowpack in the tributary catchments, and in general occur when winter precipitation in the Clearwater River catchment exceeds 100 mm combined with rapid snowmelt conditions (Peters and Prowse, 2006). Between 1958 to 1996, the average date of maximum river level during ice break-up located just below Fort McMurray was found to be April 21st plus or minus 6 days (with dates spanning between April 3rd and May 4th), which is about 3 to 7 days earlier than that in the Athabasca Delta (Peters and Prowse, 2006). The associated average daily flow at these times ranged from 283 m^3/s to 1480 m^3/s, with a mean of 705 m^3/s and standard deviation of 344 m^3/s (Peters and Prowse, 2006).

In addition to spring ice-jam floods, and in contrast to the Peace River, peak annual flows in the Athabasca River occasionally overtop channel levees within the delta. These open-water floods are mainly the result of heavy rainfall-runoff from the elevated foothill and mountain regions of the basin (Peters and Prowse, 2006), and require a much greater discharge to achieve the same flood extent as that of ice jams (Peters et al., 2006). Historically these summer floods have been short, usually in the order of hours to days (Peters and Prowse, 2006), and occur fairly often, with the peak flow requirement of at least 2 600 m^3/s (Doyle, 1977b in Peters and Prowse, 2006) occurring around once every five years on average (Peters, 2003, in Peters et al., 2006).

In addition to ice jams and peak annual flows, inundation of nearby wetlands may occur due to high lake water levels in the Peace-Athabasca Delta associated with prolonged high flow conditions. Analysis of annual peak discharge sustained over 30-days indicates that high lake levels are closely associated with flow conditions in the Peace River, with a much weaker association observed for flows originating from the Athabasca River (Peters and Prowse, 2006). This result is intuitive given that the annual flow of the Peace River averages over four times that of the Athabasca (based on data presented in Alberta Environment [2007]).

Recent years have been dry in the Peace-Athabasca Delta, possibly due to the cumulative effects of flow regulation, natural climate variability, and increased temperatures associated with global warming. Construction of the Bennett Dam on the Peace River in the late 1960's is thought to have significantly changed the hydrology of the Peace-Athabasca Delta, with dampened and less frequent flooding resulting in changes in landform and vegetation types where previously perched wetlands existed (MacLock et al., 1997). The effect of climate change on flow variability is uncertain, particularly whether the recent low-flow conditions are associated with natural, cyclical phenomena, or whether they mark the start of a long-term trend, or perhaps a combination of both. This is further discussed in Appendix E. Bruce (2006) discussed the potential effects of climate change on the Peace-Athabasca Delta, and notes that while it is difficult to predict the effects on ice-jam frequency and flooding, "warmer winters, in general, as well as lowered flows due to the effects of withdrawals, and climate change on the Athabasca River, will contribute to lower water levels and adverse impacts" (Bruce, 2006:30).

A paleolimnological study by Wolfe et al. (2006) of sediments in the floodplain of the Peace River provides an indication of flood history in the Peace-Athabasca Delta over the last 300 years (approximately). It was found that changes in the hydrology of the site are natural over the medium term, with flood intervals being highly variable. For example, at one site, "major floods have occurred every 1-6 years over brief time intervals while during other periods these events have been separated by several decades" (Wolfe et al., 2006:4150). It also appeared that flood frequency has been in decline since possibly the late nineteenth century. While recent years have indeed been dry, the study was unable to distinguish between climate variability versus flow regulation to determine their relative contribution to the recent lack of flooding of the Peace-Athabasca Delta.

To summarise, the environmental values of the Peace-Athabasca Delta depend on the natural flooding of the landscape, including the intermittent flooding of perched wetlands. Flooding of the Athabasca Delta occurs at varying frequencies and magnitudes, by both spring ice-jam floods and peak flow events in summer. Ice-jam flooding is the most important mechanism for replenishing perched wetlands, and is most likely to occur when ice break-up is mechanical in nature combined with high spring flows. In the hypothetical case that maintaining the natural flood variability of the Athabasca Delta is considered more important than supplying upstream water demands, then it may be worthwhile limiting industrial extractions during peak flows in spring and possibly summer (depending on the likelihood of a mechanical ice-jam or open-water flood event respectively).

The paleolimnological study of the adjacent Peace Delta indicates that flow variability over multiple decades is natural, and that floods may occur in either rapid succession or sporadically over many years. Climate change, further discussed in Appendix E, may also have important effects on flow variability and flooding. Given mechanical ice-jams are known to be induced by low preceding water levels and thus a low stage of ice cover, combined with high spring flows, it is possible that warmer winters associated with climate change may increase winter flows and decrease peak spring flows (see Appendix E for further detail) leading to less frequent ice-jam events[26]. This in turn would have a significant effect on the long-term vegetation and habitat values in the Peace-Athabasca Delta.

A.3 Landscape change and groundwater use

In addition to the direct impacts of surface-water extraction, the range of activities associated with surface mining points to a range of potential impacts on streamflow quantities and regional ecosystems.

The initial preparation for surface mining involves the drainage and removal of the overlying muskeg layer, with drainage from this process generally disposed to the tributaries (Rogers, 2006). Once the mine is exposed, licence conditions require that

[26] Climate-change effects on the frequency of ice-jam floods in the Peace-Athabasca Delta, including decreased thickness of ice-cover, are investigated by Beltaos et al. (2006a).

surface runoff be contained on-site. To avoid flooding the site while mining is carried out, the surrounding groundwater level must be drawn down below the depth of the mine, with the pumped groundwater either retained on-site or (in the case of CNRL, due to the extremely high chloride content of pumped groundwater) injected into an aquifer (Rogers, 2006). Many operations also use groundwater (fresh and saline) for water supply purposes, either to supplement surface-water supplies or as their main water source[27].

The activities outlined above would each have associated environmental impacts. Schindler et al. (2007) describe that the muskeg surface layer, which is interspersed with wetlands and in particular wooded fens, acts to absorb precipitation and to provide a slow continuous supply of water to the Athabasca River. Draining the muskeg layer is likely to increase river flow in the short term. Following this, the removal of the muskeg layer is likely to decrease river flow due to a reduction in the effective catchment area for surface runoff (reducing fresh inflows particularly in spring) combined with reduced groundwater inflow. This change in hydrology would apply to affected tributaries as well as the Athabasca River.

Approved developments in the Oil Sands, up to and including the CNRL Horizon mine (i.e. not including the Imperial Kearl project), are forecast to reverse groundwater flow from the basal aquifer to the Athabasca River, from a baseline of 5 100 m^3/day of saline inflow to the river, to 28 500 m^3/day of freshwater seepage from the river between 2019 and 2027 (CNRL, 2003). This is equivalent to a total change in flow in the Athabasca River of 33 600 m^3/day or 0.39 m^3/s. The freshwater seepage from the river attributable to the CNRL Horizon mine of 24 000 m^3/day (2019 to 2027), or 0.28 m^3/s, is equivalent to 17% of the CNRL average licensed water-use following the start-up phase of their operations. This seepage rate does not form part of their licensed water-use accounting.

The environmental quality of the pond-peatland complexes of the region would be dependent on natural levels of soil moisture and drainage, and may also be altered by mining activities. Mine dewatering and groundwater use may draw down regional groundwater levels, while aquifer injection may create the opposite effect, and in general this would have an effect on the drainage of the boreal plains landscape (i.e. either

[27] Allocated groundwater use comprises 13% of the total allocated water-use for the petroleum sector in the Athabasca River basin (refer Table 7-4 for further details).

increasing or decreasing the natural rates of vertical downwards seepage, respectively). The impacts of groundwater extraction and the extent to which groundwater from a certain aquifer may support overlying ecosystems depends on the soil permeability, the connectivity of the aquifer with the surface aquifer, the distance between the point of groundwater extraction and the location of interest (i.e. its location along the pressure drawdown cone of the aquifer), and the hydraulic conductivity of the aquifer(s) that affects the time response of the potential impact. In the Oil Sands region, it appears that the low hydraulic conductivity of soils may buffer the potential impacts to surface drainage. Ferone and Devito (2005) conducted a detailed water-balance study of two shallow pond-peatland complexes of the boreal plains of Alberta, located 300 km north of Edmonton in the Peace River basin. The clay-rich soils of the study area are similar to that found across two-thirds of the boreal plains landscape (Ferone and Devito, 2005). They found that surface runoff was virtually non-existent, and that shallow groundwater-surface water interactions were the predominant non-atmospheric influence on the water balance. Due to the low hydraulic conductivity of the soils, the pond-peatland complexes were found to be "functionally isolated from the regional groundwater flow systems" (Ferone and Devito, 2005:91) over the short, one-year period of the study. While they recommend additional analysis, Ferone and Devito (2007) suggest that the pond-peatland complexes of the boreal plains are likely to be more sensitive to land-use disturbance within the immediate peatland catchment than regional land-use influences.

As demonstrated in the case of CNRL, the flow impact of groundwater draw-down by a single mine is relatively minimal along the Athabasca River. Regional drainage impacts to wetland ecosystems that overlie the zone of groundwater draw down may also be minimal given the low permeability of soil types that are typical to the boreal plains landscape, although such impacts depend on a range of factors including the duration of development activities. Of greater concern is the cumulative impacts of groundwater-surface water interaction across all developed sites, in particular the effect on the hydrology of tributaries and the Athabasca River. These surface water and groundwater impacts would also have associated effects on a range of water quality parameters.

A.4 Fish habitat

There are at least 26 species of fish found in the mid to lower Athabasca basin, some of which spawn in spring, while others spawn in late fall and develop under ice (Nelson and Paetz, 1992).

Although there is a current management focus on flow within the lower Athabasca River, the tributaries, side channels and shoals may serve as important fish habitat, providing fry with relative protection from the strong current, high bed load and other harsh extremities of the main river channel (pers. comm., David Schindler, 6/5/2008). As mentioned by Schindler et al. (2007), fall-spawning fish species may be particularly at risk of lower flows in both the river and tributaries, given low flows during late fall and early winter may impede access to spawning sites, and low flows during winter (when the mouths of tributaries may become frozen solid) may impede access to nursery habitat in the river.

Off-stream storage has the potential to mitigate the seasonal impacts on fish habitat by extracting flow from the river during selective periods. While winter, spring peak flow and ice break-up conditions should be avoided, there is potentially a 6-week window of high flow conditions after late June when filling of an off-stream storage would cause least disruption to fish spawning (pers. comm., David Schindler, 4/3/2008)[28].

A.5 Dissolved oxygen

One of the main ecological concerns raised regarding increases in water extraction is the reduced levels of dissolved oxygen in the Athabasca River during winter, when ice coverage limits the exchange of oxygen between the atmosphere and the river. Water extraction during winter reduces the total volume of dissolved oxygen available to support aquatic life and assist in decomposition processes. Dissolved oxygen is required for the in-stream decomposition of organic matter derived from natural sources, as well as matter discharged with wastewater. Thus minimising wastewater discharge, in addition to minimising water extraction, is another strategy for maintaining dissolved oxygen levels in winter.

[28] It is unknown whether such an off-stream storage option would be technically feasible, given location, size and water demand characteristics.

The Grand Rapids, located along the Athabasca River upstream of Fort McMurray, aerate flow and remain uncovered throughout winter. The rapids replenish dissolved oxygen back up to saturation levels (Chambers and Mill, 1996) as well as serving as a major fish-spawning area (MacLock et al., 1997). Given this function, and concern regarding wastewater discharged from upstream municipalities and pulp and paper mills, the NRBS did not consider dissolved oxygen levels downstream of the Grand Rapids to be an issue, but rather recommended that action be taken to minimise impacts to dissolved oxygen upstream of the Grand Rapids (MacLock et al., 1997).

Below Fort McMurray, low dissolved oxygen levels have been recorded particularly near the mouths of tributaries during the low-flow winter period, with these conditions known to negatively impact on fall-spawning fish species (Schindler et al., 2007). The NRBS previously found that a number of tributaries (Pembina, Lac La Biche, Muskeg and Firebag rivers) demonstrated levels of dissolved oxygen below the Alberta Surface Water Quality Objective of 5 mg/L "on a fairly consistent basis" (Chambers and Mill, 1996:72). Given the information available at the time, those sites identified as having low dissolved oxygen levels were thought to be distinct and unlikely to represent significant habitat for fall or winter-spawning fish species (Chambers and Mill, 1996).

A.6 Water quality and contaminants

Although water quality is not a focus of this current study, the NRBS found that water quality and contaminants were the main environmental impacts in the lower Athabasca River. Downstream of Fort McMurray, cautionary levels of nutrient enrichment were found, and both contaminants and human health implications were considered to be of sufficient concern to recommend action (Wrona et al., 1996).

There is an associated risk that the contaminants stored within the massive tailings ponds (located on-site) may enter the downstream environment and surrounds via evaporation, seepage, and potential embankment failure. Recent bird deaths due to contact with tailings water have been widely reported, while exposure of tailings water to other fauna is also an ongoing risk. Other concerns include the deposition of airborne contaminants and their effect on ecosystems and human health.

In determining the impacts of development, it is important to note that the Athabasca River cuts through oil sands at Fort McMurray and tar has historically been present along its banks (MacLock et al., 1997). Some contaminants and water quality indicators measured downstream of Fort McMurray, such as elevated levels of polycyclic aromatic hydrocarbons (Schindler et al., 2007), are considered the result of natural inputs (Evans et al., 2002, in Schindler et al., 2007). Another potential example is the results of an ethoxyresorufin-O-deethylase (EROD) test, an indicator of toxin exposure collected as part of the NRBS, that show increased readings downstream of oil-sands activity (Schindler et al., 2007). In this case, the increased reading is in comparison to sampling taken well upstream (at a site nearby the town of Athabasca) and so the heightened levels found downstream of Fort McMurray may again be related to natural inputs. Further downstream, natural uranium deposits are found near Lake Athabasca (MacLock et al., 1997).

Appendix B Lower Athabasca Water Management Framework

B.1 Habitat area thresholds

- **Table 7-1 Relationship between Weighted Useable Area (WUA) and flow for Longnose Sucker (LNSC)-A, Reach 4[A]**

Ice-cover period		Open water period	
Discharge (m^3/s)	**Weighted Useable Area (m^2)**	**Discharge (m^3/s)**	**Weighted Useable Area (m^2)**
0	0	0	0
50	1 291 687	100	1 385 462
55	1 322 693	120	1 489 545
60	1 361 890	140	1 564 752
70	1 403 477	160	1 634 749
80	1 436 613	180	1 728 473
90	1 476 563	200	1 779 005
100	1 524 848	220	1 836 249
120	1 624 518	250	1 962 860
133	1 706 310	300	2 093 381
140	1 731 316	350	2 248 420
160	1 864 245	400	2 365 007
180	2 019 820	450	2 465 571
200	2 089 173	500	2 645 223
220	2 145 115	600	2 937 947
250	2 202 124	700	3 122 893
300	2 322 964	800	3 232 918
350	2 348 123	900	3 310 552
400	2 350 212	1000	3 385 666
450	2 360 299	**1500[B]**	**3 448 647**
500[B]	**2 361 488**	2000	3 337 036
600	2 308 895		

Notes to Table 7-1:

A. Information provided by Preston McEachern, Alberta Environment, 10/12/2007.

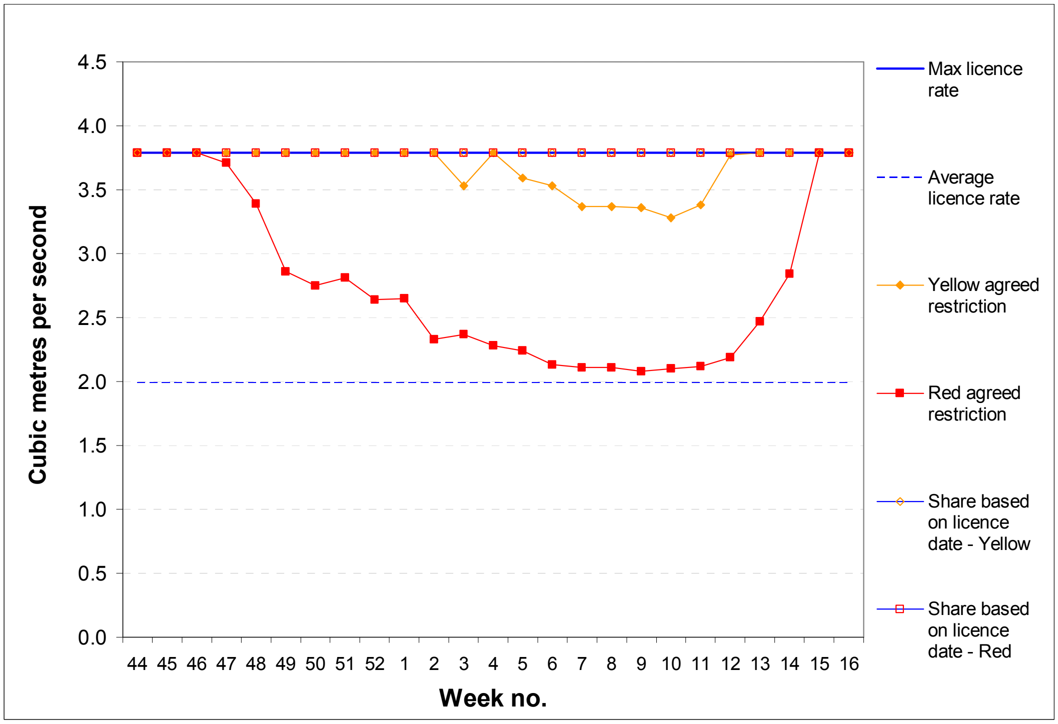
B. Peak value of Weighted Useable Area. Discharges above this level were considered “green” flow conditions.

B.2 Industry sharing agreement for 2007-08 season

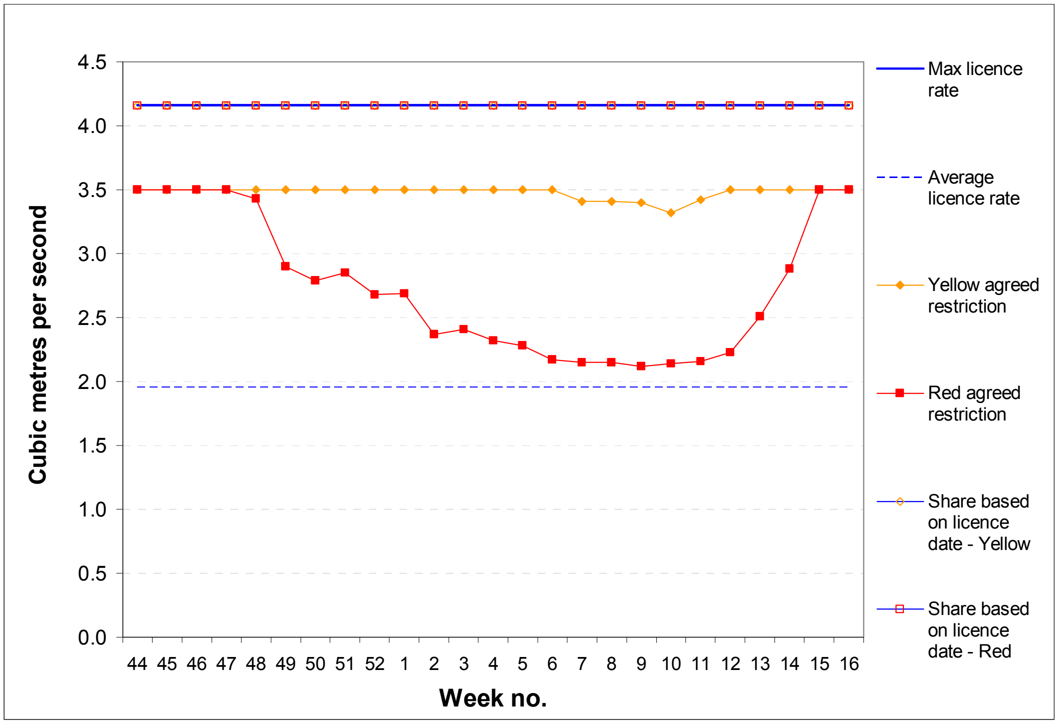
The Oil Sands Mining Water Management Agreement for the 2007-2008 season (Athabasca Regional Issues Working Group, 2007) was devised by industry representatives. This agreement covers the first period of implementation of the framework for the four surface-mining companies in operation: Suncor, Syncrude, Albian Sands and Canadian Natural Resources Ltd. The agreement outlines the maximum rates of extraction during red and yellow flow conditions for each company during the low-flow weeks of the year when restrictions may become binding (Table 7-2). Excess or unassigned rates of extraction, equal to the total allowable rate of extraction minus the extraction rates assigned to each company, are also specified for both red and yellow flow conditions.

The maximum rates set in the agreement are based on the licensees limiting water use at differing levels of severity. Suncor and Syncrude both agreed to reduce their maximum instantaneous rates of extraction to levels just above their average licensed allocation. The remaining companies of the agreement, Albian Sands and CNRL, were to reduce water usage with the assistance of water storage if necessary to meet the flow targets of the framework. The relative preference in the industry agreement for scarce water supplies to be issued to Suncor and Syncrude reflects the relative seniority of their water licences.

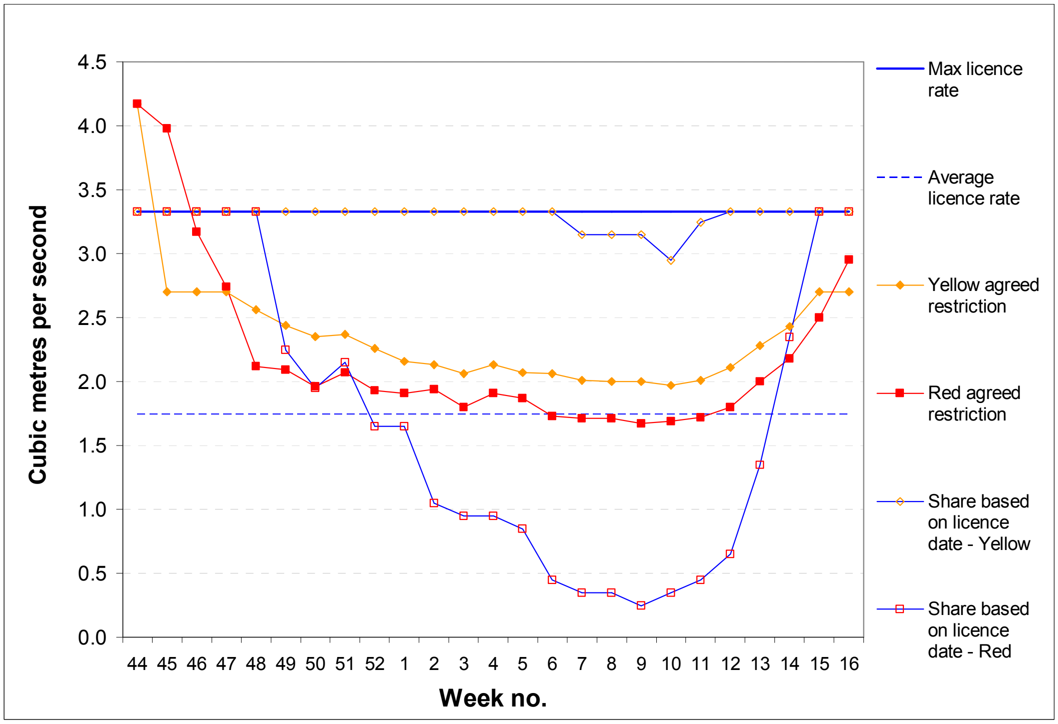
Figure 7-1 to Figure 7-4 show, for each operating company, the maximum rate of licensed extraction, the maximum rates of extraction during red and yellow flow conditions if water is shared based on licence priority (using the prior allocation approach of the *Water Act*), and the industry-agreed maximum rates of extraction during red and yellow flow conditions. Figure 7-5 presents the unassigned rates of extraction of the agreement. The charts show that Suncor and Syncrude both significantly lowered their maximum rates of extraction from levels that would otherwise have been unaffected by Phase 1 of the Water Management Framework. Conversely, Albian Sands and CNRL were able to negotiate access to water at levels similar to their average licensed rates, when both may otherwise have faced very limited supplies if red conditions were triggered at certain times. For example, if red conditions were triggered between December to mid-April, under the first-in-time first-in-right system CNRL would have been subject to a full ban on water use.



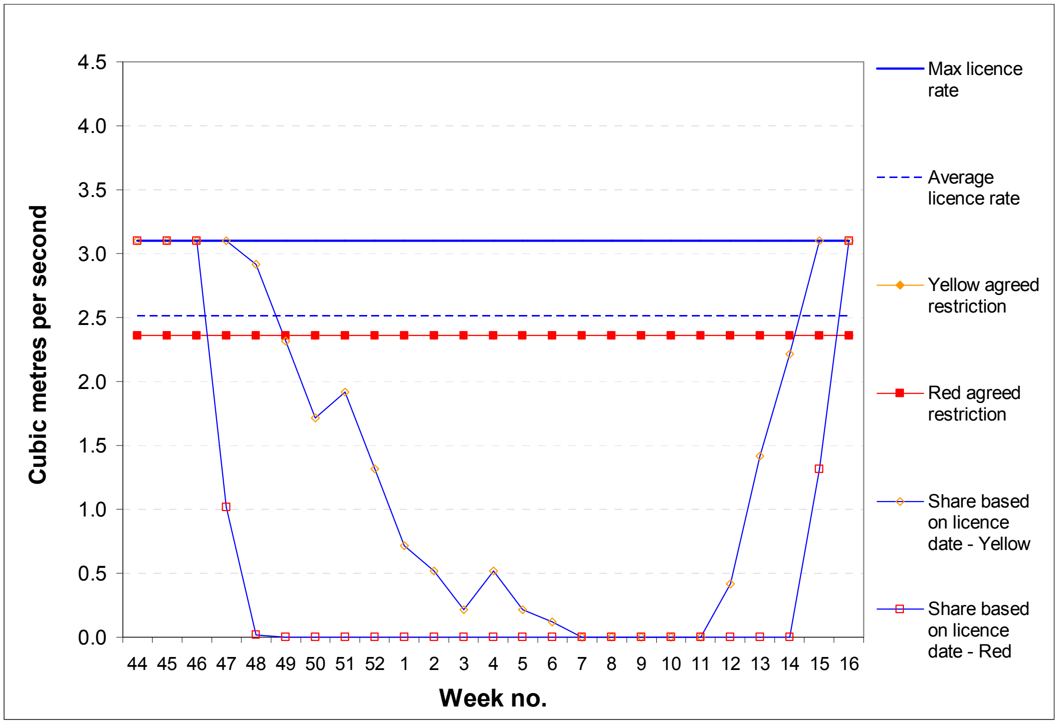
- **Figure 7-1 Suncor maximum instantaneous withdrawals under the Oil Sands Mining Water Management Agreement for the 2007-08 season**



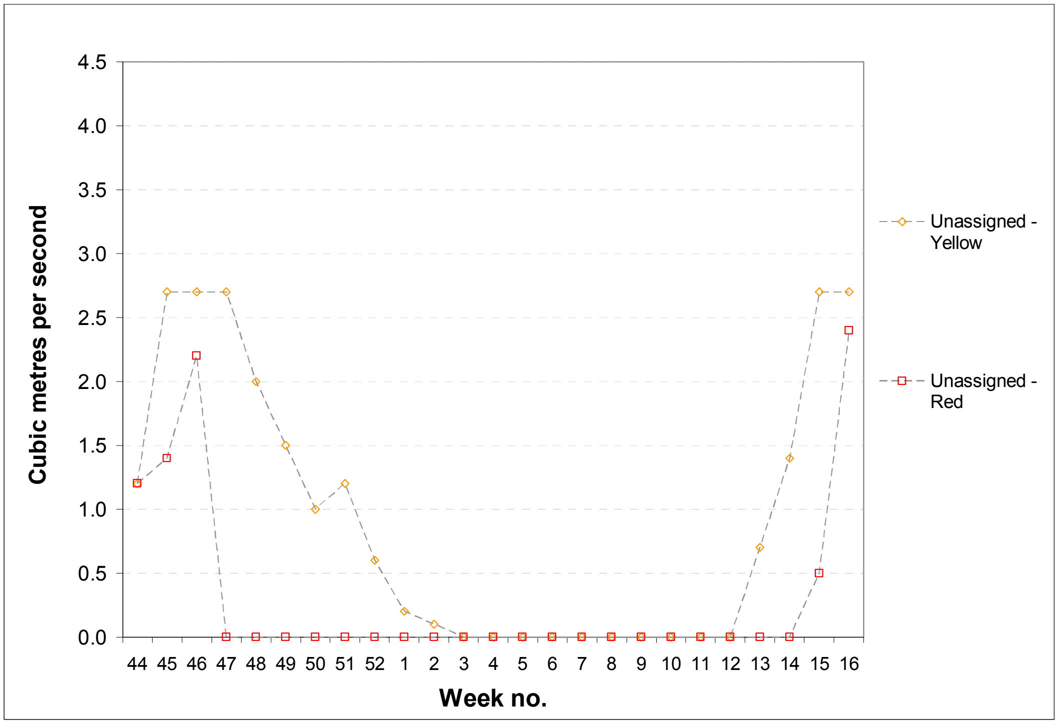
- **Figure 7-2 Syncrude maximum instantaneous withdrawals under the Oil Sands Mining Water Management Agreement for the 2007-08 season**



- **Figure 7-3 Albian Sands maximum instantaneous withdrawals under the Oil Sands Mining Water Management Agreement for the 2007-08 season**



- **Figure 7-4 Canadian Natural Resources Limited maximum instantaneous withdrawals under the Oil Sands Mining Water Management Agreement for the 2007-08 season**



- **Figure 7-5 Unassigned volumes under the Oil Sands Mining Water Management Agreement for the 2007-08 season**

- **Table 7-2 Oil Sands Industry Agreement for the 2007 to 2008 Winter Period: agreed maximum peak instantaneous withdrawals[A], m^3/s**

Week	Week start	Framework Target		Suncor		Syncrude		Albian Sands		Canadian Natural		WAy, cumulative		WAr, cumulative	
		Yellow	Red	WAy	WAr	WAy	WAr	WAy	WAr	WAy	WAr	Sum	Excess	Sum	Excess
44	29-Oct	15.00	15.00	3.79	3.79	3.50	3.50	4.17	4.17	2.36	2.36	13.80	1.20	13.80	1.20
45	5-Nov	15.00	15.00	3.79	3.79	3.50	3.50	2.70	3.98	2.36	2.36	12.40	2.70	13.60	1.40
46	12-Nov	15.00	15.00	3.79	3.79	3.50	3.50	2.70	3.17	2.36	2.36	12.40	2.70	12.80	2.20
47	19-Nov	15.00	12.30	3.79	3.71	3.50	3.50	2.70	2.74	2.36	2.36	12.40	2.70	12.30	0.00
48	26-Nov	14.20	11.30	3.79	3.39	3.50	3.43	2.56	2.12	2.36	2.36	12.20	2.00	11.30	0.00
49	3-Dec	13.60	10.20	3.79	2.86	3.50	2.90	2.44	2.09	2.36	2.36	12.10	1.50	10.20	0.00
50	10-Dec	13.00	9.90	3.79	2.75	3.50	2.79	2.35	1.96	2.36	2.36	12.00	1.00	9.90	0.00
51	17-Dec	13.20	10.10	3.79	2.81	3.50	2.85	2.37	2.07	2.36	2.36	12.00	1.20	10.10	0.00
52	24-Dec	12.60	9.60	3.79	2.64	3.50	2.68	2.26	1.93	2.36	2.36	11.90	0.60	9.60	0.00
1	1-Jan	12.00	9.60	3.79	2.65	3.50	2.69	2.16	1.91	2.36	2.36	11.80	0.20	9.60	0.00
2	8-Jan	11.80	9.00	3.79	2.33	3.50	2.37	2.13	1.94	2.36	2.36	11.80	0.10	9.00	0.00
3	15-Jan	11.50	8.90	3.53	2.37	3.50	2.41	2.06	1.80	2.36	2.36	11.50	0.00	8.90	0.00
4	22-Jan	11.80	8.90	3.79	2.28	3.50	2.32	2.13	1.91	2.36	2.36	11.80	0.00	8.90	0.00
5	29-Jan	11.50	8.80	3.59	2.24	3.50	2.28	2.07	1.87	2.36	2.36	11.50	0.00	8.80	0.00

Week	Week start	Framework Target		Suncor		Syncrude		Albian Sands		Canadian Natural		WAy, cumulative		WAr, cumulative	
		Yellow	Red	WAy	WAr	WAy	WAr	WAy	WAr	WAy	WAr	Sum	Excess	Sum	Excess
6	5-Feb	11.40	8.40	3.53	2.13	3.50	2.17	2.06	1.73	2.36	2.36	11.40	0.00	8.40	0.00
7	12-Feb	11.10	8.30	3.37	2.11	3.41	2.15	2.01	1.71	2.36	2.36	11.10	0.00	8.30	0.00
8	19-Feb	11.10	8.30	3.37	2.11	3.41	2.15	2.00	1.71	2.36	2.36	11.10	0.00	8.30	0.00
9	26-Feb	11.10	8.20	3.36	2.08	3.40	2.12	2.00	1.67	2.36	2.36	11.10	0.00	8.20	0.00
10	4-Mar	10.90	8.30	3.28	2.10	3.32	2.14	1.97	1.69	2.36	2.36	10.90	0.00	8.30	0.00
11	11-Mar	11.20	8.40	3.38	2.12	3.42	2.16	2.01	1.72	2.36	2.36	11.20	0.00	8.40	0.00
12	18-Mar	11.70	8.60	3.77	2.19	3.50	2.23	2.11	1.80	2.36	2.36	11.70	0.00	8.60	0.00
13	25-Mar	12.70	9.30	3.79	2.47	3.50	2.51	2.28	2.00	2.36	2.36	11.90	0.70	9.30	0.00
14	1-Apr	13.50	10.30	3.79	2.84	3.50	2.88	2.43	2.18	2.36	2.36	12.10	1.40	10.30	0.00
15	8-Apr	15.00	12.60	3.79	3.79	3.50	3.50	2.70	2.50	2.36	2.36	12.40	2.70	12.20	0.50
16	15-Apr	15.00	15.00	3.79	3.79	3.50	3.50	2.70	2.95	2.36	2.36	12.40	2.70	12.60	2.40

A. Notes: Albian/Shell is currently limited to 1.8% of river flow. This cannot be pre-calculated. The yellow/green and yellow/red flows were chosen to be conservative. This conservative assumption ensures that cumulative use does not exceed the Framework Targets. In some cases Albian will be restricted further by its 1.8% provision.

Maximum instantaneous withdrawal limits herein are measured and managed on a daily average basis.

WAy: Maximum peak instantaneous withdrawal available in a yellow flow period.

WAr: Maximum peak instantaneous withdrawal available in a red flow period.

Appendix C Water licences and water use

This appendix contains background information on water licences in the Athabasca Basin, water licences specific to the petroleum industry in the basin, and historic water use by oil sands surface-mining operations.

C.1 Water licences in the Athabasca Basin

A report by Alberta Environment (2007) provides details on licensed allocations and estimates of current (2005) and future water-use for each river basin in Alberta, collated from a range of available sources[29]. Table 7-3 provides the information reported on licences and water use (for both surface water and groundwater resources) for the Athabasca basin. The majority of licensed water-use in the Athabasca River basin is allocated to the petroleum industry, with 92% of licensed surface-water use and 81% of all licensed water-use (2005 data) allocated to surface-mining operations in the Oil Sands (Alberta Environment, 2007). This information clearly shows the dominance of the petroleum sector in terms of share of both licensed and actual water-use in the Athabasca basin.

Water statistics for the petroleum sector are further separated in Table 7-4 into thermal petroleum extraction, surface mining, gas and petrochemical plants, and other petroleum. This information is also illustrated in Figure 7-6. As shown, most (90%) of the allocated water-use is for oil-sands mining, and most (89%) of this allocation is supplied by surface-water sources (Athabasca River, tributaries or surface runoff).

[29] In many cases the measurement of actual water-use was unavailable, and so estimates were made based on proportional use information collated for similar entities, or 100% usage of the licensed volume (see Alberta Environment [2007] for details).

- **Table 7-3 Summary of allocations and estimated water-use for both surface water and groundwater resources, Athabasca River basin [a]**

Sector	Licensed allocation and use				Estimated actual water-use		
	Allocation, ML	**Water use, ML**	**Return flow, ML**	**% total use**	**Use, ML**	**% licensed use**	**% total use**
Municipal	46 097	8 907	37 190	1	5 508	62	2
Agricultural							
Stock watering	9 122	9 122	1	1	8 055	88	3
Irrigation	3 475	2 094	-	0	2 094	100	1
Commercial	3 801	3 749	52	1	3 749	100	1
Petroleum	581 792	540 569	41 223	85	183 664	34	67
Industrial	145 364	24 016	121 348	4	22 566	94	8
Other [b]	59 988	47 508	12 480	7	47 508	100	17
Total	**849 639**	**635 965**	**213 674**	**100**	**273 144**	**43**	**100**

Notes:

a. Source: Table 11-35, Alberta Environment (2007: 476)

b. The majority (96.4%) of licences in "Other" category are used for water management purposes related to flood control and lake stabilisation, and were assumed to be fully utilised (Alberta Environment, 2007).

- **Table 7-4 Licensed allocations and estimated actual water-use in the Athabasca Basin by the petroleum sector [a]**

Water Use	Source	No. of licences	Licensed allocation and use, ML			Estimated actual water-use		
			Allocation	Allocated Water Use	Return	Est. Actual Water Use, ML	% of Licensed Use	% of Allocation
Thermal [b]	Surface	35	38 211.6	35 394.2	2 817.4	8 108	22.9	21.2
	Groundwater	204	15 583.2	15 583.2	-	3 430	22.0	22.0
	Subtotal	239	53 794.8	50 977.3	2 817.4	11 538	22.6	21.4
Oil sands Mining [c]	Surface	22	471 272.8	433 064.6	38 208.2	158 077	36.5	33.5
	Groundwater	27	52 418.4	52 418.4	-	12 224	23.3	23.3
	Subtotal	49	523 691.2	485 483.0	38 208.2	170 302	35.1	32.5
Gas/Petrochemical Plant [d]	Surface	3	1 609.0	1 609.0	-	546	34.0	34.0
	Groundwater	33	2 689.6	2 492.4	197.2	1 272	51.0	47.3
	Subtotal	36	4 298.6	4 101.4	197.2	1 818	44.3	42.3
Other Petroleum [e]	Surface	0	-	-	-	-	0.0	0.0
	Groundwater	4	7.1	7.1	-	7	100.0	100.0
	Subtotal	4	7.1	7.1	-	7	100.0	100.0
Total	**Surface**	**60**	**511 093.4**	**470 067.8**	**40 025.6**	**166 732**	**35.5**	**32.6**
	Groundwater	**268**	**70 698.3**	**70 501.1**	**197.2**	**16 933**	**24.0**	**24.0**
	Subtotal	**328**	**581 791.7**	**540 568.8**	**41 222.8**	**183 664**	**34.0**	**31.6**

Notes to Table 7-4:

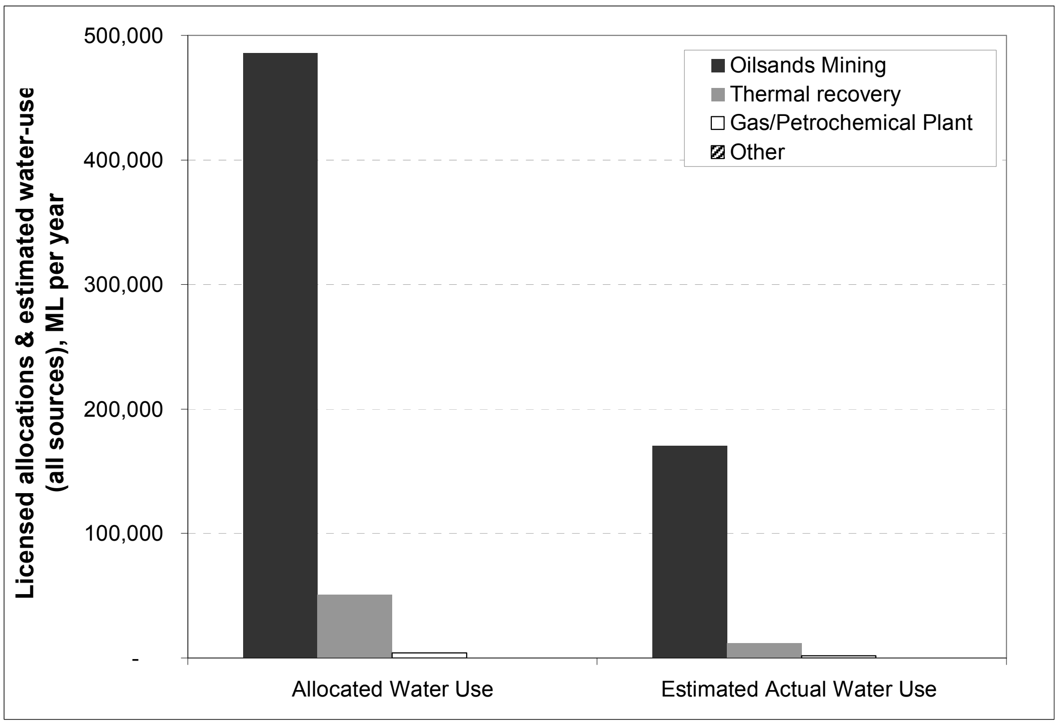
a. Source: Alberta Environment (2007: 455)

b. Estimated water use based on a review by Geowa Information Technologies Ltd. of the Alberta Energy and Utilities Board (EUB) database

c. Estimated water use based on Alberta Environment for withdrawals from the Athabasca River and 100% from other sources

d. Estimated water use is based on Alberta Environment's Water Use Reporting System (WURS) data

e. Estimated water use assumes 100% use.



- **Figure 7-6 Allocated water-use and estimated actual water-use in 2005 for the petroleum sector in the Athabasca Basin (Source: Alberta Environment, 2007)**

Table 7-5 provides a listing of licensed allocations for oil sands projects by licensee (excluding the Kearl [Imperial] project, whose licence was approved after the Alberta Environment [2007] study). Excluding the Imperial licence, most (69%) of the total licensed allocation is to be sourced directly from the Athabasca River, while 13% is to be sourced from other surface-water, a further 8% from surface runoff, and 10% from groundwater.

- **Table 7-5 Licensed allocations for Oil Sands Projects [a]**

Licensee	Licensed allocation, ML per year: Athabasca River	Other Surface	Surface Runoff	Ground-water	Total
Albian Sands Energy Inc.	55 100	3 830[b]	-	7 130	66 060
Canadian Natural Resources Ltd.	79 320	34 700[c]	-	7 301	121 321
Fort Hills Energy Corporation	39 270	-	6 847	6 665	52 782
Shell Canada Limited	63 500	8 900[d]	-	26 000	98 400
Suncor Energy Inc.	62 825	3 390[e]	16 235	3 839	86 289
Syncrude Canada Ltd [f]	61 675	15 557	20 124	1 255	98 611
Other	-	-	-	228	228
Total	**361 690**	**66 377**	**43 206**	**52 418**	**523 691**

a. Source: Table 11-23, Alberta Environment (2007: 457), with minor correction. Kearl (Imperial) licence not approved at the time of table collation.

b. Surface runoff tributary to the Muskeg River.

c. Tar River and surface runoff tributary to the Tar and Calumet rivers.

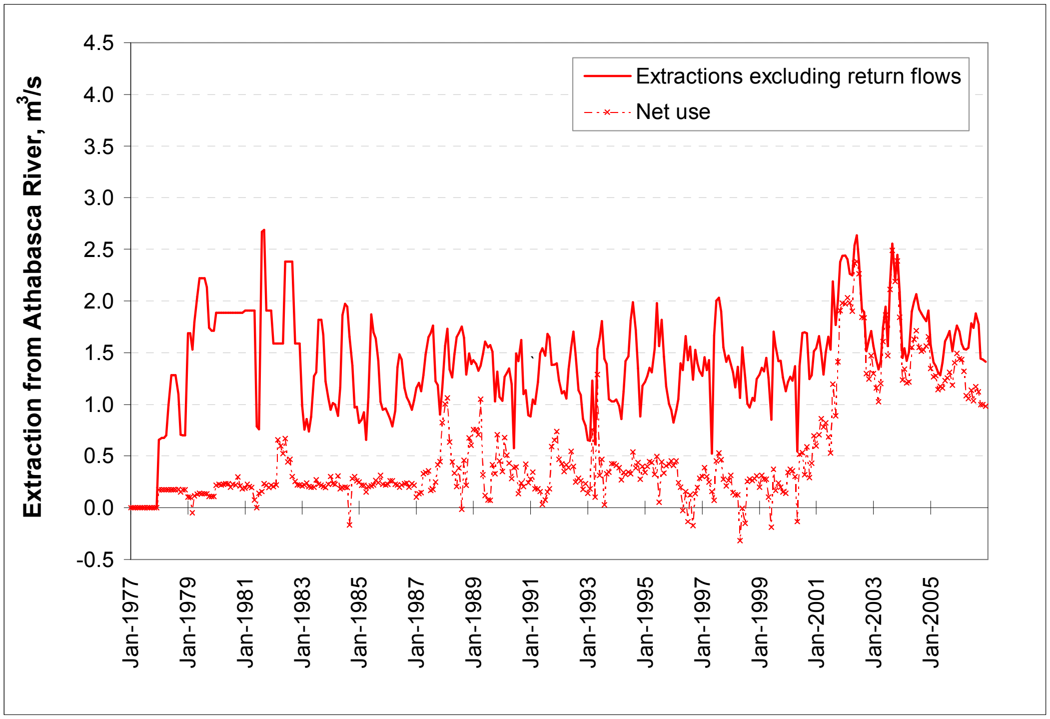
d. Surface runoff tributary to the Muskeg River and Jackpine Creek.

e. Surface runoff tributary of the Athabasca River.

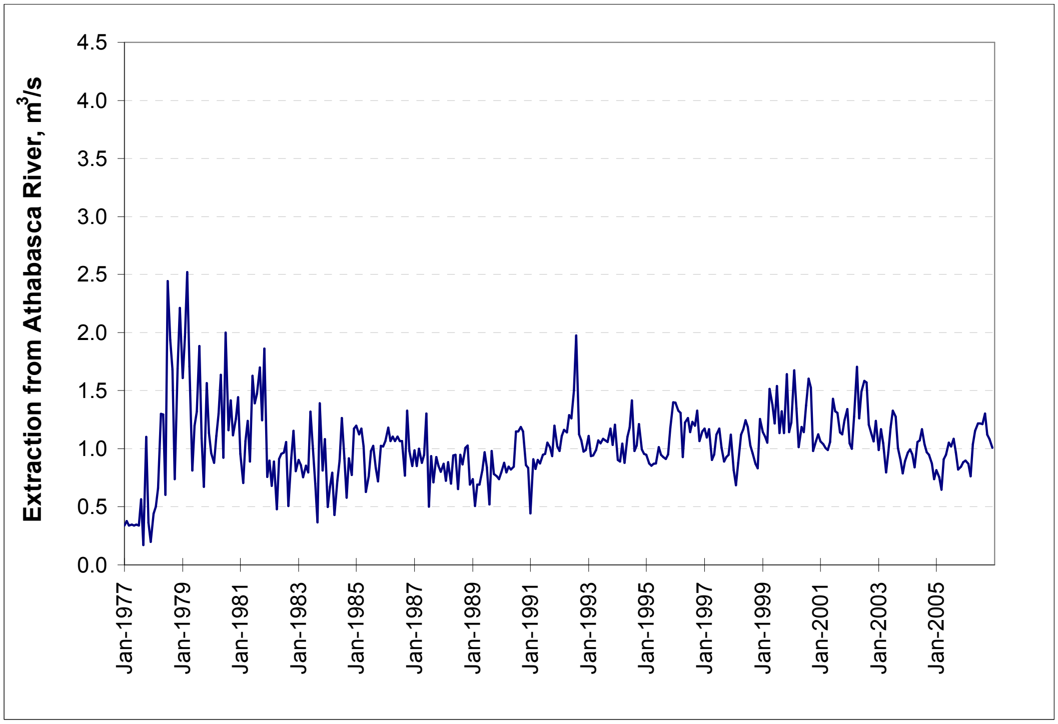
f. Source of "other surface" unclear. Numbers inconsistent with other source data.

C.2 Historic water use

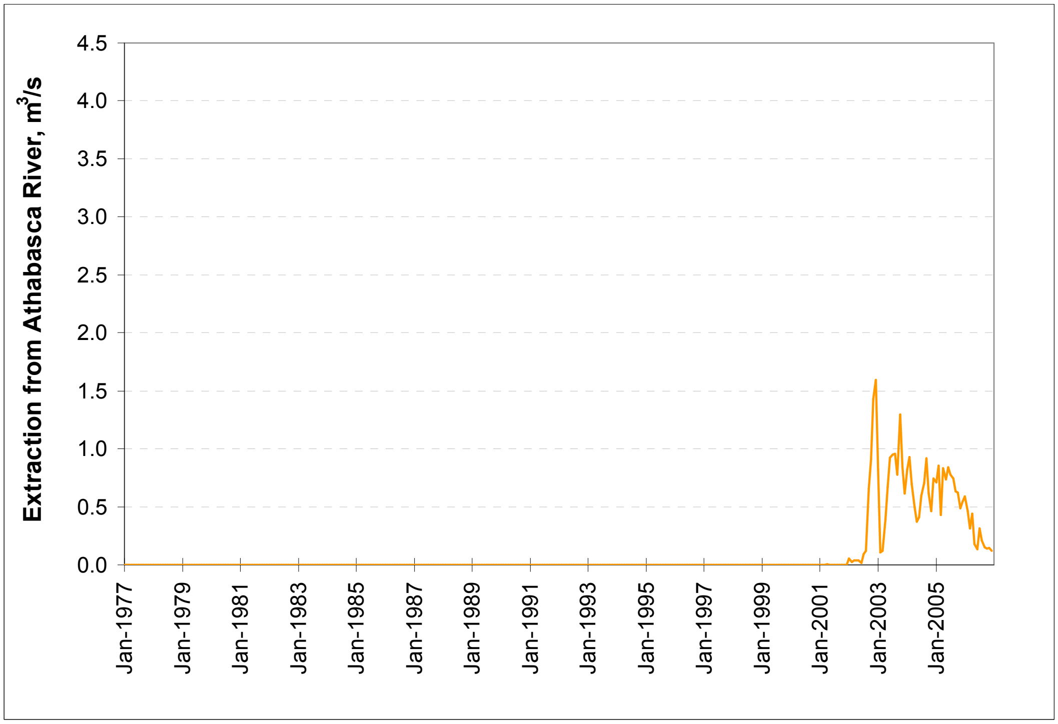
Historic water extractions from the Athabasca River and return flows were provided by Alberta Environment (pers. comm., Carmen de la Chevrotière, 15/2/2008) for each of the four oil-sands mining companies currently in operation. This information is presented in Figure 7-7 to Figure 7-10 in terms of monthly volumes, and also in Figure 7-11 in terms of annual licence utilisation. Figure 7-11, along with information listed in Table 7-4, demonstrates that licences have been issued well in excess of current requirements, with an estimated 34% utilisation of licensed water-use. This is partly due to the issuing of licences following planning approval (when operations are yet to commence), and also due to the prior practice of issuing excessive licence volumes that do not adjust with project life-cycle (recently-issued licences have specified separate volumes during different phases of operation of each project, as indicated in the notes below Table 2-1).



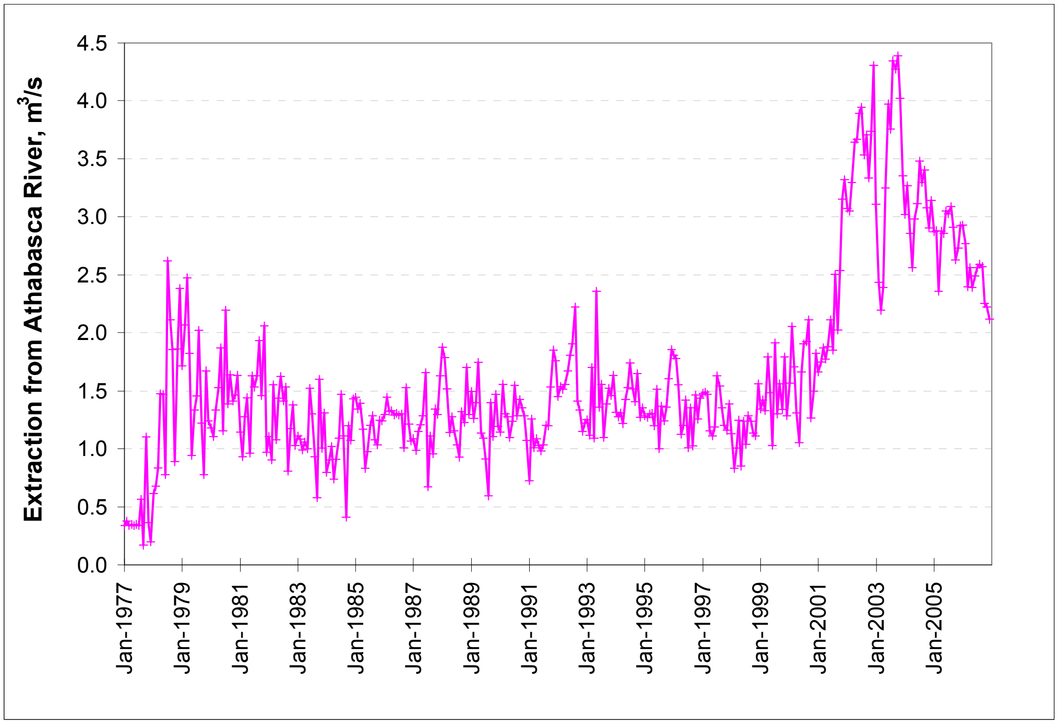
- **Figure 7-7 Suncor historic extraction and return flows to the Athabasca River (monthly data provided by Alberta Environment)**



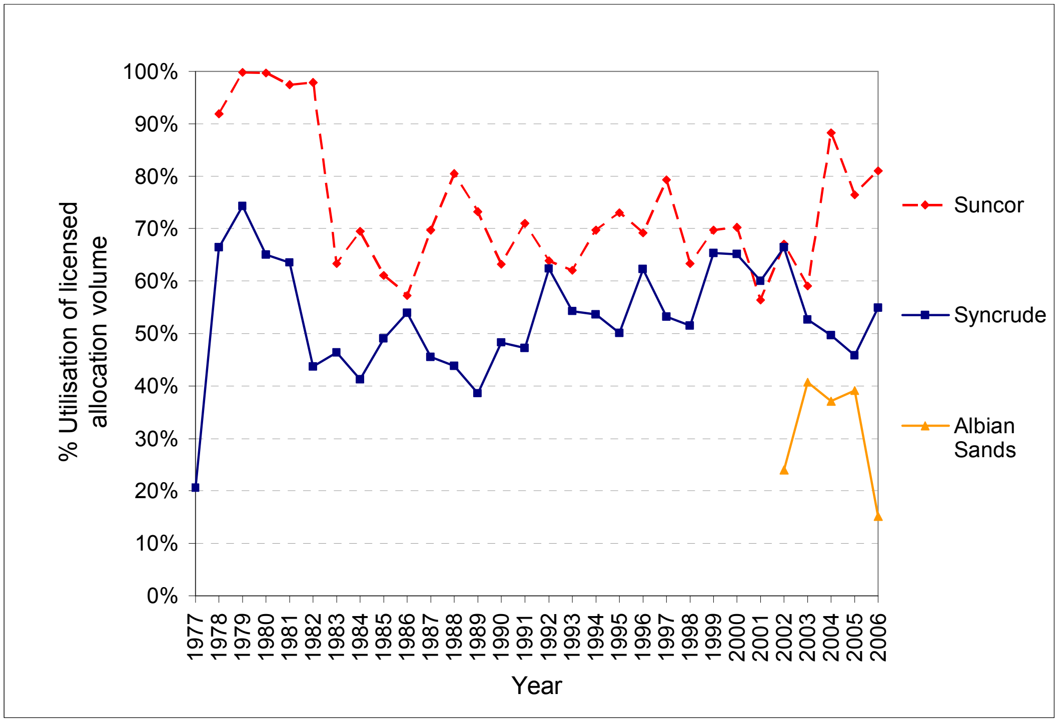
- **Figure 7-8 Syncrude historic extraction from the Athabasca River (monthly data provided by Alberta Environment)**



- **Figure 7-9 Albian Sands historic extraction from the Athabasca River (monthly data provided by Alberta Environment)**



- **Figure 7-10 Historic extraction (net) by Oil Sands Surface-Mining Operations from the Athabasca River (monthly data provided by Alberta Environment)**

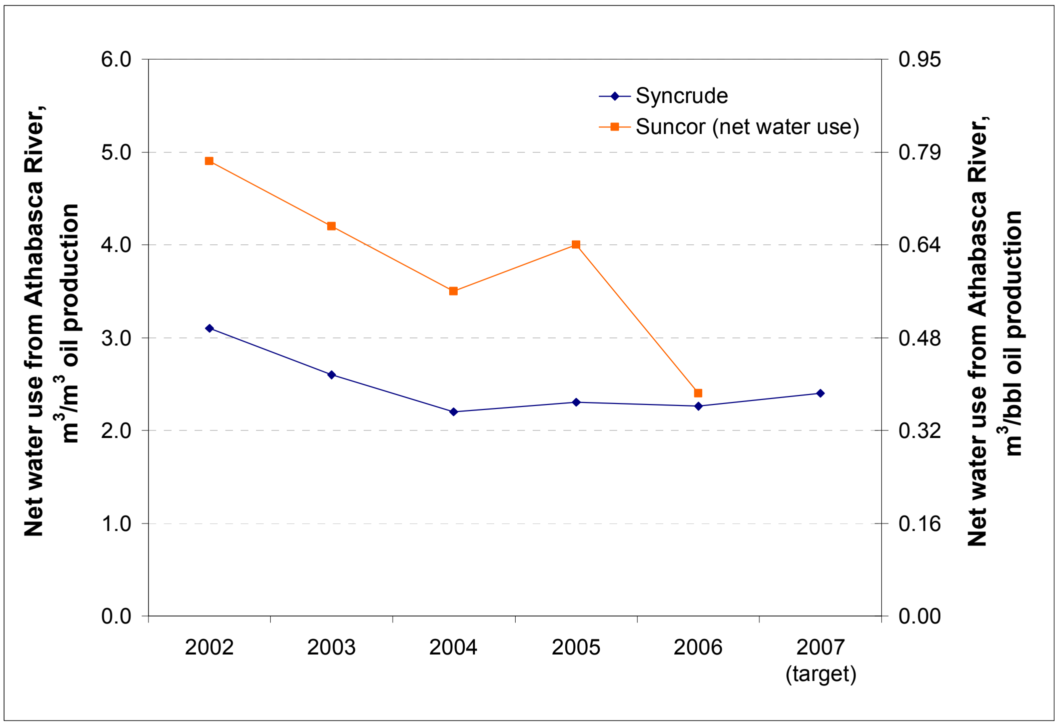


- **Figure 7-11 Percent utilisation of licensed allocations by operating licence holders in the oil-sands mining sector, 1977 to 2006**

Corporate sustainability reports provide an explanation for the water-use patterns in recent years. In 2006, Albian Sands had a lower demand than otherwise due to operational issues, and drew water from excess amounts stored on-site (Shell Canada Ltd, 2007). In the same year, Syncrude experienced lower production than originally planned and higher water recycling, although water use was still greater than in 2005 due to higher overall production and additional start-up water demands associated with expansion (Syncrude Canada Ltd, 2007). Suncor's return flows significantly decreased from 2002 onwards, which in turn significantly increased their net water-use. Previously, the return flow from Suncor comprised treated wastewater from upgrade processes and mine drainage (MacLock et al., 1997). Suncor appears to have recycled water that would otherwise have been discharged to the river due to the company nearing the limit of its water licence. Suncor are not planning to seek an increase in their water licence for their Voyageur upgrader expansion, which is expected to increase production by 10% (Suncor Energy, 2008).

C.3 Historic water-use efficiency

Historic water-use efficiency for the two long-established surface-mining operations, Suncor and Syncrude, is provided in their corporate sustainability reports (Suncor Energy [2008], Syncrude Canada Ltd [2007]). This information is presented in Figure 7-12. The most recent estimate of water-use efficiency for both companies (2006 or 2007 target water-use), in terms of net water use from the Athabasca River, is 2.4 m^3 of water per m^3 of oil production (or 0.38 m^3 per bbl of oil).



- **Figure 7-12 Net water use from the Athabasca River per unit of oil production, Suncor and Syncrude mining operations, 2002 to 2006 (plus 2007 target where available)**

Appendix D Background flows in the lower Athabasca River

This appendix provides a short description of the basin followed by a summary of the available flow information for the lower Athabasca River and tributaries.

D.1 Basin description

The Athabasca River is the largest unregulated river in Alberta and the province's second-largest river after the Peace River. The basin has a total area of 157 000 km^2, covering approximately 22% of Alberta (MacLock et al., 1997).

The headwaters of the Athabasca River are fed by melting glaciers of the Columbia Icefield and melting snow in the Rocky Mountains and foothills of Jasper National Park. Other inflows are received from groundwater (base flow and interflow), surface runoff from the direct catchment, and tributaries that include the McLeod, Pembina, Lesser Slave, and Clearwater rivers. Over its total length of approximately 1350 km (Peters and Prowse, 2006), the Athabasca River flows through two major types of terrain: the Rocky Mountains and foothills, and the boreal forest.

Along its lower reaches the terrain flattens and streamflow branches out into the Peace-Athabasca Delta, including Lake Athabasca. Approximately 80% of the Peace-Athabasca Delta lies within Wood Buffalo National Park (Peters and Prowse, 2006). Water slowly drains to the north of the delta, joining the Peace River to form the Slave River, then flowing into Great Slave Lake and eventually the Beaufort Sea via the Mackenzie River system.

Major population centres include Jasper, Hinton, Edson, Whitecourt, Athabasca, and Fort McMurray, all of which extract water for urban water supply and discharge wastewater. Land uses in the basin include gas wells, forestry, agriculture, open-pit coal and oil-sands mining, urban area, and national parks (see MacLock et al. [1997] for further details).

D.2 Available flow data

Daily flow data for the lower Athabasca River were provided by Alberta Environment (Preston McEachern, 10/12/2007). The flow data were separated into five reaches below Fort McMurray, as described in the hydraulic modelling report by Seneka (2002), and represent background flow conditions given these do not take into account extractions for oil sands mining. Reach 5 to Reach 4 (Table 7-6) are of main interest, given this is where water is currently extracted for oil sands mining and is the focus of the WMF (with Reach 3 to Reach 1 specified further downstream). Of the two reaches, the downstream reach - Reach 4 - includes monitored inflows from tributaries in the Oil Sands (up to and including the Steepbank River) and would be affected by the majority of approved mining developments, and so was selected for the analysis of restrictions.

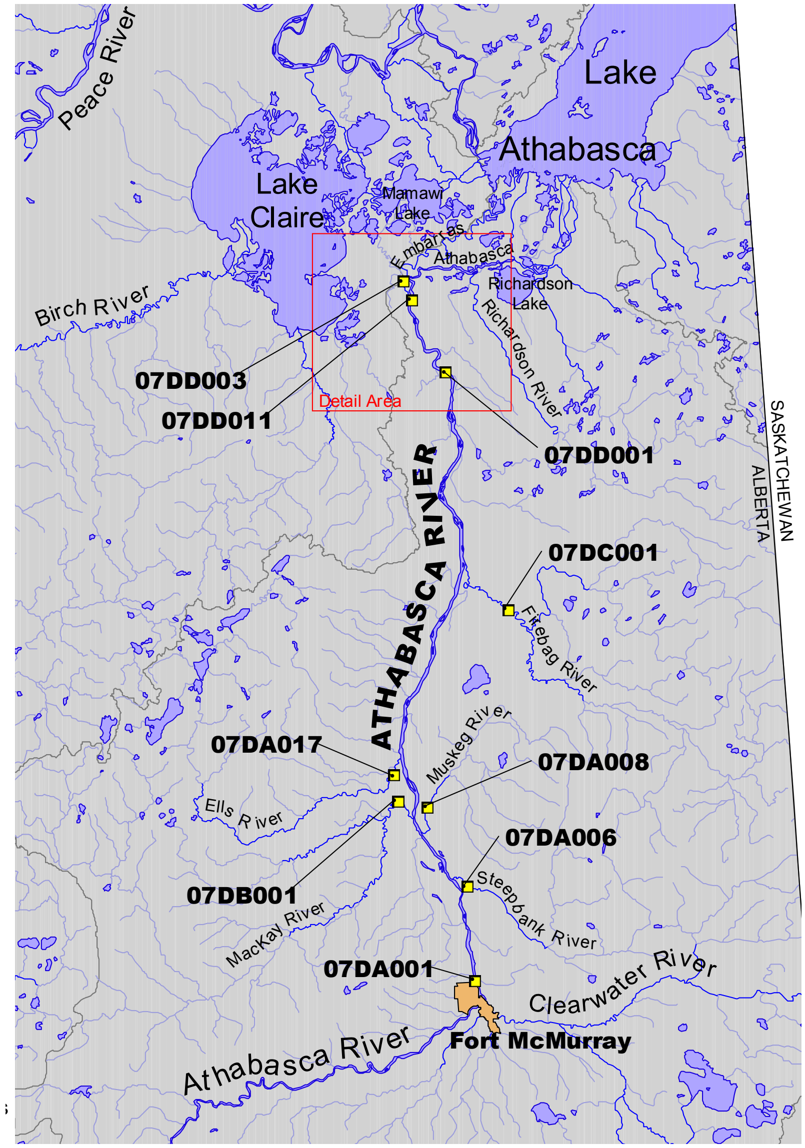
- **Table 7-6 Selected flow data for the Lower Athabasca River**

River Section	Description	Available time period	Source
Reach 5	Downstream of Fort McMurray to upstream of the confluence with the Steepbank River	1/10/1957 to 31/12/2004, continuous	Water Survey of Canada (WSC) gauge 07DA001. (Includes upstream extractions and return flows.)
Reach 4	Downstream of the confluence with the Steepbank River to upstream of the confluence with the Firebag River	1/10/1957 to 31/12/2004, daily	Flow-routing model by Alberta Environment (Seneka, 2002). Model takes into account inflow from Steepbank River (WSC gauge 07DA006). Does not include extractions or return flows downstream of Fort McMurray.

Additional Water Survey of Canada (WSC) data of monitored flow below Fort McMurray, including tributary inflows, were received from Alberta Environment (pers. comm., Tom Tang, 28/03/2008). A list of received data for the tributaries is provided in Table 7-7, while Figure 7-13 shows the location of the monitored sites within the lower Athabasca basin.

- **Table 7-7 Flow data for the Lower Athabasca River received from Alberta Environment**

WSC Gauge no.	Description	Time period	Frequency	Comments
07DA006	Steepbank River	20/09/1972 to 31/10/2005	1974-1986 Continuous 1987-2005 Seasonal operation	Break in winter flow data from November 1987 onwards. Major data gaps in starting period of record.
07DA008	Muskeg River	1/01/1974 to 31/10/2005	1974-1986 Continuous 1987-2005 Seasonal operation	Break in winter flow data from November 1987 onwards.
07DB001	Mackay River	15/03/1972 to 31/10/2005	1974-1986 Continuous 1987-2005 Seasonal operation	Break in winter flow data from November 1987 onwards. Major data gaps in starting period of record.
07DA017	Ells River	28/07/1975 to 31/12/1986	Continuous	Site discontinued.
07DC001	Firebag River	6/05/1971 to 31/10/2005	1972-1986 Continuous 1987-2005 Seasonal operation	Break in winter flow data from November 1987 onwards. Major data gaps in starting period of record.



▪ **Figure 7-13 Flow monitoring sites of the Lower Athabasca River and tributaries (Source: Seneka [2002:2])**

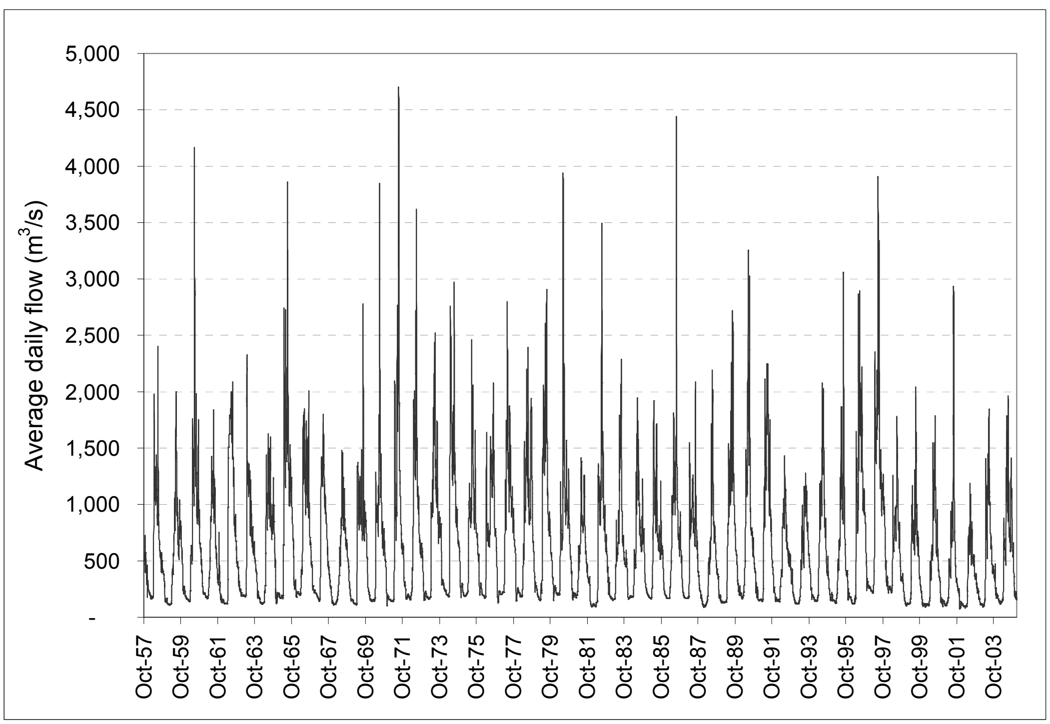
D.3 Annual flow

The average annual flow in Reach 4 from 1958 to 2004 was 19 975 GL or 633 m^3/s on average, with a standard deviation of 4 342 GL or 138 m^3/s. Median annual flow over the same time period was 14 698 GL or 466 m^3/s on average.

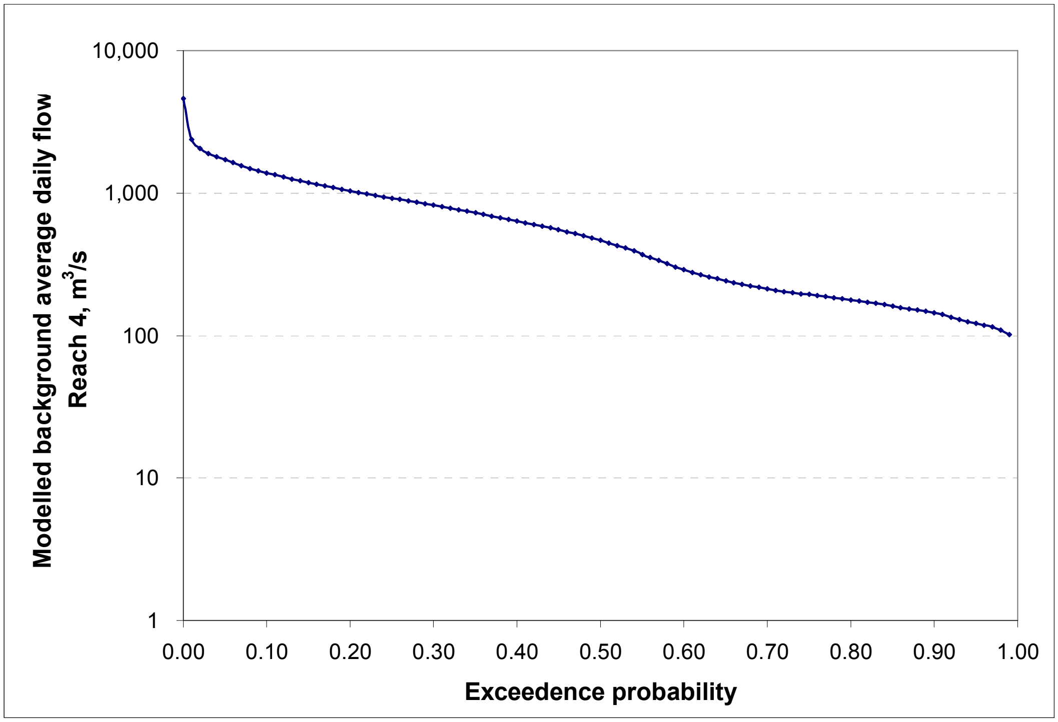
D.4 Seasonal variability of flow

Two seasons are defined for the analysis of flows: winter (ice cover) and summer (open water). Winter is specified in the WMF as being from week 44 (late October) of the year through to week 15 (early April) of the following year. Summer occurs during the remaining period from week 16 (April) to week 43 (October). Also mentioned in the WMF is the fish spawning period, which overlaps the summer period and is specified from week 16 through to week 24 (April to early June).

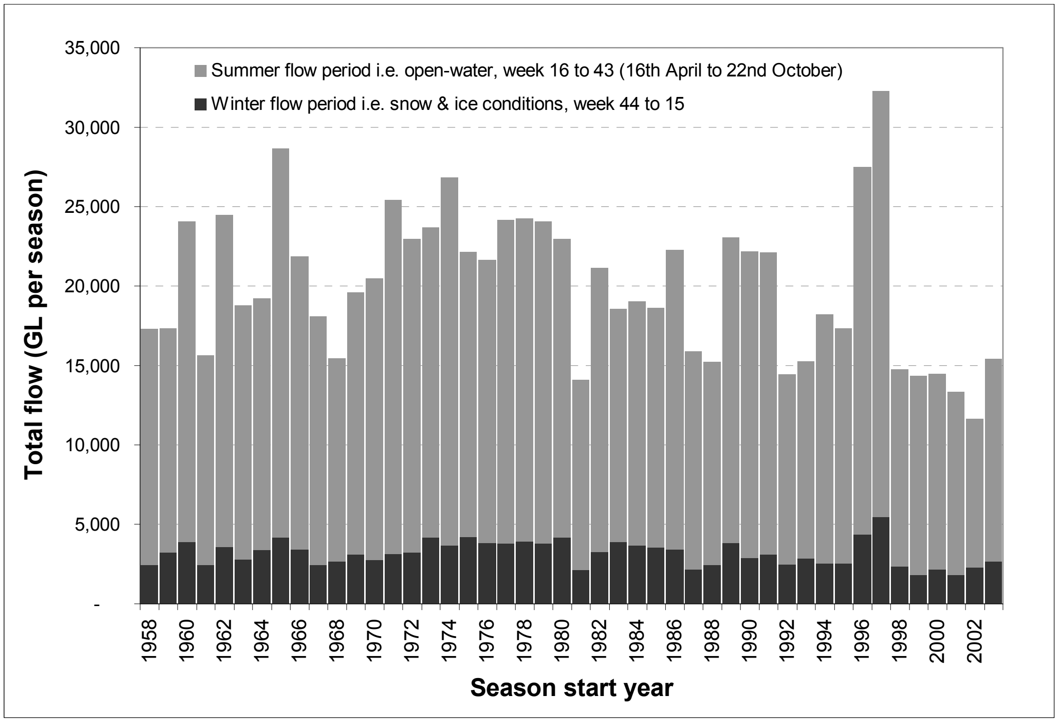
The high variability of flow in the Athabasca River is shown in the hydrograph in Figure 7-14 and the flow duration curve in Figure 7-15 (log scale). The difference in seasonal flow volumes in Reach 4 is presented in Figure 7-16. As shown, the greatest flows occur during summer. Peak daily flow also occurs in summer, while flows greater than 3 000 m^3/s occur almost exclusively in June and July. Due to the cold conditions, flow during winter is likely to consist entirely of base flow from groundwater sources.



- **Figure 7-14 Hydrograph, Athabasca River at gauge downstream of Fort McMurray (Reach 5), 1/10/1957 to 31/12/2004**



▪ **Figure 7-15 Flow duration curve, Lower Athabasca River, Reach 4, 1/10/1957 to 31/12/2004**



- **Figure 7-16 Seasonal flow (GL) in Reach 4 of the Lower Athabasca River, April 1958 to April 2004**

D.5 Low flows

Restrictions under the WMF are most likely to occur during low flow periods in the Athabasca River. Minimum flows in the river will result in the greatest severity of restrictions.

Golder Associates (2005) analysed the frequency of annual minimum daily flows in the lower Athabasca River (07DA001). Table 7-8 presents their estimates of minimum flows based on annual recurrence intervals of 1 in 2, 1 in 10, and 1 in 100. In considering this information it is important to note that flow under ice is estimated based on adjustment of the open-water stage-discharge relationship to take into account manual readings. Interpolation is carried out between manual readings, and data may also be adjusted to reflect a range of other factors, including temperature fluctuations, flows recorded at other stations, and, particularly during ice formation, the physical form of ice (pers. comm., Dennis Lazowski, Environment Canada, 13/8/2008). Thus low flows are based on generated estimates and not recorded data, and so may contain inaccuracies.

- **Table 7-8 Statistics of Daily Low Flows on the Lower Athabasca River (Source: Golder Associates [2005:18])**

Parameter	Fort McMurray Station (07DA001) [a]	Below Muskeg River [b]
Drainage area	133 000 km^2	136 800 km^2
Daily Low Flow		
Highest annual daily low flow on record (m^3/s)	213 (occurred in 1997)	215
2-year daily low flow (m^3/s)	139	140
10-year daily low flow (m^3/s)	97	98
100-year daily low flow (m^3/s)	70	71
Lowest annual daily low flow on record (m^3/s)	75 (occurred in 2001)	76
Standard deviation in annual daily low flow (m^3/s)	32	n/a
7Q (Mean flow over a duration of 7 days) low flow		
Lowest 7Q low flow on record (m^3/s)	81 (occurred in 2001)	82
7Q10 (m^3/s) (7Q low flow with a 10-year return period)	101	102
Standard deviation in annual 7Q low flow (m^3/s)	33	n/a
30Q (Mean flow over a duration of 30 days) low flow		
Lowest 30Q low flow on record (m^3/s)	97 (occurred in 2002)	98
30Q5 (m^3/s) (30Q low flow with a 5-year return period)	123	124
30Q10 (m^3/s) (30Q low flow with a 10-year return period)	109	109

Notes:

a. Based on recorded flows for the period 1958 to 2002

b. There is no hydrometric station at this location

D.6 Influence of tributaries downstream of Fort McMurray

The five monitored tributaries listed previously in Table 7-7 represent 74% of the basin drainage area between Fort McMurray and Embarras Airport (Seneka, 2002). The largest of these tributaries is the Firebag River, whose catchment has some planned development (Synenco Northern Lights) although is largely clear of the main development located further upstream. The second-largest of the five tributaries is the Mackay River, whose catchment is also reasonably clear of development.

Summary annual information on the contribution of each of the tributaries to flow in the Athabasca River is provided in Table 7-9. Figure 7-17 provides this information in an average monthly format, excluding the Firebag River. Note the results are based on flow data where available and may be affected by difficulties in flow measurement during the ice-cover period. As shown, the tributaries contribute only minor flow volumes during the winter period. Thus although tributary inflows are not fully taken into account by flow modelling along the lower Athabasca River, the modelled flows are still likely to be reasonably accurate.

- **Table 7-9 Summary information of flow data for the Lower Athabasca River including tributaries received from Alberta Environment**

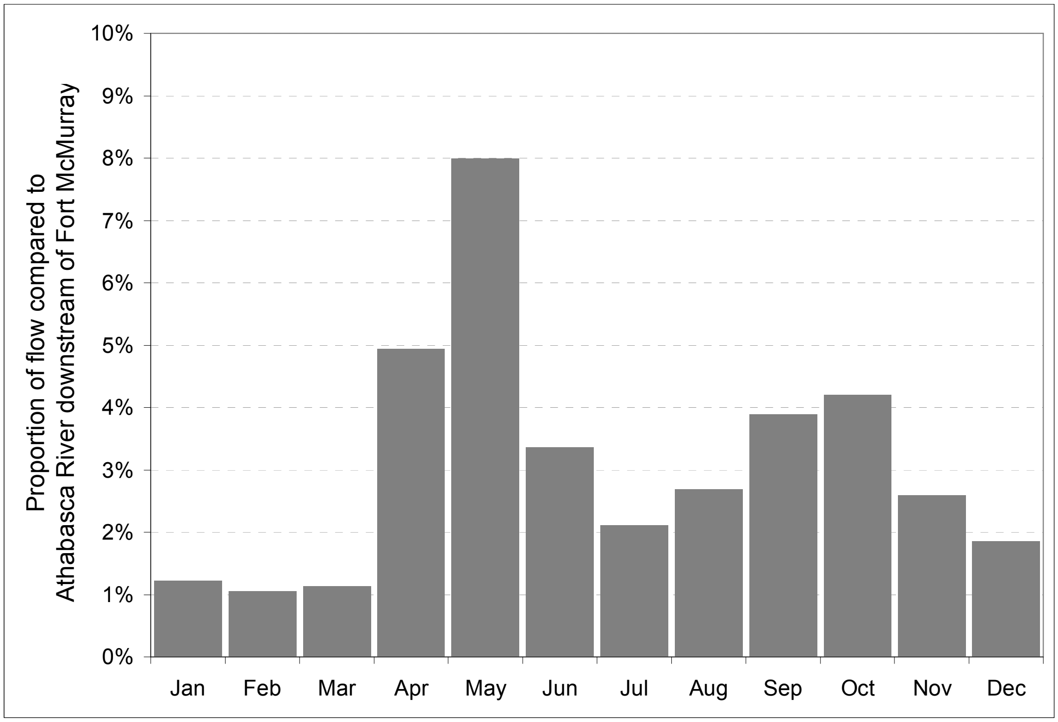
WSC Gauge no.	Description	Average annual flow, m^3/s [a]	Average annual flow, expressed as proportion of flow compared to that in Athabasca River [b]	Maximum daily proportion of flow compared to that in Athabasca River [c]
07DA001	Athabasca River	630.18	100.0	100.0
07DA006	Steepbank River	5.12	0.6	8.4
07DA008	Muskeg River	4.09	0.5	4.3
07DB001	Mackay River	14.04	1.4	27.8
07DA017	Ells River	7.19	0.9	18.5
07DC001	Firebag River	25.78	4.5	37.6
Total of monitored tributaries excluding Firebag River (located furthest downstream)			**3.1**	**46.5**
Total of monitored tributaries			**7.3**	**62.2**

Notes:

a. Values based on average monthly flow where data available, summated over all months

b. Proportions based on daily average instantaneous flow in the tributary divided by daily average instantaneous flow in the Athabasca River below Fort McMurray (07DA001), calculated where information for each component is available. From this calculation, an average monthly proportion is obtained, which is summated over all months to obtain an annual figure.

c. As per note 2, except maximum daily proportion obtained (rather than monthly and annual collation). All maximums occurred between April 20th and May 19th.



- **Figure 7-17 Average monthly tributary flow expressed as a proportion of flow in the Athabasca River (07DA001), excluding Firebag River**

D.7 Travel time of flow

The report of the Lower Athabasca River Hydrol Routing Model by Alberta Environment (Seneka, 2002) provides information on the travel time of flow along each reach for different discharge volumes. This information is reproduced in Table 7-10.

The information shown in Table 7-10 was linearly interpolated to obtain the average and median travel times of flow based on the average and median flow volumes in the Athabasca River. The results (Table 7-11) show that in the slower winter period, flow typically takes less than one day to pass from the gauge below Fort McMurray to the confluence with the Steepbank River (Reach 5), and three days in total to pass the confluence with the Firebag River (Reach 5 and Reach 4 combined).

- **Table 7-10 Time of storage (in hours) for the Lower Athabasca River from below Fort McMurray to Embarras Airport [a]**

River section[b]	Dist. (km)	Time of storage (hours) within river reach for various river discharges									
		Discharge, m^3/s									
		57	**283**	**566**	**850**	**1133**	**1699**	**2265**	**2832**	**3964**	**5097**
07DA001 - Steepbank (5)	33.0	25.2	13.5	10.9	9.2	8.1	7.0	6.4	5.9	5.1	4.6
Steepbank - Muskeg - MacKay (4a)	18.3	14.0	7.5	6.0	5.1	4.5	3.9	3.5	3.3	2.9	2.5
MacKay - Ells (4b)	17.4	13.3	7.1	5.7	4.8	4.3	3.7	3.4	3.1	2.7	2.4
Ells - Firebag (4c)	56.0	42.8	23.0	18.4	15.6	13.7	11.8	10.8	10.0	8.7	7.7
Total	124.7	95.3	51.1	41	34.7	30.6	26.4	24.1	22.3	19.4	17.2

Notes:

a. Source: Table 3.1, Lower Athabasca River Hydrol Routing Model (Seneka, 2002:5). Firebag to Embarras Airport and Old Fort river reach also included in original report.

b. Corresponding River reach numbers of the WMF shown in brackets.

- **Table 7-11 Cumulative average and median travel time of flow (days) from gauge below Fort McMurray (07DA001)**

River section no.	Description	Cumulative time of storage (days) from gauge below Fort McMurray (07DA001) for selected flow velocities [a]			
		Average annual flow, 633 m^3/s	Median annual flow, 466 m^3/s	Mode summer flow, 725 m^3/s	Mode winter flow, 174 m^3/s
5	07DA001 - Steepbank	0.4	0.5	0.4	0.8
4a	Steepbank - Muskeg - MacKay	0.7	0.8	0.6	1.2
4b	MacKay - Ells	0.9	1.0	0.9	1.7
4c	Ells - Firebag	1.6	1.9	1.6	3.0

a. Selected flow rates based on modelled data for Reach 4

Appendix E Potential streamflow effects of climate change

Long-term climate change is an important consideration for the future management of the lower Athabasca basin. Previous studies based in the region include the calculation of trends in streamflow using historic data, as well as the use of climate-based modelling to predict future changes in streamflow. The results of these studies are summarised below. In general, hydrologic data tend to follow a cyclical pattern over multiple years, with wet years often being preceded by wet years, and dry years often preceded by dry years. This pattern, combined with inherent variability and limited data, makes it very difficult to conclusively detect and explain the underlying trends in hydrologic data in order to assist in the prediction of future streamflows. Given this difficulty, an alternative approach is outlined that makes use of longer-term streamflow estimates using tree-ring data. Provided below is a review of previous studies in the region of trends in flow and streamflow predictions using climate-based modelling, followed by a description of the future streamflow scenarios to be used in this study for economic modelling purposes.

Trend analyses of flow data in the Lower Athabasca include those reported by Golder Associates (2005), and Schindler and Donahue (2006). Golder Associates (2005) report the overall result of a number of cursory trend analyses conducted separately by Golder Associates (previously undertaken in 2003) and Environment Canada. Using the Spearman statistical test on flow recorded below Fort McMurray (WSC gauge 07DA001), no trend was apparent from 1958 to 2001, while including data in 2002 - the lowest annual flow on record - indicated a negative trend at the 5% level of significance. No trend was apparent at the 5% level of significance when using an annual time series of seven-day low flows. Schindler and Donahue (2006) found a decline in summer flow (May to August) in the lower Athabasca of 33.3% since 1970 to 2003, and a decline of 19.8% over the entire period of record (since 1958), both of which were significant at the 5% level. These trends were apparent even though flow had concurrently increased at the headwaters due to glacial melt caused by increasing air temperatures (Schindler and Donahue, 2006). Extending this analysis to the winter period, Schindler et al. (2007)

conducted a linear regression of minimum daily flow recorded in each year from 1970 to 2003, indicating an average annual decrease of 1.5 m^3 per second[30].

Three studies, by Schindler and Donahue (2006), Bruce (2006), and Toth et al. (2006), present the results of climate-based modelling which is then used to predict changes in streamflow in the lower Athabasca. Schindler and Donahue (2006) present the results of general circulation model predictions of temperature and precipitation under climate warming scenarios. In a region that includes the Athabasca River basin, it is predicted that climate change will increase temperature and precipitation, however the increase in precipitation is expected to be offset by a much larger increase in potential evapotranspiration. Although potential evapotranspiration does not equate to actual evapotranspiration unless there is sufficient moisture availability, given the numerous wetlands below Fort McMurray it is thought that the difference between the two types is unlikely to be significant (Schindler et al., 2007) so as to affect the conclusions drawn[31]. Bruce (2006) points out that actual evapotranspiration would be much less than potential evapotranspiration across the whole basin, however agrees that increased evapotranspiration - rather than any change in precipitation - is likely to be the dominant influence on streamflows due to climate change in the medium term. Based on an average warming scenario of 3 °C by 2050, Schindler et al. (2007) project that average streamflows (April to October) would decline from 8% to 26% across the analysed sub-catchments of the lower Athabasca region. For an average warming scenario of 6 °C by 2100, they project that average streamflows would decline from 24% to 68% across the sub-catchments. In each case the maximum annual change (as compared to the average annual change) in streamflow across the model period was much greater.

Bruce (2006) summarises the available information on water demands in the Oil Sands and climate change to analyse the implications for water management, and provides a forecast of the likely streamflow effects of climate change. The geophysical data (temperature, precipitation, river flow and water level) analysed in the study were largely collected since 1970, given it was from this year onwards that the cause of observed

[30] Note that the average seasonal minimum flow from 1958 to 2004 was 137 m^3/s, and so the rate reported by Schindler et al. (2007) represents a rate of decline of approximately 1.1% per season.

[31] Similar rates of potential and actual evapotranspiration were found by Kim and Verma (1996) for an open fen in north-central Minnesota (pers. comm., David Schindler, 7/8/2008). This occurred when plants were actively growing and the watertable was within the root zone.

global warming is almost exclusively due to rising levels of atmospheric greenhouse gas (Intergovernmental Panel on Climate Change [2001], in Bruce [2006]). However, the 1970s were a relatively wet period for the region (pers. comm., Michael Seneka, Alberta Environment, 6/5/2008), with the largest recorded flood in the Athabasca River occurring in 1971. Thus the truncated data sets used in the trend analyses mentioned by Bruce, with flow analyses starting in either 1971 or 1972 (e.g. Woo and Thorne [2003], Burn, Aziz and Pietroniro [2004], in Bruce [2006]), would naturally be biased toward generating a negative trend result.

Based on a review of previous studies, Bruce (2006) concludes that although winter flows in the Athabasca River have been maintained in the headwaters, this is not expected to continue due to shrinking of the Athabasca glacier; and that recent low-flow conditions in the lower Athabasca are primarily due to reduced flows in downstream sub-catchments. Bruce reports that between 1971 and 2000, autumn precipitation was observed to decline by about 6%, winter precipitation declined by about 12%, spring precipitation experienced an overall increase (increased rainfall and reduced snowfall), and summer rainfall remained steady, with an overall effect of an increase in annual precipitation of approximately 4%. From 1961 to 2000, air temperatures rose by between 1.5 °C to 1.8 °C (Environment Canada, in Bruce [2006]). Increased air temperature has the corresponding effect of increased temperatures of shallow water bodies and soils, resulting in increased evapotranspiration. Based on a 2 °C average global temperature increase by 2026-2060, that may in turn translate to a 3.5 °C to 4 °C rise in the Athabasca basin, Bruce (2006) estimates that the minimum flows in the Athabasca River may reduce by between 7 to 10% (based on various climate models [Gan and Kerkhoven, 2004 in Bruce, 2006]), while annual runoff may decrease by between 3 and 30%.

Contrasting results were found by Toth et al. (2006). They separately apply the temperature and precipitation predictions of five global circulation models to a regional hydrological model, based on a 2040-2069 climate change scenario of a doubling of CO_2 concentrations. The mean runoff in the Athabasca River below Fort McMurray was found to be 6.6% higher on average under climate change compared to the modelled base period (1961-1990). Results within one standard deviation ranged from -3.2% to 16.4%. The calibrated model, however, overestimated total runoff at Fort McMurray by 29% (Toth et al., 2006).

The studies outlined above use previous trends in geophysical data to predict future impacts due to climate change, or rely on a model calibration period that is relatively short. However, this approach is contentious given the potential influence of naturally occurring climate modes that contribute to dynamic climate variability over various timescales, such as the Pacific Decadal Oscillation (PDO). Bruce (2006) acknowledges the potential effect of the PDO in contributing to the warm, dry conditions recently experienced, and explains that climate models include this natural variability and that fluctuations on either side of the overall downward trend may be expected. However, the reference used to support this claim, by Wang and Schimel (2003), outlines the important influence of climate modes on climate patterns, and cautions on the reliability of climate change models to predict changes in precipitation.

Wang and Schimel (2003) outline the important link between research on the influence of natural climate modes, such as the PDO, and human-induced climate change. They discuss that the recent patterns in climate and observed global warming are seasonal with distinct spatial variability, and can be explained by natural modes of atmospheric circulation. For instance, the rapid temperature increases since the 1970s (with the greatest warming being observed in winter and spring in an area that includes the northwest of North America) can largely be explained by positive trends of the North Atlantic Oscillation and the PDO, and increased occurrence of the El Niño Southern Oscillation. The authors postulate that human-induced climate change may manifest itself as changes in the preferred mode of low-frequency climate variability. Thus greenhouse gases might affect direct radiation and global warming (over decadal and century timescales), as well as having a dynamic effect on climatic patterns (over seasonal and decadal timescales). While there may be “ample evidence” (Wang and Schimel, 2003:15) of this based on climate modelling, the authors caution that more data are required along with careful analysis of the simulated links between greenhouse gas additions and climate modes. In terms of modelling the precipitation impacts of climate change, they discuss that this is more difficult to predict than temperature, and while modelling results show an overall increase in global land precipitation this increase “is small relative to its inter-annual and multi-decadal variability” (Wang and Schimel, 2003:12).

In a study of the historic changes in streamflows originating from the Rocky Mountains region, including data from the Athabasca River near Jasper, Rood et al. (2005)

recognised the importance of the PDO in influencing streamflow patterns. They recommend using hydrologic data sets that span longer than half a century to avoid the confounding effects of the PDO on trend analyses. Based on all data collected, they found an average decline in streamflow of 0.22% per year (0.087% decline in the Athabasca River at Jasper), indicating that streamflow had declined by about 20% over the past century (i.e. about a 8.7% decline in the Athabasca River at Jasper). This could indicate a further 10% average decline by 2050 (i.e. about a 4.4% decline in the Athabasca River at Jasper), however such extrapolation "must be regarded cautiously since the historic hydrologic data record is limited and there is an incomplete understanding of many atmospheric, oceanic and landscape processes that collectively underlie streamflow" (Rood et al., 2005:230). Three patterns of inter-annual variation were apparent: (i) stochastic variability producing seemingly random variation in streamflow from year to year, (ii) a harmonic, half-century oscillation of streamflow, that followed a pattern similar to temperatures of the Pacific Ocean (the cause of which is not understood nor adequately modelled by general circulation models), and (iii) a progressive decline in streamflow, likely in response to reduced annual precipitation over the last century (Rood et al., 2005). Rood et al. (2005) then compared three previous attempts to predict streamflows in the Rocky Mountains based on global circulation modelling, along with their own trend analysis of historic streamflows, and found variable results.

Rood et al. (2008) extended their previous work by confirming changes in observed seasonal patterns across 14 rivers in Alberta, British Columbia, Montana and Wyoming that drain the central Rocky Mountains. Their analysis indicated that, in general, winter flows had increased, and late summer flow decreased. Overall, there was a slight increase in winter flow, the rising limb of the spring surge in flow occurred more gradually and earlier in the season, spring peak flow arrived earlier, and summer flow substantially decreased – particularly in late summer and early autumn. This pattern may be explained by increased winter and spring temperatures (particularly minimum temperatures), that led to increased rainfall relative to snowfall and so increased winter streamflows and reduced snow-packs, along with advanced melting of the snow pack, earlier spring flows and spring peak flows, and reduced spring peak flows as a result of the reduced snow-pack (Rood et al., 2005). These general trends were found to be somewhat variable across the basins, with rivers in southern Alberta experiencing the most prominent changes, and northern rivers such as the Athabasca (recorded near Jasper) experiencing a less-pronounced decline in late-summer flow.

Given the lack of long-term flow data, and the potential effects of medium-term influences on streamflow such as the PDO, studies that link streamflow to long-term data such as tree growth provide very useful information on the natural hydrologic variability. Case and MacDonald (2003) present estimates of annual streamflow (October to September hydrologic year) based on tree-ring information for the North Saskatchewan, South Saskatchewan, and Saskatchewan Rivers, covering reconstruction periods of 1113-years, 522-years, and 325-years up to either 1992 or 1996 (depending on available data at each site analysed). The method involved the reconstruction of streamflows on an annual basis, and so was unable to uncover seasonal trends such as those identified by Rood et al. (2005). Importantly, the analysis of tree rings in the three sub-basins found that the "20th Century appears to be typified by relatively high flows" (Case and MacDonald, 2003:712), with flows estimated to be between 6.5 and 8.6% higher in the 20th Century than the long-term mean and above the median since the 1950s. Case and MacDonald (2003) found their results to be comparable to a similar tree-ring study of Lake Athabasca by Stockton and Fritts (1973), explained by the Athabasca headwaters also originating in the southern Canadian Rocky Mountains (where the majority of sampling sites for the Saskatchewan River sub-basin were located). The results revealed a high variability in annual and long-term streamflows, and that the low flows experienced in 2001 were not as severe in magnitude or duration as previous low-flow periods estimated using tree-ring data (Case and MacDonald, 2003). Given this result, Case and MacDonald (2003) warn of the risks associated with relying on historic flow records for designing future water policy and infrastructure.

Thus, while the results of trend analyses of flow in the Athabasca River are of interest, given the select data periods used (chosen to coincide with the period of climate change caused by a rise in atmospheric greenhouse gases), the insufficient length of record, and the variable nature of hydrologic data in general, the use of this information to forecast future streamflows is not advised. Specifically, there is considerable doubt regarding the degree to which the trends observed are associated with long-term climate change, or a phase within the natural climatic pattern of the PDO, or a combination of both. The use of climate-based models to forecast streamflow effects are similarly problematic, with concerns regarding their accuracy for the prediction of precipitation patterns and the incorporation of dynamic climate modes.

As the reconstruction of long-term streamflows in southern adjacent basins indicates that the 1900s have been unusually wet in Alberta, water management planning ought to take into account the scenario of a return to historic average conditions as estimated by tree-ring analysis. For this analysis, a decline in the historic average flow of 10% is considered an appropriate basis for the base-case scenario. This figure is a rounded number (rounded upwards for conservative reasons) based on the long-term average streamflows uncovered by tree-ring analyses for the South Saskatchewan, North Saskatchewan and Saskatchewan river basins; assuming that the results found in these basins hold for the Athabasca River basin. In turn, the historic data for the lower Athabasca River will be considered the "wet period" for the analysis, while for symmetry a decline in the historic average flow of 20% will be considered the "dry period" (note that this range lies within that estimated by Bruce (2006) and Schindler et al. (2007) for the 2050 scenario). For interest, an extreme case of a decline in historic flows of 50% will also be analysed.

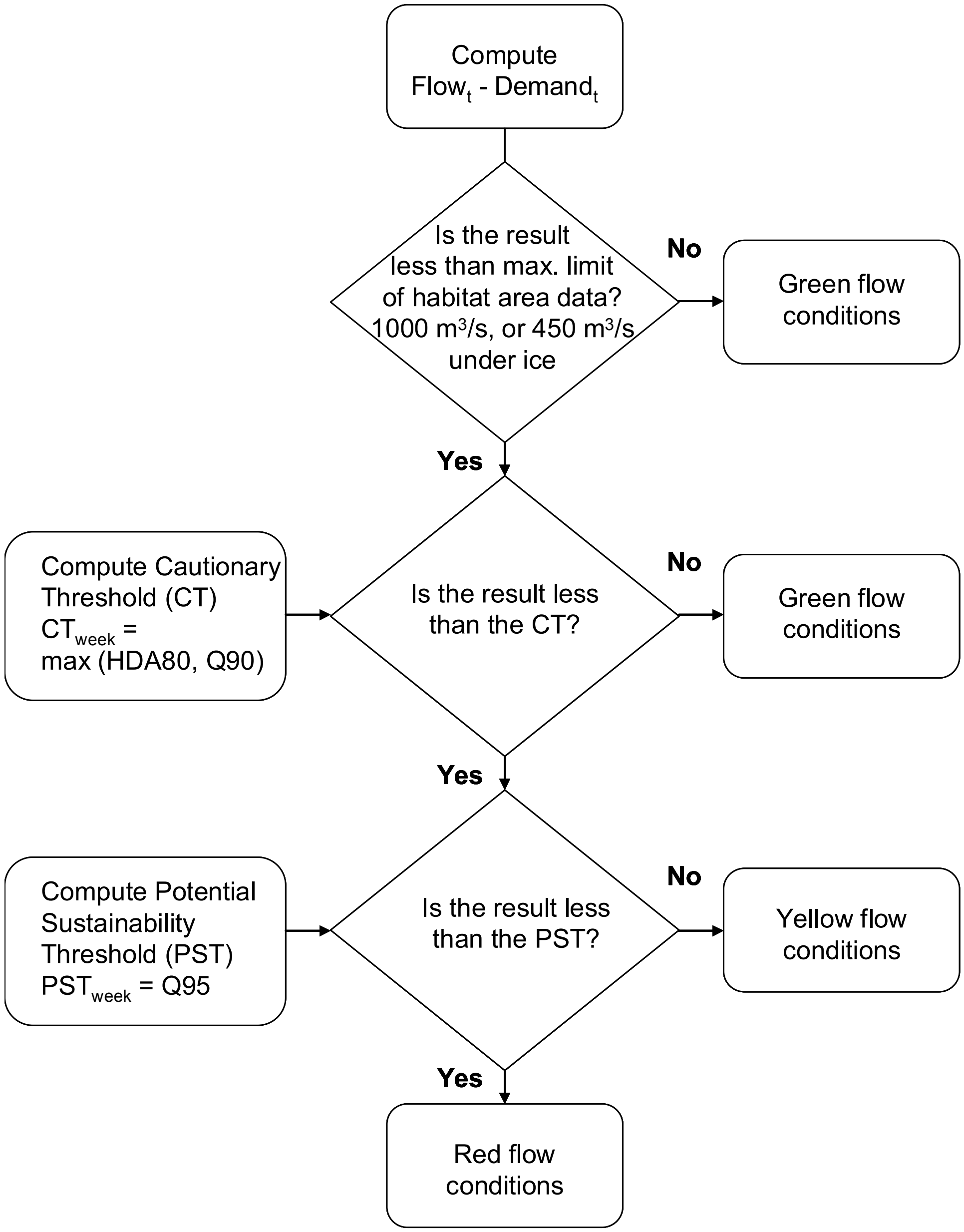
Appendix F Water supply availability[32]

To examine the implications of Phase 1 of the Lower Athabasca WMF, the frequency of green, yellow and red flow conditions were analysed for a range of flow and extraction scenarios. The analysis considers when the flow conditions would be "binding" - that is, when the limits on water extraction specified in Table 1-2 may be reached. When a limit is binding during red flow conditions, for example, this indicates that there is the potential for heightened ecological impacts, that the maximum extraction limits have been reached and are less than the total water demand, and that the shortfall in supply may in turn have negative effects on industry.

F.1 Method

Modelling was carried out using an Excel spreadsheet. For each flow and extraction combination, the flow condition (green, yellow or red) in each week was determined using a series of logic statements (Figure 7-18) that compared the background flow to the cautionary and potential sustainability thresholds (Table 1-2). Once the flow condition was established, the diversion limit and the potential shortfall were then calculated. The calculation of thresholds and diversion limits of the framework (Table 1-2) were updated with each change in the modelled flow scenario. Results are presented in the form of stacked column charts (excluding Figure 7-20). Selected flow and extraction scenarios arising from the background information, and a description of the ecosystem base flow scenario, are described below.

[32] A version of this appendix has been accepted for publication. Mannix, A. E., Dridi, C. and W. L. Adamowicz. 2009. Water Availability in the Oil Sands under projections of increasing demands and a changing climate: An assessment of the Lower Athabasca Water Management Framework (Phase 1). *Canadian Water Resources Journal*.



- **Figure 7-18 Decision process for assigning flow conditions of the WMF (refer to Table 1-2 for definitions)**

Historic background flows were used to first analyse the case with no extractions and the theoretical maximum water-use limits of the current thresholds of the water management framework. Following this, for the analysis of potential future restrictions, a decline in the historic average flow of 10% was selected for the base-case scenario (rounded upwards from 8.6% for conservative reasons), while the historic flow record was considered the wet scenario, and for symmetry a 20% reduction in flow was considered the dry scenario. The base case was broadly based on the results of the tree-ring analysis by Case and MacDonald (2003) for the adjacent North Saskatchewan basin; the base case also corresponds to the 2050 extrapolation of an average declining trend in long-term streamflows of 0.2% per year detected across the broader region (Rood et al., 2005). Though the streamflow effects of climate change are uncertain, the dry scenario was considered to test the resilience of the framework in the case that climate change may cause further reductions in streamflows beyond that of the base case. To further test the resilience of the framework, an extreme climate change scenario of a 50% reduction in flow was included for interest. These proportions (-10%, -20%, -50%) were applied across all weeks in the 47-year historic flow record (January 1st, 1958 to December 31st, 2004), and the flow thresholds of the framework then updated; thus the revised thresholds and results represent the expected frequency of green, yellow and red flow conditions over the long run. Future studies could also consider changes in the seasonal pattern of flow associated with climate change as described by Rood et al. (2008).

For the demand scenarios, a no-extraction (background flow only) scenario was selected for analysis in addition to four scenarios of constant demand for water extracted from the Athabasca River in Reach 4 (below Fort McMurray), as follows:

1. Water demand of 2.5 m^3/s (or 78 GL/year), based on the average rate of net industrial water-use extracted direct from the Athabasca River in 2006 (excludes extraction from other sources e.g. tributaries and surface runoff, includes return flows from Suncor operations).

2. Water demand of 5.7 m^3/s (or 180 GL/year), based on the existing average rate of licensed extraction (Table 2-1).

3. Water demand of 11.6 m^3/s (or 366 GL/year), based on the Alberta Environment (2007) forecast of actual surface-water use in the Athabasca basin by the petroleum sector in 2025, under low and medium growth scenarios.

4. Water demand of 14.0 m^3/s (or 442 GL/year), based on the Alberta Environment (2007) forecast of actual surface-water use in the Athabasca basin by the petroleum sector in 2025, under a high growth scenario. This scenario is

also the current existing and approved licensed average rate of extraction (Table 2-1).

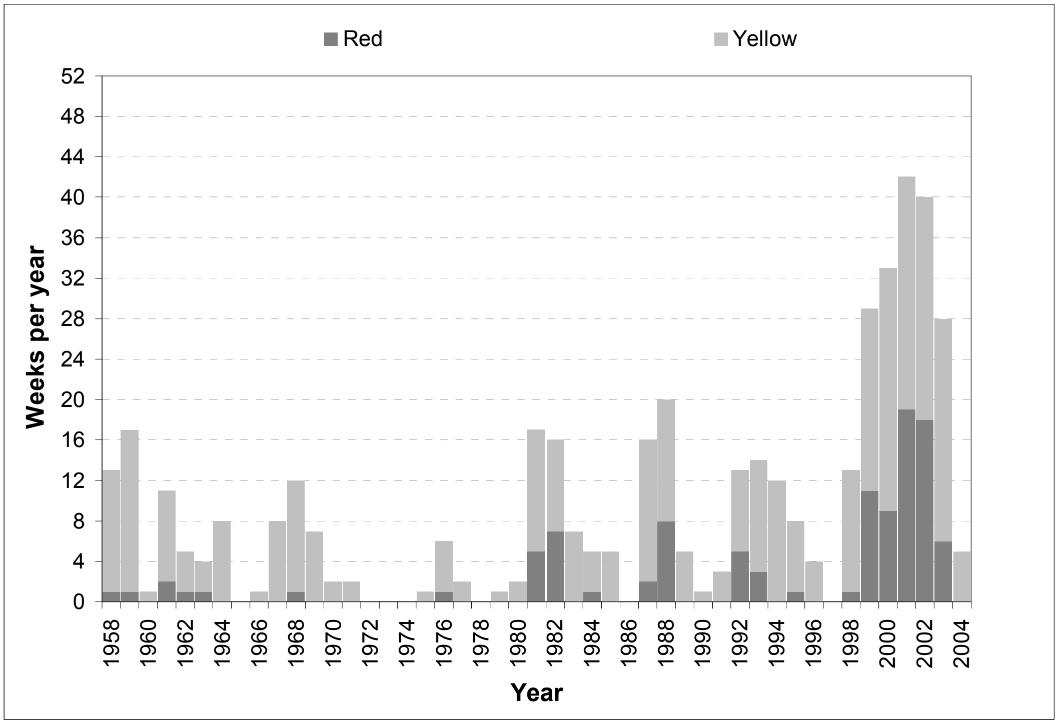
All demand scenarios were analysed in conjunction with the base case flow scenario. For other flow scenarios, a constant demand of 14 m^3/s is assumed.

Finally, an amendment to the WMF was analysed that includes an ecosystem base flow (EBF). An EBF specifies the flow threshold below which no extractions are allowed. If the background flow falls below the EBF then this would trigger a ban on all extractions. If the background flow is above the EBF, yet the background flow minus water demands falls below the EBF, then this would trigger a ban on extractions to a level that preserves the EBF. While an EBF has not been specified for the Athabasca River, a hypothetical, constant EBF of 100 m^3/s, combined with Phase 1 of the WMF, was modelled to determine its potential effect on restrictions. This selected flow rate is an approximation of the minimum weekly value of the 95% flow exceedance (Q95) calculated using the historic flow record (equal to 97.2 m^3/s, occurring in week 10 - i.e., early March). An extension of the analysis could consider the use of a seasonal EBF, as discussed by the Surface Water Working Group of the Cumulative Effects Management Association (Hardy and Richards, 2006). The EBF management scenario was modelled assuming a constant demand of 14 m^3/s and the base case flow scenario.

F.2 Results

F.2.1 Flow conditions under background historic (wet scenario) flows

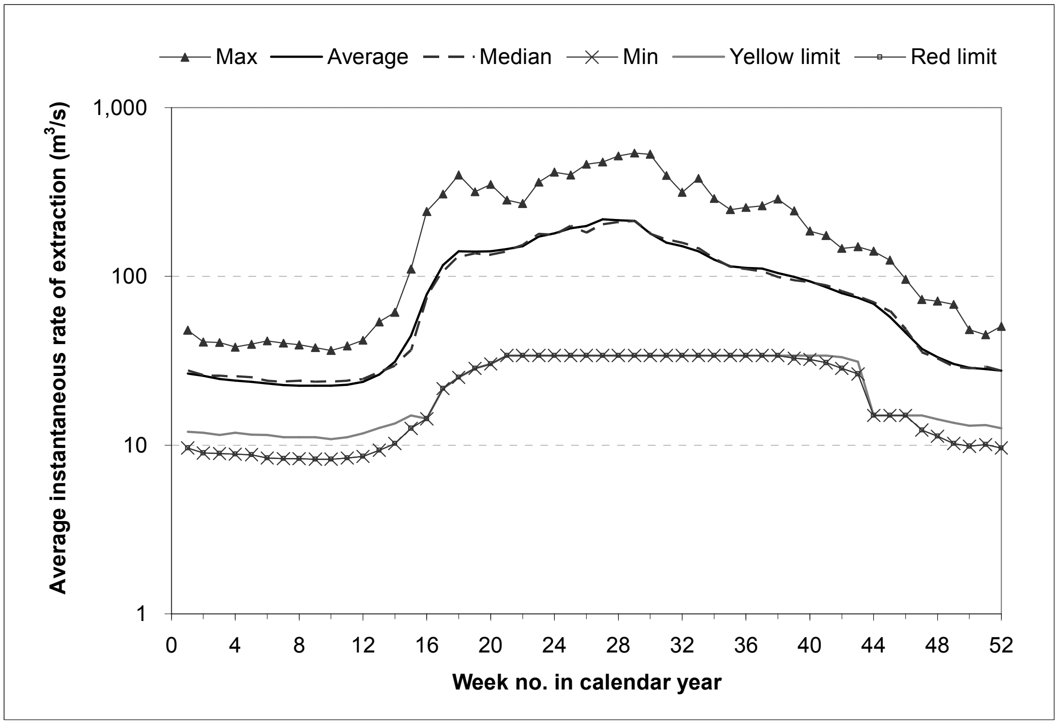
Background flows were first analysed assuming no water extraction and using the historic flow record (wet scenario). The annual frequency of green, yellow and red flow conditions for this scenario calculated over the analysis period is shown in Figure 7-19 as a stacked column chart. The historic record demonstrates that dry years tend to occur in succession, thus years with a high frequency of red conditions tend to occur in a clustered pattern. The period from 1999 to 2003 was particularly dry, with low-flows triggering more weeks of yellow and red flow conditions than green in each year.



- **Figure 7-19 Modelled annual frequency of flow conditions of the WMF, historic background flow (wet scenario)**

F.2.2 Extraction limits under background historic (wet scenario) flows

The analysis of historic background flows (wet scenario) was extended to consider the range of allowable extraction in each week and year of the analysis period. The range of allowable rates of extraction in each week of the year, including the average and median extraction rates, is shown in Figure 7-20. Also shown in Figure 7-20 are the limits under the yellow and red conditions of the WMF. The red conditions of the WMF match the minimum allowable rate of extraction in Figure 7-20 due to the red limit being reached at least once in each week of the year over the analysis period. Taken to its limits, the maximum extraction from the Athabasca River allowed by the WMF varies from 1 065 GL per year in 2002 (over twice the approved licensed use) to 4 825 GL per year in 1997, with an average of up to 2 840 GL per year. However, these volumes are not achievable in practice under current management due to limited demand and maximum limits on instantaneous water extraction stipulated in most licences.



▪ **Figure 7-20 Weekly allowable extraction and extraction limits under the WMF, log scale**

F.2.3 Flow conditions and supply shortfalls, base case flow scenario

Various demand scenarios were modelled to analyse the frequency of green, yellow, and red flow conditions of the WMF and the characteristics of supply shortfalls when extraction limits become binding. Results are shown in Table 7-12 and Table 7-13 for the base case flow scenario (10% reduction in historic flows) and all extraction scenarios. Results for the 14.0 m^3/s extraction scenario, corresponding to both the current average rate of approved licences and the 2025 high-growth forecast of actual water-use by Alberta Environment (2007), are presented in Figure 7-21, Figure 7-22 and Figure 7-23.

The results indicate that the average frequency of restrictions may increase from zero to six weeks per year by 2025 (based on long-run assumptions, including that future flows are 10% lower than the historic record). These binding conditions are likely to occur only during the low flow, ice-cover period (Figure 7-22), and may cause shortfalls that regularly reach up to 6.6 m^3/s, or almost 50% of the total demand under the high growth forecast, by 2025 (Table 7-13 and Figure 7-23). Using trial and error it was found that demand during low-flow periods would need to be below 7.5 m^3/s to avoid restrictions under the base case flow scenario.

- **Table 7-12 Modelled summary statistics of weeks per year of flow conditions of the WMF, base case flow scenario**

Demand scenario	No. of weeks per year of flow condition			No. of weeks per year flow condition is binding	
	Green	Yellow	Red	Yellow	Red
Background flow, **no extraction/demand**					
Average	42	7	2	n/a	n/a
Median	46	5	0	n/a	n/a
Standard deviation	11	7	4	n/a	n/a
Maximum	52	25	19	n/a	n/a
Minimum	9	0	0	n/a	n/a
Current (2006) water-use, **2.5 m^3/s**					
Average	41	8	3	0	0
Median	45	6	1	0	0
Standard deviation	11	7	5	0	0
Maximum	52	24	22	0	0
Minimum	8	0	0	0	0
Existing licensed extraction (average rate), **5.7 m^3/s**					
Average	41	8	3	0	0
Median	43	7	1	0	0
Standard deviation	11	7	5	0	0
Maximum	52	24	23	0	0
Minimum	8	0	0	0	0
Forecast 2025 petroleum water-use, low & medium growth scenarios, **11.6 m^3/ s**					
Average	39	8	4	2	2
Median	40	8	1	0	0
Standard deviation	12	7	7	3	4
Maximum	52	23	27	11	14
Minimum	6	0	0	0	0

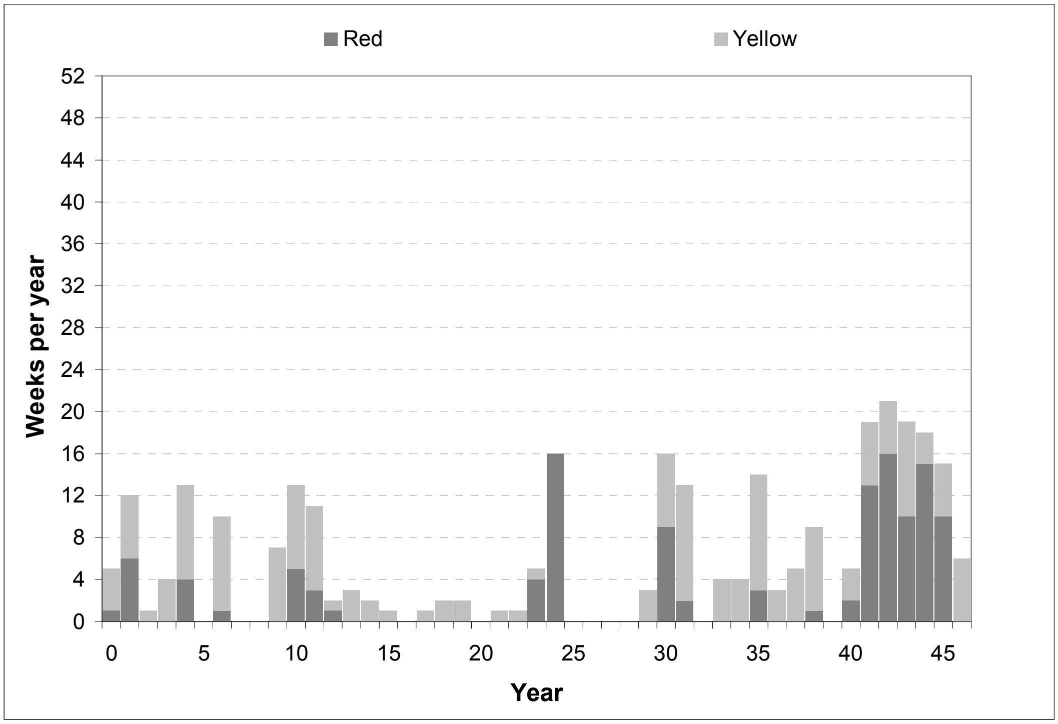
Demand scenario	No. of weeks per year of flow condition			No. of weeks per year flow condition is binding	
	Green	Yellow	Red	Yellow	Red
Current existing & approved licensed extraction (average rate) & Forecast 2025 petroleum water-use, high growth scenario, **14.0 m^3/ s**					
Average	39	9	5	3	3
Median	39	9	1	3	0
Standard deviation	12	7	7	3	5
Maximum	52	24	27	11	16
Minimum	5	0	0	0	0

n/a – not applicable

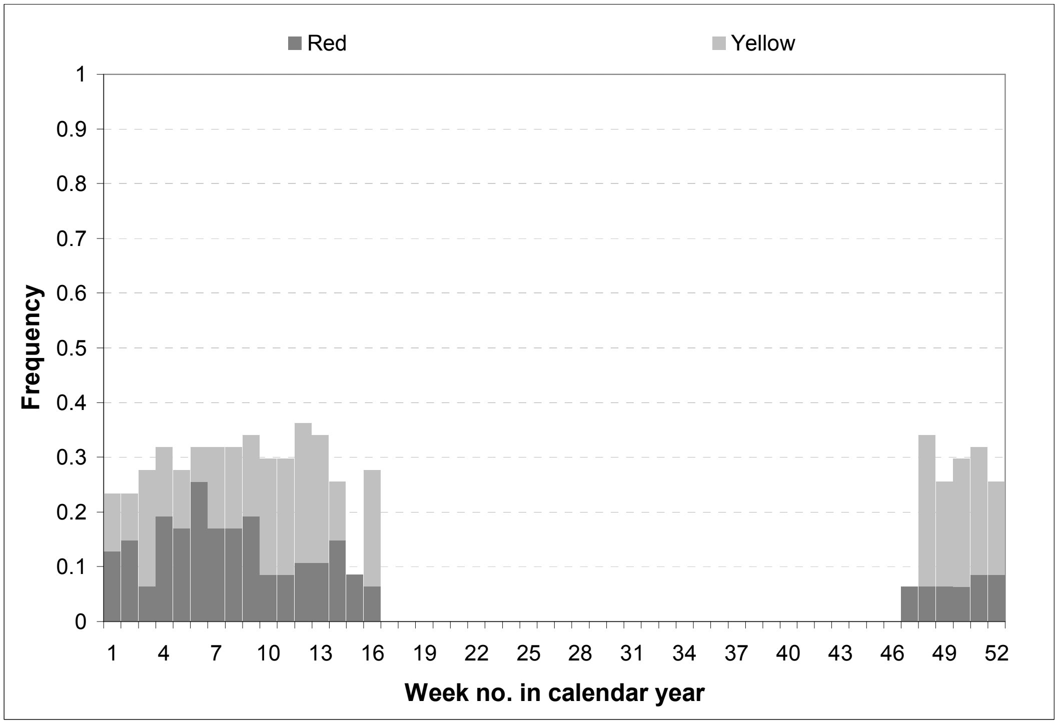
- **Table 7-13 Modelled summary statistics of supply shortfalls associated with implementation of the WMF, base case flow scenario**

Shortfall statistic	Demand scenario, m^3/s			
	2.5	**5.7**	**11.6**	**14.0**
Peak shortfall, m^3/s	0	0	4.2	6.6
Longest shortfall event				
No. weeks	-	-	20	21
Average weekly shortfall, m^3/s	-	-	3.0	5.2
Total shortfall, GL	-	-	35.8	66.6
Annual shortfall, % total demand				
Average	0	0	2	3
Median	0	0	0	1
Standard deviation	0	0	3	4
Maximum	0	0	8	14
Minimum	0	0	0	0
Annual no. of weeks of shortfall				
Average	0	0	4	6
Median	0	0	1	4
Standard deviation	0	0	6	6
Maximum	0	0	18	21
Minimum	0	0	0	0
Annual average weekly shortfall, % total demand [a]				
Average	-	-	16	23
Median	-	-	15	24
Standard deviation	-	-	9	9
Maximum	-	-	28	40
Minimum	-	-	2	8

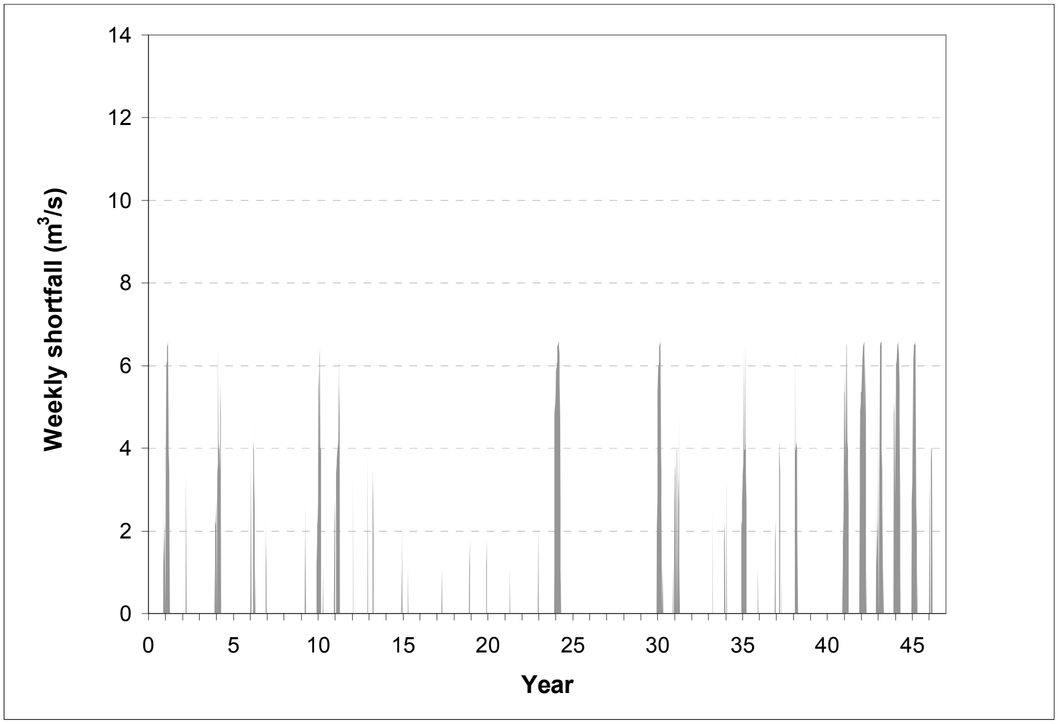
a. Calculation of annual average weekly shortfall only includes weeks within the year when a shortfall occurs. Years without shortfall not included.



▪ **Figure 7-21 Modelled binding flow conditions under the WMF, base case flow scenario and 14.0 m^3/s demand (approved average licensed water-use)**



- **Figure 7-22 Modelled weekly average frequency of binding flow conditions under the WMF, base case flow scenario and 14.0 m^3/s demand (approved average licensed water-use)**



- **Figure 7-23 Modelled supply shortfalls associated with implementation of the WMF, base case flow scenario and 14.0 m^3/s demand (approved average licensed water-use)**

F.2.4 Flow conditions and supply shortfalls, climate change flow scenarios

Results for the flow scenarios under climate change are shown in Table 7-14 and Table 7-15 for a constant rate of water demand of 14.0 m^3/s. With drier conditions, the red and yellow flow conditions of the WMF will be experienced more frequently, while the total volume of flow able to be extracted under the WMF would also be reduced. For example, switching from the historic conditions (wet scenario) to the base case of a 10% reduction in flow would reduce the average maximum volume able to be extracted under the framework by approximately 10%, from 2 840 GL/yr to 2 552 GL/yr (again, this measure is theoretical rather than actual). With reduced flows, peak shortfalls would be greater and would represent a greater proportion of total demand, and shortfall events would become more frequent and longer in duration (Table 7-15). These impacts are highlighted by the results of the dry scenario of a 20% reduction in flow, shown in Figure 7-24, Figure 7-25 and Figure 7-26.

- **Table 7-14 Summary statistics of weeks per year of flow conditions of the WMF, based on various flow scenarios (long run analysis) and 14.0 m^3/s water demand**

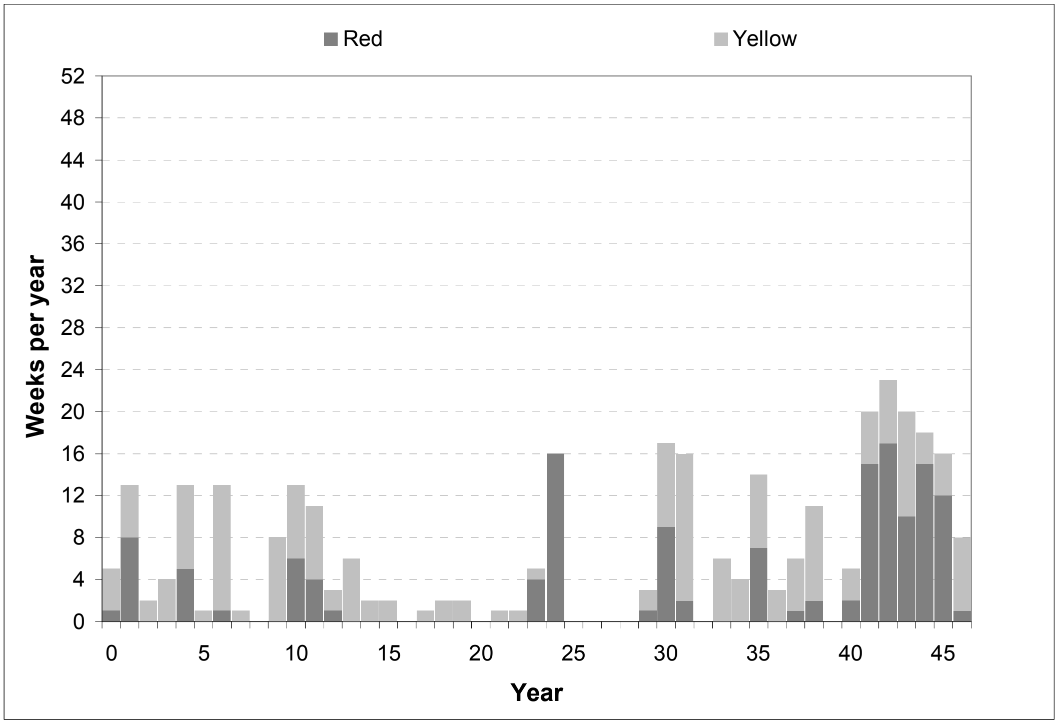
Flow scenario	No. of weeks per year of flow condition			No. of weeks per year flow condition is binding	
	Green	**Yellow**	**Red**	**Yellow**	**Red**
Wet scenario: historic background flow					
Average	40	8	4	3	2
Median	41	7	1	2	0
Standard deviation	12	6	7	3	4
Maximum	52	22	27	12	15
Minimum	7	0	0	0	0
Base Case: reduction in flow of **10%**					
Average	39	9	5	3	3
Median	39	9	1	3	0
Standard deviation	12	7	7	3	5
Maximum	52	24	27	11	16
Minimum	5	0	0	0	0
Dry scenario: reduction in flow of **20%**					
Average	38	9	5	4	3
Median	39	9	2	3	0
Standard deviation	12	7	7	4	5
Maximum	52	25	27	14	17
Minimum	4	0	0	0	0
Extreme dry scenario: reduction in flow of **50%**[a]					
Average	36	10	6	5	5
Median	34	10	3	4	2
Standard deviation	13	7	8	4	7
Maximum	52	24	35	16	22
Minimum	3	0	0	0	0

a. Green flow conditions would be binding for an average of 4 weeks per year under this scenario.

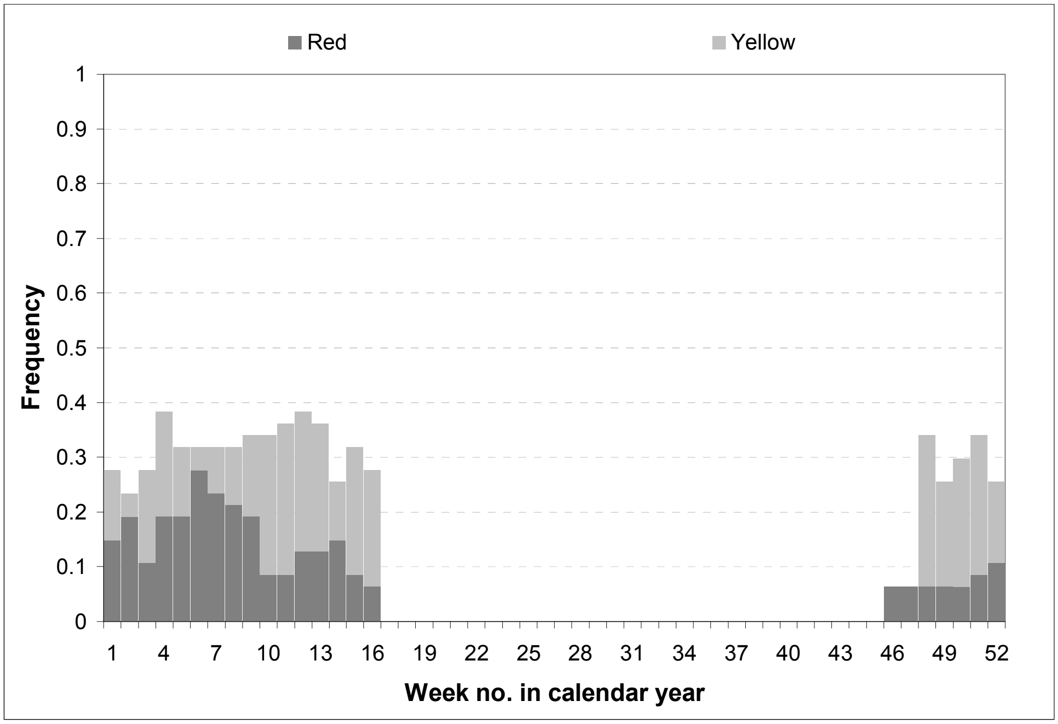
- **Table 7-15 Summary statistics of modelled supply shortfalls associated with implementation of the WMF, various flow scenarios (long run analysis) and 14.0 m^3/s water demand**

Shortfall statistic	Flow scenario			
	Wet	Base Case	Dry	Ext. Dry
Peak shortfall, m^3/s	5.8	6.6	7.4	9.9
Longest shortfall event				
No. weeks	20	21	23	28
Average weekly shortfall, m^3/s	4.5	5.2	5.8	7.8
Total shortfall, GL	54.9	66.6	80.1	131.3
Annual shortfall, % total demand				
Average	2	3	5	11
Median	0	1	2	10
Standard deviation	3	4	5	9
Maximum	11	14	17	29
Minimum	0	0	0	0
Annual no. of weeks of shortfall				
Average	5	6	7	14
Median	3	4	4	14
Standard deviation	6	6	7	7
Maximum	19	21	23	28
Minimum	0	0	0	0
Annual average weekly shortfall, % total demand [a]				
Average	17	23	30	37
Median	19	24	31	40
Standard deviation	10	9	10	19
Maximum	34	40	46	66
Minimum	3	8	6	1

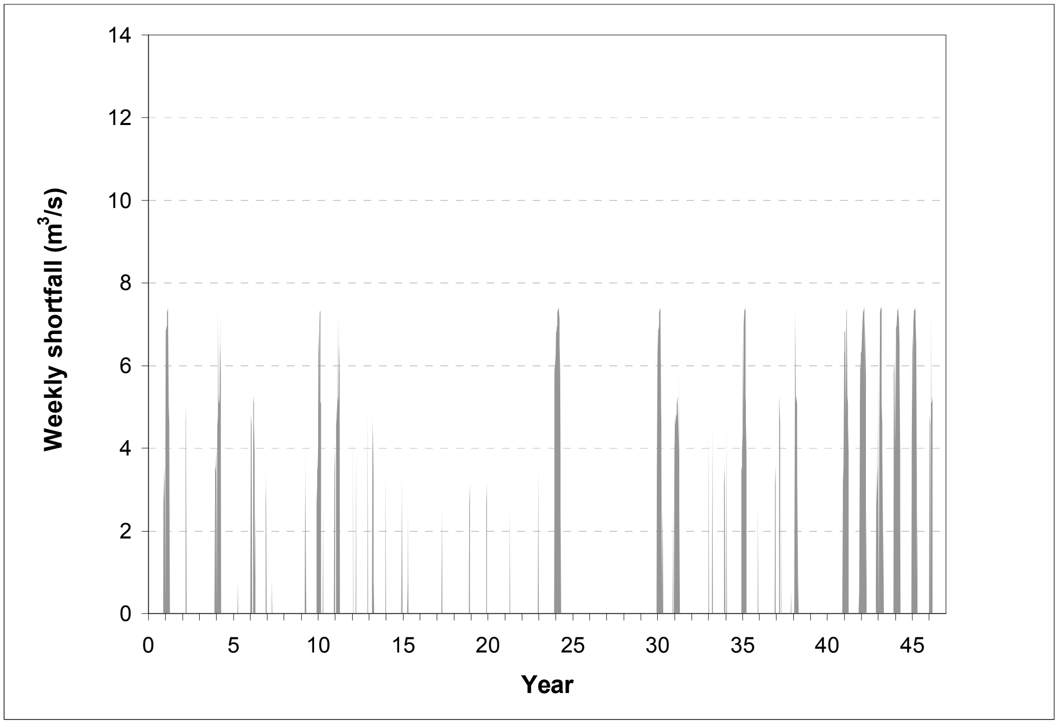
a. Calculation of annual average weekly shortfall only includes weeks within the year when a shortfall occurs. Years without shortfall not included.



▪ **Figure 7-24 Modelled long-run binding flow conditions under the WMF, based on dry scenario of 20% reduction in historic flow and 14.0 m^3/s demand (approved average licensed water-use)**



▪ **Figure 7-25 Modelled long-run weekly average frequency of binding flow conditions under the WMF, based on dry scenario of 20% reduction in historic flow and 14.0 m^3/s demand (approved average licensed water-use)**

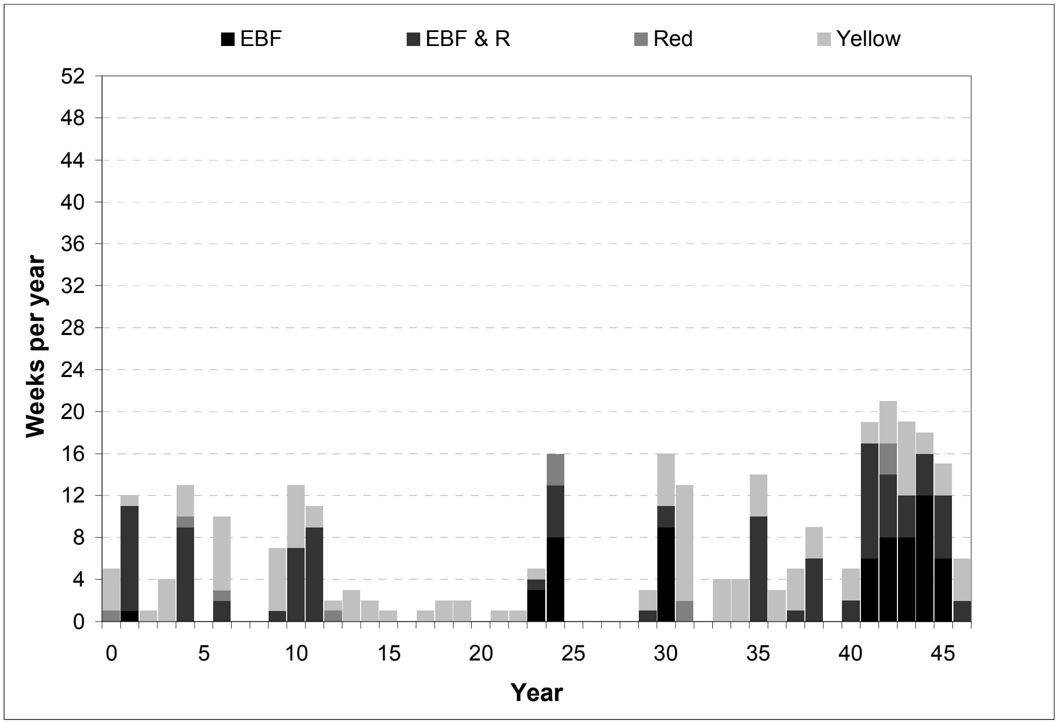


▪ **Figure 7-26 Modelled long-run supply shortfalls associated with implementation of the WMF, based on dry scenario of 20% reduction in historic flow and 14.0 m^3/s demand (approved average licensed water-use)**

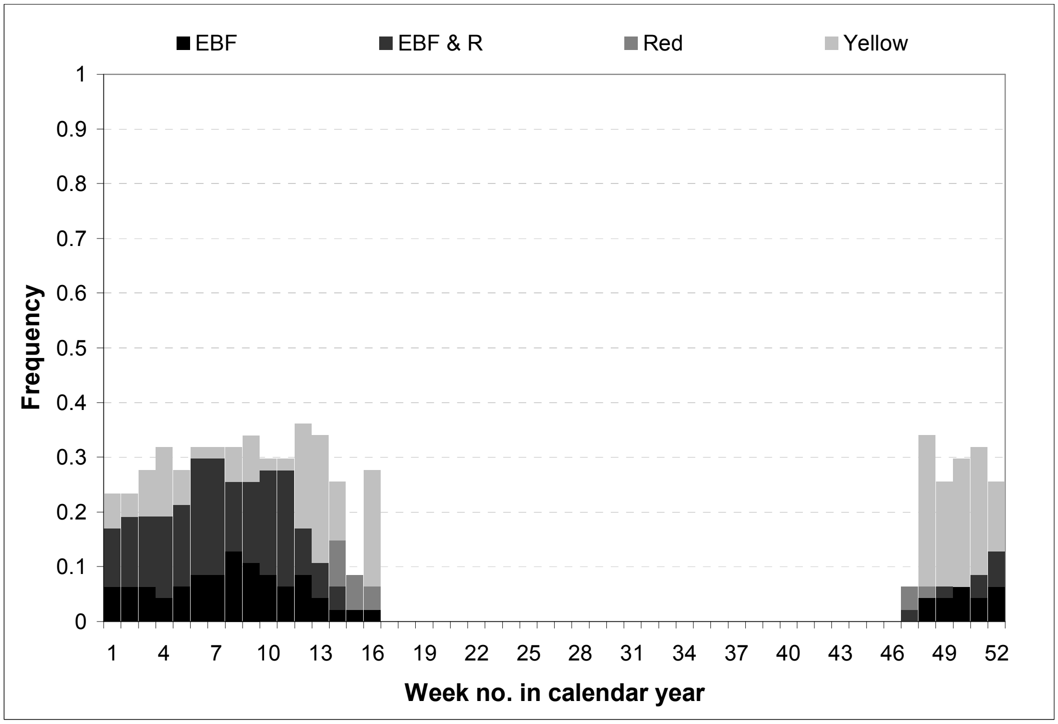
F.2.5 Ecosystem base flow scenario

The frequency of binding flow conditions is shown in Figure 7-27 and Figure 7-28 for a constant EBF of 100 m^3/s and a constant demand of 14.0 m^3/s. As expected, it was found that the Phase 1 flow conditions continue to apply as before except at times when the EBF threshold is triggered, with the average frequency of restrictions remaining similar.

The major difference in the EBF scenario is of course the magnitude of restrictions. As per the EBF definition, peak shortfalls of 14.0 m^3/s, or 100% of total demand, occur during EBF conditions (Table 7-16 and Figure 7-29) and are over double that of the Phase 1 framework (Table 7-13 and Figure 7-23).



- **Figure 7-27 Modelled binding flow conditions under the WMF combined with a hypothetical EBF of 100 m^3/s, base case flow scenario and 14.0 m^3/s demand (approved average licensed water-use)**

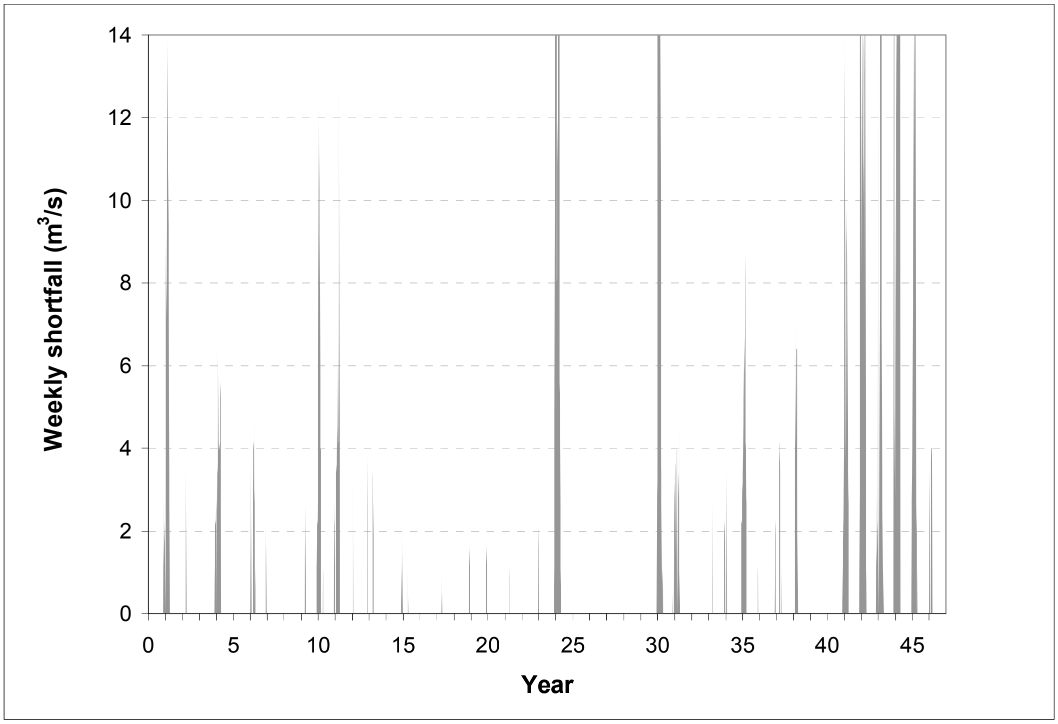


- **Figure 7-28 Modelled weekly average frequency of binding flow conditions under the WMF combined with a hypothetical EBF of 100 m^3/s, base case flow scenario and 14.0 m^3/s demand (approved average licensed water-use)**

- **Table 7-16 Modelled summary statistics of supply shortfalls associated with implementation of the WMF, combined with a hypothetical EBF of 100 m³/s, base case flow scenario**

Shortfall statistic	**Demand scenario, m³/s**			
	2.5	**5.7**	**11.6**	**14.0**
Peak shortfall, m³/s	2.5	5.7	11.6	14.0
Longest shortfall event				
No. weeks	13	13	21	21
Average weekly shortfall, m³/s	2.3	5.5	9.8	12.2
Total shortfall, GL	18.5	43.6	124.5	155.0
Annual shortfall, % total demand				
Average	3	3	4	5
Median	0	0	0	1
Standard deviation	6	7	8	8
Maximum	23	25	28	29
Minimum	0	0	0	0
Annual no. of weeks of shortfall				
Average	2	2	5	6
Median	0	0	1	4
Standard deviation	3	4	6	6
Maximum	13	15	18	21
Minimum	0	0	0	0
Annual average weekly shortfall, % total demand [a]				
Average	86	74	34	32
Median	93	87	22	24
Standard deviation	26	28	30	23
Maximum	100	100	91	84
Minimum	12	7	2	8

a. Calculation of annual average weekly shortfall only includes weeks within the year when a shortfall occurs. Years without shortfall not included.



- **Figure 7-29 Modelled supply shortfalls associated with implementation of the WMF combined with a hypothetical EBF of 100 m^3/s, base case flow scenario and 14.0 m^3/s demand (approved average licensed water-use)**

F.3 Discussion

The modelling results of the various water demand and background flow scenarios provide an outlook of the potential frequency and seasonal timing of future water shortages in the Oil Sands. Model results show an increased frequency of restrictions from zero weeks per year under current water-use and the base case flow scenario, to an estimated average of six weeks per year in 2025 due to increased demands (high-growth scenario). If restrictions do occur these are only expected during the winter, low-flow months of the year, while the risk of restrictions is not equal across years given dry years tend to occur in succession. For the restriction policy to be effective, limits on other sources of licensed water-use (e.g. groundwater and surfacewater from tributaries) that may significantly affect freshwater volumes in the Athabasca River should be taken into account.

The base-case background flow scenario attempts to simulate conditions associated with mean streamflows in the long term (based on the results of Case and MacDonald [2003]).

While there is evidence of an underlying decline in annual streamflows (Rood et al., 2005), seasonal trends toward increasing winter streamflows (Rood et al., 2008), combined with the prediction of increased winter streamflows due to climate change (Toth et al., 2006), may reduce the risk of restrictions. A possible future extension of this study could consider a flow scenario that depicts seasonal (as opposed to annual) trends in water availability. Over a decadal timescale, it is interesting to note that regional streamflows oscillate in a half-century pattern that coincides with that of the Pacific Decadal Oscillation (Rood et al., 2005). The historic data indicates a wet phase influence from 1948 to 1975 followed by a dry phase influence up to 2000 (Rood et al., 2005), that in turn indicates that streamflows in the medium term (i.e., up to 2025) may be higher than recent dry years and may tend toward above-average annual streamflows.

Under the current restriction policy (Phase 1 of the Lower Athabasca Water Management Framework) the risk associated with reduced streamflows is shared between industry and the environment. The outlook of increased industrial demand combined with the potential for drier conditions in the long term is expected to trigger water restrictions with greater frequency and severity, and longer duration. An ecosystem base flow (EBF), if adopted for Phase 2, would further restrict water supplies and may result in a ban on extraction when weekly limits are reached (assuming an in-stream flow threshold of 100 m^3/s based on the minimum weekly Q95). As such, the implementation of an EBF may necessitate major changes in water-use practices, in particular by the long-established operations that hold senior licences and were designed based on a continuous supply of freshwater from the Athabasca River.

To avoid restrictions under the base-case flow scenario it was found that the total demand during low-flow periods would need to be below 7.5 m^3/s i.e., three times the average rate of water-use in 2006 and almost 50% lower than the average extraction limit allowed under current approved licences (Table 2). To obtain this rate on average while reaching the surface-mining production forecast of approximately 2.3 million barrels of crude oil per day by 2020 (Canadian Association of Petroleum Producers, 2006) would require an average water-use by surface mines of 0.29 m^3 per barrel of crude oil production, which is approximately 25% less than recent reported use (Suncor Energy [2008], Syncrude Canada Ltd. [2007]). While several planned developments are expected to use less than this rate, the rate is substantially lower than that reported for a number of existing and proposed oil-sands operations (Dyer et al., 2008).

While the average risk of water restriction may appear modest, assuming approved demands (14 m^3/s) the forecast restriction in peak years may result in up to 21 weeks of consecutive shortfalls. Thus there is potential for significant financial implications for industry. The sharing of scarce water supplies under the Alberta Water Act is based on the prior allocation system, which in practice works similar to the prior appropriation rights system during times of shortage (Percy, 2004). For the first period of implementation of the Water Management Framework (Phase 1), a water sharing agreement was devised among active oil-sands operations that provides relatively greater water availability to more senior licensees, with junior licensees to rely upon water storage if available and necessary to meet demands above their restricted allocation (Athabasca Regional Issues Working Group, 2007). Under the prior allocation system and similar water sharing agreements, future water shortages may severely limit the supply to relatively new developments at certain times.

In summary, water demand in the oil sands does not appear to be at risk of restriction under the current management framework (Phase 1) in the immediate term. However, additional demands from approved developments and potential drier conditions in the future are expected to trigger industrial water-use restrictions during the winter season in the medium term (once demands rise above approximately 7.5 m^3/s). Restrictions may occur with increasing frequency and severity, and longer duration, while an ecosystem base flow - if adopted and based on the Q95 flow - would further reduce water availability. The risk of water restriction is not equal across years given dry years tend to occur in succession, and may be dampened by seasonal trends indicating an increase in winter flow. The findings demonstrate the potential risk to water supply in the Oil Sands under the current management framework, and the need to develop a long-term, cost-effective approach for sharing water amongst industry. Finally, the results highlight the problematic nature of specifying licences in fixed annual volumes rather than proportional shares, given the short-term fluctuations in water availability in unregulated basins such as the Athabasca, and the potential longer-term fluctuations that may be associated with cyclical climate modes (such as the Pacific Decadal Oscillation) and long-term climate change.

Appendix G GAMS code

G.1 Rationing under prior allocation (base case)

```
*Model of prior allocation in the Lower Athabasca, all time-steps
*
*Amy Mannix, December 2008

*Include the equation slacks in output
OPTION SOLSLACK=1;

*keep zeros in output
$setglobal zeros yes;

Sets
*define sets to allow for the fact that some mines/companies hold
several licences
*(that in some cases have combined maximum use conditions)
         i       oil sands licences /Shell_Jackpine, AOSP_Muskeg,
                                     CNRL_Horizon, PC_FortHills,
                                     Imperial_Kearl,
                                     Suncor_Mill-Steep1,
                                     Suncor_Mill-Steep2,
                                     Suncor_Voyageur,
                                     Syncrude_Mil-Aurora1,
                                     Syncrude_Mil-Aurora2,
                                     Total_Joslyn /
         j       oil sands mines    /Shell_Jackpine, AOSP_Muskeg,
                                     CNRL_Horizon, PC_FortHills,
                                     Imperial_Kearl, Suncor,
                                     Syncrude_Mil-Aurora,
                                     Total_Joslyn /;

*Define sets (year and week) and read in table of water supply
availability data
*from Excel (without listing in output file)
$offlisting;

set year year of water supply availability data /
$call =xls2gms r=GAMS!a4:a50 i="C:\Documents and Settings\Amy\My
Documents\Uni Master's Course\Thesis\Data\d01aem_GAMS link.xls"
o=setk.inc
$include setk.inc
/;

set week week of water supply availability data /
$call =xls2gms r=GAMS!b3:ba3 s="," i="C:\Documents and
Settings\Amy\My Documents\Uni Master's
Course\Thesis\Data\d01aem_GAMS link.xls" o=setl.inc
$include setl.inc
/;

table water(year,week) table of water supply availability
$call =xls2gms r=GAMS!a3:ba50 i="C:\Documents and Settings\Amy\My
Documents\Uni Master's Course\Thesis\Data\d01aem_GAMS link.xls"
o=pard.inc
```

```
$include pard.inc
;

$onlisting;

*Display water supply availability data from Excel
display water;


Parameters
         qave(i)  quantity of water licence in M m3 water per
                  year by 2020
*i.e. Shell_Jackpine (stage 2) CNRL_Horizon (steady)
Imperial_Kearl (stage C)
                 / Shell_Jackpine        35.3
                   AOSP_Muskeg           55.1
                   CNRL_Horizon          51.02
                   PC_FortHills          39.27
                   Imperial_Kearl        80
                   Suncor_Mill-Steep1    30.8375
                   Suncor_Mill-Steep2    28.98725
                   Suncor_Voyageur       3
                   Syncrude_Mil-Aurora1  60.4415
                   Syncrude_Mil-Aurora2  1.2335
                   Total_Joslyn          0.176625 /

         qmax(j)  maximum instantaneous licence volume in m3
                  water per second
*Fort Hills based on average use as unspecified
                 / Shell_Jackpine        1.95
                   AOSP_Muskeg           2.22
                   CNRL_Horizon          3.1
                   PC_FortHills          1.245243531
                   Imperial_Kearl        4.6
                   Suncor                3.79
                   Syncrude_Mil-Aurora   4.163
                   Total_Joslyn          0.02 /

         s(i)    seniority of water licence in order from 1 =
                  most senior to 11 = least senior
                 / Shell_Jackpine        7
                   AOSP_Muskeg           5
                   CNRL_Horizon          8
                   PC_FortHills          6
                   Imperial_Kearl        11
                   Suncor_Mill-Steep1    1
                   Suncor_Mill-Steep2    4
                   Suncor_Voyageur       9
                   Syncrude_Mil-Aurora1  2
                   Syncrude_Mil-Aurora2  3
                   Total_Joslyn          10 /

         ymax(j)  estimated company production by 2020 in Mm3 of
                  oil per year
                 / Shell_Jackpine        17.41
                   AOSP_Muskeg           15.67
                   CNRL_Horizon          33.48
```

```
                  PC_FortHills          11.03
                  Imperial_Kearl        17.41
                  Suncor                25.59
                  Syncrude_Mil-Aurora   34.41
                  Total_Joslyn          5.80 /;

Table l(i,j)     licences allocated to each mine
                   Shell_Jackpine      AOSP_Muskeg
CNRL_Horizon    PC_FortHills    Imperial_Kearl  Suncor
Syncrude_Mil-Aurora     Total_Joslyn
Shell_Jackpine       1                   0               0
0               0               0               0
0
AOSP_Muskeg          0                   1               0
0               0               0               0
0
CNRL_Horizon         0                   0               1
0               0               0               0
0
PC_FortHills         0                   0               0
1               0               0               0
0
Imperial_Kearl       0                   0               0
0               1               0               0
0
Suncor_Mill-Steep1   0                   0               0
0               0               1               0
0
Suncor_Mill-Steep2   0                   0               0
0               0               1               0
0
Suncor_Voyageur      0                   0               0
0               0               1               0
0
Syncrude_Mil-Aurora1 0                   0               0
0               0               0               1
0
Syncrude_Mil-Aurora2 0                   0               0
0               0               0               1
0
Total_Joslyn         0                   0               0
0               0               0               0
1             ;


Scalar a net revenue per m3 of oil produced for all firms set to
         274 per m3 (43.5 per barrel) /274/
*initial water availability entered as scalar
       X total water available in m3 per second for all mines
/15/
       k penalty for prior appropriation /10/;

Parameter e(j) estimated 2020 water efficiency of each firm j in
               units of m3 oil per m3 water;
         e(j)=ymax(j)/sum(i,l(i,j)*qave(i));

Display e;
```

```
Parameter s_high(i) licence priority rank in order from highest
                    (most  senior) to lowest (least senior) for
                    eleven licences;
         s_high(i)= 11-s(i)+1 ;

Variables
         w(i)      water supplied to each licence in m3 per
second
         pa        prior appropriation score to be minimised ;

Positive variable w;

Equations
         rank        objective function for licence ordering
purposes
         supply      total water supply constraint
         licensee(j) maximum water supply constraint associated
                     with each company
         licence(i)  water supply constraint associated with each
                     licence - assumes average licence usage
                     constraint;

*allocate water in order of prior appropriation, using
progressive benefit function
*for licences of higher seniority
rank..           pa =e= sum(i,w(i)*s_high(i)**k);

supply..         sum(i,w(i)) =l= X ;

licensee(j)..    sum(i,l(i,j)*w(i)) =l= qmax(j);

licence(i)..     w(i) =l= qave(i)*1000000/(60*60*24*365);

Model Athabasca_PA /all/ ;

solve Athabasca_PA using lp maximising pa ;

*display results
parameter revenue(j) mine revenue in units of dollars per second;
revenue(j)= sum(i,l(i,j)*w.L(i))*e(j)*a ;

parameter production(j) production associated with each mine;
production(j)= sum(i,l(i,j)*w.L(i))*e(j);

parameter answers1 solution values;
answers1(i,"water")=w.L(i);
display answers1;

parameter answers2 solution values;
answers2(j,"water")=sum(i,l(i,j)*w.L(i));
answers2(j,"production")=production(j);
answers2(j,"revenue")=revenue(j);
display answers2;

parameter totals solution values;
totals("water")=sum(j,sum(i,l(i,j)*w.L(i)));
```

```
totals("production")=sum(j,production(j));
totals("revenue")=sum(j,revenue(j));
display totals;

parameter totals_ALL output;

*Calculate model across all weekly time-steps
*first specify parameters for output
parameter watersupply(year,week,j) output;
parameter watershortfall(year,week,j) output compared to average
demand;
parameter revenue_t(year,week,j) mine revenue in units of dollars
per second;
parameter production_t(year,week,j) production m3 of oil per
second;
parameter total_revenue(year,week) output;

*loop analysis for all weeks over analysis period, and display
results
loop((year,week),
X=water(year,week);
solve Athabasca_PA using lp maximising pa ;
watersupply(year,week,j)=sum(i,l(i,j)*w.L(i));
watershortfall(year,week,j)=sum(i,qave(i)*l(i,j))*1000000/(60*60*
24*365) - sum(i,l(i,j)*w.L(i));
revenue_t(year,week,j)=sum(i,l(i,j)*w.L(i))*e(j)*a;
production_t(year,week,j)=sum(i,l(i,j)*w.L(i))*e(j);
total_revenue(year,week)=sum(j, sum(i,l(i,j)*w.L(i))*e(j)*a));

parameter av_net_rev total value of objective function in
billions of net revenue per year (on average);
av_net_rev=sum((year,week),total_revenue(year,week)*60*60*24*7/10
00000000)/(2004-1958+1);

parameter av_water(j) total water supply in millions of cubic
metres per year (on average);
av_water(j)=sum((year,week),watersupply(year,week,j)*60*60*24*7/1
000000)/(2004-1958+1);

parameter av_shortfall(j) total water supply shortfall in
millions of cubic metres per year (on average);
av_shortfall(j)=sum((year,week),watershortfall(year,week,j)*60*60
*24*7/1000000)/(2004-1958+1);

display av_net_rev;

*Export results to Excel
scalar col column number /1/;
file putfile /"C:\Documents and Settings\Amy\My Documents\Uni
Master's Course\Thesis\Data\GAMS\Opt_2a.xls" /;
put putfile;
*page format delimited by tabs (p131 of GAMS manual)
putfile.pc=6;
*increase page width to fit in all data
putfile.pw=10000;
put 'Run on ' system.date ' using source file ' system.ifile/// ;
```

```
*Print average licence volumes and seniority
put 'Licence' 'Rank (1- most senior)';
put 'Average licence volume in m3 per second'/;
loop(i, put i.tl; put s(i):2:0; put
(qave(i)*1000000/(60*60*24*365)):10:3; put /;);
put /;

*print scalar quantity a
put 'net revenue $ per m3 of oil produced' a //;

*Print results of water efficiency & shadow price of water for
each company
put ' ' 'Est. 2020 water efficiency in units of m3 oil per m3
water';
put 'shadow value of water $ per m3'/;
loop(j, put j.tl e(j):10:4 (a*e(j))/);
put ///;

*Print results of water supply
put 'Total water supply in m3 per second'/;
put ' ';
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0; loop(week, put water(year,week)); put
/);
put ///;

*Print results of water supply shortfall
put 'Total water supply shortfall in m3 per second'/;
put ' ';
col=1;
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0;
loop(week, put sum(j,watershortfall(year,week,j))); put /);
put //;
put 'Average water supply shortfall in m3 per second (all
companies)';
put sum((year,week),sum(j,watershortfall(year,week,j)/52/(2004-
1958+1)));
put ///;

*Print results of total revenue
put ///;
put 'Net revenue in $ per second'/;
put ' ';
col=1;
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0; loop(week, put
total_revenue(year,week)); put/);
put //;
put 'Average net revenue per year, billions' av_net_rev;
put ///;

*Print results of water supply to each company
put 'Water supply to each company in m3 per second'/;
```

```
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put watersupply(year,week,j):10:3;); put /);
put /;
put 'Average water supply GL/year' av_water(j):20:5; put ///;);

*Print results of water shortfall to each company
put 'Water shortfall to each company in m3 per second'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put watershortfall(year,week,j):10:3;); put /);
put /;
put 'Average water supply shortfall GL/year'
av_shortfall(j):20:10; put ///;);

*Print results of net revenue for each company
put 'Net revenue in $ per second per company'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put revenue_t(year,week,j):10:3;); put /);
put /;
put 'Average net revenue per year, millions';
put sum((year,week),(revenue_t(year,week,j)/52/(2004-
1958+1)*60*60*24*365/1000000));
put ///;);
```

G.2 Water trade

```
*Model of water trade in the Lower Athabasca, all time-steps
*
*Amy Mannix, December 2008

*Include the equation slacks in output
OPTION SOLSLACK=1;

*keep zeros in output
$setglobal zeros yes;

Sets
*define sets to allow for the fact that some mines/companies hold
several licences
*(that in some cases have combined maximum use conditions)
         i       oil sands licences /Shell_Jackpine, AOSP_Muskeg,
                                     CNRL_Horizon, PC_FortHills,
                                     Imperial_Kearl,
                                     Suncor_Mill-Steep1,
                                     Suncor_Mill-Steep2,
                                     Suncor_Voyageur,
                                     Syncrude_Mil-Aurora1,
```

```
                                   Syncrude_Mil-Aurora2,
                                   Total_Joslyn /
         j        oil sands mines    /Shell_Jackpine, AOSP_Muskeg,
                                   CNRL_Horizon, PC_FortHills,
                                   Imperial_Kearl, Suncor,
                                   Syncrude_Mil-Aurora,
                                   Total_Joslyn /;

*Define sets (year and week) and read in table of water supply
availability
*data from Excel (without listing in output file)
$offlisting;

set year year of water supply availability data /
$call =xls2gms r=GAMS!a4:a50 i="C:\Documents and Settings\Amy\My
Documents\Uni Master's Course\Thesis\Data\d01aem_GAMS link.xls"
o=setk.inc
$include setk.inc
/;

set week week of water supply availability data /
$call =xls2gms r=GAMS!b3:ba3 s="," i="C:\Documents and
Settings\Amy\My Documents\Uni Master's
Course\Thesis\Data\d01aem_GAMS link.xls" o=setl.inc
$include setl.inc
/;

table water(year,week) table of water supply availability
$call =xls2gms r=GAMS!a3:ba50 i="C:\Documents and Settings\Amy\My
Documents\Uni Master's Course\Thesis\Data\d01aem_GAMS link.xls"
o=pard.inc
$include pard.inc
;

$onlisting;

*Display water supply availability data from Excel
display water;


Parameters
         qave(i)  quantity of water licence in M m3 water per
                  year by 2020
*ie Shell_Jackpine (stage 2) CNRL_Horizon (steady) Imperial_Kearl
(stage C)
                 / Shell_Jackpine        35.3
                   AOSP_Muskeg           55.1
                   CNRL_Horizon          51.02
                   PC_FortHills          39.27
                   Imperial_Kearl        80
                   Suncor_Mill-Steep1    30.8375
                   Suncor_Mill-Steep2    28.98725
                   Suncor_Voyageur       3
                   Syncrude_Mil-Aurora1  60.4415
                   Syncrude_Mil-Aurora2  1.2335
                   Total_Joslyn          0.176625 /
```

```
         qmax(j)  maximum instantaneous licence volume in m3
                  water per second
*Fort Hills based on average use as unspecified
                 / Shell_Jackpine        1.95
                   AOSP_Muskeg           2.22
                   CNRL_Horizon          3.1
                   PC_FortHills          1.245243531
                   Imperial_Kearl        4.6
                   Suncor                3.79
                   Syncrude_Mil-Aurora   4.163
                   Total_Joslyn          0.02 /

         s(i)    seniority of water licence in order from 1 =
                    most senior to 11 = least senior
                 / Shell_Jackpine        7
                   AOSP_Muskeg           5
                   CNRL_Horizon          8
                   PC_FortHills          6
                   Imperial_Kearl        11
                   Suncor_Mill-Steep1    1
                   Suncor_Mill-Steep2    4
                   Suncor_Voyageur       9
                   Syncrude_Mil-Aurora1  2
                   Syncrude_Mil-Aurora2  3
                   Total_Joslyn          10 /

         ymax(j)  estimated company production by 2020 in Mm3 of
                  oil per year
                 / Shell_Jackpine        17.41
                   AOSP_Muskeg           15.67
                   CNRL_Horizon          33.48
                   PC_FortHills          11.03
                   Imperial_Kearl        17.41
                   Suncor                25.59
                   Syncrude_Mil-Aurora   34.41
                   Total_Joslyn          5.80 /;

Table l(i,j)     licences allocated to each mine
                     Shell_Jackpine      AOSP_Muskeg
CNRL_Horizon    PC_FortHills    Imperial_Kearl  Suncor
Syncrude_Mil-Aurora     Total_Joslyn
Shell_Jackpine       1                   0               0
0               0               0               0
0
AOSP_Muskeg          0                   1               0
0               0               0               0
0
CNRL_Horizon         0                   0               1
0               0               0               0
0
PC_FortHills         0                   0               0
1               0               0               0
0
Imperial_Kearl       0                   0               0
0               1               0               0
0
```

```
Suncor_Mill-Steep1   0                    0               0
0               0               1               0
0
Suncor_Mill-Steep2   0                    0               0
0               0               1               0
0
Suncor_Voyageur      0                    0               0
0               0               1               0
0
Syncrude_Mil-Aurora1 0                    0               0
0               0               0               1
0
Syncrude_Mil-Aurora2 0                    0               0
0               0               0               1
0
Total_Joslyn         0                    0               0
0               0               0               0
1             ;


Scalar a net revenue per m3 of oil produced for all firms set to
         274 per m3 (43.5 per barrel) /274/
*initial water availability entered as scalar
       X total water available in m3 per second for all mines
/15/;

Parameter e(j) estimated 2020 water efficiency of each firm j in
               units of m3 oil per m3 water;
         e(j)=ymax(j)/sum(i,l(i,j)*qave(i));

Variables
         w(j)  water supplied to each licencee in m3 per second
         z     revenue;

Positive variable w;

Equations
         net_revenue     objective function in units of dollars
                          per second
         supply          total water supply constraint
         production(j)   production capacity constraint for each
                          company or mine in m3 of oil per second
         w_instant       maximum instantaneous water supply
                          constraint across all companies
         w_average       maximum average water supply constraint
                          across all licences;

net_revenue..        z =e= sum(j,a*w(j)*e(j));

supply..             sum(j,w(j)) =l= X;

production(j)..      w(j)*e(j) =l=
ymax(j)*1000000/(60*60*24*365);

w_instant..          sum(j,w(j)) =l= sum(j,qmax(j));
```

```
w_average..          sum(j,w(j)) =l=
                     sum(i,qave(i)*1000000/(60*60*24*365));

Model Athabasca /all/ ;

solve Athabasca using lp maximising z ;

*display results in GAMS output
parameter revenue(j) mine revenue in units of dollars per second;
revenue(j)= w.L(j)*e(j)*a ;

parameter answers solutions values;
answers(j,"water")=w.L(j);
answers(j,"production")=production.L(j);
answers(j,"revenue")=revenue(j);
display answers;

parameter totals solution values;
totals("water")=sum(j,w.L(j));
totals("production")=sum(j,production.L(j));
totals("revenue")=sum(j,revenue(j));
display totals;


*Calculate model across all weekly time-steps
*first specify parameters for output
parameter waterprice(year,week) output;
parameter watersupply(year,week,j) output;
parameter watershortfall(year,week,j) output compared to average
demand;
parameter revenue_t(year,week,j) mine revenue in units of dollars
per second;
parameter production_t(year,week,j) production m3 of oil per
second;
parameter obj_fn(year,week) output;

loop((year,week),
X=water(year,week);
solve Athabasca using lp maximising z ;
waterprice(year,week)=supply.M;
watersupply(year,week,j)=w.L(j);
watershortfall(year,week,j)=sum(i,qave(i)*l(i,j))*1000000/(60*60*
24*365) - w.L(j);
revenue_t(year,week,j)=w.L(j)*e(j)*a;
production_t(year,week,j)=production.L(j);
obj_fn(year,week)=sum(j,a*w.L(j)*e(j)));

parameter av_net_rev total value of objective function in
billions of net revenue per year (average of individual weeks);
av_net_rev=sum((year,week),obj_fn(year,week)*60*60*24*7/100000000
0)/(2004-1958+1);

parameter av_water(j) total water supply in millions of cubic
metres per year (average of individual weeks);
av_water(j)=sum((year,week),watersupply(year,week,j)*60*60*24*7/1
000000)/(2004-1958+1);
```

```
parameter av_shortfall(j) total water supply shortfall in
millions of cubic metres per year (average of individual weeks);
av_shortfall(j)=sum((year,week),watershortfall(year,week,j)*60*60
*24*7/1000000)/(2004-1958+1);

display waterprice;
display av_net_rev;

*Export results to Excel
scalar col column number /1/;
file putfile /"C:\Documents and Settings\Amy\My Documents\Uni
Master's Course\Thesis\Data\GAMS\Opt_1a.xls" /;
put putfile;
*page format delimited by tabs (p131 of GAMS manual)
putfile.pc=6;
*increase page width to fit in all data
putfile.pw=10000;
put 'Run on ' system.date ' using source file ' system.ifile/// ;

*Print average licence volumes and seniority
put 'Licence' 'Rank (1- most senior)';
put 'Average licence volume in m3 per second'/;
loop(i, put i.tl; put s(i):2:0; put
(qave(i)*1000000/(60*60*24*365)):10:3; put /;);
put /;

*print scalar quantity a
put 'net revenue $ per m3 of oil produced' a //;

*Print results of water efficiency & shadow price of water for
each company
put ' ' 'Est. 2020 water efficiency in units of m3 oil per m3
water';
put 'shadow value of water $ per m3'/;
loop(j, put j.tl e(j):10:4 (a*e(j))/);
put ///;

*Print results of water supply
put 'Total water supply in m3 per second'/;
put ' ';
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0; loop(week, put water(year,week)); put
/);
put ///;

*Print results of water supply shortfall
put 'Total water supply shortfall in m3 per second'/;
put ' ';
col=1;
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0;
loop(week, put sum(j,watershortfall(year,week,j))); put /);
put //;
put 'Average water supply shortfall in m3 per second (all
companies)';
```

```
put sum((year,week),sum(j,watershortfall(year,week,j)/52/(2004-
1958+1)));
put ///;

*Print results of water price
put 'Water price in $ per m3'/;
put ' ';
col=1;
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0; loop(week, put
waterprice(year,week):5:2); put/);

*Print results of objective function
put ///;
put 'Net revenue (obj. fn.) in $ per second'/;
put ' ';
col=1;
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0; loop(week, put obj_fn(year,week));
put/);
put //;
put 'Average net revenue per year, billions' av_net_rev;
put ///;

*Print results of water supply to each company
put 'Water supply to each company in m3 per second'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put watersupply(year,week,j):10:3;); put /);
put /;
put 'Average water supply GL/year' av_water(j):20:5; put ///;);

*Print results of water shortfall to each company
put 'Water shortfall to each company in m3 per second'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put watershortfall(year,week,j):10:3;); put /);
put /;
put 'Average water supply shortfall GL/year'
av_shortfall(j):20:10;
put ///;);

*Print results of net revenue for each company
put 'Net revenue in $ per second per company'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put revenue_t(year,week,j):10:3;); put /);
put /;
put 'Average net revenue per year, millions';
```

```
put sum((year,week),(revenue_t(year,week,j)/52/(2004-
1958+1)*60*60*24*365/1000000));
put ///;);
```

G.3 Pricing with refund scheme

```
*Model of water pricing with refund (based on output) in the
Lower *Athabasca
*Final model version
*
*Amy Mannix, December 2008

*Include the equation slacks in output
OPTION SOLSLACK=1;

*keep zeros in output
$setglobal zeros yes;

*list order of sets in list (results) file
$onuellist;

Sets
*define sets to allow for the fact that some mines/companies hold
several licences
*(that in some cases have combined maximum use conditions)

*j is an ORDERED set from most water efficient to least water
efficient
*order must be maintained for correct model optimisation
         j       oil sands mines         / 1_Total_Joslyn,
                                           2_CNRL_Horizon,
                                           3_Syncrude_Mil-Aurora,
                                           4_Shell_Jackpine,
                                           5_Suncor,
                                           6_AOSP_Muskeg,
                                           7_PC_FortHills,
                                           8_Imperial_Kearl /

*"_L" is licence identifier (distinguishes licence names from
mine[j] names)
         i       oil sands licences      / Shell_Jackpine_L,
                                          AOSP_Muskeg_L,
                                           CNRL_Horizon_L,
                                          PC_FortHills_L,
                                           Imperial_Kearl_L,
                                           Suncor_Mill-Steep1_L,
                                           Suncor_Mill-Steep2_L,
                                           Suncor_Voyageur_L,
                                           Syncrude_Mil-
                                          Aurora1_L,
                                           Syncrude_Mil-
                                          Aurora2_L,
                                           Total_Joslyn_L /;
```

```
*Define sets (year and week) and read in table of water supply
availability
*data from Excel (without listing in output file)
$offlisting;

set year year of water supply availability data /
$call =xls2gms r=GAMS!a4:a50 i="C:\Documents and Settings\Amy\My
Documents\Uni Master's Course\Thesis\Data\d01aem_GAMS link.xls"
o=setk.inc
$include setk.inc
/;

set week week of water supply availability data /
$call =xls2gms r=GAMS!b3:ba3 s="," i="C:\Documents and
Settings\Amy\My Documents\Uni Master's
Course\Thesis\Data\d01aem_GAMS link.xls" o=setl.inc
$include setl.inc
/;

table water(year,week) table of water supply availability
$call =xls2gms r=GAMS!a3:ba50 i="C:\Documents and Settings\Amy\My
Documents\Uni Master's Course\Thesis\Data\d01aem_GAMS link.xls"
o=pard.inc
$include pard.inc
;

$onlisting;

*Display water supply availability data from Excel
display water;

Parameters
         qave(i)  quantity of water licence in M m3 water per
                  year by 2020
*ie Shell_Jackpine (stage 2) CNRL_Horizon (steady) Imperial_Kearl
(stage C)
                / Shell_Jackpine_L        35.3
                  AOSP_Muskeg_L           55.1
                  CNRL_Horizon_L          51.02
                  PC_FortHills_L          39.27
                  Imperial_Kearl_L        80
                  Suncor_Mill-Steep1_L    30.8375
                  Suncor_Mill-Steep2_L    28.98725
                  Suncor_Voyageur_L       3
                  Syncrude_Mil-Aurora1_L  60.4415
                  Syncrude_Mil-Aurora2_L  1.2335
                  Total_Joslyn_L          0.176625 /

         qmax(j)  maximum instantaneous licence volume in m3
                  water per second
*PC_FortHills based on average use as unspecified maximum licence
conditions
                / 1_Total_Joslyn          0.02
                  2_CNRL_Horizon          3.1
                  3_Syncrude_Mil-Aurora   4.163
                  4_Shell_Jackpine        1.95
                  5_Suncor                3.79
```

```
                 6_AOSP_Muskeg           2.22
                 7_PC_FortHills          1.237
                 8_Imperial_Kearl        4.6    /

         s(i)    seniority of water licence in order from 1 =
                  most senior to 11 = least senior
                / Shell_Jackpine_L        7
                  AOSP_Muskeg_L           5
                  CNRL_Horizon_L          8
                  PC_FortHills_L          6
                  Imperial_Kearl_L        11
                  Suncor_Mill-Steep1_L    1
                  Suncor_Mill-Steep2_L    4
                  Suncor_Voyageur_L       9
                  Syncrude_Mil-Aurora1_L  2
                  Syncrude_Mil-Aurora2_L  3
                  Total_Joslyn_L          10 /

         ymax(j)  estimated company production by 2020 in Mm3 of
                  oil per year
                / 1_Total_Joslyn          5.80
                  2_CNRL_Horizon          33.48
                  3_Syncrude_Mil-Aurora   34.41
                  4_Shell_Jackpine        17.41
                  5_Suncor                25.59
                  6_AOSP_Muskeg           15.67
                  7_PC_FortHills          11.03
                  8_Imperial_Kearl        17.41 /;

Table l(i,j)     licences allocated to each mine
                          1_Total_Joslyn     2_CNRL_Horizon
3_Syncrude_Mil-Aurora  4_Shell_Jackpine   5_Suncor
6_AOSP_Muskeg     7_PC_FortHills    8_Imperial_Kearl
Shell_Jackpine_L           0                   0               0
1               0               0               0
0
AOSP_Muskeg_L              0                   0               0
0               0               1               0
0
CNRL_Horizon_L             0                   1               0
0               0               0               0
0
PC_FortHills_L             0                   0               0
0               0               0               1
0
Imperial_Kearl_L           0                   0               0
0               0               0               0
1
Suncor_Mill-Steep1_L       0                   0               0
0               1               0               0
0
Suncor_Mill-Steep2_L       0                   0               0
0               1               0               0
0
Suncor_Voyageur_L          0                   0               0
0               1               0               0
0
```

```
Syncrude_Mil-Aurora1_L     0                    0               1
0               0               0               0
0
Syncrude_Mil-Aurora2_L     0                    0               1
0               0               0               0
0
Total_Joslyn_L             1                    0               0
0               0               0               0
0   ;


Scalar op output price per m3 of oil produced for all firms set
          to 440 per m3 (70 per barrel) /440/
       uc unit cost per m3 of oil produced for all firms set to
          166 per m3 (26.5 per barrel) /166/
*initial water availability entered as scalar
       X total water available in m3 per second for all mines /8/
*MINIMUM starting price of water
*(algorithm inserted below to determine maximum price)
       wp water price per m3 of water extracted /0/;

Parameter a net revenue per m3 of oil produced;
          a = op - uc;

Parameter e(j) estimated 2020 water efficiency of each firm j in
               units of m3 oil per m3 water;
          e(j)=ymax(j)/sum(i,l(i,j)*qave(i));

Display e;

Parameter max_prod maximum 2020 production level in Mm3 of oil
                   per year;
          max_prod=sum(j,ymax(j));

Parameter lic_av total of licensed average water use in m3 per
second;
          lic_av= sum(i,qave(i))*1000000/(60*60*24*365);

Variables
         w(j)       water supplied to each licencee in m3 per
second
         z          revenue across all companies in dollars per
second
         tp         total production in m3 of oil per second
         tw         total water use in m3 per second;

Positive variables
w
tp
tw;

*starting point definitions for tw and tp
*Note tp level is dependent on tw, tp optimised below based on
efficiency

*First find highest water-efficiency order of mine at which mine
water *use will be totally satisfied
```

```
parameter max_j mine order from highest efficiency(1) to
                lowest(card(j)) - highest order at which demand
                able to be fully satisfied;
parameter watstep step in water usage (m3 per second) for below
                 while statement;
parameter count count step used for following while statement;
*initialise parameters
watstep=0;
count=1;

if( X > lic_av,
         tw.L = lic_av;
         tp.L = tw.L*sum(j,ymax(j))/sum(i,qave(i));
         else    tw.L = X;
                 while((watstep < X),
                        watstep = sum(j$(ord(j) le
count),sum(i,l(i,j)*qave(i)))*1000000/(60*60*24*365);
                        count = count + 1;);
                 max_j = count - 2;
                 tp.L= sum(j$(ord(j)<=max_j),

sum(i,l(i,j)*qave(i)*1000000/(60*60*24*365)))*
                       sum(j$(ord(j)<=max_j),ymax(j))

/sum(j$(ord(j)<=max_j),sum(i,l(i,j)*qave(i)))
                       +(tw.L - sum(j$(ord(j)<=max_j),

sum(i,l(i,j)*qave(i)*1000000/(60*60*24*365))))*
                       sum(j$(ord(j)=(max_j+1)),
                       (ymax(j)/sum(i,l(i,j)*qave(i))));   );

Equations
         revenue         objective function - unit of dollars per
                          second
         supply          total water supply constraint
         production(j)   production capacity constraint for each
                          mine in m3 of oil per second
         w_instant       maximum instantaneous water supply
                          constraint across all companies
         w_average       maximum average water supply constraint
                          across all licences;

*"revenue" equation refers to total revenue across all companies,
with *each individual company charged a water price, wp, then
provided with
*a refund issued in proportion to share of total output

revenue..        z =e= sum(j,(op-uc)*w(j)*e(j)-
                        wp*w(j)+wp*tw.L*w(j)*e(j)/tp.L);

supply..         sum(j,w(j)) =l= X;

production(j)..  w(j)*e(j) =l= ymax(j)*1000000/(60*60*24*365);

w_instant..     sum(j,w(j)) =l= sum(j,qmax(j));

w_average..     sum(j,w(j)) =l= lic_av;
```

```
Model Athabasca /all/ ;

solve Athabasca using lp maximising z;

tp.L = sum(j,w.L(j)*e(j));
tw.L = sum(j,w.L(j));


*Calculate model across all weekly time-steps

parameter prod_alias alias parameter of total production for use
                     in loop statement;
prod_alias=tp.L;

*Specify parameters for output
parameter waterprice(year,week)  output final wp (water price per
m3);
parameter marketprice(year,week) price assoc. with water trade
                                 among companies (if applicable);
parameter watersupply(year,week,j) water supplied to each
                                    licencee m3  per second;
parameter watershortfall(year,week,j) shortfall compared to
                                       licensed average supply m3
                                       per second;
parameter revenue_t(year,week,j) net revenue from oil production
                                 $ per second;
parameter watercost_t(year,week,j) water charges (exc. refund) $
                                   per second;
parameter refund_t(year,week,j) revenue from refund payment $ per
                               second;
parameter production_t(year,week,j) production m3 of oil per
second;
parameter obj_fn(year,week) objective function in units of $ per
                            second;

loop((year,week),
X=water(year,week);
*re-initialise variables
         wp=0;
         watstep=0;
         count=1;
         if( X > lic_av,
                 tw.L = lic_av;
                 tp.L = tw.L*sum(j,ymax(j))/sum(i,qave(i));
                 else    tw.L = X;
                         while((watstep < X),
                                watstep = sum(j$(ord(j) le
count),
                                          sum(i,l(i,j)*qave(i)))*
                                          1000000/(60*60*24*365);
                                count = count + 1;);
                                max_j = count - 2;
                         tp.L= sum(j$(ord(j)<=max_j),

sum(i,l(i,j)*qave(i)*1000000/(60*60*24*365)))*
                               sum(j$(ord(j)<=max_j),ymax(j))
```

```
/sum(j$(ord(j)<=max_j),sum(i,l(i,j)*qave(i)))
                                +(tw.L - sum(j$(ord(j)<=max_j),

sum(i,l(i,j)*qave(i)*1000000/(60*60*24*365))))*
                                sum(j$(ord(j)=(max_j+1)),
                                (ymax(j)/sum(i,l(i,j)*qave(i))));
);
solve Athabasca using lp maximising z ;
prod_alias = tp.L;
*find maximum water price able to be charged to ensure water use
is
*within limit, accurate to the nearest additional unit added to
wp with each iteration
if((tw.L = X),
*note: rounding needed in below statement to ensure consistent
results
         while( (round(tp.L,3) eq round(prod_alias,3)),
                 wp = wp + 10;
                 solve Athabasca using lp maximising z;
                 tp.L = sum(j,w.L(j)*e(j)););
*bring water price back one step so that water-use and production
is maximised
         wp = wp - 10;
*re-initialise tp and tw variables
         tw.L = X;
         tp.L = prod_alias;
         solve Athabasca using lp maximising z;
else     solve Athabasca using lp maximising z;
);
waterprice(year,week)=wp;
marketprice(year,week)=supply.M;
watersupply(year,week,j)=w.L(j);
watershortfall(year,week,j)=sum(i,qave(i)*l(i,j))*1000000/(60*60*
24*365) - w.L(j);
revenue_t(year,week,j)=w.L(j)*e(j)*a;
watercost_t(year,week,j)=w.L(j)*wp;
refund_t(year,week,j)=wp*tw.L*w.L(j)*e(j)/tp.L;
production_t(year,week,j)=production.L(j);
obj_fn(year,week)=sum(j,a*w.L(j)*e(j)));

parameter av_net_rev total value of objective function in
                     billions of net revenue per year (average of
                     individual weeks);
av_net_rev=sum((year,week),obj_fn(year,week)*60*60*24*7/100000000
0)/card(year);

parameter av_water(j) total water supply in millions of cubic
                     metres per year (average of individual
                     weeks);
av_water(j)=sum((year,week),watersupply(year,week,j)*60*60*24*7/1
000000)/card(year);

parameter av_shortfall(j) total water supply shortfall in
                          millions of cubic metres per year
                          (average of individual weeks);
```

```
av_shortfall(j)=sum((year,week),watershortfall(year,week,j)*60*60
*24*7/1000000)/card(year);

parameter netwatcost(year,week,j) water cost less refund in
                                  dollars per second;
netwatcost(year,week,j)=watercost_t(year,week,j)-
refund_t(year,week,j);

display waterprice;
display av_net_rev;

*Export results to Excel
scalar col column number /1/;
file putfile /"C:\Documents and Settings\Amy\My Documents\Uni
Master's Course\Thesis\Data\GAMS\Opt_3a.xls" /;
put putfile;
*page format delimited by tabs (p131 of GAMS manual)
putfile.pc=6;
*increase page width to fit in all data
putfile.pw=10000;
put 'Run on ' system.date ' using source file ' system.ifile/// ;

*Print average licence volumes and seniority
put 'Licence' 'Rank (1- most senior)';
put 'Average licence volume in m3 per second'/;
loop(i, put i.tl; put s(i):2:0; put
(qave(i)*1000000/(60*60*24*365)):10:3; put /;);
put /;

*print scalar quantity a
put 'net revenue $ per m3 of oil produced' a //;

*Print results of water efficiency, shadow price of water,
average max
*use of water, production levels and production share for each
company
put ' ' 'Est. 2020 water efficiency in units of m3 oil per m3
water';
put 'shadow value of water $ per m3';
put 'average licence volume in m3 per second';
put 'Est. 2020 production level in Mm3 of oil per year' 'Est.
2020 production share'/;
loop(j, put j.tl e(j):10:4 (a*e(j));
        put (sum(i,l(i,j)*qave(i))*1000000/(60*60*24*365)):10:3;
        put ymax(j) (ymax(j)/max_prod) /);
put ///;

*Print results of water supply
put 'Total water supply in m3 per second'/;
put ' ';
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0; loop(week, put water(year,week)); put
/);
put ///;

*Print results of water supply shortfall
```

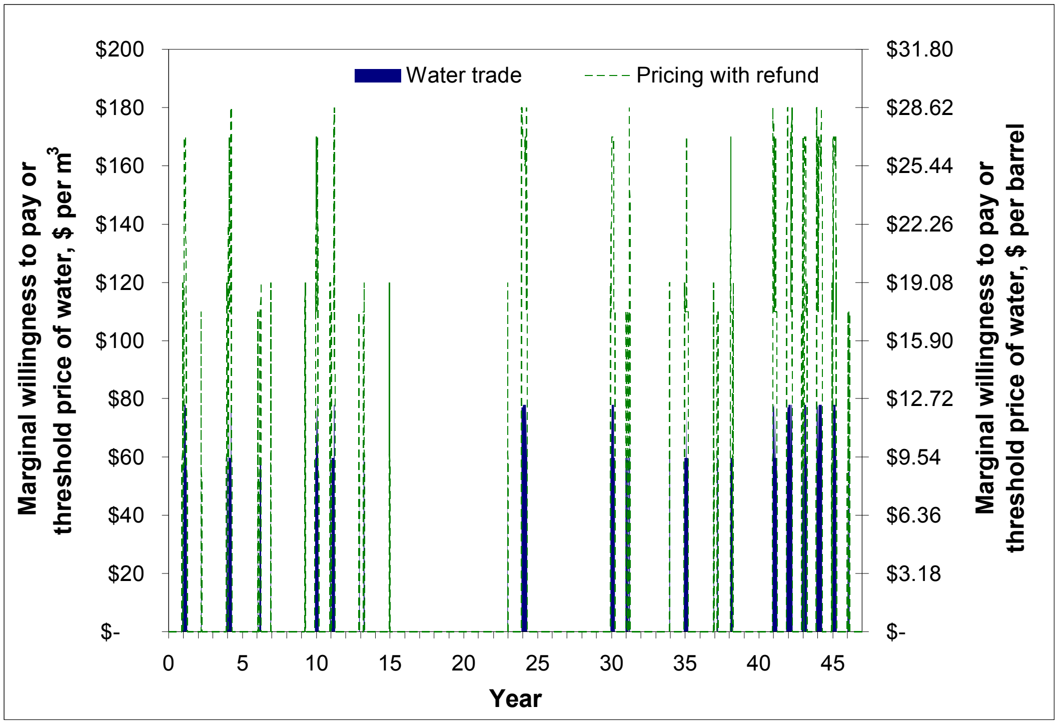
```
put 'Total water supply shortfall in m3 per second'/;
put ' ';
col=1;
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0;
loop(week, put sum(j,watershortfall(year,week,j))); put /);
put //;
put 'Average water supply shortfall in m3 per second (all
companies)';
put
sum((year,week),sum(j,watershortfall(year,week,j)/card(week)/card
(year)));
put ///;

*Print results of water price
put 'Water price in $ per m3'/;
put ' ';
col=1;
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0; loop(week, put
waterprice(year,week):6:0); put/);

*Print results of objective function
put ///;
put 'Net revenue (obj. fn.) in $ per second'/;
put ' ';
col=1;
loop(week, put col:2:0; col=col+1;);
put /;
loop(year, put year.tl:4:0; loop(week, put obj_fn(year,week));
put/);
put //;
put 'Average net revenue per year, billions' av_net_rev;
put ///;

*Print results of water supply to each company
put 'Water supply to each company in m3 per second'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put watersupply(year,week,j):10:3;); put /);
put /;
put 'Average water supply GL/year' av_water(j):20:5; put ///;);

*Print results of water shortfall to each company
put 'Water shortfall to each company in m3 per second'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put watershortfall(year,week,j):10:3;); put /);
put /;
put 'Average water supply shortfall GL/year'
av_shortfall(j):20:10; put ///;);
```

```
*Print results of net revenue for each company
put 'Net revenue in $ per second per company'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put revenue_t(year,week,j):10:3;); put /);
put /;
put 'Average net revenue per year, millions';
put
sum((year,week),(revenue_t(year,week,j)/card(week)/card(year)*60*
60*24*365/1000000));
put ///;);

*Print results of water charge (excluding refund) to each company
put 'Water charge in $ per second per company'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put watercost_t(year,week,j):10:3;); put /);
put /;
put 'Average water charge per year, millions';
put
sum((year,week),(watercost_t(year,week,j)/card(week)/card(year)*6
0*60*24*365/1000000));
put ///;);

*Print results of water refund payment to each company
put 'Water refunded charge (based on output) in $ per second per
company'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put refund_t(year,week,j):10:3;); put /);
put /;
put 'Average refunded charge per year, millions';
put
sum((year,week),(refund_t(year,week,j)/card(week)/card(year)*60*6
0*24*365/1000000));
put ///;);

*Print results of water cost less refund payment to each company
put 'Water cost less refund in $ per second per company'/;
col=1;
loop(j, put j.tl / ' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put netwatcost(year,week,j):10:3;); put /);
put /;
put 'Average water cost less refund per year, millions';
put
sum((year,week),(netwatcost(year,week,j)/card(week)/card(year)*60
*60*24*365/1000000));
put ///;);
```

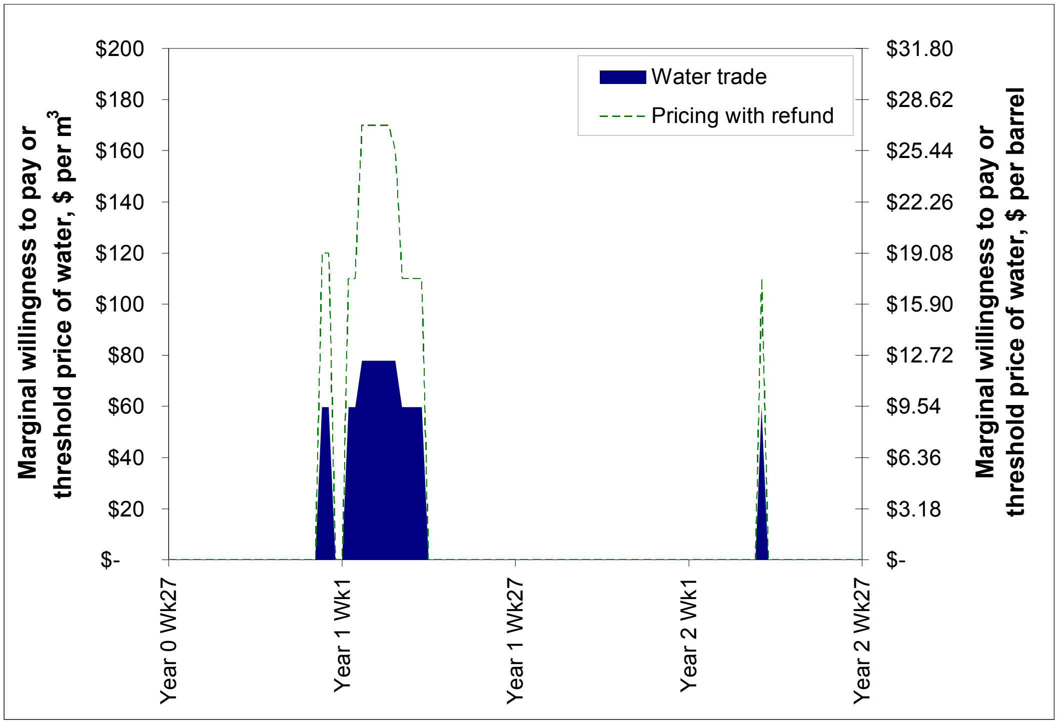
```
*Print results of market price for water trade
*(Note that water trade is not part of this option, so output
should be *a residual value if water price is not maximised to
full extent
*i.e. arising from incremental/discontinuous water price in the
main *loop statement)
put 'Water price in $ per m3'/;
col=1;
put' '; col=1;
loop(week, put col:2:0; col=col+1); put /;
loop(year, put year.tl:4:0;
loop(week, put marketprice(year,week):10:3;); put /);
put /;
put 'Average weekly water price';
put
sum((year,week),(marketprice(year,week)/card(week)/card(year)));
put ///;
```

Appendix H Additional details on pricing with refund scheme

H.1 Price comparison with water trade



- **Figure 7-30 Comparison of marginal willingness to pay for water under the water trade scenario, versus the threshold price for water able to be sustained under the pricing with refund scheme while maximising use of the available water supply. Short run response to water shortfalls (i.e., reduced production).**



- **Figure 7-31 Comparison over a truncated period of marginal willingness to pay for water under the water trade scenario, versus the threshold price for water able to be sustained under the pricing with refund scheme while maximising use of the available water supply. Short run response to water shortfalls (i.e., reduced production).**

H.2 Explanation of threshold price relationship

See Section 3.5 for description of terms.

Objective function:

Maximise

$$\sum_{j=1}^{m}\left[a\ .e_j.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right) - p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right) + p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right).\frac{q_j}{\left(\sum_{j=1}^{m} q_j\right)}\right]$$

For each mining operation:

$$\pi_j = a \;.e_j.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right) - p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right) + p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right).\frac{q_j}{\left(\sum_{j=1}^{m} q_j\right)}$$

Where:

π_j = profit (revenue minus variable cost) of individual mining operation, *j*.

To determine the maximum price of water, p_w, for mining operation *Z*, where *Z* is the next least-efficient mining operation of those mines (*j*) currently in operation, set profit equation equal to zero ($\pi_Z \leq 0$) and rearrange as follows:

$$0 \geq a \;.e_Z.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right) - p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right) + p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right).\frac{q_Z}{\left(\sum_{j=1}^{m} q_j\right)}$$

$$0 \geq e_Z.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\cdot\left[a \; - \frac{p_w}{e_Z} + p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right).\frac{1}{\left(\sum_{j=1}^{m} q_j\right)}\right]$$

$$0 \geq e_Z.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\cdot\left[a \; - \frac{p_w}{e_Z} + p_w.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right).\frac{1}{\left(\sum_{j=1}^{m} e_j.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\right)}\right]$$

$$0 \geq \left[a \; - \frac{p_w}{e_Z} + p_w.\frac{\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right)}{\left(\sum_{j=1}^{m} e_j.\left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\right)}\right]$$

$$\left[\frac{p_w}{e_Z} - p_w \cdot \frac{\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right)}{\left(\sum_{j=1}^{m} e_j \cdot \left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\right)}\right] \geq a$$

$$p_w\left[\frac{1}{e_Z} - \frac{\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right)}{\left(\sum_{j=1}^{m} e_j \cdot \left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\right)}\right] \geq a$$

$$p_w\left[\frac{\left(\sum_{j=1}^{m} e_j \cdot \left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\right) - e_Z\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right)}{e_Z \cdot \left(\sum_{j=1}^{m} e_j \cdot \left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\right)}\right] \geq a$$

$$p_w \geq a \cdot e_Z \cdot \left[\frac{\sum_{j=1}^{m} e_j \cdot \left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)}{\left(\sum_{j=1}^{m} e_j \cdot \left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\right) - e_Z\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right)}\right]$$

Note:

$p_w \uparrow$ as $a \uparrow$

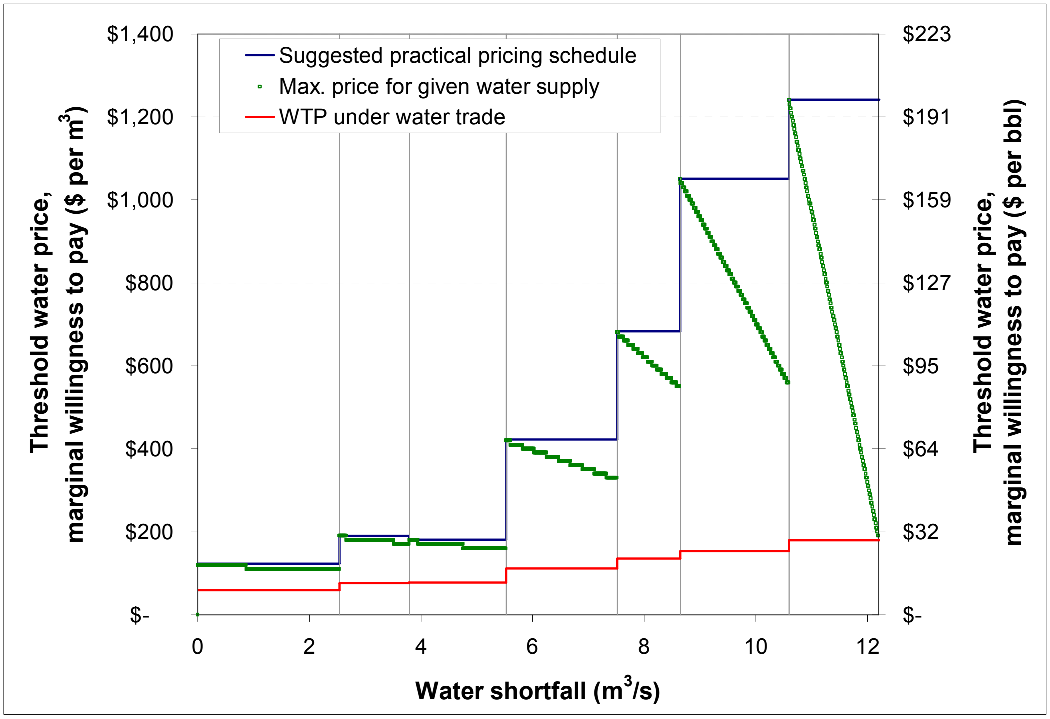
$p_w \uparrow$ as $e_Z \uparrow$

$p_w \downarrow$ as $e_Z\left(\sum_{i=1}^{n}\sum_{k=1}^{K} l_{i,k}.w_{i,k}\right)\downarrow$ relative to $\left(\sum_{j=1}^{m} e_j \cdot \left(\sum_{i=1}^{n}\sum_{k=1}^{K} b_{i,j}.w_{i,k}\right)\right)$

i.e., threshold price (p_w) declines as the proportion of total output attributable to firm Z declines (associated with a reduced share of water supply to firm Z as water becomes more scarce).

The above explanation relies on the assumption of linear production functions and fixed water-use efficiency of each mining operation (e_j), allowing water to be supplied to operations in order of water-use efficiency (most water-efficient firms are supplied first, i.e., prior to firm *Z*).

H.3 Example of practical pricing structure under linear demands



- **Figure 7-32 Comparison of the marginal willingness-to-pay under water trade, and a practical threshold price schedule, with the threshold price for water ($ per m^3 and $ per barrel) able to be sustained in the short run under the pricing with refund scheme while maximising the use of available water supplies, shown for each possible level of water shortfall.**

Appendix I Sensitivity analysis

I.1 Sensitivity of results to background flow in the Athabasca River

This section presents selected results of the sensitivity analysis of background flows for the following scenarios:

- Wet flow scenario: historic flow series (1958 to 2004)
- Base case flow scenario: 10% decline in historic flows
- Dry flow scenario: 20% decline in historic flows
- Extreme dry flow scenario: 50% decline in historic flows.

I.1.1 Water availability

Refer to Table 7-17 on following page.

- **Table 7-17 Summary statistics of modelled supply shortfalls associated with implementation of the WMF under various flow scenarios and constant 12.22 m^3/s demand**

Shortfall statistic	Flow scenario			
	Wet	Base Case	Dry	Ext. Dry
Peak shortfall, m^3/s	4.0	4.8	5.6	8.1
Longest shortfall event				
No. weeks	19	20	21	26
Average weekly shortfall, m^3/s	2.8	3.7	4.4	6.5
Total shortfall, GL	31.7	44.8	56.4	102
Annual shortfall, % total demand				
Average	1	2	3	9
Median	0	0	1	6
Standard deviation	2	3	4	8
Maximum	7	10	13	26
Minimum	0	0	0	0
Annual no. of weeks of shortfall				
Average	4	5	6	10
Median	0	3	4	9
Standard deviation	6	6	6	8
Maximum	17	19	21	26
Minimum	0	0	0	0
Annual average weekly shortfall, % total demand [a]				
Average	15	16	22	41
Median	15	17	23	42
Standard deviation	8	10	10	14
Maximum	29	32	39	62
Minimum	6	3	6	8

a. Calculation only includes weeks within the year when a shortfall occurs. Years without shortfall not included.

I.1.2 Consolidated tailings and increased water recycling

- **Table 7-18 Sensitivity to background flow conditions of estimated net present value of consolidated tailings and increased water recycling, by mining operation.**

Mining operation	NPV of option under constant operation, $ M				NPV of option under intermittent (as required) operation, $ M			
	Wet	**Base Case**	**Dry**	**Ext. Dry**	**Wet**	**Base Case**	**Dry**	**Ext. Dry**
Firm 1	-	-	-	-	-	-	-	-
Firm 2	540	920	1 770	4 310	720	1 090	1 940	4 480
Firm 3	-	-	-	-	-	-	-	-
Firm 4	-	100	370	2 020	-	230	500	2 140
Firm 5	20	50	180	430	80	110	240	490
Firm 6	-	-	-	670	-	-	-	860
Firm 7	-	-	-	1 000	-	-	40	1 130
Firm 8	680	1 030	1 380	2 420	930	1 280	1 630	2 660
Total	**1 200**	**2 100**	**3 700**	**10 900**	**1 700**	**2 700**	**4 400**	**11 800**

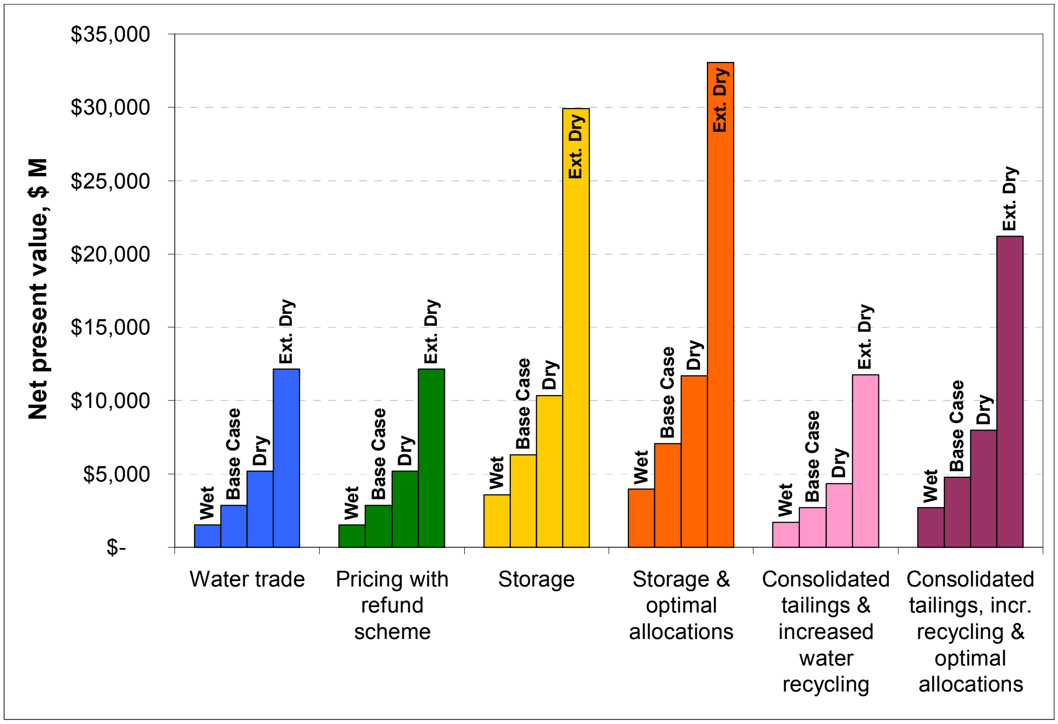
- **Table 7-19 Sensitivity to background flow conditions of incremental net present value of consolidated tailings and increased water recycling, by mining operation, combined with optimal allocations (e.g. following water trade)**

Mining operation	**NPV of option under constant operation, $ M**				**NPV of option under intermittent (as required) operation, $ M**			
	Wet	**Base Case**	**Dry**	**Ext. Dry**	**Wet**	**Base Case**	**Dry**	**Ext. Dry**
Firm 1	-	-	-	-	-	-	-	-
Firm 2	-	-	-	-	-	-	-	-
Firm 3	-	-	-	-	-	-	-	-
Firm 4	-	-	-	490	-	-	-	620
Firm 5	-	-	-	2 260	-	-	-	2 460
Firm 6	-	90	290	1 730	10	280	480	1 910
Firm 7	70	200	520	1 300	210	340	660	1 430
Firm 8	680	1 030	1 380	2 420	930	1 280	1 630	2 660
Total	**800**	**1 300**	**2 200**	**8 200**	**1 200**	**1 900**	**2 800**	**9 100**

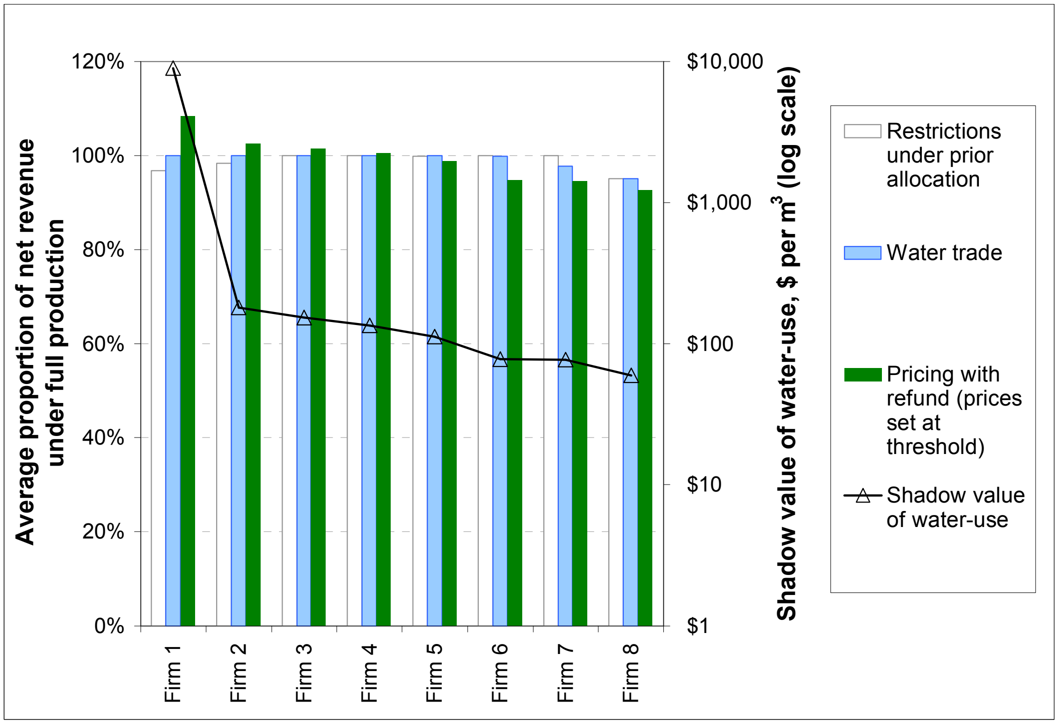
I.1.3 Results summary

- **Table 7-20 Sensitivity to background flow conditions of estimated net present value of options, $ M**

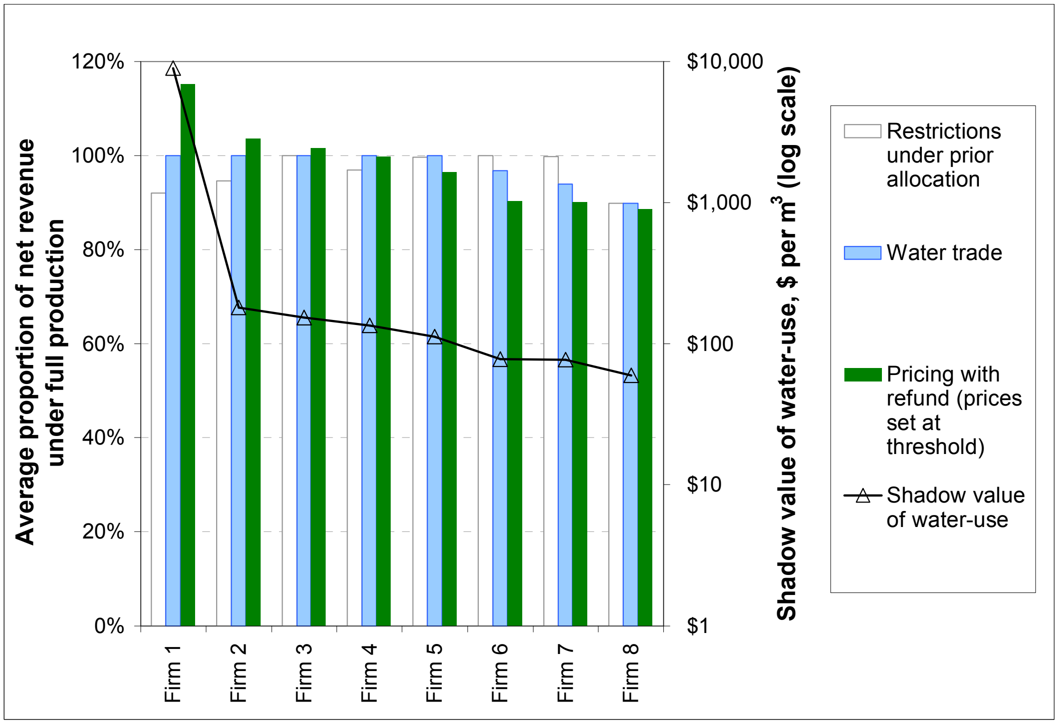
Option	PV of costs (capital, operation and maintenance)				PV of reduced costs associated with shortfalls				NPV			
	Hist.	-10%	-20%	-50%	Hist.	-10%	-20%	-50%	Hist.	-10%	-20%	-50%
Policy options												
Restrictions under prior allocation (base case)	-	-	-	-	-	-	-	-	-	-	-	-
Water trade	-	-	-	-	1 500	2 900	5 200	12 100	1 500	2 900	5 200	12 100
Pricing with refund scheme	-	-	-	-	1 500	2 900	5 200	12 100	1 500	2 900	5 200	12 100
Technical and combined technical and policy options												
Storage	50	50	60	70	3 600	6 400	10 400	30 000	3 600	6 300	10 400	29 900
Storage combined with optimal allocations (e.g. following water trade)	50	50	60	70	4 000	7 100	11 700	33 100	4 000	7 100	11 700	33 000
Consolidated tailings and increased water recycling	190	250	290	420	1 900	3 000	4 600	12 200	1 700	2 700	4 400	11 800
Consolidated tailings and increased water recycling combined with optimal allocations	190	240	250	420	2 900	5 000	8 200	21 600	2 700	4 800	8 000	21 200



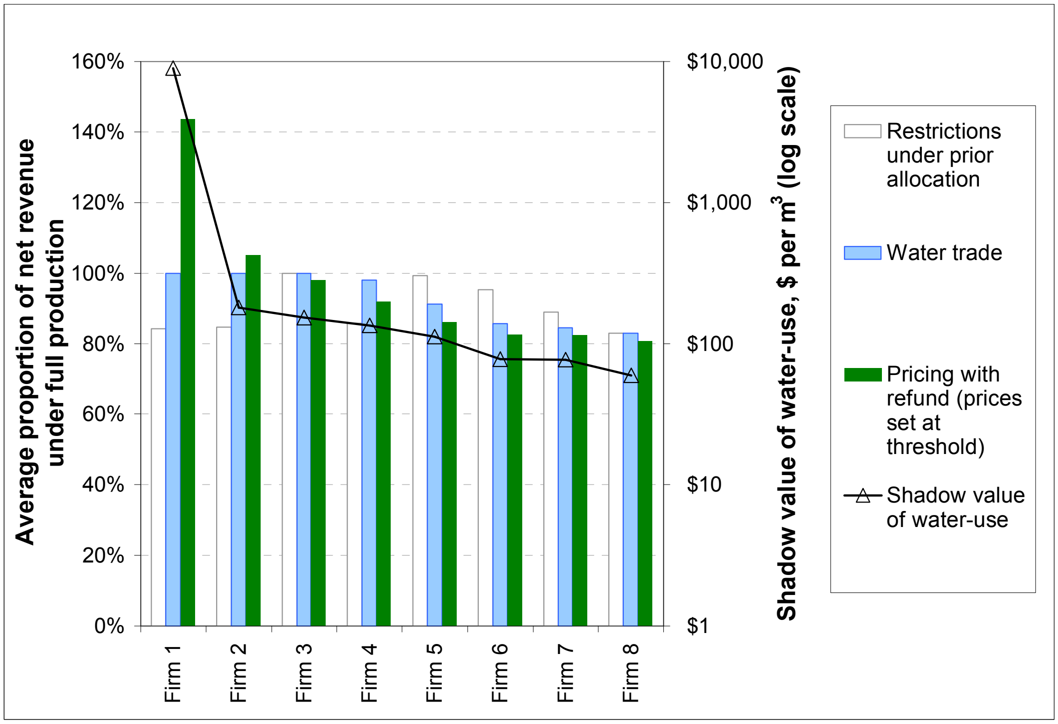
- **Figure 7-33 Sensitivity to background flow conditions of estimated net present value of options, $ M. Labels depict background flow scenario.**



- **Figure 7-34 Comparison of policy options in terms of average net revenue as a proportion of that under full production by mining operation associated with short run response to water shortfalls (i.e., reduced production). Sensitivity analysis of background flows using wet (historic) flow scenario. Shadow value of water-use shown on secondary axis in log scale.**



- **Figure 7-35 Comparison of policy options in terms of average net revenue as a proportion of that under full production by mining operation associated with short run response to water shortfalls (i.e., reduced production). Sensitivity analysis of background flows using dry (-20%) flow scenario. Shadow value of water-use shown on secondary axis in log scale.**



- **Figure 7-36 Comparison of policy options in terms of average net revenue as a proportion of that under full production by mining operation associated with short run response to water shortfalls (i.e., reduced production). Sensitivity analysis of background flows using extreme dry (-50%) flow scenario. Shadow value of water-use shown on secondary axis in log scale.**

I.2 Sensitivity of results to oil price

This section presents selected results of the sensitivity analysis of oil prices for the following scenarios:

- Low price scenario of $30 per barrel
- Base case scenario of $70 per barrel
- High price scenario of $110 per barrel.

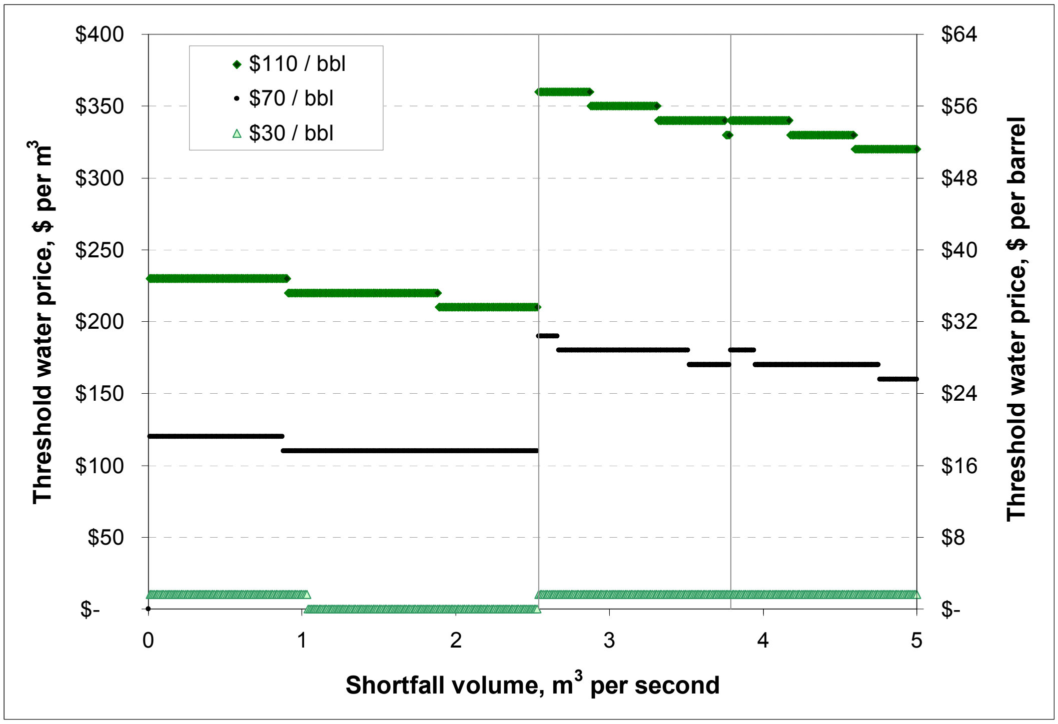
The sensitivity analysis continues to assume an average cost of production of $26.50 per barrel (Section 3.2.4).

I.2.1 Value of water-use by mining operation

- **Table 7-21 Sensitivity to oil price of estimated shadow value of water use ($ per m^3) by mining operation**

Mining operation	Shadow value of water use, $ per m^3		
	$30 / bbl	**$70 / bbl**	**$110 / bbl**
Firm 1	755	8 998	17 273
Firm 2	15	180	345
Firm 3	13	153	293
Firm 4	11	135	259
Firm 5	9	112	214
Firm 6	7	78	150
Firm 7	6	77	148
Firm 8	5	60	114
Median	**10**	**123**	**237**

I.2.2 Pricing with refund scheme



▪ **Figure 7-37 Sensitivity to oil price of estimated threshold price for water ($ per m^3 and $ per barrel) able to be sustained in the short run (i.e., shortfall response of reduced production) under pricing with refund scheme while maximising use of available water supplies, 0 to 5 m^3/s range of water shortfalls.**

I.2.3 Consolidated tailings and increased water recycling

- **Table 7-22 Sensitivity to oil price of estimated net present value of consolidated tailings and increased water recycling, by mining operation.**

Mining operation	NPV of option under constant operation, $ M			NPV of option under intermittent (as required) operation, $ M		
	$30 / bbl	**$70 / bbl**	**$110 / bbl**	**$30 / bbl**	**$70 / bbl**	**$110 / bbl**
Firm 1	-	-	-	-	-	-
Firm 2	-	920	1 980	20	1 090	2 160
Firm 3	-	-	-	-	-	-
Firm 4	-	100	360	-	230	490
Firm 5	-	50	180	-	110	240
Firm 6	-	-	-	-	-	-
Firm 7	-	-	-	-	-	-
Firm 8	-	1 030	2 310	10	1 280	2 560
Total	**-**	**2 100**	**4 800**	**30**	**2 700**	**5 400**

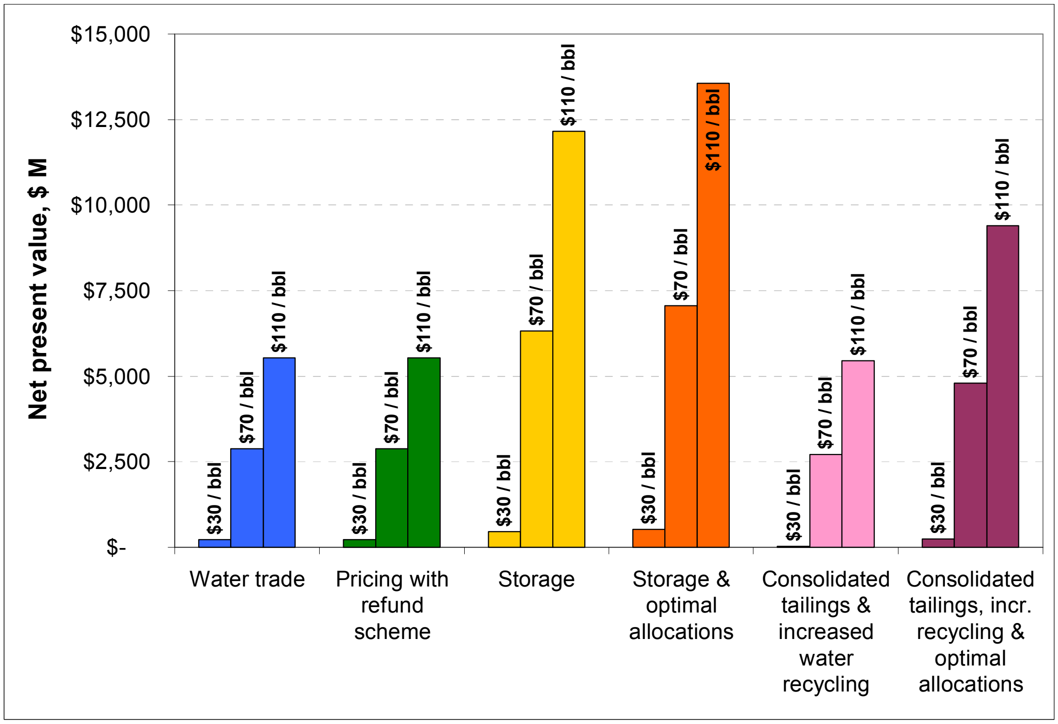
- **Table 7-23 Sensitivity to oil price of incremental net present value of consolidated tailings and increased water recycling, combined with allocations under either water trade or pricing with refund scheme, by mining operation.**

Mining operation	NPV of option under constant operation, $ M			NPV of option under intermittent (as required) operation, $ M		
	$30 / bbl	$70 / bbl	$110 / bbl	$30 / bbl	$70 / bbl	$110 / bbl
Firm 1	-	-	-	-	-	-
Firm 2	-	-	-	-	-	-
Firm 3	-	-	-	-	-	-
Firm 4	-	-	-	-	-	-
Firm 5	-	-	-	-	-	-
Firm 6	-	90	420	-	280	610
Firm 7	-	200	560	-	340	710
Firm 8	-	1 030	2 310	10	1 280	2 560
Total	**-**	**1 300**	**3 300**	**10**	**1 900**	**3 900**

I.2.4 Results summary

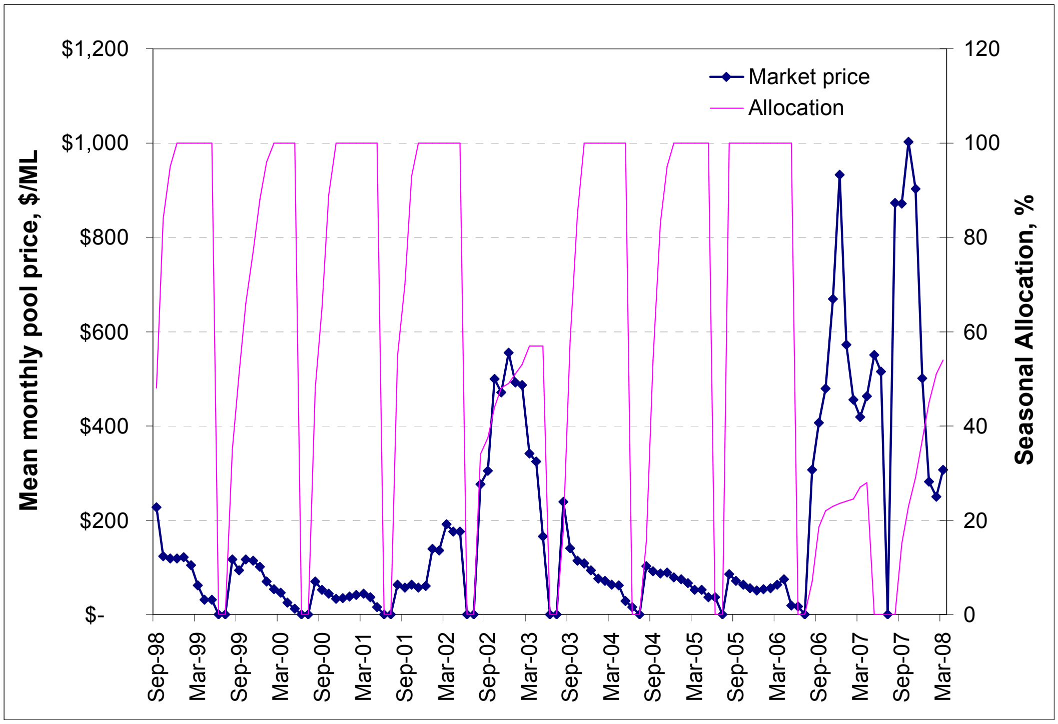
- **Table 7-24 Sensitivity to oil price of estimated net present value of options, $ M**

Option	PV of costs (capital, operation and maintenance)			PV of reduced costs associated with shortfalls			NPV		
	$30 / bbl	$70 / bbl	$110 / bbl	$30 / bbl	$70 / bbl	$110 / bbl	$30 / bbl	$70 / bbl	$110 / bbl
Policy options									
Restrictions under prior allocation (base case)	-	-	-	-	-	-	-	-	-
Water trade	-	-	-	230	2 900	5 500	230	2 900	5 500
Pricing with refund scheme	-	-	-	230	2 900	5 500	230	2 900	5 500
Technical and combined technical and policy options									
Storage	50	50	50	510	6 400	12 200	460	6 300	12 100
Storage combined with optimal allocations (e.g. following water trade)	50	50	50	570	7 100	13 600	520	7 100	13 600
Consolidated tailings and increased water recycling	170	250	250	210	3 000	5 700	30	2 700	5 400
Consolidated tailings and increased water recycling combined with optimal allocations	100	240	240	340	5 000	9 600	240	4 800	9 400



- **Figure 7-38 Sensitivity to oil price of estimated net present value of options, $ M. Labels depict oil price per barrel.**

Appendix J Example of market prices for water in Australia



- **Figure 7-39 Seasonal allocations and market price for temporary (seasonal) water entitlements in the Goulburn Irrigation Area, Victoria, Australia, 1998 to 2008**

Source of information:

Historic water prices of temporary transfers in the Goulburn region (trading zone 1A) were downloaded from the Watermove website for the period August 2002 to April 2008. Earlier water prices (from September 1998) provided by Asif Zaman of Melbourne University (pers. comm., 30/11/2006).