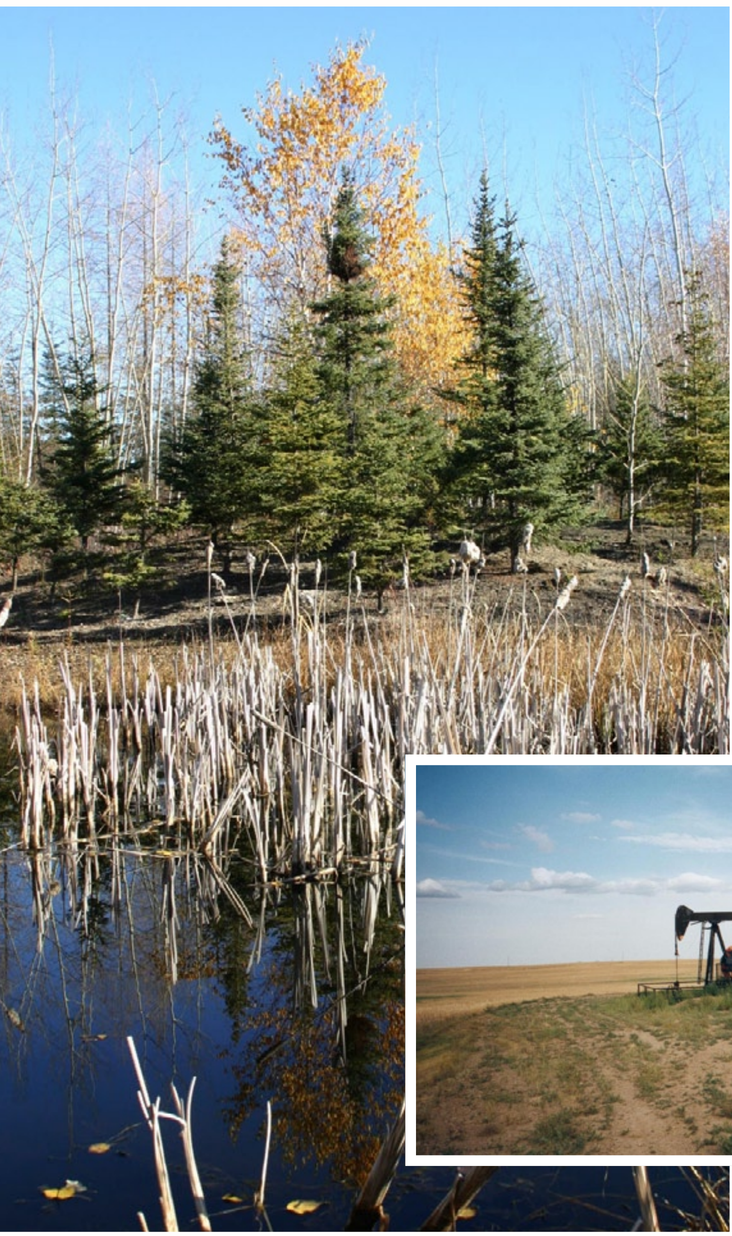
Heating Up in Alberta

Climate Change, Energy Development and Water



Mary Griffiths

Dan Woynillowicz

February 2009

the PEMBINA institute

Sustainable Energy Solutions

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About the Pembina Institute

The Pembina Institute is a national non-profit think tank that advances sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy, and environmental governance. For more information about the Pembina Institute, visit www.pembina.org or contact info@pembina.org.

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Heating Up in Alberta

Climate Change, Energy Development and Water

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Foreword

The advantages and disadvantages of energy sources for the future have been hotly debated in Alberta for several years. The heavy reliance of the province's economy on extracting oil, gas and bitumen has led politicians and industrialists to support these activities at whatever the environmental cost. But a large percentage of Alberta's citizens would like to see a switch to an economy based on cleaner, less environmentally damaging sources of energy.

The debate is usually framed in terms of greenhouse gas emissions, pollution or efficiency of energy extraction. Water use has been a factor in selected areas, such as the high water removal and toxic tailings ponds of the oil sands or the permanent loss of surface water through "water flooding" to increase the efficiency of extracting conventional oil.

In a water-scarce province like Alberta, framing environmentally and socially sound energy policy must account for the water use and water pollution resulting from taking different energy pathways. In *Heating Up in Alberta*, Mary Griffiths and Dan Woynillowicz, two of the Pembina Institute's most senior researchers on water and energy, broadly review the water use of all energy sectors for the first time. They review and summarize documents that are not readily accessible to the general public. The report, written in highly readable prose, should be on the "must read" list of the Ministers of Environment, Energy and Sustainable Resources, and of other MLAs and private citizens who are interested in policies for the future where energy, economics and water supplies are balanced.

D. W. Schindler
Killam Memorial Chair and Professor of Ecology
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1. Alberta's Climate Change Challenge

1.1 Examining the Challenge

Much of the wealth in the Province of Alberta comes from the fossil fuel energy industry, with exports of crude oil, natural gas, natural gas liquids and coal accounting for two-thirds of the province's merchandise exports, and even more if petrochemicals are included.[1] As industry and population have expanded, so has the demand for electricity. Many forms of energy production require water, but the extraction of bitumen from the oil sands in particular is consuming ever greater quantities as production grows.

At the same time, the province's fresh water resources are under pressure. Summer river flows are declining, periods of prolonged drought experienced in the past are likely to return, and climate change is further increasing the uncertainty about future water supplies. The challenge is to ensure the sustainable management of the province's surface water and groundwater resources in the face of climate change. Ways must be found to limit the demand for water and ensure a fair share for all. This report examines the impacts of the energy industry on water, but recognizes that water conservation is essential in all sectors of the economy.

> "Water is too critical a resource to be ignored. The threats to water availability and quality are real and are particularly evident in the West. Population growth, economic expansion and climate change all contribute to putting western Canada's water resources at risk.
>
> These emerging challenges need to be addressed head on, and soon. There is no more time to waste. The longer we wait, the more it will cost to respond and adapt."[2]

The threats to water availability and quality in the Prairie provinces are real and, as indicated in the Senate Committee report cited above, there is no time to waste. All sectors of the economy need water, but the greatest growth in demand in Alberta is for energy production in the northern and central part of the province. In the North Saskatchewan, Beaver and Athabasca River Basins half or more of all the water consumed is for the production of energy, primarily to extract and upgrade bitumen, but also as cooling water for power plants.[3] In the southern part of the province, the amount of water used for fossil fuel energy is much smaller, but so is the supply, since water resources in the South Saskatchewan River Basin have already been fully allocated.[4] It is worth noting that if the use of irrigation for biomass to support biofuel production is included, the use of water for energy production is larger, but it is currently unknown how much irrigated acreage is used to produce biomass.

This report focuses on the production of the main forms of energy in the province — electricity, oil (including oil sands) and gas — and how each one uses water. It includes the use of water for renewable forms of energy where figures are available. The report examines the expected growth in energy production, the limited and uncertain supply of water and the implications of water supply for future energy production. It also proposes ways to reduce the consumption of fresh water and improve water management in light of the ongoing impacts of climate change.

Concerns about the future availability of water gained public attention in Alberta with the development of the province's Water for Life strategy, announced in 2003. The Alberta Water Council is working on the implementation of the strategy and many people are undertaking research to reduce water use and protect the natural environment. For example, the Alberta Water Research Institute aims to tackle water flow and water quality issues (as well as the associated issues of habitat decline and biodiversity loss).[5] Similarly, one of the Alberta Energy Research Institute's goals is to improve water management and reduce water use for energy production.[6] Western Economic Diversification Canada is interested in the impacts of water on economic development.[7] There are many challenges.

> "…the energy industry faces an enormous and complex challenge as it shifts to developing sustainable, clean energy. This is a time of increasing constraints on water use, atmospheric pollution and greenhouse gas emissions."[8]

Much of the water used for energy production comes from surface water, primarily rivers, but groundwater also supplies water for oil extraction, for both conventional oil and bitumen. In fact, surface water and groundwater are connected: groundwater levels near the surface affect surface flows, and vice versa.[9] Groundwater is recharged by precipitation, which infiltrates through the soil and surface waters. Wetlands, sloughs and lakes, which collect water, slow surface runoff to rivers, thereby reducing flooding and assisting in the recharge of shallow groundwater. Inevitably, any impacts on water quality, as a result of water use or pollution, will also spread with the flow.

With depth, groundwater becomes increasingly saline, so it is especially important to protect both the quality and quantity of fresh (non-saline) water resources, as well as deeper water, which can be easily treated for use. In this report the current Alberta Environment definition of saline water is used, which is water with more than 4,000 milligrams per litre of total dissolved solids (TDS).[10]

Although Canada appears to have large water resources and has about 7% of the world's renewable supply of water (comparable to the country's land area), much is held in lakes and only a very small amount is renewed each year.[11]

The next section briefly examines the impacts that climate change is likely to have in Alberta, including the probable impacts on surface water and groundwater.

1.2 Rising Temperatures, Changing Precipitation

> "Climate change impacts on water availability could alter a lot of things we currently take for granted."[12]

Future climate change is expected to have various impacts in Alberta, some of which may be positive and others that will most certainly be adverse. The adverse impacts, which are likely to outweigh the positive impacts, will affect energy production. A recent federal government report, which uses the findings from various climatic models, indicates that climate change is expected to affect a number of climatic variables that influence the hydrological cycle,[13] including the following:

- **Temperatures**: Temperatures are expected to increase considerably in the future. Different models give different results but the values taken from a median scenario indicate that, compared with the baseline period 1961–1990, temperatures in Alberta could increase by up to 4°C by the 2050s and by up to 6°C by the 2080s.[14] The expected increases are highest in the north and much of the increase in temperature is expected in the winter and spring.
- **Precipitation**: The potential changes to future precipitation levels show considerable variability between models. Different scenarios for Alberta suggest that by the 2080s mean precipitation may be 10% below or 20–30% above the1961–1990 baseline. Not only is there a considerable degree of uncertainty, but also the mean figures can conceal large variations between years and variations between seasons. Models show that by the 2050s, mean precipitation levels in the grassland area of the Prairies are expected to increase 12–14% above the 1961–1990 baseline in winter and spring but to decline 6% below the baseline in summer.[15]
- **Evapotranspiration**: Increased summer and fall temperatures are expected to increase the potential evapotranspiration in the Prairie region.[16] Since this will not be offset by increased precipitation, the potential moisture deficit[17] in the region is expected to increase between 0 and 75 mm by the 2050s, the arid area will increase in size and severe droughts are likely to be twice as frequent.[18]
- **Snow and ice**: Abnormally higher temperatures in the winter are expected to reduce the overall accumulation of snow in alpine areas. Throughout the 20th century there has been rapid recession of glaciers. Glaciers in the headwaters of the Bow, Saskatchewan and Athabasca rivers have shrunk by approximately 25% in the last century.[19] Although it is unknown exactly when it will occur, glacial sources of water to these rivers will eventually cease to exist.[20]
- **Surface water and groundwater resources**: The combination of low snow and ice accumulations, an increasing amount of winter precipitation falling as rain, and earlier spring runoffs are expected to reduce summer river flows.[21] Groundwater supplies, which provide potable water to 23% of Albertans,[22] are expected to fluctuate across the Prairie region based on variations in springtime precipitation and summertime evapotranspiration. Since demand for water in Alberta is expected to increase in all major watersheds, variations in groundwater supplies and increasing future demand are expected to result in an overall deficit in future water supplies.[23]

> "From a regional or national perspective, our understanding of climate variability and climate impacts on groundwater resources — related to availability, vulnerability and sustainability of freshwater resources — remains limited."[24]

In addition to the above anticipated variations in the hydrologic cycle, a changing climate is expected to increase the probability of extreme weather events. Particularly, it is anticipated that a greater frequency of flooding and severe drought, as well as longer drought periods, will characterize future extreme weather events.[25]

Given the level of uncertainty with all modelling and the increased variability that is expected in future climactic conditions at the local level, it is important to consider the range of potential environmental impacts when planning future development. A study on the North Saskatchewan River Basin found, for example, that, "The effects of climate change on the water yield from the [North Saskatchewan River Basin] will affect water uses and water management within the basin."[26]

> "We predict that in the near future climate warming, via its effects on glaciers, snow-packs, and evaporation, will combine with cyclic drought and rapidly increasing human activity in the [Western Prairie Provinces] to cause a crisis in water quantity and quality with far-reaching implications."[27]

1.3 Greenhouse Gas Emissions

Carbon dioxide (CO_2), released by the combustion of fossil fuels, is the most important gas contributing to global climate change. CO_2 constitutes approximately 78% of Canada's global warming emissions.[28]

To avoid dangerous climate change in the future, widely defined as a global average temperature increase of 2°C relative to pre-industrial levels, industrialized countries including Canada need to make deep reductions in their greenhouse gas (GHG) emissions: 25–40% below 1990 levels by 2020 and 80–95% below 1990 levels by 2050.[29] At the December 2007 United Nations climate conference in Bali, Canada agreed to negotiations on a post-2012 global climate agreement guided by the science-based target range of 25–40% reductions by industrialized countries below the 1990 level by 2020.[30]

Alberta is responsible for 32.5% of Canada's GHG emissions[31] — in large part due to the fossil fuel industries, fossil-fuel power generation, fugitive emissions from oil and natural gas, and development of oil sands in the province, as shown in Figure 1-1.[32] Environment Canada recently indicated that development of the oil sands is expected to be the single largest contributor to the growth of Canada's GHG emissions.[33] Their most recent assessment, which covers the period 2006–2020, shows that under the current business-as-usual scenario (which excludes any policies announced after 2005) Canada's total emissions will increase from 756 Mt in 2006 (29 Mt from oil sands) to 937 Mt in 2020 (108 Mt from oil sands). This means that the GHG contribution of oil sands development would rise from 4% of national emissions to 12%, and would account for 44% of the total increase in Canada's emissions over that period.

Given Alberta's significant contribution to Canada's GHG emissions, the largest of any province in the country, Alberta plays an important role in determining whether Canada meets its federal and international commitments on climate change.

Currently, Alberta's climate change plan is built on an emissions intensity target, which means that GHG emissions will continue to increase if fossil fuel production rates exceed the rate of emissions intensity reductions. This is likely to occur unless there is more stringent government policy;[34] the Government of Alberta itself projects that absolute GHG emissions will continue to increase until 2020.[35]

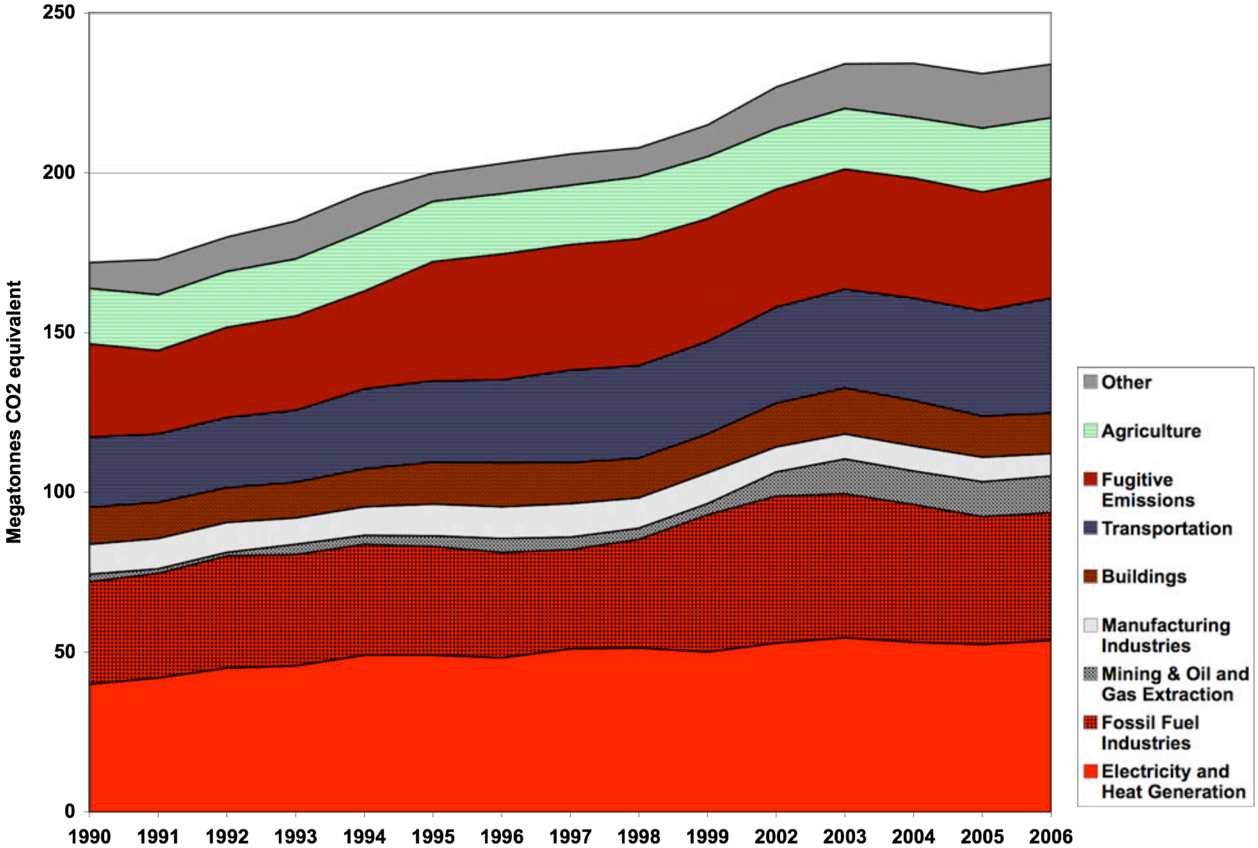

Figure 1-1: Alberta Greenhouse Gas Emissions, 1990–2006, Showing the Contribution from Electricity/Heat and Fossil Fuels

Data Source: Environment Canada[36]

Similarly, the Government of Canada's current climate change plan would allow GHG emissions from the oil sands to increase from 29 Mt in 2006 to 80 Mt in 2017[37] before dropping to 49 Mt by 2020.[38] In other words, the federal plan will allow absolute emissions from the oil sands to increase by 69% between 2006 and 2020.

It is clear that current policies to address GHG emissions do not meet many Canadians' expectations. In a poll conducted by McAllister Opinion Research in March 2008, 79% of Canadians and 81% of Albertans questioned said that GHG emissions from the oil sands sector should be "capped at current levels and then reduced" because of the impact on global warming. Only 12% of respondents, both in Alberta and in Canada as a whole, said that emissions from the oil sands sector should be "allowed to exceed current levels" in order to encourage economic growth.[39] Yet reducing GHG emissions in Alberta to avoid dangerous climate change will require a more aggressive approach than the one advocated by the federal and Alberta governments.

1.4 Water Use for Energy Production in Alberta

1.4.1 Current Water Allocation, Use and Consumption

As shown in Figures 1-2 and 1-3, Alberta Environment has four main categories for water used in energy production:

- injection for oil recovery
- industrial (oil, gas, petroleum), which is primarily water used for bitumen production and upgrading as well as for refining and gas production[40]
- drilling, to develop oil and gas wells
- commercial cooling (primarily in power plants)

The water allocation for energy production in Alberta in 2007 was about 33% of total allocations. The largest single category of use is commercial cooling, which takes about one quarter of the total water allocations.[41] However, much of the water for cooling is later discharged back to the rivers from which it is drawn. In contrast, much of the water withdrawn for industrial processing of oil, gas and petroleum is actually consumed, and none of the water used for oil recovery (injection) is returned to the source from which it was withdrawn (see sections 3.4 and 3.5, below).

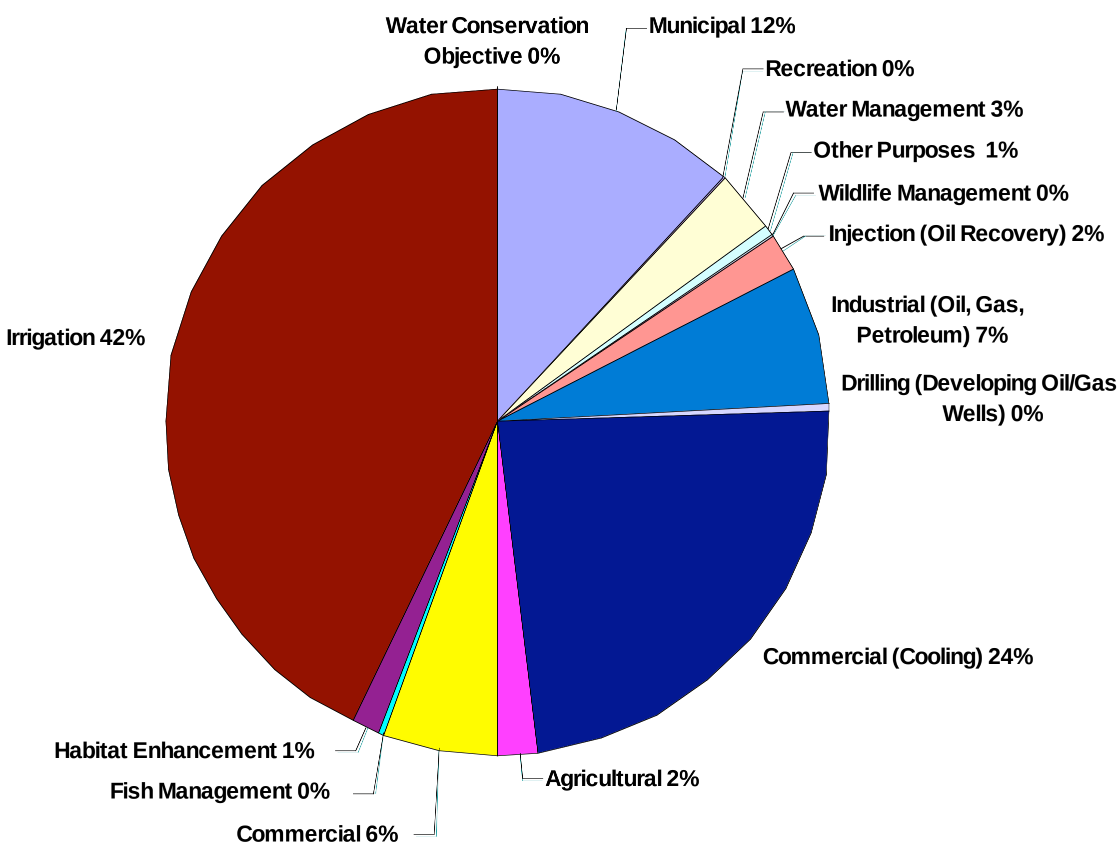

Figure 1-2: Total Water Allocation in Alberta, 2007

Data Source: Alberta Environment, personal communication, December 11, 2008.

The volume of water consumed is the difference between the intake volume and the volume discharged back to the source.

The majority of water allocations in Alberta come from surface water, with about 3% of the total volume allocated coming from non-saline (fresh) groundwater.[42] The allocation of groundwater for energy production differs strongly from the total allocation, with 42% of all allocations being for oil recovery and the industrial processing of oil, gas and petroleum, compared with only 1% for cooling (see Figure 1-3). Some saline groundwater is also used, especially for oil production, but a company is not required to obtain an allocation from Alberta Environment for the use of saline water.

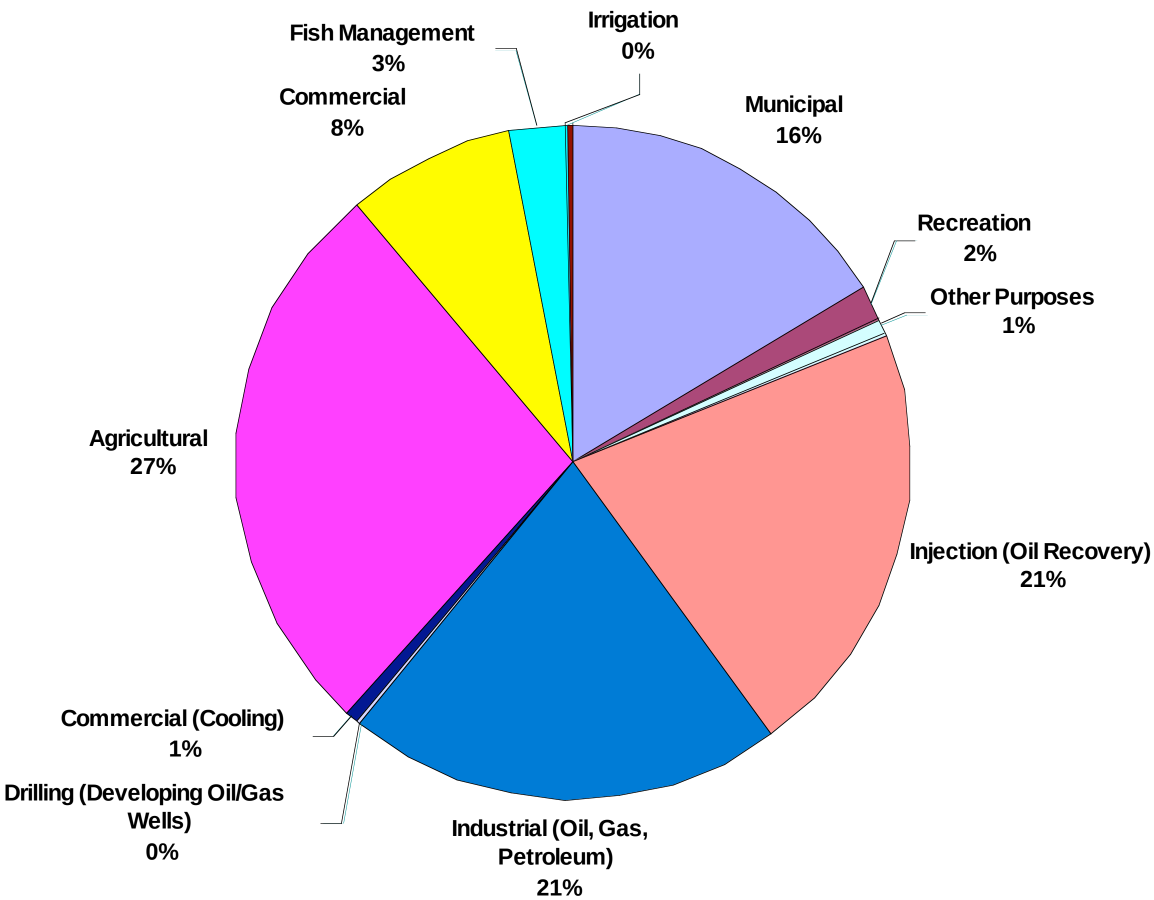

Figure 1-3: Groundwater Allocation in Alberta, 2007

Data Source: Alberta Environment, personal communication, December 11, 2008.

Water volumes in this report are expressed in cubic metres (m^3). One cubic metre is equivalent to about six full bathtubs of water. An Olympic-size swimming pool holds 2,500 m^3.

In Edmonton, the average person uses about 84 m^3 of water a year.[43] The City of Edmonton treats about 130 million m^3 water a year to supply the domestic and commercial needs of a population of about one million people. The volume or water consumed by the City of Edmonton is probably around 10 million m^3 a year, with the rest returning to the wastewater treatment facility.

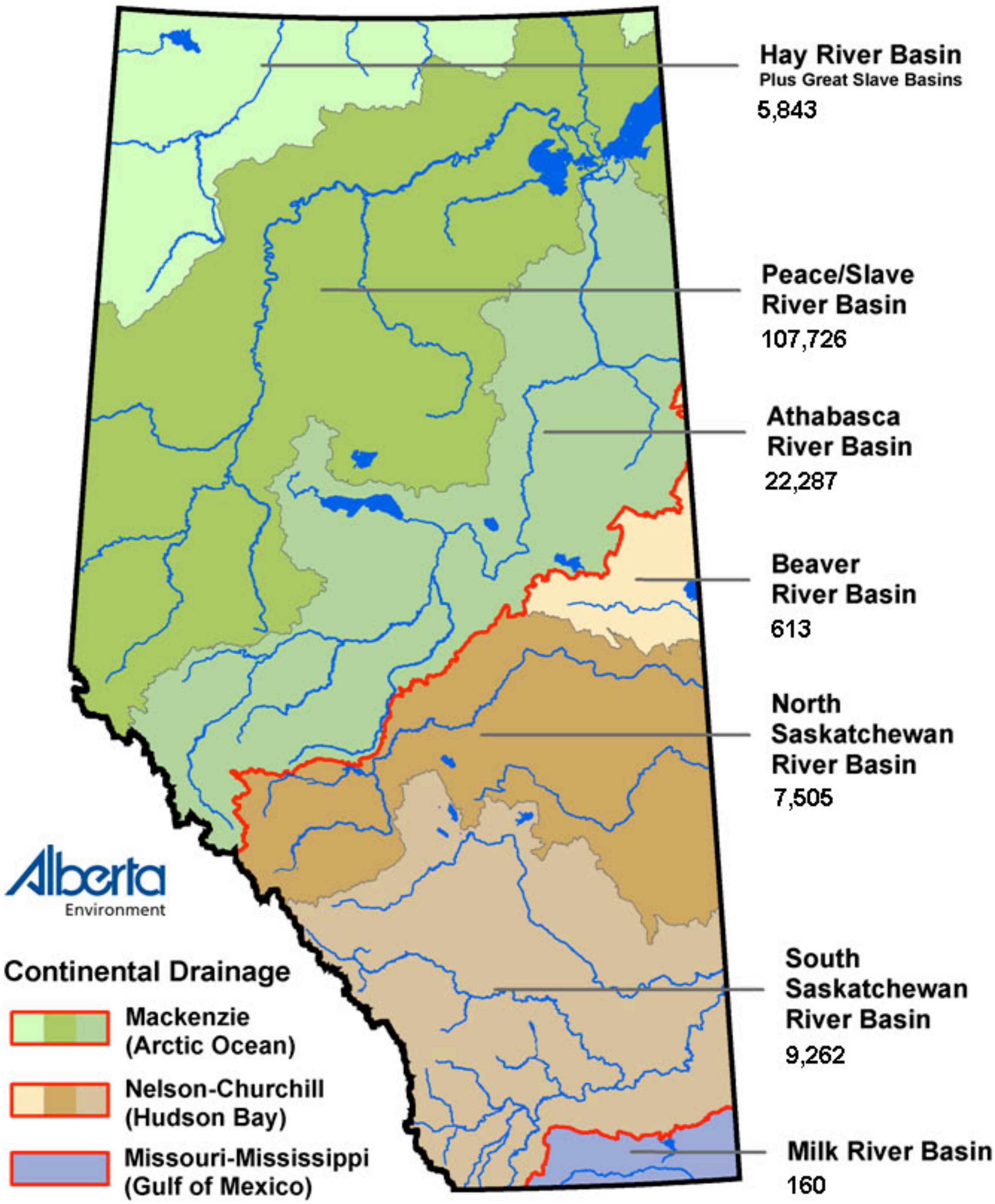

Figure 1-4: Major river basins of Alberta, with water discharges (million m^3/year)

Source: Alberta Environment, © 2008 Government of Alberta

It is important to consider water use not on a province-wide scale, but rather with respect to the availability of water in individual river basins. The main river basins in Alberta are shown in Figure 1-4. The map shows not only the location and size of each basin but also the average volume of water discharged each year. The graphs in this report show the river basins in geographical sequence from south to north, rather than in alphabetical order.

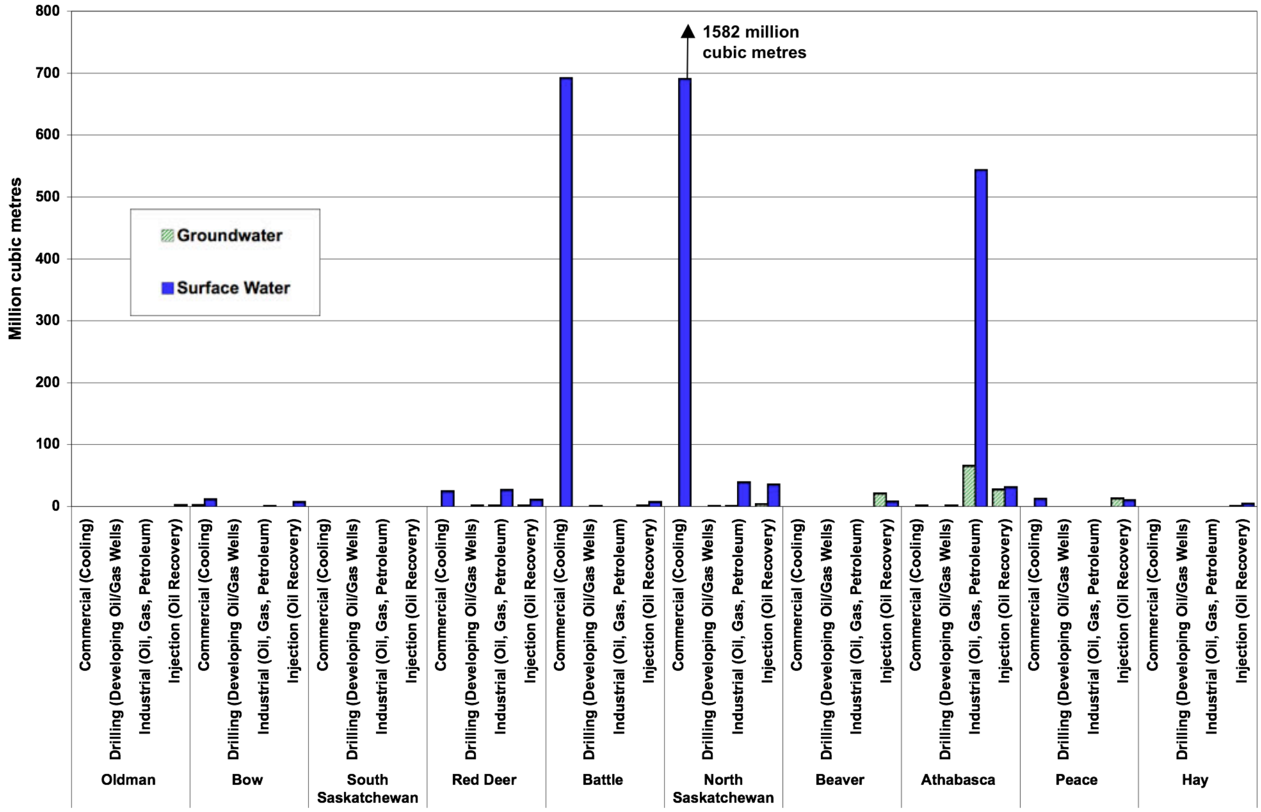

Figure 1-5: Surface Water and Groundwater Allocations for Energy in Major River Basins in Alberta, 2007

Data Source: Alberta Environment, personal communication, December 11, 2008

Note: The value next to the arrow indicates the total allocation for the North Saskatchewan River Basin, which is too large for the scale of this chart.

As can been seen in Figure 1-5, the volume of water allocated for energy production varies widely in different river basins. The largest allocations are for commercial cooling in the Battle and North Saskatchewan River Basins where large coal-fired power plants are located, The quantities in Figure 1-5 refer to total water allocation, but in Chapters 2 and 3 amounts are given for actual water use. When using the term "water use" it is important to distinguish between the volume diverted (i.e., the throughput) and the volume consumed (i.e., not returned to the source) as these values are quite different in some instances. The largest allocation of water for energy production that is consumed is in the Athabasca River Basin.

1.4.2 Potential Future Water Use

Alberta Environment commissioned a study to examine current and future water use in the province.[44] This not only provides a review of licences, water use and consumption in each major river basin in the province in 2005, but also gives scenarios for potential future use. The data is for surface water and non-saline groundwater only; a licence is not required for the withdrawal of saline groundwater.

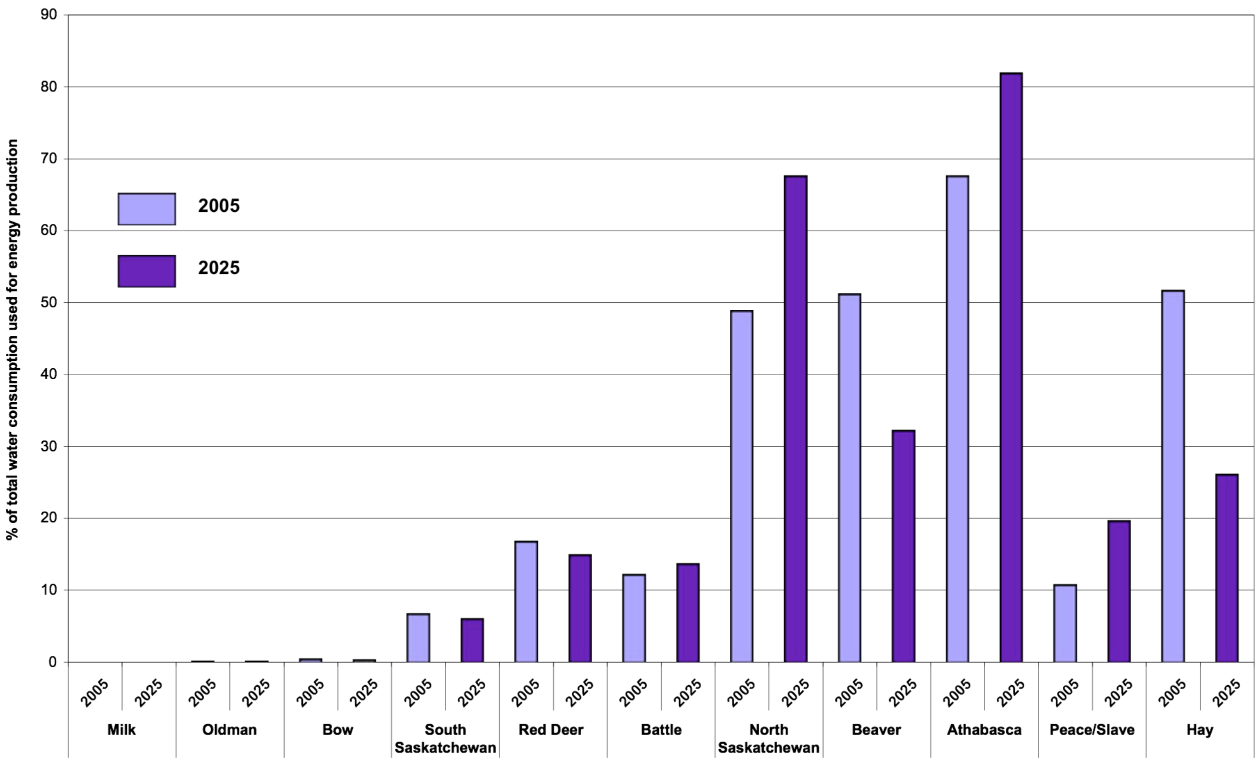

Figure 1-6: Percent of Fresh Water Consumption for Energy Production in Alberta River Basins in 2005 and Predicted Consumption in 2025, Medium Growth Scenario

Data Source: Alberta Environment, Current and Future Water Use in Alberta.[45]

Note: See text for an explanation of the energy categories included.

The Alberta Environment report projected future water use requirements for all sectors of the economy and for three different growth scenarios: low, medium and high. Figures 1-6 and 1-7 show the medium growth scenarios for energy production for the main river basins in the province. The medium growth scenario is used since, based on current knowledge, it is the most likely to occur. However, it should be recognized that actual future demand could differ considerably from this scenario. Energy production includes water for thermal cooling for the generation of electricity,[46] oilfield injection, thermal production of bitumen (through in situ (in place) operations), oil sands mining and the use of water for gas plants and petrochemical industries.

As shown in Figure 1-6, the proportion of water currently used for energy production varies across Alberta, from a negligible percentage of water consumption in southern Alberta basins, to around 50% in the North Saskatchewan and Beaver River Basins and as much as 68% in the Athabasca River Basin.[47] The graph is based on the actual volume of water consumed in 2005 and estimated water consumption for 2025, based on a medium growth scenario. It can be seen that, based on current information, the proportion of water used for energy production is expected to increase considerably in the North Saskatchewan and Athabasca Basins to 68% and 82%, respectively. In contrast, the proportion of water in the Beaver (Cold Lake) and Hay Basins is expected to decline.

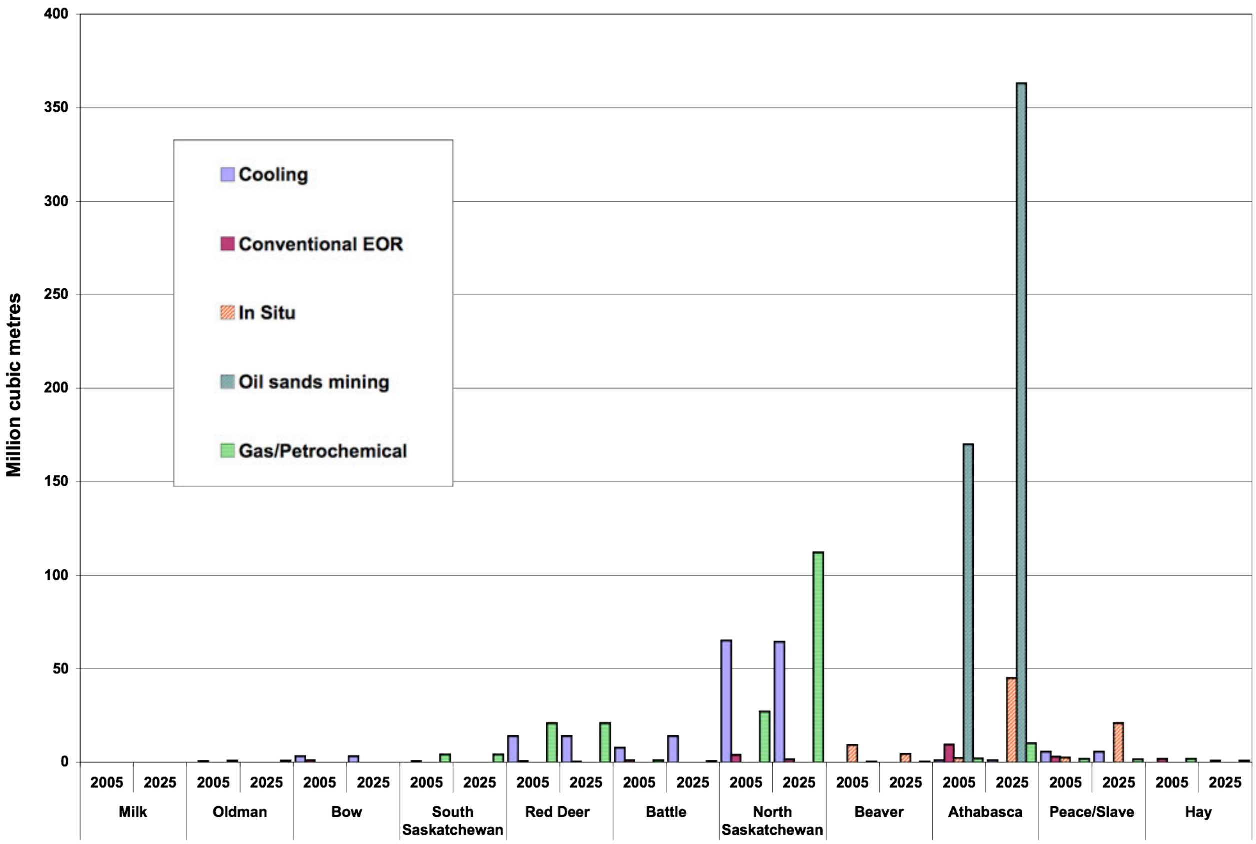

Figure 1-7: Water Consumption for Energy Production in Major Alberta River Basins in 2005 and Predicted in 2025, Medium Growth Scenario

Data Source: Alberta Environment, 2007, *Current and Future Water Use.*[48]

Note: For 2025, the in situ bar includes conventional enhanced oil recovery (EOR) in the Athabasca and Peace River Basins, as well as in situ thermal and in situ waterflood. For further clarification please refer to the endnote.

Figure 1-7 shows the volume of water consumed by the various energy sectors in 2005 and forecasts the demand in 2025 based on a medium growth scenario for the major river basins in the province. The figures are for the estimated net consumption, which is the difference between the water intake and the volume returned (e.g., to a river).[49] It can be seen that the high percentage of water used for energy production in the Athabasca Basin is for oil sands mining and injection (including thermal extraction), while in the North Saskatchewan Basin it is for both cooling (thermal power) and upgrading of bitumen (which is included in the gas/petrochemical category). It seems likely that the medium growth scenario for the Athabasca River Basin will be an underestimate; Alberta Environment has already approved allocations from the Athabasca River for mining operations that exceed the predicted use in 2025 (see Section 3.5.2).

Based on this scenario, the volume of water expected to be required to extract conventional oil using oilfield injection will be far less than it is today and further declines are anticipated further into the future. Conversely, a 150% increase in water required for injection and thermal projects in the Athabasca and Peace Basins is anticipated by 2025, primarily due to the large increase in "in situ" operations using steam to extract bitumen. The volume of fresh water consumed for injection in the Beaver Basin is expected to decline in this 2025 scenario, as greater use of saline water will likely reduce the consumption of fresh water.

Oil sands mining requires large volumes of water to process and upgrade bitumen. In situ recovery of bitumen that is very deep uses a lot of water to generate steam. The steam is injected into the ground to warm the bitumen so that it flows and can be pumped to the surface. Two to four barrels of water are consumed in the production of one barrel of synthetic crude oil from mining operations and about half as much water for in situ operations.

By 2007 oil sands mining operations had been issued licences for approximately 550 million m^3 of water per year, a volume equivalent to that required annually by a city of over three million people.[50]

Given the expected increase in demand for water in some river basins and the increasing variability in supply, it is important to find ways to reduce the volume of water required for energy production.

Chapter 2 describes the way in which water is used for the generation of electricity and Chapter 3 for the production of oil and gas. Chapter 4 examines how the volume of fresh water used for energy production can be reduced and Chapter 5 recommends ways to improve the management of water in Alberta.

2. Water Use for Electricity Production

2.1 Introduction

Researchers predict that, “with population and energy demands increasing there is going to be a compelling need for the electric power industry to be more water efficient.”[51] Climate change makes such efficiency imperative. In fact, a shift toward those power producing technologies that use little or no water may become necessary.

Different types of electricity generation require different amounts of water. The most obvious use of water for electricity production is hydroelectric power, but fossil fuel energy, nuclear power and biomass can require large amounts of water. In 2007 almost 24% of water allocations in Alberta were for cooling, primarily for thermal power plants.[52] Almost all the 2.3 billion m^3 water allocated for cooling in 2007 was for surface water. The actual volume diverted for cooling in 2007 was just under 40% of the allocation,[53] and it was estimated that in 2005 about 95 million m^3 was actually consumed for industrial cooling in the province.[54] Most of the water used in Alberta is for cooling coal-fired plants; this is discussed in Section 2.2.

Table 2-1: Cooling Water Withdrawal and Consumption for Thermal Power Plants and Cooling Systems

Power plant type	Cooling system	Water withdrawal (litres/MWh)	Water consumption (litres/MWh)
Fossil/biomass /waste-fuelled steam	Once-through cooling	75,000–190,000	~ 1100
	Pond cooling	1100–2300	1100–1800
	Cooling towers	1900–2300	~ 1800
Nuclear steam	Once-through cooling	95,000–227,000	~ 1500
	Pond cooling	1900–4200	1500–2700
	Cooling towers	3000–4200	~ 2700
Natural gas combined cycle	Once-through cooling	28,000–76,000	~ 400
	Cooling towers	~ 890	~ 700
	Dry cooling	0	~ 0
Coal/petroleum residuum-fuelled combined cycle	Cooling towers	~ 1400	~ 800

Data Source: Electric Power Research Institute[55]

> "There is a significant dependence on water used for thermal cooling in electricity generating plants such as coal fired, natural gas and nuclear and for oil and gas production from both conventional and unconventional resources. Although most of the water is recycled, there is still about 20% of potable make-up water that is required, and this creates concerns over the need for conservation and sustainability."[56]

The range in water requirements for different types of thermal power plants is shown in Table 2-1 and depicted in Figure 2-1. It is clear that the volume of water withdrawn depends not only on the electricity generation process but on the type of cooling system used. Once-through cooling systems, where the water is returned to a river or lake, require much larger withdrawals than do systems where the water is recycled through cooling ponds or cooling towers.[57] However, the amount of water consumed depends on the amount that evaporates into the atmosphere. For this reason, actual water consumption is often higher with pond cooling and cooling towers than with once-through systems, where evaporative losses are lower and most of the water flows back to its source.

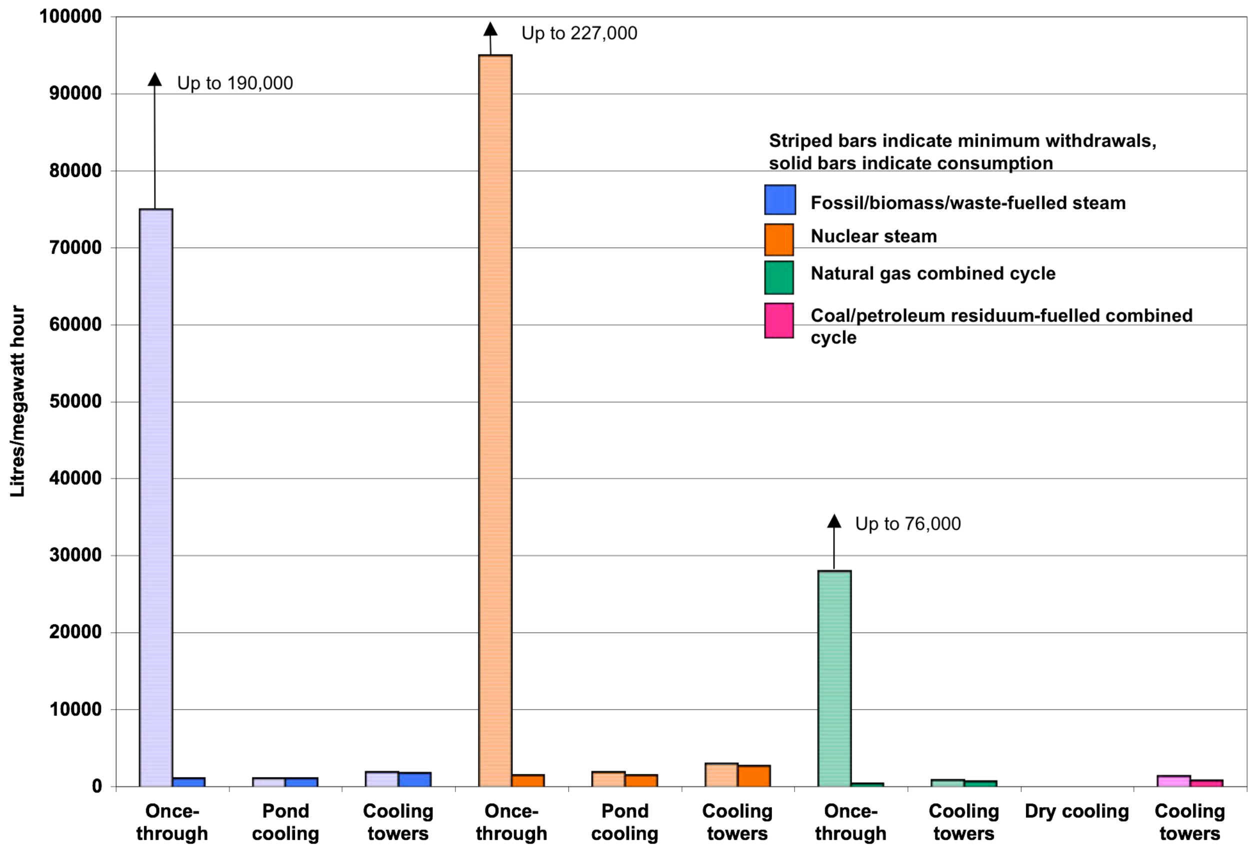

Figure 2-1: Cooling Water Withdrawal and Consumption for Thermal Power Plants and Cooling Systems

Data Source: Electric Power Research Institute[58]

Table 2-2: Alberta Generation Capacity, 2007

	MW	% of total
Coal	5,893	48.6
Gas	4,609	38.0
Hydro	900	7.4
Wind	521	4.3
Biomass	184	1.5
Fuel Oil	13	0.1
Total	12,120	100.0

Source: Alberta Energy[59]

As can been seen in Table 2-2, the majority of power stations in Alberta use fossil fuels such as coal and gas to generate electricity. The locations of the main electricity generating facilities are shown in Figure 2-2.[60]

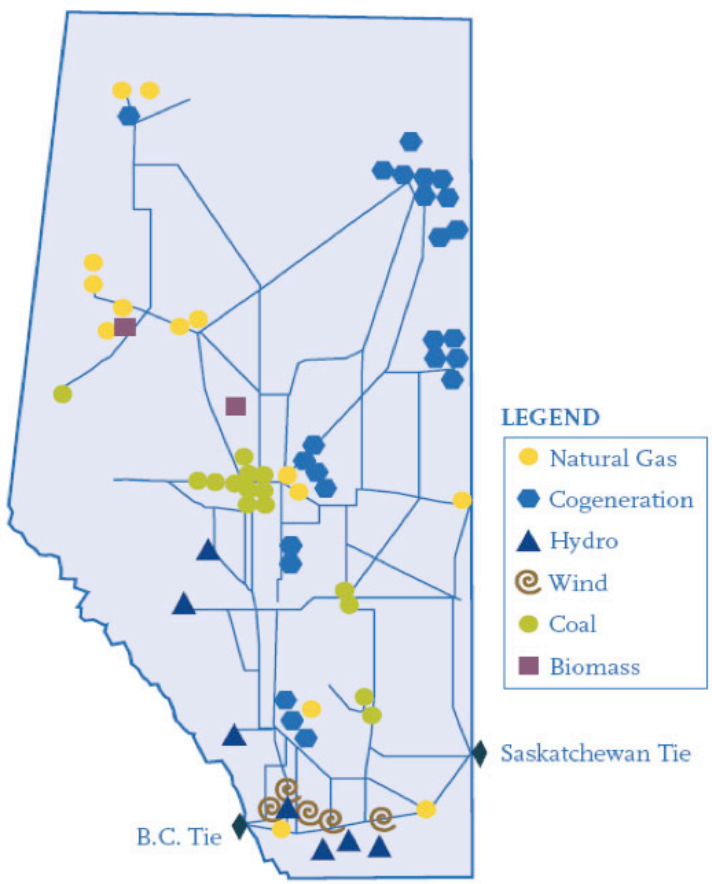

Figure 2-2: Alberta's Electric System — Generation and Transmission, 2007

Source: Government of Alberta[61]

Coal is currently the largest single source of power in the province. Because coal-fired power plants cannot be quickly turned on and off, they provide much of the base load to consistently meet electricity demand. In 2007, 64% of all electricity generated in Alberta came from coal-fired power plants; this is far more than is suggested by their 48% share of the generating capacity.[62] Almost three-quarters of the electricity on the Alberta grid came from coal in 2007, as a considerable proportion of the natural gas-fired generation in the province comes from co-generation facilities, which use some of the electricity on site to run their operations.[63] Thus, although 30% of the province's electricity was generated using natural gas in 2007, the contribution to the grid was much less.

Some cogeneration plants, which use gas to produce steam for industrial operations (such as bitumen production and upgrading), also provide base load, since they need a continuous source of steam for their plants. In contrast, some natural gas-fired plants and hydropower can be quickly brought online to handle peak loads.

Although cooling for fossil fuel power generation uses by far the largest volume of water, other forms of electricity production also use small amounts of water. This chapter will briefly examine water use and consumption for all the main forms of electricity generation and will offer some future predictions of water use. More information on electricity generation in Alberta can be found in another Pembina Institute publication, *Greening the Grid*.[64]

2.2 Coal-fired Electricity Generation

2.2.1 Coal Mining

Surface mining for coal has a considerable impact on groundwater and adjacent surface waters, since, as with all mining sites, the mine area intercepts groundwater flows and water must be drained from the site.[65] Lowering of the water table can affect adjacent stream flows and surface water bodies, both as a result of the reduction in the water table and by changing the topography and thus surface discharge. Groundwater flows may resume again once a mined area is reclaimed. Although much of the coal mined in Alberta is for electricity generation, some bituminous coal is exported.

2.2.2 Coal-fired Electricity Generation

Coal-fired power plants use a large amount of water to cool and condense the steam used to drive the turbines.[66] Some water is needed to generate the steam itself, but since this is a closed-loop system, only make-up water is required for the actual generation process. Some water is also used for vacuum priming and sealing, washing air filters and wetting ash.

As discussed in Section 2.1, various systems can be used to cool water. Cooling ponds are often used to dissipate energy from condenser cooling systems in coal-fired power plants in Alberta.[67] Water is recirculated from the pond back into the plant, but due to the higher temperatures in the pond, some water will evaporate and some additional make-up water will be required from a river or lake.[68] It is sometimes necessary to discharge water from a cooling pond back to a river to prevent an increase in total dissolved solids that have accumulated in the cooling pond (as a result of evaporation). This process is referred to as blowdown. This blowdown water will increase the level of total dissolved solids in the river immediately downstream of the discharge point and increase the temperature of the water.[69] To compensate for the discharge, the volume of make-up water withdrawn from the river will increase during blowdown. The effect that the increase in river temperatures and reduction in flows has on aquatic life will partly depend on the size of the flows and quality of the water, relative to the river's natural conditions.

In some circumstances it is possible to use grey water, such as treated water from a municipal wastewater treatment plant, as cooling water.[70] Use of such water can reduce the discharge of pollutants to a river (compared with discharges from both a municipal waste treatment plant and power plant), but it still reduces river flows, as that water is reused instead of being discharged back to the river.

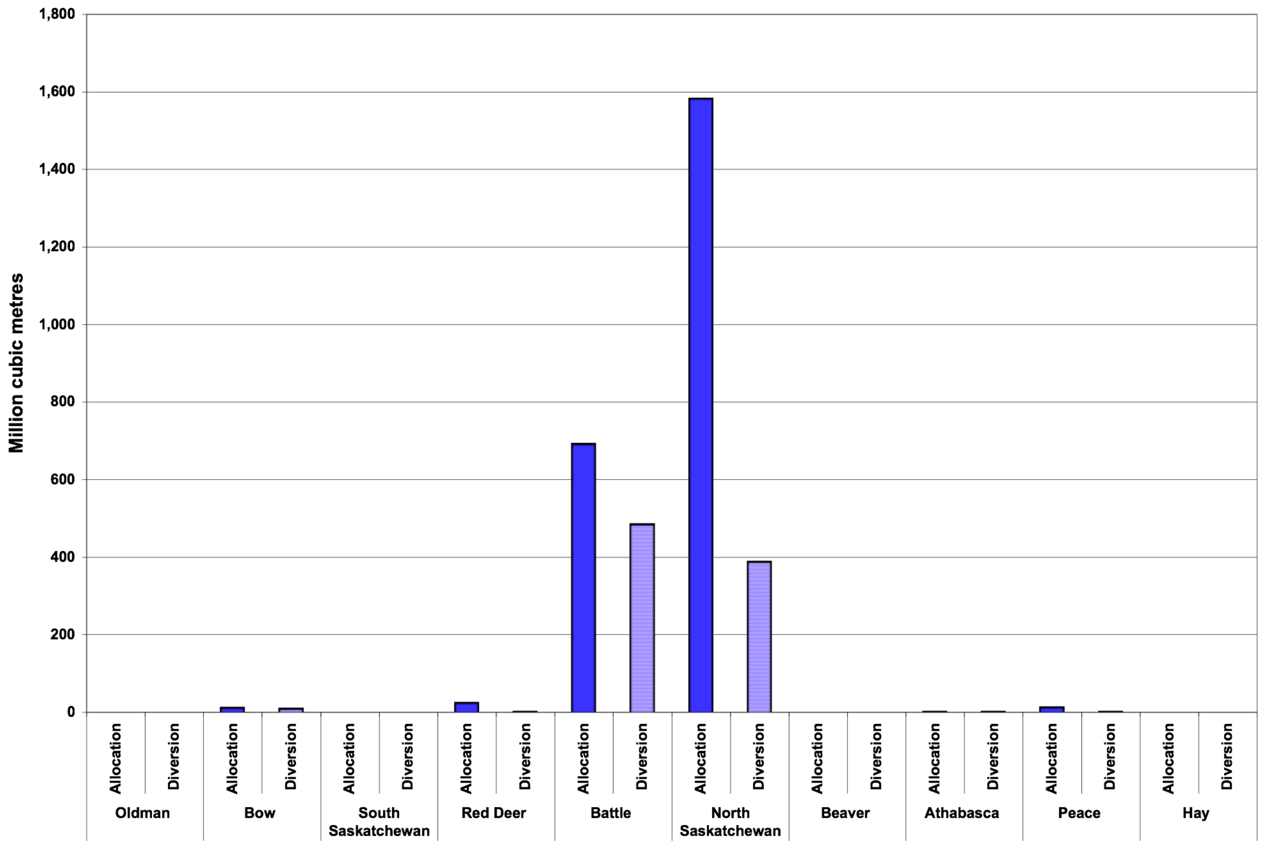

Figure 2-3: Surface Water Allocation and Diversion for Commercial Cooling in Major River Basins in Alberta, 2007

Data Source: Alberta Environment, personal communication, December 11, 2008[71]

As can be seen from Figure 2-3, the main allocation and use of water for commercial cooling in Alberta is in the North Saskatchewan and Battle River Basins. The figure shows the volume of water reported as diverted, and much of the water used for cooling is later returned to its source. It should be noted that while the water allocations are accurate, the volumes for water use (diversion) from the Alberta Environment database have not been verified.[72] The figure shows all water for commercial cooling in the province, but the predominant allocation and use is for coal-fired power plants. There is one coal-fired power plant in the Battle River Basin, which uses a relatively large volume of cooling water.[73] The main centre of coal-fired power generation is west of Edmonton, where EPCOR's Genesee plants and TransAlta's Sundance, Keephills and Wabamun plants account for almost three-quarters of the coal-fired capacity in the province. Water for these power plants is taken from the North Saskatchewan River.[74] Within the river basin, water for cooling accounts for almost 80% of total water allocations. Operations are expected to return most of their allocation for cooling back to the river.[75] In fact, they may consume considerably less than the net consumption allowance. Water for cooling accounted for about one-third of actual (net) water use in the North Saskatchewan Basin in 2005.[76]

Whereas cooling ponds have been used in the past in association with power plants, a cooling tower is being planned for a new power plant being built west of Edmonton.[77] The tower will be used in association with an existing cooling pond. Cooling towers remove much of the heat in discharged waters and limit the temperature increase of the cooling pond to which water is discharged.[78]

Where cooling water is withdrawn from and discharged to a lake, as at Lake Wabamun west of Edmonton, the lake will be impacted.[79] Studies show that the lake's water temperature, water quality and water volume have been affected by power plant discharges.[80] Changes in these elements can in turn have an impact on fish larva and other life in the lake. Since 1997 TransAlta has been treating and pumping water from the Sundance Cooling Pond into Lake Wabamun to help restore lake levels.[81] The treatment process ensures that organisms from the North Saskatchewan River (the original source of the water) do not enter the lake and that the temperature of the discharged water is within three degrees of the lake temperature.[82] The impacts from the current Wabamun power plant will decline after 2010 when the remaining unit is due to be decommissioned.

> "Declining water quantity in the Prairies region resulting from climate change will reduce the supply of cooling water to power plants during drought periods or in other low-flow periods."[83]

2.2.3 Coal Gasification

As supplies of conventional natural gas decline, coal gasification is being considered as a source of synthetic gas, or syngas, which is a mixture of hydrogen, carbon dioxide and carbon monoxide. The syngas may be used to generate electricity in an integrated gasification combined cycle (IGCC) power plant. An IGCC power plant is slightly more efficient than a conventional power plant that burns coal (on a net basis), the process creates a concentrated carbon dioxide stream, which is easy to capture, and it produces fewer emissions of particulate matter, sulphur dioxide and nitrogen oxides.[84]

The first IGCC plant for power generation in Alberta is being developed by EPCOR for its Genesee site, west of Edmonton. If all investment and construction decisions proceed as outlined, the plant will generate 270 MW of electricity and be able to capture over 1.25 million tonnes of CO_2 per year.[85] As the plant is currently at the design stage, the amount of water it will require has not been announced. It is currently unknown whether the plant construction will proceed, and capture of CO_2 is not presently required by government.

Sherritt is proposing a coal gasification project for the Dodds-Roundhill area, east of Edmonton.[86] The proposed project includes an IGCC plant to produce hydrogen for market and for power generation. The gasification unit and power plant will use approximately 9.5 million m^3 of water a year.[87] EPCOR, which will supply the water, intends to use treated wastewater from the City of Edmonton. This will reduce the discharge of residual chemicals (e.g., pharmaceuticals and cleaning products) from the municipal waste treatment plant and is to some extent preferable to the withdrawal of fresh water, but it will still reduce flows from the North Saskatchewan River.[88] It will thus add to the cumulative impact of new upgraders and other industrial operations withdrawing water from this river.[89]

Bow City Power is also proposing construction in the form of a 1,000 MW power plant that will use gasified coal near Brooks in southern Alberta.[90] The exact water requirements for this project are not yet known.

2.2.4 Carbon Capture and Storage

One benefit of an IGCC power plant over a conventional coal-fired power plant is that its CO_2 emissions are easier to capture as they are in a concentrated form. While the capture of CO_2 is beneficial, given that it reduces the emission of this GHG to the atmosphere, this activity increases the demand for water and the size of the coal mine.[91] This is true for all coal-fired power plants that capture their CO_2 emissions; it is mainly due to the extra power required to capture and compress the CO_2. The volume of water required for CO_2 capture and compression from IGCC plants is considerably less than that for post-combustion capture from pulverized coal (PC) combustion plants, ranging from approximately 3.4 litres per kilowatt hour (l/kWh) for an IGCC plant to 5.3 l/kWh for a supercritical PC plant and 6.1 l/kWh for a subcritical PC plant. These figures may be lower if a chilled ammonia process is used for post-combustion capture in PC plants, instead of an amine process.[92]

In addition to water, energy is required to boost the pressure in the pipeline transporting the gas to an underground injection site and for the injection process, but this is negligible compared with the energy (and, indirectly, water) required for the capture and compression process. The CO_2 should be injected deep underground (usually at 800–1,000 metres deep or deeper, where it will be in a supercritical state).[93] The injected CO_2 may displace oil (in enhanced oil recovery) or be trapped in deep saline groundwater formations. Gradually some of the CO_2 will dissolve in the formation water, but if any CO_2 leaks from the injection well, abandoned wells or through faults, it could reach shallower zones and affect fresh groundwater or escape to the atmosphere.[94]

The Government of Alberta’s plan to combat climate change relies heavily on carbon capture and storage (CCS).

> The Government of Alberta’s Climate Change Strategy relies on CCS to achieve 70% of the proposed reductions in forecast GHG emissions by 2050. Their plan aims to reduce GHG emissions to 50% below business as usual and 14% below 2005 levels by that date.[95] This objective is far short of the GHG reductions needed according to the international scientific community, but the heavy reliance on CCS will impact the demand for fresh water. It is not yet possible to determine how much extra water might be needed to realize the strategy’s objectives, as it will depend on the process used to capture the CO_2.

Various carbon storage projects are being proposed and initial development will be subsidized by the Government of Alberta,[96] but it is too early to determine whether the government’s carbon capture target, which would require a large number of new pipelines and injection wells, is realistic.[97]

2.3 Electricity from Gas

2.3.1 Natural Gas

Gas-fired power plants account for about 38% of Alberta's electricity generation capacity.[98] Cogeneration plants are likely to contribute to the base load (since the electricity is generated in combination with the production of steam for industrial processes), but single cycle gas plants will be switched on to meet demand at peak periods. As noted above, gas-fired plants supply about 30% of all electricity generated in the province.

Natural gas plants have a gas turbine fired by natural gas.[99] A basic, single cycle gas-fired power plant, which can be easily switched on to meet peak demand, consumes relatively little water. This water is injected to increase the efficiency and power of the engine, but is not required for the production of steam. For example, ENMAX estimates that their proposed 120 MW Crossfield Plant's water consumption "will average 3 to 6 million gallons of water annually . . . about the same as 30 to 60 homes."[100]

However, as Table 2-1 shows, a combined cycle gas-fired plant uses considerably more water than will be required by ENMAX's single cycle plant. A combined cycle gas-fired plant not only has a gas turbine, but also a steam boiler and turbine system, which are heated by the exhaust gas from the gas turbine. Such combined cycle plants are more efficient than a simple gas turbine, but they inevitably require more water.[101] The exact amount required depends on the specific technology used,[102] but it is likely that approximately one-third of the electricity generated from a combined cycle plant comes from the steam cycle. Thus, the volume of water used will be roughly comparable to that required by straight steam turbine cycle generation for a plant with one-third of the total combined cycle plant capacity. The basic principles and water use for a steam turbine are the same, irrespective of the fuel used to heat the water.

In cogeneration plants, where electricity is generated in conjunction with the production of steam for industrial processing, water requirements will be partly determined by the demand for steam, so it is not possible to generalize on the volume of water required for power. However, in general, combined cycle cogeneration operations make the most efficient use of resources.[103]

2.4 Nuclear Energy

2.4.1 Uranium Extraction

2.4.1.1 Uranium Mining

Uranium provides the fuel for nuclear reactors. Uranium deposits, which are mined in northern Saskatchewan, extend into northeastern Alberta where they are being assessed at several locations.[104] The mining of uranium impacts both groundwater and surface water. The dewatering of the mine area disrupts groundwater flows and quality can be affected by leachate from mine tailings and rock waste storage areas.[105] Discharges from some mining and milling operations are toxic to fish and other organisms.[106]

2.4.1.2 In Situ Uranium Extraction

In some situations, uranium may be extracted in situ, instead of through mining. Several companies have been exploring for uranium in southern Alberta, close to the U.S. border.[107] In situ extraction involves the injection of water and chemicals to leach out the uranium minerals, which are then pumped back to the surface with the water. Once the extraction process is complete, contaminated groundwater must be removed, especially if the uranium deposits are in shallow areas with fresh groundwater. Replacing contaminated groundwater requires a large amount of fresh water,[108] so is not suitable for dry areas where there is little water and slow groundwater recharge. It is not yet known if uranium extraction will proceed in Alberta, but as the supply of rich uranium reserves declines and uranium prices increase, companies will find it economic to produce from lower quality or more expensive sites.[109]

2.4.2 Nuclear Power Plants

There is no nuclear power generation in Alberta at present but Bruce Power has applied to the Canadian Nuclear Safety Commission for a licence to prepare a site that could generate 4,000 MW of electricity from two to four reactors near Peace River.[110] It is not known how much water would be required for the proposed nuclear facility, but in general, commercially available nuclear power plants use more water than does any other form of electricity generation (see Table 2.1). There is clearly a wide variation in the volume of water required for different processes, but Environment Canada provides a broad generalization, saying that, "Production of one kilowatt-hour of electricity requires 140 litres of water for fossil fuel plants and 205 litres for nuclear power plants."[111]

Not only are large volumes of water required, but the operation of nuclear generation stations has resulted in routine and accidental release of radioactive contaminants to surface waters, with tritium oxide and carbon-14 releases being of primary concern.[112]

The release of cooling water to rivers or surface waters will raise the temperature of those waters, and may affect local fish populations.[113] The effects will be similar to those from the release of warm cooling water from coal-fired power generation facilities, but the impact could be greater due to the larger volumes of cooling water to be released. The large demands for water for cooling could make nuclear energy even more vulnerable to climate change than fossil fuel-generated energy. Nuclear reactors in France have been shut down when there was insufficient water for cooling.[114]

Even if research into new, Generation IV nuclear reactors results in the production of reactors that can be cooled by gas or liquid metal,[115] the heat must still be dissipated through transfer from the primary coolant to a water stream that is then cooled in the same way as with current reactors. Thus, the need for cooling water remains.

2.5 Hydroelectricity and Run-of-River Hydro

In hydro generation, the flow of water turns turbines to generate electricity. The water then continues to flow downstream. However, a distinction must be made between conventional hydro generation and low impact run-of-river hydro. Under conventional hydroelectric production, where a dam is created across a river to create a reservoir, water is conserved during peak flows for use at a later date. The construction of reservoirs floods land and affects fish movements. A dam interrupts the flow of silt downstream, and eventually the silt will reduce the capacity of the reservoir. In addition, rotting vegetation under the water produces methane as it decomposes, which leads to GHG emissions. These emissions are highest soon after the reservoir first fills, but it is now understood that they continue throughout the lifetime of the reservoir, fuelled by the influx of carbon into the reservoir.[116]

> "The emission of greenhouse gases from reservoirs due to rotting vegetation and carbon inflows from the catchment is a recently identified ecosystem impact of dams. This challenges the conventional wisdom that hydropower produces only positive atmospheric effects (e.g., reductions in emissions of CO_2 and nitrous oxides), when compared with conventional power generation sources."[117]

It is usually assumed that water used for hydroelectricity will pass through the turbines and continue flowing downstream. Thus allocations for hydroelectricity projects do not take into consideration water losses,[118] even though some evaporation will occur from the reservoir surface.[119, 120] The evaporative losses will vary from place to place and from year to year.[121] Alberta Environment estimates and routinely computes evaporative losses from reservoirs, usually for project-specific purposes, not for water use reporting.[122]

Run-of-river hydro, which avoids the construction of large dams, is considered a lower-impact, sustainable source of electricity. In run-of-river projects, a small dam raises the water level at the powerhouse sufficiently to create a head of water to drive the turbines. However, as there is little or no water storage, generation capacity depends on river flows and is variable. Fishways may be created beside the dam to enable fish to travel upstream.[123]

All hydropower generation can be affected by variability in runoff and drought, especially run-of-river hydro. It will also be affected by changes in precipitation (both seasonal and total volumes) as a result of climate change.

> "Forecasts of future capacity for generating hydroelectric power must take into account decreasing average spring and summer flows for the western portion of the Prairies due to glacial ice decline . . . and lower overall snow accumulations."[124]

Hydroelectric power capacity is currently sufficient to meet about 5% of Alberta's electricity requirements and can be turned on quickly to meet peak power demand.[125] The main hydropower sites are on the North Saskatchewan River, at the Bighorn and Brazeau dams, and on the Bow River.[126] Sites have been proposed for future run-of-river hydro, such as on the Slave River in northern Alberta, but such sites may be controversial because of environmental impacts.[127]

2.6 Other Types of Renewable Energy

Aside from hydroelectricity, other types of renewable energy production also have water requirements. For example, some biofuels require considerable amounts of water. While not all types of renewable energy are used to generate electricity, for interest, each type is addressed in this section.

2.6.1 Biofuels

Biofuels rely on biomass, organic material of biological origin, as their energy source. Biomass includes materials such as wood chips, corn stubble and manure. The biomass may be used to generate electricity or may be converted into methane gas, ethanol or biodiesel.

In Alberta, there are five biomass generating plants using wood waste with a generating capacity of 178 MW, about 1.5% of the province's total generation capacity.[128]

Between 2 and 4% of Alberta's total energy requirements could potentially be derived from organic waste from agriculture.[129] To what extent in the province biomass is economic depends on a number of factors including the scale of operations and the distance biomass must be transported.[130]

It is impossible to generalize about the impact of biofuels on water, since it depends both on the type of biomass and how it is processed to produce energy. The impact also depends on whether the fuel is burned as gas or biodiesel or used to generate electricity.[131] The use of waste products such as manure or municipal sewage sludge for the production of biogas is clearly beneficial and can reduce the risk of groundwater pollution.[132] However, the cultivation of crops such as grain or corn specifically for the production of ethanol will use considerable volumes of water, not only for growing the crop but also to process it into ethanol.[133,134] In some cases, the production of ethanol or biodiesel from biomass may even use more energy than it generates.[135] Using wood waste or peat to produce ethanol uses less water, but the extraction of peat means removing muskeg or draining peatbogs, which act as natural sponges, recharging groundwater and reducing peak flows in rivers.

2.6.2 Geothermal Energy

There are several ways to capture geothermal energy. The most common methods use ground source heat pumps to pump air or antifreeze through pipes buried in the earth. The fluid heats up and flows back to circulate through pipes to warm a building on the surface.[136] Heat pumps utilize heat at relatively shallow depths of less than 300 metres, while hydrogeothermal systems access heat at much greater depths — up to three kilometres — by pumping up hot water and using the heat from the water to generate steam, turn turbines and produce electrical power. The water can be re-circulated via injection wells. Whether geothermal power has a negative impact on groundwater depends on the way in which it is exploited.[137]

A preliminary study indicates there is a significant heat resource in Alberta, but more data and analysis is needed to better evaluate the potential and identify the most suitable areas.[138] It may be possible to utilize the hot water produced with oil in some locations, but it is probably not economic for commercial companies at the present time.[139]

> "There are current proposals for new baseload power generation in Alberta that range from new IGCC level coal plants to large nuclear facilities. Geothermal power based on Engineered Geothermal Systems may be able to reduce or substitute for these proposed power sources at competitive prices while providing a side benefit of lower GHG emissions and ultimately tradable credits on carbon markets."[140]

2.6.3 Solar Power

Solar thermal electric plants direct sunlight onto a pipe containing a heat transfer fluid (e.g., oil), which then boils water to turn a generator.[141] Such operations may need water for cooling. Photovoltaic power panels do not require water for use.[142] The Pembina Institute report *Greening the Grid* provides an analysis of solar power potential in Alberta.[143]

2.6.4 Wind Energy

In humid areas, rainfall keeps the wind turbine rotor blades clean, but in dry areas water may be used to clean the blades of dust and insect buildup to optimize performance. The quantity of water required is negligible compared to fossil-fuelled power plants.[144]

At present Alberta has nearly 500 MW of wind generation capacity, about 4% of the province's total capacity,[145] but there are plans for many new developments.[146] Alberta's total generating potential for wind energy is estimated at 64,000 MW, which is more than five times the installed generating capacity in 2007.[147] With investments in proven wind technology, Alberta could use wind energy to generate more than one-fifth of its electricity within 20 years.[148]

2.7 Future Water Demands for Electricity

As seen in Figures 1-7 and 2-3, the largest allocation of water for cooling is in the North Saskatchewan River Basin, where the main coal-fired power plants are currently located. The medium growth scenario of consuming 64 million m^3 of water per year for cooling in 2025, shown in Figure 1-7, is based on the expectation that water consumption from this river basin for cooling will be constant and that existing operations will continue without major changes.[149] At the time of writing, TransAlta is building a third unit at Keephills (to generate 450 MW (net)) and EPCOR is planning a 270 MW IGCC plant, mentioned above, which will increase the demand for water. Also in the North Saskatchewan Basin, the Sherritt Gasification Plant at Dodds-Roundhill (as well as the upgraders being planned for the Industrial Heartland, see Section 3.5.4) will increase the volume of water from the North Saskatchewan River that is diverted and consumed.

Some water is used in cooling in the Red Deer and Battle River Basins. The water use for cooling in the medium growth scenario in the Battle River assumes that the full licence allocation is used, but no specific projects are mentioned.[150] The use of water for thermal cooling in the Red Deer Basin has been constant since 2000, and, as there is no specific information available, the Alberta Environment report assumes that the demand will remain constant.

In all cases, almost all the water used for cooling comes from surface sources.

3. Water Use for Gas and Oil Production

3.1 Introduction

Oil and gas resources are located across much of Alberta, as shown in Figure 3-1.

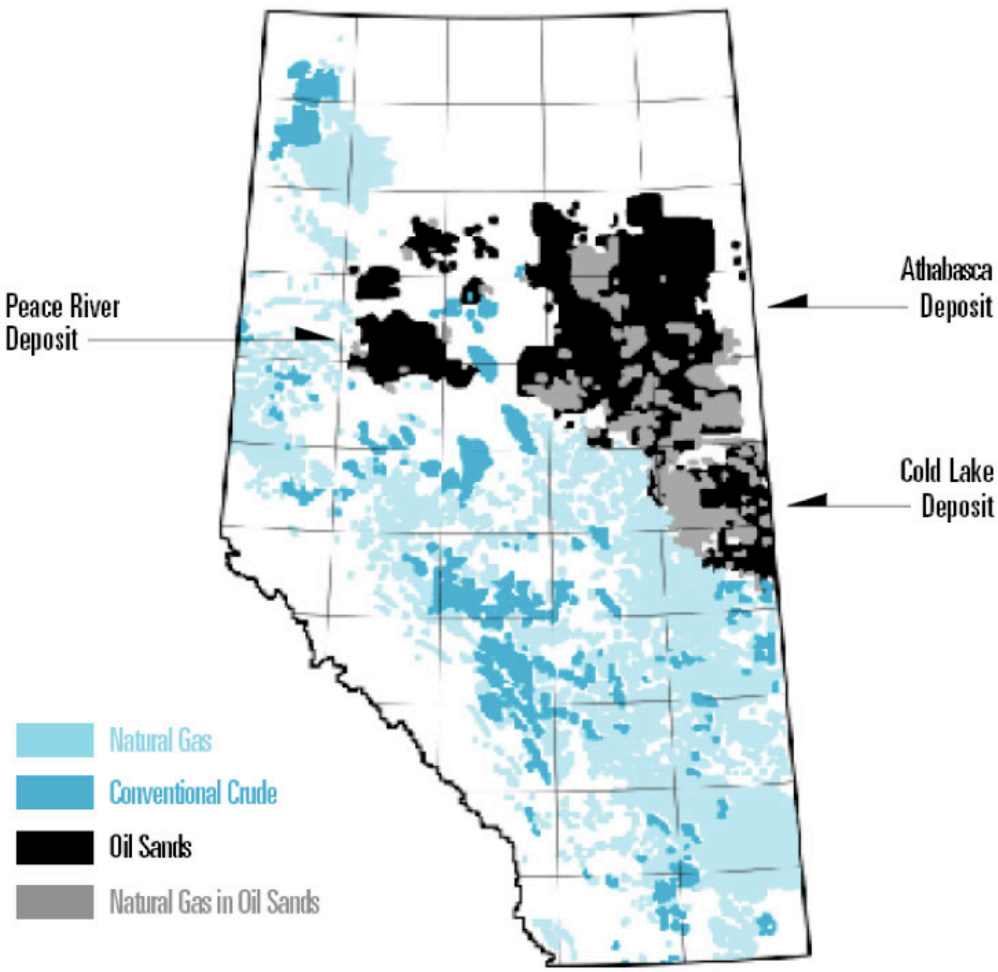

Figure 3-1: Oil, Oil Sands and Natural Gas Resources in Alberta

Source: Canada West Foundation. Treasure in the Sand: An Overview of Alberta's Oil Sands Resources.[151]

In 2007 9% of water allocations in Alberta were for the petroleum sector, with three quarters of this being for industrial (oil, gas, petroleum) and the rest for injection, both for conventional oil and for in situ production of bitumen (see Figure 1-2).[152] The industrial petroleum sector includes water for oil sands mining and upgrading, as well as for gas and petrochemical plants. A comparatively small amount of water is used for drilling and developing wells. Figures 3-2 and 3-3 show the allocation and use of water for enhanced oil recovery (EOR) (including conventional EOR, in situ thermal recovery of bitumen and in situ waterflood[153]) and industrial (oil, gas and petroleum) applications in the major river basins in Alberta. This information is shown on two separate graphs, since the scales are so different. Both graphs need to be examined to get a complete picture of the allocation and use of water for the production of gas, oil and bitumen in the province.

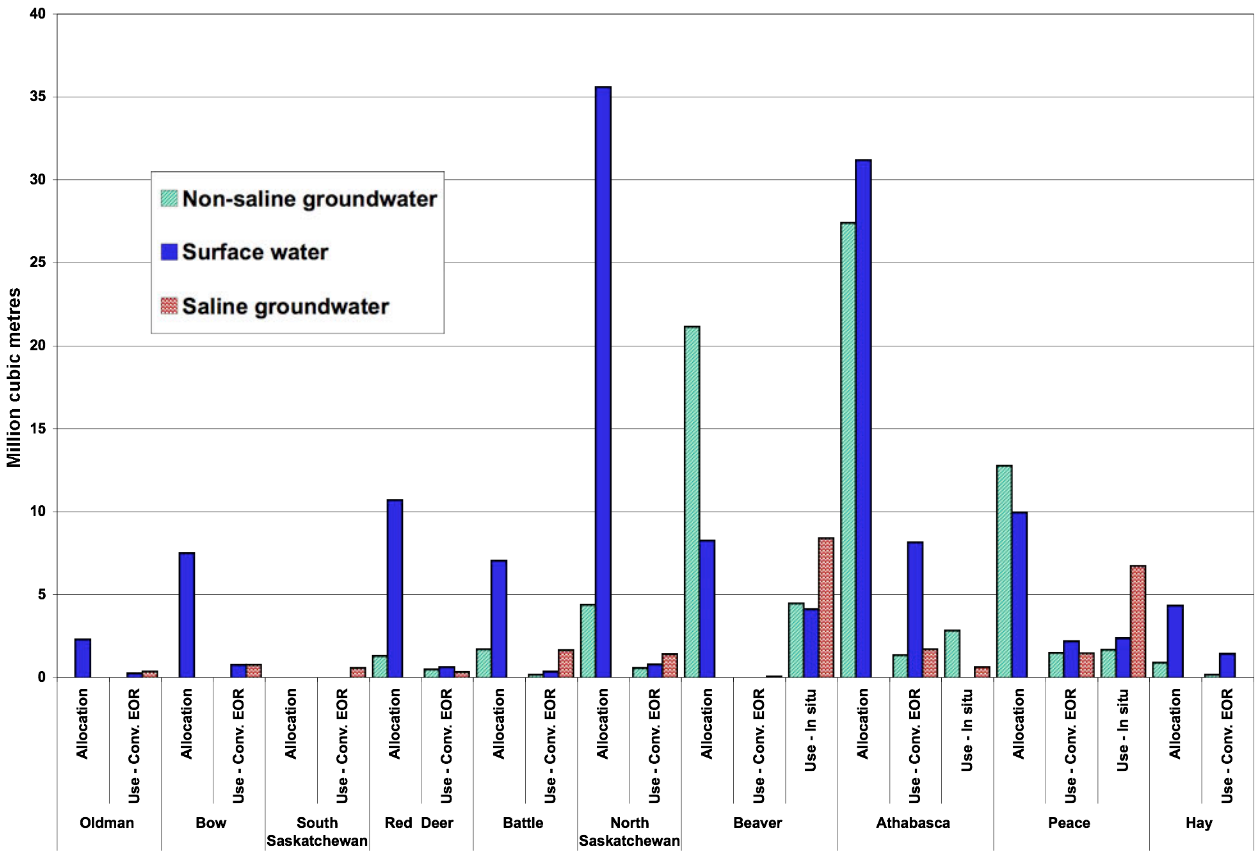

Figure 3-2: Surface Water and Non-saline Groundwater Allocation and Water Use (including Saline Water) for Enhanced Oil Recovery (Conventional EOR, In Situ Thermal and In Situ Waterflood) in Major River Basins in Alberta, 2007

Data Source: Alberta Environment, personal communication, December 11, 2008.

Note: The category "Conv. EOR" refers to enhanced oil recovery in conventional oil reservoirs. Saline water is included in the water use figures, but not in the allocations, as companies are not required to have an allocation to use saline water.[154]

Figure 3-2 shows not only the allocation and use of surface water and groundwater, but also the use of saline water for all types of EOR. Across southern and central Alberta (Oldman, Bow, South Saskatchewan, Red Deer and North Saskatchewan River Basins) all the water used is for conventional EOR using waterflood. In the Athabasca River and Peace River Basins some fresh water is used for conventional EOR and some for in situ production of bitumen, while in the Beaver River Basin, all the fresh water allocation is for thermal in situ production. The variations in water use for in situ bitumen production are described in more detail in Section 3.5.3 below. As can be seen by comparing Figure 3-2 and 3-3, the total volume of water for in situ operations in the Athabasca River Basin is small compared with the volume allocated and used for bitumen mining and upgrading operations. Figure 3-3 also shows some water used for industrial (oil, gas, petroleum) purposes in the Red Deer and North Saskatchewan River Basin. This could include water for gas plants, petrochemicals and, with respect to the North Saskatchewan River, upgrading.

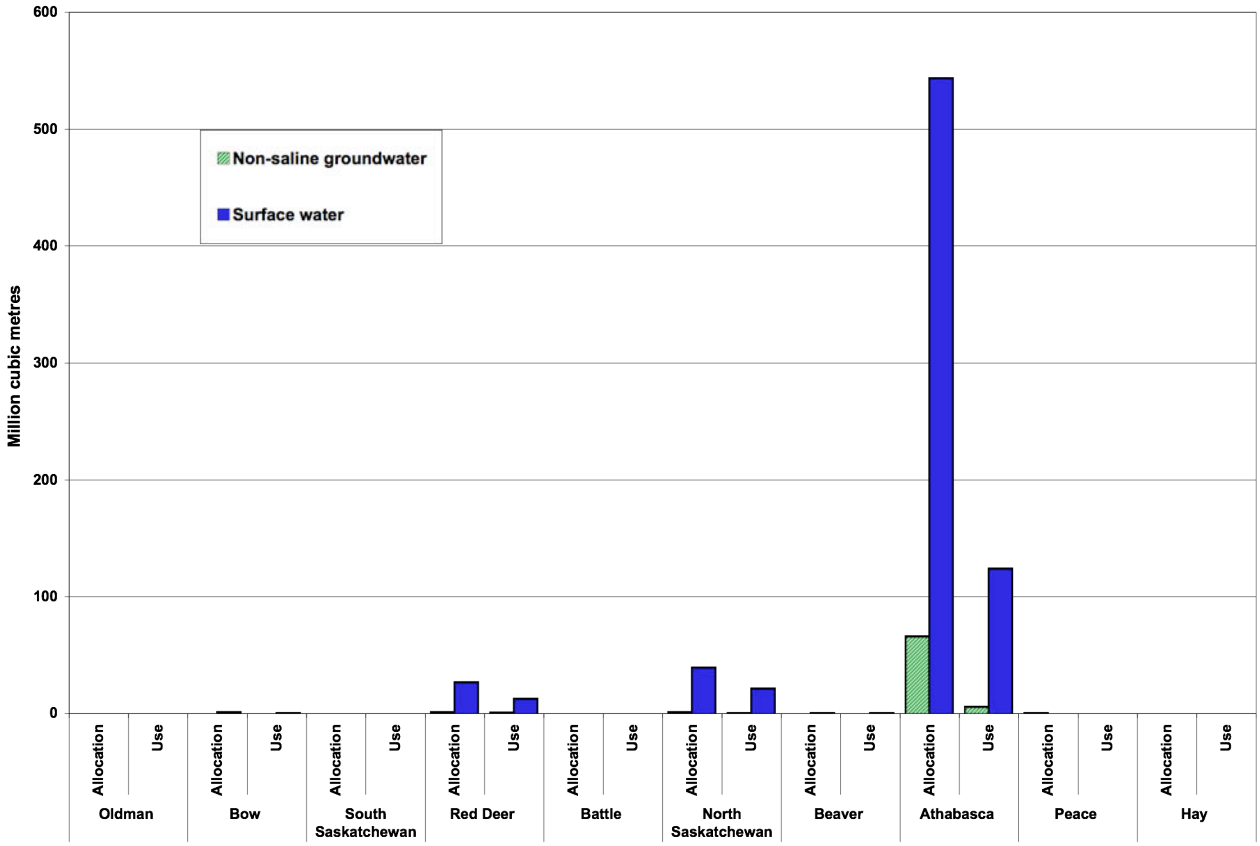

Figure 3-3: Surface Water and Non-saline Groundwater Allocation and Use for Industrial (Oil, Gas, Petroleum) Operations, Including Oil Sands Mining and Upgrading, in Major River Basins in Alberta, 2007

Data Source: Alberta Environment, personal communication, December 11, 2008[155]

Unlike electricity generation, where much of the water is returned to the rivers or lakes from which it was drawn, most of the water for the petroleum sector is actually used, so overall return flows to surface water or groundwater are very small.[156] In the case of well drilling and groundwater use for conventional EOR or in situ recovery, there are no return flows back to the water source. Thus, in 2005 the total estimated water consumption for the petroleum sector was nearly three times that for cooling operations.[157] However, water use varies across the province, with more than two-thirds of all allocations in the Athabasca River Basin for energy operations (see Sections 3.5.2 and 3.5.3). Examining all river basins except the Athabasca, water consumption for cooling (primarily for electricity generation) exceeds water consumption in the petroleum sector.[158]

The actual significance of the petroleum sector varies within each river basin. Concern about the permanent removal of water is greatest in water-short areas of the province.

3.2 Well Development

Well development involves the drilling of a well and, in many cases, fracturing the formation to enable oil or gas to flow more freely to the well bore. Although water for well development is a small percentage of the total volume of water allocated for oil and gas production, well development may impact shallow groundwater in ways of increasing concern if there are droughts as a result of climate change. During 2007, 16,700 wells were drilled in Alberta,[159] and it is possible that the number of wells drilled each year could increase to compensate for declining natural gas production (see Section 3.3.2).

> "Well development seems to be an area of fresh water consumption that has 'flown under the radar screen' because the recorded data represents it as an insignificant percentage of Alberta's fresh water consumption based on allocation. It appears possible that it is not insignificant in relation to the amount of fresh water used for other UPI [upstream petroleum industry] activities which are moving to greater recycle and saline water use. At the moment, it appears that this segment consumes large volumes and sends most of it to deep well disposal, removing it from the fresh water balance."[160]

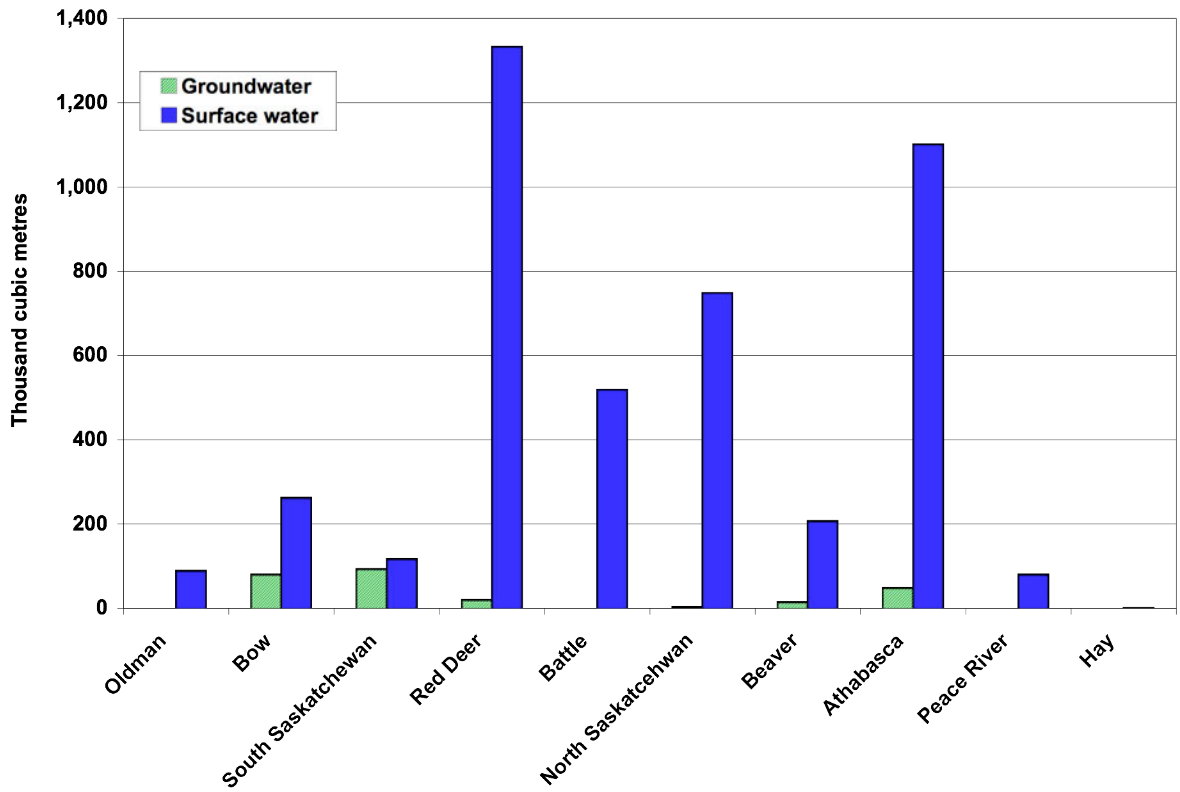

Figure 3-4: Water Allocation for Drilling (Developing Oil and Gas Wells) in Alberta, 2007

Data Source: Alberta Environment, personal communication, December 11, 2008.

Note: The scale of the y axis is in thousands, not millions as in other figures.

A very small proportion of all water allocated in the province is for drilling and fracturing, amounting to 4.8 million m^3 in 2007.[161] Drilling licences are temporary and are usually for a relatively small amount. The average volume of a licence for drilling and fracturing is 19,200 m^3.[162] Much of the water is probably used to fracture unconventional gas wells, such as shale gas, tight gas reservoirs and some coalbed methane (CBM) wells.[163] Figure 3-4 shows water allocation for well drilling and development in the major river basins in 2007. Due to the large number of wells drilled and fractured in central Alberta, the total allocation was largest in the Red Deer River Basin, with the Athabasca Basin coming second.[164] The allocation of non-saline groundwater for well development is greatest in the water-short south, in the Bow and South Saskatchewan River Basins.

The volume of water required for drilling depends on the depth of a well. Approximately 100 m^3 of water may be used to drill a shallow well, but much more is needed for a deeper well. The water is used in drilling mud, which is circulated down the drill pipe to cool the drilling bit and to bring drill cuttings back to the surface and, most important, to maintain the desired pressure in the well bore and prevent communication between zones. To achieve this various substances are added to the drilling mud. If there is loss of circulation (i.e., the drilling mud does not return to the surface), the drilling mud may enter groundwater. If the loss of circulation occurs at shallow depth, contaminants may enter fresh groundwater. These contaminants may be from the water (such as bacteria, if the water for the drilling mud is drawn from a dugout or other untreated source) or from constituents in the drilling mud. How far the contamination might spread depends on the nature of the rock formation and local groundwater conditions.[165]

A well may be fractured with a gas-, water- or oil-based substance. The volume of water used for fracturing may vary widely and this can be an issue in a dry region.[166] It is possible to use recycled water.[167]

The Energy Resources Conservation Board (ERCB) prohibits the use of toxic substances for drilling and fracturing wells above the base of groundwater protection (i.e., where the groundwater is fresh). If a company uses a toxic substance for shallow fracturing where the groundwater is fresh, the ERCB classifies it as a serious offence.[168]

3.3 Natural Gas Production

3.3.1 Introduction

Natural gas resources are becoming depleted and sources of gas are changing, with an increasing proportion coming from unconventional sources, where there may be a greater impact on water than if the gas came from conventional sources. These impacts have been discussed in detail in an earlier Pembina Institute publication.[169] This chapter focuses on those issues of natural gas production specifically relevant to climate change.

3.3.2 Conventional Natural Gas

Conventional natural gas production does not require water, except for drilling wells and fracturing the formation to facilitate the movement of gas to the well bore (see Section 3.2). However, gas production may affect groundwater. Gas naturally pools at the top of a formation, but as it is withdrawn and pressure in the gas “cap” is reduced, water that is lower in the formation becomes mobile and moves up into the gas cap. Thus, as a well ages, some water is produced with the gas. Traditionally, this was saline water and was managed using deep well disposal. Much of the inflow of water is likely to come from elsewhere in the formation, but there could also be natural flow or seepage from other formations that are closer to the surface. Little is known about the volume of water that might be involved or how long it would take to replace the gas. However, calculations suggest that over time a very large volume of water could be needed to meet this "water repressurization debt" and this could impact fresh groundwater where shallow gas has been produced.[170] It is an issue that should be considered, especially where there is a high density of shallow wells, where fresh (non-saline) groundwater might be affected.[171] The impact of recharge could become more serious as a result of climate change.

As gas resources become depleted, more wells are likely to be drilled into shallower formations, where fresh water will be produced with the gas. Alberta Energy is proposing to encourage the drilling of many new wells, to help compensate for the decline in production from deeper sources.[172] As the pressure in shallow gas formations is relatively low, the density of wells required to access the gas will be higher than for deeper gas. Thus there may be eight or as many as 16 gas wells per section (640 acres).[173] This is of concern since there are, at present, no requirements for companies to conduct baseline testing of water wells in the area adjacent to a conventional gas well, and Alberta Environment does not require a company to apply for an approval for the removal of shallow groundwater, except for CBM wells. However, the ERCB requires companies to report water withdrawals from above the base of groundwater protection and can take action to prevent large quantities of water being withdrawn from shallow aquifers.[174]

3.3.3 Coalbed Methane

CBM is natural gas found in coal seams. If a coal seam contains water,[175] it must first be pumped out to reduce pressure so that gas can flow to the well bore. It is important that this water is properly handled, since salts in the produced water can damage soils and vegetation.[176] It is also important to ensure that the withdrawal of water does not impact overlying fresh water aquifers.[177]

> "It is unclear as to what the CBM development impacts will be on provincial aquifers, and what the scientifically based volume of produced water should be from a single CBM well or multiple wells in a specific area. . . ."[178]

In Alberta, produced water from CBM wells is usually sent for deep well disposal. At the time of writing, a company must provide Alberta Environment with a considerable amount of information about the groundwater and water wells in the area of a proposed CBM well and obtain an approval before withdrawing fresh (non-saline) water to facilitate CBM production.[179] Alberta Environment is preparing a Code of Practice to allow withdrawals of a limited volume of water without an approval. Since following the code is likely to be less time consuming than applying for an approval, it may result in the development of more shallow CBM wells where the formation contains fresh water.[180]

In water-short areas there could be interest in using water produced from CBM and other wells. Produced water could be injected into oil wells to enhance oil recovery or the water could be treated to reduce its salinity and used for other purposes. A combination of techniques will probably be required to treat produced water for an appropriate level of use. An approval is currently required to allow the beneficial use of the water but Alberta Environment is preparing a new policy on the beneficial use of water.[181]

3.3.4 Shale Gas and Tight Gas

As gas prices rise, interest in the production of gas from shales and tight gas in Alberta has increased and the number of wells could be growing rapidly. However, since the ERCB does not have a separate code for shale gas or tight gas, it is not known how many wells produce gas from these sources.

Tight gas is produced from reservoirs with low porosity and low permeability; they thus tend to be dry and produce little water. The characteristics of shale formations vary, so it is impossible to generalize; experience in the U.S. shows that some shales produce considerable volumes of water, while others are dry. A large volume of water is used for fracturing some shales in the U.S. and water consumption may also be high for fracturing tight gas wells.[182]

3.4 Conventional Oil Production

3.4.1 Water Production with Conventional Oil

When oil is pumped to the surface, the pressure in the formation gradually declines and some of the water in the formation will also be pumped to the surface with the oil. This is referred to as produced water and the proportion of produced water to oil generally increases as a well ages. The produced water is often recycled back into the zone of origin during the ongoing production of oil to help maintain pressure, and it eventually remains in the depleted reservoir.[183]

3.4.2 Conventional Enhanced Oil Recovery

In EOR in conventional oil reservoirs, water or a gas such as carbon dioxide is injected into an oil well to restore the pressure and enable more oil to be recovered (thus EOR is sometimes referred to as "oilfield injection"). Either fresh or saline water may be used for the waterflood in conventional EOR. The use of fresh water for conventional EOR is of concern, since the water stays in the formation and does not return to the watershed.

> "The energy industry in Alberta developed over the last one hundred years on the assumption of an endless supply of free fresh water. However, over the last five years, the realization that water is a finite resource has caused changes in public opinion and in policy and regulation that is limiting water availability."[184]

A previous Pembina Institute report, *Troubled Waters, Troubling Trends,*[185] showed that the total volume of fresh water used for conventional EOR has been declining for several decades.[186] This is partly because once the formation is re-pressured it is only necessary to replace a volume equivalent to the amount of oil removed, and partly as a result of government policy. Figure 3-5 shows that the decline in the volume of water consumed for EOR has levelled off since 2005. Surface water supplies more than half the water used for conventional EOR, almost a third comes from saline groundwater and nearly one-fifth comes from non-saline groundwater.

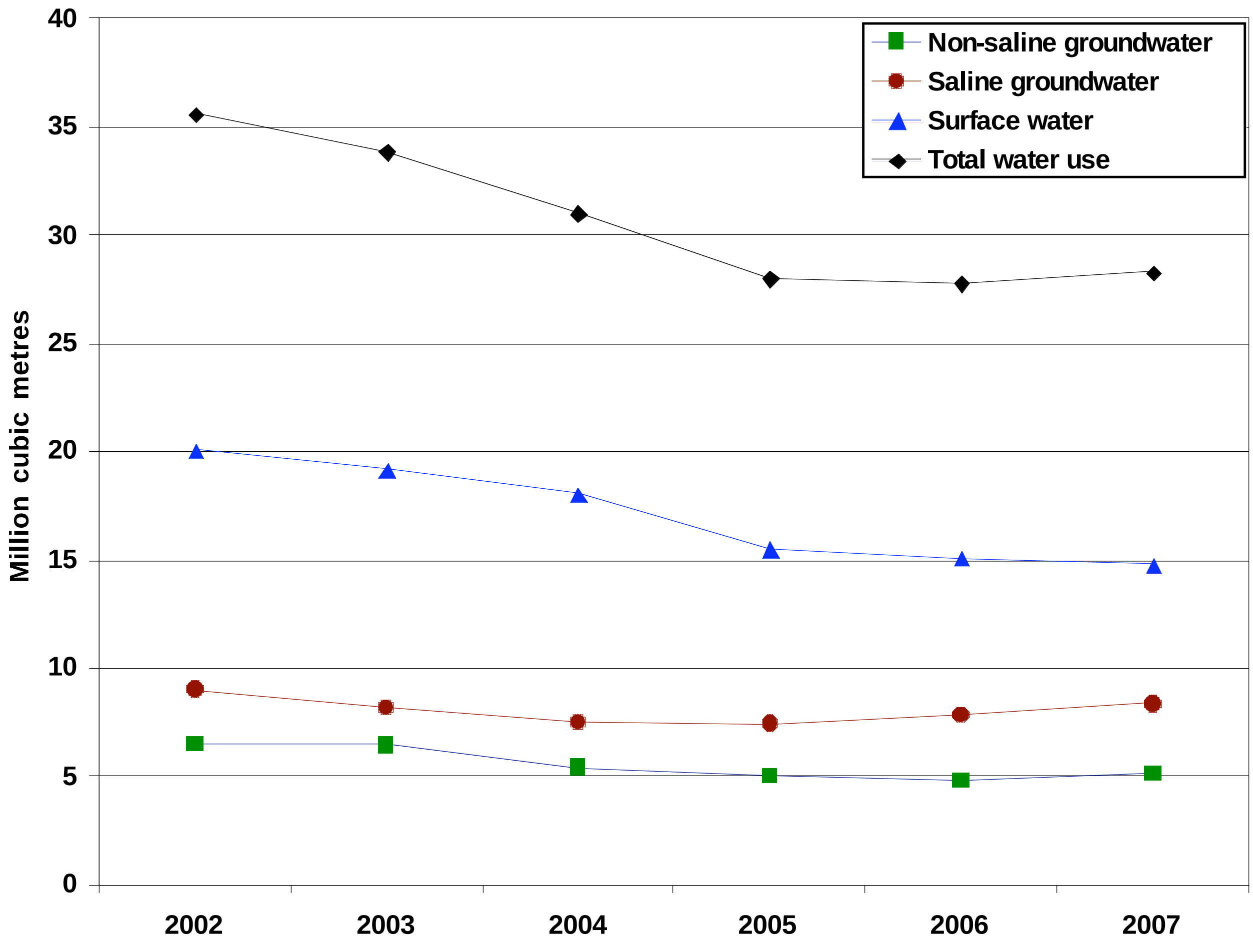

Figure 3-5: Water Consumption for Conventional Enhanced Oil Recovery (Waterflood) in Alberta, 2002–2007 updated

Data Source: Alberta Environment, personal communication, November 7, 2008.

Conventional EOR has traditionally been used in only a small proportion of Alberta's reservoirs, which contained about 35% of the original oil in place, but as oil prices rise there may be some increase in EOR, which would explain the levelling off in water use.[187] A recent study forecasted that the historical decline in the use of water for conventional EOR would continue and that by 2020, this use of fresh water would be close to zero.[188] It is too early to say if this will be achieved. Studies have also been conducted to show the potential volumes of produced water available for use (see Section 4.3.1 below).

Since 2006, a company wishing to undertake any type of EOR using water is required to first look for saline water or other substances before applying for a licence to use fresh water.[189] However, the fact that the total volume of water used for EOR has been static over the period 2005–2007 indicates that on a province-wide scale the new policy is not having any effect. The requirement to search for alternatives must be made more stringent in water-short areas and for projects requiring large volumes of water. Water-short areas encompass all of southern Alberta. As mentioned in Section 1.1, water in the South Saskatchewan River Basin has been over-allocated and no new allocations are allowed for any purpose.[190]

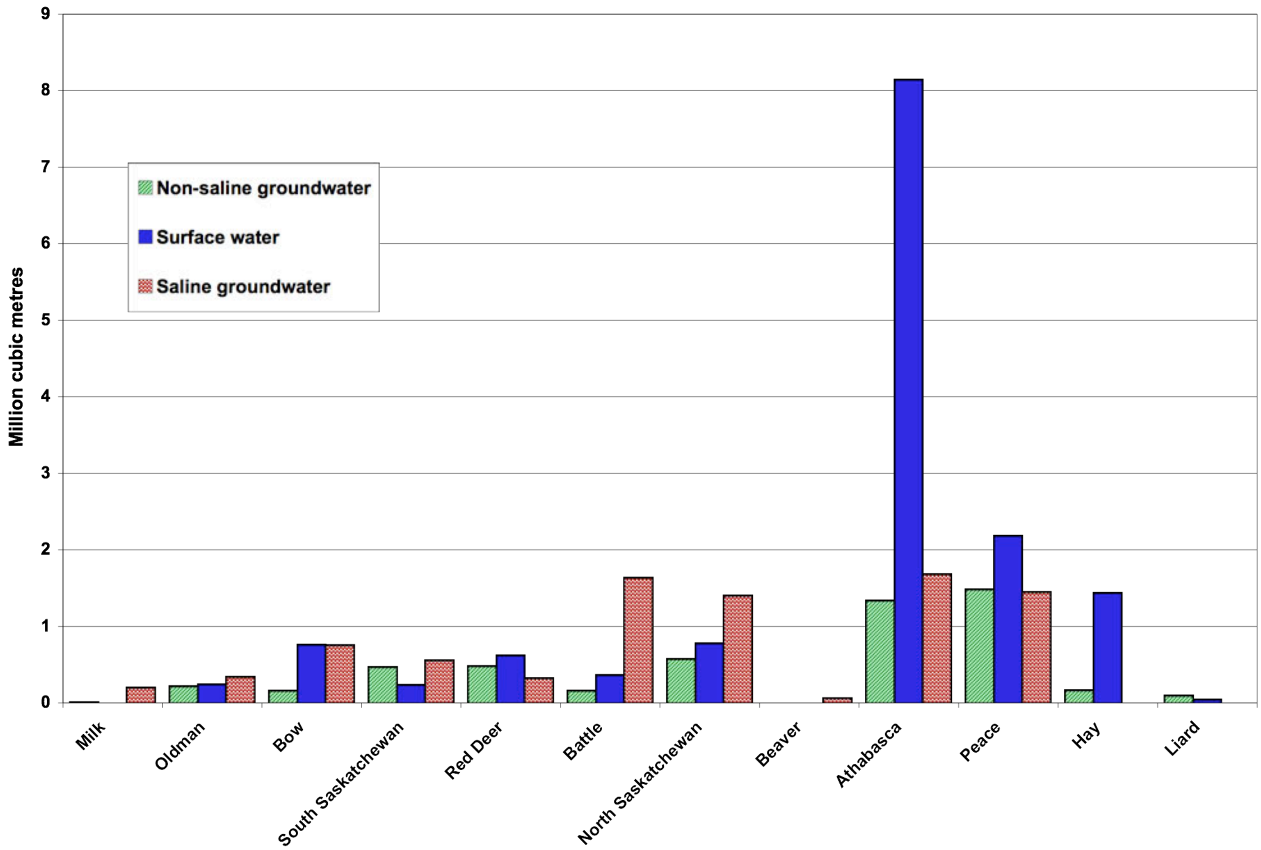

Figure 3-6: Surface Water, Non-saline and Saline Groundwater Use for Conventional Enhanced Oil Recovery in Major River Basins in Alberta, 2007

Data Source: Alberta Environment, personal communication, December 11, 2008.

While Figure 3-2 shows the water allocation and use for all types of EOR (conventional EOR and in situ) in river basins in Alberta in 2007, Figure 3-6 shows the use for only conventional EOR. As a result of the adjusted scale on the latter graph, it is easier to read the data and possible also to show the Milk and Liard River Basins (for which the values were too small to depict in Figure 3-2). Fresh water use for EOR in the river basins of southern Alberta is small, relative to the total water use, but the watersheds are short of water, so the use of fresh water for conventional waterflood should be phased out.

3.5 Oil from Bitumen

3.5.1 Introduction

Oil sands deposits containing bitumen underlie about 140,000 km^2 of Alberta, which is about one-fifth the area of the province or an area approximately the size of Florida. Within this area, the thickest, most economic bitumen deposits are being developed first. Large quantities of water are required to extract the bitumen, with the volume and source of water used depending on the depth of the deposits. Where the bitumen is less than 75 metres deep, it is economic to mine, but at greater depths it is extracted through in situ operations.[191] Only about 20% of oil sands production is expected to come from surface mining operations.[192] Within Alberta, approximately 500 km^2 of land is currently disturbed by oil sands surface mining activity;[193] this is located on either side of the Athabasca River. In situ operations extend over wide areas, not only in the Athabasca River basin, but also in the Cold Lake and Peace River regions. In 2007, crude bitumen production from the oil sands averaged 1.3 million barrels per day (bb/d);[194] given that this is expected to triple by 2020, the impacts on water will be huge.

> "By 2020, [oil sands] production is expected to grow to almost four million barrels per day."[195]

The use of water and the impacts of bitumen mining and in situ extraction on water resources have been described in another Pembina Institute report.[196] This report serves to update the information and focus on the impacts likely to result from climate change.

3.5.2 Oil Sands Mining

> "One of the biggest environmental concerns is with the amount of water used in the oil sands and the impact of developments on both the quality and quantity of water. . . . Over the long term the Athabasca River may not have sufficient flows to meet the needs of all the planned mining operations and maintain adequate instream flows."[197]

It requires between approximately two and four barrels of water to produce a barrel of synthetic crude oil from mining operations.[198] Companies that have been operating for some time have gradually reduced their average water requirements, but a new project is likely to require more water than an established operation, since it may not be able to recycle as much water in the early stages of development.

Very large quantities of water are removed from the Athabasca River to extract the bitumen from the sand and upgrade it to produce synthetic crude oil. As noted earlier, more than two-thirds of all water allocations from the Athabasca River Basin are for energy development, most of it for oil sands mining operations and a smaller volume for in situ operations. In 2007, the water allocation for oil sands mining operations in the Athabasca Basin was more than 550 million m^3/year.[199] Of this nearly 80% was allocated from the Athabasca River, with the remainder coming almost equally from groundwater and surface runoff.[200]As mentioned earlier, the City of Edmonton treated about 130 million m^3/year of water for a region containing about one million people, but consumed less than one-tenth of that amount.[201] The allocations for the seven companies with licences for mining bitumen are shown in Figure 3-7. The actual volume diverted from the Athabasca River in 2007 was 129 million m^3. This was equal to roughly one-fifth of the maximum allocation; two companies had not started diverting any water and two more were in the early stages of operations.[202] Thus, although the allocations have been made, it is not yet possible to observe the impacts of maximum allocations on the Athabasca River. Recent licences for oil sands mining operations do not require any return of water to the Athabasca River.[203]

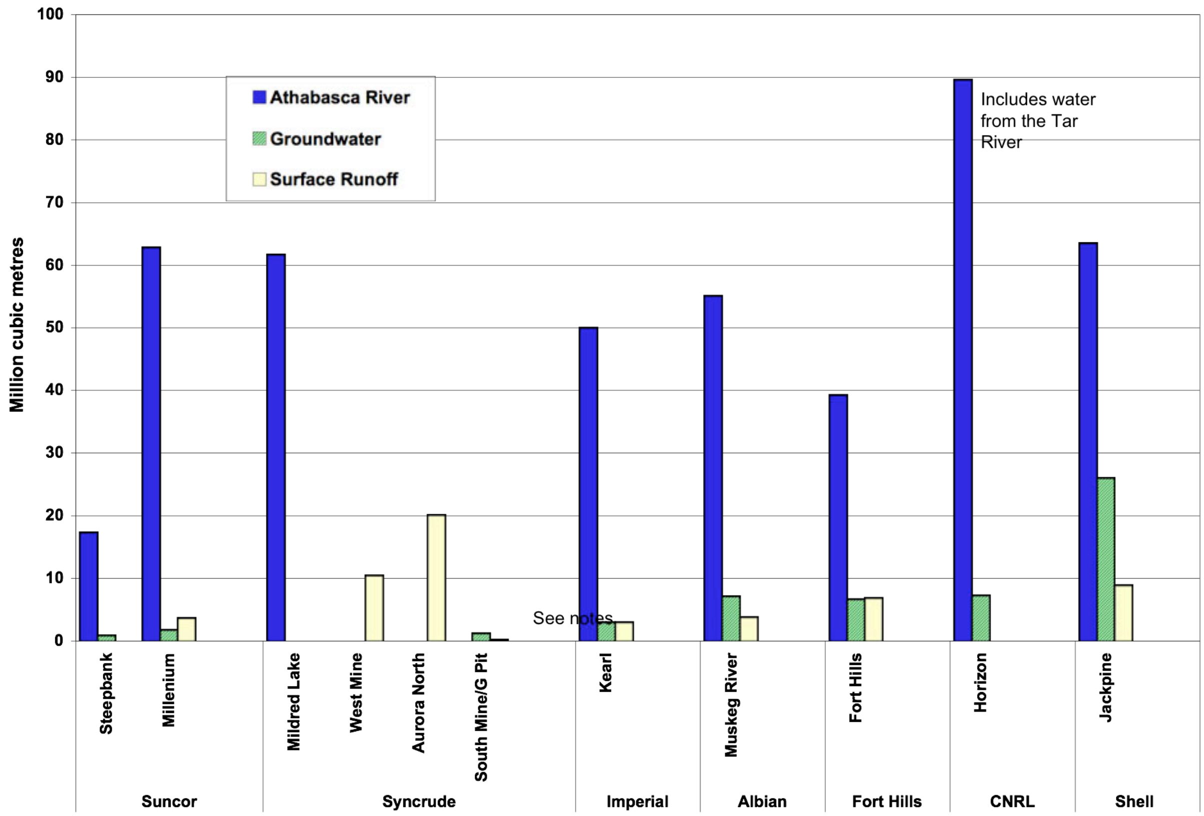

Figure 3-7: Maximum Water Allocation for Oil Sands Mining Operations, 2007

Data Source: Alberta Environment, personal communication, December 11, 2008

Note: See endnote for further explanation.[204]

The volume of water in the Athabasca River Basin appears to be declining. The Athabasca glacier has shrunk by about one quarter in the last 100 years[205] and with ongoing climate change the water provided in early summer by the melting of ice and snowpacks is expected to decline significantly. The spring melt will occur earlier, which will further reduce summer flows.[206] One study shows that summer catchment runoff at all monitoring stations on the Athabasca River below Hinton has declined by about 50% in the last 30 years.[207] The magnitude of this reduction in summer flow is due to the fact that the 1970s were a relatively wet decade. Although summer flows are declining, there does not appear to be a significant trend in annual flows over the last 80 to 90 years.[208] The observed reduction in summer flow in recent decades in the Athabasca River may be related to climate warming and drought as well as to changes in activities within the basin. It has been suggested that the decline could in part be due to "natural gas development, logging, access road construction and beaver trapping, and not just the impacts of climate change and measured withdrawals."[209] The reduction in beaver trapping from historic levels results in more beaver dams, which change the hydrology in river basins. Beaver dams create ponds that help maintain wetlands in time of drought.[210]

It has been pointed out that, based on the projected water requirements of fully developed oil sands projects (11.2 to 19 m^3/sec), the water resources of the Athabasca River would sometimes have been inadequate during the flow regimes of the last 25 years and that "even at the lower end of the water withdrawals from oil sands projects, there would have been 10 times during the past 25 years when the minimum flows of the Athabasca River would have been insufficient to avoid short term impacts on ecosystems. For longer term ecosystem impacts, the recommended water restrictions on oil sands project withdrawals indicate that minimum flows would not have met full development needs in 34 of the past 35 years."[211] The upper limits for water demand have been revised, but they are still high.[212]

> "… it is noteworthy that current and approved withdrawals would already put the river in 'red' zone conditions for several months in winter during low flow years."[213]

When the flow in a river declines, it is likely to impact the fish and water quality. The river flow required to keep a river healthy is referred to as the instream flow needs (IFN). Research is not complete to determine the actual IFN of the Athabasca River, but the provincial and federal governments have established an interim Water Management Framework while further research is undertaken.[214] This is based on historic flows in the river and does not take climate change into consideration.[215] The framework identifies green, yellow and red flow regimes, which are designed to manage the increasing risk of impacts associated with declining river flows, and limits withdrawals to a certain percentage of flow in each category. The framework permits some withdrawals even during red zone conditions, when impacts are "potentially significant and long-term."[216] The Pembina Institute believes that water withdrawals of any kind should not be allowed during red conditions, except for those related to domestic and safety needs.[217]

> Even in the red zone, "the Framework still allows industry to collectively withdraw a large volume of fresh water, between 8 and 15 cubic metres of water per second, or enough to fill between 25 and 50 bathtubs each second."[218]

In a second phase the Water Management Framework will identify any changes required to meet long-term environmental and socio-economic goals, but it is not stated whether it will incorporate potential impacts due to climate change. However, several climate models indicate that minimum flows are likely to decline by a further 7% to 10% in the next four decades.[219]

Low flows in the Athabasca River impact both the river itself and areas downstream of Fort McMurray, especially the Peace–Athabasca Delta, a world heritage site where the two rivers enter Lake Athabasca.

> "The vast Delta wetlands are already exhibiting negative effects of declining water supply from climate change and the Bennett Dam on the Peace, but large industrial oil-sands projects in the Athabasca drainage and reservoirs on the Peace River continue to be proposed and approved."[220]

The mining operations not only use large volumes of water from the Athabasca River, they also impact groundwater.[221] Much of the surface overlying the bitumen is covered by muskeg, wetlands and peatlands, which must be drained before the overburden can be cleared to access the bitumen. This naturally impacts surface flows in the area. Once a mining area is reclaimed, there will be larger areas of dry uplands and peatlands will be replaced, to a certain extent, by other types of wetland. With the area of natural sponges reduced, there will be more rapid runoff to the rivers and an impact on groundwater levels. This could, in turn, also affect the Athabasca and other rivers.[222]

Another major water concern associated with oil sands mining is the tailings ponds. The tailings ponds are actually large lakes covering approximately 130 km^2 that contain wastewater from oil sands mining operations.[223] This wastewater is contaminated with toxic substances, such as naphthenic acids, polycyclic aromatic hydrocarbons, arsenic, mercury and several toxic trace metals. It can leach into groundwater, a resource that may become increasingly important as a result of climate change. Although some water from the tailings ponds is recycled and research is under way to extract more water from tailings, there is currently no solution that avoids the construction of tailings ponds.

Given the increasing volume of water required for expanding oil sands operations and declining river flows, finding ways to extract water from tailings is essential.[224] Moreover, as a result of climate change, "extreme precipitation events could cause overflows and spillage of contaminated or fresh water in storage."[225] A very large area could be affected if tailings ponds were to leak or overflow due to extreme climate events.[226]

3.5.3 In Situ Oil Sands Production

Over 90% of the bitumen resource in Alberta is too deep to mine. In situ extraction involves drilling wells through the overburden. In many cases steam is injected to reduce the viscosity of the bitumen so that it can be pumped to the surface, but waterflood can be used in some locations.

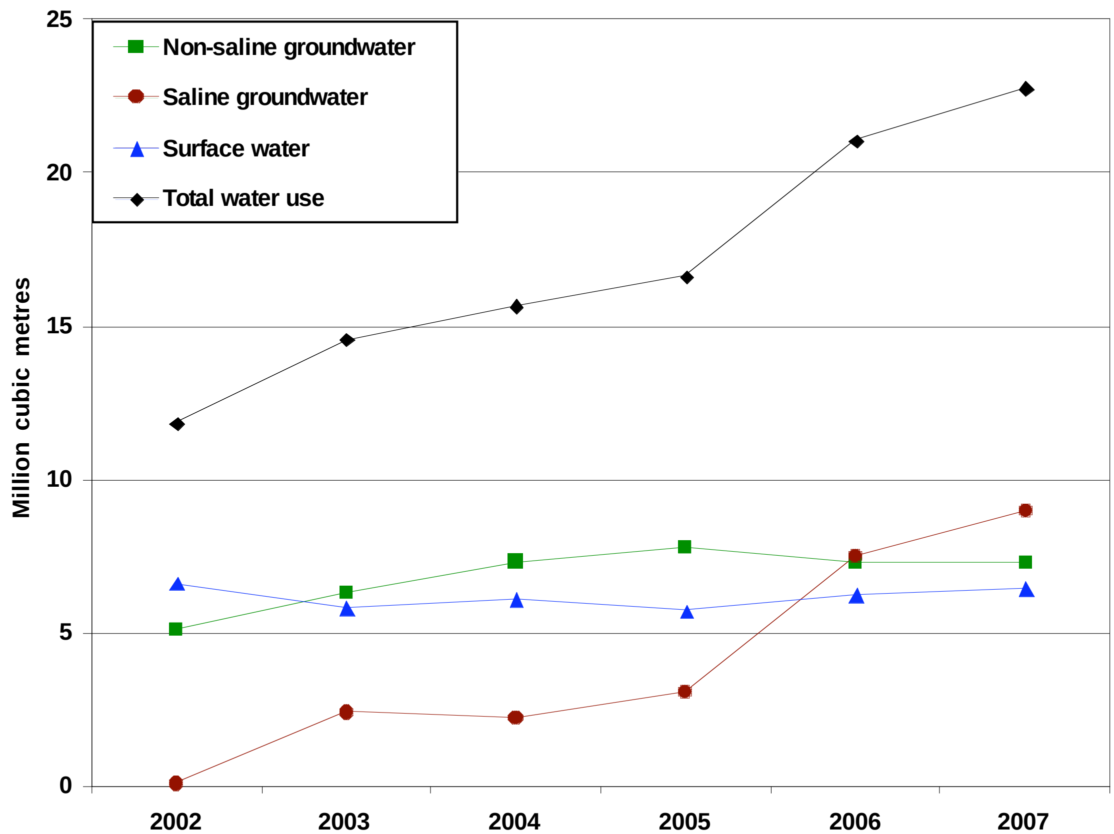

Figure 3-8: Water Consumption for In Situ Thermal Production of Bitumen in Alberta, 2002–2007

Data Source: Alberta Environment, personal communication, November 7, 2008.

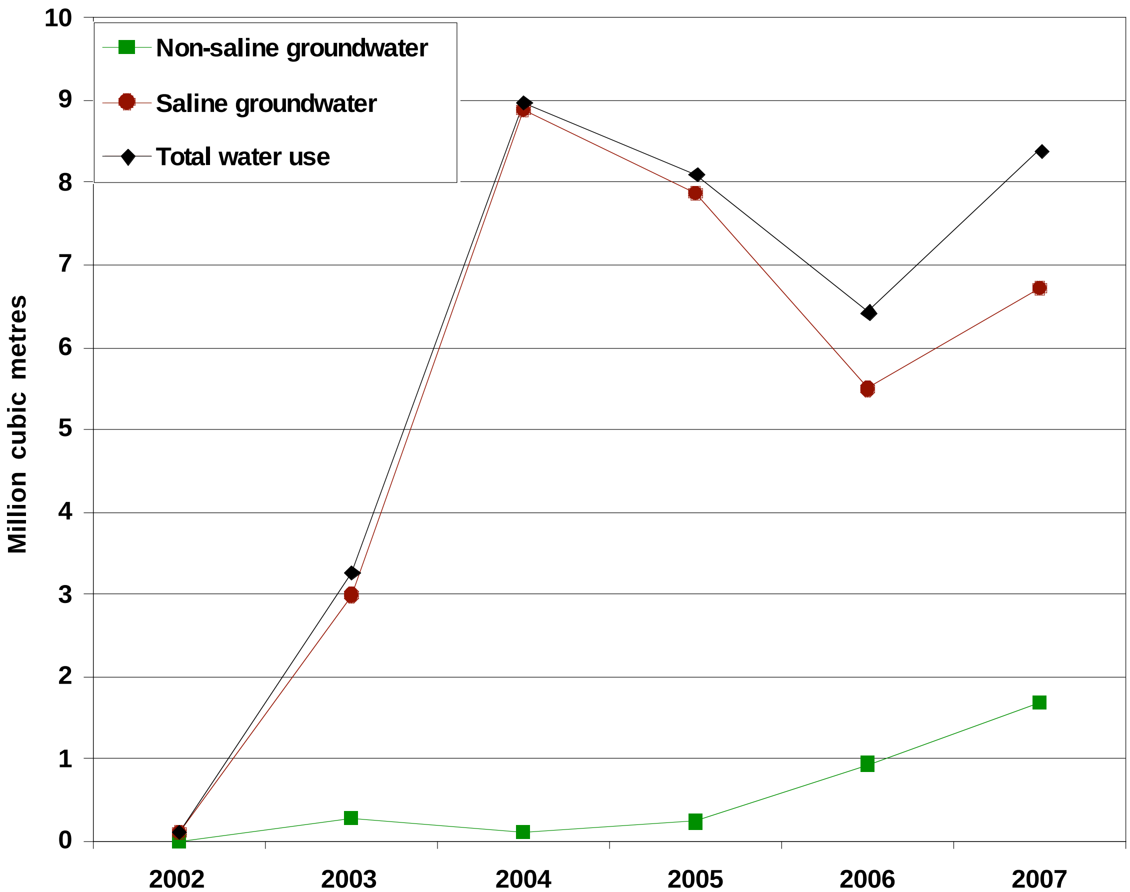

Figure 3-9: Water Consumption for In Situ Production of Bitumen in Peace River Basin Using Waterflood, 2002–2007

Data Source: Alberta Environment, personal communication, November 7, 2008.

Figures 3-8 and 3-9 show the volume of water used for the recovery of bitumen in Alberta between 2002 and 2007. During that time the volume of water used for thermal recovery almost doubled and in 2007 nearly 23 million m^3 was used to generate steam for in situ recovery of bitumen. Although growth in the use of saline water has been greatest, the use of non-saline groundwater increased by over 40% between 2002 and 2007. Non-saline water accounted for almost one-third (32%) of the water used for in situ thermal recovery in 2007, while saline groundwater made up 40%.

Even more dramatic has been the increase in water consumption for in situ bitumen recovery using waterflood. Waterflood, which is similar to conventional EOR, can be used to produce bitumen in some reservoirs where the bitumen is not too viscous. Some bitumen in the Peace River Basin is in this category. Figure 3-8 shows that in 2007 over 8 million m^3 of water was used for waterflood to extract bitumen and that the use of non-saline groundwater has been increasing, accounting for 20% of all water used for waterflood in 2007.

The two graphs show that, although it was known that Alberta Environment intended to introduce a policy requiring companies to look for alternative sources before applying to use fresh water for in situ production of bitumen,[227] the 2006 policy had not yet been effective in reducing the use of fresh groundwater by the end of 2007.

Figures 3-2 and 3-6 show the water allocation and use in all river basins in the province. The data in Figure 3-10 provide slightly more detail by distinguishing between various types of injection — conventional EOR, in situ thermal and in situ waterflood — in the three basins where in situ production of bitumen occurs: the Beaver, Athabasca and Peace River Basins.

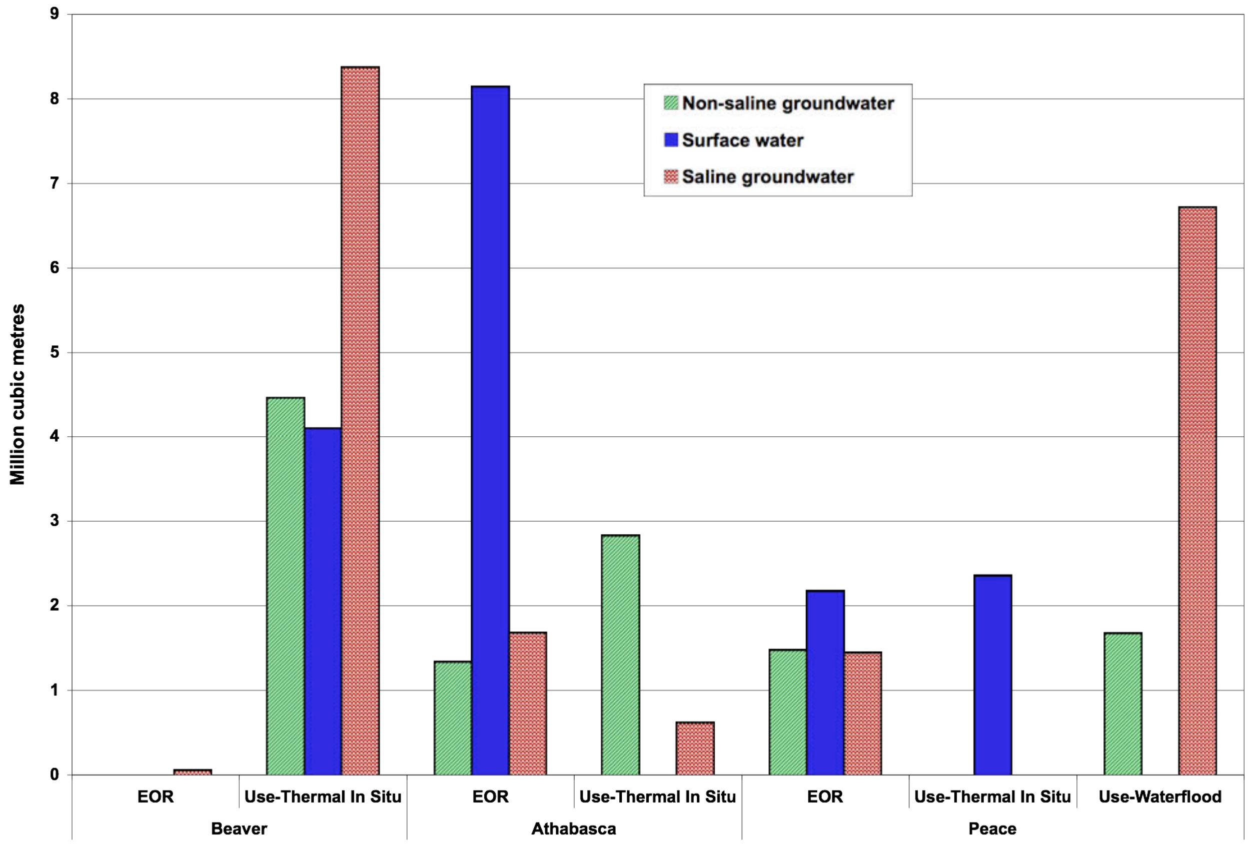

Figure 3-10: Water Consumption for Oilfield Injection (Conventional Enhanced Oil Recovery and Thermal and Waterflood In Situ Production of Bitumen) in the Beaver, Athabasca and Peace River Basins, 2007

Data Source: Alberta Environment, personal communication, November 7, 2008.

The greatest volume of non-saline groundwater is used for the in situ production of bitumen in the Beaver River Basin, but about half of all water used for bitumen production in that basin in 2007 was from saline sources. Saline water is used for waterflood in the Peace River Basin but some non-saline water is also used. Of note is the fact that in the Athabasca River Basin, about 80% of the water used for the thermal recovery of bitumen is non-saline groundwater. Given the fact that many more in situ thermal projects are developing in the Athabasca River Basin, this use of fresh groundwater is a trend that must be carefully watched. The impacts of in situ operations on shallow non-saline groundwater occur over a wide area and add to the impacts on groundwater from oil sands mining operations along the Athabasca River. Companies must be required to look very carefully for alternatives to non-saline groundwater.

Fresh water used for in situ operations is permanently removed from the watershed. Although most of the injected steam is pumped back to the surface as water with the bitumen, some remains in the formation. Before the water is recycled to generate more steam, it must be treated to remove contaminants and the residual from the treatment process is either sent for deep well disposal or, in some cases, to landfill. Thus, a constant supply of make-up water is required. Where fresh groundwater is used, it will gradually be recharged by precipitation and inflows from other areas, but it is estimated that it will take decades for an aquifer to recover after in situ operations and water withdrawals cease.[228] Although companies estimate the length of time it will take aquifers to recover, “it is very difficult to measure natural groundwater recharge rates.”[229] It is even more difficult to anticipate the effect of climate change on the rate of recharge. While the impact of one well may be small, the cumulative impact of a large number of in situ operations, each operating for 30 to 40 years, could be huge.[230] Each project is assessed separately, and there is not yet a model to analyze the interactions of surface water and fresh groundwater and cumulative impacts over a wide area.[231] Moreover, some aquifers are found in narrow buried glacial channels, which were formed by meltwater during one of a number of glaciations that covered the region. These channels are of great significance because they provide important water reservoirs, but the recharge rates in each one needs to be carefully evaluated.[232]

In addition to reducing the flow in fresh water aquifers, leaks from in situ wells pose a risk of contamination. A leak may result from a casing failure or a failure in the caprock, which allows steam and bitumen to escape into fresh water aquifers.[233]

Although much of the area underlain by oil sands currently has relatively few settlements, and farming activities are mainly in the Cold Lake[234] and Peace River areas, there is likely to be an extension of the agricultural zones to the north as a result of climate change. Thus, in the future, the importance of clean, uncontaminated fresh water aquifers will be even greater than at present.

3.5.4 Upgrading in Central Alberta

The bitumen produced from the oil sands is a viscous tar-like substance. In most cases it has to be upgraded to synthetic crude oil before it can be used. Upgrading is integrated into the production process at mine sites, but some of the bitumen produced in northern Alberta is sent elsewhere for upgrading. As of February 2009, one upgrader was operating northeast of Edmonton and construction had started on two more. The recession that began in the second half of 2008 may affect how many upgraders ultimately proceed, but another has been approved and several applications are pending, as described in another Pembina Institute publication.[235] Water used for upgrading in the Edmonton area is taken from the North Saskatchewan River and is included in the industrial (oil, gas, petroleum) category, shown in Figure 3-3, above.

As with the production of bitumen, the upgrading process consumes a large volume of water. If all eight upgraders proceed as originally planned, they could require about 114 million m^3 of water a year, of which about 80 million m^3 would be consumed. This is about 10 times as much as is currently consumed by the City of Edmonton.[236] Water for the upgraders will come either directly or indirectly from the North Saskatchewan River and will thus reduce river flows. Due to concerns that the removal of large withdrawals of water will harm the health of the river, Alberta Environment has set limits on the volume that may be withdrawn during low flow periods, but will still allow some water to be withdrawn even during low water conditions.[237] The construction of two dams in the upper reaches of the river several decades ago helps to stabilize flows, but, as with other rivers in Alberta, the long-term flow is likely to continue to decline or become more variable as a result of climate change, the increasing demands of industry and a growing population in the region.

3.6 Future Water Demands for the Oil and Gas Sector

The future fresh water demand for the upstream petroleum industry (that is, the production of oil, bitumen and gas) has been examined in a 2008 feasibility study, *A 2020 Fresh Water Neutral Petroleum Industry*.[238] The province-wide data in Figure 3-11 estimates future water demand (consumption) by using the forecast growth in oil, bitumen and gas production, water consumption ratios for oil/bitumen production, and water use to gas production relationships. The huge increase in demand for water for bitumen production is clearly evident. The largest volume of water will be tied up in the tailings ponds, but increases are also predicted in the volume of water used in oil sands processing. The volume of water for EOR shows a continuous decline. After increasing somewhat, it is predicted that the volume of fresh water for in situ recovery will decrease. Noteworthy is the expectation that the volume of water used for well development will increase several fold. This is based on the assumption that all water for well development is consumed and that "the use of fresh water will increase at the rate at which unconventional gas production increases since large unconventional gas well stimulations will potentially have the greatest water demand of all the development well activities."[239] Since much unconventional gas development is likely within agricultural regions, this is of special concern.

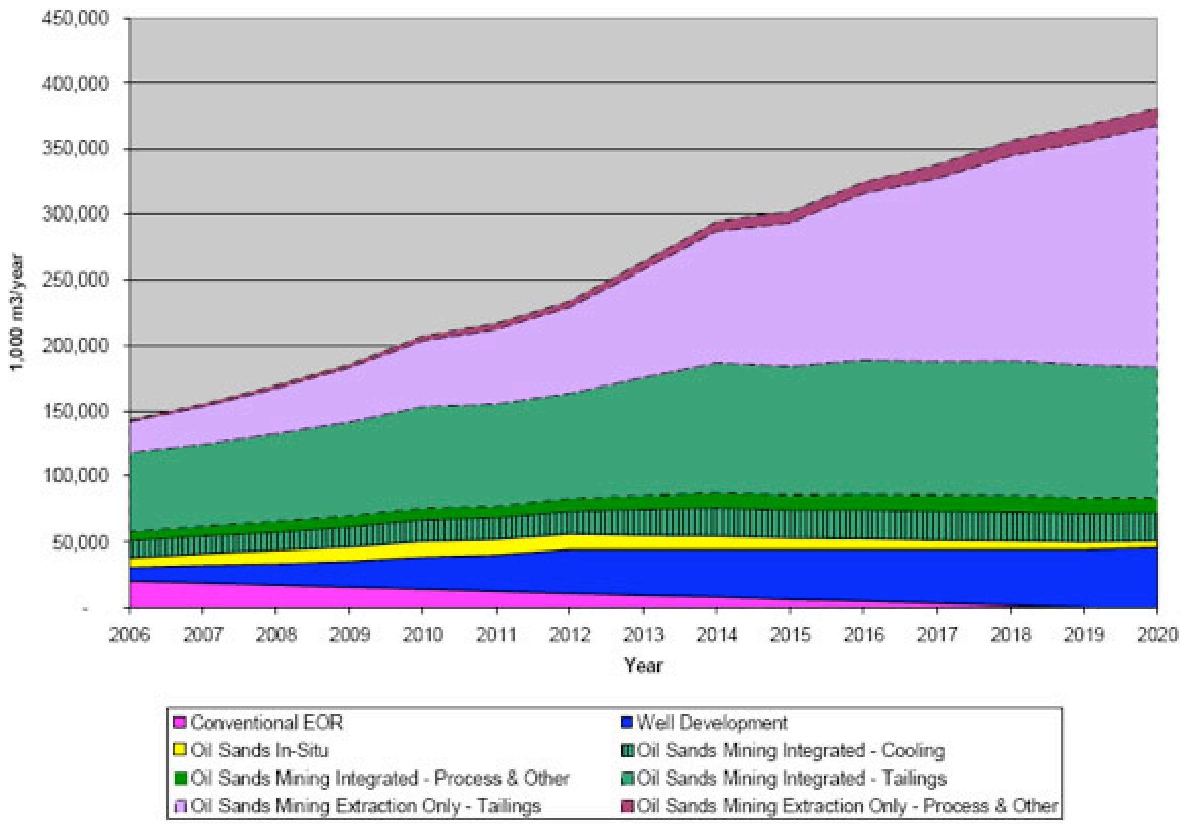

Figure 3-11: Fresh Water Demand (Consumption) by the Upstream Petroleum Industry, Forecast 2006–2020

Source: Alberta Energy Research Institute[240]

The province-wide data in Figure 3-11 provides more detailed categories on a province-wide basis than does the Alberta Environment forecast for future water use in *Current and Future Water Use in Alberta,* referred to in Chapter 1 (Figures 1-6 and 1-7), above. Both expect a huge increase in water consumption for oil sands mining,[241] but there is some discrepancy with respect to future expectations for in situ production. Alberta Environment's medium growth scenario predicts an increase in the consumption of fresh water for thermal recovery in both the Athabasca and Peace River Basins, which exceeds the expected decline in the Beaver River Basin (see Figure 1-7). Figure 3-11 forecasts that the total fresh water consumption across the province for in situ recovery will peak in about 2012 and then decline.[242] Which of these scenarios is likely to be closest to reality will depend on how rapidly saline water or other processes are used to replace fresh water for in situ operations. This, in turn, will depend on various factors. For example, an increase in the use of saline water means deeper wells and higher energy use (often with an associated increase in air and GHG emissions). If the saline water must be treated before use there will also be a waste stream, which will be sent to landfill or for deepwell disposal, creating other impacts and costs.

The next chapter suggests how fresh water use can be reduced in all energy sectors.

4. Implications for Alberta's Energy Production

4.1 Potential Impacts on the Environment

The previous chapters have shown that energy production can use large quantities of water. The impacts on rivers and groundwater vary across the province. Water supplies have already been over-allocated in the South Saskatchewan River Basin, a region that will become increasingly dry as a result of climate change. The use of water for drilling wells and EOR is coming under increasing scrutiny, especially in central and southern Alberta, and landowners are concerned that CBM development could impact groundwater resources.

> "If climate change results in lower precipitation in the southern regions, as predicted, water shortages could become acute very quickly."[243]

In central Alberta, a growing population, continuing demand for water for fossil fuel electricity generation and increasing demand for water for upgraders are likely to place a strain on the North Saskatchewan River.

In the northern part of the province, the production of bitumen from the oil sands is already using a large volume of surface water and groundwater in both the Athabasca River Basin and in the Cold Lake region, which is drained by the Beaver River. There are also concerns about the impact on water quality. People living downstream of the oil sands operations are very concerned about the potential impacts of mining operations on the watershed and their health. Chiefs representing the nations covered by Treaties Six, Seven and Eight in Alberta "unanimously passed a resolution calling for a moratorium on all new tar sands approvals 'until Treaty First Nations have approved a comprehensive watershed management plan and resource development plan for the region.'"[244]

> "Michael Miltenberger, who is N.W.T. deputy premier and minister of environment and natural resources, said his government is worried about oilsands and other developments on the Athabasca and Peace Rivers and the impact they have on the Mackenzie River Basin. 'We're very concerned and committed and recognize the need for watershed management,' he told a water conference in Fort Chipewyan."[245]

In addition to developments in the Athabasca River Basin, expansion of oil sands production in the Peace River region will require more water than in the past. Local people worry that a proposed huge nuclear energy facility could also seriously impact water resources.

The impact of changes in water availability is most clearly seen in river flows. Changes in the availability of groundwater, while less obvious, will be of enormous consequence, since approximately 90% of rural Albertans rely on groundwater for their supplies.[246]

Alberta Environment has approximately 200 groundwater monitoring wells across the province.[247] This is about half the number that were in use in the early 1990s,[248] and only one-third the number used in the province of Manitoba.[249] A good monitoring network is needed not only to gauge water levels but also to identify problems with water quality. Unfortunately, "the existing groundwater monitoring system does not offer an adequate coverage of major aquifers most vulnerable to groundwater contamination."[250] The Rosenberg International Water Forum expressed the view that, "The existing network of groundwater monitoring is insufficient to provide reliable information on water quality and water levels and their variability."[251]

> "The development and projected exploitation of oil sands and coal bed methane are likely to pose special threats to both groundwater quantity and quality. These threats will be exacerbated unless both public and private stakeholders remain fully accountable for any adverse environmental consequences that result from their activities."[252]

Water shortages have already led to approvals of four inter-basin transfers of water.[253] Such transfers help by supplying communities short on good quality water, but will increase pressure on the rivers from which the water is drawn. As demand for water continues to increase dramatically and is already creating shortages, climate change means that supplies are likely to continue declining and become more variable.

The Alberta Water for Life strategy set an overall goal to increase the efficiency of water use by 30% between 2005 and 2015.[254] Work is in progress to establish individual sector goals, but the conservation, efficiency and productivity plans for the power generation and oil and gas sectors are not due until December 2010.[255] However, while efficiency goals are a first step, with the huge expansion of oil sands production, the demand for water will continue its steep upward trend unless more drastic efforts are made to limit water consumption. Wetlands are extremely important in regulating water flows and the recharge of aquifers. After three years of deliberations, the Alberta Water Council has proposed a wetlands policy for Alberta,[256] but at the time of writing it is not known whether the government will endorse it as written, as two industry organizations representing the oil sands submitted non-consensus letters.[257]

> "We have options, but the past is not one of them."[258]

The rest of this chapter examines ways in which the use of water can be reduced.

4.2 Electricity Systems that Use Less Water

The cooling systems for fossil fuel energy usually require the diversion of large quantities of water, so one way to reduce water use in the future is to develop more electricity from renewable sources. In fact, this is a double benefit, since it not only reduces water use but also GHG emissions, which contribute to climate change. Wind energy has great potential. Geothermal energy needs more attention and there are likely to be niche opportunities for photovoltaics. Run-of-river hydropower depends on the volume and timing of river flows, which may be affected by climate change.[259] There is scope for run-of-river hydro in Alberta, but more work is needed to determine the potential.[260] The Alberta Energy Research Institute is working to increase the proportion of Alberta's electricity needs met by renewable sources from 11% (in 2008) to 20% in 2020.[261] A new report by the Pembina Institute shows that, "Clean renewable and transitional energy resources in Alberta are more than capable of meeting future demand, even if electricity consumption doubles over the next 20 years."[262]

Given the large potential for renewable energy, and the large water requirements for nuclear power (quite apart from the issues around the risk of radioactive contamination and nuclear waste), there is no justification for considering the development of nuclear energy in the province at this time.

A shift from coal to natural gas for generating electricity will result in a reduction in water use. The benefit is even greater in high thermal efficiency cogeneration units, which use steam for industrial processing, instead of condensing it. There has been a large increase in cogeneration since deregulation.[263] If there is a price on carbon emissions, cogeneration projects that were previously considered uneconomic may become viable and contribute to reducing electricity production and probably water use.[264] Where there are stand-alone coal-fired power plants, opportunities should be sought to utilize the waste heat (e.g., for district heating), rather than dissipate it all through cooling.[265]

"As energy costs increase and water availability decreases more efficient power generation technologies are becoming viable."[266]

It has been estimated that at present approximately one-fifth of electricity sales in Alberta go to upstream oil and gas operations for pumps and compressors.[267] Much of this power is used to pump out water and oil at conventional oil operations at over 100,000 sites across the province. It may be feasible to use natural gas for distributed generation/cogeneration at large produced water sites. Locally generated gas-fired power would use less water than electricity from centralized coal-fired power plants. An added benefit is that loss of power would not occur during transmission. Using the gas on site also saves the energy that might otherwise be used to compress the gas for piping.[268]

4.3 Reducing Fresh Water Use in the Oil and Gas Sector

The upstream oil and gas sector (also referred to as the upstream petroleum industry, UPI), recognizes that water is a finite resource and that both public opinion and government policy call for industry to minimize and eliminate its use of fresh water. The feasibility study, *A 2020 Fresh Water Neutral Petroleum Industry*, considered how water use could be reduced by

- reducing consumption (i.e., cutting demand)
- increasing and improving the use of recycled water
- recovering produced water for beneficial reuse (i.e., increasing the supply).[269]

The study identifies existing and developing technologies that could reduce fresh water use. These include the use of carbon dioxide to reduce the use of water for EOR, the beneficial reuse of produced water and reductions in the use of water for oil sands mining operations. The potential impact of introducing these technologies is summarized in Figure 4-1. It appears that the predicted water use could be reduced by three-quarters, using technologies that are already commercial (the green bars in the graph). Whether it is possible to reduce the net use of fresh water to almost zero will depend on regulatory requirements and economic conditions, as well as on the application of "Generation 1" technologies, which exist today, and the development of "Generation 2" technologies to treat highly contaminated, very saline water.[270] It must be noted that the study does not distinguish between produced water, which is available for treatment and beneficial reuse, and produced water, which needs to be re-injected to maintain pressure in the formation and enable more oil to be recovered.[271]

> "In the management of Alberta's economy, water should be viewed as being every bit as important as oil. Evolving water policy should be proactive in anticipating the needs and demands of a growing economy rather than simply providing reactive response to resource development and population growth and pressures."[272]

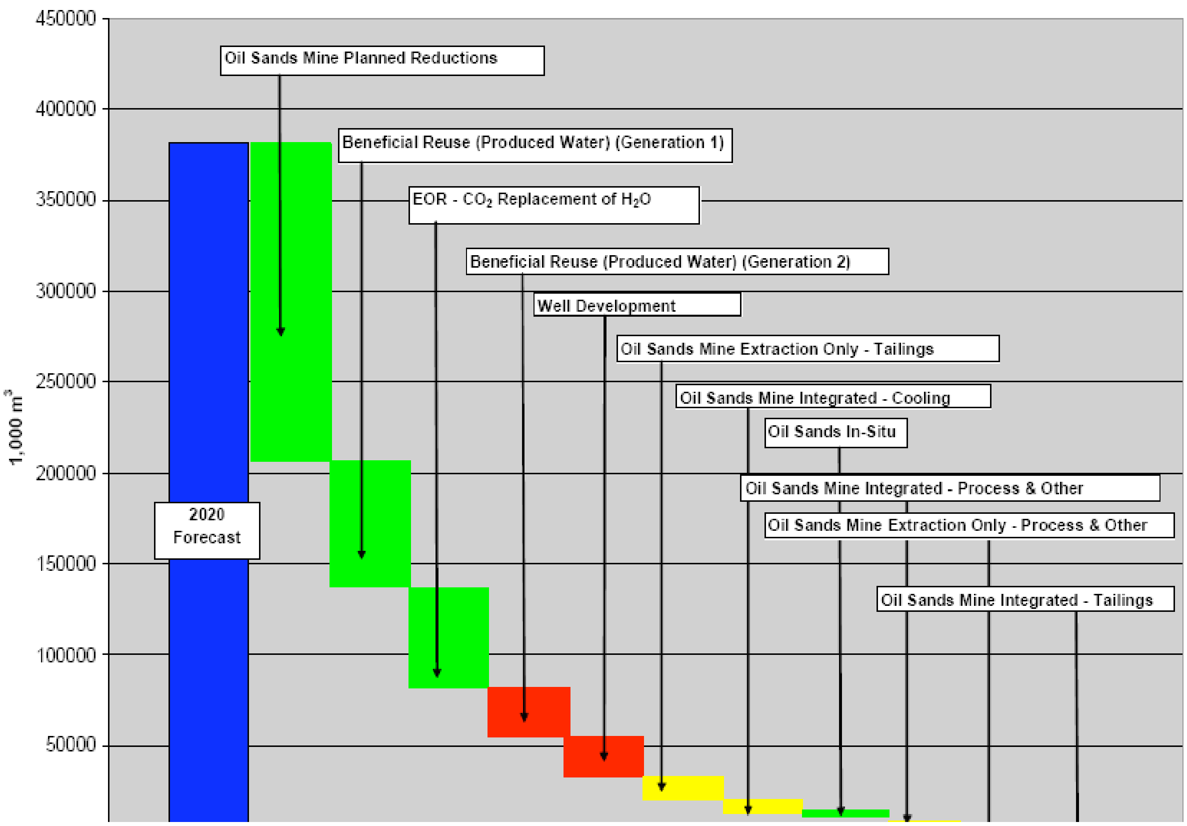

Figure 4-1: Forecast of 2020 Upstream Petroleum Industry Fresh Water Demand and Offsetting Technologies Ranked by Magnitude of Potential Reductions

Source: Alberta Energy Research Institute[273]

Note: Commercial technologies for reducing water consumption are shown in green, technologies that are not yet pilot-tested are in yellow and those not yet fully researched are in red. Generation 1 technologies exist today.

> "The greatest obstacle to achieving a fresh-water-neutral UPI by 2020 is the growth in oil sands mining development using water-based extraction technologies."[274]

Achieving a fresh water neutral upstream petroleum industry must be a province-wide objective, not something to be achieved within each watershed or by individual producers. Thus, produced water would be treated for use in water-short southern Alberta and would compensate, in province-wide accounting, for the use of some fresh water for production of oil sands in the north.

The beneficial use of produced water and the reduction of water use in oil sands operations are examined in the next sections.

> "At this time, there do not appear to be any technologies that can fully eliminate fresh water consumption in the oil sands mining operations within the forecast period. However, there are technologies that can generate a surplus of fresh water for recycle and reuse from conventional production."[275]

4.3.1 Re-use of Produced Water

The reuse of produced water is considered to be the single most important way in which the application of research can reduce water use in the upstream petroleum industry.[276] About 265 million m^3 of produced water is disposed of in deep injection wells each year.[277] This includes water with all levels of salinity and all types of injection (i.e., water injected for EOR as well as industrial wastewater). There are large clusters of injection wells in the Redwater/Fort Saskatchewan, Provost/Hayter, Taber/Grand Forks and Alliance areas and about four-fifths of the total volume injected is disposed of in 18 areas of the province. The source from which the water is produced will affect its salinity and this, in turn, affects the costs of treatment and opportunities for use. In general, water with lower salinity is produced in southern Alberta, which is also the driest.[278]

Produced water may be used for a variety of purposes. One of the most obvious is to increase the use of saline produced water for EOR. According to researchers, "Gathering and treating produced water from different geological pools for injection in specific waterflood projects is a viable alternative to fresh and/or brackish water demand."[279] This should be encouraged by current Alberta Environment policies (see Section 3.4.2, above). If CO_2 is used for EOR, it can displace some of the water in the reservoir and this water can then be used for other purposes.[280]

While the beneficial use of produced water is desirable, it will often be necessary to treat the water before it can be used, whether it is used for fracturing operations,[281] steam generation[282] or other purposes. If produced water is to be used for agricultural purposes, care is needed as salts and other substances in the water could damage soils, surface waters or animals.[283] The selected technology will depend on the end use and a combination of methods may be required.[284] It is also important to ensure that the waste from the treatment process, which is sent for deep well disposal or to a landfill depending on the treatment method, does not contaminate the environment. When treating water used for well development it will probably be necessary to remove a range of contaminants (including emulsifiers, polymers and heavy metals).[285]There are, moreover, a number of legal uses that need to be addressed to enable the beneficial use of the water, while at the same time protecting aquifers.[286]

> "… the regulatory framework for beneficial re-use could be enhanced if the AEUB [now the Energy Resources Conservation Board] and/or AENV [Alberta Environment] indicated the beneficial re-use options that may be considered for approval and the conditions that may apply."[287]

4.3.2 Cutting Water Use in Oil Sands Production

The best way to reduce the demand for water for oil sands mining would be to reduce the volume of water stored in tailings ponds, which account for 75–90% of the water used in oil sands operations.[288] Efforts to produce consolidated tailings are expected to reduce the volume of mature fine tailings per barrel of bitumen produced, but research to obtain dry, stackable tailings is still under way.[289] There are still uncertainties about how successful the processes will be, and there will probably be some residual water left in the tailings material.[290, 291]

> "Nothing is easy in the oilsands because of the volume and tonnage of materials you're working with."[292]

In the future, switching to cooling technologies (such as systems that dissipate energy to the ground, air or tailings ponds via cooling loops) in integrated oil sands mining and processing operations could reduce losses to evaporation and thus reduce water use.[293]

Off-stream storage will be required to reduce withdrawals from the Athabasca River during low flow periods.[294, 295] It might be worthwhile to consider the potential for underground storage if evaporative losses from the storage pond surface become too high.[296]

Various methods are being developed that could potentially reduce the use of fresh water for in situ operations, including the use of more saline water or the replacement of steam, partially or wholly, with solvents.[297] One process — toe-to-heel air injection (THAI) — requires water in the initial stages and then produces water, which can be sold to those using steam for their in situ bitumen recovery.[298] Direct contact steam generation is being researched as a way to reduce the volume of water required, especially for oil or bitumen found in carbonate formations.[299]

Some technologies are already available for wider implementation, while others require a lot more research. The Alberta Energy Research Institute, for example, hopes to develop technologies to enable 95% of water to be recycled in steam-assisted gravity drainage (SAGD) and to reduce the water that is stored in tailings ponds by 25%.[300]

Many initiatives will be needed to reduce water consumption for the production of oil sands and other forms of energy production. An overview of some of the requirements is provided in *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet.*[301] Even when research finds ways to reduce water consumption, companies may be reluctant to be the first to take a new technology to the commercial level. While the final decision to introduce a new method for reducing water use is likely to remain with the companies producing energy, implementation must be encouraged by government policy and legislation.[302]

The final chapter in this report suggests ways in which water management in the province can be improved.

> "[T]he rapid development of Alberta's oil sands, coupled with accelerating population growth and climate change, has turned arid Alberta into Canada's ground zero for water."[303]

5. Meeting the Challenge: Recommendations

A wide variety of measures will reduce the use and consumption of water for energy production. We may not be able to exactly predict what future climate change will bring, but the historic record shows that Alberta suffered prolonged droughts in the 18th and 19th centuries that exceeded those of the 20th century. Given the huge increase in population and demand for water, common sense tells us that it would be wise to minimize our water consumption and "be prepared."

The Alberta government wisely initiated the *Water for Life* strategy in 2003, and the Alberta Water Council and Alberta Environment are trying to ensure that its goals are met, but much more needs to be done. This includes anticipating the potential impacts of climate change. For example, "The Strategy ought to include measures that will allow the Government of Alberta to respond flexibly to the likelihood that the Provincial water supply will not stay constant over time due to climatic variability and climate change."[304]

In the following sections we outline some of the measures necessary to reduce the use of water and help Alberta better adapt to climate change.[305]

5.1 Increase Efforts to Reduce Greenhouse Gas Emissions

Climate change will bring major impacts for the entire globe and every effort must be made to limit the impacts by minimizing GHG pollution. The Government of Alberta must take much stronger measures to reduce emissions in the province. These should include setting a clear, increasing price for GHG emissions from major industrial emitters over the next decade. Most energy companies are large final emitters and this sector of the economy has shown that it is responsive to price signals.[306] A firm signal about the increasing price will give industry a clear timetable and time to adapt.[307] Our current analysis is that price levels of at least $30/tonne carbon dioxide equivalent (CO_2e) emitted by 2008–10, at least $50/tonne by 2015 and at least $75/tonne by 2020 are necessary to obtain the deep GHG reductions needed for Canada to play its part in preventing dangerous climate change.[308] Very recent analysis indicates that Canada may need an economy-wide price on emissions of $200 per tonne of carbon dioxide equivalent by 2020 in order to meet a science-based GHG target by that year.[309]

The Pembina Institute has compiled a comprehensive list of measures that should be adopted to address climate change.[310] One important recommendation concerns new industrial facilities that have major point sources of CO_2. As soon as a strong regulatory framework is in place "to ensure permanence, public safety, adequate monitoring and clear attribution of liabilities," these facilities should be required to capture and permanently store any CO_2 emissions as a condition of their approval.[311] Reduction of fugitive emissions has also been identified as one of the key measures to reduce GHG emissions.[312]

5.2 Conserve Energy and Switch to Processes with Low/No Water Requirements

Every effort should be made to promote energy efficiency. Energy efficient technologies save energy and thus save water.

Water can be saved by switching from energy sources that use a lot of water, such as coal, to renewable energy sources,[313] such as wind, run-of-river hydro and, potentially, geothermal energy. When evaluating new energy sources for the future, the water requirements must be carefully considered. This is especially important for large-scale electricity generation plants, which are likely to be in operation for 40 years or more.

> "In the absence of reliable projections of future changes in hydrological variables, adaptation processes and methods which can be usefully implemented in the absence of accurate projections, such as improved water-use efficiency and water-demand management, offer no-regrets options to cope with climate change."[314]

5.3 Take Practical Steps to Reduce Fresh Water Use

5.3.1 Quickly Implement Water Conservation Targets

One of the goals of the *Water for Life* strategy is to ensure "reliable, quality water supplies for a sustainable economy."[315] One specific objective is that "[T]the overall efficiency and productivity of water use in Alberta has improved by 30% from 2005 levels by 2015".[316] The Alberta Water Council is developing objectives for each sector, and these need to be determined and implemented as soon as possible for power generation and all aspects of oil sands operations and EOR.[317] A scheme could be develped that not only sets targets, but allows tradable performance standards.[318]

However, while increasing efficiency is very important, many other measures are needed. As shown in earlier chapters, the demands for water for energy production are in some cases expected to far outstrip the reductions achieved by increasing efficiency.

5.3.2 Ensure Alberta Environment's Policy for Oilfield Injection is Effective

When the Advisory Committee on Water Use Practice and Policy wrote its report on ways to reduce or eliminate the use of fresh water for EOR and in situ operations, it recommended that "the Government of Alberta and the Alberta Water Council review progress in 2007 as part of the *Water for Life* strategy and evaluate whether significant reductions in underground injection water use have occurred."[319] The actual policy states that it will be reviewed in 2007/2008.[320] Now, in 2009, it is time for this evaluation to be conducted. Figures 3-5, 3-8 and 3-9 (water consumption for EOR and in situ production of bitumen in Alberta 2002–2007) show the decline in the use of surface water for conventional EOR has levelled off, the use of non-saline groundwater for in situ thermal extraction has remained constant, and the use of non-saline groundwater for waterflood (in the Peace River Basin) has increased.

5.3.3 Encourage Beneficial Re-use of Water

The first priority must be to protect groundwater resources, but if it is found that some water can be produced with energy resources without causing damage to aquifers, it seems sensible to make productive use of the water where possible. The opportunity for the beneficial re-use of water varies, but there may be some potential for the reuse of produced water. It has been pointed out that "regulations currently focus on re-injection/disposal to avoid environmental upset rather than on reuse."[321] It is essential to ensure that re-use is carefully regulated to avoid damage to the environment, but it seems that beneficial re-use might occur more frequently if there were a more pro-active policy. Alberta Environment is considering a beneficial re-use policy for produced water from CBM wells.[322]

5.4 Better Protect Groundwater

Groundwater tends to be "out of sight and out of mind" until water levels fall significantly. When this happens, depending on the cause and situation, it can take a long time for levels to recover.

> "Despite its significance, groundwater has received little attention in climate change impact assessment compared to surface water resources."[323]

Precaution is better than cure, so every effort should be made to facilitate groundwater recharge and protect groundwater from contamination. The next sections suggest how this might be done.

> "Groundwater is a covenant with future generations. It is a necessary backup supply for emerging needs and provides communities with flexibility in responding to hydrological variability and to climate change. This generation could provide an important legacy to descendents by attending to emerging groundwater governance issues now."[324]

5.4.1 Improve the Recharge of Groundwater

Recharge of groundwater can be facilitated by protecting existing wetlands and establishing new ones, since wetlands act as natural sponges, slowing runoff and holding the water until it can infiltrate. Maintaining good vegetation cover in riparian zones can also help. Thus, a sound wetlands policy should not only ensure there is not a net loss of remaining wetlands, but should also aim to restore wetlands and riparian zones where they have been lost over much of the settled areas of the province.

> "Although little can be done to halt the disappearance of snowpacks and ice fields, much can be done to protect the integrity of the watersheds of the WPP [Western Prairie Provinces], by retaining or restoring wetlands and riparian zones."[325]

It is hoped that the Alberta government will accept and implement the Alberta Water Council's proposed wetland policy as submitted.[326] This policy should replace the interim policy on wetland management for the settled areas of the province and the draft policy for the non-settled areas.

5.4.2 Ensure Protection of Deeper Aquifers for Future Generations

Groundwater with up to 10,000 mg/l TDS should be protected; the current policy restricts protection to water with up to 4,000 mg/l TDS. This recommendation from the Rosenberg International Water Forum should be implemented as soon as possible.[327]

> "[G]roundwaters between 4,000 and 10,000 mg/L have become an important global resource because they can be economically treated for domestic and other uses. Given the potential for heavy demands on water in the future it would be advisable to expand the definition of regulated groundwater in Alberta so as to ensure that all waters with economic value are regulated."[328]

In the future, during a prolonged drought, it may become necessary to draw water from deeper groundwater zones, which contain somewhat saline water. It is thus important to minimize the contamination of this zone with drilling and fracturing fluids, which means amending the regulations under the *Water Act,*[329] as well as ERCB directives.

While water with salinity of up to 10,000 mg/l TDS would need treatment before it would be suitable for human consumption or many industrial uses, it is economically feasible to remove the salts.[330]

> "Water of quality in the 4,000 to 10,000 mg/L total dissolved solids range has considerable value as a resource after treatment. Therefore, the definition of groundwater resource should be extended to include this quality range."[331]

5.5 Better Manage Water Resources

5.5.1 Improve Knowledge of Climate Change Impacts on Water Resources

It is essential to learn as much as possible about the potential impacts of climate change on water resources. Many energy projects that use water are likely to be in operation for 40 years or more, so it makes good business sense as well as good environmental sense to be prepared for long-term changes in precipitation and temperatures. The better we understand the nature of the impacts, the better we can prepare. Although a start has been made at looking at impacts and necessary adaptation,[332] this work must be ongoing.

5.5.2 Improve Monitoring of Water Quality and Quantity

Surface water and especially groundwater monitoring networks should be expanded. Even during stable climatic conditions, a sound water monitoring network is essential to ensure that resources are not depleted. Such a network becomes even more important in times of water uncertainty. It is essential not only to ensure that resources are not depleted, but to identify any sources of contamination.

Climatic change is expected to increase the variability in weather conditions; periods of extended drought, which could last as long as a decade, are likely even on the basis of the historic record. During drought periods the recharge of shallow aquifers will be reduced, withdrawals are likely to increase and river flows are likely to decline. To manage groundwater in a sustainable manner, it is essential to have long-term records. The longer the period of records, the better scientists are able to determine whether an observed change is temporary or part of a long-term trend.

> "Monitoring networks need to be maintained over time and be sufficiently dense to allow trends to be measured and analyzed and to permit early detection of contamination episodes."[333]

The monitoring network needs to be sufficiently dense to identify not only trends but regional and local differences, which will mean increasing the number of monitoring wells, especially in areas of high use.[334] It is, of course, essential that the data is not only collected, but analyzed. With climate change some trends may be seasonal, rather than annual, so study of monthly data is necessary.[335]

5.5.3 Set Absolute Limits on Water Withdrawals to Protect Ecosystems

The instream flow needs should be determined for all rivers from which there are large withdrawals for energy and other purposes. If river flows decline during dry conditions, withdrawals should be reduced to protect a river's ecosystem. If flows are so low that there could be long-term impacts, no withdrawals should be permitted, with the exception of those required to meet domestic and safety needs.[336] Requiring off-stream storage, which can be replenished with water during high stream flows, will help provide requirements for industry while limiting impacts on natural ecosystems.

5.5.4 Develop Integrated Watershed Management Plans

Surface water and groundwater are essentially one resource and monitoring data should be used to enable water resources to be conserved and managed on a watershed basis. Sufficient monitoring data is needed to enable the construction of reliable models to estimate the rate of groundwater recharge and the development of water budgets. These should then provide the foundation for land use management.

> "An enhancement of the collection of baseline water (surface and groundwater) and ecosystem information coupled with analysis, interpretation, and reporting tools will promote and enable informed water and land use management decisions, for now and into the future."[337]

5.5.5 Provide Alberta Environment with Adequate Resources

The number of staff at Alberta Environment has not grown to keep pace with the growth in industrial activity. Moreover, as a result of industrial expansion many well-qualified people, including hydrologists, have moved to the private sector. The current staff need more help, in order to ensure that Alberta Environment is able to fulfill its role of protecting water resources in the province, including groundwater monitoring and management.

The department wisely sought the advice of the Rosenberg International Water Forum, which made many important recommendations, some of which are repeated in this chapter. The forum's report clearly indicates it is not only expedient but cost effective to be pro-active in the management of groundwater.

> The Rosenberg Water Forum pointed out that "because response times are often quite slow in groundwater systems, it is important and highly cost-effective to develop the capability to detect changes in water levels on a continuous basis, so that rates of water use may be adjusted, if necessary, to ensure that the supply is not depleted considerably before action is taken."[338]

5.6 Accelerate Research on Ways to Reduce Water Use

Writing in 2007, the Rosenberg International Water Forum stated: "The exploitation of Alberta's energy resources is proceeding at a pace much faster than had been anticipated. There has been no parallel acceleration in the research upon which protection of the associated water resources could be based."[339] However, there is increasing recognition of the importance of research into improving water use and efficiency.

Several important research bodies recognize the importance of conserving water and reducing demand. The Alberta Energy Research Institute and the new Alberta Water Research Institute are focusing water research on three important areas:

- produced water treatment and recycling
- oil sands tailings treatment with water recycling
- reducing water use in electrical power generation[340]

The Institute for Sustainable Energy, Environment and Economy at the University of Calgary is engaged in research that will complement the government's long-range water management strategy.[341] Some of the staff at the Alberta Research Centre[342] and CANMET Energy Technology Centre[343] are also engaged in water research relating to energy. Since 2005, the Petroleum Technology Alliance of Canada has held an annual forum to stimulate water efficiency and innovation and facilitate the transfer of knowledge to the industry.[344]

To all those engaged in this research to improve efficiency and conserve water, we say "Keep up the good work," and we encourage government and industry to ensure there is sufficient funding for this work to continue.

5.7 Putting a Price on Water Use for Energy Production

Even when research has identified new ways to reduce water consumption, companies can be reluctant to adopt new technology to reduce water use if there is no direct, short-term economic benefit. An appropriate charge for fresh water would provide such an incentive. Such a charge could be introduced in stages, to give the energy industry time to adapt, but the timelines and cost should be clearly set out.[345]

Charging for the use of fresh water makes it a cost of production and stimulates efficiency. The charge for water consumption (when water is permanently removed from the watershed) should be higher than for water use. Such a charge would encourage use of saline rather than fresh water and stimulate further recycling (where this is not already required). Recycling water or selecting the process that achieves the highest rate of recycling costs money.

The policy options for putting a price on water use vary, but the most common instruments include tradable water permits and water charges. These and other economic instruments are clearly discussed in the paper *Water Use and Alberta Oil Sands Development — Science and Solutions: An Analysis of Options.*[346] Tradable water permits establish a minimum amount of water that must be left in a water basin to ensure sufficient ecosystem protection. The balance of the water supply is then allocated to water users through water permits, which set a limit on the amount of water that can be used or consumed from the water basin.[347] Water charges or taxes are levied on water users according to the amount of water consumed or used. The rate of tax or charge can increase or decrease with the volume of water consumed.

The revenue from a water charge or auctioning of permits should be put into a dedicated "water management" fund to finance some of the other recommendations, above, especially more extensive water quality and quantity monitoring, improved data gathering and analysis and the development of integrated watershed management plans.

5.8 In Conclusion

"Alberta has an opportunity to transform its water management challenges into world class solutions. The strategy envisions policies and resources far beyond *ad hoc* decisions and incremental change. . . . Success will depend on focus, innovation, balanced social values and a growing appreciation of the value of water as a scarce resource."[348]

Alberta Environment has the legal mandate to protect Alberta's water resources and the Alberta Water Council is working to improve water management in the province, but as the council points out in its 2007 report, Alberta's *Water for Life* strategy is a shared responsibility. It will be a challenge and require the dedication of researchers, the commitment of companies and the strong leadership of government to ensure that actions are taken to reduce the consumption of fresh water in the province.

"We are water-short, and there are limits to growth. But who wants to be the politician who shatters the Alberta myth and says we are running out of stuff on the last frontier?"[349]

Future generations will thank the politicians who have the insight today to immediately steer Alberta on a course to wisely manage water and ensure that use for energy production and all other purposes does not harm natural ecosystems or the long-term sustainability of the resource. Action now is likely to be far less expensive and painful than reaction when we are in the midst of a period of prolonged drought.

Endnotes

Unless otherwise indicated, all website sources were accessed and the data verified on January 4–5, 2009.

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[3] See Figure 1-6 in Section 1.4.2.

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[8] Alberta Energy Research Institute, *A Clean Energy Future* (undated), 1, www.aeri.ab.ca/sec/new_res/docs/A-Clean-Energy-Future.pdf.

[9] Thomas C Winter et al., *Ground Water and Surface Water: A Single Resource* (U.S. Geological Survey Circular 1139, 1998), pubs.er.usgs.gov/usgspubs/cir/cir1139.

[10] Saline groundwater is defined in the *Water (Ministerial) Regulation*, section 1(1)(z)) as water containing more than 4,000 milligrams of TDS per litre (TDS/l), www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=9780779732326. Fresh, or non-saline, water, as defined, may not be suitable for drinking but might be used for watering livestock or for irrigation (suitability for irrigation depending on the level of salts in the water, the crop grown and the sodium adsorption ratio of the soil). Potable water should have less than 500 milligrams TDS/l. Some companies refer to saline water as "brackish" water, but there is no official definition of brackish water, and occasionally the term has been used to refer to fresh water that has more dissolved solids than acceptable in drinking water.

[11] Environment Canada, *Threats to Water Availability in Canada*, NWRI Scientific Assessment Report Series No. 3 and ACSD Science Assessment Series No. 1 (Burlington, ON: National Water Research Institute, 2004), xi and 5, www.ec.gc.ca/INRE-NWRI/default.asp?lang=En&n=0CD66675-1. In the Great Lakes less than 1% is renewed each year. See also, Government of Canada, *A Federal Perspective on Water Quantity Issues* (2007), Draft report released under the Access to Information Act, 4, www.canadians.org/water/documents/FederalWaterQuantity.pdf. The "myth of water abundance" is also described in the policy report by Kevin Wilson, "The Next Revolution: Water Use and the Western Canadian Economy," cited above.

[12] Robert Sandford, *Water, Weather and the Mountain West* (Surrey, BC: Rocky Mountain Books, 2007), 33.

[13] Dave Sauchyn and Suren Kulshreshtha, "Chapter 7: Prairies," in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 275–328,

adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php. The full report can be downloaded at adaptation.nrcan.gc.ca/assess/2007/index_e.php.

[14] Ibid., 285 and 288. Scenario values are derived using the Canadian Coupled Global Climate Model 2. Other model results for the Prairies are shown in scatter plots on p. 286.

[15] Ibid., 287.

[16] Evapotranspiration is the sum of evaporation from the Earth's surface, which is a combination of the transpiration from vegetation and evaporation from the ground surface. The U.S. Geological Survey defines it as "water lost to the atmosphere from the ground surface, evaporation from the capillary fringe of the groundwater table, and the transpiration of groundwater by plants whose roots tap the capillary fringe of the groundwater table." U.S. Geological Survey, *The Water Cycle: Evapotranspiration*, ga.water.usgs.gov/edu/watercycleevapotranspiration.html.

[17] Moisture deficit is a measurement of annual precipitation minus potential evapotranspiration.

[18] Dave Sauchyn and Suren Kulshreshtha, "Chapter 7: Prairies," in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 298, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php.

[19] D.W. Schindler and W.F. Donahue, "An Impending Water Crisis in Canada's Western Prairie Provinces," *Proceedings of the National Academy of Sciences (PNAS)* 103, no. 19 (2006): 7210–7216, www.pnas.org/cgi/reprint/0601568103v1.

[20] Ibid, 7214.

[21] The refilling of reservoirs is also a cause of the summer decline in flow in all Alberta rivers except the Athabasca River. David Schindler, personal communication, January 26, 2009.

[22] Dave Sauchyn and Suren Kulshreshtha, "Chapter 7: Prairies," in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 290, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php.

[23] Dave Sauchyn and Suren Kulshreshtha, "Chapter 7: Prairies," in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 298 and 307, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php.

[24] Environment Canada, *Threats to Water Availability in Canada,* 77. Chapter 10, "Climate Variability and Change – Groundwater Resources," examines the impact of climate change on groundwater.

[25] Dave Sauchyn and Suren Kulshreshtha, "Chapter 7: Prairies," in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 307, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php.

[26] Golder Associates Ltd., *Assessment of Climate Change Effects on Water Yield from the North Saskatchewan River Basin.* Report submitted to the North Saskatchewan Watershed Alliance (Calgary, AB: Golder Associates Ltd., 2008), i, nswa.ab.ca/userfiles/NSWA_NSRB_ClimateChange_Final%20Report_23Jul2008.pdf. The report notes that, by assessing the potential effects, watershed planners will be able to take advantage of positive effects and take action to minimize negative effects. Modelling results showed (p. 44) that, "The simulations of the forecasted climate scenarios result in a relatively wide range of possible impacts on water yield from the NSRB [North Saskatchewan River Basin]. Notwithstanding that the GCMs [Global Climate Models] most representative of baseline climate in the NSRB predict increases in future annual yield, the range of possible impacts should be considered in watershed planning because the model predictions have some degree of uncertainty associated with them." The report further notes (p. 44) that "the deviations in the simulated monthly yield from the baseline value are much larger than would be implied by the deviations in the mean annual yield" and that "maximum decrease in monthly yield occurs during the summer months and into the fall."

[27] D.W. Schindler and W.F. Donahue, "An Impending Water Crisis in Canada's Western Prairie Provinces," *Proceedings of the National Academy of Sciences (PNAS)* 103, no. 19 (2006): 7210, www.pnas.org/cgi/reprint/0601568103v1.

[28] Environment Canada, *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada, 1990–2006,* Executive Summary, ES 3.1 (2008), www.ec.gc.ca/pdb/ghg/inventory_report/2006_report/som-sum_eng.cfm#s2.

[29] Sujata Gupta et al., "Policies, Instruments and Co-operative Arrangements," in *Climate Change 2007: Mitigation.* Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Ed. B. Metz et al. (Cambridge, UK and New York, NY: Cambridge University Press, 2007), 776. Also available online at www.mnp.nl/ipcc/pages_media/AR4-chapters.html. These emission reductions are based on stabilizing the atmospheric GHG concentration at 450 parts per million CO_2e, which corresponds to only about a 50% probability of respecting the 2°C limit.

[30] Ibid.

[31] Environment Canada, *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada, 1990–2006* Executive Summary, Section 2.1 (2008), www.ec.gc.ca/pdb/ghg/inventory_report/2006_report/s2_eng.cfm#s2_1. This report shows that Canada's GHG emissions in 2006 were 721 Mt. Annex 10.9.1 of the same report shows that Alberta's GHG emissions in 2006 were 234 Mt; www.ec.gc.ca/pdb/ghg/inventory_report/2006_report/ a10_eng.cfm#a10_9_1.

[32] The term "fossil fuel industries" includes the upstream oil and gas industry, upgrading and refining. "Mining and oil and gas extraction" includes emissions from commercial fuel sold to metal and non-metal mines, mineral and oil and gas extraction industries. "Fugitive emissions" are from oil and natural gas, including the emissions from production, processing, transmission and distribution activities. (In 2006, fugitive emissions in Alberta totaled 37 Mt, or about 55% of all fugitive emissions in Canada (66.8Mt).) Environment Canada, "Chapter 2: Greenhouse Gas Emission Trends 1990–2006," in *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada, 1990–2006* (2008), www.ec.gc.ca/pdb/ghg/inventory_report/2006_report/s2_eng.cfm#s2_3_1. Chapter 2 and Annex 8, Table 8-1, explain the major categories used to compile Figure 1-1.

[33] Environment Canada, *Turning the Corner: Detailed Emissions and Economic Modelling* (Ottawa, ON: Government of Canada, 2008), 41–42. Also available online at www.ec.gc.ca/doc/virage-corner/2008-03/pdf/571_eng.pdf.

[34] M.K. Jaccard and Associates, *Economic Analysis of Climate Change Abatement Opportunities for Alberta.* Prepared for Alberta Environment (Vancouver, BC: MKJA, 2007), 1.

[35] Government of Alberta, *Alberta's 2008 Climate Change Strategy* (Edmonton, AB: Government of Alberta, 2008), 20, environment.gov.ab.ca/info/library/7894.pdf.

[36] Data for the graph was adapted from Environment Canada, *National Inventory Report: Greenhouse Gas Sources and Sinks in Canada, 1990-2006* (2008), Annex 11, Table 11-18 1990-2006 GHG Emission Summary for Alberta, www.ec.gc.ca/pdb/ghg/inventory_report/2006_report/ta11_18_eng.cfm. A footnote in the table indicates that fugitive emissions from refineries and the bitumen industry are reported only at the national level. The "buildings" category in Figure 1-1 was obtained by combining data from residential, commercial and institutional stationary sources.

The data for years 1991–1994 and 1996–1999 was taken from Environment Canada, *Canada's Greenhouse Gas Inventory 1990–2001* (Ottawa, ON: Environment Canada, 2003), www.ec.gc.ca/pdb/ghg/inventory_report/ 1990_01_report/1990_01_report_e.pdf (accessed January 17, 2009).

[37] Environment Canada, *Turning the Corner: Detailed Emissions and Economic Modelling* (Ottawa, ON: Government of Canada, 2008), 8. Also available online at www.ec.gc.ca/doc/virage-corner/2008-03/pdf/571_eng.pdf.

[38] Ibid., 32.

[39] Mike de Souza. "Canadians Want Action on Oil Sands 'Dirty Secret'," *Edmonton Journal,* March, 25, 2008, www.canada.com/edmontonjournal/news/story.html?id=c4176f8f-9575-41d4-9559-fc4646f991cd.

[40] Some licences for oil sands mining are classified in the commercial category (cooling and other); this is a function of when they were issued. In this report some have been reclassified for inclusion in the industrial (oil, gas, petroleum) category. Alberta Environment, personal communication, December 11 and 15, 2008.

[41] Note that commercial cooling water is primarily for thermal power plants (with a smaller amount used by upgraders), but the category also includes air conditioning.

[42] The total water allocation in Alberta in 2007 was 9,832 million m^3, of which 329 million m^3 or 3% was from non-saline groundwater. Alberta Environment, personal communication. December 11, 2008.

[43] The average domestic daily demand per person is 230 litres. EPCOR, *Water Utility Statistics 2007,* www.epcor.ca/en-ca/Customers/water-customers/pressure-and-supply/Pages/WaterUtilitiesStats2007.aspx.

[44] Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf. This report provides a breakdown for surface and groundwater for current licences, water use and water consumption, as well as for future scenarios.

[45] Ibid. The percentages, which are for the medium growth scenario, were calculated from data in the report for each river basin. The report also includes separate figures for surface water and groundwater, and estimates future water use in 2010, 2015, 2020 and 2025.

[46] Cooling water is primarily for cooling thermal power plants, although Alberta Environment also includes water used for air conditioning in this category.

[47] The Liard Basin, which covers less than 1% of the area of Alberta and lacks significant use of water for energy production, has been excluded from the figure.

[48] Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf. The thermal/injection category in the Beaver River Basin refers to thermal recovery of bitumen. However, in the Athabasca River and Peace River basins the 2025 data includes water for both conventional and thermal recovery, since these are not separated in the Alberta Environment report. Data for 2005 in the Athabasca River Basin was taken from the revised Table 11-22 on the website, and for the Peace River Basin it was taken directly from the Geowa report, as at the time of writing the Peace River table has not been revised in the *Current and Future Water Use in Alberta* report. In situ waterflood refers to the use of water (rather than steam) for the in situ recovery of bitumen.

[49] The data used for the graphs is net water consumption. According to Alberta Environment, “Actual water use reflects the fact that licensees may not actually withdraw the maximum amount of their entitlement and that net consumption must also consider the difference between what they withdraw and what they put back (return flow).” Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 9, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf. The main source of information for determining water use was Alberta Environment’s Water Use Reporting System. The reader is referred to the Alberta Environment report for a full explanation of the data used by Alberta Environment.

[50] Alberta Environment provided data on licence allocations for the withdrawal of water from the Athabasca and Tar River, a tributary of the Athabasca. Edmonton, a city of one million people, treats 130 million m^3/year. See also Danielle Droistch, Dan Woynillowicz and Steve Kennett, *Curing Environmental Dis-Integration* (Drayton Valley, AB: Water Matters and The Pembina Institute, 2008), www.pembina.org/pub/1625. See also Section 3.5.2.

[51] Paul Freedman and John Wolfe, *Thermal Electric Power Plant Water Uses: Improvements Promote Sustainability and Increase Profits*. Research paper sponsored by the Electric Power Research Institute, Washington, DC (Ann Arbor, MI: Limno Tech, 2007), 10, policyresearch.gc.ca/doclib/Freedman_Wolfe_PP_Water_Uses_091407.pdf.

See also William Jones, “How Much Water Does it Take to Make Electricity?” *IEEE Spectrum*, April 2008, www.spectrum.ieee.org/apr08/6182. This article is cited since it has converted data from another article into litres/1000kWh. The original article is Rachelle Hill and Tamin Yournos, *The Intertwined Tale of Energy and Water,* Virginia Water Resources Research Centre, www.vwrrc.vt.edu/watercooler_apr08.html.

[52] See Figure 1-2, above, for 2007. Alberta Environment, personal communication, December 11, 2008. Figures for 2005 are given in Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 597, www.assembly.ab.ca/lao/library/egovdocs/2007/

alen/164708.pdf. In 2005 industrial water licences accounted for 28% of provincial water allocations and 88% of these allocations were for cooling (power plants). Thus, 24.6% of all water allocations were for cooling power plants. See also p. 598 and Table 15-10.

[53] The total volume of water diverted for commercial cooling in Alberta in 2007 was almost 890 million m^3, or 38% of the allocation. However, almost all 2 million m^3 of the groundwater allocation was diverted. Alberta Environment, personal communication, December 11, 2008.

[54] Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 600, Table 15-10, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf.

[55] Electric Power Research Institute, *Water and Sustainability (Volume 3): U.S. Water Consumption for Power Production – The Next Half Century* (Technical Report, 2002. R. Goldstein and W. Smith, Project Managers), Table S-1, www.epriweb.com/public/000000000001006786.pdf. Data in the source table has been converted from gallons to litres and is approximate. Consumption refers to the evaporation to the atmosphere.

[56] Eddy Isaacs and Duke du Plessis, *Energy Development and Future Outlook.* Presentation to the Standing Senate Committee on Energy, the Environment and Natural Resources (Calgary, AB: Alberta Energy Research Institute, 2007), www.aeri.ab.ca/sec/new_res/docs/Isaacs_du_Plessis_Submission_to_Senate_Committee_050307.pdf.

[57] A summary of the different types of cooling is provided in Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 29, footnote 31, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf.

[58] Electric Power Research Institute, *Water and Sustainability (Volume 3): U.S. Water Consumption for Power Production – The Next Half Century* (Technical Report, 2002. R. Goldstein and W. Smith, Project Managers), Table S-1, www.epriweb.com/public/000000000001006786.pdf.

[59] Alberta Energy, *Electricity Statistics*, www.energy.gov.ab.ca/Electricity/682.asp

[60] Government of Alberta, *Alberta's Energy Industry: An Overview 2007*, 5, www.energy.gov.ab.ca/Org/pdfs/Alberta_Energy_Overview.pdf.

[61] Ibid.

[62] Clean Air Strategic Alliance, *Discussion Guide and Survey 2008: Air Quality and Electricity Generation in Alberta*, 2 , www.casahome.org/wp-content/uploads/2008/12/Casa-discussion-Guide-webReady.pdf. The document shows that in 2007 coal was used to generate 44,244 GWh of electricity, natural gas 20,384 GWh, hydro 2013 GWh, wind 1433 GWh and biomass and waste heat (combined) 1138 GWh. The source data is from the Alberta Electricity System Operator web site at ets.aeso.ca/.

[63] Jeff Bell and Tim Weis, *Greening the Grid: Powering Alberta's Future with Renewable Energy* (Drayton Valley, AB: The Pembina Institute, 2009), 11, pubs.pembina.org/reports/greeningthegrid-report.pdf. Figure 6 shows the proportion of electricity from different sources that supply the Alberta electric grid.

See also Natural Resources Canada, *Canada's Energy Outlook: The Reference Case 2006* (Ottawa, ON: Natural Resources Canada, 2006), www.nrcan-rncan.gc.ca/com/resoress/publications/peo/peo-eng.php. See p. 99, which states that "In 2004, electricity generation from coal accounted for 80 percent, natural gas 12 percent and hydro 5 percent." See also Appendix V, p. 196 for more details.

[64] Jeff Bell and Tim Weis, *Greening the Grid: Powering Alberta's Future with Renewable Energy* (Drayton Valley, AB: The Pembina Institute, 2009), pubs.pembina.org/reports/greeningthegrid-report.pdf.

[65] Lake Wabamun Watch, *Issues of Concern: Mining Activities*, www.wabamunwatch.com/issues-ma.htm.

[66] For example, it was estimated that EPCOR's Genesee 3 power plant would require the diversion of 6 million m^3 water from the North Saskatchewan River for cooling a power plant with a maximum continuous rating of 450 MW. The return flow to the river, as blowdown from the cooling pond, was estimated at 2.7 million m^3 and the net evaporative losses at 3.3. million m^3. EPCOR Genesee Generating Station, Phase 4.4-36. Thus each megawatt of capacity at this modern plant would consume about 7,300 m^3/yr water. Assuming the power plant operates 90% of

the time, approximately 1 m^3 of water is consumed for every megawatt hour of electricity generated (There are 8,760 hours in a year; 90% of this is 7,884 hours. The power plant thus produces approximately 7884 MWh of electricity each year. Divided by 7,300 m^3/yr water equals 1.1 m^3 of water used per megawatt hour of electricity generated.) EPCOR, *2003 Generating Report: Genessee Generating Station* (2004), www.epcor.ca/SiteCollectionDocuments/Corporate/pdfs/corporate%20reports/2003/2003%20Genesee%20Environmental%20Report.pdf.

[67] Although modern systems are more efficient than older ones, for every unit of energy produced in the generating station, a certain amount of energy is introduced into the cooling pond from the condensers. At the EPCOR Genesee Plant, two units producing 1,032 MW increased the temperature of the water discharged to the cooling pond by 12 to 15°C over intake temperatures, but it was expected that with the more efficient Genesee 3 expansion (which increased total power generation by approximately 560 MW), the temperature increase for the more efficient new unit would be 8 °C. EPCOR, *Genesee Generating Station, Phase 3, Alberta Energy and Utilities Board/Alberta Environment Integrated Application* (2001), Volume 1, p.4.4-27. The temperature of the cooling pond is normally about 27 to 30°C in summer and the temperature of this water is approximately 8 to 10°C above the river temperature (Volume 1, p. 4.4-70).

The addition of the Genesee 3 unit was expected to increase annual evaporation at the cooling pond (which serves three power plants) to 14.8 million m^3/yr. EPCOR Application Volume 1, p. 4.4-34. EPCOR's Genesee plant is licensed to withdraw about 22 million m^3/yr from the North Saskatchewan River and to return up to 11 million m^3/yr as blowdown from the cooling pond. The actual volumes are likely to be slightly less (withdrawals at 20.3 million m^3/yr and blowdown at 10.4 million m^3/yr). About 4 million m^3/yr is added to the cooling pond by precipitation.

[68] EPCOR, *Genesee Generation Station Phase 3*: *Alberta Energy and Utilities Board/Alberta Environment Integrated Application*, Volume 1, Section 4, Water Management Works, especially 4.4.3.2 Cooling Pond Water Balance.

[69] See, for example, EPCOR, Volume 1, 4.4-69, 4.4-70 and 4.6-16 to 4.6-25.

[70] Paul Freedman and John Wolfe, *Thermal Electric Power Plant Water Uses: Improvements Promote Sustainability and Increase Profits*. Research paper sponsored by the Electric Power Research Institute, Washington, DC (Ann Arbor, MI: Limno Tech, 2007), 6–7, policyresearch.gc.ca/doclib/Freedman_Wolfe_PP_Water_Uses_091407.pdf.

[71] The data on water diversion is from records that have not been verified, so may not be complete.

[72] Alberta Environment advised that where information on water diversion was not available the gaps have been filled as follows:
1. Average of the data for the reported years is used if water diversion data is available for the past years.
2. Maximum annual diversion quantities are used if there is no diversion data at all.

[73] The licensed diversion for cooling from the Battle River is 691 million m^3/year, but the licensed use for the power plant is 13 million m^3/year. Most of the water loss is through evaporation. Power production may be reduced in the summer due to the warm temperature of the cooling water. Watrecon Consulting, *Battle River Basin: Water Use Assessment and Projections* (Edmonton, AB, Watrecon Consulting, 2005), submitted to Alberta Environment, Red Deer, Alberta, i and 71. Cooling water is taken from a reservoir that is created by a dam on the Battle River. ATCO, Power, *Battle River Coal-fired Generating Station*, www.atcopower.com/Our%20Facilities/North%20America/Battle%20River%20(AB)/.

[74] Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 356–361 and 374, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf.

[75] A licence is issued for a specific purpose, so although the return flow is not specified for compliance purposes, if a licence holder wishes to change or expand a specified use of water (for example, in a way that it would reduce return flows) a licence would normally have to be opened up for review and/or amendment.

[76] The proportion consumed could change, if new power generation capacity is added, using water from existing water licences.

[77] The cooling tower is planned so that an additional generating unit will not increase the temperature of the cooling pond. TransAlta, *Keephills Thermal Generating Plant*, *Keephills 3 Project Application for Amendment to EUB*

Approval U2002-162 to Construct and Operate the Keephills 3 Project (2006), 35. Table 4.1 (p. 69–71) estimates that total make-up water from the North Saskatchewan River to the cooling pond for Keephills 3 to be 10.3 million m^3/year, and the blowdown back to the river to be 4.6 million, m^3/year, for a total consumption of 5.7 million m^3/year. Since Keephills 3 will have a net generation capacity of 450 MW, the expected annual water consumption is 12,700 m^3 per MW of generation capacity.

[78] Evaporative losses from a cooling tower can be reduced, compared to a cooling pond, if the water vapour is condensed and returned to the cooling system. Paul Freedman and John Wolfe, *Thermal Electric Power Plant Water Uses: Improvements Promote Sustainability and Increase Profits.* Research paper sponsored by the Electric Power Research Institute, Washington, DC (Ann Arbor, MI: Limno Tech, 2007), 4, policyresearch.gc.ca/doclib/Freedman_Wolfe_PP_Water_Uses_091407.pdf. It is also possible to condense water losses from fuel combustion in the flue stack, which makes more efficient use of the energy in the fuel. See Bruce Peachey, "Environmental Stewardship — What Does it Mean?" *Process Safety and Environmental Protection* 86 (2008): 229–236.

[79] Don Meredith, "Fixing Wabamun Lake," *Alberta Outdoorsmen* (2005), www.donmeredith.ca/outdoorsmen/Wabamun.html. This article provides a brief overview of the lake, including impacts of thermal power operations.

[80] Bill Donahue, E.W. Allen and D.W. Schindler, "Impacts of Coal-fired Power Plants on Trace Metals and Polycyclic Aromatic Hydrocarbons (PAHs) in Lake Sediments in Central Alberta", *Journal of Paleolimnology* 35, no. 1 (2006): 111–128. An abstract and graph showing higher levels in Lake Wabamun are available at www.ualberta.ca/ERSC/water/industrial/wabamun.htm.

[81] David Schindler, *Lake Wabamun: A Review of Scientific Studies and Environmental Impacts*. Report prepared for Alberta Environment and submitted to the Minister of Environment. (Edmonton, AB: Alberta Environment, 2004), 10, www3.gov.ab.ca/env/water/reports/wabamun/Wabamun_Report_Dec04.pdf. This report gives a comprehensive overview of the impact of power plants and other activities on Lake Wabamun. See also Alberta Environment. *An Overview of Recent Studies on Wabamun Lake* (Edmonton, AB: Alberta Environment, undated), environment.gov.ab.ca/info/library/6138.pdf.

[82] David Schindler, *Lake Wabamun: A Review of Scientific Studies and Environmental Impacts*. Report prepared for Alberta Environment and submitted to the Minister of Environment. (Edmonton, AB: Alberta Environment, 2004), 10, www3.gov.ab.ca/env/water/reports/wabamun/Wabamun_Report_Dec04.pdf.

[83] Dave Sauchyn and Suren Kulshreshtha, "Chapter 7: Prairies," in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 312, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php. The sentence cited refers to refining, but applies equally to cooling water requirements for thermal power plants, upgraders and so on.

[84] Bruce Laverty, *The Push to Coal Gasification in Alberta* (Edmonton, AB: University of Alberta, School of Business, 2007), www.business.ualberta.ca/cabree/pdf/2007%20Winter/Laverty_Coal_Gasification_560.pdf. The paper provides a useful overview of gasification proposals in Alberta. It points out (p. 6) that IGCC generation is only marginally more efficient when compared to straight coal-fired electrical generation based on net coal-to-power efficiency (42% efficiency for IGCC, 41% for current coal-fired generation), for although the basic plant efficiency may be about 54%, about 12% of the coal energy is used to run the gasification plant. The paper does not indicate whether the efficiency values are based on lower heating values, which ignore the energy in stack gases, or on higher heating values.

[85] EPCOR, "EPCOR and Siemens Partner to Design Near-zero Emission Coal Fuelled Power Facility," news release, August 15, 2008, www.epcor.ca/en-ca/about-epcor/news-Publications/NewsReleases/2008/Pages/081508.aspx The project is at the front-end engineering and design (FEED) stage, which is scheduled to be complete in 2009.

[86] Sherritt, *Dodds Roundhill Project*, www.sherritt.com/doc08/subsection.php?submenuid=operations&category=operations/dodds_roundhill.

[87] Sherritt. 2008. *Dodds-Roundhill Coal Gasification Project: Community Newsletter*, January, 4, www.sherritt.com/doc08/files/coal/dodds/January_Newsletter_2008.pdf. Water requirements are estimated at 26 million litres per day, which is approximately 9.5 million litres per year. It seems likely that much of this water will be consumed, but since the environmental impact assessment has not yet been completed, the exact consumption figures are not yet

known. The power plant is expected to have a generation capacity of about 380 MW. Much of the electricity from the power plant will be used for the gasification operations, but some will be supplied to the grid.

[88] The eventual fate of chemicals in the water will depend on the water treatment process. Sometimes waste from water treatment is sent for deep well disposal and sometimes to landfill.

[89] EPCOR proposes piping this water from the Gold Bar Wastewater Treatment Plant in Edmonton. See Slide 10, www.sherritt.com/doc08/files/coal/dodds/Posters_-_Open_Houses_Dec_4-5.pdf.

[90] Bow City Power, "Bow City Power Project Plans to Move Forward with the Incorporation of Carbon Capture and Storage," news release, August 5, 2008, www.marketwire.com/press-release/Bow-City-Power-Ltd-886284.html. See also Gordon Jaremko, "Bow City Power Offer a Contender: 'Short Guy Behind David' Steps Up", *Calgary Herald*, July 3, 2008, www.canada.com/calgaryherald/news/calgarybusiness/story.html?id=32ea8e57-e908-451c-8d3a-0f6263eaf778.

[91] Barbara Bennett, Massood Ramezan and Sean Plasynski, "Impact of Carbon Capture and Sequestration on Water Demand for Existing and Future Power Plants" (paper presented at the Sixth Annual Conference on Carbon Capture and Sequestration, National Energy Technical Laboratory, U.S. Department of Energy, 2007), www.netl.doe.gov/publications/proceedings/07/carbon-seq/data/papers/wed_006.pdf. Values for water consumption in the above text are converted from gallons in this poster.

[92] Alstom Power, *Clean Power Today: Chilled Ammonia Carbon Capture*, www.power.alstom.com/home/about_us/clean_power_today/chilled_ammonia_carbon_capture/28478.EN.php?languageId=EN&dir=/home/about_us/clean_power_today/chilled_ammonia_carbon_capture/.

The process is still being developed for commercial use but, "Studies demonstrate that Alstom's technology may result in an energy loss of approximately 10% versus other methods of post-combustion CO_2 separation, which result in losses of nearly 30%." Alstom, "Alstom and Statoil to Jointly Develop Project for Chilled Ammonia-based CO_2 Capture for Natural Gas in Norway," news release, June 7, 2007, www.power.alstom.com/pr_power/2007/june/31816.EN.php?languageId=EN&dir=/pr_power/2007/june/&idRubriqueCourante=3981. See Prachi Patel-Predd, "Carbon Capture Starts from Coal Plant, Advances in Lab," *IEEE Spectrum*, March 2008, www.spectrum.ieee.org/mar08/6058, for a comparison of the amine and ammonia processes.

[93] Intergovernmental Panel on Climate Change. *Special Report on Carbon Dioxide Capture and Storage* (2005), www.ipcc.ch/ipccreports/srccs.htm. A footnote on page six of the report ("Summary for Policymakers") explains that, "At depths below 800–1,000 m, CO_2 becomes supercritical and has a liquid-like density . . . that provides the potential for efficient utilization of underground storage space and improves storage security . . . ." Chapter 5, page 205, of the report states that, "When CO_2 is injected into a deep saline formation in a liquid or liquid-like supercritical dense phase, it is immiscible in water. . . . Because supercritical CO_2 is much less viscous than water and oil . . . migration is controlled by the contrast in mobility of CO_2 and the *in situ* formation fluids." At the surface CO_2 is in a gas or liquid state, but at the higher temperatures and pressures found deep underground it is in a liquid-like (supercritical) phase.

[94] Ibid., 13.

[95] Government of Alberta, *Alberta's 2008 Climate Change Strategy* (Edmonton, AB: Government of Alberta, 2008), 20, environment.gov.ab.ca/info/library/7894.pdf. The plan calls for a reduction of 200 MT reduction of CO_2e each year by 2050, of which 139 MT (i.e., 70%) is expected to come from CCS.

[96] Government of Alberta, *Talk About Carbon Capture and Storage* (Edmonton, AB: Government of Alberta, 2008), www.energy.gov.ab.ca/Org/pdfs/FactSheet_CCS.pdf.

[97] See Marlo Raynolds and Matthew Bramley, *The Pembina Institute's Perspective on Carbon Capture and Storage (CCS)* (Drayton Valley, AB: The Pembina Institute, 2007), pubs.pembina.org/reports/Pembina-perspective-CCS.pdf. See also, Mary Griffiths, Paul Cobb and Thomas Marr-Laing, *Carbon Capture and Storage: A Canadian Primer* (Drayton Valley, AB: The Pembina Institute, 2005), pubs.pembina.org/reports/CCS_Primer_Final_Nov15_05.pdf.

[98] Alberta Electricity System Operator, *Current Supply Demand Report*, accessed January 19, 2009, ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet.

[99] Natural gas is the usual fuel for gas-fired electricity generation, but occasionally methane from landfill may be used.

[100] ENMAX, *Crossfield Energy Centre: What You Have Asked*, brochure (Calgary, AB: ENMAX, 2008). There are 264 gallons in a cubic metre, so the total volume of water required is approximately 11,000 to 22,000 m^3/yr.

[101] Wikipedia, *Power Station*, en.wikipedia.org/wiki/Power_station, and *Combined Cycle*, en.wikipedia.org/wiki/Combined_cycle.

[102] The proposed ENMAX 800 MWcombined cycle power plant at Shepard, near Calgary is expected to use an average of 10 m^3/min, i.e., approximately 5.2 million m^3 of water each year. The volume of water used will highest during peak conditions in summer and most of the water will be consumed. The water is expected to come from municipal waste water. ENMAX, personal communication, January 6, 2009.

[103] Bruce Peachey, "Environmental Stewardship — What Does it Mean?" *Process Safety and Environmental Protection* 86 (2008): 229. Peachey points out that as a result of cogeneration, a doubling of oil production has been achieved with a 56% increase in on-site energy use.

[104] Alberta Geological Survey, *2007 Alberta Mineral Exploration Highlights and Industrial Minerals Production Update* (2008), www.ags.gov.ab.ca/publications/pdf_downloads/Alberta_Overview_2007_Exploration_Final.pdf.

[105] Winfield et al., *Nuclear Power in Canada: An Examination of Risks, Impacts and Sustainability* (Drayton Valley, AB: The Pembina Institute, 2006), 32–36, pubs.pembina.org/reports/Nuclear_web.pdf.

[106] Winfield et al., 35 and endnotes 65 to 69.

[107] Gina Teel, "The Rush for Alberta's Uranium," *Calgary Herald*, November 27, 2005, www.internationalranger.com/view.php?site_id=articles&content_id=109 . Also, Raymon Paquette, "International Ranger Receives Final Report on Whiskey Gap Drilling," *Business Network*, findarticles.com/p/articles/mi_pwwi/is_200705/ai_n19161581/pg_1.

Firestone Ventures, "Firestone Ventures Reports New Uranium Targets at Alberta Sun Project," news release, February 28, 2008, www.firestoneventures.com/s/NewsReleases.asp?ReportID=289007&_Title=Firestone-Ventures-Reports-New-Uranium-Targets-at-Alberta-Sun-Project. See also the map at www.firestoneventures.com/i/pdf/Firestone_S_Alberta_U.pdf.

[108] J.A. Davis and G.P. Curtis, U.S. Geological Survey, *Consideration of Geochemical Issues in Groundwater Restoration at Uranium In-Situ Leach Mining Facilities* (Washington, DC: U.S. Nuclear Regulatory Commission, 2007), www.nrc.gov/reading-rm/doc-collections/nuregs/contract/cr6870/cr6870.pdf.

[109] Unlike several other provinces Alberta does not have a moratorium on uranium extraction. British Columbia imposed a ban on mining exploration in April 2008; New Brunswick restricted areas where exploration is permitted in July 2008; Nova Scotia has had a moratorium on uranium mining and exploration since 1982; in April 2008, the Nunatsiavut government imposed a three-year moratorium on the production and development of uranium on Labrador Inuit lands (but not on exploration). World Information Service on Energy Uranium Project, Regulatory Issues, www.wise-uranium.org/ureg.html#CDN.

[110] Bruce Power Alberta, *Introducing Ourselves*, www.brucepower.com/pagecontentAB.aspx?navuid=9090.

Canadian Nuclear Safety Commission, *Bruce Power Alberta*, www.nuclearsafety.gc.ca/eng/licenseesapplicants/powerplants/newapplicants/brucealberta/.

[111] Environment Canada, *Water Works*, section on *Thermal Power Generation*, www.ec.gc.ca/water/en/info/pubs/fs/e_FSA4.htm.

[112] Winfield et al., 70–73. Tritium releases are larger with CANDU reactors than other types, due to their use of deuterium (heavy water). Releases affect mostly surface water but groundwater contamination was also reported near the Pickering nuclear power site (Winfield et al., 71). The current level of tritium in water sources near nuclear power plants in Ontario is less than the European Union standard (100 Becquerel/litre), which is far more stringent than the Canadian standard (7,000 Bq/l), with the exception of at least one water well near Pickering, which exceeds the EU standard. Canadian Nuclear Safety Commission, *Tritium Studies: Standards and Guidelines to Tritium in*

Drinking Water, Table 3, www.nuclearsafety.gc.ca/eng/readingroom/healthstudies/tritium/index.cfm#executive_summary.

[113] Ibid., 73.

[114] In 2003 France lost 7–15% of its nuclear electricity production for five weeks, as well as 20% of its hydro production. Bob Goldstein and Mike Hightower. *Energy and Water*, PowerPoint Presentation, Slide 8, www2.bren.ucsb.edu/~keller/energy-water/6-1%20Mike%20Hightower%20-%20Bob%20Goldstein.pdf.

[115] Idaho National Laboratory Nuclear Programs, *Powering the Future,* inlportal.inl.gov/portal/server.pt/gateway/PTARGS_0_1646_9680_0_0_18/generation_iv_nuclear_technology.pdf. More information about research into nuclear energy at the laboratory can be accessed at https://inlportal.inl.gov/portal/server.pt?open=512&objID=255&mode=2.

[116] International Rivers Network, *Fizzy Science: Loosening the Hydro Industry's Grip on Reservoir Greenhouse Gas Emissions Research.* Written by Patrick McCully (Berkeley, CA, International Rivers Network, 2006), www.internationalrivers.org/files/FizzyScience2006.pdf.

[117] Bates et al., *Climate Change and Water* (Technical Paper of the Intergovernmental Panel on Climate Change, IPCC Secretariat, Geneva, 2008), 122, www.ipcc.ch/pdf/technical-papers/ccw/chapter6.pdf.

[118] Licences for hydroelectricity generation do not allocate any water for use. See, for example, the two licences for hydroelectricity on the North Saskatchewan River. Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 358, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf.

[119] The evaporation from a lake can be calculated from a lake's area and data on wind, temperature and relative humidity. The evaporation will the same for both shallow and deep lakes, but a higher percentage of the water will be lost from shallow lakes. See Patricia Mitchell and Ellie Prepas, *Atlas of Alberta Lakes* (Edmonton, AB: University of Alberta Press, 1990), 18, sunsite.ualberta.ca/Projects/Alberta-Lakes/characteristics2.php.

[120] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet,* (EnergyINet, 2005), 40, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf.

[121] Calculation of the evaporative losses from a reservoir can be made using the "Penman equation," which takes into consideration the available energy and atmospheric conditions. However, the calculation of evaporative losses is quite complex. See R.J. Granger, "An Examination of the Concept of Potential Evaporation," *Journal of Hydrology* 111 (1999): 9–19. One study in the United States, where average higher temperatures cause higher surface water evaporation than would be expected in Alberta, found that "In thermoelectric plants, 0.47 gal (1.8 L) of fresh water is evaporated per kWh of electricity consumed at the point of end use. Hydroelectric plants evaporate an average of 18 gal (68 L) of fresh water per kWh used by the consumer." P. Torcellini, N. Long and R. Judkoff, *Consumptive Water Use for U.S. Power Production* (Golden, CO: National Renewable Energy Laboratory, 2003), iv, www.nrel.gov/docs/fy04osti/33905.pdf.

[122] Alberta Environment, personal communication, December 11, 2008.

[123] Canadian Hydro Developers Inc., *Dunvegan Hydro Project: Project Description* (2006), www.canhydro.com/projects/dunvegan/projdesc.htm.

[124] Dave Sauchyn and Suren Kulshreshtha, "Chapter 7: Prairies," in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 312, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php.

[125] Government of Alberta, *Large Water Power Developments,* www.waterforlife.gov.ab.ca/html/infobook/info10.html.

[126] Alberta Electricity System Operator, *Current Supply Demand Report,* ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet.

[127] Darcy Henton, "Ex-chief Girds to Battle Massive $5-billion Hydro Generator," *Edmonton Journal*, August 21, 2008, A1, www.canada.com/edmontonjournal/news/story.html?id=474f342b-f3b2-479b-87c0-ca5c96c260d7.

[128] Alberta Electricity System Operator, *Current Supply Demand Report,* ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet. The biomass plants are located in Athabasca, Drayton Valley, Grande Prairie, Westlock and Whitecourt. In addition, there is one plant, Cancarb, that uses waste heat to generate electricity for the grid.

[129] Alberta Agriculture and Rural Development, *Biogas Energy Potential in Alberta*, www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/agdex11397.

[130] Peter Flynn, *Biomass Energy: Cost and Scale Issues,* www.aeri.ab.ca/sec/new_res/docs/presentations/Biomass_Economics_060927.pdf. This study refers to some real cases in Alberta.

[131] One review found, for example, that electricity generation from the most efficient type of fuel ethanol used 1/30th as much water as electricity produced using biodiesel. William Jones, "How Much Water Does it Take to Make Electricity?" *IEEE Spectrum,* April 2008, www.spectrum.ieee.org/apr08/6182. This article converts the original data to efficiency in litres per kWh. For the original data see Rachelle Hill and Tamin Yournos, *The Intertwined Tale of Energy and Water,* Virginia Water Resources Research Centre, www.vwrrc.vt.edu/watercooler_apr08.html.

[132] Alberta Agriculture and Rural Development, *Biogas Energy Potential in Alberta*, www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/agdex11397.

[133] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 38, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf. See also IPCC, *Climate Change and Water* (Geneva: IPCC Secretariat, 2008), 136, www.ipcc.ch/pdf/technical-papers/ccw/chapter8.pdf.

[134] Mark Jacobson, "Review of Solutions to Global Warming, Air Pollution, and Energy Security," *Energy and Environmental Science* 2009, Section 7, shows the very large difference in water consumption for different types of fuel. In the U.S., corn and cellulosic ethanol (for E85 ethanol to fuel on road vehicles) require far more water than any other process that could be used to power vehicles, except battery electric vehicles using hydro power. This paper was first published on the web December 1, 2008, www.rsc.org/delivery/_ArticleLinking/DisplayHTMLArticleforfree.cfm?JournalCode=EE&Year=2009&ManuscriptID=b809990c&Iss=Advance_Article.

[135] David Pimental and Tad Patzek, "Ethanol Production Using Corn, Switchgass, and Wood; Biodiesel Production Using Soybean and Sunflower," *Natural Resources Research* 14, no. 1 (2005): 65-76. A detailed examination of the issues is provided in David Pimental (Editor), *Biofuels, Solar and Wind as Renewable Energy Systems: Benefits and Risks* (New York, Springer-Verlag, 2008).

[136] Union of Concerned Scientists, *How Geothermal Energy Works,* www.ucsusa.org/clean_energy/technology_and_impacts/energy_technologies/how-geothermal-energy-works.html. This article describes examples of several types of geothermal energy and potential impacts on water.

[137] IPCC, *Climate Change and Water* (Geneva: IPCC Secretariat, 2008), 118–119, www.ipcc.ch/pdf/technical-papers/ccw/chapter6.pdf.

[138] Jacek Majorowitcz and Michal Moore, *Enhanced Geothermal Systems (EGS) Potential in the Alberta Basin,* Draft Report of the Alberta Energy Research Institute, www.aeri.ab.ca/sec/new_res/docs/Enhanced_Geothermal_Systems.pdf.

[139] Bruce Peachey has suggested that it may be possible to use the heat in pools with high water production rates (such as Judy Creek and Swan Hills). According to Peachey, "Power generation potential would be limited to Organic Rankin Cycle systems as all the streams are below 100 degrees C, however, since most gas plants in these regions have propane refrigeration systems there is potential to use propane as the power fluid, use the waste heat to help generate cooling for the gas plants and back out some of the power required for well pumping." See Bruce Peachey, "Distributed Energy – A Perfect Fit for Oil and Gas Production?" *2008 Canadian Decentralized Energy Conference: Exploring Alternatives to Traditional Generation* (paper presented to Canadian Energy Research Institute, Institute of Sustainable Energy, Environment and Economy and World Alliance for Decentralized Energy, Calgary, September 16, 2008). The return on the systems would be too low for an oil and gas company, but may be acceptable for a municipality with lower profit expectations. Bruce Peachey, New Paradigm Engineering, personal communication, November 12, 2008.

[140] Jacek Majorowitcz and Michal Moore, *Enhanced Geothermal Systems (EGS) Potential in the Alberta Basin*, Draft Report of the Alberta Energy Research Institute, 31, www.aeri.ab.ca/sec/new_res/docs/ Enhanced_Geothermal_Systems.pdf.

[141] Wikipedia, *Power Station*, en.wikipedia.org/wiki/Power_station.

[142] The only exception would be in areas with very low precipitation, where a little water is required to wash the panels. American Wind Energy Association, *Wind Energy FAQ*, www.awea.org/faq/water.html. Some water will also be used for the construction of the panels.

[143] Jeff Bell and Tim Weis, *Greening the Grid: Powering Alberta's Future with Renewable Energy* (Drayton Valley, AB: The Pembina Institute, 2009), 48–50, pubs.pembina.org/reports/greeningthegrid-report.pdf.

[144] American Wind Energy Association, *Wind Energy FAQ*, www.awea.org/faq/water.html. The volume of water used in dry areas is approximately 4 litres per 1,000 kWh, or about 1/500th of the volume consumed by coal-fired power plants. Some water will be used during the construction of wind turbines.

[145] Alberta Electricity System Operator, *Current Supply Demand Report*, ets.aeso.ca/ets_web/ip/Market/Reports/ CSDReportServlet.

[146] Alberta Energy, *Electricity Statistics*, www.energy.gov.ab.ca/Electricity/682.asp.

[147] Jeff Bell and Tim Weis, *Greening the Grid: Powering Alberta's Future with Renewable Energy* (Drayton Valley, AB: The Pembina Institute, 2009), 34, pubs.pembina.org/reports/greeningthegrid-report.pdf.

[148] Jeff Bell and Tim Weis, *Greening the Grid: Powering Alberta's Future with Renewable Energy* (Drayton Valley, AB: The Pembina Institute, 2009), 69, pubs.pembina.org/reports/greeningthegrid-report.pdf. Table 17 on page 69 shows the potential wind energy generation and capacity in 2028, but there is information about wind energy in many sections of the report.

[149] Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 360, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/ 164708.pdf. When this report was written, there was considerable uncertainty about future generation in the area, so the low growth scenario is only 39 million m^3/year in 2025 (and assumes that the Wabamun plant will close down completely), while the high growth scenario assumes that companies will increase their consumption to the full amount allowed in their licences, which would mean an increase to 155 million m^3/year.

[150] Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 303, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/ 164708.pdf.

[151] Todd Hirsch, *Treasure in the Sand: An Overview of Alberta's Oil Sands Resources* (Calgary, AB: Canada West Foundation, 2005). Used with permission of the Canada West Foundation.

[152] See also Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 591, www.assembly.ab.ca/lao/library/egovdocs/ 2007/alen/164708.pdf. See also page 592 and Table 15-8.

[153] In situ waterflood uses water instead of steam to recover the bitumen.

[154] Note that the data on water use is from records that have not been verified.

[155] Note that the data on water use is from records that have not been verified. Water use for the Athabasca River includes 1.8 million m^3 of surface runoff that is captured by the Syncrude tailings ponds area. Alberta Environment, personal communication, January 15, 2009.

[156] Overall, the petroleum sector uses 92% of its withdrawals and returns the remainder to the source. Hardly any groundwater withdrawals are returned to the source. Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 592, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf.

[157] See also Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 594 and 600, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf. Total estimated water use (consumption) for the petroleum sector was 261 million m^3, compared with 96 million m^3 for cooling (thus a factor of 2.7 higher).

[158] The total estimated consumption by the petroleum sector in 2005 was 261million m^3, but the total estimated consumption in all basins excluding the Athabasca was 78 million m^3. The total estimated consumption for cooling everywhere in the province except the Athabasca River basin was 94.5 million m^3 (95.7 million m^3 total, minus 1.2 million m^3 for the Athabasca Basin). Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 466, 593 and 600, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf.

[159] Energy Resources Conservation Board, *Alberta Drilling Activity: Monthly Statistics — December, 2007*, Statistical Series 59, www.ercb.ca/docs/products/STs/st59/st59-2007.pdf.

[160] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry*. Feasibility Study 1730 v.3, written by P. Kim Sturgess, Alberta WaterSMART (Calgary, AB: AERI, 2008), 16, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[161] In 2007, 260,000 m^3 of groundwater and 4,510,000 m^3 of surface water were allocated for drilling wells. This represents 0.08% of groundwater and 0.05% of surface water allocations. Alberta Environment, personal communication, December 11, 2008.

[162] Alberta Environment, personal communication, November 7, 2008.

[163] Water is not used to fracture dry coal seams, which are often found in the Horseshoe Canyon Formation in Central Alberta. Where the coal is dry, nitrogen is most commonly used for fracturing.

[164] Many of the wells drilled in the Athabasca River Basin are likely to be for steam-assisted gravity drainage (SAGD) of bitumen.

[165] This issue and others relating to fracturing are discussed in Mary Griffiths, *Protecting Water, Producing Gas* (Drayton Valley, AB: The Pembina Institute, 2007), 47–48, www.pembina.org/pub/1434. The ERCB has commissioned a report on the use of untreated water for drilling mud.

[166] Clyde Fulton, "Recycling Blowback from Fracture Stimulation of Shallow Gas Wells" (paper presented at the Water and Innovation in the Oil Patch Conference, Petroleum Technology Alliance Canada, Calgary, June 21–22, 2006), www.ptac.org/env/dl/envf0602p07.pdf. Approximately 1 million m^3 of water was used each year for fracturing the 5,000 to 7,000 wells drilled annually in southeast Alberta and southwest Saskatchewan between 2001 and 2005. This water comes from municipal supplies, irrigation canals or other fresh water bodies.

[167] Tim Leshchyshyn, "Produced Formation Water and Recycled Fluids for Propped Fracturing" (paper presented at the Water Efficiency and Innovation Forum for the Oil Patch, Petroleum Technology Alliance Canada, Calgary, June 23, 2005), www.ptac.org/env/dl/envf0502p06.pdf.

[168] A complaint about the use of methanol above the base of groundwater protection resulted in a High Risk Enforcement Action by the ERCB. Alberta Environment, letter to Rob Schwartz, October 17, 2008. Methanol is highly soluble in water and very poisonous. As little as four milliliters can cause blindness and 80 to 150 milliliters can be fatal (or as little as about half a milliliter per kilogram of weight). Canada Safety Council, *Methanol*, www.safety-council.org/info/OSH/methanol.htm.

[169] Mary Griffiths, *Protecting Water, Producing Gas* (Drayton Valley, AB: The Pembina Institute, 2007), www.pembina.org/pub/1434.

[170] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 23–26, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf. Peachey points out that, "Shallow gas requires more water to displace it than oil or deep gas (as the actual volume of gas at reservoir conditions is higher than for deep gas for the same volume at standard conditions) and the water will have to come from natural flow or seepage from other formations . . . ." (p. 24). See also the discussion of the potential impact of shallow gas development in the Athabasca River Basin, in Section 3.5.2.

[171] Bruce Peachey, "Environmental Stewardship — What Does it Mean?" *Process Safety and Environmental Protection* 86 (2008): 230. Peachey points out that, (a) the volume of gas in a shallow reservoir is much larger than in deeper reservoirs as the initial reservoir pressures are much lower, (b) much of the gas is being produced from reservoirs that are located in active fresh water environments, and (c) development of the wells has led to the construction of many roads and pipelines that disrupt the surface water. He explains the concept of a "repressurization water debt" and says, "When the trapped gas is produced this results in large volumes of pressure depleted formation which, if connected to a fresh water aquifer, will naturally fill with water." He notes that the water is likely to flow in from below, since the overlying formation that held the gas is place would be impermeable.

[172] Alberta Energy, *Shallow Rights Reversion*, www.energy.alberta.ca/Tenure/603.asp.

[173] For example, EnCana is applying to drill 16 wells per section to access shallow gas in Suffield in SE Alberta. See, Joyce Hildebrand, "Encana Drilling Plans Would Endanger Rare Suffield Wildlife," opinion editorial, *Edmonton Journal*, April 7, 2008, www.naturecanada.ca/parks_nwa_current_suffield_article2.asp.

[174] Energy Resources Conservation Board, *Requirements for the Surveillance, Sampling, and Analysis of Water Production in Oil and Gas Wells Completed Above the Base of Groundwater Protection (BGWP),* Directive 44 (Calgary, AB: ERCB, 2006), www.ercb.ca/docs/documents/directives/directive044.pdf. A company must report to the ERCB if a well that is completed into a zone where the groundwater is non-saline (i.e., above the base of groundwater protection) produces more than 5 m^3/water per month. Where necessary the ERCB consults with Alberta Environment and can require a company to take whatever action is needed to protect shallow groundwater.

[175] About 90% of coalbed methane wells drilled in Alberta to date are drilled into the Horseshoe Canyon formation, where most of the coals are dry. In the future, an increasing number of wells will probably be drilled into water-bearing formations. Water from shallow formations is non-saline, whereas water from greater depths is saline. Water with more than 4,000 mg/l TDS is defined as saline. Waters with lower salinity are non-saline or low TDS. *Water (Ministerial) Regulation, section 1(1(z),* www.qp.gov.ab.ca/documents/Regs/ 1998_205.cfm?frm_isbn=9780779732326.

[176] Allan Ingelson, Pauline McLean and Jason Gray, *CBM Produced Water — The Emerging Canadian Regulatory Framework* (Calgary, AB: Institute for Sustainable Energy, Environment and Economy, University of Calgary, 2006), www.iseee.ca/files/iseee/ABEnergyFutures-04.pdf. This paper summarizes produced water management options as well as the regulatory context.

[177] See Mary Griffiths, *Protecting Water, Producing Gas* (Drayton Valley, AB: The Pembina Institute, 2007), www.pembina.org/pub/1434 for potential issues relating to coalbed methane and water. The methane gas is adsorbed on the coal rather than being free gas, so it takes up much less space than conventional natural gas. Thus there should be little repressurization debt in deeper CBM and possibly shale gas deposits. Also these deposits are often relatively impermeable to water flow so the rate of water inflow will likely be very low compared to other shallow gas zones. Bruce Peachey, New Paradigm Engineering, personal communication, November 26, 2008.

[178] Allan Ingelson, Pauline McLean and Jason Gray, *CBM Produced Water — The Emerging Canadian Regulatory Framework* (Calgary, AB: Institute for Sustainable Energy, Environment and Economy, University of Calgary, 2006), 23, www.iseee.ca/files/iseee/ABEnergyFutures-04.pdf.

[179] Alberta Environment, *Alberta Environment Guidelines for Groundwater Diversion for Coalbed Methane/Natural Gas in Coal Development* (Edmonton, AB: Alberta Environment, 2004), www3.gov.ab.ca/env/water/Legislation/ Guidelines/groundwaterdiversionguidelines-methgasnatgasincoal.pdf. At the time of writing, these guidelines are being revised.

[180] Government of Alberta, *Coalbed Methane/Natural Gas Multi-Stakeholder Advisory Committee Final Report* (Edmonton, AB: Government of Alberta, 2006), recommendations 3.3.1, 3.3.2 and 3.3.3, www.energy.gov.ab.ca/ NaturalGas/CBM_MAC/THE_FINAL_REPORT.pdf.

[181] Government of Alberta, *Coalbed Methane/Natural Gas Multi-Stakeholder Advisory Committee Final Report* (Edmonton, AB: Government of Alberta, 2006), recommendations 3.5.1, 3.5.2 and 3.5.3.

[182] Mary Griffiths, *Protecting Water, Producing Gas* (Drayton Valley, AB: The Pembina Institute, 2007), 36-44, www.pembina.org/pub/1434.

[183] For a description of produced water, see Argonne National Laboratory, *A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas, and Coal Bed Methane* (Washington, DC: U.S. Department of Energy, 2004), www.ead.anl.gov/pub/doc/ProducedWatersWP0401.pdf.

[184] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry*. Feasibility Study 1730 v.3, written by P. Kim Sturgess, Alberta WaterSMART (Calgary, AB: AERI, 2008), 16, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[185] Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 40, www.pembina.org/pub/612.

[186] In the early stages of a "water flood" large volumes of water will be required to raise or maintain the reservoir pressure near original conditions, but as some of the water is pumped to the surface with the oil, it can be recycled. Since the additional make-up water required will be similar to the volume of oil removed, the total new water required for EOR had been declining at the provincial level since 1973.

[187] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 10, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf.

[188] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry*. Feasibility Study 1730 v.3, written by P. Kim Sturgess, Alberta WaterSMART (Calgary, AB: AERI, 2008), 15, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[189] Alberta Environment, *Water Conservation and Allocation Policy for Oilfield Injection* (Edmonton, AB: Alberta Environment, 2006), www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_Policy.pdf and *Water Conservation and Allocation Guideline for Oilfield Injection* (Edmonton, AB: Alberta Environment, 2006), www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf. The former policy, which dated from 1990, was less stringent and applied only to agricultural regions of the province.

[190] Alberta Environment, *South Saskatchewan River Basin Approved Water Management Plan*, environment.alberta.ca/1674.html.

[191] Energy Resources Conservation Board, *Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008–2017*, ST98–2008 (Calgary, AB: ERCB, 2008), 2-9, www.ercb.ca/docs/products/STs/st98_current.pdf.

[192] Canadian Association of Petroleum Producers, *Canada's Oil Sands: Overview,* www.canadasoilsands.ca/en/overview/.

[193] Alberta Energy, *Alberta's Oil Sands*, oilsands.alberta.ca/.

[194] Energy Resources Conservation Board, *Alberta's Energy Reserves 2007 and Supply/Demand Outlook 2008–2017*, ST98–2008 (Calgary, AB: ERCB, 2008), 3. The ERCB gives the figure of 482 million barrels production for the year.

[195] Canadian Association of Petroleum Producers, *Canada's Oil Sands: Overview,* www.canadasoilsands.ca/en/overview/.

[196] Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), www.pembina.org/pub/612.

[197] Government of Alberta, *Investing in our Future: Responding to the Rapid Growth of Oil Sands Development — Final Report* (Edmonton, AB: Government of Alberta, 2006), 112, www.alberta.ca/home/395.cfm. This report is often referred to as the Radke Report, after the report coordinator, Doug Radke.

[198] Suncor reports 2.29 m^3/m^3 synthetic crude oil and Syncrude reports 2.26 m^3/m^3 synthetic crude oil. Suncor Energy Ltd. *A Closer Look: An Update on Our Progress* (2008), *4,* www.suncor.com/doc.aspx?id=178. This is an update on Suncor's *2007 Report on Sustainability: A Closer Look at Our Journey toward Sustainable Development* (2008), p. 65, www.suncor.com/doc.aspx?id=114. Note that Suncor's operations include in situ projects, which use less water per unit of bitumen produced than do mining operations, so Suncor's average water use for mining

operations may exceed 2.29 m^3/m^3 of synthetic crude oil. Syncrude Canada Ltd, *2007 Sustainability Report* (2008), sustainability.syncrude.ca/sustainability2007/enviro/water/.

Shell's recent 3-year average water consumption for bitumen production from the Athabasca is 2.15 m^3/m^3 bitumen output, and the average including upgrading (at Scotford, using water from the North Saskatchewan River) is 2.23 m^3/m^3 synthetic crude oil. Shell Canada Ltd. *Water: Oil Sands*, www.shell.com/static//ca-en/downloads/about_shell/what_we_do/oil_sands/aosp/oilsands_water.pdf.

Shell Canada Ltd., *Application for the Approval of the Muskeg River Mine Expansion Project*, (2005), Volume 1, Section 10.5, 10-22, indicates that it will require 4.09 m^3 water per m^3 of bitumen produced. See also Jeremy Moorhouse et al., *Under-mining the Environment: The Oil Sands Report Card* (Drayton Valley, AB: The Pembina Institute and Toronto, ON: World Wildlife Fund Canada, 2008), Appendix 4 – Water, 32, www.oilsandswatch.org/pub/1571. The information in the application was confirmed by Shell, based on water use of 28.3 million m^3/year and daily bitumen production of 120,000 bbl/day.

Where necessary, values have been converted. There are approximately 6.292 barrels in a cubic metre. Note that if water volumes are expressed in terms of bitumen production, the requirement for a comparable unit of synthetic crude oil is usually higher.

[199] This figure is based on the initial allocation for Imperial's Kearl project, but the licence permits an increase in the volume of water withdrawn from the Athabasca River at later stages in the project.

[200] Data provided by Alberta Environment shows that in 2007 the surface water allocations from the Athabasca River (including the Tar River) were approximately 440 million m^3/year. The surface runoff allocation is likely to be over 54 million per year, but the absolute figure depends on how much of Imperial's Kearl allocation is taken from the Athabasca River, and how much from surface runoff, as explained in the endnote to Figure 3-7. The total groundwater allocation for energy production in the basin is likely to be more than 51 million m^3/year, but could be up to 61 million m^3/year, if the Kearl project takes a larger proportion of its total allocation from groundwater. The Kearl project is the only one with an allocation of connate water — up to a maximum of 10 million m^3/year.

[201] EPCOR, *Edmonton Water Utility Statistics 2007*, www.epcor.ca/en-ca/Customers/water-customers/pressure-and-supply/Pages/WaterUtilitiesStats2007.aspx. Of the water used, 48% was for 207,000 residential and multi-family dwellings, about 25% was for commercial and industrial use and a further 26% was for nine wholesale/regional customers.

[202] The actual use was about 22% of the total allocation. Alberta Environment data shows that neither Imperial Oil nor Fort Hills diverted any water in 2007; CNRL diverted a small portion of their allocation from the Athabasca River and Shell diverted only surface runoff.

[203] Suncor returned some water to the Athabasca River in 2007, but there were no returns from the Syncrude or Albian Sands projects. Alberta Environment, personal communication.

[204] Figure 3-7 shows the names of the projects and the companies responsible for carrying them out. Note that the data for the CNRL Horizon Project includes water from the Tar River, a tributary of the Athabasca River. Imperial Oil's Kearl Project is allowed a maximum diversion of 56 million m^3/year from all sources, with a maximum of 50 million m^3/year from the Athabasca River. If the volume taken from the river is less than the maximum allowed, the company is permitted to divert a larger volume from other sources (up to a maximum of 52 million m^3/year from surface runoff, 10 million m^3/year from groundwater and 10 million m^3/year from connate water).

[205] D.W. Schindler and W.F. Donahue, "An Impending Water Crisis in Canada's Western Prairie Provinces," *Proceedings of the National Academy of Sciences (PNAS)* 103, no. 19 (2006): 7211, www.pnas.org/cgi/reprint/0601568103v1.

[206] Ibid., 7212.

[207] D.W. Schindler, W.F. Donahue and John P. Thompson, "Future Water Flows and Human Withdrawals in the Athabasca River," in *Running Out of Steam? Oil Sands Development and Water Use in the Athabasca River-Watershed: Science and Market Based Solutions* (Toronto, ON and Calgary, AB: Munk Centre for International Studies, University of Toronto and Environmental Research and Studies Centre, University of Alberta, 2007), 8 and 28 (Figure 14), www.ualberta.ca/ERSC/water.pdf. Figure 14 shows drainage basin subcatchment areal water yields

for May–August, 1971–1975 and 2001–2005. Flows downstream of Ft. McMurray have declined 30%. D.W. Schindler and W.F. Donahue, "An Impending Water Crisis in Canada's Western Prairie Provinces," *Proceedings of the National Academy of Sciences (PNAS)* 103, no. 19 (2006): 7212, www.pnas.org/cgi/reprint/0601568103v1.

[208] Michael Seneka, *Trends in Historical Annual Flows for Major Rivers in Alberta* (Edmonton, AB: Alberta Environment, 2004), environment.gov.ab.ca/info/library/6792.pdf. Referring to the Athabasca River at Athabasca, the report (p. 6) states: "Other than alternating cycles of wetter and drier periods, there does not appear to be any long-tem trend in the annual runoff yields." See also p.15 and Appendix for trend line.

[209] Bruce Peachey, "Environmental Stewardship — What Does it Mean?" *Process Safety and Environmental Protection* 86 (2008): 229.

[210] G. A. Hood and S. E. Bayley, "Beaver *(Castor canadensis)* mitigate the effects of climate on the area of open water in boreal wetlands in western Canada", *Biological Conservation* 141, no. 2 (2008): 556–67. See also, University of Alberta, "Beavers Can Help Ease Drought," news release, February 20, 2008, www.eurekalert.org/pub_releases/2008-02/uoa-bch022008.php. The ability to reduce the effects of drought occurs even though there is more evaporation from a river basin due to the increased area of surface water.

[211] James Bruce, "Oil and Water — Will They Mix in a Changing Climate? The Athabasca River Story," in *Implications of a 2^{0}C Global Temperature Rise on Canada's Water Resources: Athabasca River and Oil Sands Development, Great Lakes and HydroPower Development* (Toronto, ON: The Sage Centre and World Wildlife Fund-Canada, 2006), 14, assets.wwf.ca/downloads/wwf_global warming_implicationsof2degressoncanadawaterresources.pdf. This paper combines an analysis of trends in water availability due to climate change, and the trends in water demand for the oil sands project.

[212] The future water requirements were estimated to be 11.2–19 m^3/sec. in Bruce's paper. A later industry presentation revises the upper number in the range to approximately 16 m^3/sec. Stuart Lunn, Athabasca Regional Issues Working Group, *Oil Sands Mining Cooperation to Meet the Athabasca River Water Management Framework* (presentation to Canadian Association of Petroleum Producers, January 21 2008), slide 13, oilsandsdevelopers.ca/pdfs/Water%20Presentation%20to%20CAPP%20Forum%202008%20LUNN.pdf.

[213] D.W. Schindler, W.F. Donahue and John P. Thompson, "Future Water Flows and Human Withdrawals in the Athabasca River," in *Running Out of Steam? Oil Sands Development and Water Use in the Athabasca River-Watershed: Science and Market Based Solutions* (Toronto, ON and Calgary, AB: Munk Centre for International Studies, University of Toronto and Environmental Research and Studies Centre, University of Alberta, 2007), www.ualberta.ca/ERSC/water.pdf. This report gives an overview of climate changes.

[214] Alberta Environment and Fisheries and Oceans Canada, *Water Management Framework: Instream Flow Needs and Water Management System for the Lower Athabasca* (2007), environment.alberta.ca/documents/Athabasca_RWMF_Technical.pdf.

[215] Ibid., 36.

[216] Ibid., 35.

[217] Dan Woynillowicz and Chris Severson-Baker, *Down to the Last Drop? The Athabasca River and Oil Sands* (Drayton Valley, AB: The Pembina Institute, 2006), www.pembina.org/pub/211.

[218] The Pembina Institute, "Government Protects Oil Sands Industry, Fails to Protect the Athabasca River," news release, March 2, 2007, www.pembina.org/media-release/1384.

[219] James Bruce, "Oil and Water — Will They Mix in a Changing Climate? The Athabasca River Story," in *Implications of a 2^{O}C Global Temperature Rise on Canada's Water Resources: Athabasca River and Oil Sands Development, Great Lakes and HydroPower Development* (Toronto, ON: The Sage Centre and World Wildlife Fund-Canada, 2006), 29, assets.wwf.ca/downloads/wwf_global warming_implicationsof2degressoncanadawaterresources.pdf. The paper cites T.Y. Gan and E. Kerkhoven, "Modeling the Hydrology and Possible Impact of Climate Change on Athabasca River Basin by a Modified ISBA with GCM-scale Data," *Proc. Of 10th Annual Scientific Meeting of Mackenzie GEWEX Study (MAGS)* (2004): 163-176.

[220] D.W. Schindler and W.F. Donahue, “An Impending Water Crisis in Canada’s Western Prairie Provinces,” *Proceedings of the National Academy of Sciences (PNAS)* 103, no. 19 (2006): 7213, www.pnas.org/cgi/reprint/0601568103v1.

[221] For a more detailed description of the impacts, see Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 30–35 and 67–81, www.pembina.org/pub/612.

[222] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 36, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf. Peachey cites a personal communication with Dr. Kevin Parks, Alberta Geological Survey (AGS), who stated that the AGS estimates that 15–25% of river channel flows in northeastern Alberta are directly contributed by groundwater.

[223] ERCB, “ERCB Releases Draft Directive on Oil Sands Tailings Management and Enforcement Criteria,” news releasebackgrounder, June 26, 2008, www.ercb.ca/portal/server.pt/gateway/PTARGS_0_0_303_263_0_43/http;/ercbContent/publishedcontent/publish/ercb_home/news/news_releases/2008/nr2008_14.aspx.

[224] For a discussion of tailings ponds and end pit lakes, see Jennifer Grant, Simon Dyer and Dan Woynillowicz, *Fact or Fiction: Oil Sands Reclamation* (Drayton Valley, AB: The Pembina Institute, 2008), pubs.pembina.org/reports/Fact_or_Fiction-report.pdf. See also ERCB, *Directive 74: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes* (2009), www.ercb.ca/docs/documents/directives/directive074.pdf.

[225] Dave Sauchyn and Suren Kulshreshtha, “Chapter 7: Prairies,” in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 313, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php.

[226] Dave Sauchyn and Suren Kulshreshtha, “Chapter 7: Prairies,” in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 313, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php. Citing another study, the authors point out that naphthenic acids from tailings ponds “could affect up to 25,000 km^2 of oil sands developments and much more if tailings ponds leak or overflow due to extreme climate events.”

[227] Alberta Environment, *Water Conservation and Allocation Policy for Oilfield Injection* (Edmonton, AB: Alberta Environment, 2006), www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_Policy.pdf and Alberta Environment, *Water Conservation and Allocation Guideline for Oilfield Injection* (Edmonton, AB: Alberta Environment, 2006), www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_GUIDELINE.pdf

[228] Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 85, www.pembina.org/pub/612.

[229] ConocoPhillips, *Surmont Thermal Project Submission to the EUB and Alberta Environment Application and EIA*, Volume 2, Part 3 (2001), 3–14.

[230] The potential impacts of in situ operations on fresh groundwater are discussed in more detail in Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), www.pembina.org/pub/612, especially pp. 85–90.

[231] An environmental impact assessment is required for each project, but while each project may examine the potential impacts on their immediate neighbours, there is no overall analysis. This is also hampered by the fact that there is relatively little historical data on groundwater and no consistency in the models used to analyze data.

[232] Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 98–103, www.pembina.org/pub/612.

[233] Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 95–98, www.pembina.org/pub/612. See also, Carolyn Campbell, “In Situ Tar Sands Extraction

Risks Contaminating Massive Aquifers," *Wild Lands Advocate* 16, no. 5 (October 2008), www.albertawilderness.ca/AWRC/WLA/2008/200810_WLA.pdf.

[234] Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 90–98, www.pembina.org/pub/612.

[235] Mary Griffiths and Simon Dyer, *Upgrader Alley: Oil Sands Fever Strikes Edmonton* (Drayton Valley, AB: The Pembina Institute, 2008), 1, www.pembina.org/pub/1654. Chapter 6 of the report examines the use of water for the upgraders. For an update see Alberta's Industrial Heartland, *Project Status*, www.industrialheartland.com/index.php?option=com_content&task=view&id=130&Itemid=160.

[236] As noted above, the City of Edmonton treats about 130 million m^3 of water a year, but 90–96% of the water flows back into the river after treatment.

[237] Alberta Environment, *The Water Management Framework for the Industrial Heartland and Capital Region* (Edmonton, AB: Alberta Environment, 2007), environment.gov.ab.ca/info/library/7864.pdf. The framework includes plans for an integrated wastewater treatment system, so that in the future companies will use wastewater rather than drawing water directly from the North Saskatchewan River. This system has some benefits as it reduces the load of nutrients and other substances discharged to the river, but it also reduces river flows. The instream flow needs of the river have not yet been determined.

[238] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry*. Feasibility Study 1730 v.3, written by P. Kim Sturgess, Alberta WaterSMART (Calgary, AB: AERI, 2008), 11, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[239] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry*. Feasibility Study 1730 v.3, written by P. Kim Sturgess, Alberta WaterSMART (Calgary, AB: AERI, 2008), 17, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf. Alberta Environment does not show separate province-wide predictions for drilling in its 2007 report, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental (Edmonton, AB: Alberta Environment, 2007), 596–597, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf.

[240] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry*. Feasibility Study 1730 v.3, written by P. Kim Sturgess, Alberta WaterSMART (Calgary, AB: AERI, 2008), 22, Figure 7, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[241] Alberta Environment's forecast (Alberta Environment, *Current and Future Water Use in Alberta*, prepared by AMEC Earth and Environmental [Edmonton, AB: Alberta Environment, 2007], 596, www.assembly.ab.ca/lao/library/egovdocs/2007/alen/164708.pdf) includes allocation for the proposed Syncrude, Imperial, Deer Creek and Synenco projects, but does not include any later applications.

[242] See Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry*. Feasibility Study 1730 v.3, written by P. Kim Sturgess, Alberta WaterSMART (Calgary, AB: AERI, 2008), 18–19, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf, for a discussion of the methodology used.

[243] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 31, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf.

[244] Lori Walker, "'We Can No Longer Be Sacrificed': First Nations Resistance to Tar Sands Development Is Growing," *Briarpatch Magazine* (June/July 2008), briarpatchmagazine.com/category/magazine/junejuly-2008-indigenoussettler-relations/.

[245] Darcy Henton, "Territory Demands Action on Water", *Edmonton Journal*, August 17, 2008, www.canada.com/edmontonjournal/story.html?id=87d53aba-5cd0-46c4-8130-9845d60c25f7.

[246] Alberta Agriculture, Food and Rural Development, *Water Wells that Last for Generations: Module 1 Understanding Groundwater*, www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/wwg404.

[247] Alberta Environment. *Groundwater Observation Well Network,* www3.gov.ab.ca/env/water/gwsw/quantity/waterdata/gwdatafront.asp.

[248] Komex International Ltd., *Groundwater Monitoring Networks Master Plan Development: Final Report.* Prepared for Alberta Environment (2005), ii.

[249] For an overview of groundwater monitoring in Alberta, see Mary Griffiths, *Protecting Water, Producing Gas* (Drayton Valley, AB: The Pembina Institute, 2007), 12–18, www.pembina.org/pub/1434, and Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 65–67, www.pembina.org/pub/612.

[250] Komex International Ltd., *Groundwater Monitoring Networks Master Plan Development: Final Report.* Prepared for Alberta Environment (2005), 49.

[251] Rosenberg International Forum on Water Policy, *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta* (Berkeley, CA: Rosenberg International Forum on Water Policy, University of California, 2007), 10, rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf.

[252] Ibid., 13.

[253] Meghan Beveridge and Danielle Droitsch, *Piping Water Between Watersheds: An Analysis of Basin-to-basin and Sub-basin-to-sub-basin Diversions in Alberta* (Canmore, AB: Water Matters Society of Alberta, 2008), 10, www.water-matters.org/docs/piping-water-between-watersheds.pdf.

[254] Government of Alberta, *Water for Life: Alberta's Strategy for Sustainability* (Edmonton, AB: Alberta Environment, 2003), 8, www.waterforlife.gov.ab.ca/docs/strategyNov03.pdf. The medium-term (2007/8 to 2009/10) goal is that, "All sectors are demonstrating best management practices and improving efficiency and productivity associated with water use." The long-term (2010/11 to 2013/14) goal is that, "The overall efficiency and productivity of water use in Alberta has improved by 30% from 2005 levels by 2015 (firm targets to be determined by the Provincial Water Advisory Council)."

[255] Alberta Water Council, *Recommendations for Water Conservation, Efficiency and Productivity Planning Sector Planning* (Edmonton, AB: Alberta Water Council, 2008), 1, www.albertawatercouncil.ca/Portals/0/pdfs/CEP%20Sector%20Plan%20Final%20Report.pdf.

[256] Alberta Water Council, *Alberta Water Council Recommendations for a New Alberta Wetland Policy* (Edmonton, AB: Alberta Water Council, 2008), www.albertawatercouncil.ca/Portals/0/pdfs/WPPT%20Policy%20web.pdf and Alberta Water Council, *Alberta Water Council Recommendations for an Alberta Wetland Policy Implementation Plan* (Edmonton, AB: Alberta Water Council, 2008), www.albertawatercouncil.ca/Portals/0/pdfs/WPPT%20Plan%20web.pdf.

[257] The *Alberta Water Council Recommendation for a New Alberta Wetland Policy* was submitted to the Minister of Environment in September 2008. The Alberta Chamber of Resources and the Canadian Association of Petroleum Producers submitted non-consensus letters to the Chair of the Alberta Water Council as they objected to the principle of no-net loss of wetlands. A response to these letters was signed by 12 non-governmental organization representatives at the Alberta Water Council. These letters can be found on the Alberta Water Council website at www.albertawatercouncil.ca/Projects/WetlandPolicyProjectTeam/tabid/103/Default.aspx.

[258] Dave Sauchyn and Suren Kulshreshtha, "Chapter 7: Prairies," in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 295, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php.

[259] Bates et al., *Climate Change and Water* (Technical Paper of the Intergovernmental Panel on Climate Change, IPCC Secretariat, Geneva, 2008), 103, www.ipcc.ch/pdf/technical-papers/ccw/chapter5.pdf.

[260] Jeff Bell and Tim Weis, *Greening the Grid: Powering Alberta's Future with Renewable Energy* (Drayton Valley, AB: The Pembina Institute, 2009), 36, pubs.pembina.org/reports/greeningthegrid-report.pdf. The authors state, "The Canadian Hydro Association estimates that Alberta has more than 11,500 MW of remaining economic hydro potential in the province including both reservoir and run-of-the river projects." Referring to the *Study of the*

Hydropower Potential in Canada, a report prepared by the EEM for the Canadian Hydropower Association in March 2006, Bell and Weis point out that although some of the hydro-electric potential is low impact, much would be higher impact development. Thus further study of the resource is necessary to determine what could be developed in a low-impact manner.

[261] Alberta Energy Research Institute, *Alberta Energy Research Institute 2008–2013 Strategic Business Plan* (Calgary, AB: AERI, 2007), 39, www.aeri.ab.ca/sec/new_res/docs/AERI_2008-13_BusinessPlan.pdf.

[262] Jeff Bell and Tim Weis, *Greening the Grid: Powering Alberta's Future with Renewable Energy* (Drayton Valley, AB: The Pembina Institute, 2009), 1, pubs.pembina.org/reports/greeningthegrid-report.pdf.

[263] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 29, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf, says: "Since 1999 there has been over 1,600 MW of cogeneration capacity (efficiencies of 70% or more) installed at oil sands, petrochemical and pipeline compressor station sites in Alberta, which has reduced demand for stand-alone coal or gas power generation (efficiency of 30%)."

[264] For example, one report estimated that there may be potential for over 1,000 MW of cogeneration potential at Alberta's sour gas plants. See PTAC Knowledge Centre, *Upstream Oil and Gas Energy Efficiency,* www.ptac.org/links/EnergyEfficiencyKC/SourGas.pdf.

[265] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 31–32, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf.

[266] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 29, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf.

[267] Bruce Peachey, "Distributed Energy — A Perfect Fit for Oil and Gas Production?" in *2008 Canadian Decentralized Energy Conference: Exploring Alternatives to Traditional Generation* (Canadian Energy Research Institute, Institute of Sustainable Energy, Environment and Economy and World Alliance for Decentralized Energy, Calgary, September 16, 2008), slide 12. In a personal communication, Bruce Peachey explained how he calculated this figure using data from Natural Resources Canada, *Canada's Energy Outlook, The Reference Case 2006,* www.nrcan-rncan.gc.ca/inter/publications/peo_e.html.

[268] The capital cost of power generation equipment might be similar to the cost of equipment for dehydration and compression to allow piping of small volumes of solution or vent gas. If the gas is used to generate electricity on site, it will increase on-site GHG emissions, but provincial GHG emissions will decrease (since natural gas produces fewer emissions that coal-fired electricity, which supplies much of the provincial electricity at the present time). The companies should thus get some credit for this overall reduction in GHGs. Bruce Peachey, New Paradigm Engineering, personal communication, November 12, 2008.

[269] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry*. Feasibility Study 1730 v.3, written by P. Kim Sturgess, Alberta WaterSMART (Calgary, AB: AERI, 2008), 11, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[270] Next generation technologies include the treatment of contaminated, extremely saline water (i.e., more than 10,000 mg/L TDS) and "blue-sky" technologies such as nanotechnology, biological treatment and waterless bitumen extraction/production. See Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry.* Feasibility Study 1730 v.3, written by P. Kim Sturgess, Alberta WaterSMART (Calgary, AB: AERI, 2008), 45, Appendix B, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[271] For example, the Redwater field produces over 100 m^3 water/m^3 of oil, but all the water produced is reinjected to bring more oil to the producing wells. Also, less energy and equipment is required to desalinate hydrocarbon free water from a deep saline aquifer than to treat oil contaminated produced water of a similar salinity from a hydrocarbon-bearing formation. Water produced with gas is not needed for reinjection, but the volume is much lower and it is widely distributed. Bruce Peachey, New Paradigm Engineering, personal communication, November 12, 2008.

[272] Rosenberg International Forum on Water Policy, *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta* (Berkeley, CA: Rosenberg International Forum on Water Policy, University of California, 2007), 10, rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf.

[273] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry* (Calgary, AB: AERI, 2008), 34, Figure 11, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[274] Ibid., 5.

[275] Ibid., 36.

[276] Ibid., 32.

[277] Fossil Water Corporation, *Produced Water Beneficial Re-Use — High TDS Waters* (Calgary, AB: Petroleum Technology Alliance Canada, 2007), 4, www.ptac.org/etalk/dl/HighTDS.pdf. See also, Fossil Water Corporation, *Produced Water Beneficial Re-Use — Low TDS Waters* (Calgary, AB: Petroleum Technology Alliance Canada, 2007), 4, www.ptac.org/etalk/dl/LowTDS.pdf. This report focuses on water with low TDS and examines potential treatment technologies as well as beneficial reuse options. It deals with all sources of produced water and does not identify the total volume of water produced from CBM wells. Water production tends to decline as gas production increases, so CBM wells do not provide a long-term sustainable supply of water.

[278] Fossil Water Corporation, *Produced Water Beneficial Re-Use — Low TDS Waters,* (Calgary, AB: Petroleum Technology Alliance Canada, 2007), 18. This report identifies various water treatment options.

[279] Florence Hum et al., *Review of Produced Water Recycle and Beneficial Reuse* (Calgary, AB: Institute for Sustainable Energy, Environment and Economy, University of Calgary, 2005), 35, www.iseee.ca/files/iseee/ABEnergyFutures-19.pdf.

[280] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry* (Calgary, AB: AERI, 2008), 28, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[281] Patrick Horner, "Mobile Oilfield Wastewater Recycling" (paper presented at the Petroleum Technology Alliance Water Efficiency and Innovation in the Oilpatch Forum, Calgary, 2005), www.ptac.org/env/dl/envf0502p10.pdf.

[282] See Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 115–117, www.pembina.org/pub/612.

[283] Mary Griffiths, *Protecting Water, Producing Gas* (Drayton Valley, AB: The Pembina Institute, 2007), 75–77, www.pembina.org/pub/1434. This report provides an overview of issues that need to be considered when reusing produced water.

[284] Petroleum Technology Alliance Canada, *Filling the Gap: Unconventional Gas Technology Roadmap* (Calgary, AB: PTAC, 2006), 37 and 39, www.ptac.org/cbm/dl/PTAC.UGTR.pdf. This report identifies various current technologies and some advanced water treatments.

[285] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry* (Calgary, AB: AERI, 2008), 28, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf. At present, treated municipal water is used for well development in some areas.

[286] Arlene Kwasniak, *Waste Not Want Not: A Comparative Analysis and Critique of Legal Rights to Use and Re-use Produced Water — Lessons for Alberta*, (Calgary, AB: Institute for Sustainable Energy, Environment and Economy, University of Calgary, 2006), www.iseee.ca/files/iseee/ABEnergyFutures-05.pdf.

[287] Fossil Water Corporation, *Produced Water Beneficial Re-Use – High TDS Waters* (Calgary, AB: Petroleum Technology Alliance Canada, 2007), 42, www.ptac.org/etalk/dl/HighTDS.pdf.

[288] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry* (Calgary, AB: AERI, 2008), 29–30, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[289] Melanie Collinson, "Taming the Tailings," *Oilweek*, September 2008, 45-50, www.oilweek.com/articles.asp?ID=602.

[290] Jennifer Grant, Simon Dyer and Dan Woynillowicz, *Fact or Fiction: Oil Sands Reclamation* (Drayton Valley, AB: The Pembina Institute, 2008), 29–31, pubs.pembina.org/reports/Fact_or_Fiction-report.pdf.

[291] Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 117–118, www.pembina.org/pub/612.

[292] Randy Mikula, Team Leader, Emulsions and Tailings, Advanced Separation Technologies, Natural Resources Canada, CANMET Energy Technology Centre, quoted in Melanie Collinson, "Taming the Tailings," *Oilweek*, September 2008, 4, www.oilweek.com/articles.asp?ID=602.

[293] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry* (Calgary, AB: AERI, 2008), 32, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[294] Dan Woynillowicz and Chris Severson-Baker, *Down to the Last Drop? The Athabasca River and Oil Sands* (Drayton Valley, AB: The Pembina Institute, 2006), www.pembina.org/pub/211.

[295] Horizon Oil Sands Project, "Off-stream Water Storage," in *2008 Steward of Excellence Award Nominations* (Calgary, AB: Canadian Petroleum Producers, undated), www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=139249.

[296] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 41, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf. Peachey refers to underground storage in the context of hydroelectric generation, but this storage method might also be useful for oil sands operations. See also, The Geological Society of America, "Droughts and Reservoirs: Finding Storage Space Underground," news release, September 18, 2006, www.geosociety.org/news/pr/06-39.htm.

[297] Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 119–121, www.pembina.org/pub/612.

[298] Graham Chandler, "What Lies Beneath," *Oilweek*, September 2008, 55, www.oilweek.com/articles.asp?ID=601.

[299] The main savings in water in direct contact steam generation are due to, (a) capture of water of combustion as the flue gases including water vapour are all injected with the steam, and, (b) potentially, the utilization of untreated produced water that reduces water losses in the water treatment process. About two tonnes of water are generated per tonne of methane burned as fuel or about one tonne of water per tonne of liquid fuel burned. Direct contact generation also improves over all energy efficiency by 15–20% so reduces fuel use and GHG emissions. Bruce Peachey, New Paradigm Engineering, personal communication, November 12, 2008. For a summary of the carbonate formations, refer to the presentations made at the Petroleum Technology Alliance Canada's Technology Roadmap for Inaccessible Bitumen and Heavy Oil Resources Workshop, 2006, www.ptac.org/cho/chow0601.html, especially Marc Godin, "Bitumen in Carbonate Formations," www.ptac.org/cho/dl/chow0601p04.pdf**.**

[300] Alberta Energy Research Institute, *Alberta Energy Research Institute 2008–2013 Strategic Business Plan* (Calgary, AB: AERI, 2007), www.aeri.ab.ca/sec/new_res/docs/AERI_2008-13_BusinessPlan.pdf.

[301] Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 36–37, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf, refers to oil sands operations.

[302] ERCB, *Directive 74: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes* (2009), www.ercb.ca/docs/documents/directives/directive074.pdfhttp://. This directive, which aims to reduce tailings, may result in an increase in the volume of water recycled.

[303] Andrew Nikiforuk, "Liquid Asset: Could the Oil Sands, Canada's Greatest Economic Project, Come Undone Simply Because No One Thought about Water?" *Globe and Mail, Report on Business*, March 28, 2008, www.reportonbusiness.com/servlet/story/RTGAM.20080327.wrob-0408-liquidasset/BNStory/specialROBmagazine/home?cid=al_gam_mostemail.

[304] Rosenberg International Forum on Water Policy, *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta* (Berkeley, CA: Rosenberg International Forum on Water

Policy, University of California, 2007), 24, rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf. For information on the Rosenberg International Water Forum on Water Policy see rosenberg.ucanr.org/index.html.

305 The Pembina Institute has made recommendations to help reduce water consumption and improve water management in previous publications: Mary Griffiths, Amy Taylor and Dan Woynillowicz, *Troubled Waters, Troubling Trends: Technology and Policy Options to Reduce Water Use in Oil and Oil Sands Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2006), 141–154, www.pembina.org/pub/612 and Mary Griffiths, *Protecting Water, Producing Gas* (Drayton Valley, AB: The Pembina Institute, 2007), 47–48, www.pembina.org/pub/1434. Those recommendations that are relevant to climate change, water and energy are included in this report.

306 Clare Demerse and Matthew Bramley, *Choosing Greenhouse Gas Emission Reduction Policies in Canada* (Drayton Valley, AB: The Pembina Institute, 2008), 1, climate.pembina.org/pub/1720: "As approximately 50% of Canadian emissions come from heavy industry, a portion of the economy that has shown itself responsive to price signals, carbon pricing appears to be a crucial piece of the puzzle in cutting Canada's emissions." See also Matthew Bramley, *The Case for Deep Reductions: Canada's Role in Preventing Dangerous Climate Change* (Drayton Valley, AB: The Pembina Institute, 2005), climate.pembina.org/pub/536.

307 This price signal should apply not only to stack emissions and so on, but also to fugitive emissions. A clear price signal would, for example, encourage companies to take measure to check equipment and reduce fugitive emissions from valves, tanks and other equipment. For example, a company might install equipment to reduce fugitive emissions from compressors. See CETAC-West, *Capturing Fugitive Emissions to Optimize Fuel Usage of Compressor Station Engines* (undated), www.advancededucation.gov.ab.ca/technology/wwwtechnology_asp/techprior/techcomm/actionplan/pdf/success_stories/Productsheet4.pdf.

308 Matthew Bramley and Clare Demerse, *The Pembina Institute's Perspective on Carbon Pricing in Canada* (Drayton Valley, AB: The Pembina Institute, 2008), 1, climate.pembina.org/pub/1584.

309 The Pembina Institute and the David Suzuki Foundation, *Deep Reductions, Strong Growth: An Economic Analysis Showing Canada Can Prosper Economically While Doing its Share to Prevent Dangerous Climate Change* (Drayton Valley, AB: The Pembina Institute and Vancouver, BC: David Suzuki Foundation, 2008), 2, www.pembina.org/pub/1740.

310 Marlo Raynolds, *A Checklist for Alberta's Climate Change Plan: What to Look for in a Comprehensive Action Plan for Alberta to Fight Global Warming* (Drayton Valley, AB: The Pembina Institute, 2008), 3 and 4, pubs.pembina.org/reports/ABCCPolicyChecklist.pdf.

311 Marlo Raynolds, *A Checklist for Alberta's Climate Change Plan* (Drayton Valley, AB: The Pembina Institute, 2008), 3 and 4, pubs.pembina.org/reports/ABCCPolicyChecklist.pdf. The citation is taken from footnote c on page 4. For a full list of conditions that the Pembina Institute believes should be attached to the permanent geologic storage of CO_2, the reader is referred to *The Pembina Institute's Perspective on Carbon Dioxide Capture and Storage (CCS)*, available online at www.pembina.org/pub/1542.

312 The Pembina Institute and the David Suzuki Foundation, *Deep Reductions, Strong Growth: An Economic Analysis Showing Canada Can Prosper Economically While Doing its Share to Prevent Dangerous Climate Change* (Drayton Valley, AB: The Pembina Institute and Vancouver, BC: David Suzuki Foundation, 2008), 3. www.pembina.org/pub/1740.

313 Coal-fired power plants can be run using aerial coolers instead of water cooling, but this alternative reduces the overall plant efficiency (and thus creates more GHGs per unit of electricity available for purchase) since some of the produced energy is required to run the fans on the coolers and the capital costs of aerial coolers are higher than for water cooling. The operating temperature tends to be higher with aerial coolers than with water cooling, which reduces the power from the steam turbines. Bruce Peachey, New Paradigm Engineering, personal communication, November 12, 2008.

314 Bates et al., *Climate Change and Water* (Technical Paper of the Intergovernmental Panel on Climate Change, IPCC Secretariat, Geneva, 2008), 136, www.ipcc.ch/pdf/technical-papers/ccw/chapter8.pdf.

[315] Government of Alberta, *Water for Life: Alberta's Strategy for Sustainability* ((Edmonton, AB: Alberta Environment, 2003), 27, www.waterforlife.gov.ab.ca/docs/strategyNov03.pdf.

[316] Ibid.

[317] See, for example, one of the recommendations of the Advisory Committee on Water Use Practice and Policy (set up by former Minister of Environment Lorne Taylor to address water use for oilfield injection and for in situ recovery), that "In 2007, the Government of Alberta should ensure that specific targets are established and that actions to achieve those targets are initiated." Advisory Committee on Water Use Practice and Policy, *Final Report*. Submitted to Minister of Environment Lorne Taylor (2004), 21, www.waterforlife.gov.ab.ca/docs/Final_Recommend_Online.pdf.

[318] Vic Adamowicz, "Water Use and Alberta Oil Sands Development — Science and Solutions: An Analysis of Options," in *Running Out of Steam? Oil Sands Development and Water Use in the Athabasca River-Watershed: Science and Market Based Solutions* (Toronto, ON, and Calgary, AB: Munk Centre for International Studies, University of Toronto and Environmental Research and Studies Centre, University of Alberta, 2007), 49–50, www.ualberta.ca/ERSC/water.pdf.

[319] Advisory Committee on Water Use Practice and Policy, *Final Report*, Submitted to Minister of Environment Lorne Taylor (2004), 19, www.waterforlife.gov.ab.ca/docs/Final_Recommend_Online.pdf.

[320] Alberta Environment, *Water Conservation and Allocation Policy for Oilfield Injection* (Edmonton, AB: Alberta Environment, 2006), 7, www.waterforlife.gov.ab.ca/docs/Oilfield_Injection_Policy.pdf.

[321] Alberta Energy Research Institute, *A 2020 Fresh Water Neutral Upstream Petroleum Industry* (Calgary, AB: AERI, 2008), 24, www.aeri.ab.ca/sec/new_res/docs/Fresh_Water_Neutral_Upstream_Petroleum_Industry.pdf.

[322] Robert George, Alberta Environment, "2008 — Groundwater Policy" (presentation made at the Petroleum Technology Alliance of Canada's 2008 Spring Water Forum, May 7, 2008), www.ptac.org/env/dl/envf0802p02.pdf.

[323] Bates et al., *Climate Change and Water* (Technical Paper of the Intergovernmental Panel on Climate Change, IPCC Secretariat, Geneva, 2008), 136, www.ipcc.ch/pdf/technical-papers/ccw/chapter8.pdf.

[324] Rosenberg International Forum on Water Policy, *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta* (Berkeley, CA: Rosenberg International Forum on Water Policy, University of California, 2007), 14, rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf.

[325] D.W. Schindler and W.F. Donahue, "An Impending Water Crisis in Canada's Western Prairie Provinces" *Proceedings of the National Academy of Sciences (PNAS)* 103, no. 19 (2006): 7214, www.pnas.org/cgi/reprint/0601568103v1.

[326] Alberta Water Council, *Alberta Water Council Recommendations for a New Alberta Wetland Policy* (Edmonton, AB: Alberta Water Council, 2008), www.albertawatercouncil.ca/Portals/0/pdfs/WPPT%20Policy%20web.pdf and Alberta Water Council, *Alberta Water Council Recommendations for an Alberta Wetland Policy Implementation Plan* (Edmonton, AB: Alberta Water Council, 2008), www.albertawatercouncil.ca/Portals/0/pdfs/WPPT%20Plan%20web.pdf. We recommend that the recommendations be accepted as submitted by the Alberta Water Council; as noted earlier, two industry organizations wanted the policy to be weaker.

[327] Alberta Environment is currently reviewing this. See Robert George, Alberta Environment, "2008 — Groundwater Policy" (presentation made at the Petroleum Technology Alliance of Canada's 2008 Spring Water Forum, May 7, 2008), www.ptac.org/env/dl/envf0802p02.pdf.

[328] Rosenberg International Forum on Water Policy, *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta* (Berkeley, CA: Rosenberg International Forum on Water Policy, University of California, 2007), 15, rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf.

[329] Under the *Water Act*, Alberta Environment is responsible for all groundwater. The *Water (Ministerial) Regulation, section 1(1(z)* currently defines saline water as water with more than 4,000 mg/l TDS; www.qp.gov.ab.ca/documents/Regs/1998_205.cfm?frm_isbn=9780779732326.

[330] The Pembina Institute first pointed out in 2003 that the U.S. protects underground sources of drinking water with up to 10,000 mg/l total dissolved solids to ensure an adequate supply for present and future generations. See Mary Griffiths and Chris Severson-Baker, *Unconventional Gas: The Environmental Challenges of Coalbed Methane Development in Alberta* (Drayton Valley, AB: The Pembina Institute, 2003), 53, www.pembina.org/pub/157.

[331] Rosenberg International Forum on Water Policy, *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta* (Berkeley, CA: Rosenberg International Forum on Water Policy, University of California, 2007), 21, rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf

[332] Dave Sauchyn and Suren Kulshreshtha, "Chapter 7: Prairies," in *From Impacts to Adaptation: Canada in a Changing Climate 2007*, ed. Donald Lemmen et al. (Ottawa, ON: Government of Canada, 2008), 275–328, adaptation.nrcan.gc.ca/assess/2007/pr/index_e.php. This report looks at the type of adaptation that might be required. Bruce Peachey, *Strategic Needs for Energy Related Water Use Technologies: Water and the EnergyINet* (EnergyINet, 2005), 36, www.aeri.ab.ca/sec/new_res/docs/EnergyINet_and_Water_Feb2005.pdf, recommends detailed studies of the Atahbasca River to provide projections of water availability over the next 50–100 years.

[333] Rosenberg International Forum on Water Policy, *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta* (Berkeley, CA: Rosenberg International Forum on Water Policy, University of California, 2007), 10, rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf

[334] See Section 4.1.

[335] A report from the International Panel on Climate Change pointed out that, "Most of the impact studies of climate change on water stress in countries assess demand and supply on an annual basis. Analysis at the monthly or higher temporal resolution scale is desirable, since changes in seasonal patterns and the probability of extreme events may offset the positive effect of increased availability of water resources." Bates et al., *Climate Change and Water* (Technical Paper of the Intergovernmental Panel on Climate Change, IPCC Secretariat, Geneva, 2008), 136, www.ipcc.ch/pdf/technical-papers/ccw/chapter8.pdf.

[336] For proposals on protecting the Athabasca River, see Dan Woynillowicz and Chris Severson-Baker, *Down to the Last Drop: The Athabasca River and Oil Sands* (Drayton Valley, AB: The Pembina Institute, 2008), www.pembina.org/pub/211.

[337] Alberta Water Council, *Water for Life: Recommendations for Renewal* (Edmonton, AB: Alberta Environment, 2003), 16, www.albertawatercouncil.ca/Portals/0/pdfs/Renewal_Final_Report.pdf.

[338] Rosenberg International Forum on Water Policy, *Report of the Rosenberg International Forum on Water Policy to the Ministry of Environment, Province of Alberta* (Berkeley, CA: Rosenberg International Forum on Water Policy, University of California, 2007), 18, rosenberg.ucanr.org/documents/RegRoseAlbertaFinalRpt.pdf

[339] Ibid., 10.

[340] Alberta Ingenuity Fund, "Water Institute to Fund Practical, Innovative Water Research," media release, October 3, 2007, www.albertaingenuity.ca/index.php?media-room,news-releases,14.

[341] Institute for Sustainable Energy, Environment and Economy, *Alignment with Alberta's Water Strategy,* www.iseee.ca/collaboration/water_strategy.

[342] Alberta Research Council, *Water Resource Management: Technology and Innovations,* www.arc.ab.ca/areas-of-focus/water-resource-management/integrated-water-management/research/.

[343] Natural Resources Canada CANMET Energy Technology Centre, canmetenergy.nrcan.gc.ca/eng/oil_sands/water_management.html.

[344] Petroleum Technology Alliance Canada, www.ptac.org/techenvf.html.

[345] The Pembina Institute limits its recommendation to the use of water for energy production, since this is the area on which it focuses.

[346] Vic Adamowicz, "Water Use and Alberta Oil Sands Development — Science and Solutions: An Analysis of Options," in *Running Out of Steam? Oil Sands Development and Water Use in the Athabasca River-Watershed: Science and Market Based Solutions* (Toronto, ON, and Calgary, AB: Munk Centre for International Studies,

University of Toronto and Environmental Research and Studies Centre, University of Alberta, 2007), 40–58, www.ualberta.ca/ERSC/water.pdf.

[347] Government of South Australia, *River Murray: Water Trade Overview* (Adelaide, South Australia: Department of Water Land and Biodiversity Conservation, 2008), www.dwlbc.sa.gov.au/murray/trade/index.html.

[348] Alberta Water Council, *Review of Implementation Progress of* Water for Life*, 2005-2006* (Edmonton, AB: Alberta Water Council, 2007), 1, www.albertawatercouncil.ca/Portals/0/pdfs/Review_Report_2005-06.pdf.

[349] John Thompson, resource economist, cited in Andrew Nikiforuk, "Liquid Asset: Could the Oil Sands, Canada's Greatest Economic Project, Come Undone Simply Because No One Thought about Water?" *Globe and Mail, Report on Business,* March 28,2008, www.reportonbusiness.com/servlet/story/RTGAM.20080327.wrob-0408-liquidasset/BNStory/specialROBmagazine/home?cid=al_gam_mostemail.