Extraction Limits and Demand for Water in the Oil Sands of Alberta

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Abstract

This paper examines the relationship between water and oil, as it exists in the production of crude oil from oil sands of Alberta. By examining the official water extraction framework for the Athabasca River and some critiques of this framework, this paper tries to establish if there are binding constraints on production from the oil sands. We find that under the official framework that there are currently no limits on production and that it would take greatly reduced extraction caps to have a significant effect on industry output. Then we examine what the rate of technological progress may be for water use in production and develop a regression model to see what effect learning-by-doing has on the change in water use intensity in production. We find that as expected, learning-by-doing eventually is likely to reduce water use in oil sands operations.

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Section I: Introduction

In the heady summer of 2008, as a prolonged period of economic growth looked set to continue well into the future, the price of crude oil reached previously unparalleled levels. By peaking at $136.32 US dollars per barrel on July 18 (Energy Information Administration, 2009) market forces made sources of oil that had previously appeared economically unviable due to technology or infrastructure costs extremely attractive. While the credit crisis and subsequent recession that spread throughout the world economy in the fall of 2008 has pushed down the price of oil, companies and investors continue to think about and invest in these alternative sources of oil.

Known about for more than two hundred years and having been a focus of development since the early decades of the twentieth century (Syncrude, 2009), the vast oil sands deposits in Northern Alberta have long presented a beguiling, largely untapped source of oil. Representing more than 95 per cent of the 179 billion barrels of proven oil reserves Canada is believed to have remaining (Energy Information Administration, 2008), the oil sands are a vast and relatively untapped source of oil for both Canada and the world.

However, it is only recently that technological innovation and more attractive market conditions have made the widespread development of operations dedicated to the extraction of oil from the oil sands a viable and economically possible procedure. From a high of 64 percent in 1995, the value of a barrel of oil that is claimed by operating costs had declined to 44 percent in 2006 (Pembina Institute, 2007). This has allowed the development of the oil sands to boom, with production doubling in the nine years between 1995 and 2000 and now exceeding more than a million barrels a day (Pembina Institute, 2006).

This explosion in the level of production has put a tremendous strain on a number of inputs, ranging from workers to water, that are required to transform the oil sands to just oil. While these increased demands for men and materials had a transforming effect on the province of Alberta in the early part of the twenty-first century, allowing it to completely pay off the provincial debt (Alberta 2007), it also brought concerns about the environment and the pace of long-term development to the forefront of public discussion. While many of these issues are important, this paper examines just one crucial relationship that exists between water and oil production in the oil sands.

Water is crucial for both vibrant ecosystems and as an input in the production processes of the oil sands. Given the finite amount that is available in Northern Alberta from the Athabasca River basin, it is crucial that water is allocated correctly between the various demands for it. The basis for any system to allocate demand stems from determining the flow rate of the river that is necessary to satisfy environmental demands and then including demands from oil sands producers and other human users to establish plausible withdrawal limits from the river. Accounting for these demands forms the basis of any analysis that hopes to efficiently allocate water from the river. We deal with them in the first section of the paper.

Then we turn our attention to the current water use in production (WIP) ratio to develop three intensity levels that allow us to discuss how changes to the composition of the oil sands industry could alter the effect of water extraction limits in the current setting and under different frameworks. We then attempt to develop a regression model to see what effect learning by doing has on the change in WIP and what the correct specification for such a model may be. As an extension of this we consider what the rate of technological change for WIP may be and how this could impact industry production and water demand in 2017, the point at which industry output is projected to have doubled by.

Since the entire oil sands sector has only recently become a viable sector there are a large number of areas that present interesting avenues for future study. In a final section of the paper we discuss a couple of these as well as point out the limitations that make them challenging. We summarize our conclusions at the end of the paper.

Section II: What's A Plausible Water Withdrawal Limit?

Before any conclusions can be made regarding the plausibility of future oil sands development, we must first establish what plausible water extraction rates are from the Athabasca River. That is because the river represents the major source of water in the area of the province home to most of Alberta's oil sands operations. As a result, the approval of new or expanded projects going forward will increase the withdrawal of water from the Athabasca River, since water is an important input to produce usable oil from the bitumen of the oil sands (CAPP, 2007).

With a combination of different economic and supply factors, and pressures projected to result in more and larger projects in the oil sands, Alberta is on pace to rely on this single industry for roughly 20 percent of its GDP by 2020 (Tilmilsina, LeBlanc and Walden, 2005). However, oil sands projects are not the only users of the Athabasca

River and this prevents the government of Alberta from granting companies almost unlimited access to the water resources to feed their growth.

Running for more than 1400 kilometres, bearing a designation as a UNESCO World Heritage Site, the Athabasca River is one of the longest undammed rivers on the continent (Schindler, Donahue and Thompson, 2007). Competing with oil sands operators for its water resources are multiple communities, thousands of migratory birds, and large numbers of other animal and plant life (Alberta Environment and Fisheries and Oceans Canada, 2007). Each of these users represents a competing demand for the resource and their needs must be accounted for and satisfied by any extraction framework developed by the province.

The development of a suitable extraction framework is also crucial because the cost of water charged by the government to oil sands operations is relatively nominally. Allocation costs vary depending on operation size, but to oil sands operators the licensed price per m^3 of water is between \$0.00133 and \$0.0012 (Alberta Environment, 2009) which is in line with what non-industrial users are require to pay for water licences. Though the Water Act of the Province of Alberta was updated in 1996 and again in 1999, only minor changes to help water allocation were enacted with no changes to prices made (Adamowicz, 2007). Given the relatively flat cost of water oil sands producers face and the fact that prices have not changed much during the development of the oil sands we will not focus on the cost of water in our analysis. Only if the extraction framework presents a binding cap would the price of water likely be forced up if there were a market established to trade water licences. However, as we will show that is not a likely case under even relatively stringent extraction frameworks.

Given this knowledge about water pricing and all of the additional demands the river must satisfy and the sources of these demands, it is reasonable to assume that water extraction limits are the crucial part affecting demands. As a result, it is likely that any limit placed on total water extraction from the Athabasca River will be established to protect primarily the environmental and non-industrial community users (Alberta Environment and Fisheries and Oceans Canada, 2007). This assumption further extends to mean that the establishment of the extraction caps has been done without any attempt to monetize the value that is gained by the non-oil sands users. Rather, the intention of the limits is to ensure their survival level of water demand is met.

With these concerns and constraints in mind, the Government of Alberta in partnership with the Government of Canada (Alberta Environment and Fisheries and Oceans Canada, 2007) has developed an official extraction framework with three levels outlining the total volume of water that may be extracted from the Athabasca River. Under ideal conditions the Athabasca River is considered to be "above the cautionary threshold" and in the "green level." At this level, all human extraction from the river, including those for oil sands operations, is capped at a level of 15 percent of the Athabasca River's minimum present flow rate. If the flow has been determined to fall below the cautionary threshold but above an arbitrary measure defined as Q95, it is considered to be in the "yellow level" (a level where the ecosystem is likely to experience short term stress) and the cap declines to 10 percent of minimum river flow. If the flow falls below the Q95 level, the river has now entered the "red level" which is a level where habitats are likely to damaged or destroyed by low level of flow in the basin and the extraction cap drops to 5.2 percent of minimum river flow. Within these percentage caps on extraction, there are additional caps that exist for both the yellow and red levels that may kick in, even if the percentage cap has not been reached. In particular no more than 15 m^3/s (cubic meters per second) of water may be withdrawn during the winter period[1] and no more than 34 m^3/s during the summer period[2]. The different levels and extraction limits are summarized below in Table 1.

While the description of the extraction limits for both the red and yellow levels suggest that users could potentially face the same extraction caps because of the permitted flow rates, this is unlikely to occur because of the different percentage caps that the two levels are based on. Additionally, the fact that at the yellow level, the reductions in water withdrawal are phased in and voluntary while they become obligatory in the red zone (WWF, 2005) make it unlikely that during most periods of the year the red and yellow extraction limits will be functionally the same.

Table 1: Flow Condition Levels of the Athabasca River

Flow Condition/Level	Environmental Effect	Extraction Restrictions
Green	*River flows are able to meet ecosystem demands	*Maximum withdrawal is capped at 15% of minimum river flow
Yellow	*Natural low flows occurring *Stress experienced from 15% extraction limit	*Maximum withdrawal is capped at 10% of minimum river flow or 15 m^3/s during winter months and 34 m^3/s during summer months, whichever is lower
Red	*Flows may limit habitat available *Water extraction above limit may lead to habitat loss	*Maximum withdrawal is capped at 5.2% of minimum river flow or 15 m^3/s during winter months and 34 m^3/s during summer months, whichever is lower

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[1] A flow rate that would be equivalent to a cap on water extraction at 4.73×10^8 m^3/yr.

[2] A flow rate that would be equivalent to a cap on water extraction at 1.072×10^9 m^3/yr.

These limits represent the cumulative withdrawal of water by all human and industrial users from the Athabasca River. So while there may appear to be a large pool of resources for the oil sands to tap into, the amount of water the industry may actually use is much less. According to Griffiths, Taylor and Woynillowicz (2006), of the total withdrawal limit for the Athabasca River, oil sands operations are licensed to take roughly 66 percent. This 2/3rds allocation of water resources from the Athabasca River also represents a permanent cap for the industry because under current Alberta legislation governing water use in Alberta, users are prohibited from trading water access rights (Adamowicz, 2007). The remainder of the water allocation goes to other industries, commercial users, municipalities and agriculture. This breakdown of water demands, with industry representing by far the largest share of demand is high compared to the rest of the Canada where industrial water use typically only accounts for between 30 and 40 percent of total end use demand (Renzetti, 1992).

Taking this information into account and combining it with the separate flow rate caps for both the winter and summer periods, we can determine the level of water that could be extracted from the Athabasca River. According to Schindler, Donahue and Thompson (2007), for the river basin, the months from the start of May to the end of August can be considered the summer while the remaining months of the year can be considered the winter season. If the river was in the yellow or red zones and the flow rate was binding rather than the percentage cap, total water withdrawal for the 2007 year would have been limited to 672.7 million m^3 of water. Multiplying by 2/3 yields a limit of 448.4 million m^3 in 2007 for the oil sands industry.

However, taking into account that the Athabasca River has recently had flows recorded well below the levels assumed in the existing withdrawal framework and the lack of any means to trade water rights suggests that the framework developed by Alberta and the federal government may be inadequate and incorrectly balances water demands. Schindler, Donahue and Thompson (2007) argue strongly that this is indeed the case. It is their opinion that the condition that any framework must allocate enough water to support and sustain environmental needs before even considering human needs has been violated in the official framework because:

> [the framework] does not ensure flooding of side channels and delta lakes that are critical spawning and nursery habitats for fish and other organisms at high flow. Its reliance on past conditions offers little protection for the ecosystem from low oxygen, high contaminant concentrations or reduced winter habitat under winter ice. It also offers no measures for protection of the large Delta wetland ecosystem and its great diversity of plants and animals. It does not account for the effects of climate warming.—(Schindler, Donahue and Thompson, 2007)

With this basic condition violated, Schindler, Donahue and Thompson (2007) believe that not only does the existing extraction framework incorrectly allocate water resources, but also that there is insufficient information available to develop a proper, sustainable extraction limit. In the face of this information constraint, they contend that the withdrawal limit should be much lower, but are reluctant to propose a hard level.

This misallocation is compounded by the fact that since 1977 the level of runoff entering the Athabasca River basin has decreased by half (Schindler, Donahue and Thompson, 2007) and there are likely to be further declines due to climate change. So, over time the initial miscalculation of river flow included in the framework will be compounded and could in the long run lead to not enough water resources available to sustain either environmental or human needs. This concern is shared by others as well including Bruce (2006) and Griffiths, Taylor and Woynillowicz (2006).

As a result, it is worth considering much lower water extraction limits and examining the effects of such limits on oil sands development. Since Schindler, Donahue and Thompson (2007) do not put forward specific extraction caps in their work, in Table 2 we propose four different scenarios, representing fractions of the caps in the official framework. Additionally, according to Griffiths, Taylor, and Woynillowicz (2006) oil sands producers were licensed to extract 359 million m^3 of water in 2007, an amount less than the cap imposed under the official extraction framework. As a result in table 2 we summarize potential extraction scenarios A, B, C, D, and E, which represent 1/2, 1/3, 1/4, 1/5, and 1/6 respectively of the official, flow rate caps (15 m^3/s and 34 m^3/s in the summer) and the difference between the scenarios extraction cap and 2007 water use by oil sands producers. Although our proposed are much more restrictive than the official framework, it will emerge nonetheless that even these stringent limits do not seriously impede the oil sands industry.

Table 2: Water Extraction Level Scenarios

Scenario	Winter Flow Rate Cap (m^3/s)	Summer Flow Rate Cap (m^3/s)	Maximum Water Extraction Level Per Year (million m^3)	Two-thirds of Maximum Water Extraction Level (million m^3)	Difference between 2007 Licensed Water Extraction Amount and Scenario's Two-Thirds of Maximum Water Extraction Level (million m3)
Official Framework	15	34	672.7	448.4	89.4
A (1/2)	7.5	17	336.7	223.47	-135.53
B (1/3)	5	11.33	224.2	149.49	-209.51
C (1/4)	3.75	8.5	168.2	112.13	-246.87
D (1/5)	3	6.8	134.41	89.61	-269.39
E (1/6)	2.5	5.67	112.13	74.76	-284.24

Section III: The Current Relationship Between Water and Oil Sands Production

A crucial consideration for our analysis is how much water is necessary to produce a single barrel of oil and how this relationship is evolving over time. In industry parlance, this measure is referred to as the intensity of water use in production (WIP).

It must be noted that, as in many other cases when seeking information about oil sands operations, this paper is somewhat limited in sources for data. Only in the last fifteen years have the combination of economic changes and technological advancements made oil sands production viable, allowing its share of Alberta oil production to increase from almost zero percent in the early 1990s to just over fifty percent currently (Natural Resources Canada, 2006). This somewhat limited timeframe means that there is not a large series of robust and complete data available on oil sands operations water use that has been verified by academic or independent sources. As a result, this paper relies heavily on information made publicly available by a number of companies and industry sources and relies on their standards for the veracity of the data.

Table 3 presents data on WIP for three different industry operations and the industry average.

Table 3: Water Use in Production (WIP), m^3 of water per m^3 of Oil

Year	Suncor	Syncrude	Other Oil Sands Producers	Production Weighted Average
2002	2.9	3.1	4.9	3.79
2003	2.5	2.63	4.2	3.39
2004	1.7	2.21	3.5	2.78
2005	1.7	2.28	4	3.23
2006	1.3	2.26	2.4	2.11
2007	1.1	2.03	2.3	2.00
2008	1.6	NA	3.1	NA

Source: Suncor Energy Inc (2007, 2009), Syncrude Canada Ltd (2003, 2007) and Canadian Association of Petroleum Producers Stewardship Report (2008, 2006)

The table shows that WIP roughly falls into three levels across the industry, which for our purposes can be labelled low (Suncor), medium (Syncrude) and high (other oil sands operations) levels. The difference in these values demonstrates that the industry is not uniform in its water demands and intensities. The table also suggests that by changing the share of industry output accounted for by each level, it is possible to achieve the same level of oil with less water use. This is an important point and one that we will return to in the next section. The table also shows that the contention put forward in other research that as late as 2005 it took between 2 and 4.5 m^3 of water to produce a single m^3 of oil (Griffiths, Taylor and Woynillowicz, 2006), a result which is not supported by our results. In fact, we show that while there is a range in which oil sands producers may fall, that in 2007, the WIP ranges between 1.1 and 2.3 m^3 of water to produce a single m^3 of oil. This range is not extraordinarily different from that put forward by Griffiths, Taylor and Woynillowicz (2006), but it does suggest that the industry is more efficient and likely to have a lower demand for water than they concluded.

Section IV: The Current Effective Limit on Oil Sands Production

Given our assumption regarding the demands that an extraction framework should satisfy and the data on the water intensity in production, we are now able to develop ideas about what the current effective cap on oil sands production is. This will allow us to analyze whether the official water management framework (Alberta Environment and Fisheries and Oceans Canada, 2007) imposes a binding constraint on the oil sands water use and what, if any, effect this will have on the current output level. Further, we test the effect the more restrictive caps presented in Table 2 (Scenarios A-E) would have on industry output.

Since 2007 is the most current year for which data are available for the three different water use intensity levels (Table 3), this will be the year on which we base our analysis. In 2007 the total production of oil from the Alberta oil sands was 1.201 million barrels a day (CAPP, 2009), or just over 438 million barrels (69.69 million m^3) per year[3]. By combining this value with the industry average WIP ratio from 2007 as shown in Table 3 it is possible to estimate the volume of water that was required to provide this output.

It must also be noted that the water use information our study employs is for what the companies have termed "raw water" (Syncrude, 2007; Suncor, 2009). This means that the water is being removed from the Athabasca River specifically for production processes and does not count the water used in production that is being recycled from previous uses. This is an important distinction because companies have used water recycling methods and processes to reduce their total net water use (Griffiths and Woynillowicz, 2003). Syncrude (2007) reports that it has been able to recycle roughly 85 percent of all the water it uses. Since this increase in water recycling may help explain the changes to WIP over time, we will revisit it and comment further on its implications in section V.

As a result, we will calculate three additional levels of water use for 2007 by assuming that all oil production was the result of operations that had either a low, medium or high intensity of water use level. This approach will allow us to establish a

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[3] One barrel is equivalent to 0.158987 m^3 (Woynillowicz, Severson-Baker and Raynolds, 2005).

range over which to analyze the current extraction framework. If the official cap does not satisfy current water demands in a situation of low WIP ratios (Suncor in Table 3), then it cannot satisfy real world conditions (weighted average in Table 3).

Table 4 captures the resulting amount of water that would be necessary—given 2007 WIP ratios—for each level to achieve the 2007 level of industry output. Note that the value under "average" is the actual industry use of water.

Table 4: 2007 Industry Output under 2007 WIP Ratios For Each WIP Level

	Low WIP (Suncor)	**Medium WIP (Syncrude)**	**High WIP (Other Oil Sands Producers)**	**Production Weighted Average WIP**
m^3 of water (in millions) necessary to achieve industry 2007 production level	76.663	141.48	160.297	139.21

This table shows that though differences in WIP between the three levels captured in Table 3 may seem minor, the effect on aggregate water use is quite large.

Comparing Table 2 and Table 4, we can clearly state that the summer and winter caps in the official extraction framework did not constrain the oil sands sector in 2007, nor would they have constrained it even if every company had operated with the highest WIP level. However, this result is based on the assumption that even if the flow rate of the Athabasca River was reduced to the yellow or red levels outlined in the official framework, that the maximum extraction levels of 15 m^3/s during the winter months and 34 m^3/s during the summer months would be permitted. As previously noted, Schindler, Donahue and Thompson (2007) believe this is unlikely to be the case and indeed there is evidence to suggest that these caps may be optimistic on the part of the framework.

The winter of 2001-02 provides a useful example. During this period the Athabasca River experienced one of the lowest flow rates on record (Bruce, 2006). During that winter, if the official extraction framework had been in place[4], the flow rate of the Athabasca River would have fallen into the yellow zone, bringing the corresponding extraction rate cap of 15 m^3/s into effect. However, due to the percentage cap (10 percent of minimum river flow in the yellow zone) actual total withdrawal would have been limited to just 7.5 m^3/s, a level just half the maximum of 15 m^3/s permitted by the official framework (Bruce, 2006)[5]. This is represented by scenario A in Table 2.

By taking this previously recorded historical flow rate into account, we can test the robustness of our conclusion that there was not a restriction on oil sands production in 2007. We do this by developing results based on an assumption that 7.5 m^3/s represented the actual cap on water extraction during the winter and 17 m^3/s represented the cap in summer (half of the flow rate cap of 34 m^3/s). However, comparing Tables 2 and 4 we see that, even under this set of assumptions (Scenario A), there would have been no binding constraint on water use for the oil sands operations in 2007, even if the industry were composed entirely of producers with high WIP values. This result suggests that the official framework is not likely to place any constraint on the industry as it currently exists, even during a period of historically low water flow, as occurred during the winter of 2001-02. This conclusion is supported by evidence in AMEC (2006) that existing licences may entitle current operators to as much as 76 percent of permitted withdrawal, rather than the 66 percent used in Table 2.

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[4] The official framework came into force with the start of 2007.

[5] A flow rate that caps the extraction of water at 2.37 $x10^8$ m^3/yr.

In contrast, more restrictive limits on water extraction would bind. For example, if the water extraction caps were 1/3rd the level proposed in the official framework (scenario B in Table 2), there would be an effective limit on the production from an oil sands sector where all producers had high WIP values. With the extraction limit set at ¼ the official limit (scenario C in Table 2), an industry composed completely of medium WIP firms would face a binding constraint and be forced to reduce production. For an oil sands industry composed solely of low WIP firms, a binding constraint on their water use would not come into effect unless the limit was reduced to just 1/6th of those set out in the official framework (scenario E in Table 2). For the average WIP value, which is the industry as it existed in 2007, a reduction of extraction limits to ¼ of those set out in the official framework (scenario C in Table 2) would constrain production. This is the same level at which a medium WIP industry would face output reductions as well.

In table we show what the result on production for industries composed entirely of high, medium, low and average WIP levels would be if they faced the extraction caps we proposed in table 2. Additionally, we develop what the decrease in oil production would be for each level if with the WIP ratio held constant, but the amount of water available for use in production declined as a result of the scenario water extraction limits.

This table shows that even if the contention of Schindler, Donahue and Thompson (2007) is correct and the current framework sets the water extraction limits too high, it would take a very restrictive regime to significantly reduce industry production. Only if the "much lower extraction limits" Schindler, Donahue and Thompson (2007) advocate are set at least 1/3 less than those of the current framework would there be a binding constraint on output. This indicates that there is enough water presently to reserve more water for environmental uses without negatively affecting the current oil sands operations. Furthermore, given that the oil sands producers are running at full capacity and that it takes a large investment in time, increased infrastructure and manpower to increase the production capacity of oil sands operators, there is also likely to be enough water available for both environmental and oil sands production demands in the near future.

Table 5: Effect of Proposed Scenarios on Water Demand and Industry Output:

Scenario		**B (1/3)**	**C (1/4)**	**D (1/5)**	**E (1/5)**
Water Extraction Limit (millions m^3/year)		149.489	112.13	89.6	74.76
High Intensity	Difference Between 2007 Water Demand and Extraction Limit (millions m^3)	10.81	48.16	70.69	85.54
	Decrease in Production of Oil (percent) Resulting from Limit	6.7%	30.1%	44.10%	53.30%
Medium Intensity	Difference Between 2007 Water Demand and Extraction Limit (millions m^3)	Constraint not binding	29.35	51.88	66.73
	Decrease in Production of Oil (percent) Resulting from Limit	NA	20.7%	36.7%	47.2%
Low Intensity	Difference Between 2007 Water Demand and Extraction Limit (millions m^3)	Constraint not binding	Constraint not binding	Constraint not binding	1.91
	Decrease in Production of Oil (percent) Resulting from Limit	NA	NA	NA	2.5%
Industry at 2007 WIP and Output	Difference Between 2007 Water Demand and Extraction Limit (millions m^3)	Constraint not binding	27.08	49.61	64.46
	Decrease in Production of Oil (percent) Resulting from Limit	NA	19.5%	35.6%	46.3%

As a result we find that the concerns put forward by Schindler, Donahue and Thompson (2007) and other critics about the level of the extraction framework are somewhat unfounded. Through scenarios B-E that we presented, we found that even if the caps on water flow were set at flow rates not observed (1/4 or 1/5 of the levels put forward in the official extraction framework), the decline in oil production would likely be only be 1/3 from the current level. As we noted previously, 2001 saw the lowest flow rates recorded on the Athabasca River and even under those circumstances no binding constraint on water extraction would have been imposed on oil sands producers.

Section V: The Rate of Technological Change As It Affects Water Use in the Oil Sands

While the current implications of water extraction limits are important for the oil sands industry, how these caps will affect future growth are also important. Converting bitumen into oil requires that a large amount of capital be invested in equipment, machinery and technology, which in turn requires companies to be as concerned about the evolution of WIP and extraction limits as they are about the current levels.

There are many factors that will determine the long run demand for water from the Athabasca River basin, but one of the most important for the oil sands industry relates to the rate of technological change with respect to WIP[6]. How this rate evolves over time is important because if the extraction levels permitted remain static, but producers are making improvements in the WIP level, more oil sands development or a greater number of projects are feasible.

We observe a general decline in the intensity of water use during the six-year period covered by the table. During this period, the average annual improvement in WIP ratios is 6.54 percent for the low intensity level (Suncor), 7.84 percent for the medium

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intensity level (Syncrude) and 4.34 percent for the high intensity level (other oil sands producers). Even across the brief period of time captured in the table there is remarkable improvement at all three water use intensity levels. This suggests that if the extraction caps were set in 2002 and were binding on the companies when they were set, over the course of the intervening six years either the firms would able to increase their output or the caps would no longer bind.

Table 6 presents annual percentage changes in WIP based on the data in Table 3.

Table 6: WIP (percentage change)

Years	Suncor	Syncrude	Other Oil Sands Producers
2002-2003	-13.79	-15.16	-14.29
2003-2004	-32.00	-15.97	-16.67
2004-2005	0.00	3.17	14.29
2005-2006	-23.53	-0.88	-40.00
2006-2007	-15.38	-10.18	-4.17
2007-2008	45.45	NA	34.78

Syncrude is a good candidate for this exercise, as it is one of the oldest operators and, as shown in Table 3, its performance is close to the industry average. There are a number of factors that may explain the decline of WIP over time, including learning-by-doing, research and development and the share of surface mining compared with in situ extraction. The latter point is particularly important as in situ extraction involves piping steam directly deep into the ground to force the oil to the surface and can make use of saline water, which mining operations can not (Griffiths, Taylor and Woynillowicz, 2006). Companies and the industry are dramatically increasing the development of in situ oil sands operations because of this factor and because in situ operations are able to recycle larger amounts of raw water and are less water intensive overall (CAPP, 2009).

However, since in situ is only suitable for deposits of oil sands deep below the surface and mining operations are used for surface oil sands deposits they are extraction techniques suited for different types of operations. This suggests that in the industry there are likely to be at least two sets of WIP data and rates of technological change depending on production type. However, this is tangential for our purposes because all of Syncrude's operations during the period covered by the data (Appendix A) involved surface mining and therefore, the breakdown between surface mining and in situ is not an issue in the present analysis.

It is worth nothing that because the lead-time in oil sands operations from planning, building of infrastructure to production is so long that the change in relative price of inputs does not drastically alter the production process of companies. Rather, only sustained increases in the price of oil or inputs like manpower cause new production facilities to be built which may be more sensitive to different relative input prices. However, with the time frame extending between planning and production up to a decade (CAPP, 2009) for new projects and with new stand along projects not having been completed in Syncrude's case, it is a tangential concern to our analysis.

Learning-by-doing is usually represented in empirical work as a function of cumulative production (Arrow, 1962). Appendix A includes annual production data obtained from Syncrude, which is used to calculate cumulative production beginning from 1979.

Research and development involves inputs of personnel, current knowledge and equipment to yield outputs of new knowledge, in the form of discoveries. In the empirical literature, new knowledge is sometimes measured by patent counts (see for example Popp

2005). However, difficulties with that approach often lead researchers to use input measures as a proxy for research and development. Expenditure on research inputs is a logical candidate for this role. Alternatively, one may consider capital expenditures for this role, on the assumption that new knowledge must first be embodied in new equipment before it has any impact on the firm's production. Unfortunately, Syncrude has not made available consistent time series data on research inputs or capital expenditures. Therefore, the present analysis will focus exclusively on learning-by-doing and the hypothesis that it will eventually lead to a decline in WIP levels.

The model that we will develop evolves from the following equation:

$$F(WIP) = G(PROD, beta) + \varepsilon$$

Equation 1

In our model the dependant variable WIP represents the water intensity in production as it has for throughout the paper. In this case, the WIP is from the Syncrude data available in Appendix 1. Based on testing we will include a constant term in our model because under tests of various specifications the constant is a significant term, and its addition greatly improves the explanatory power of all model specifications. The PROD term in the model represents the cumulative production of Syncrude in million of m^3 of oil. The final variable we include in the model is TIME. This represents a time trend running from 1 to 29 for the years 1979 to 2007 that are included in the regression.

This is the basic composition of all of our models because having WIP as our dependant variable implies that changes to cumulative production have a direct effect on WIP. Additionally, since we assume that our variables are trend-stationary, we have included a time trend in our regression to avoid the problem of spurious results.

While we find that we are able to develop a model that has strong explanatory power and an explanation of the effect of cumulative production on WIP, there are still a number of limitations to our model. Foremost among these is cumulative production and WIP is likely to be affected by a number of other factors. Additionally, our model entirely omits pricing either on the output or input side of the oil sands that may directly affect the level of production or WIP. These are factors that will likely make the coefficient for PROD that develop different from its true value. However, we still expect that this coefficient should be negative since it is intuitive that learning-by-doing should make production more efficient and therefore less water intensive.

With these caveats in mind, we tested a number of different model specifications using standard OLS to determine which had significant explanatory power and was best. All of the models we tested included a constant and a time trend. The results for each regression with the coefficient estimates, standard errors, measures of goodness of fit and additional diagnostic test statistics are summarized below in Table 7. Graphs of variables are included in Appendix A. The different specifications we tested were an equation with WIP as the dependent variable with a lagged value for PROD (equation 2), an equation with the natural logarithm of WIP as the dependant variable and lagged PROD, lagged PROD squared as the explanatory variables (equation 3), an equation with WIP as the dependant variable and the natural logarithm of PROD (equation 4) as the explanatory variable, an equation with the natural logarithms of both WIP and PROD (equation 5) and finally, an equation with the natural logarithm of WIP and the natural logarithms of both lagged PROD and lagged PROD squared as the explanatory variables (equation 6).

Table 7: Summary of Regression Results

Coefficient	**WIP (2)**	**lnWIP (3)**	**WIP (4)**	**lnWIP (5)**	**lnWIP (6)**
Constant	8.813195 (0.591590)	2.717252 (0.134574)	19.57408 (1.136118)	3.363873 (0.169101)	3.086993 (0.430141)
PROD					
lnPROD			-4.892308 (0.435154)	-0.576523 (0.064769)	
PROD(-1)	0.069280 (0.012448)	0.042112 (0.006782)			
$((PROD(-1))^2$		-0.0000418 (8.74E-06)			
ln(PROD(-1))					-0.708742 (0.305423)
$(\ln(PROD(-1))^2$					0.085481 (0.072984)
TIME	-0.856199 (0.127810)	-0.358412 (0.047995)	0.393096 (0.058394)	0.028598 (0.008692)	-0.033079 (0.037658)
R^2	0.817059	0.916707	0.905897	0.919425	0.879688
R^2 adjusted	0.802424	0.906296	0.898659	0.913226	0.864649
Observations	28	28	29	29	28
Akaike Info Criterion	2.278253	-1.456803	2.734463	0.45694	-1.089077
Schwarz Criterion	2.420989	-1.266489	2.875907	-1.075285	-0.898762
Jarque-Bera P-Value	0.778641	0.654796	0.811071	0.494793	0.364827
Durbin-Watson Test Statistic	0.918741	1.829134	1.256218	1.307604	1.673439
Breusch-Pagan-Godfrey Heteroskedasticity Test F-Statistic P-Value	0.032	0.5222	0	0.4303	0.7707

In order to determine which model specification performs best we carried out a number of standard econometric tests and looked and different measures for ranking and goodness of fit. One of the diagnostic tests we carried out was the Jarque-Bera test for normality, which has as its null hypothesis that the errors are normally distributed. For all specifications of the model, we considered a significance level of 0.05 and found that in all specification, we could retain the null hypothesis. While this is a positive result for our specifications, caution must be exercised when analyzing this result. The Jarque-Bera test is an asymptotically valid test, which means that it is a very sensitive test for small samples. With only 28 or 29 observations included in our regressions depending on the specification, our sample is fairly small and this could affect the results of the Jarque-Bera p-values we obtained.

In addition to normality, we carried out Durbin-Watson tests for autocorrelation on all specifications and obtained values for the test statistic. The null hypothesis is a standard Durbin-Watson test is that there is no autocorrelation while the alternative hypothesis is that the output follows an AR(1) process. In our results table we obtained the value of the test statistic for the different specifications. As a result we determined the necessary critical values for each specification to determine when the null hypothesis held. For both equations 3 and 6 we have a constant, 28 observations and 3 regressors, so combining this with standard Durbin-Watson significance tables for a 0.05 level of significance we found that the lower bound for these two model specifications is 1.181 and the upper bound is 1.65. For equations 4 and 5 we have a constant, 29 observations and 2 regressors, which yields a lower bound of 1.270 and an upper bound of 1.563. For equation 2, it also has a constant term, 28 observations and 2 regressors, meaning the lower bound for its decision rule is 1.255 while the upper bound is 1.560. Comparing the corresponding decision rules for Durbin-Watson tests to the relevant upper and lower bounds and the test statistics for each specification of the model, we found that for specifications 3 and 6 we can not reject the null hypothesis that there is autocorrelation, for specifications 2 and 4 we reject the null hypothesis and for model specification 5, the results of the Durbin-Watson test are indeterminate since the value for the test statistic lies between its corresponding upper and lower bounds. It is based on these results that we are able to suggest that specifications 3 and 6 are better than the others we have developed.

$$\ln(WIP) = \beta_0 + \beta_1 \ln(PROD(-1)) + \beta_2 \ln(PROD(-1))^2 + \beta_3 TIME$$

Equation 6

A final major test that we carried out to help determine a suitable specification for our model was the Breusch-Pagan-Godfrey test for heteroskedasticity. We conducted this test using a standard level of significance (0.05) and the definition that for this test the null hypothesis is that there is no heteroskedasticity. For both model specifications 3 and 6, the p-values we obtained from the Breusch-Pagan-Godfrey test demonstrate that we cannot reject the null hypothesis and can therefore conclude that neither specification suffers from heteroskedasticity.

Based on the results of these tests, we can see that both model specifications 3 and 6 perform better than the others. However, we believe that specification 3 is the better of the two due to better performance on both the ranking measure and under the goodness of fit criteria. Since both equations have the same dependant variable, number of variables and observations, we can compare the values for the Akaike Info and Schwarz Criterion and the values for the R^2 and adjusted R^2 obtained for both specifications. Specification 3 had lower values, which is better, and higher values the two measure of goodness of fit, which suggests that specification 3 has slightly more explanatory power than specification 6.

$$\ln(WIP) = \beta_0 + \beta_1 PROD(-1) + \beta_2 (PROD(-1))^2 + \beta_3 TIME$$

Equation 3

Based on our conclusion that specification 3 is the best for our model, we can see that the model suggests that learning-by-doing (as represented by the lagged PROD squared variable) does have some effect on reducing the WIP. Indeed, given the estimates we have achieved, it is possible to calculate the level of PROD at which WIP is maximized. But, we must caution again that the exact magnitude of these effects are likely to differ in the real world or, as other relevant variables which we were lacking access to data for, are added into the model. However, we are confident in our result that does have a negative effect on WIP.

Returning to a broader discussion of the rate of technological change and its potential effect on WIP, in many areas of empirical work, the rate of technological change is implied by the addition of a time trend. From our regression results we can see according to the coefficient on our time trend, the rate of technological change has a effect on WIP that the effect it has is much greater than the learning-by-doing variable. This suggests that the rate of technological change may have a large impact on the reduction in WIP than has been caused by learning-by-doing. This is an important result because between 2007 and 2017 output from all oil sands projects is forecast to double (CAPP, 2009) to 2.402 million barrels a day. Table 8 presents the water requirements for this output level assuming the WIP ratios remained unchanged at the 2007 values. Comparing Table 8 with Table 2, we see that, if the extraction caps as outlined in the official extraction framework did not change from current levels, none of the WIP sectors would face a production constraint.

The output, type of production operation and technologies of the oil sands industry are not the only factor that is projected to change in the coming decades. The decline of water inflows to the Athabasca River are expected to continue as a result of global climate and may decline by as much as 7-10 percent in the period between 2007 and 2050 (Bruce, 2006; WWF 2005). While this reduction is likely to result in reduced extraction rates, the rate of technological progress for oil sands producers combined with the excess water allocation we found in section IV and the move to a less water intensive type of production suggests that the industry would be able to absorb reductions to compensate for this level of reduced flow without any major issues. Only if the rate of improvement in WIP declines markedly, the inflow declines are much greater than projected, or in situ operations develop unforeseen issues with water is it likely that the oil sands industry could face future production declines.

Table 8: Projected Water Demand Given 2017 Output and 2007 WIP Levels

	Low WIP (Suncor)	Medium WIP (Syncrude)	High WIP (Other Oil Sands Producers)	Production Weighted Average WIP
m^3 of water (in millions) necessary to achieve projected 2017 output level	153.327	282.959	320.594	278.778

This points to the crucial impact of the rate of technological change. With the massive investment of capital and time that are required to get an oil sands operation to produce, this rate ensures that the operations can remain viable, even in the face of changing situations.

Section VI: Topic For Future Study

Since it has only been very recently that economic pressures and technological developments have combined to make oil sands projects practical for many companies, there are a vast number of areas where further study could take place. Even the work we have conducted on water use and its relationship to the production process has a number of other areas that could be looked into in greater detail. A primary area for future study would be to build on the structural modeling we attempted to undertake in section V of the paper. With complete data sets for more variables that covers more years it should be possible to develop a regression equation that is more robust than our univariate regression. These improved models could provide meaningful and more accurate insight into what affects the change in WIP and what the truer magnitudes of the coefficients are.

An additional area that would be of great interest would be to combine data on leases companies have paid to the Alberta government for land in oil sands producing regions with the projected reserves on these parcels of land. With this data it could be worked out what the companies expected profit from the land parcel would be, assuming that the land was auctioned off in a perfectly competitive environment. While the current framework does not impose water access as a binding constraint, our look at alternative frameworks in section IV show that reductions in water extraction by ¼ or more would make the constraint a binding one.

So, by making a further simplifying assumption that access to water and reserves per acre are the only two constraints on possible production it would be possible to work out what the present value to companies of the access to water would be if it is assumed that water is the binding constraint of the two. The result of this work would then be to give a lower bound of what companies might pay for access to water rights were they auctioned off in a perfectly competitive process.

However, the lack of publicly available data regarding expected reserves from different parcels of land greatly complicates this avenue of study. Companies discuss the future output of their oil sands operations in terms of barrels per day and with only a few minor exceptions, they do not appear willing to publicly disclose projected reserve data per lease holding. This may be a result of the companies not having certain accounting of the reserves themselves or because they are unwilling to signal the volume to the government for fears of provoking further adjustments to the province's royalty collection formula.

An additional complicating factor is that the information made available by the government of Alberta regarding land leases only includes the initial leasee. With the large amount of consolidation that has occurred in the industry since many of the leases were first issued and the added complication that many leases are initially picked up by land holding companies on behalf of clients and are subsequently then turned over to another party makes it time consuming to track which initial lease prices correspond to different companies holdings. While these factors do not pose impossible barriers to future study, they do require a much larger base of data than is currently publicly available

Another area of study regarding water use in the oil sands would be to build upon the work that we have completed in this study by further including water being returned into the Athabasca River basin by the oil companies to determine the effective production limits. We noted previously that currently this is a niche process and there is a lack of widely available information, which constrains us from using net water flows in our calculations. However, with time and more companies implementing processes to allow the return of water to the river basin, this data should become more widespread and applicable to studying the industry's water demands.

Section VII: Conclusion

With declining oil reserves around the world, the vast size and openness of the Alberta oil sands represents one of the largest remaining pools of proven reserves available. However, the essential role that water plays in the production process requires that the Athabasca River basin must be able to continue supporting both the expanded demands of the growing industry and the aquatic and natural life that depends on it.

Based on our work and a few simplifying assumptions we have shown that the official water management framework (Alberta Environment and Fisheries and Oceans Canada, 2007) as developed does not effectively constrain or limit the current production of the oil sands. Indeed, even by including some criticism of the limits permissible under the framework as put forward by Schindler, Donahue and Thompson (2007) and others, we found that the permitted water extraction levels would need to be drastically cut before having any effect on industry output. So, while the official framework might have some flaws or not accurately reflect the environmental needs, the allocation of water to oil sands users could be reduced without a large reduction in current production.

With an eye to the future we also have found that the rate of technological change appears to provide a lot of future flexibility when allocating water demands. Depending on how the oil sands industry grows and what data developed on the Athabasca River's requirements suggests, the government can reduce or maintain extraction limits to meet both economic and environmental needs. If the caps are reduced, then the industry will not stagnate or decline, but rather it extends the length of time for which the resource will provide a return. How to balance the natural and economic needs for the water from the river will be a crucial issue as economic factors increase the price of oil and make development more attractive. Our results suggest that that these needs can be balanced without entirely abandoning the official extraction framework (Alberta Environment and Fisheries and Oceans Canada, 2007).

We began by stating that water is a crucial input not just for the development of the oil sands, but also for life itself. This underlying importance is why we looked at how the Athabasca River basin's resources are allocated and what if the proposed extraction limits placed a constraint on current or future oil sands development. We hope that this paper is just the first examination of the relationship between water and oil sands production and how changes to that relationship may change the economic and environmental futures of Alberta and Canada.

Appendix A: Econometric Data

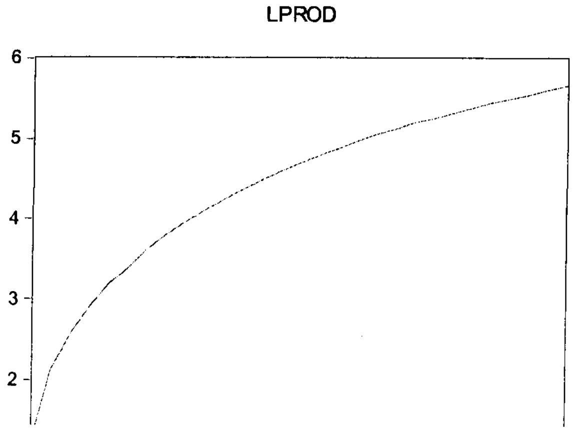
Data Set 1: Syncrude Change (in %) of Intensity of Water Use:

Year	Water Intensity (m^3/m^3 oil)	Oil Production (millions m^3)	Cumulative Oil Production (millions m^3)
1979	16.3	2.86	3.43
1980	8.6	4.71	8.14
1981	8.4	4.74	12.88
1982	5.5	4.98	17.86
1983	4.4	6.49	24.35
1984	5.2	5.01	29.36
1985	4.1	7.46	36.82
1986	4.4	7.54	44.36
1987	3.5	7.95	52.31
1988	3.1	8.73	61.04
1989	2.9	8.59	69.63
1990	3.2	9.08	78.71
1991	3.3	9.59	88.3
1992	3.7	10.4	98.7
1993	3.1	10.65	109.35
1994	2.8	11.1	120.45
1995	2.6	11.8	132.25
1996	3.3	11.7	143.95
1997	2.7	12.04	155.99
1998	2.6	12.2	168.19
1999	3.1	12.94	181.13
2000	3.4	11.8	192.93
2001	2.8	12.94	205.87
2002	3.1	13.32	219.19
2003	2.63	12.29	231.48
2004	2.21	13.87	245.35
2005	2.28	12.42	257.77
2006	2.26	14.99	272.76
2007	2.03	17.7	290.46

- Data provided by Syncrude Canada Ltd.

Graph 1:

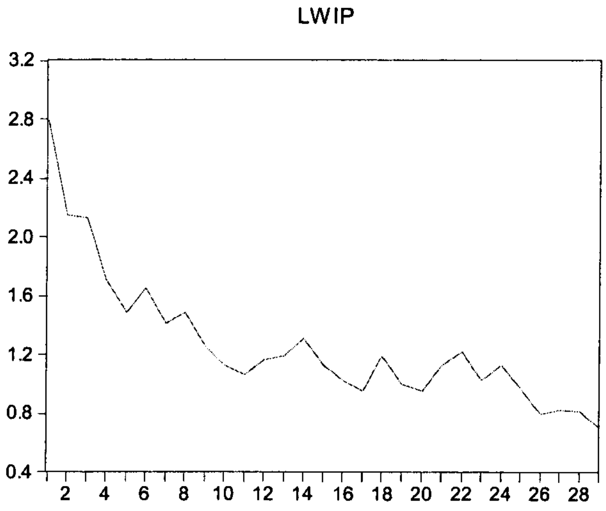
Log(PROD)



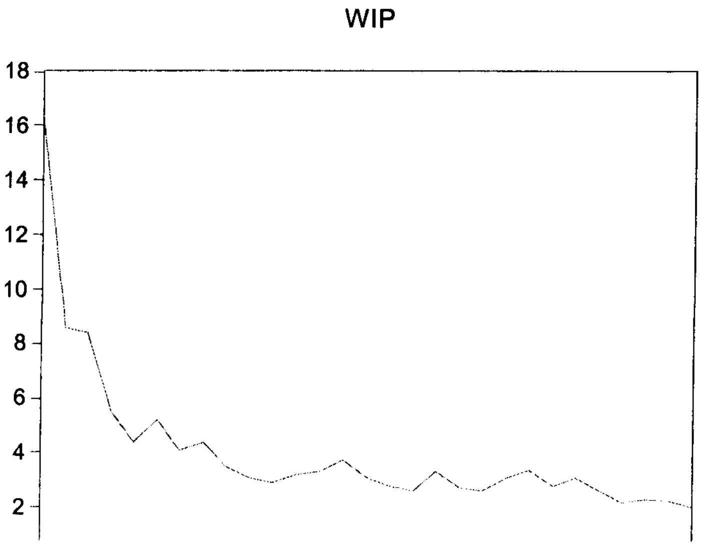
Graph of

Variable:

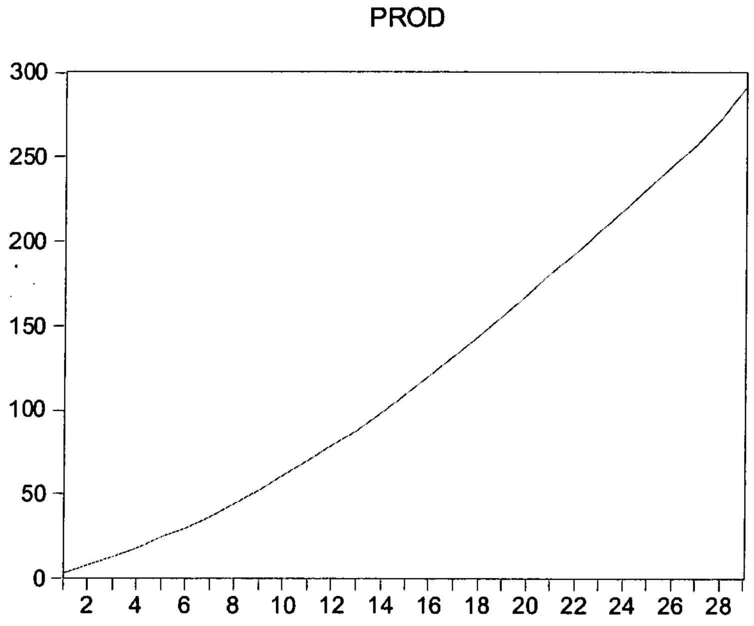
Graph 2: Graph of Log(WIP) Variable:



Graph 3: Graph of WIP Variable:



Graph 4: Graph of PROD Variable:



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