Paper #1-6

UNCONVENTIONAL OIL

Prepared by the Unconventional Oil Subgroup
of the
Resource & Supply Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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Potential of North American Unconventional Oil Resource

Canadian Oil Sands, US Oil Sands, Tight Oil, Oil Shale, and Canadian Heavy Oil

Abstract

North America's unconventional resource is massive - oil in the ground is over 3.5 trillion barrels - nearly two times larger than all of the world's economically recoverable conventional oil. Even though only a fraction of this oil can be commercially produced, it is already an important pillar of North American oil supply - equivalent to 14 percent of total US crude oil demand[1]. Today, the majority of unconventional production comes from the Canadian oil sands.

Oil supply from North America's unconventional resources is forecast to grow. In our likely scenario, unconventional supply grows from 2 MB/D now to 7 MB/D by 2035. By 2035, unconventional production is equivalent to 50 percent of US crude oil demand. The majority of the growth stems from the Canadian oil sands. However, tight oil – oil produced from tight formations using a combination of horizontal wells and fracturing - also makes a sizable contribution. Tight oil production grows from 400,000 B/D now to between 2 and 3 MB/D by 2035. These are early days for tight oil production, and its full potential could even exceed current estimates.

The Canadian oil sands, by far the world's largest source of unconventional oil supply, offer a constructive example for unconventional resource development. Ingredients for success include, long-term investment supported by public-private partnerships and fiscal measures aimed at risk reduction. These factors, combined with high-cost investments in actual field trials (an activity critical to advancing new methods and ideas), were critical in the development of the Canadian oil sands industry. For non-commercial unconventional resources in the US (oil shale and oil sands), the ingredients that were critical to the development of the Canadian oil sands are, for the most part, absent.

Actions most likely to foster sustainable economic and environmentally sustainable growth of North American unconventional oil supply include; clarifying environmental and regulatory aspects of unconventional supply that are uncertain, and creating an environment that fosters continuous technical innovation and healthy investment.

Potential of North American Unconventional Oil Resource

Canadian Oil Sands, US Oil Sands, Tight Oil, Oil Shale, and Canadian Heavy Oil

1. Executive Summary

Unconventional Resource and Supply

North America's unconventional resource is massive and largely untapped. Oil in the ground is over 3.5 trillion barrels – nearly two times larger than all of the world's currently economically recoverable conventional oil. But, therein lies the challenge, North America's unconventional oil is just that - in the ground. Only 5 percent of the oil in place is recoverable using current technologies. North America is defined as Canada and the United States for this paper – Mexico is not included.

North America's unconventional resource is already an important part of oil supply; capable of providing 14 percent of total US crude oil demand[2]. Although just a fraction of the resource has been tapped, unconventional oil is already an important part of US oil supply – the majority of production is derived from the Canadian oil sands.

In our likely scenario, North American unconventional supply grows from 2 to 7 MB/D over the next 25 years. By 2035, unconventional production is equivalent to 50 percent of US crude oil demand. The majority of supply growth stems from Canadian oil sands and tight oil. US oil sands and US oil shale, resources with no commercial production today, make relatively small contributions. However for any supply growth from these new sources of supply, major innovations are required. In our high case scenario – a true stretch case for unconventional supply growth – production reaches 10 MB/D by 2035. However, without a radical shift in government policy combined with successful and rapid development of new technologies, this projection is highly unlikely. In our low case scenario, more challenged economics (higher environmental costs, less incentives, and environmental limits) ultimately constrain growth to 3.7 MB/D.

The newest innovation in unconventional supply is tight oil; production is projected to grow from about 400,000 B/D to between 2 and 3 MB/D by 2035. These are early days for tight oil production - its full potential could even exceed current estimates. In the past, the oil was locked in low-permeability siltstones, sandstones, and carbonates – unable to flow through the tight rock. However, recent advancements in horizontal drilling and well fracturing technologies are now enabling production. Notable plays include the Bakken play in the Williston Basin (spanning Saskatchewan, Manitoba, Montana, and North Dakota), the Eagle Ford play in Texas, the Cardium play in Alberta, and the Miocene Monterey play of California. Numerous other plays have potential. Although tight oil is not likely to become a “game changer” (in the way that North American shale gas has recently emerged), it’s poised to become an important new source of North American oil supply.

Aspects of Unconventional Supply

The Canadian oil sands, by far the world’s largest source of unconventional oil supply, offers a constructive example for unconventional resource development – with both positive and negative attributes. Ingredients for success include, long-term investment supported by public-private partnerships and fiscal measures aimed at risk reduction. These factors, combined with high-cost investments in actual field trials (an activity critical to advancing new methods and ideas), were critical in the development of the Canadian oil sands industry. For US oil shale and US oil sands, the ingredients that were critical to the development of the Canadian oil sands are, for the most part, absent. The oil sands story also highlights the need for early and comprehensive assessment of the environmental and social impacts of resource development, including the need for mitigation strategies and long range planning; factors not fully considered in early oil sands development.

The environmental impacts, and potential impacts, from unconventional resource development are a topic of great debate and often confusion. Few energy-related issues currently have the national and international profile of Canada’s oil sands. Canada’s oil sands have been called by some as too carbon intense and environmentally unsustainable. Critical aspects are often not well understood - for instance, the greenhouse gas (GHG) emission intensity or effects on water supplies.

Successful deployments of new technologies - ones that meet both economic and environmental goals - are critical to sustainable growth from unconventional resources. For US oil sands and oil shale, commercial technology must be deployed. For resources with current production, as productive capacity grows, environmental factors have the potential to constrain the ultimate production level; land use, air emissions, including GHG, waste disposal, and water consumption. New technologies and management practices can reduce environmental impacts and mitigate these possible “limits to growth”.

Recommendations

Actions most likely to foster economic and environmentally sustainable growth of North American unconventional oil supply:

- **Clarify aspects of unconventional supply that are uncertain.** Formation of a Federal Advisory Committee Act (FACA) committee to provide an independent forum to research and clarify aspects of unconventional supply – topics that are a source of confusion and debate. For instance, the GHG emission intensity of various crude oils, possible impacts of tight oil development on local water, or water demands relative to local supply. The FACA committee could ensure that future government initiatives and policies are both well informed and effective. Additionally, the FACA could identify key environmental factors that should be considered in planning for unconventional supply growth, aspects not fully considered in the early days of Canadian oil sands development.

- **For supply with no current production (US oil shale and US oil sands):** Create an environment that fosters innovation and results in production growth; access to acreage with sufficient oil resources combined with long-term stable fiscal regimes and fiscal measures that provide industry the certainty and time needed to develop unconventional resources in an economically viable, socially acceptable, and environmentally responsible manner.

- **For supply with current production (primarily Canadian oil sands):** The US continues to work closely with Canada on energy technology and policy/programs - approaches to advance a secure and environmentally responsible North American energy system. Given the integrated nature of the US and Canadian economies, investing in new oil sands technologies could create new economic opportunities for US firms while addressing current environmental challenges. In the future, new technologies could be deployed to facilitate the development of US oil shale and US oil sands resources.

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About This Paper

This sub-topic paper aims to quantify the potential of North America's unconventional resource. How much oil is produced from unconventional sources today? What is the history, and how much oil could each resource eventually supply? What are the critical ingredients for growth?

This report has 9 chapters including the executive summary. The executive summary (Chapter 1) highlights key conclusions. Chapter 2 summarizes the possibilities and challenges for North America's unconventional resource as whole. Chapters 3 to 7 provide information on each source of unconventional supply including US Oil Shale, Canadian Oil Sands, Canadian Heavy Oil, US Oil Sands, and the newest innovation in unconventional oil production - tight oil. Chapter 8 summarizes the acronyms and abbreviations, while Chapter 9 contains all references.

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2. Potential of North American Unconventional Oil Resource

What is Unconventional Oil?

The term "unconventional oil" is synonymous with oil that cannot be produced, transported or refined using traditional techniques. Within this topic paper, the North American unconventional resource includes US Oil Shale, Canadian Oil Sands, Canadian Heavy Oil, US Oil Sands, and Canadian and US Tight Oil. North America is defined as the United States and Canada only within this paper, Mexico is not included.

Unconventional heavy oil occurs throughout the world; the largest resources being the extra heavy oil bearing deposits in Canada and Venezuela. The US also has oil sands deposits containing extra heavy oil. Canadian conventional heavy oil is also extra heavy; because of this it has been included within the unconventional oil category of this paper. These extra heavy oils (also called bitumen), are extremely viscous – sometimes nearly solid - and typically contain high concentrations of sulfur and metals such as nickel and vanadium. These properties make them difficult to produce and process.

However, not all unconventional oils are heavy. A growing source of unconventional supply is tight oil – which is produced from low-permeability siltstones, sandstones, and carbonates. The produced oil has the same properties (density, sulfur content, etc) as conventional oil. Historically, the oil was locked in the formations and could not flow through the tight formation rock. However, recent advancements in horizontal drilling and well fracturing technologies are now enabling production of the tight oil - notable plays include the Bakken (spanning Saskatchewan, Manitoba, Montana, and North Dakota), the Eagle Ford play in Texas, the Cardium play in Alberta, and the Miocene Monterey play in California. For the largest tight oil play, the Bakken, the produced oil is sweet and light - here only the oil extraction is unconventional.

Unconventional oil is also contained in US Oil Shale deposits. The petroleum component of the oil shale (kerogen) is less mature, not yet being fully transformed into oil or natural gas. So, unlike conventional oil and gas operations, the kerogen in the oil shale cannot be pumped directly from the ground or refined with traditional techniques – the oil shale must be heated to high temperatures to transform the kerogen into an upgraded hydrocarbon product - similar to diesel.

How Big?

Oil in place is massive at more than 3.5 trillion barrels. However the reserves, or the amount of oil that can be economically produced, make up 5 percent of this total. Even though the recoverable oil is only a small part of the total – the volume is still significant – large enough to supply more than 35 years of US crude oil demand[3].To describe, how big, the following definitions are used within this report:

- **Oil in place** is an estimate of both the discovered and undiscovered oil – how much oil is in the ground.
- **Resources -** Resources includes both oil volumes that are economically recoverable today and oil volumes that could be recovered in the future– although they are not considered commercial at the time of estimation. Unconventional resources that lack commercial production have no resources - no oil can be economically/commercially produced now or in the foreseeable future with known technology.
- **Reserves** are a sub-set of the resources. They are just the oil that can be produced economically with current technology – considered commercial at the time of estimation.
- **Ultimate potential** is an educated guess of the amount of oil that could be recoverable with significant improvements in recovery technologies and economics (beyond what is included in the resources).

Table U1 – Size of North American Unconventional Oil Resources*

	Oil in Place (BB)	Resources (includes Reserves)(BB)	Ultimate Potential (BB)
US Oil Shale (Green River formation only)	1,500	0	800
Canadian Oil Sands	1,804	169.8 (Reserves)	308
Canadian Heavy Oil	35	1	N/A
US Oil Sands	63	0	N/A
Tight oil	N/A	5.5 to 34 (Resources)	N/A
Total	Greater than 3,500	Greater than 200	Greater than 1100

* See sources and details in each unconventional chapter within this report.

Today's Oil Production and Future Potential

Unconventional resources are, generally, not "easy oil". Unique technologies are required to produce the oil within environmental and economic constraints. Unconventional oil supply has been growing - unconventional oil supply was 2 MB/D in 2009 or equivalent to 14 percent of US crude oil consumption[4].

Low Unconventional Oil Supply Projection (3.7 MB/D by 2035). The low projection assumes production growth is slowed by a number of factors. For sources of supply with no current production (US oil sands and US oil shale), barriers to development include limited access to acreage, minimal financial incentives and investment capital to pursue research and eventual commercial development. For sources of supply with current production, more challenged economics (higher environmental costs and environmental limits) ultimately constrain growth.

Likely Unconventional Oil Supply Projection (7 MB/D by 2035). The projection assumes steady growth from existing supply sources and the successful development of new technologies which are gradually implemented. US oil sands and US oil shale require the largest innovations – commercial methods for production must be deployed. Other supply sources require ongoing improvements to existing extraction methods. Unconventional oil production is projected to reach 7 M/D by 2035 - equivalent to 50 percent of US crude oil demand[5].

High Unconventional Oil Supply Projection (10 MB/D by 2035). The projection assumes an ideal set of circumstances to maximize production growth. Major innovations in unconventional extraction occur, solutions are found to minimize environmental effects, and strong government support in both the US and Canada fosters development. New technology is developed and rapidly deployed. Physical constraints are virtually the only limits to growth; requirements to build pipeline capacity, time to build infrastructure, reasonable time to learn and ramp up capacity, water constraints, labor constraints, manufacturing equipment or drilling constraints. In this projection - a true "stretch case" for unconventional supply - production reaches 10 MB/D by 2035 - equivalent to 70 percent of US crude oil demand[6].

Table U2 – Size of North American Unconventional Oil Supply*

	2009 Actual (B/D)	2035 Low (B/D)	**2035 Likely (B/D)**	2035 High (B/D)
US Oil Shale	**0**	0	**250,000**	1,000,000
Canadian Oil Sands	**1,350,000 ****	3,000,000	**4,500,000**	6,000,000
Canadian Heavy Oil	**382,000**	135,000	**250,000**	350,000
US Oil Sands	**0**	10,000	**25,000**	150,000
Tight Oil	**265,000 (2010 ~ 365,000)**	600,000	**2,000,000**	3,000,000
Total	**2,000,000**	3,700,000	**7,000,000**	10,000,000

*See sources in each unconventional chapter. The total unconventional production is weighted for the two sources of supply that are not currently commercial (oil shale and US oil sands). If one reaches its full potential, it is likely the other one would not. Therefore both projections are weighted 50 percent in the production capacity roll-up, all others are relatively independent of each other and have 100 percent weightings.

** The production of bitumen is 1,490,000 B/D, but after upgrading part of the bitumen to SCO part of the volume is lost, therefore supply is lower.

A View to 2050

Assuming that the 2035 likely projection is met with economic and environmentally sustainable methods, production levels could continue to grow to 2050. The resources are massive, and could even support production levels beyond our high 10 MB/D projection.

With an outlook for declining oil demand in North America, how much oil will be required in 2050? Even assuming a steady drop in US crude oil demand to 2050 (1 percent/year), North American unconventional oil supply could grow to 12 MB/D before supply would exceed domestic demand[7]. Still, the size of the North American market should not be considered a limit to growth; post 2050, global oil demand will still be significant, providing a potential export market for surplus domestic production.

Environmental Footprint of Unconventional Supply

The potential is vast; however the environmental footprint of unconventional supply is larger than most conventional oil sources. To grow production from unconventional resources, techniques to economically produce oil within acceptable environmental constraints are needed. There is often great confusion and debate on the environmental footprint of unconventional supply. This section aims to help clarify key environmental metrics.

Land use. Compared with conventional oil supply, generally, unconventional oil developments have higher land impacts.

- **Mining surface disturbance -** For about 20 percent of the unconventional resources - oil is very close to surface and can be mined (US oil sands, US oil shale, and Canadian oil sands all have potential for mining). Today, the largest mineable resource is the Canadian oil sands – where the mineable area is 1,854 square miles or about 0.7 percent of Alberta's land area. For mining projects, the surface material, including vegetation, topsoil, etc., or overburden, is completely removed to expose the resource for surface mining to occur. Following mining, the land will be reclaimed. Although the land is irrevocably changed by mining, reclamation will restore the land to an "equivalent land capability" The goal is to reclaim the landscape so it can support native vegetation and wildlife. Depending on the type of land, the difficulty in achieving this target varies. For instance, grasslands are easier to restore than wetlands.

- **Land Fragmentation** – Some unconventional resources cover large areal extents, such as the Canadian oil sands and some tight oil plays. During the period of oil production, the land use is changed, for example drilling pads and access roads can fragment wildlife habitat, and there are some concerns about impacts on wildlife habitat. Recently, the industry has increased use of "Ecopads" that allow the drilling of multiple wells from a much smaller surface area, reducing the number of drilling pads and associated access roads.

  For Canadian oil sands, the areal extent of the resource is very large (about 20 percent of Alberta's land mass is amenable to "non-mineable" oil extraction – "insitu" or "in place"). Prior to development, the land is mostly pristine boreal forest. When insitu extraction commences about 6 to 7 percent of the land is disturbed[8]. Although a fraction of the land is disturbed, the biodiversity is still impacted as some wildlife leaves the area. To minimize the effects on biodiversity, the Alberta government is developing a policy to manage cumulative effects through its Land Use Framework (LUF). The LUF aims to establish limits for the amount of land that can be disturbed. If the area of disturbance is constrained, the negative effects on biodiversity can be reduced.

GHG Emissions. Generally, extraction of unconventional oil is more energy intensive than conventional crude oils. Insitu production from Canadian and US oil sands, US oil shale, and parts of the Canadian Heavy oil resource require energy to mobilize the oil. Mineable resources also require heat to assist in the separation of the oil from the ore. Energy input is synonymous with GHG emissions, as most often hydrocarbons are burned to produce the energy required. Tight oil is unique, as it does not require heat.

Considering all of the GHG emissions from a barrel of oil, 70 to 80 percent of the emissions come from combusting the fuel in a vehicle. The energy used to extract, refine and transport the oil is the remainder. When well-to-wheel emissions are considered (emissions from producing the oil through to consuming the fuel in a vehicle) the Canadian oil sands are 5 to 15 percent higher than the average crude consumed in the US and on par with some other sources of conventional supply including crudes from Nigeria, Venezuela, and some domestic sources[9]. Over time, incremental efficiency improvements, as well as new technologies, such as the application of solvents to mobilize oil insitu (as an alternative to heat) are expected to continue to reduce GHG intensity of unconventional operations. Over the much longer term, technologies such as Carbon Capture and Storage (CCS) and low or zero-emission sources of energy, such as nuclear, offer the possibility of lower emissions.

Water Consumption - Conventional oil production, on average, uses between 0.1 and 0.3 barrels of water per barrel of oil produced[10]. Across the spectrum of unconventional oil supply, water demand ranges between 0.6 to 4 barrels of water per barrel produced. However, in the case of tight oil it is likely much lower. In some cases, fresh water is required for unconventional extraction; however non-potable water sources are also used. Water consumption is a local issue - the absolute level of water use must be sustainable compared to the local supply. For US oil shale and oil sands, located in arid regions (Utah and its neighboring states), successful operations must be water efficient. For the Alberta oil sands found in sparsely populated wetlands, the issue is not as extreme, but considering the potential scale-up of production there must be enough water to sustain growth. Water management practices (which are already in place) are being further strengthened.

Water Quality. The risk of local water supply contamination from for unconventional oil developments is a concern. For instance, in the case of tight oil, there is concern that the chemicals in the fracture fluid or the oil could enter the water supply. This could occur if the reservoir is fractured at too high a pressure - allowing break-though to other zones or up the wellbore. However, application of proper well design, completion, operations and monitoring in accordance with regulations that already exist in most states and provinces minimizes ground water concerns from fracture operations.

For the Canadian oil sands, water quality concerns center principally around mining operations and the storing of their tailings waste in large settling ponds. These ponds concentrate the naturally occurring materials that are present in the oil sands -- residual bitumen, clay, sand and other materials such as naphthenic acids (NAs) and polycyclic aromatic hydrocarbons (PAHs), mercury, and arsenic. No tailings water can be released to the Athabasca River or any other watercourse, but as the tailings ponds are unlined earthen structures, there is the risk of some leakage into the environment. The potential for seepage is mitigated by containment systems which include ditches around the ponds to prevent any seepage from entering the regional groundwater systems or waterways. Monitoring of the Athabasca River does indicate the presence of these naturally occurring materials and concerns remain that oil sands mining operation may be increasing the concentration. A new regulatory directive requiring a slowing in the growth of accumulated tailings and the eventual elimination of legacy tailings ponds led to the first complete pond reclamation in 2010. Implementation of tailing pond remediation technology will significantly reduce the potential for water quality to be impacted by oil sands operations.

United States: Benefits of NA Unconventional Oil Supply

Global Oil Demand – Growing under all Scenarios

The IEA World Energy Outlook 2010 current policies scenario predicts that, between now and 2035, global oil demand will grow from 84 M/D in 2009 to 107.4 MB/D in 2035. The IEA expects that most of this growth will come from developing nations such as China and India and not from developed nations. While it is largely expected that the world will be able to balance supply and demand, the volume of new resources required is still immense - taking into account oilfield declines[11] and forecast demand by the IEA, over the next 25 years the world has the formidable task of developing new oil supply capacity that is equivalent to today's global supply (about 85 MB/D). Even under the most aggressive IEA scenario, one which countries take the strongest measures to curb greenhouse gas emissions, the world will still needs to develop major new sources of oil supply - the equivalent of adding seven more Saudi Arabia's [12].

US Oil Demand and Supply – Ongoing Need for Oil Imports

In the US, the oil demand trend is opposite from the global trend. Over the next two decades, US demand for crude oil is expected to decline by 1 percent per year, driven by improved fuel efficiency and expanded consumption of renewable fuels. Even considering the slight decline in oil demand, the US will maintain its position as one the world's largest crude oil market over the coming decades demanding about 14.7 MB/D of crude oil in 2035[13]. In the absence of unconventional oil supply growth, the US is projected to require imports of crude oil at levels similar to today or higher – about 9 MB/D[14].

Unconventional Supply – Potential to Reduce Oil Imports

In 2004, Canada became the largest supplier of crude oil to the United States, surpassing Saudi Arabia[15]. Like the United States, Canada's supply of domestic conventional crude oil production has been declining. However, over the past decade Canadian unconventional resource growth, principally driven by oil sands expansion, has more than outpaced conventional production declines. This trend is expected to continue in Canada.

It is widely recognized that the US is on a trajectory towards an economy which is less carbon intensive; however, this transition will not occur overnight as it will take many decades to gradually replace fossil fuels as part of the fuel mix. Prudent development of US and Canadian unconventional resources, including Canada's oil sands, could help to bolster American energy security throughout this period.

In addition to contributing to energy security, obtaining crude oil from domestic sources has other obvious benefits for the US, including contributing to economic growth and employment as well as driving technology development and innovation. As with most forms of energy production there are environmental impacts associated with their production. Compared to other possible sources of supply, sourcing energy locally provides greater transparency and control over environmental impacts. In the case of North American supply sources, in addition to proximity to market, oil sourced from Canada has similar benefits as domestic supply: Canada and the US share similar policy and regulatory environments, compared with other possible sources of supply. In the case of the Canada/US relationship there are also shared values, history and trade policies, including similar transparent approaches to environmental management and sustainable development.

Canadian Oil Sands, a constructive example for unconventional resource development

The Canadian oil sands, the world's largest source of unconventional oil supply, offer a constructive example for unconventional resource development.

The Canadian oil sands grew from a demonstration of hot water extraction techniques in 1925, to currently producing 1.5 MB/D of bitumen[16]. It is a thriving industry that provides livelihoods to Canadians and US suppliers, taxes and royalties to governments, and goes a long way to meeting energy security and economic prosperity in North America. It is an industry that has made Canada a global leader in the extraction of unconventional resources and their conversion to transportation fuels.

The commercialization of the Canadian Oil Sands is a story of enormous effort, and years of patient research and persistence. It took leadership on the part of the government and bold investments in innovation on the part of both industry and government. It is a story that offers an example for the development of other unconventional resources world-wide.

Furthermore, the learnings from the Canadian Oil Sands continue today as Canada tries to balance the obvious benefits of oil production with the environmental implications of further growth.

Opening Up a Frontier

A few key events stand apart in defining the Canadian oil sands industry's growth from a fringe player to a world leading resource development. In 1967, a small mining project, known as the Great Canadian Oil Sands (GCOS), a subsidiary of US based Sun Oil, was the first commercial-scale operation, with a design capacity of 45,000 B/D. The investment of $250 million, or $1.6

billion in today's dollars, represented a bold risk for a first-of-a-kind production operation. In the 1970s a second project, led by the Syncrude Canada Limited joint venture, received approval for a much larger surface mining and bitumen extraction operation and began production in 1978. Both of these operations included upgrader facilities to convert the extracted bitumen into Synthetic Crude Oil (SCO) for transportation via pipeline and sale into the North American oil marketplace. However, the vast majority of the oil sands buried were too deep for surface mining techniques. In 1985 Imperial Oil was the first to unlock this deeper resource, with the first Canadian "insitu" commercial production - pioneering cyclic steam stimulation (CSS) at its Cold Lake facility[17]. CSS is still an important thermal insitu production technique for producing heavy oil in Canada and around the world.

The energy crises of the 1970s highlighted the importance of energy security and governments took a more active role in encouraging domestic sources of supply, including in the oil sands. In addition to federal tax breaks and direct federal and provincial funding, the Alberta government became a more active partner in oil sand technology development through the creation of the Alberta Oil Sands Technology and Research Authority (AOSTRA). In 1987, AOSTRA announced a breakthrough in Steam Assisted Gravity Drainage (SAGD), the development of this new insitu extraction technique eventually added about 100 billion barrels to the oil sands reserves – catapulting the Canadian oil sands to the world's second largest oil reserve – only behind Saudi Arabia. AOSTRA subsequently evolved into *Alberta Innovates – Energy and Environment Solutions,* an organization that continues to be a catalyst for developing innovative, integrated energy technology[18]. The total amount invested by both government and industry over the next 15 years in research projects was in the order of $1 billion, roughly equal to $2.2 billion in today's dollars. Those investments are now paying dividends estimated in the billions of dollars. The Institute for Energy, Environment and Economy (ISEEE), based at the University of Calgary, estimated the impacts of a scenario where oil sands developments after the mid-1970s were either delayed or did not occur. These results show the impact to be a loss of $140 billion in GDP, $55 billion in personal income and $16 billion in government revenue for Alberta alone from 1975 to 2001[19]. The impacts in the future are even larger.

In the mid-1990s the industry received another push from the recommendations of the National Task Force on Oil Sands Strategies which led to a favorable fiscal regime for the emerging industry.

After a decade of rising oil prices, coupled with more limited access to global oil resources resulting from growing government control, international companies started moving into the oil sands. From an industry with a handful of players a decade ago, by 2008, there were a total of 15 companies producing in the oil sands and another 10 projects under construction[20].

The surge of investment activity quickly pushed productive capacity higher, and pressed the industry to another critical turning point - demanding a strategic look at how to manage production growth within environmental limits.

Oil Sands Industry and the Environment

In an era of heightened public awareness and expectations around corporate responsibility, few energy-related issues currently have the national and international profile of Canada's oil sands. This is in part due to the broader global discussion on climate change and the future role of fossil fuels in meeting our energy requirements. Canada's oil sands have been called by some environmental groups as too carbon intense and environmentally unsustainable. First Nations communities in the region have expressed concern about the way that development is impacting their traditional way of life, land use and health. Opponents of the industry campaign to stop development and even its ardent supporters are uneasy at the rapid pace of growth.

The scale and extent of the reaction has taken both the government and the industry by surprise. It is clear that, whereas the last 20 years have been more focused on the development and application of technology that enables more economic extraction of the resource, the next 20 years will be defined by the solutions that emerge to manage the major environmental and social challenges. Technology is key to reducing those impacts and government recognizes its role to invest in and incubate transformative technologies.

The Next Oil Sands Frontier

The Government of Canada has set a target to reduce GHG emissions by 17 percent below 2008 levels by 2020 – a target that aligns with the US Administration's commitment.

Alberta is the first region in North America to establish a carbon tax for large emitters. Alberta, through the Climate Change Emissions Management Corporation (CCEMC) redirects this levy back towards investments in innovative and transformational technology to reduce GHG emissions. As of June 2010, the CCEMC had funded 16 projects totaling $71.4 Million[21].

Carbon Capture and Storage (CCS) holds promise in reducing the GHG emissions from coal plants and oil sands upgraders. Canadian federal and provincial governments have allocated over $3 billion to large-scale CCS demonstration projects to accelerate the development of CCS technology and encourage the necessary investment from industry to make CCS commercially viable[22].

The Province of Alberta is also redefining its role in managing growth. Major reforms in environmental regulation, land use planning and cumulative effects management in Alberta have formalized integrative approaches to environmental stewardship.

Oil sands operators recognize that the industry is at cross roads and that future growth is dependent on the industry becoming a global leader in long-term sustainable development. This is prompting the sector to redefine its role, focusing on how individual projects can contribute to public policy outcomes over longer planning horizons of 20-50 years. Though the industry has lowered its GHG emissions intensity per barrel by 39 percent from 1990 to 2008[23] as well as reduced water use, more must be done and the industry is continuing to invest in further reductions. Critical to managing increasing societal concerns, will be the oil and gas industry's ability to demonstrate responsible environmental and social performance.

In summary, three important insights can be derived from the Canadian oil sands experience:

- The development of unconventional resources takes considerable time and requires the kind of long-term, patient investment that is more likely to result from public-private partnership. Government participation in oil sands included broad-based science and technology (S&T) research, pre-commercialization investments including field trials, favorable fiscal terms, loan guarantees, as well as direct financial investment. Oil sands have since become an important economic driver for Canada, with economic benefits extending well beyond its borders to the United States and beyond.
- Investing in pilot projects to test technologies that have potential to expand future production is critical to creating a suite of options for the future development of large unconventional resources.
- Developing unconventional resources demands an early and comprehensive assessment of the environmental and social impacts and full integration of the mitigation strategies into long range planning.

Recommendations to Support Future Growth of North America's Unconventional Oil Supply

For each source of unconventional oil supply, the path to eventual production will be unique. In some cases, the advancement of broadly applicable oil and gas technology could lead to surprisingly rapid production growth – potentially the case for tight oil. However, the development of tight oil technology is likely to be the exception, not the norm. Generally, unconventional resources will require unique new techniques to extract the oil. Learning from the Canadian oil sands example, the yardstick for measuring the successful development and deployment of new technologies is decades – not years. As such, if the goal is to increase domestic oil supply and shore up energy security - then unconventional resources will surely need to be tapped. These types of resources necessitate strong government policy.

1) Conflicting information on the environmental impacts of unconventional supply, for instance the relative GHG emission intensity of oil sands development or water quality impacts from tight oil production, could lead to policy that is misinformed or ineffective. As unconventional supply has a larger environmental footprint, In growing new unconventional supply, the environmental effects associated with production growth should be considered and planned for - aspects not fully considered in past Canadian oil sands development plans.

   Recommendation: Provide access to independent and accurate information to support the formation of policy. Establish a Federal Advisory Committee Act (FACA) committee to provide an independent forum to research and clarify aspects of unconventional supply. This will identify areas of uncertainty and illuminate facts - ensuring that government initiatives are both informed and effective. The FACA could also contribute to the development of early, long-range, planning which considers the environmental effects associated with future unconventional supply growth.

2) For unconventional sources with no production, specifically US oil shale and US oil sands – the ingredients critical to the development of the Canadian oil sands are mostly not in place.

- Limited Access - Corporations and individuals are unduly constricted in the ability to assemble contiguous leases with large resources[24]. Without certainty in resource size, there is less incentive for companies and their financiers to risk capital for without the prospect of a sufficiently large resource reward.

- Additional fiscal measures to spur growth – Canadian and Alberta government participation in oil sands included broad based S&T research, pre-commercialization investments, favorable fiscal terms, loan guarantees, as well as direct financial investment over decades. The US government provides vital funding for basic research, however these ideas must move from the lab into the field – the next critical step in resource development; entrepreneurial firms often struggle to finance high-risk field pilots. Unconventional royalties are another example; current US royalties are 12.5 percent - the same level as lower risk, established conventional oil production.

Recommendation: Create an environment that fosters innovation and results in production growth; access to acreage with sizable oil resources and long-term stable fiscal regime with federal fiscal measures to support the industry, ideally over multiple decades, to develop unconventional resources in an economically viable, socially acceptable and environmentally responsible manner. Fiscal measures could include loan guarantees, severance tax incentives, lower royalties, accelerated capital depreciation and job creation programs (including retraining and financial support). Other ideas include upfront investments to pursue technology deployment and creative oil and gas that considers the higher operating and capital costs of unconventional production).

3) For unconventional supply with production (primarily Canadian oil sands). Develop new technologies that lower the environmental footprint of supply that also offer higher, more sustainable, oil production levels. For instance, Canadian oil sands have about 5 – 15 percent higher GHG emission per barrel than the average crude consumed in the United States[25]. Development of new technologies to lower the GHG emission intensities would help to close this gap. In turn, these technologies could be implemented domestically to improve the environmental footprint of new US unconventional resources (oil shale and US oil sands). Investments in low or possibly zero-carbon emitting energy sources – such as low-energy extraction methods or small nuclear to fuel extraction, or CCS - all hold potential for reducing GHG emissions.

   Recommendation: Continue to participate in international and bilateral activities - such as the Energy Partnership of the America's Heavy Oil Working Group[26]. Identify technology areas of mutual interest between the US and Canada - areas that target more environmentally sustainable methods of production. New technologies could result in economic opportunities for US firms, as well as position North America for increasing energy security. New technologies will most likely advance the development, and reduce the environmental impact, of US oil shale and US oil sands supply and may ultimately prove useful to other extractive industries.

3. Oil Shale

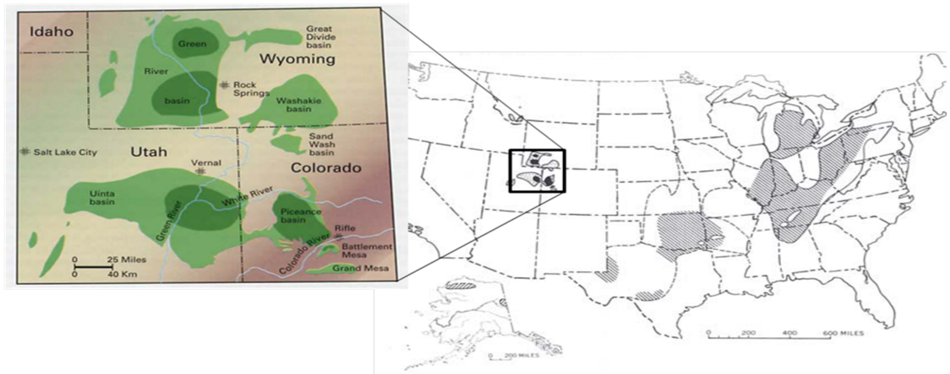
Oil shale is made up of rock and a solid organic sediment called kerogen. This naturally occurring source of hydrocarbon has not yet undergone the full transformation to oil and gas by heat and pressure over long periods of geologic time, creating a unique challenge to commercializing this resource.

Where and how big?

Oil shale represents one of the largest unconventional hydrocarbon deposits in the world with an estimated eight trillion barrels of oil-in-place. Approximately six trillion barrels of oil-in-place is located in the United States including the richest and most concentrated deposits found in the Green River Formation in Colorado, Utah and Wyoming[27] . Documented efforts to develop oil shale in the US go back to ~1900.[28] These prior efforts have produced a wealth of knowledge regarding the geological description as well as technical options and challenges for development. Thus far, however, none of these efforts have produced a commercially viable business in the US. The recent oil price increase sparked renewed interest in oil shale and industry is working to find economically viable, socially acceptable and environmentally responsible development solutions.

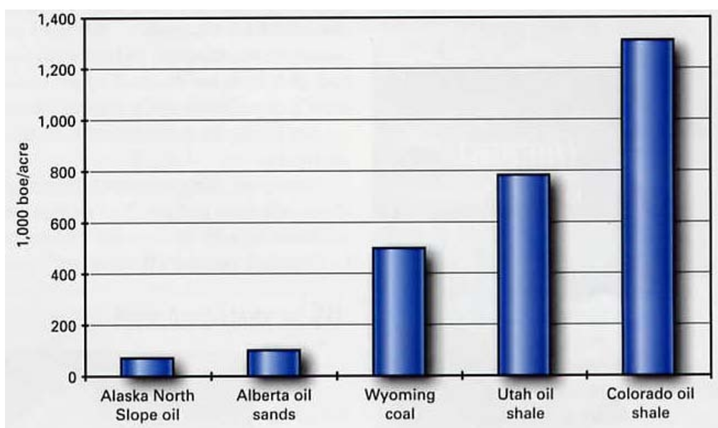
The economics for a commercial oil shale project depend on many factors including oil price, oil shale richness, oil shale thickness, oil shale overburden depth, recovery efficiency, energy output per unit of energy input, cost and availability of water and power, the effectiveness of the recovery technology, and the social and environmental mitigations that are integrated into the project. As such, only a fraction of the six trillion barrels of oil shale resource in the USA will be suitable for commercial development. Using 15 gallons of oil per ton of rock as a first approximation for the minimum oil shale richness that is economically recoverable, the RAND Corporation estimates that between 500 and 1100 BB of oil shale may be recoverable in the US. This estimate is similar to the many other estimates that have been made over the years. A mid-point value of 800 BB is frequently quoted as ultimately potentially recoverable using current and foreseen technologies.[29] The majority of this giant untapped hydrocarbon resource is concentrated within the Green River Formation in Colorado, Utah and Wyoming. The Green River Formation is most frequently identified as having commercial potential and is estimated to contain 1.5 trillion barrels of oil-in-place. It is important to note that nearly 80 percent of this oil shale resource is located on federal lands.[30]

Figure OS1 – US Oil Shale Location[2]



Because of thicknesses that can exceed 1000 feet, together with high richness, the Piceance Basin in Colorado is the most concentrated of these deposits with more than 1 BB of resource per square mile near the center of the Basin.

Figure OS2 – Resource Volume per Surface Area[31]



The challenge of developing a commercial Oil Shale industry starts with its geologic state. The Green River Formation is carbonate rock, generally marlstone that is very rich in kerogen. This source of oil has not had the natural forces of pressure and temperature over the millennia to convert it to oil and gas. So, unlike conventional oil and gas operations, oil shale cannot be pumped directly from the ground. Oil shale must be processed either above ground or in place (insitu) to convert the kerogen into oil. Numerous attempts have been made, but to date, commercially-viable oil shale production does not exist in the US. Some oil shale production from surface mining and retort is active in Estonia, China and Brazil for a total of ~10,000 B/D, an insignificant amount compared to the worldwide oil demand in the range of 85 MB/D.

Production History

Oil shale has a very limited production history in the United States. The energy industry effort that last produced oil shale occurred as a result of the late 1970s oil price increase following the 1973 oil embargo and the 1979 Iranian Revolution supply disruption. The business landscape at the time was shaped by the fact that Lower-48 US crude oil reserves peaked in 1959 and Lower-48 production peaked in 1970. Oil discoveries were slowing, demand was rising, and crude oil imports, largely from the Middle East, were rising to meet demand. Oil prices, while still relatively low in the early 1970s, were rising due to changing market conditions. Companies began work in Colorado and Utah to initiate commercial oil shale projects. Oil shale research was re-energized and new projects were envisioned by energy companies seeking alternative fuel feed stocks.

The companies that pushed significant efforts in the late 1970s and early 1980s included Unocal, Occidental, Exxon, Shell, and Amoco. Of these companies only one company, Unocal, was "successful" in commercially producing oil. Unocal started production at Parachute Creek mine – this success was largely due to the fact that Unocal was able to negotiate a price guarantee with the US Government. When the market price fell below the contract price of $51.20/bbl (in constant 1985 dollars), the Synthetic Fuels Corporation, an entity created by the federal government , paid the difference.[32]

Unforeseen price reduction caused the industry to retrench in core business. The oil price reduction was created by a loosening of supplies by the Organization of Petroleum Exporting Countries (OPEC) – high oil prices had in-turn spurred OPEC productive capacity growth – combined with an easing of political pressures in the Middle East. This time oil prices collapsed from above $30 to well below $20 per barrel. Another oil boom was gone.

The effort to develop oil shale ended and is marked by one well documented case, a dramatic exit that was known locally as "Black Sunday", May 2, 1982, when Exxon's Colony project – a mega project that was under construction, but had not yet commenced commercial production - was shut down.[33] The repercussions are still talked about today by many in the region because of the sudden loss of jobs, devaluation of property, and loss of tax revenue to local governments.

After 1982 the oil industry in the US suffered a substantial workforce reduction and consolidation as a result of low oil prices, and interest in oil shale declined. However, even though oil prices remained generally depressed, oil shale research continued[34].

As oil prices started to rise after 2000 and peak conventional oil was identified in a number of countries, interest once again returned to the huge resource potential of oil shale. As a part of the Energy Policy Act 2005, the Bureau of Land Management began development of a leasing program on federal land that contained oil shale. The first round of leases is defined as Research, Development and Demonstration (RD&D) leases. The lease holder is initially awarded an acreage position of ~160 acres. A pilot project must be executed on the lease that demonstrates commercial production within the initial 10-year term. If the pilot project is successful, an Environmental Impact Assessment is completed, and a Fair Market Value lease bonus is paid, the leaseholder can convert to an eight square mile commercial lease. There were six RD&D leases awarded in late 2006. Five are in northwest Colorado and one is in Utah. The companies awarded RD&D leases include Shell (three insitu leases), Chevron (one insitu lease), American Shale Oil, LLC - AMSO (one insitu lease), and in Utah, the Oil Shale Exploration Corporation – OSEC (one mining / surface retort lease). The BLM also promulgated regulations for commercial oil shale leasing and completed a Programmatic Environmental Impact Statement for leasing of oil shale and tar sands.

A second round of RD&D leases was offered in 2009. The commercial leases offered in the second round were only one square mile or one-eighth the size of the first round. Only three companies applied for the second Round of RD&D leases, and to date, the leases have not been awarded. The largest difference from the late-1970's to the current efforts to progress oil shale is that the work in the late-1970's was all mining based technology and the most recent work includes both mining & retort technology and insitu technology. Five of the RD&D leases were awarded based on insitu technology.[35]

Current Production

There is no current commercial production from oil shale in the United States. The only commercial production was developed using mining and surface retort. This ended in 1991 when operational issues and financial losses caused Unocal to close its Parachute Creek oil shale mine and surface retort process plant after producing some 5 MB over the course of 10 years.

Unocal mined oil shale from the Mahogany zone of the Green River Formation that yielded as much as 35 gallons of oil per ton of rock. The mine used conventional room-and-pillar construction and opened at a portal about 1000 feet above the valley floor in the cliff face. The Unocal Parachute Creek mine and retort was designed to produce 9,000 B/D. The process plant included a rock pump that moved crushed oil shale into a counter flow of hot-recycled gas that operated at 950 to 1000 ^{o}F. The heat pyrolyzed the kerogen into gas and oil. Gases, solids and produced liquids were cooled by the fresh shale that entered the lower section of the retort.[36]

Impediments to Past Production Growth

As previously stated, Colorado, Utah and Wyoming contain oil shale in-place equal to at least three times the proven oil reserves of Saudi Arabia. Efforts to unlock oil shale have been ongoing since the early 20th century and have proven to be a formidable challenge. These attempts were limited by numerous factors - technology development, challenging economics, and environmental concerns.

Because of the long time cycle and high up-front capital requirements of an oil shale project, broad and consistent government support would be required if a commercial industry is to be developed. Supporting government policy and regulatory certainty are necessary for private industry to reasonably assess risks, economics and be confident in the assessment so that the billions of dollars of required investments can be made. Commercial scale technologies that have economically attractive recovery efficiency and acceptable environmental impacts are required for success. As the road to commercialization is likely to be measured in decades not years - a long time horizon is required to allow development to occur through the "bust and boom" oil and gas price cycles.

Past Government policy supporting production

Government support of unconventional supply growth, including new supply from Oil Shale, will provide benefits in terms of energy security and economic growth (see Chapter 2 - United States: Benefits of NA Unconventional Oil Supply).

Federal regulations specific to the leasing of oil shale do not exist as they do for oil and gas and other minerals. The Energy Policy Act of 2005 (EPACT 2005) set the foundation for oil shale leasing and a good start was made when the first round of RD&D leases were awarded in 2006 and 2007.

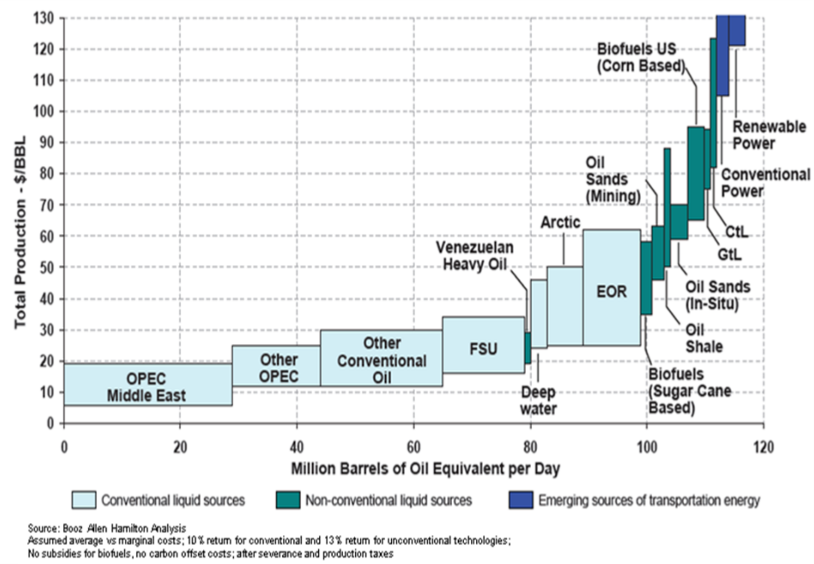
As has been demonstrated with the Canadian oil sands, it could take decades for an industry to grow to 1 MB/D. The leasing of Federal oil shale is an important and necessary step to developing the huge untapped resource that resides in Colorado, Utah and Wyoming. Lessons have been learned from the past efforts. A methodical and deliberate approach is being progressed to answer the key technical, economic, social and environmental questions before proceeding. To be successful, this effort will need to exist for multiple decades allowing industry to develop and improve commercial technologies. This would occur through successive efforts by multiple companies and supporting industries.

The long time horizon for supply growth is not unique to unconventional oil. Looking back at history, it takes around 30 years for new forms of energy to achieve 1 percent of the market after a commercial business is established. Biofuels are just now reaching 1 percent of the world oil market, or about 0.5 percent of total energy, after decades of development and government support. Wind may get to the 1 percent mark in the next few years, nearly three decades after the first large wind farms were built in Denmark and the USA. Gaining experience and building industrial capacity must occur before a new technology can contribute in a meaningfully to energy supply – and this requires billions of dollars of investment for growth over decades.[37]

Future Economics Compared with Other Sources of Supply

In an efficient market, low cost resources are produced first. As such, oil shale and other new forms of energy are appropriately named "marginal barrel" on the world supply curve. As demand for liquid hydrocarbons continue to increases while conventional supplies decrease; some of these new higher cost resources will be added (see Chapter 2 - United States: Benefits of NA Unconventional Oil Supply). Although not economic with the vast majority of hydrocarbon supply today, current assessments indicate that if the oil shale technology advances oil shale could be a competitive source of supply.

Figure OS3 – Forecasted Transportation Fuels Supply Curve (2020)[38]



Depending on the economic climate post 2020 and the advancement of technology for oil shale extraction, oil shale and other high cost transportation fuels could be both economic and in production. Going forward, learning and industry capacity will increase, innovation will occur and the cost per barrel of production should be reduced. If oil shale follows the pattern of other new technologies, the number of companies and rate of production growth is directly proportional to the amount of learning that is incorporated in each successive development. Therefore, as production grows, economics should improve.

The composition and shape of the world liquid fuel supply curve could change dramatically based on the decline rate of the conventional liquid sources and number of emerging energy sources that are found to be commercially viable. Therefore, the exact position of oil shale on the world supply curve in 2035 or 2050 is uncertain.

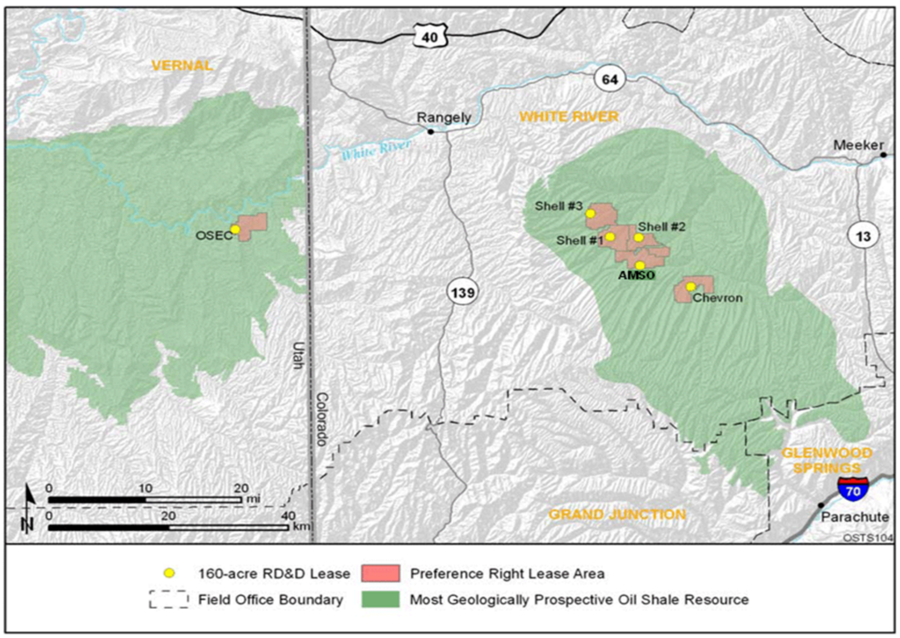
Production Technologies

Oil Shale production Technologies fall into two broad categories: insitu and exsitu. In an insitu development the resource is converted to oil and gas without ever mining the oil shale ore. An exsitu development requires that the ore be mined and transported to a surface retort where it is heated and converted into oil and gas. Many variations and hybrid development schemes have been considered in the past 100 or so years.

In the US, the richest and thickest oil shale lands are owned by the Federal Government. The rich accumulations in Colorado may be best developed by insitu technologies because of the high mining costs associated with the 500 - 1000 feet of overburden covering the resource. The rich, shallow accumulations in Utah are generally not as thick as the Colorado deposits but may be developed using by mining and surface retort technologies near the resource outcrop.

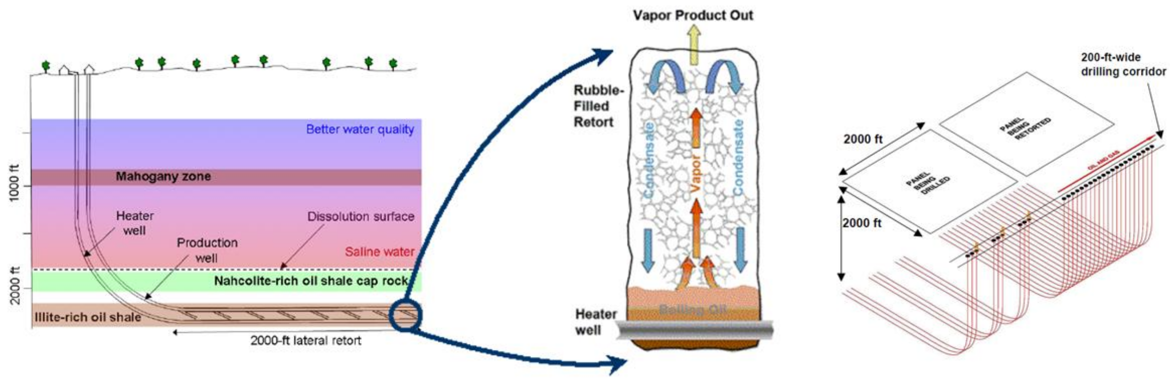
A number of new technologies are being pursued. The most promising technologies are being used to pursue the RD&D leases on Federal land awarded as a result of the Energy Policy Act of 2005.[39]

Figure OS4 – Location of six RD&D leases and associated commercial lease (Preference Right Lease Area)



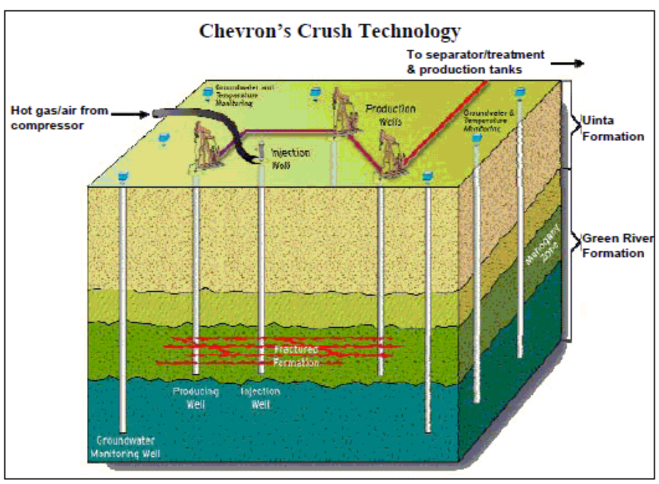
American Shale Oil (AMSO) plans include the use of horizontal wells to target a deeper interval of oil shale that is isolated from shallower aquifers (possible contamination of shallow water aquifers has been one of the environmental challenges that has slowed oil shale development). Electric heaters will be used to reach pyrolysis temperatures of 650°F (the temperature required to cook the kerogen, cracking the hydrocarbon molecules to produce oil and gas). AMSO has submitted a plan of development to the BLM and expects to start testing in 2011. AMSO indicates that a commercial project could yield 100,000 B/D of oil.

Figure OS5 – AMSO RD&D pilot project description



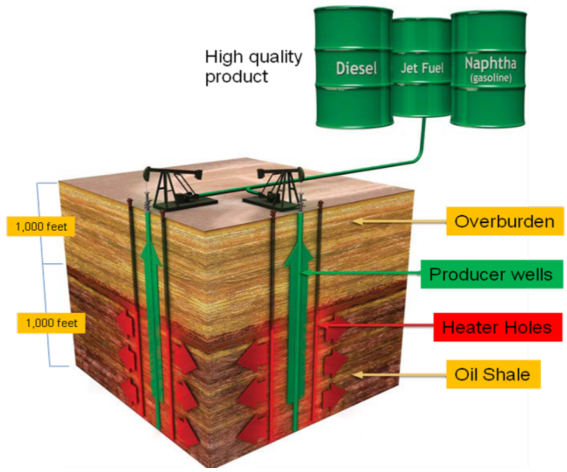
Chevron technology involves developing a series of fractures to increase the surface area of kerogen exposed, followed by use of a chemical process (as an alternative to high temperature) to convert the exposed kerogen to oil and gas. The proposed pilot will consist of four injectors and one producer.

Figure OS6 – Chevron RD&D pilot project description



Shell has focused on an Insitu Conversion Process (ICP) since 1980. The ICP heats oil shale by thermal conduction using a closely spaced array of electric heaters. Near 650 ^{o}F, the kerogen present in the oil shale is converted to oil and gas which can be produced by conventional means. Since 1970, Shell has completed seven field pilots, with one pilot in current operation. Four of the pilots focused on demonstrating technology and determining recovery efficiency and energy balance. One pilot evaluated oil shale recovery in the nahcolite region. One pilot enabled heater testing. One pilot studied the formation of a freeze wall for isolating and protecting ground water, and a second, larger freeze wall test is currently in operation. Shell has three RD&D leases in Colorado based on variations of the ICP technology. The pilots include an integrated pilot (freeze wall and ICP), an advanced heater pilot and a multi-mineral pilot that demonstrates oil shale production in nahcolite.[40]

Figure OS7 – Shell Insitu Conversion Process



Oil Shale Exploration Company (OSEC) was formed to mine, extract, upgrade, transport and sell commercial quantities of Synthetic Crude Oil (SC) from oil shale. OSEC, in partnership with Petrobras and Mitsui, has the only RD&D lease located in Utah and the lease area includes the site of the White River Oil Shale Mine. The proposed plan is to use a surface retort technology owned by Petrobras, the Petrosix process, which is currently operating in Brazil and producing 4,600 B/D. OSEC completed the project Feasibility Study for a 50,000 B/D oil shale plant. In 2010 OSEC began baseline environmental work and estimates commercial production by 2017, considerably earlier than any of the other five RD&D leases.

Figure OS8 – Petrosix Retort Facility in Brazil

There are a number of technologies being pursued by other companies including ExxonMobil, Red Leaf Resources and Mountain West Energy, and the lessons learned are expected to increase as these and other technologies are tested in the field. The RD&D lease program, which creates access to the richest oil shale, is an important step in developing future oil shale production.

Environment

Existing environmental laws, including the *Clean Air Act*, *Clean Water Act*, the *Safe Drinking Water Act*, the *Resource Conservation and Recovery Act*, and the *National Environmental Policy Act* (NEPA), ensure that energy development follows strict requirements for environmental protection. Additional state and local rules and regulations ensure best practices and technologies are used to minimize impact. A number of new legislative and regulatory actions are under consideration, Cap & Trade for GHG management, increased scrutiny of permits including contingency plans for managing spills, etc. Oil shale has a set of unique challenges that must be thoughtfully considered – the prize is potentially huge and steps must be taken along the way to ensure development is socially acceptable and environmentally responsible. Current regulatory processes allow for this to occur.

Water usage - Water is a highly valued commodity in Colorado, Utah and Wyoming where the vast majority of the US oil shale deposits are located. Demands between agricultural, municipal and industrial users have created competition amongst the various parties. Most western states follow a water appropriation doctrine that follows the “first in time first in right” principle. This has resulted in many senior rights being held by ranches that first settled the region. Many industrial users, including prospective oil shale developers, have acquired rights that will enable them to satisfy their project requirements. Water consumption varies based on the technology being used and the scope of the project. The generally accepted and independently published by BLM and others[41] as reasonable for planning purposes is approximately three barrels of water consumed for each barrel of oil produced. For insitu projects that use electrical power, the primary used of water are power plants and reclamation of the developed subsurface intervals.

GHG Emissions – The amount of GHG produced depends on the technology being used and the properties of the resource. As an example, for insitu oil shale development schemes that rely on electric heating the primary source of CO_2 is the power plants used to run the projects. If hydrocarbons (coal, natural gas, or byproducts of oil shale production) are used to produce the electricity, then the GHG footprint of oil shale would be higher than most other sources of oil supply. If alternative energy sources –low or zero GHG emission sources - such as wind or nuclear, the CO_2 emissions would be substantially reduced. Also, there are a number of Carbon Capture and Storage technologies being studied and piloted to mitigate GHG emissions that could reduce emissions from oil shale production.

Productive Capacity Projection

The reasons for the development of oil shale are compelling; public sector revenue from taxes and royalties, combined with economic development and diversification in rural areas near to the resource (e.g. Western Slope of Colorado). Shale oil development could provide citizens of these regions long-term employment opportunities, educational growth, skill development, and the fiscal support required to improve public infrastructure. In addition, increased supply also provides national benefits – for instance strengthened energy security through reduced reliance on oil imports and improved balance of trade. However, these benefits are out of reach as the technical, environmental, and regulatory challenges have not yet been overcome. Currently there is no production in the US.

Projection to 2035

Table OS1 – Projected US Oil Shale Supply

	2009 Actual (B/D)	2035 Low (B/D)	**2035 Likely (B/D)**	2035 High (B/D)
US Oil Shale	**0**	0	**250,000**	1,000,000

Low case assumes that no commercial production develops. Barriers to development in this scenario include limited access to acreage, and minimal financial incentives to pursue research and eventual commercial development.

Likely case assumes that oil shale leases produce 3 to 5 projects that move forward into commercial production. The production growth rate is supported by analog data. One analog is the Alberta oil sands SAGD projects; here production rates grew from 1,800 B/D in 1999 to 300,000 B/D in 2010. Assuming oil shale development starts near or just after 2020 – this provides ample time to reach 250,000 B/D in the "2035 Likely" case. The 2020 timing is based on conversion of RDD leases to commercial leases near 2015/16 and allows time for commercial project engineering and permitting.

High case assumes a more rapid pace of technical success and strong oil price signals, which propel the industry to move forward with much larger projects. The "High" case represents a number of projects near 50,000 B/D plus 3 or 4 mega projects that take 3-5 years for project execution and 5 – 7 years to reach plateau production. These projects occur with some overlap to align with the large workforce and infra-structure requirements. An example for the "High" case is Prudhoe Bay where production grew to ~1 million B/D within 15 years. Another example is the Heavy oil field in Sumatra. It is important to note that developments of this scope and scale could not go forward without increased government support compared with today.

The high case forecast assumes physical limitations impact the pace of production growth. For example, export pipelines and power plants need to be permitted and built in the region. Reaching a high level of production in a few decades would require multiple large projects in a relatively small area; in the high case, project "congestion" is likely creating a local market anomaly with the potential to increases costs and slow development. Other physical constraints to growth include air emission and the availability of industrial water rights. Finding acceptable solutions to these challenges will take time – constraining the ultimate growth achievable.

Other Forecasts

Forecasts of production capacity are highly uncertain, and very few authors have produced detailed assessments. Existing studies show that rates above the “High” case are possible. if demand warrants the investment. Recent work to estimate production potential was completed by INTEK which shows that production under a business as usual scenario could reach 500,000 B/D by 2020 and would remain steady through 2035. The high case had the potential of reaching 2.4 MB/D.[42]

Another interesting source comes from the Department of Energy under a Task Force on Strategic Unconventional Fuels which determined that oil shale development in the US could produce as much as 2.5 MB/ by 2030, if a number of significant constraints can be overcome including[43]:

- Readiness of oil shale technology for commercial development

And, mitigations for potential environmental impacts:

- Surface and wildlife disruptions/impacts
- Surface water and groundwater protection
- Demand for limited water resources
- Air pollutants
- GHG emissions
- Energy use and sources
- Socio-economic impacts
- Infrastructure and market issues

A number of policy changes are needed to improve the likelihood that oil shale development becomes economically viable, socially acceptable and environmentally responsible. Energy policy that provides access to acreage, a stable fiscal regime and financial incentive to pursue research and eventual commercial developments must be in place for a sustained period of time - ideally multiple decades.

A View to 2050

Assuming productive capacity is established over the next 25 years, and then further growth is likely. The resource is large. The ultimate supply level is likely to be shaped by future levels of US oil demand combined with oil shales competiveness with other sources of supply and the environmental footprint of development.

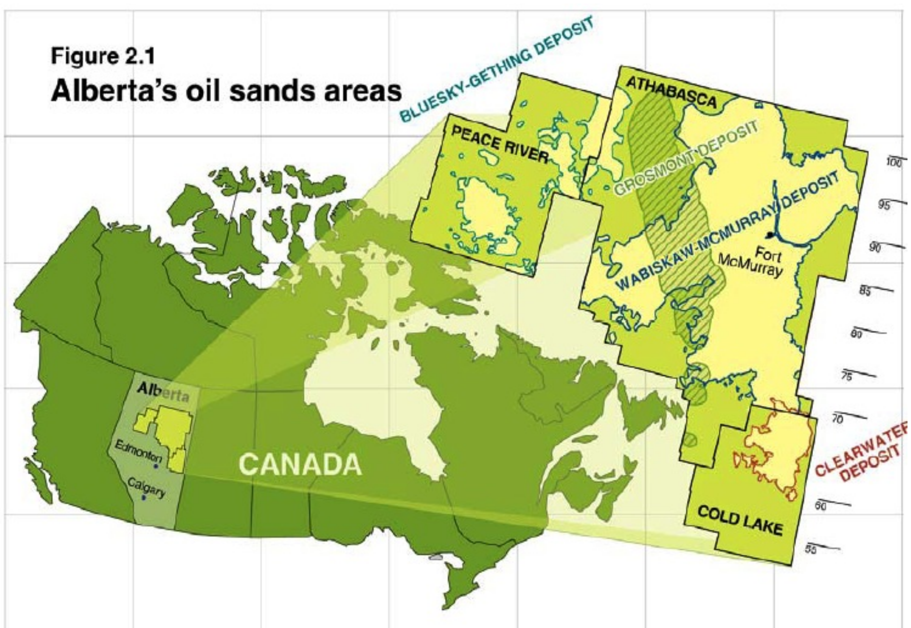
4. Canadian Oil Sands

With estimated initial oil-in-place of approximately 1.8 trillion barrels[44] of crude bitumen, Canada's oil sands, located in the Province of Alberta, are one of the world's largest hydrocarbon accumulations. When the Oil & Gas Journal released its estimates of global proved petroleum reserves at year-end 2002, it increased Canada's proved oil reserves to 180 BB, compared to 4.9 BB the previous year. This almost forty-fold increase catapulted Canada into second position for total oil reserves behind only Saudi Arabia, and cut the OPEC's share of world oil reserves by more than 10 percent.[45]

Where and how big?

The oil sands are located in three distinct areas in Northern Alberta: the largest Oil Sands Area (OSA) is Athabasca, the second largest is Cold Lake, and the smallest is Peace River. The three OSAs occupy an area of about 54,000 square miles and are shown in Figure COS1.

Figure COS1[46]
Alberta's Oil Sands Areas



Alberta's crude bitumen resources are contained in sand (clastic) and carbonate formations in the three OSAs shown in Figure COS1. Contained within the OSAs are 15 major Oil Sands Deposits (OSDs), which designate the specific geological zones containing the oil sands. Each OSA contains a number of bitumen-bearing deposits.

The known extent of the largest OSD, the Athabasca Wabiskaw-McMurray, as well as the significant Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are shown in Figure COS1. The bitumen in these three OSDs is contained in sand (clastic) formations. The vast majority of the development activity to date has occurred in these three OSDs.

The bitumen in four of the 15 major OSDs is contained in carbonate formations. While there is no commercial production of bitumen from the carbonate deposits, several companies have acquired oil sands carbonate leases and are developing recovery technologies. The areal extent of the Grosmont Deposit, the largest carbonate deposit and the focus of some initial insitu technology development activity, is also shown on Figure COS1.

While most industry activity to date has focused on Alberta, a few companies have leased land in northwest Saskatchewan and are evaluating the extent of the Saskatchewan oil sands resources and investigating bitumen recovery technologies. However, these deposits are still not well defined, while resource appraisal activity is underway, production has not occurred yet.

Resources and Reserves

Oil sands are a mixture of sand and other rock materials that contain crude bitumen (extra-heavy non-conventional crude oil). Oil sands are composed of approximately 80-85 percent sand, clay and other mineral matter, 5-10 weight percent water, and anywhere from 1-18 weight percent crude bitumen.

Crude bitumen is a thick, viscous crude oil that, at reservoir temperature, is in a near solid state. While most crude bitumen does not have mobility in its naturally occurring viscous state, some oil sands contain crude bitumen that is less biodegraded, less viscous and has natural mobility. This bitumen in being produced using primary and secondary recovery technologies as discussed later in this section. However, because it is located in designated OSDs, it is defined as crude bitumen by Alberta regulatory agencies and included in oil sands resource, reserve and production statistics.

At year-end 2009, the Alberta Energy Resources Conservation Board (ERCB) estimated the Initial Volume of oil-in-place of crude bitumen in Alberta's oil sands to be 1,804 BB.[47]

The ERCB reported that 7 percent of the oil-in-place, 131 BB, is contained in shallow deposits – that are generally less than 215 feet to the top of the oil sands zone. All of the shallow oil sands (amenable to surface mining) are located in the Athabasca OSA. Surface mining and bitumen extraction technologies are used to recover crude bitumen from these shallow deposits.

The remaining 93 percent of the oil-in-place, 1,673 BB, is contained in deeper deposits that are present in all three OSAs. Insitu recovery techniques are used to recover crude bitumen from the deeper deposits.

The ERCB estimated that approximately 10 percent of the oil-in-place is recoverable with approximately 22 percent of the recoverable volume located in shallow deposits that will be developed using surface mining and 78 percent located in deeper deposits that will be developed using insitu recovery.

To year-end 2009, approximately 4 percent of the initial established reserves had been produced with approximately 65 percent produced using surface mining and 35 percent produced using insitu recovery.

The ERCB's resource and reserve estimates are provided in Table COS1.

Table COS1
Alberta Resource and Reserve Estimates

	Billion Barrels (BB)				
	Initial oil in place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mineable	131	38.8	4.5	34.2	23.2
Insitu	1,673	138.1	2.4	135.6	3.3
Total	1,804	176.8	6.9	169.8	26.6

Ultimate Potential

Established Reserves are defined by the ERCB as those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.[48] Technology improvements, improved economics and additional drilling are expected to increase recoverable reserves beyond those that have already been classified as Established Reserves.

The ERCB estimates the Ultimate Potential of crude bitumen recoverable by insitu recovery methods from Cretaceous sediments to be about 210 BB and from Paleozoic carbonate sediments to be about 37 BB. Nearly 70 BB is expected from within the surface-mineable boundary. The total ultimate potential of crude bitumen is therefore about 315 BB, of which 7 BB has been produced, leaving 308 BB remaining.

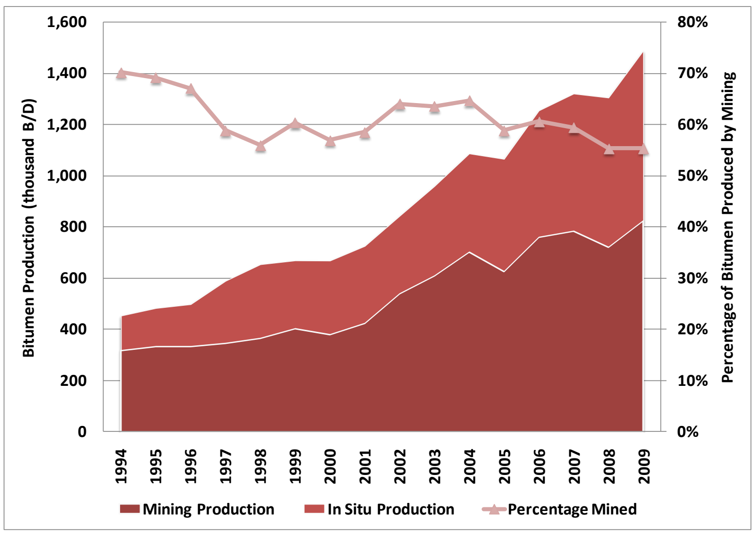
Production History

See Chapter 2 for more details on the technologies, government initiatives, and organizations that shaped the early growth of the Canadian Oil Sands.

As of 2009, oil sands production has reached 1,490,000 B/D of crude bitumen,[49] 826,000 B/D from surface mining and 664,000 B/D from insitu projects. By 2009, the oil sands industry represented approximately 50 percent of Canada's total oil production.[50]

Historical bitumen production over the last 15 years is illustrated in Figure COS2.

Figure COS2
Historical Bitumen Production[51]

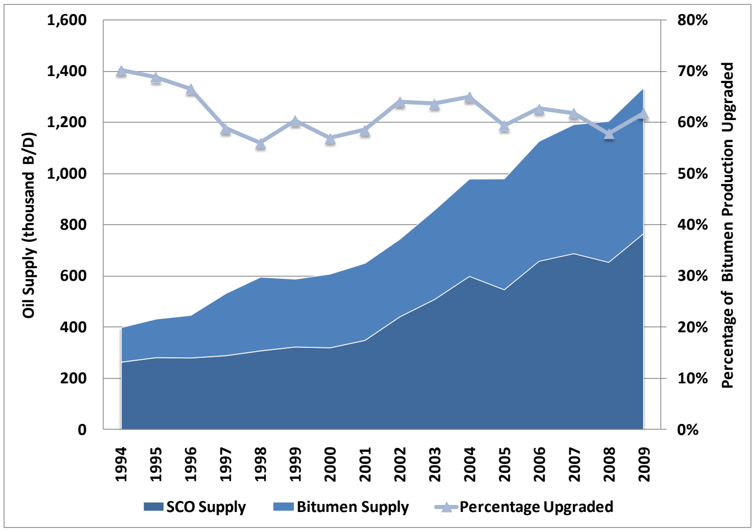


As new commercial insitu capacity has come on stream, the percentage of bitumen produced by mining projects has declined from 70 percent of total annual bitumen production in 1994 to 55 percent of total annual bitumen production in 2009.

Bitumen is a carbon rich, extra heavy, and very viscous unconventional crude oil, containing contaminants such as sulfur, oxygen, nitrogen and heavy metals. It cannot be transported to market by pipeline without adding diluents to meet pipeline density and viscosity limitations. Condensate (pentanes plus) produced at gas processing plants is the most common diluent.

To remove contaminants and improve the value of the oil sands crude, a large portion of Alberta's bitumen production is upgraded to Synthetic Crude Oil (SCO) and other products before shipment to market. After upgrading, supply of SCO (including other products) and non-upgraded crude bitumen totaled 1,335,000 B/D in 2009[52] (766,000 B/D of SCO and 570,000 B/D of non-upgraded crude bitumen) as illustrated in Figure COS3.

Figure COS3
Historical Oil Sands Supply[53]



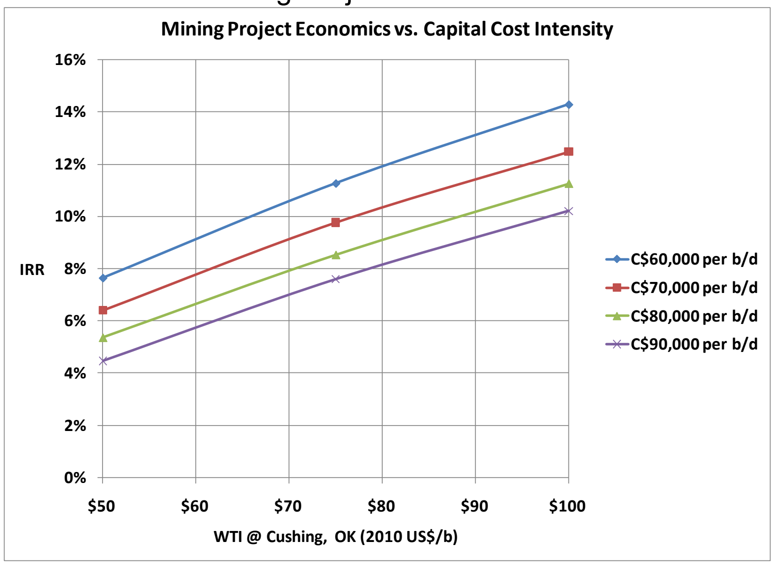
Note that some volumetric loss occurs due to upgrading – i.e., total bitumen production of 1,490,000 B/D resulted in the oil sands industry supplying 1,335,000 B/D of SCO and non-upgraded crude bitumen to downstream markets. Bitumen produced at all existing mining operations is normally upgraded, while most insitu bitumen production is not.

Oil Sands Industry Economics

In addition to uncertainties regarding the economic outlook (i.e., oil demand, oil prices and oil price differentials), the oil sands industry faces challenges regarding capital availability, market access, labor availability, regulatory uncertainties (particularly respecting GHG emissions), and capital and operating cost management. To help spur oil sands development, the Alberta government has a favorable royalty regime - low royalties (between 1 and 9 percent of gross revenues) until project payback, followed by profit sharing after payback (between 25 and 40 percent of net profits).

Oil sands mining projects require high oil prices to provide attractive investment opportunities. Figure COS4 shows returns on invested capital[54] for a range of capital cost intensities for a standalone mining project. The economics do not include upgrading of the produced bitumen which is sold into the market as a blended-bitumen product. In the past, mining projects were always coupled with upgraders, however, the first mining-only project is currently under construction by Imperial Oil/ExxonMobil. The project is called Kearl Lake. Due to relatively high prices for heavy crudes, the trend is towards more mining only (no upgrader) projects in the future.

Figure COS4
Mining Project Economics[55]



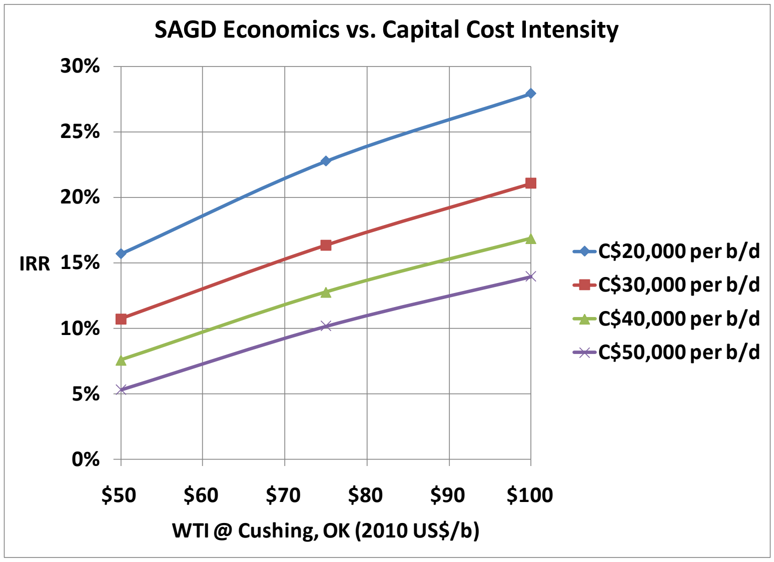
Limited capital cost data are available for standalone mining projects. However, Imperial Oil has stated that Phase 1 of the Kearl Lake mining-only project will require C$8 billion of total capital for the 110,000 B/D project (or a capital cost intensity of C$73,000 per B/D of flowing capacity). The C$60,000-90,000 per B/D range (real 2010 Canadian dollars) displayed in this chart is believed to adequately bracket possible mining project capital costs.

New greenfield projects would likely incur costs in the middle to upper part of this range and require West Texas Intermediate (WTI) oil prices of about $75-100/B (real 2010 US $/B @ Cushing, OK) to justify investments in new greenfield capacity (i.e., yield a 10 percent return on capital after royalty and after corporate income taxes).

It may be possible for mining project operators to add capacity to existing projects for costs in the lower part of this range. They would require WTI oil prices of about $65-80/B (real 2010 US $/B @ Cushing, OK) to justify investments in new greenfield capacity (i.e., yield a 10 percent return on capital after royalty and after corporate income taxes).

While mining projects require high oil prices, SAGD project economics are more attractive as illustrated in Figure COS5

Figure COS5
SAGD Project Economics[56]



The most recent SAGD project built was the 10,000 B/D Algar project owned by Connacher Oil and Gas (steam circulation at Algar commenced in May 2010). Connacher reported the final capital cost as C$366 million (or a capital cost intensity of C$36,600 per B/D flowing capacity).[57] Others have reported capital costs of C$35,000 – 40,000 per B/D. It is concluded that oil sands SAGD requires WTI oil prices of about $55-65/B (real 2010 US $/B @ Cushing, OK) to justify investments in new greenfield capacity (i.e., yield a 10 percent return on capital after royalty and after corporate income taxes).

Expanding existing projects may be even more economic. In recent investor communications, Cenovus stated that it expects to be able to add capacity to its existing Foster Creek and Christina Lake SAGD projects at a capital cost intensity of ~C$20,000 per B/D of flowing capacity. On this basis, attractive returns on investment would occur at WTI oil prices of about $45-50/B (real 2010 US $/B @ Cushing, OK). Cenovus also stated that its emerging oil sands plays have supply costs ranging from WTI oil prices of $45-70/B (real 2010 US$/B @ Cushing, OK),[58] confirming the data in Figure COS5.

SAGD projects offer better returns on investment primarily due to lower capital cost intensities. SAGD projects can also be built in smaller increments with lower total capital requirements. Small projects can be built quickly (one to two years) compared to a 3-4 year construction period for a typical mining project. SAGD projects are also amenable to off-site modular construction and present fewer project management challenges.

Bitumen Upgrading

Bitumen from mining/extraction and in-situ operations is either blended with diluents (light low-viscosity hydrocarbon liquid) for shipment to market (downstream refineries) by pipeline or upgraded to a higher value SCO or other petroleum products. Upgraders may be located on-site or off-site and may be either dedicated to a specific project or standalone facilities (merchant upgraders) that process crude bitumen from many projects on a fee-for-service or other commercial basis. After upgrading, the SCO is shipped via pipeline to downstream markets (refineries) for conversion into refined petroleum products (e.g. gasoline, diesel, jet fuel, fuel oils, etc.).

In the upgrading process, bitumen is converted from a viscous unconventional crude oil that is deficient in hydrogen and with high concentrations of sulfur, nitrogen, oxygen and heavy metals, to a high-quality "synthetic" or "upgraded" crude oil that has density and viscosity characteristics similar to conventional light sweet crude oil, but with a very low sulfur content (0.1- 0.2 percent).[59]

Upgrading technologies are not unique to the oil sands industry; the same technologies have been employed in the refining industry for decades. Many refineries in Canada and the US have existing heavy oil “conversion” capacity and are able to process blended crude bitumen from Canada without intermediate upgrading.

Upgrading technologies are not discussed further in this report.

Production Technologies

The hydrocarbon component of the oil sands, crude bitumen, must be separated from the sand, other mineral materials and formation water before it is delivered to downstream upgraders or refineries. Shallow oil sands deposits, generally less than about 215 feet to the top of the oil sands zone, are exploited using surface mining to recover ore-grade oil sands, which are then delivered to an extraction plant for separation of bitumen from the sand, other minerals and water. Deep oil sands, generally greater than about 215 feet to the top of the oil sands zone, are exploited using insitu recovery techniques, whereby the bitumen is separated from the sand insitu (“in-place”) and produced to the surface through wells.

Established Oil Sands Mining and Bitumen Extraction Technologies

Over time, different techniques have been used for oil sands mining. Suncor started its mining operations using bucketwheel excavators that discharged their loads onto large conveyor belts. The initial Syncrude operation used large draglines to remove oil sands ore from the mine-face and place it in windrows from which bucketwheel reclaimers loaded it onto conveyor belts for transportation to the extraction plant. Suncor and Syncrude have since retired their bucketwheel- and dragline-based mining systems.

In the early 1990s, large mining trucks and power shovels were introduced to replace the early mining systems at the Syncrude and Suncor mining operations. Truck and shovel mining is considerably more flexible and less prone to interruption of service than the earlier systems used. In mining systems today, trucks capable of hauling up to 400 tons of material are loaded by electric- and hydraulic-power shovels with bucket capacities up to 58 cubic yards. The trucks transport the oil sands ore to preparation facilities where the ore is crushed and prepared for transport to the extraction plant (where bitumen is separated from the sand). In their early operations, Suncor and Syncrude used long conveyor systems for ore transportation. These systems have been replaced by hydrotransport with the first commercial applications of this technology occurring in the early 1990s. For hydrotransport, the oil sands ore is mixed with warm water (and chemicals in some cases) at the ore preparation plant to create oil sands slurry that is pumped via pipeline to the extraction plant. Hydrotransport achieves partial separation of the bitumen from the sand matrix during flow and preconditions the ore for extraction of crude bitumen. Hydrotransport can be operated at relatively low temperature and provides for greater energy efficiency and environmental performance compared to conveyor systems and alternative preconditioning methods.

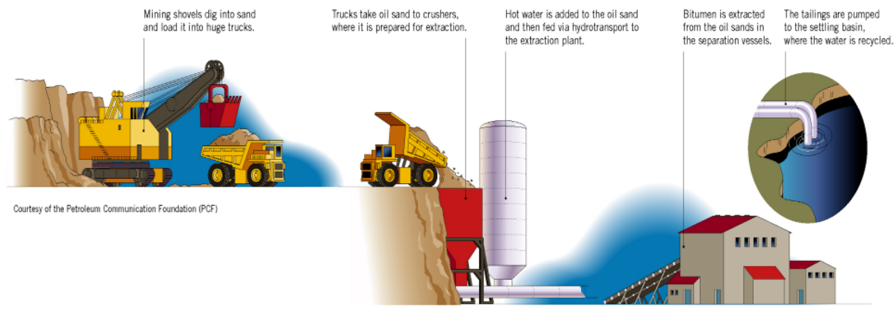
At the extraction plant, bitumen is separated from the sand, other minerals and water using variations on the hot water extraction process developed by Dr. Karl Clark at the Alberta Research Council in the 1920s. An important feature of the oil sands deposits is that the sand grains are generally surrounded by thin water film (estimated at about 10 nm) which makes separation of the bitumen from the sand facile and reduces the energy intensity of extraction, compared to oil-wetted deposits such as the Utah Oil Sands.

At remote mines, primary extraction occurs at the mine site. After primary extraction, bitumen froth is transported to a central site by pipeline for secondary extraction and upgrading. Syncrude has remote primary extraction at its Aurora Mine, 22 miles north of the Mildred Lake Plant. Suncor has remote primary extraction at its Millennium Mine on the east side of the Athabasca River.

Tailings are a byproduct of the oil sands extraction process. After bitumen extraction, the tailings, a mixture of water, sand, silt and fine clay particles, are pumped to a settling basin. Tailings also contain residual bitumen that is not initially recovered and residual solvents and chemicals used in the extraction process. Sand and coarse minerals settle rapidly and can be quickly restored to a dry surface to enable reclamation. Fine tailings, consisting of slow-settling fine clay particles and water, are more challenging. Water use in extraction processes is an environmental concern for surface mining operations.

The overall configuration of the oil sands mining and bitumen extraction operations is shown in Figure COS6.

Figure COS6 - Oil Sands Mining and Bitumen Extraction



Developing Mining and Bitumen Extraction Technologies

Oil sands mining project operators continue to investigate new mining and extraction processes to further improve performance, reduce environmental impact and reduce costs. New technologies that could be introduced in the future include:

- Mine-face crushing and slurry preparation to eliminate the use of heavy-hauler trucks – a commercial scale unit (5,500 t/h) was tested at the Suncor mine.
- The Counter Current Drum Separator extraction process (Bitmin process) which was developed to replace hot water extraction. The Bitmin Process produces relatively dry tailings sand and was tested a few years ago at a field scale at the Fort Hills Project Site.
- Mine-face-extraction: TSC Company has developed an extraction process that uses cyclones to separate bitumen from the sand at the mine face; however, no field tests have been conducted.

Established Insitu Bitumen Recovery Technologies

In general, the heavy, viscous nature of the bitumen means that it will not flow under normal reservoir temperature conditions. For recovery of bitumen from deep deposits, the bitumen viscosity must be reduced insitu to increase the mobility of bitumen in the reservoir. This enables flow to wellbores that bring the bitumen to the surface. Bitumen viscosity can be reduced insitu by injecting steam to increase reservoir temperature, injecting solvents, injecting air, or using electric heating. Steam-based thermal recovery is the dominant recovery technique used at Athabasca, Cold Lake and Peace River. The industry is also conducting field tests of other insitu recovery methods including solvent-based recovery, co-injection of steam and solvents, co-injection of steam and non-condensing hydrocarbons, insitu combustion and electric heating.

Compared to surface mining, insitu bitumen production does not produce tailings that require disposal, requires less water due to higher recycle rates, and has a smaller surface footprint. However, thermal insitu processes are more energy intensive than surface mining and have higher GHG emission intensities.

Primary Recovery

Bitumen can be produced from some oil sands reservoirs using primary recovery or “cold production”; no external energy is applied to mobilize the bitumen in the reservoir. The bitumen in these reservoirs is similar to conventional heavy oil and is less bio-degraded and less viscous than the bitumen in other oil sands reservoirs; however, is still classified as crude bitumen because it is contained within ERCB designated OSDs.

Several primary recovery projects are operating in the Athabasca (Wabasca), Cold Lake, and Peace River OSAs and in the Lindbergh, Elk Point, and Bonnyville areas - a transition region between clearly identified bitumen at Cold Lake and clearly identified conventional heavy oil at Lloydminster. Early primary production in the Cold Lake OSA was ridden with problems caused by extreme wear on the pumps used to bring bitumen to the surface. Beginning in the early 1990s, introduction of the progressing cavity pump represented a significant innovation, with the new equipment being better suited to handle sand. Operators found that producing sand along with the bitumen, especially early in a well’s life, was conducive to higher production rates. This was because a system of preferential fluid flow paths, or "wormholes", were formed and expanded in the reservoir as the sand was produced. The mechanism to drive the heavy oil is due to gas that comes out of solution and remains dispersed (does not coalesce) keeping the effective viscosity low while providing energy that helps drive the oil towards the producing well. This “foamy oil” behavior accounts for unusually high production rates in these reservoirs lowering operating costs and improving economics. This type of production technology is commonly referred to as cold heavy oil production with sand (CHOPS). Recovery factors range from three to ten percent using CHOPS in this area. Research studies designed to increase ultimate recovery as follow-up processes to CHOPS such as use of combustion or solvents, including CO_2 injection, are being carried out at the Alberta Research Council (now Alberta Innovates Technology Futures or AITF) and the Universities of Calgary and Regina.

Development in the Wabasca area gained interest with the advent of horizontal well technology in the 1990s that yielded higher production rates. The oil sands reservoirs are relatively thin (~15 feet) and consolidated, with no significant sand production problems, and better suited to primary production using horizontal wells. Horizontal well technology has advanced to the stage that very long single-leg and "multi-leg" or "multilateral" producing wells can be drilled and successfully operated. Recovery factors of seven to ten percent are achieved using primary recovery in this area.

Primary production in the Peace River Oil Sands Area has also been growing rapidly.

Secondary Recovery

Several operators have also been having success with application of secondary recovery techniques (water and polymer flooding) in the Wabasca region of the Athabasca OSA.

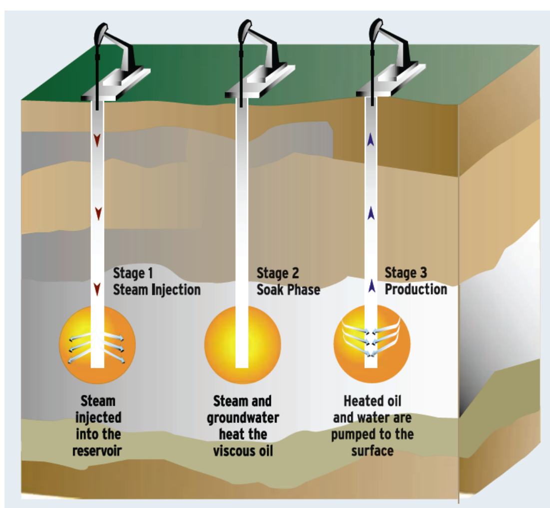
Steam-Based Thermal Recovery

Numerous insitu recovery technologies have been developed that apply thermal energy to heat the bitumen and reduce its viscosity thereby allowing it to flow to the well bore.

The most common thermal techniques involve steam injection into the reservoir using either cyclic steam stimulation (CSS) or steam assisted gravity drainage (SAGD). Steam is injected into the oil sands zone using vertical, deviated, horizontal or horizontal multi-lateral wells. The steam heats the bitumen, lowers its viscosity, and increases its mobility in the reservoir so it can be brought to the surface through wells using reservoir pressure, gas lift or downhole pumps.

CSS is a cyclic 3-stage process which was originally developed for California heavy oil and also applied in heavy oil and extra heavy oil reservoirs in Venezuela, China, Indonesia and the Middle East. During the initial injection cycle, steam is injected into the reservoir at high temperature and pressure. The wells then enter the soak cycle during which latent heat from the injected steam heats the bitumen and lowers its viscosity as the steam condenses. During the final production cycle, the heated bitumen and condensed steam are produced to the surface. The process is repeated over several cycles. Bitumen, water and produced gas are separated in surface production-treating facilities. During the separation process, produced bitumen is mixed with the diluent that enables pipeline transportation to upgraders or heavy-oil refineries. Produced water is treated and recycled to the maximum extent possible. Produced natural gas is used on site as fuel. CSS is effective in reservoirs with vertical permeability of less than 1 Darcy and is best suited to operations in the Cold Lake and Peace River OSAs. The CSS process is illustrated in Figure COS7.

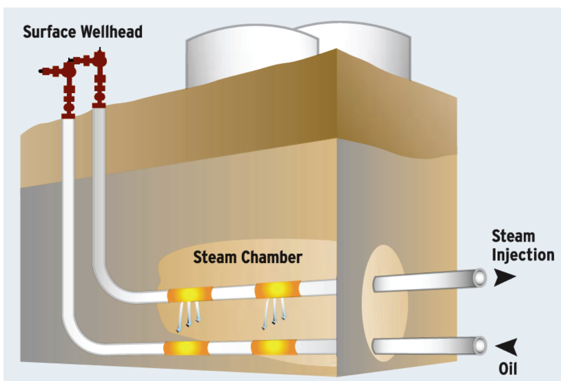
Figure COS7
Cyclic Steam Stimulation Process



CSS performance is measured based on steam-oil-ratio[60] (SOR), well productivity, and overall recovery factor. Operating mature CSS projects reported average SORs of about 3.0-6.0 and average bitumen production rates of about 40-90 B/D per well in 2009.[61] Individual well pad recovery expectations range from less than 10 percent to over 60 percent of the original bitumen in place within the project area.[62]

The concept of utilizing gravity-stable continuous heating and production, rather than the discontinuous CSS process, led to the development of the SAGD process during the late 1970s and early 1980s. The development of SAGD was also prompted by the limited success of CSS pilot projects in the Athabasca reservoirs. SAGD uses horizontal well pairs, up to 3,300 feet in length, which are completed near the base of the oil sands zone. The upper horizontal well is drilled and completed about 16 feet above the lower horizontal well. Steam is injected into the upper well to heat the bitumen, reduce its viscosity and cause it to drain by gravity into the lower part of the reservoir. The bitumen and condensed steam are collected and produced to the surface through the lower well. SAGD is applied in thick reservoirs, with high vertical permeabilities (above 1 Darcy), and is being successfully used in the Athabasca OSA. The SAGD process is illustrated in Figure COS8.

Figure COS8
SAGD Gravity Drainage

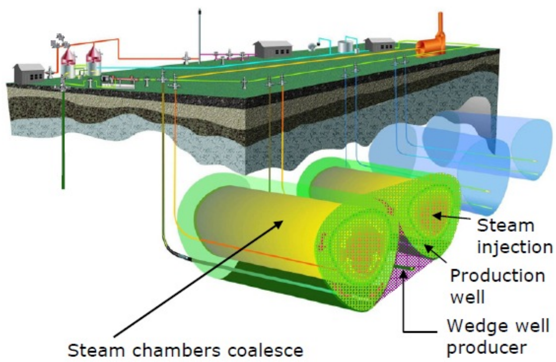


Operating mature SAGD projects reported average SORs of about 2.0-4.0 and average bitumen production rates of about 400-1,300 B/D per well-pair in 2009.[63] Recovery factors up to 65 percent of the bitumen in place within the project area are expected.

Considerable technology development activity is underway to improve existing steam-based insitu recovery processes. Some important examples include the introduction of electric submersible pumps at SAGD projects to permit lower pressure operations thereby achieving lower SORs (a 15-20 percent reduction in SOR),[64] liner design improvements, co-injection of non-condensable gases, possible use of insulated tubing, and others (a potential further 10 percent reduction in SOR).[65]

Cenovus Energy is also testing the use of “wedge wells” at its Foster Creek and Christina Lake SAGD projects as illustrated in Figure COS9. Wedge wells enable the recovery of bitumen between existing well pairs with little or no additional steam injection, thereby improving SORs (a potential 10 percent reduction in SOR)[66] and recovery factors.

Figure COS9
Wedge Well[67]



As mentioned previously, a primary disadvantage of steam-based thermal recovery techniques is the large amount of energy that must be consumed for the generation of steam. A common industry rule-of-thumb is that 1,000 standard cubic feet of natural gas (~1 MMBtu of energy) is consumed for every barrel of bitumen produced;[68,69] however, many projects are using more. Large energy use results in substantial GHG emissions. Success in reducing SORs leads to proportionately lower GHG intensities.

Developing Insitu Bitumen Recovery Technologies

In addition to improvements to existing technologies discussed above, new insitu recovery processes are being developed to reduce energy requirements, reduce water use, lower costs, improve recovery factors and reduce environmental impacts.

Hybrid Steam-Solvent Processes

Several operators are injecting hydrocarbon solvents (i.e., propane, butanes and condensate) with steam to reduce SORs and energy use and improve recovery factors.

Imperial Oil has implemented "LASER" (Liquid Assisted Steam Enhanced Recovery) at its Cold Lake CSS project. A low concentration of diluent is added to steam to enhance recovery at mid-life. Imperial Oil is also considering infill drilling, steam flooding and other follow-up processes.[70]

Cenovus Energy is testing "SAP" (Solvent Aided Production) at its Foster Creek and Christina Lake SAGD operations and is considering the full-scale commercial application of SAP at its proposed Narrows Lake project. With SAGD, bitumen viscosity is reduced by heating with steam. With SAP, small amounts of solvent such as butanes are injected with the steam to help reduce bitumen viscosity. The result is an enhanced rate of production and higher recovery factor along with reduced SOR, leading to reduced fuel consumption and GHG emissions. In addition to a 30 percent reduction in SOR, SAP at Narrows Lake is expected to allow use of more widely spaced well pairs, significantly increase the recovery factor and increase the API gravity of the produced bitumen.

Other hybrid steam-solvent processes have also been proposed and are being field tested. These include “ES-SAGD” (Expanding-Solvent SAGD) and “TSS-SAGD” (Tapered-Steam-Solvent SAGD). The use of solvents with steam is generally more cost effective at high natural gas prices.

Solvent Only Processes

Several operators have tested both the non-thermal and thermal injection of solvents without steam; however, there is no commercial application of these technologies to date.

The “VAPEX” (Vapor Extraction) process has been tested in the field at the Dover project, which was operated by Petro-Canada, and by others. VAPEX uses a similar well configuration to SAGD. A hydrocarbon solvent (propane or butanes) is injected into an upper well, and allowed to diffuse into the reservoir where it reduces the viscosity of the bitumen, which then drains into a lower well and is pumped to the surface. VAPEX field tests have been unsuccessful in the oil sands due to low solvent diffusion rates and significant solvent losses. Variations of the VAPEX process have been patented but not field tested.[71] [72]

The proposed N-Solv (Nenniger) process[73] uses a heated solvent with a similar well configuration to SAGD. Heated solvent vapor is injected at moderate pressures into the gravity drainage chamber. The vapor flows from the injection well to the colder perimeter of the chamber where it condenses, delivering heat and fresh solvent directly to the bitumen extraction interface. The condensed solvent and bitumen then drain by gravity to the bottom of the chamber and are recovered via the production well. N-Solv has not been tested in the field.

Both VAPEX and N-Solv would produce partially upgraded crude bitumen when using paraffinic solvents due to insitu precipitation of asphaltenes. Economic application of solvent processes requires that solvent losses in the reservoir are minimized.

Insitu Combustion

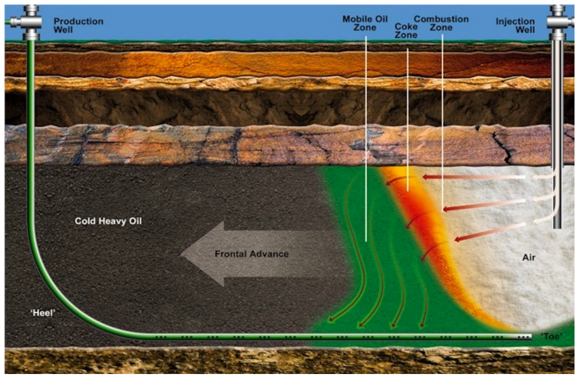
Insitu combustion dates back to 1888 when it was suggested the insitu conversion of coal into combustible gases might be possible.

Several insitu combustion pilot projects using vertical wells were operated in the Athabasca and Cold Lake OSAs, beginning in the 1920s, however all encountered technical problems.

During the late 1980s and 1990s interest in the field application of insitu combustion waned. However, there was a continued interest in the insitu combustion process among the research fraternity, as the higher energy efficiency of the process could not be ignored. Several new approaches to the process were proposed, based on advances in horizontal drilling. One of these is the Toe-to-Heel-Air-Injection (THAI™) process that had been studied theoretically with numerical simulation and physical laboratory models and is now being field tested by Petrobank Energy at the Whitesands experimental project in the Athabasca OSA.

The THAI™ process operates with an array of parallel horizontal production wells (producers) placed near the base of the oil sands zone. Vertical air injector wells (injectors) are drilled with an offset from the toe of the producers and are opened at the top of the pay zone. A steam preheat is initially conducted to establish communication between the injector and the producer. When air is injected, ignition is initiated and a combustion front develops. The THAI™ process is illustrated in Figure COS10.

Figure COS10
Toe-to-Heel-Air-Injection Process (THAI™)



Hot combustion gases that are depleted of oxygen contact the bitumen ahead of the combustion zone and heat it to above 750ºF. The high temperatures in the presence of formation clays cause thermal cracking and upgrading of the bitumen by 7 – 8ºAPI in laboratory physical models. The hot lighter cracked oil, reservoir water and combustion gases drain downward into the horizontal production well for transmission directly to the surface by produced gas lift. Some virgin bitumen warmed by conductive heating ahead of and behind the combustion front also drains into the horizontal well. Up to ten percent of the original bitumen, the heavier, higher-boiling fraction, is left behind on the reservoir and becomes the combustion fuel as the burning front advances. THAI™ consumes only air as an injected raw material.

Cenovus has also been testing combustion at its EnCAID project where combustion has been used to maintain pressure and allow production of natural gas from a reservoir where gas overlies the oil sands zone. Cenovus now plans to drill a horizontal bitumen production well to allow production of the bitumen that has been heated by combustion while natural gas is being concurrently produced from the reservoir.[74]

Insitu combustion laboratory work is also being conducted at the Calgary Centre for Innovative Technology (CCIT) at the Department of Chemical and Petroleum Engineering at the University of Calgary and the AITF. Other insitu combustion techniques that may eventually be tested and applied in the field are:

- Combustion Override Split-Production Horizontal Well (COSH)
- Top-Down Combustion

All of these gravity-stable technologies are variations on insitu combustion and are short displacement processes that are now possible by advances in horizontal drilling technology. However, only the THAI™ process has advanced to the field trail stage and is now being proposed for commercial development at Petrobank's May River project in the Athabasca OSA.

Electric Heating

Studies have shown some promise in electromagnetic reservoir heating processes, however there are few field applications of electromagnetic heating or comprehensive modeling efforts. Compared to other thermal enhanced oil recovery methods, electromagnetic heating still remains a peripheral technology, even though it the potential was recognized more than three decades ago. However, electromagnetic heating is experiencing renewed interest for possible application in Canada's oil sands and US oil shale deposits.

Electrical heating of a formation can occur in a number of ways, depending on the frequency of the electrical current. In the high frequency range (radio frequency and microwave), dielectric heating prevails, as is seen in microwave ovens. When low frequency alternating current is used, resistive heating is dominant. A third method of electrical heating is inductive heating, where alternating current flowing through a set of conductors induces a magnetic field in the surrounding medium. The variation of the magnetic field generates heat.

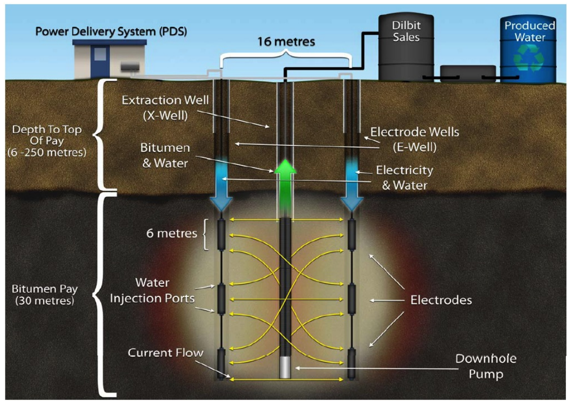
Petro-Canada and its joint-venture partners conducted electrical resistive heating tests at the Hangingstone project during the 1980s; however, testing was unsuccessful and was subsequently abandoned.

More recently, since 2004, E-T Energy Limited (E-T Energy) has been conducting electrical resistive heating tests on its project lands north of Fort McMurray, Alberta. E-T Energy's Electro-Thermal Dynamic Stripping Process (ET-DSP) uses closely-spaced electrodes drilled into the oil sands formation. Water is injected into the electrodes to transfer heat rapidly into the oil sands. The heated bitumen can then be extracted at production wells using surface pumps.

In July 2009, E-T Energy applied for approval to construct and operate a 10,000 B/D bitumen extraction facility on its oil sands leases.

The ET-DSP process is illustrated in Figure COS11.

Figure COS11[75]
Electro-Thermal Dynamic Stripping Process



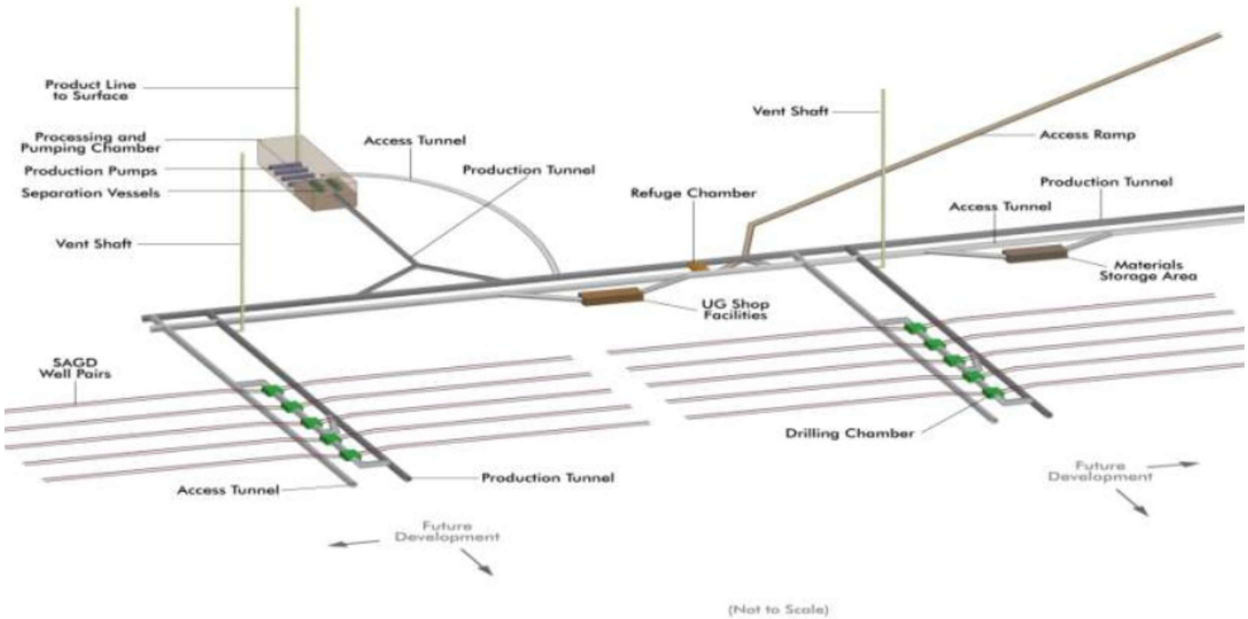
Shell has also tested electric heating at Peace River and has received approval for an electric heating experimental scheme in the Grosmont carbonates. The Shell process would heat the oil sands to high temperatures for long periods of time effectively coking the formation and producing upgraded or partially refined products. The process was originally developed for application to US oil shales.

Underground Well Recovery

Prior to the advent of horizontal wells, the initial development of the SAGD process evolved from work by AOSTRA at the Underground Test Facility (UTF) with field testing beginning in 1987. At the UTF project, shafts were drilled into the limestone layer underlying the oil sands formation. These shafts were connected by tunnels. Pairs of “horizontal” wells were drilled from the tunnels into the overlying oil sands mimicking horizontal wells drilled from the surface. Steam was injected into the oil sands formation through dedicated injection wells and heated bitumen was drained from the formation through dedicated production wells. The success of the UTF project and advances in horizontal drilling technology led to the development of SAGD, with the drilling of horizontal well pair from the surface. UTF was operated on the Dover Lease west of Fort McMurray; the project has now been abandoned.

The same concept has been proposed by Osum Oil Sands (Osum) for recovery of crude bitumen from the Grosmont carbonates. A series of tunnels would be developed in the underlying formation from which “horizontal’ well pairs would be drilled into the overlying bitumen bearing zone. The wells would be operated as SAGD well pairs with the bitumen and steam condensate draining to the tunnels below the pay zone rather than being lifted to the surface above. Project applications have not been filed. The conceptual layout of Osum’s Underground Well Recovery System (UGWRS) is provided in Figure COS12.

Figure COS12
Osum's UGWRS Conceptual Layout



Other Insitu Recovery Technology Concepts

Numerous other insitu recovery technology concepts are advancing through both industry and government; numerous ideas have been developed at Universities. A few include:

- CSS and SAGD variants, "JAGASS/JAGD" (J-well and Gravity Assisted Steam Stimulation) and "iSAGD" (mobility ratio optimized SAGD), are designed to take advantage of bitumen viscosity gradients in the reservoir.
- "LEMUR" (Low Emission Microbial Upgrading and Recovery) is examining the possibility of using microbes to accelerate insitu bitumen biodegradation for production of methane.

Environmental and Social Challenges

All forms of energy require accounting for environmental and social impacts within a broader energy context and public interest. The development of oil sands, in particular, brings a unique set of environmental and social challenges. Compared with most conventional crude oils, these can include land disturbed by mining, higher water use including tailings ponds and higher than average GHG emission intensity. Of concern to local and Aboriginal communities is the extremely fast pace of development in a remote, northern area.

Pace of development

The growth of oil sands development surprised many. In 1995, the National Oil Sands Task Force examined the conditions necessary to reach a goal of 1.2 MB/D by 2020. A combination of favorable tax and royalty policies, technology improvements and rising oil prices resulted in rapid growth after 2000, with the industry reaching that goal by 2007.The rapid growth has created social pressures, which are particularly acute in the City of Fort McMurray and throughout the Regional Municipality of Wood Buffalo, Peace River and Cold Lake, Alberta. The entire province has also felt the repercussions as an overheated economy pushed up housing costs and strained social services.

As the industry grows, so do the associated challenges. Rural residents face increased construction activity and traffic congestion, and communities struggle to meet the pressure placed on infrastructure, medical care, housing and schools. Project developments are affected by a global shortage of skilled workers and the challenge of attracting workers to a relatively remote location with an extreme northern climate.

Project development strategies take into account the risk of another boom-bust cycle. Most operators support programs aimed at training local Aboriginal communities in critical technical skills, as well as training and bringing in temporary foreign workers. On-site camps to house workers relieve some of the infrastructure pressure in the surrounding communities.

At the end of 2008, as oil prices declined and capital markets contracted, many planned oil sands projects were delayed or cancelled. While the economy has recovered from the trough of the crisis and some of these projects have been revived, the industry remains cautious about overheating the labor and services markets and risking cost overruns and further project delays. Several previously planned upgrader projects, which are particularly labor and capital intensive, are likely to remain under consideration for the foreseeable future and this could provide a much-needed opportunity to develop the infrastructure required to meet future growth plans.

Aboriginal Rights and Traditional Land Use

In Canada, indigenous people or Aboriginals are comprised of First Nations, Métis and Inuit. Their Aboriginal and Treaty Rights are enshrined in Section 35 of the Constitution Act, 1982. The honor of the Crown is always at stake when it deals with Aboriginal people’s potential and established Section 35 rights. The Supreme Court of Canada determined that the Crown owes a duty to consult Aboriginal groups if it contemplates conduct which could adversely impact their potential or established Section 35 rights. Federal and provincial governments share responsibility to consult Aboriginal groups depending on the nature of the potential impact. Both levels of government have developed policies to help ensure Aboriginal concerns are heard and their rights are respected with respect to resource development.

Nevertheless, Aboriginal leaders in the oil sands region have passed joint resolutions calling for a moratorium on oil sands project approvals until strategic watershed and land use planning is completed. Some Aboriginal groups are advancing litigation challenging whether consultation was adequate and the lease approval process valid. If successfully litigated, and it is determined that there was a permitting defect or the permitting violated existing law, these challenges have the potential to delay projects and invalidate leases.

While federal and provincial governments share the responsibility to consult, oil sands producers are also expected to proactively manage their relationships with Aboriginal communities and to accommodate the communities' Section 35-related concerns. Impact Benefit Agreements commit companies to work with communities to ensure that project benefits, such as employment and procurement opportunities, as well as revenue sharing and environmental mitigation responsibilities are all clearly defined. Aboriginal elders, advocates, and leaders work with government and industry to identify ways to improve the standard of living in local communities.

Successful partnerships have resulted in the development of centers and programs for education, health, recreation, and elders. Companies actively assist Aboriginal entrepreneurs develop business opportunities and training and capacity development is a key part of the industry's community investment activity, directed at employing Aboriginal workers and awarding contracts to Aboriginal businesses. Between 1998 and 2008, Aboriginal companies earned more than $3 billion in oil sands contract work.[76] In 2008, the oil sands industry awarded over $575 million in contracts to Aboriginal companies, employed about 1,500 Aboriginal employees in permanent jobs, and provided more than $2.5 million in support of Aboriginal community programs.

While some localized Aboriginal leaders have publicly recognized the value of the economic benefits that accrue through oil sands development, they are also concerned about the impact on their environment and traditional activities.

Land Use

Canada's oil sands deposits lie under approximately 54,000 square miles or 4 percent of Canada's Boreal Forest. The Boreal Forest is a mosaic landscape of trees and wetlands stretching across 1,200,000 square miles of Canada's landmass. The Boreal Forest is of immense value for the biodiversity and the ecological services it provides. Oil sands operations alter the ecosystem and disturb the habitat for the part of the forest they disturb.

In Alberta, about 35,000 square miles of the boreal forest is protected from development including National and Provincial Parks and wild land areas. In northeastern Alberta alone, approximately 22,000 square miles of boreal forest are currently protected and additional areas are under consideration.[77] In addition, several oil sands companies are working in partnership with regional conservation groups to purchase land in the region for preservation of habitat through the terrestrial conservation offset program.

Cumulative effects

Introduced in 2008, The Alberta Land Use Framework (LUF) is under active development which will allow land use plans to more fully take into account environmental, social and economic considerations. It formalizes the approach of evaluating the cumulative effects of existing and planned development in an area to understand the combined impact of past, present and reasonably foreseeable human activities on a region. Environmental cumulative effects management recognizes that watersheds, airsheds and landscapes have a finite carrying capacity and seeks to manage growth such that it does not exceed that capacity. The LUF requires formal land use planning for each of seven regions, including the Athabasca region, to set out objectives, provide context for decision-making and identify priorities. Through anticipating future pressures and establishing limits on the effects of future growth on the air, land, water and biodiversity of the region, the effects on the environment are balanced with the economic opportunity. For instance, the current vision of the LUF for Athabasca region recommends that a upper limit be set for the cumulative area that oil sands leases can disturbed at any one time. If this limit is ratified, it would help to reduce the effects of development on the regions biodiversity.

Mining

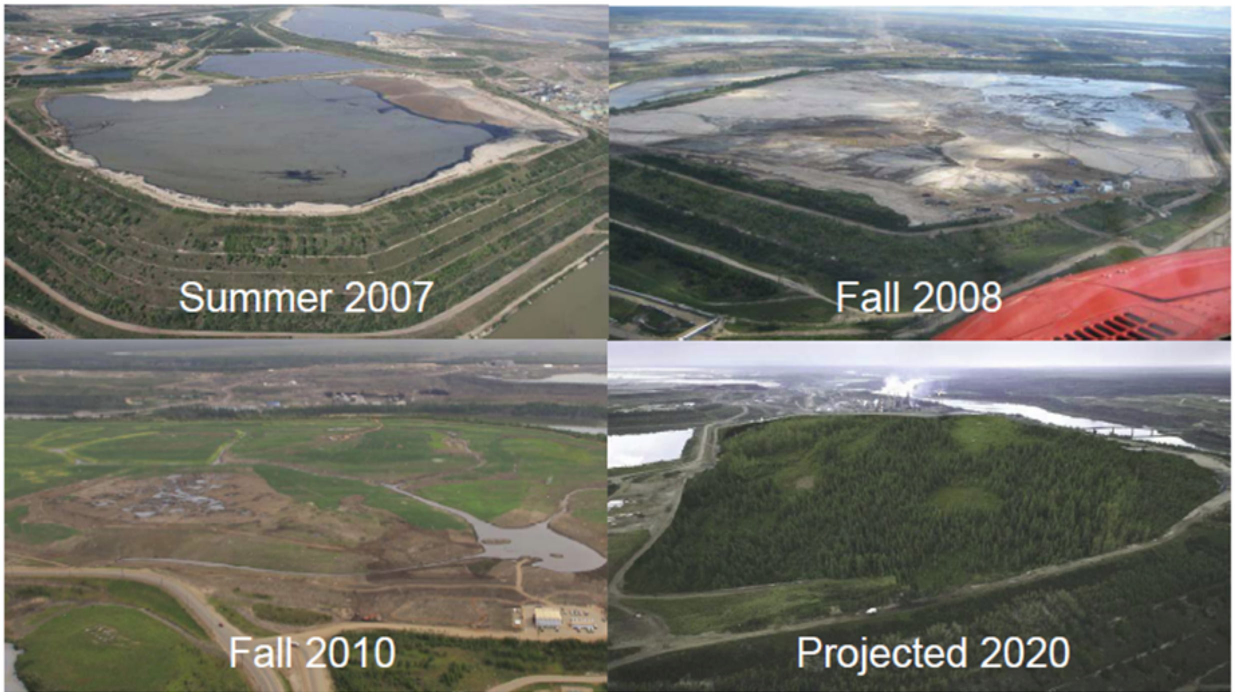
Oil sands mining requires the complete removal of overburden – the surface vegetation and soil – which can be up to 215 feet in depth. The overburden is stored until required for reclamation. The Province of Alberta requires land to be reclaimed to an "equivalent land capability" with a goal that the reclaimed landscape is capable of supporting native vegetation and wildlife. This is accomplished by rebuilding the foundations that allow a diverse, natural landscape and ecosystem to take hold. Innovative technologies, such as computerized landscape contouring and traditional Aboriginal knowledge are used to reclaim land. Recreating wetlands, in particular peatlands, that have been drained is more challenging and has not been demonstrated to date.

About 1,854 square miles, or about three percent of Canada's Boreal Forest area, contain mineable deposits and of that area approximately 230 square miles has been mined to-date, with 25 square miles reclaimed[78]. All projects operate under progressive reclamation directives, requiring areas to be reclaimed when they are no longer required for the mining operations.

A major obstacle to progressive reclamation is the creation of large tailings ponds, often in discontinued mine pits. The footprint of current tailings facilities is about 66 square miles[79] - covering close to 30 per cent of the lands disturbed by oil sands mines. The ponds are a mixture of water, clay, sand and residual bitumen. The clay materials do not settle, resulting in large volumes of a material that is the consistency of yogurt known as mature fine tails. Before the ponds can be reclaimed, the mature fine tailings must be consolidated, which would take hundreds of years if allowed to consolidate naturally.

The oil sands industry has employed various technologies to accelerate this consolidation process. In 2010, Suncor's Pond 1 was the first pond to be reclaimed after more than 40 years of operations (see Figure COS13 for history and projection of tailings pond reclamation).

Figure COS13
Suncor Tailings Pond Reclamation Progress



New processes to speed up the tailings consolidation have been successful in trials at reducing the time it takes to reclaim the tailings ponds. Suncor has approval for a new remediation process (Tailings Reduction Operations or TRO) that adds a polymer that binds to the tailings. The resulting slurry is drained over a slightly graded slope, allowing the water to run off and be treated for recycling. This approach is expected to eliminate the need for long-term tailings storage and reduce the tailings cycle to 7-10 years post disturbance. Other promising technologies to deal with tailings are being developed in parallel - including injecting waste CO_2 into the tailings slurry lines before the tailings enter the pond, where it reacts to form carbonic acid. This reaction changes the pH of the tailings mixtures and allows the fine clays, silts and sand to settle quickly and leave clearer water available for recycling.

In February 2009, the Alberta ERCB issued Directive 074 with new requirements for operators to manage tailings. Between 2012 and 2016, companies are required to implement plans that will reduce the accumulation of tailings and provide target dates for closure and reclamation of legacy ponds. This is a challenging target; although firms have submitted plans it is still uncertain if the industry will achieve the requirements of this directive. After 2016, under the directive, the industry will have to process fluid tailings at the same rate they produce them. While operators will incur significant capital costs in tailings remediation, this will be balanced by improved water recycling efficiency and cost savings from not having to maintain expensive tailings containment processes.

In addition to Directive 074, further provincial regulatory requirements are being developed under an initiative called the Tailings Management Framework (TMF). The TMF is expected to specify requirements for consolidation of legacy tailings, water management and reclamation in the oil sands mining industry. The TMF is expected to be completed by late 2010 or early 2011.

Insitu

Insitu development, which is expected to comprise an increasing portion of oil sands development, creates less land disturbance and uses similar reclamation practices to those used in conventional oil and gas production. Insitu operations are also able to reclaim land earlier than mining projects. However, the cumulative impacts of a network of structures such as well pads, steam plants, roads and pipelines, fragment the forest habitat over such a large area and has the potential to result in greater disturbance to wildlife than mining.[80] In 2009, the Alberta Biodiversity Monitoring Institute (ABMI) found that while there is clearly an impact from industrial and commercial development based on the measurement of 52 bird species and 97 plant species, the region's living resources were 94 percent intact. A variety of measures are used to reduce the impact on wildlife, including wild life corridors, raised pipelines, and low impact seismic activities which minimize seismic line width.

Oil sands water use

The industry uses both groundwater (water from underground formations) and surface water (water from lakes and rivers) to extract bitumen from the oil sands. In aggregate, oil sands operations use approximately 6.2 billion cubic feet of water per year raising concerns that too much water is used in oil sands production and that water is polluted by oil sands processes.

Mining

Oil sands mining operations use surface water from the Athabasca River to separate the bitumen from the sand in an extraction plant. On average, two thirds of the water used is recycled back into the extraction process, but fresh, so-called make-up water is continuously required. Net of recycling, it takes approximately four barrels of water to produce one barrel of bitumen. About two to three of these barrels are drawn from the Athabasca River, the balance coming from surface run-off and mine dewatering.

The Athabasca River is the largest river running through the Alberta oil sands, and is the primary source of fresh water for both communities in northern Alberta and the oil sands mining industry. In 2007, the oil sands mining industry withdrew a total of 5.6 billion cubic feet of water from the Athabasca River – less than 1 per cent of average total river flows and about 5 per cent of the lowest weekly winter flow (in the winter – when water levels are the lowest - withdrawals can have the greatest impact on fish and organisms in the river). There are concerns that the province's relatively dry climate is being exacerbated by climate change, reducing the winter flow rates and stressing the aquatic ecosystem. The Athabasca River Water Management Framework, part of the Province's *Water for Life* strategy, is an outcomes based approach to balance high levels of protection for the river with water needs. The Framework sets maximum withdrawal limits. During winter "low flow" periods companies will have to reduce their withdrawals and find ways to ensure their production isn't affected. Each operator is required to submit a plan to Alberta Environment outlining how it will manage its water withdrawals during winter. New operations will require winter water storage to avoid the need for more river water withdrawals during winter low-flow periods.

Insitu

Steam-based insitu recovery, CSS and SAGD, uses steam to heat and mobilize the bitumen, allowing it to flow to the surface. Where possible, the industry uses saline, or non-drinkable, water from deep underground formations, which has allowed the industry to reduce the amount of net water for operations to 0.6 to 0.9 barrels per barrel of bitumen produced. Some SAGD operations use no fresh water at all. In 2007, more saline water was used for insitu oil production than fresh water. After use, a waste stream of highly concentrated brackish water is re-injected into deep disposal wells. Some operators – ones that do not have a suitable disposal wells nearby – use a *zero liquid discharge* system which requires even less water as they recycle more than 90 percent of the injection steam required.

Key to water use is the steam-oil ratio (SOR). The SOR is a function of the oil sand formation geology, as well as the age of the chamber into which the steam is injected. The current industry average SOR is 3 barrels of water to one barrel of bitumen. The SOR will be higher in the early phase of steaming a well and as the well depletes. Depending on the geology of the lease, some of the proposed insitu projects may need to manage higher SOR ratios than the current industry average. Insitu combustion technologies, such as THAI™, or solvent-based approaches that reduce the amount of steam hold promise for reducing the amount of water used. Regional approaches to water use that provide the necessary infrastructure to enable producers to use recycled water from other operator's facilities have the potential to optimize water use even further.

Insitu producers face higher costs and energy use associated with water recycling and raising steam for extraction. In addition, the long-term availability of these deep saline aquifers and the impacts of large scale extraction on regional hydrogeology remain uncertain. Innovative approaches to reducing water use will be necessary to support large scale insitu development of the resource.

Water Quality

As discussed earlier, mining operations create tailings ponds to store the waste materials from the mining and extraction process. The water is stored in large ponds to help the solids settle out from the water and allow the water to be recycled for further use. Because the water in the tailings ponds is repeatedly re-used to process more raw oil sands, the naturally occurring materials that were originally present in the oil sands -- residual bitumen, clay, sand, and other materials such as naphthenic acids (NAs) and polycyclic aromatic hydrocarbons (PAHs), mercury, and arsenic - become more concentrated over time. No tailings water can be released to the Athabasca River or any other watercourse, but as the tailings ponds are unlined earthen structures, there is potential for some leakage of tailings into the environment and although remote, of a catastrophic failure of the perimeter dyke. These risks are mitigated by extensive monitoring and containment systems which include ditches constructed around the tailings ponds to prevent any seepage from entering regional groundwater systems or waterways. Monitoring of the Athabasca River does indicate the presence of these naturally occurring materials and although not proven, concerns remain that seepage may be increasing these concentrations.

Greenhouse Gas Emissions

No other individual regional activity has attracted the level of global attention from a GHG emissions perspective over the past 5 years as the Canadian oil sands. This level of attention has led to confusion and some misinformation. At approximately 37 million tonnes of GHG emissions in 2008, Canada's oil sands industry accounts for 5 percent of Canada's total GHG emissions and contributes approximately 0.1 percent of global GHG emissions. If planned projects go ahead (and total production reaches about 3 MB/D by 2020), oil sands emissions could grow to 12 percent of Canada's total GHG emissions[81]- roughly equivalent to 3 percent of the current fleet of coal-fired power plants in the US today. For our likely oil sands projection (where oil sands production reaches 4.5 MB/D by 2035), assuming a simple extrapolation from the previous data-point, emissions would be in the range of 18 percent of Canadian GHGs emissions.

It is the GHG growth trend resulting from increased production that is the key concern, even though the average intensity per barrel is expected to decline over the same period – absolute emissions will grow with production. The Government of Canada has committed to reducing GHG emissions by 17 percent below 2005 levels by 2020 – a target that is aligned with the US. In order to achieve this objective, GHG emissions will have to be reduced from business as usual forecasts across most, if not all, sectors of Canada's economy. Alberta was the first region in North America to mandate GHG reductions and institute a carbon levy which is expected to increase over time. Currently the levy is at $15 a tonne with the revenue generated being redistributed towards clean energy research and development projects.

The carbon intensity of producing gasoline and diesel from oil sands crudes is higher than that of fuel produced from the average conventional crude. Full lifecycle emission assessment quantifies the emissions of fuels from various sources along the entire value chain, from production (which, in the case of oil sands SCO, includes upgrading), refining, transportation and combustion as fuel. The analysis is typically reported as kilograms of CO_2e/barrel of refined products.

A wide range of reported values compare the GHG intensity of oil sands crudes with other crudes. IHS CERA compared the results of 13 publicly available lifecycle studies.[82] In normalizing the results of each study to a well-to-wheels analysis, IHS CERA determined that refined products wholly derived from the oil sands have an emissions intensity that is 5 to 15 percent higher than that of the average crude consumed in the US and on a par with some other US supply - including crudes from Nigeria, Venezuela, and even some domestically produced crude oils. Given that the tail pipe emissions from a barrel of refined products (approximately

70-80 percent of the total emissions) do not differ between sources of crude, the variability in carbon intensity is due to processes required to produce, upgrade, transport and refine the crude - also known as the well-to-retail pump emissions.

IHS CERA's study found that fuel produced from oil sands mining has well-to-retail-pump emissions 1.3 times the average fuel consumed in the US Fuel from crude produced from insitu methods has well-to-retail-pump emissions 1.6 times higher.

The quoted range of values comparing the carbon intensity of oil sands with other crudes is wide primarily as a result of how the information is presented. Some studies compare oil sands crudes to a barrel of US sweet, light crude which is not representative of the average barrel of crude refined in the US Others argue that the correct benchmark is the marginal barrel, or the import that would replace the oil sands barrel. According to an IHS CERA report,[83] *Mature Oil Fields: an Energy Intensity Dilemma,* oil fields that have produced over half of their initially estimated reserves make up one quarter of global oil production. As oil fields mature, they require more energy per barrel to produce and the global shift towards unconventional crudes, heavy, deep-sea offshore crudes and secondary and tertiary recovery of conventional crudes suggests that the GHG intensity of an average global barrel of crude will continue to increase.

Against this backdrop, the intensity of oil sands crudes has been dropping. By 2008, oil sands mining operations had reduced GHG emissions intensity by 39 percent from 1990 levels[84] and are working towards further reductions. Significant emission reductions in mining operations came from lowering the temperature of the water used in bitumen extraction, optimizing the fuel use per ton through larger trucks used to transport oil sands from the mine, and the replacement of conveyers with hydrotransport in pipelines. Many mining and insitu operations also switched from consuming electricity from a predominantly coal-powered electricity grid to using natural gas cogeneration to provide both heat to produce steam as well as meet their electrical power requirements. Besides the efficiency of simultaneously produced steam and electricity, many of the insitu plants generate surplus electricity that is available for export to the grid, displacing higher intensity coal generation. Further incremental reductions in carbon intensity at both mining and insitu operations are expected.

The pathway to reduced emission intensity has been, and will continue to be, very much aligned with the economics of oil sands production; the technologies or processes that improve reliability and reduce energy input substantially improve the economic return of the business. Alberta's carbon regulation has required facilities to measure and report GHG emissions since 2005 and to pay penalties (15 dollars per tonne CO_2) for not meeting facility-based intensity targets since mid-2007. The industry is responding to the carbon price signal through both internal abatement and a rapidly developing offsets market and is well-positioned to deal with future North American climate change regulations.

Looking to the future, oil sands operations, industry along with Federal and Provincial institutions, such as Alberta Innovates Technology Future and Natural Resources Canada's CanmetENERGY as well as local universities, are incubators for innovative technologies that may well provide solutions transferable to other industries. Continuous incremental improvement will come from energy efficiency initiatives. New heating methods such as electric, microwave, downhole combustion and solvent supplemented heating hold promise to move the dial more rapidly. Ultimately, new fuel technologies, such as nuclear or geothermal power, could be game-changers in carbon reduction. These technologies, however are more than two decades away, have high capital costs, long lead times, or are not currently commercial at the scale required by oil sands operations.

Canada is positioning itself to be a leader in Carbon Capture and Storage (CCS), a process that captures emissions and stores them in deep geological formations. Alberta is uniquely suited for CCS as the Western Canadian Sedimentary Basin has held oil and gas for millions of years, and these reservoirs, now depleted by conventional drilling, can be safely used to permanently store carbon emissions. The biggest challenge in implementing CCS is cost rather than technical issues, and at an estimated $80-150 per tonne depending on the site, it is now only pursued on a technical demonstration basis. Oil sands facilities, particularly the large point sources at upgraders show promise, where CCS could reduce emissions in the order of 15-20 percent (well-to-retail pump basis). While CCS is currently more expensive than the carbon price in Alberta or that expected in North America, there is a large body of applied research being done, particularly in coal-fired generation, which could offer economies of scale and further cost reductions through technology innovation.

Natural Gas Demand

Natural gas is the primary fuel used for insitu production, plus there is some demand from mining extraction and upgrading operations. In 2009, oil sands consume about 1.8 Bcf/day over 20 percent of Canada's natural gas demand[85].

Productive Capacity Projection

Projection to 2035

As stated earlier in this section, the Canadian oil sands industry is well established: first large-scale commercial production began more than 40 years ago and in 2009 production reached 1,335,000 B/D. Several new projects have recently come on stream, several are under construction, and many more are proposed. At the time of writing, the industry had proposed projects representing about 7.7 MB/D of bitumen productive capacity as illustrated in Table COS2.

TABLE COS2
Existing and Proposed Canadian Oil Sands Project Capacities

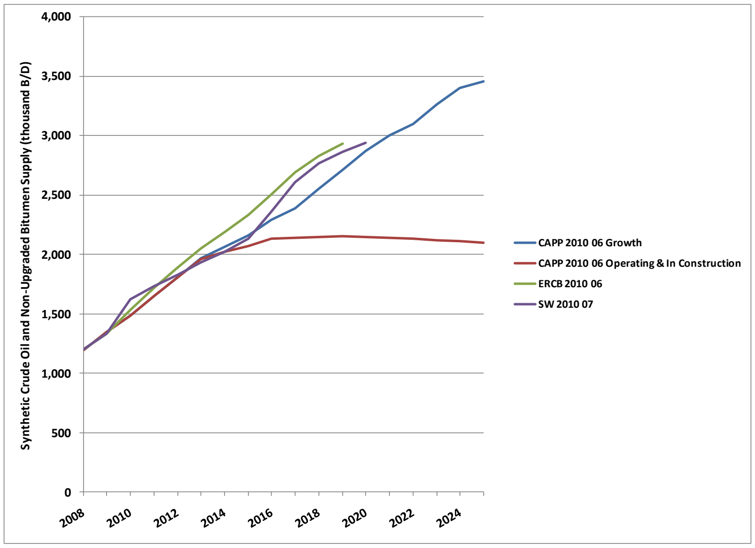
	Capacities (B/D bitumen)					
		In Situ				
	Mining	N Athabasca	S Athabasca	Cold Lake	Peace River	Total
Operating	1,018,000	128,000	327,800	300,000	13,500	1,787,300
Construction	210,000	68,000	169,800	-	-	447,800
Suspended	-	12,000	-	-	-	12,000
Approved	940,000	456,200	396,800	50,000	1,550	1,844,550
Application	520,000	219,000	667,155	79,200	80,015	1,565,370
Withdrawn	114,500	30,000	-	-	-	144,500
Disclosure	210,000	80,000	210,000	-	-	500,000
Announced	407,000	525,000	508,500	-	13,000	1,453,500
Total	3,419,500	1,518,200	2,280,055	429,200	108,065	7,755,020

Note that current productive capacity has reached almost 1.8 MB/D of crude bitumen (“Operating” projects). This includes the capacity of several new projects that were recently brought on stream and have not yet reached full capacity. Additionally, projects representing more than 0.4 MB/D of productive capacity are under construction (“Construction” projects). These projects will bring stream-day[86] productive capacity to over 2.2 MB/D of crude bitumen by early this decade.

Note also that the productive capacities illustrated in Table COS3 are for bitumen production and do not reflect the upgrading segment of the industry.

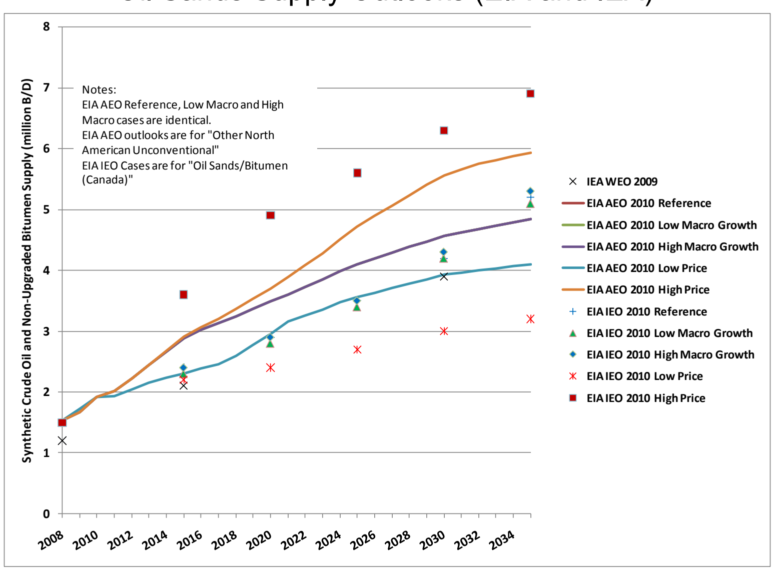
Several organizations have forecast future growth of the Canadian oil sands industry. Recent outlooks have been released by the Canadian Association of Petroleum Producers[87] (CAPP), Alberta’s Energy Resources Conservation Board ERCB[88] and Strategy West Inc.[89] These outlooks are summarized in Figure COS14.

Figure COS14
Oil Sands Supply Outlooks (Canadian Sources)



The US Energy Information Administration (EIA) and the International Energy Agency (IEA) also recently released the outlooks summarized in Figure COS15.

Figure COS15
Oil Sands Supply Outlooks (EIA and IEA)



Based on our review of the available resources, the status of the industry and the challenges it faces, it is our view that the Canadian oil sands industry has the High potential to provide up to 6 MB/D of SCO and raw non-upgraded bitumen supply by 2035 as illustrated in Table COS3.

Table COS3
Oil Sands Supply Outlook

	2009 Actual (B/D)	2035 Low (B/D)	**2035 Likely (B/D)**	2035 High (B/D)
Canadian Oil Sands	**1,350,000**	3,000,000	**4,500,000**	6,000,000

The **Low Case** assumes that governments attempt to remake their economies on a platform of clean energy. Strong policies to limit GHG emissions encourage expansion of alternative forms of energy, while regulatory oversight of the oil sands tightens further, particularly to address the cumulative impacts on air and water quality and land use created by oil sands development. The intersection of increasing costs and declining oil demand and oil prices (lower oil demand stems from government clean energy policies), squeeze producers' margins and deters significant oil sands developments after 2020. The low case would result in oil sands natural gas demand growing to 2.6 Bcf per day.

The **Likely Case** assumes that:

- Supply continues to be driven by market demand
- The current Canada/US trade relationship remains (e.g. free flow of exports)
- Oil prices remain sufficient to justify new project investments
- Sufficient pipeline transportation capacity is built to move products to market
- Public acceptance of oil sands development is maintained through ongoing environmental performance improvements.
- At this growth level, there are no undue restrictions expected on:
    - Capital availability
    - Availability of engineering services
    - Skilled labor supply
    - Material and equipment supply
- The likely case would result in oil sands natural gas demand growing to 4 Bcf per day.
- The **High Case** further assumes that there is a concerted effort by Canada and the US to address the challenges associated with unconventional oil development in general and oil sands in particular (e.g., environmental constraints, others) as a secure source of North American oil supply. The high case would result in oil sands natural gas demand growing to 5.2 Bcf per day.

A View to 2050

Based on the size of the resource base, the Canadian oil sands industry has potential to continue at a similar pace well beyond 2035. By 2050, in a likely case oil sands supply could surpass 5 MB/D, or in a High case supply – if environmental limits to growth are mitigated – production could conceivably approach 8 MB/D. Achieving this level of production would make Canada one of the world's largest oil suppliers in the 2050 timeframe.

5. Canadian Heavy

In 2009, Canadian conventional heavy oil represented about 20 percent of all Canadian crude exports[90]. The vast majority of Canadian conventional heavy oil comes from a region termed the "heavy oil belt". Canadian conventional heavy oil is extracted using many of the same techniques as the drillable insitu oil sands region, and the resulting crude oil products are virtually the same. Bitumen produced from oil sands is akin to conventional heavy oil, but is categorized as bitumen mainly because it is produced from the Alberta regulator's (ERCB) designated Oil Sands Deposits.

As a general rule, heavy oil projects north of township 53 in Alberta are classified as oil sands and projects south are classified as conventional heavy oil. In Saskatchewan, all heavy oil production (including production north of the Alberta cut-off) is categorized as conventional heavy oil. Moreover, looking forward, oil sands thermal production techniques are increasingly being applied in the conventional heavy oil belt, unlocking a greater portion of the oil in place and - to some extent - blurring the line between the oil sands and heavy oil belt resources.

Because of the overlap between bitumen produced from insitu oil sands and Canadian conventional heavy, Canadian conventional heavy oil has been included within the unconventional oil category of this study.

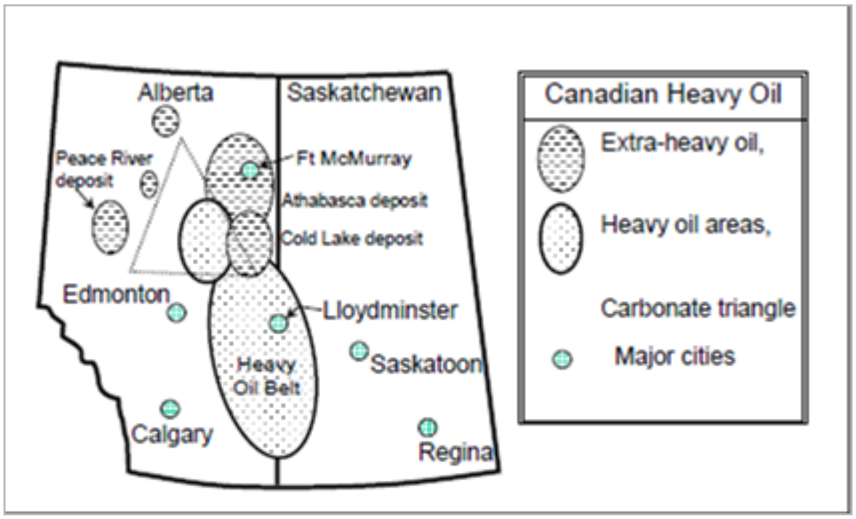
Where and how big?

The heavy oil belt straddles the border of Alberta and Saskatchewan; just south of the oil sands Cold Lake region (See figure U1). This resource has been tricky to extract; after 60 years of production, less than 10 percent of the heavy oil in place has been produced. The oil from the region has "unconventional characteristics" including density approaching water (8-18 API) and viscosity near molasses (500 - 20,000 centipoise). Besides high viscosity and high density, heavy oils typically have high asphaltene and heavy-metal content, and higher acid numbers than conventional crudes. Furthermore, Canadian heavy oils are found in relatively thin deposits of unconsolidated, loose sands making them more challenging to produce than most conventional heavy crudes.

Original heavy oil-in-place in the Canadian heavy oil belt is over 35 BB, with more than half of the oil in Saskatchewan (Saskatchewan has 21 BB[91], Alberta has 14 BB[92]). The heavy oil resource is big relative to many others in North America, but it is just 2 percent of the massive oil sands to the north (oil sands resources are estimated at 1.8 trillion barrels).

Using primary depletion/cold flow production methods, only a fraction (8 to 12 percent) of the oil in place can be produced. To date, three quarters of the reserves have been produced leaving modest reserves of 1 BB remaining (0.4 billion in Alberta [93] and 0.6 billion in Saskatchewan[94]). Without applying secondary extraction methods or finding additional reserves, the economically recoverable oil could be exhausted within the next few decades. However, ultimate potential of the resource is larger if secondary methods are applied after primary/cold flow production is depleted.

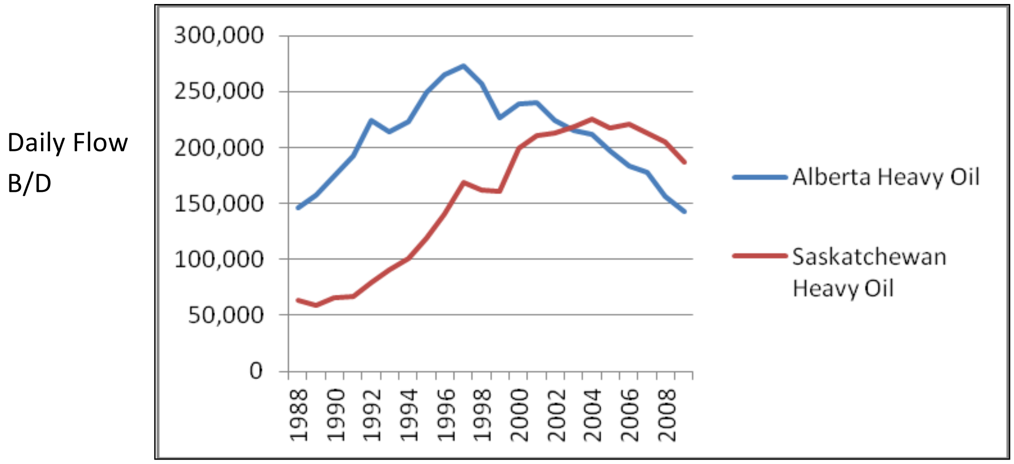
Figure CH1 – Heavy Oil and Oil Sands Regions in Alberta and Saskatchewan[95]



Production History

In 2009, production of Canadian conventional heavy oil was 382,000 B/D with production in decline (5 percent per year on average over the past 5 years).[96] Combined production from the two provinces peaked in 1997. The relatively sharp production growth in the early 1990s was driven by a combination of factors; advances in progressing cavity pumps and horizontal drilling technology, more favorable fiscal terms in both Alberta and Saskatchewan, an abundance of “easy-oil” amenable to cold production, and most importantly, heavy oil prices above the supply cost. Over the past 20 years, the “easy oil” has been largely produced and production has declined. An additional factor has been the changing focus from heavy oil to the oil sands. Since the early 2000, methods to extract oil sands have been commercialized and companies have shifted their efforts into developing oil sands leases, which may be a contributing factor in the recent decline in heavy oil production.

Figure CH2 – Historical Heavy Oil Production Alberta and Saskatchewan (1988-2009)*



*Note – Alberta production data is from the Alberta ERCB and heavy oil includes all oil under 25.7 API, meanwhile Saskatchewan production data is from the Saskatchewan Ministry of Energy and Resources and uses a under 20 API cut-off for heavy oil.

Economics and Government Policy

Although the economics of production from the heavy oil belt have improved over time (driven by advances in technology and more recently improved prices for heavy oil); cold flow production economics are marginal when compared with most other on-shore conventional oil fields. Operating costs are high and oil recovery per well is low. In 2001, the National Energy Board (NEB) of Canada estimated supply costs between 13 to 17 dollars per barrel, when indexed to today, costs range between 26 and 34 dollars per barrel[97].

To help "level the playing field", both the Alberta and Saskatchewan governments provide slightly better fiscal terms compared to production from light or medium crudes. Although both provinces give incentives, Saskatchewan has better fiscal terms than Alberta. Further, in Saskatchewan, when a project injects steam, gas, or chemical solvents, it can qualify for enhanced oil royalties which are similar to oil sands projects in Alberta (low royalties until project payback, followed by profit sharing after payback). Looking forward, more of the production in the heavy oil region is expected to move to thermal recovery, and the Saskatchewan enhanced oil royalty provides an incentive for this. In Alberta, projects south of township 53 cannot qualify for the oil sands style royalties.

Production Technologies

The Alberta ERCB has increased its estimate of Heavy oil primary recovery from 8 percent in the 1990s to 12 percent in 2009. They credit *"improvements in water handling, use of horizontal wells, improved fracturing techniques, including multistage fracturing, and increased drilling density"* [98] as drivers for the improved recoveries.

Today, heavy oil belt extraction use similar production technologies as insitu oil sands (see Chapter 4 “Insitu Bitumen Recovery – Primary Recovery and Secondary Recovery” for more detailed description of all technologies listed):

- Cold heavy oil production with sand (CHOPS). Both sand and oil are recovered with progressing cavity pumps. Recovery factors range from 3 to as high as 12 percent using in this technology.
- Horizontal well technologies – typically applied to areas of the heavy oil belt with lighter gravity crudes, similar recoveries to CHOPS.
- Secondary recovery – water and polymer flooding (which is akin to pushing jello through the formation to displace the oil) are used in lower viscosity reservoirs.
- Thermal (CSS – Cyclic Steam Simulation and steam drive) – CSS followed by steam drive has been used since the early 1980’s. Oil recovery has reached 60 percent with cumulative SOR between 3 – 5.[99] A number of factors have limited the use of thermal extraction techniques in the heavy oil region. One issue is the presence of an aquifer in communication with the oil zone; these methods are generally not amenable to bottom water because of heat losses to the aquifer. The second factor is the narrow thickness of the pay zone; thermal methods are only economic in reservoirs with thicker pay zones. Less than 5 percent of the heavy oil in place in the heavy oil belt region is found in sands greater than 25 feet in thickness[100].

New methods promise to unlock more of the oil in place and extend Canadian heavy oil production for many more decades. These new methods are now being piloted either as primary production methods or as a follow-up process after primary:

- Thermal SAGD – Ideally, the thickness of the heavy oil deposit must be more than 32 to 48 feet to apply this technology, and a very small amount of the heavy oil resource fits this criterion. However, a number of small SAGD pilots have been successful. A new larger project is under construction in Saskatchewan with start-up scheduled for 2012, with additional projects to follow. One advantage of SAGD over the CSS/Steam flood method is that it can produce with water in communication with the oil zone.
- Hybrid Steam solvent processes and solvent only processes – Adding solvent to the steam injection or solvent alone increases recovery and reduces energy use. A number of projects are being piloted in the region, including a project that injects solvent only.
- Insitu Combustion – this process combusts the heavy oil in the reservoir, mobilizing the oil; effectively combusting about 10 percent the oil to produce the rest. It is possible that combustion could be used in the thinner reservoirs prevalent in the heavy oil region. A pilot using the THAI™ method is now underway in Saskatchewan. This is not the first attempt at combustion in the region, pilots in the region date back to the early 1980’s.

- Enhanced Cold Flow Recovery – Cold flow production is driven by a combination of the reservoir porosity, pressure, and the solution gas in the thick oil that helps to lift the oil. When the solution gas is exhausted, the cold flow production slows. Currently, methods to re-inject solution gas into the thick oil are being researched, if a method to inject gas into the oil is found, this could enable a larger portion of the resource to be produced without steam.

Environment

The environmental footprint associated with heavy oil belt production is higher than typical conventional production. Key differences stem from waste products and higher than average greenhouse gas (GHG) emissions.

Waste Products:

- Disposal of emulsions - Because the density of the thick oil is close to the density of water, separation of the water-oil emulsion is difficult. The small volumes of very stable oil-water emulsion (often associated with fine solids) that cannot be economically separated are disposed into deep wells or into salt caverns.

- Sand disposal - Cold flow production results in produced sand, this sand is usually disposed of into salt caverns.

GHG emissions

- Cold flow GHG emissions - Because each well has low flow, pipelining the off-gas and heavy oil from each well is often not economic. Although some sites capture emissions, venting of fugitive emissions (mainly methane) and trucking of heavy oil is common. Because the heavy oil will not flow at standard conditions, the produced bitumen is stored in a heated tank to reduce the viscosity. All of these factors lead to higher GHG emissions than most other heavy conventional crude oils using primary/cold production methods.

- Thermal production - For production using steam for extraction, the GHG emissions are higher than oil sands thermal production. Because the thickness of the pay zone is narrow, there is less efficient use of the steam which results in higher steam-to-oil ratios than for typical oil sands production. Today, about 5 projects in the heavy oil belt use steam for recovery, but production from these methods is expected to grow.

Productive Capacity Projection

Projection to 2035

Table CH1 – Canadian Heavy Oil Supply

	2009 Actual (B/D)	2035 Low (B/D)	**2035 Likely (B/D)**	2035 High (B/D)
Canadian Heavy Oil	**382,000**	135,000	**250,000**	350,000

Low Case – This assumes an ongoing 4 percent decline per year to 2035 for cold flow production. The amount of production from thermal methods does not increase substantially, as new thermal projects are limited to the more economic oil sands deposits to the north.

Likely Case – This assumes an ongoing 4 percent decline per year to 2035 for cold flow production. The amount of production using steam method increases from about 30,000 B/D currently to 130,000 B/D. Further steam injection projects are limited as limited portions of the resource are thick enough to apply steam methods.

High Case– In addition to the events in the likely projection, two other innovations push growth higher. Between 2025 and 2035 successful and economic pilots of both combustion and heavy enhanced oil recovery (EOR) with gas re-injection are demonstrated in the heavy oil belt. By 2035, these two innovations add 100,000 B/D more to production.

A View to 2050

In the Likely Case, the steam recovery does not grow post 2035 due to limited resource. Meanwhile, cold flow continues to decline, by 2050 production less than half of current levels.

6. US Oil Sands

To begin the section concerning US Oil Sands, it is worthy to acknowledge excellent in-depth reference material. In response to a request by the US Department of Energy, the Institute for Clean and Secure Energy at the University of Utah published “A Technical, Economic, and Legal Assessment of North American Heavy Oil, Oil Sands, and Oil Shale Resources” in September 2007. A copy can be accessed at http://www.icse.utah.edu/index.jsp?leftnavid=5;&subleftnavid=24;-2007. (Readers may also wish to refer to the annotated bibliography by Dr. Wally Gwynn and Francis Hanson that was published by the UGS).

The reader is cautioned that US oil shale (Chapter 3) is often confused with US oil sands. The hydrocarbons extracted from sands and oil shale are very different, and the technologies to extract and refine are not at all universally applicable. A second confusion is that US oil sands are akin to Canadian oil sands (Chapter 4). The oil sands resource located in the US differs from the Canadian resource in a few material ways- and these attributes make US Oil sands significantly more challenging to produce economically and technically. Understanding these fundamental differences will illustrate why the US oil sands industry has lagged that of Canada:

- Varied resource ownership – US oil sands are located on a mix of Federal, State, Tribal and private land.
- Oil sand composition – US oil sands are typically oil-wetted, highly consolidated, and more viscous bitumen.
- Heterogeneity of deposits – US oil sands are 2-4 percent of the magnitude of the Canadian resource and more varied in deposition and continuity.

Beyond the variances between the oil sands composition, other impediments to US oil sands production exist:

- Environmental constraints – water, GHG/air quality, public concern and government concerns (sometimes based on erroneous information).
- Land use conflicts, including some resources occurring within national monuments, wilderness areas, wilderness study areas, national conservation areas, etc.[101]
- Layered regulatory regime - Federal, State, and County.
- Compared with Canadian oil sands, government fiscal incentives are insufficient. Although some funding for basic research is in place, other incentives such as special tax incentives or royalties treatments are not in place.
- Inadequate local infrastructure – roads, pipelines, regional upgrading.

Where and how big?

The United States has an estimated Original Bitumen In Place "OBIP" of between 54[102] to 62.9 BB of bitumen within its oil sands resources. Located in 10 states, estimated resource in place is as follows:

Table USOS1[103] - Estimated US Oil Sands Resource: Oil-in-Place

State	Discovered (BB)	Undiscovered Bitumen-in-Place (BB)	OBIP (BB)
California	1.9	3.0	4.9
Utah	11.9	8.2	20.1
Texas	3.9	0.9	4.8
Oklahoma	ND	0.8	0.8
Alabama	1.8	4.7	6.5
Kentucky	1.7	1.7	3.4
Alaska	ND	19.0	19.0
New Mexico	0.1	0.2	0.3
Tri-State	0.2	2.7	2.9
Wyoming	0.1	0.1	0.2
Total	21.6	41.3	62.9

Utah's oil sand resource is the largest and best understood of the above. While the US Department of the Interior, Bureau of Land Management (BLM) estimates Utah's oil sand resource at 19.2 BB, a 2008 report issued by the DOE[104] indicates resource in place could be as much as 32 BB or approximately one-third to one-half of the total US oil sand resource.

Covering nearly 1 million acres or 150 square miles, there are 11 major deposits which are designated as Special Tar Sand Areas ("STSA's")[105] within the State of Utah. Land ownership is split 54.4 percent Federal, 14.7 percent Park Services, 12.8 percent State, 8.8 percent Tribal and 8.5 percent freehold[106].

Like the Canadian oil sands, some of the resource is surface mineable while most is too deep for surface mining, in which case in-situ technologies will be required for extraction. Detailed information on the geologic deposition of all the US oil sand deposits are somewhat limited with the majority compiled more than 25 years ago by the United States Geological Survey (USGS), Utah Geological Survey (UGS), and other government affiliated geological/petroleum resource institutions. However, a review of the Utah STSA's suggests that approximately 20 percent[107] of the resource should be accessible by surface mining, assuming the mining economics justify the extraction of the ore body.

The reader is cautioned that many reports erroneously focus simply on the depth of the resource as to applicability for surface vs. insitu production. Additionally the concept of a stripping ratio is often used when discussing surface mineable deposits. Both of these approaches fail to consider the richness or thickness of the resource. When considering the economic thresholds for surface mining, it is not just how much material is mined but rather how much material is mined as a function of how much oil is recovered. This is referred to as the Total Volume / Bitumen in Place ("TV/BIP") ratio, the total volume of material to be mined (overburden, oil sand and interburden) divided by the bitumen in place, of which not all may be recoverable. Failing to consider the bitumen in place is a serious omission when assessing the economic viability of a surface mineable deposit. Similarly, in order for insitu deposit production methods to be technically viable and economic, the target reservoir must have a certain thickness of pay, bitumen quantity and suitable geology.

The richness of the oil sand not only impacts economics but operational success. Certain processes demand a minimum richness of ore for process stability, under which extraction efficiency can deteriorate considerably. This is especially true of the Clark Hot Water Process, the mainstay of surface-mineable bitumen extraction in the Canadian oil sands. Operations within a design envelope are mandatory for successful extraction. Six percent by weight (15 gpt) would be considered lean while 10 percent by weight (25gpt) is considered the norm and over 14 percent by weight (35 gpt) considered very rich. Surface mining operations generally harvest and co-mingle ore to achieve operation stability using a target 10-12 percent by weight ore feed. Insitu production is not as reliant on the ore richness for operational success but most certainly for economic success. The cost of drilling well pairs into 5 percent ore for a SAGD facility is very likely to be uneconomic unless oil prices are well above $100 per barrel.

In Utah, it is generally understood that the geologic deposition is fluvio-lacustrine; that being oil that has migrated into sands originally laid down by water. This differs from the oil sands found in the Athabasca oil sands region in Canada where oil migrated into either a wind-blown desert sand (loess) environment or a marine/estuarine depositional environment. The effect of a lacustrine deposition is that the resource is generally more diffused and often braided or lenticular (inter-bedded with barren shales or conglomerates). This heterogeneous deposition makes mining and insitu production more challenging from an economic and technical perspective, forcing prospective mining producers to adopt more selective mining techniques and design smaller scale production facilities.

Another important difference between Canadian oil sand and that found in the US (principally Utah) is that the US sands are “oil-wet” rather than “water-wet”. Oil-wet US sands are devoid of the film of water that is found layered between the sand grain and the bitumen in Canadian water-wet sands. The oil-wet nature of US oil sands also has the effect of leaving the deposits more highly consolidated (typically 3-4 times the compressive strength), making initial mining and ore conditioning operations more energy intensive than in Canada’s oil sands.

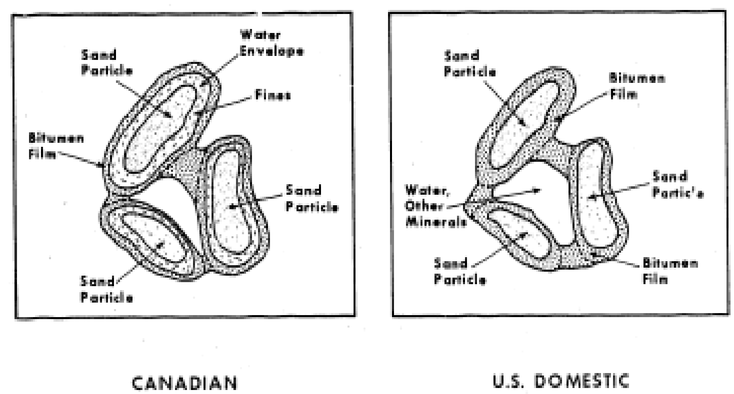


Figure 5. Comparison of U.S. to Canadian Tar Sand

Figure USOS1 – Source DOE, 1990

Cumulatively, the resultant differences are significant in that the traditional surface mineable extraction technique (the Clark Process) fundamentally relies on the film of connate water to achieve acceptable extraction levels. When engaged with Utah ores, extraction rates are typically around 80 percent giving unacceptable concentrations of residual bitumen in the discharged tailings and resultant poor economics.

While technologies (principally solvent based) have been developed at pilot scales to extract bitumen from oil-wet US oil sands, new technologies or evolutions of existing technologies, will be required to see commercial scale production from surface mineable oil-wet oil sands of Utah. A number of companies and academic institutions are currently working towards this solution.

Production History

There is currently no commercial bitumen production from US oil sands. At the time of writing, there are three pilot scale/pre-commercial operations in Utah and all operate on surface mineable deposits. These companies include Calgary, Alberta based Earth Energy Resources Inc. and two companies based in Salt Lake City, Utah; Temple Mountain Energy and Korea Technology Industry America Inc. While technologies used in these operations are not disclosed, information available suggests solvent-based derivatives of the Clark Hot Water Process.

Dating back to 1924, Utah oil sand has long been used for road paving material. Even today, Utah oil sand in its mined and un-extracted form is used for road surfacing in locales proximate to the deposits including the towns of Roosevelt and Vernal. Experimentation with hydrocarbon recovery began in the late 1950’s. Various methods were tried including steam, hot water and solvent applications, however none succeeded as commercial ventures.

Once in production, the principal market for Utah bitumen will be as a heavy crude feedstock to PADD IV refineries with upgrading capability, of which there are four with a combined upgrading capacity of 57,200 B/D[108]. Currently these refineries import Canadian bitumen as upgrading feedstock. This makes them readily available to accept Utah production which would enjoy a favorable transportation differential as well as have preferable properties such as a significantly lower sulphur content in comparison to Canadian bitumen.

In addition to refinery feedstock, optional future Utah bitumen markets include liquid road asphalt and coke. While these are not year round and/or significant long-term markets, these outlets for Utah bitumen will assist producers in early production success while infrastructure catches up to growing production.

In summary, there have been two fundamental impediments to achieving commercial production in the US, and in particular on the more accessible surface mineable deposits in NE Utah; technology and economics.

Technology

- Oil-wet and highly consolidated Utah deposits require innovation but not necessarily a revolutionary change. Processes employed in Canada are well understood however evolution occurs when environmental constraints and/or economic drivers demand processes be adapted and fine-tuned to regional constraints. Conservation of surface water and ground water is necessary as this region is one of the driest in the United States. Utah receives the second lowest amount of annual precipitation of all the states in the country, averaging only 13 inches per year[109]. Extraction processes (surface or insitu) will need to be water efficient in order to ensure sufficient supply.

- Investment in technology requires funding lead time combined with a firm belief and confidence of financiers that the technology can be successfully deployed. Availability of financing has severely restricted development and deployment of technologies that may be suitable for oil-wet oil sands production. A key underpinning to investment in new technology driven projects is regulatory certainty. Without exception, oil sand ventures in the region have suffered from regulatory uncertainty caused by unclear and/or overlapping regulatory jurisdictions and policies, changing political agendas and a general unfamiliarity with the requirements of a fledgling industry.

Economics

- The heterogeneous deposits present numerous challenges for commercial operators. Lenticular deposits are not amenable to large volume ore harvesting techniques such as those currently employed in Canadian mining operations. Recovery and processing material devoid of hydrocarbon (i.e. barren shale stringers or inter-beds) would negatively impact profitability. With insitu applications, a suitably thick pay zone is desirable to justify capital expenditures and allow for adequate separation between the steam and producing horizontal well pairs.

- Diverse land ownership makes it exceedingly difficult to assemble a resource base of sufficiently large magnitude. State land in Utah is generally restricted to four discontiguous sections per township. BLM land, while contiguous, is not an economical target for leasing due to the significant costs of PEIS pre-leasing studies and the lease size limitation (5,760 acre lease size / 50,000 acres per company or individual). Financial investment in an oil sand opportunity must present an opportunity for substantial investor returns to justify the inherent risks. Without the ability to assemble contiguous land parcels with an appropriately sized resource base (> 1 BB OBIP), major investment is very difficult to attract. The OBIP ranges widely in Utah's oil sand deposits. Based on a reasonable assumption of 40,000 B/OBIP/acre, it would take approximately 25,000 acres or about 39 square miles to accumulate 1 BB OBIP. By comparison, the current footprint of total Canadian oil sands mining operations is 232 square miles. The Denver International Airport covers 53 square miles.

- Compared with Canadian oil sands, US Federal royalties of 12.5 percent of gross production sales are excessive. By comparison, at $80 WTI, royalties on pre-payout Alberta oil sand revenue are 4.1 percent. Post-payout, the Alberta royalty would be the greater of the pre-payout royalty or 30.8 percent of net revenue. This puts a prospective producer of US federally controlled oil sands at a considerable financial disadvantage compared with an investment in Canada - both in terms of early cash flow from production from which reinvestment can be made and from a return-on-investment for investors, further raising an already high financing barrier.

- There are no US federal government programs targeted at unconventional oil production that have translated to high potential pilot projects with industry. If Canada is taken as a case study, the oil sands benefited from considerable Federal and Provincial government support. The Provincial Government in Alberta (the owner of the resource) provided numerous fiscal and royalty incentives as well as land access incentives to incubate the fledgling oil sand industry. Federally, the Canadian Government also provided preferential fiscal treatment and direct financial investment in the early days of the oil sands industry (see full discussion on oil sands history in Chapter 2).

Production Technologies

Variations of the technologies that currently exist for the water-wet Canadian oil sands can be applied; however technical challenges in producing US oil-wet oil sands with the Canadian technologies do exist. Therefore, ongoing technology advancements and adaptations to the existing technologies are required - if commercial production from the US Oil sands is to be achieved.

Oil Sands Mining and Bitumen Extraction

Utah is the most likely location of the first commercial production in the US. The industry will almost certainly commence with surface mining operations as technical challenges with transplanted Canadian technologies or proposed new solvent-based methods can be more readily overcome with surface operations vs. their insitu counterparts.

Due to water constraints in Utah, water-efficient processes are not only necessary but mandatory. Not only is water scarce, but environmental regulations essentially preclude the possibility of tailings ponds (see Chapter 4 for more information on Canadian oil sands and tailings ponds). An evolution of the Clark Process using a solvent/water mixture or solvent exclusively is a logical next step for US oil sands development.

There has been significant private research and development of possible technical adaptations; however development has been restricted primarily due to financial constraints imposed on would-be Utah producers. In general, US government support (at all levels) has been overshadowed by modest private investment to develop commercially viable technologies. Government funding has been spent in lab settings that have not pollinated to real-world field pilots and partnerships with first stage commercial ventures.

All three of the pilot scale/pre-commercial operations in Utah are operating on surface mineable deposits, however all three of these operations are constrained financially from pursuing near term commercial development. Two of the noted companies are undertaking additional R&D work to determine viable commercial process configurations, while the third is essentially shovel-ready and in a process of securing financing.

Insitu Bitumen Recovery

Deposits too deep for surface mining can be candidates for insitu production. Traditional Canadian oil sand production methods (SAGD, CSS) rely heavily on fresh and brackish water supplies sourced from deep wells for the extraction of the hydrocarbon. However, insitu production is accomplished without the creation of tailings ponds. At the time of writing, there are no pre-commercial insitu developments advancing in Utah. Dr. Milind Deo[110] at the University of Utah has performed computer modeling of a SAGD application in the Sunnyside deposit. His conclusions suggested that insitu extraction is possible if steam containment can be maintained. Geologic faulting and fracturing, prevalent in the Sunnyside deposit and others in Utah, may make this method difficult to effectively implement. Land access constraints further complicate development of an insitu development at Sunnyside. Insufficient or excessively fractured cap-rock combined with the presence of barren inter-beds make insitu development of the State’s other significant deposits unlikely in the near future.

Looking Forward

It is still early days for oil sands production in the US – it has been so for over 40 years. While the development of the US oil sands has gone on nearly as long as in Canada, the pace of development has languished. Early on, the Canadian Federal and Provincial governments recognized the importance of the oil sands resource in terms of its potential contribution to national and international energy security as well as regional and national economies. While the federal government focused primarily on broad-based S&T, the provincial government targeted pre-commercialization investments such as SAGD. At the same time, oil sands producers benefited from preferential tax treatments, lower royalty rates, access to large dedicated lease tracts, and direct government financial support. This all contributed to growing production from the Canadian oil sands.

Development of Utah resources and those elsewhere in the US, will likely require higher levels of governmental support than the Canadian oil sands due to the technical challenges and the diverse geologic deposition. For the purposes of this report, it is premature to judge the technologies that might one day unlock the US oil sands. These technologies, while they are likely to be based on current methods, will differ in their water usage, energy inputs, GHG emissions, recovery rates and environmental impacts. Suffice it to say that the market will determine which companies are successful, rather than government. Directional support is what is required; Federal/DOE and State legislation/policies, land access, financial incentives and a coordinated regulatory regime would combine to develop the significant US oil sand resource in an environmentally sustainable manner.

The small Utah deposits and corporate limitation of 5,760 acres per lease have thus far posed challenges in garnering sufficient investment capital. Major investors are looking for major reserve additions. Raising funds for technology development or capital for a new resource development play with seemingly unproven technology and an uncertain regulatory/political arena consistently equate to unacceptable risk levels for investors. A showing of proactive supporting government policy would significantly reduce the commercialization risk and expedite more ventures along the road to operational reality.

Environment

A factor that has not restricted production to date but has been an ever-increasing focus in US oil sands development is the environmental impact of oil sands production. Unlike Canadian oil sands which has existing infrastructure that makes it financially entrenched and less nimble. US oil sands have yet to be developed leaving the potential for improved technology solutions that can be more readily implemented. The US oil sands industry has an opportunity to start with a fresh environmental slate and foster the development of “made for the US” technologies and operational approaches. The fundamental pre-requisite however is proactive, coordinated direction with support from all levels of government.

Some of the environmental factors that could shape the longer-term growth of US oil sands include:

Water Supply

Production capacity will very likely be limited in some way by available water supply. As Utah and its neighboring states are in an arid climate, successful operations will need to be water efficient. Future producers will strive to maximize water efficiency in order to maximize production capacity. US producers have an opportunity to innovate and evolve technology to meet this production constraint.

Water supply is estimated to have a low to medium impact on long-term production growth, assuming water efficient technologies are developed. Water will, however, very likely limit the total eventual production capacity. For instance, to production levels that would likely level off at 10-15 percent of current Canadian production levels – or 135,000 to 200,000 B/D. Achieving long-term production levels in excess of these levels will require a continued focus on highly water efficient extraction technologies.

Environmental Sustainability

Top of mind for all parties concerned with the development of US oil sands is the environment and protection thereof. This includes governments, regulators, local communities and the public at large. Again, the development of a new industry affords an opportunity to employ production techniques that work within the regulatory constraints and serve to demonstrate environmentally responsible production to both the industry's detractors and to the general public.

Assuming that environmentally sustainable production methods are developed, this constraint could have a large and immediate impact on the start-up of the industry but decreasing as production expands. It is expected that environmental opposition will remain high despite industry proof that it can operate in an environmentally sustainable fashion.

Sustainable production encompasses extraction methods that minimize the overall environment footprint including outright land disturbance, impacts on air, water, wildlife and the local population. Pioneering (mineable) oil sand extraction facilities operating without controversial tailings ponds that are water, energy and greenhouse gas efficient will set the standard for all operations to follow. Those operations employing concurrent reclamation and zero release of contaminants to the soil and nearby watersheds will be the ones that set the bar from an environmental sustainability standpoint.

Productive Capacity Projection

Projection to 2035

Only one public report suggests possible Utah oil sand production levels by 2035. The DOE reported "*Government action and incentives could catalyze an industry of 350,000 B/D by 2035*"[111]. This report is supported by the DOE Task Force on Strategic Unconventional Fuels.[112] In working within this report's framework – which envisions a Base Case and Accelerated Development Case (each case includes a unique view of geopolitical and environmental sentiments and policies toward the development of each scenario). These original DOE forecasts were deemed as relatively high in the authors' opinions – and as such, have been adjusted down to more realistic estimates for 2035 production:

Table USOS2 – Projected US Oil Sands Supply

	2009 Actual (B/D)	2035 Low (B/D)	**2035 Likely (B/D)**	2035 High (B/D)
US Oil Sands Supply	**0**	10,000	**25,000**	150,000

The DOE forecast assumptions from page I-20 and I-21 of DOE Task Force on Strategic Unconventional Fuels, Volume I – Preparation Strategy, Plan, and Recommendations, have been considered. Chapter 1 outlines the broad assumptions relied upon when developing the US Oil Sands Supply outlook. Additionally:

Low Case: The low case contemplates the assumptions put forth for the likely case however layers certain growth constraints upon the US oil sands industry; most likely either environmental sustainability such as access to sufficient quantities of process water or financial sustainability with respect to access to growth capital.

Likely or " DOE Base" Case: The likely case assumes current law – including provisions of the Energy Policy Act of 2005 – but no new legislative or government programs or activities (state or federal). Projections are developed using the Annual Energy Outlook (AEO) 2006 show continuing growth in domestic demand and a nearly flat domestic supply. This estimate is predicated on at least one company making a pioneering technological, breakthrough in achieving economic and environmentally sustainable production.

High or "DOE Accelerated Development" Case: The high case contemplates that private capital will be attracted to develop unconventional fuels at an enhanced pace, stimulated by government policy actions and fiscal regimes that involve direct federal expenditures. The government must show leadership (as was done in the early stages of the Canadian oil sands) to provide confidence to investors as well as the tax-paying public that funds invested will be paired to technologies that result in commercially viable, environmentally sustainable development, especially for the critical first-generation stage of development.

High case conditions contemplate actions by government, some of which have already been taken (to minor degrees) for various resources including:

- Reliable access to unconventional oil resources on public lands.
- Regulatory and permit review processes that provide confidence in permitting timelines and regulatory standards and mechanisms for timely conflict resolution.
- A fiscal regime that improves the attractiveness of capital investment through tax treatments and royalty terms in the early years.
- An organizational structure that expedites Federal actions and decision-making.

- Funding for socio-economic impact assessment and community infrastructure planning and development.

These estimates are based on a variety of assumptions. Considering that conventional oil production in Utah is 60,000 B/D, while Colorado and Wyoming produce 75,000 B/D and 140,000 B/D respectively[113] ; even growth at the more likely, lower, end of this range would increase Utah's current oil production by over 40 percent. Whether the actual production is 25,000 B/D or 150,000 B/D, it does not matter for policy deliberations. Any number in this range is material, and establishing an economic production method is a significant milestone as it sets the stage for future production growth over the coming decades.

A View to 2050

Development of Utah oil sands and of the balance of the US oil sands resource will very likely continue in a slow growth curve well past 2050. Over time, the original technology is likely to become more efficient, and oil sands extraction economics should also improve. As conventional oil reserves decline, increasing reliance on heavy oil production will be the norm. As the more easily producible oil sands resources are developed and the methods advance, others will move into scope. Increasing oil prices will serve to support the growth curve while a lessened demand for hydrocarbons in the future may offset the need for less opportunistic developments.

Comparison to Canada's SAGD Pace of Development

Since 1999, Canada's SAGD development has grown from infancy at 1,800 B/D to over 300,000 B/D [114], equating to an average annual growth of over 60 percent. While tempting, it is illogical to apply a similar growth curve to the Utah oil sands, mainly as a result of the more disaggregated resource. Projects in Canada have a comparatively massive resource to work with. Therefore, production growth can expand at a higher pace due to the ability to develop more and larger scale projects.

- Throttling back to contemplate these factors, what could Utah growth look like? Applying a 20 percent year-over-year growth starting at 2,000 B/D in 2013 sees daily production at 110,000 B/D by 2035. By comparison, to achieve the DOE's 350,000 B/D Measured Development Case would require annual growth of 26.5 percent while their 500,000 Accelerated Development Case would require annual growth of 28.5 percent. It is not possible to estimate with any certainty the likely production from US oil sands in 2050. More meaningful to the reader is a summary discussion of limitations that could delay the reality of oil sands production in the United States, and in particular in Utah. Production capacity is likely to be limited by a number of factors; infrastructure, investment capital, water supply, and environmental sustainability (water supply and environmental sustainability are both covered in the environmental section).

Infrastructure

This includes transportation and regional upgrading of bitumen. All aspects of infrastructure lag in this regard. Given the scenario of established bitumen production in North East Utah (ie. >10,000 B/D), it is highly likely a merchant upgrader would be constructed in the Uinta Basin.

Most of Utah's oil sands deposits are situated in remote and often mountainous terrain. Well-established conventional oil and gas production has fortuitously provided some limited initial infrastructure for Utah's expansion into oil sand production however conventional pipelining or trucking of produced bitumen is not possible due to the physical properties of the product. Produced bitumen is too heavy and viscous to flow in its natural unrefined state (100,000 cP, 8^{o} – 14^{o} API), therefore it must be diluted to a higher equivalent gravity (minimum 18^{o} API) and lower viscosity with condensate (or maintained at a sufficiently high temperature, minimum 300^{o}F) to be transportable.

Three options exist for transportation of bitumen:

- Trucking: Until bitumen production volumes are significant (5,000 B/D to 10,000 B/D), production from Utah's reservoirs will most likely be trucked to refineries in the Salt Lake City area or other refineries in PADD IV that have upgrading capability. Most of Utah's deposits are in remote, higher elevation locations and as a consequence, much of the road access is unpaved and subject to outages during periods of inclement weather. The State of Utah has been considering upgrading the Highway 40 / I-70 connector for many years. This route would service the core production area of the State. It would foster development, improve road safety and significantly reduce levels of airborne particulate (road dust) in the region.

- Pipeline: Capacity in the State of Utah is served by two 10 inch lines originating in Rangely, Colorado and terminating in Salt Lake City. This pipeline, operated by Chevron, currently operates well below capacity and could serve the Uinta Basin's bitumen production provided that bitumen is blended with diluent to a "dilbit" blend. Typical dilbit blends use condensate from field production at a ratio of 30 percent diluent/70 percent bitumen to yield a pipelinable product. The tie-in from the deposit to the pipeline, however, is a major capital expense, estimated at approximately $1 million per mile[115].

- Rail: Rarely will rail access be found at the production site. As a consequence, trucking or an intermediary pipeline connection will be necessary to access rail. Nevertheless, rail will provide access to refining markets outside Salt Lake City and beyond the Rocky Mountain refining region which, unless upgrading capacity is added, will be necessary to meet long-term production goals.

Lack of infrastructure is a constraining factor that adds to the cost of production and thereby increases investment risk. While this factor will not be an immediate limitation, lack of infrastructure will severely limit the growth of the industry beyond, perhaps, 20,000 B/D.

Investment Capital

Since the financial crisis in late 2008, investment capital has been restricted. Since that time, oil and gas company investments have been principally confined to lower risk developments with existing production and growth potential. Development of any US oil sand resource is considered risky by investment firms and this, in conjunction with associated application of new technology increases the risk threshold, limiting interest or driving up the cost of capital.

The scarcity of funding for US oil sands ventures has been the largest obstacle for the US oil sands industry. Financial support is necessary for pre-production technology development and demonstration, land acquisition and resource delineation, and ultimately for successful commercial deployment.

7. Tight Oil

Generally, unconventional tight oil is found at unmineable depths in sedimentary rock formations that are characterized by very low permeability (thus the basis for the term "tight"). While some of the tight oil plays produce oil directly from shales, tight oil resources are also produced from low-permeability siltstones, sandstones, and carbonates that occur in close association with a shale source rock. It is important to note that in the context of this report, the term tight oil does not include resources that are commonly known as "oil shales" which refers to oil or kerogen-rich shales that are either heated insitu and produced or if surface accessible mined and heated (as described in Chapter 3). The most notable tight oil plays in North America include the Bakken play in the Williston Basin, the Eagle Ford play in Texas, the Cardium play in Alberta, and the Miocene Monterey play of California's San Joaquin Basin. In many of these tight formations, the existence of large quantities of oil has been known for decades and efforts to commercially produce those resources have occurred sporadically with typically disappointing results. However, starting in the mid-2000's, advancements in well drilling and stimulation technologies combined with high oil prices have turned tight oil resources into one of the most actively explored and produced targets in North America.

Of the tight oil plays, perhaps the best understood is the Bakken which straddles the border between Canada and the US in North Dakota, Montana, and Saskatchewan. Much of what is known about the exploitation of tight oil resources comes from industry experiences in the Bakken and the predictions of future tight oil resource development described in this study are largely based on that knowledge. The Bakken tight oil play historically includes three zones, or members, within the Bakken Formation. The upper and lower members of the Bakken are organic rich shales which serve as oil source rocks, while the rocks of the middle member may be silts, sands, or carbonates that are also typically characterized by low permeability and high oil content. Since 2008 the Three Forks Formation, another tight oil-rich formation which directly underlies the lower Bakken shale, has also yielded highly productive oil wells. Drilling, completion, and stimulation strategies for wells in the Three Forks Formation are similar to those in the Bakken and the light, sweet crude oil that is produced from both plays has been geochemically determined to be essentially identical. Therefore, for the purposes of this study the Three Forks Formation is considered to be part of the Bakken play, though the literature will sometimes refer to it as the Bakken-Three Forks play.

Where and how big?

Figure TO1 shows areas in North America that have been identified as being either producing or prospective tight oil plays. Formations that are currently producing tight oil largely occur in the Mid-Continent and Rocky Mountain portions of North America, running from central Alberta to southern Texas, with a notable exception being the Monterey Formation in southern California. Other prospective tight oil resources have been identified throughout the Rocky Mountain region, the Gulf Coast region, and the northeastern United States. The ages of the tight oil bearing formations are variable, with the oldest being late Devonian and the youngest being late Tertiary.

Many of these tight oil plays cover large areal extents. The Bakken play is the largest "continuous" oil accumulation ever assessed by the USGS[116], encompassing several counties in North Dakota and Montana as well as southern Saskatchewan. Depending on the source of the report, the Niobrara play may include large areas of Colorado, Wyoming, and perhaps New Mexico. In Canada, the productive Cardium play covers a large portion of central Alberta.

In terms of oil resources the tight oil plays are significant. Table TO1 illustrates the magnitude of the recoverable resource estimates found in literature for several producing tight oil resources in North America. Total oil in-place estimates were only found to be reported for the Bakken play, which ranged from 10 BB to 503 BB[117]. The total estimated resources of the tight oil plays identified by this report range from 5.6 to 10 BB, and are based on reports for both producing and prospective tight oil plays. It is likely that this method significantly underestimates the amount of recoverable oil when the new tight oil techniques are applied to these deposits. The NPC Resource and Supply Data study, which surveyed a wide set of studies and private industry outlooks, had a high side estimate of 34 BB. With respect to the producing tight oil plays, the Bakken is currently considered to be the largest with estimates of recoverable resources or resources ranging from 3.65 BB of oil to 4.3 BB[118]. With respect to the prospective tight oil resources, it has been calculated that the Tuscaloosa Marine Shale play of central Louisiana and southern Mississippi may hold resources of 7.0 BB[119].

The estimates for recoverable resources came from published literature, reports from state and federal government agencies such as the USGS and North Dakota Geological Survey, and industry press releases/public statements that include reserve estimates as reported to the Securities and Exchange Commission. Most of these sources presented resource estimates in terms of “reserves” or “recoverable resources”, with no distinctions being made between what may be technically recoverable and what may be economically recoverable. Because production from these tight oil plays is highly dependent on the deployment of capital-intensive technologies (e.g. deep horizontal drilling, complex completion technologies, and multi-stage hydraulic fracturing) whether or not a resource is considered economically recoverable will in turn be dependent on a wide variety of variables including the price of oil, the nature and magnitude of applicable taxes, and costs associated with regulatory compliance. While some resource estimates, such as those for the Bakken in North Dakota, may be considered to be economically recoverable under the current economic climate, for the purposes of this study the resource estimates reported should be considered to be technically recoverable.

The estimates for tight oil resources presented in this study may be considered to be conservatively low for several reasons. First, some tight oil plays (i.e. Oklahoma’s Penn Shale and Utica Shale plays) were reported to be producing oil but those reports did not include any estimates of resources or oil in-place, and thus they were not included in the resource estimates. Second, several of the tight oil plays are in the very early stages of development (i.e. Eagle Ford Shale, Barnett and Woodford Shales of the Permian Basin, and the Mowry/Niobrara

Shale of Wyoming) and discussions with industry personnel operating in some of these plays indicate that many of the resources may be significantly greater than publicly reported. Finally, continued improvements in technology and efficiency may further increase the recoverable resources of proven tight oil plays such as those in the Bakken and Cardium formations.

Figure TO1 – Reported Producing and Prospective Tight Oil Resources in North America

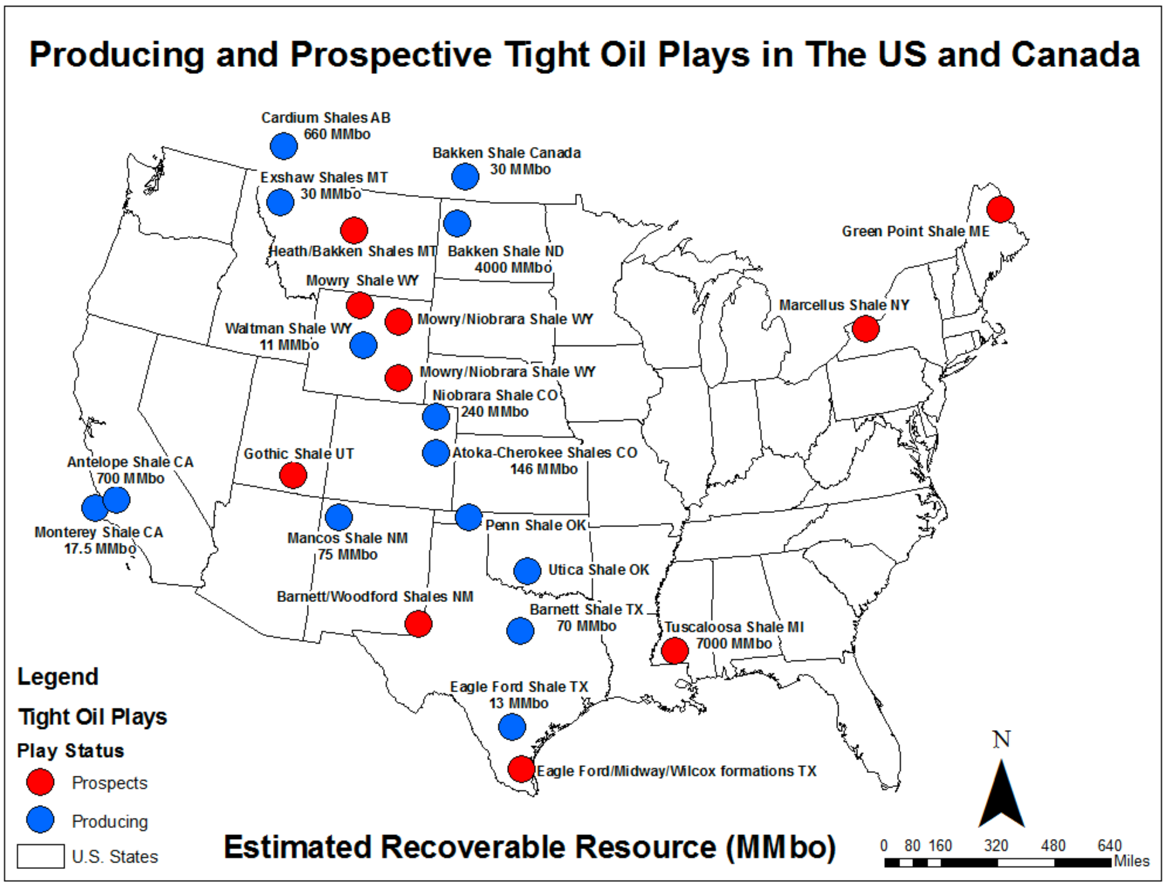


Table TO1 – Estimates of Recoverable Resources for Producing Tight Oil Plays

Formation	States/Provinces	Resources (BB)
Bakken	ND, MT, SK	3.650 to 4.300
Cardium	AB	0.660 to 1.890
Monterey (Antelope play)	CA	0.718 to 3.500
Niobrara	CO, WY	0.240
Atoka-Cherokee	CO	0.146
Mancos	NM	0.075
Barnett	TX	0.056
Exshaw	AB, MT	0.030
Eagle Ford	TX	0.013
Total		**5.588 to 10.25 (could be as high as 34 BB from NPC private industry data survey)**

Production History

In many of these tight formations, the existence of large quantities of oil has been known for decades, usually dating to the earliest exploration efforts within any given basin. In some areas multiple attempts were made to commercially produce from these oil-rich but tight zones. While initial production (IP) rates were often promising, or even exciting, productivity would typically drop off significantly within months or even days of IP. Review of the literature on other tight oil plays in North America indicates that this may be a common story for tight oil plays, but other than anecdotal information there is very little available data on the production history of most of the tight oil formations. Unfortunately, for most states and provinces the reporting of production statistics on a formation-by-formation basis is not typically readily available to the public, which makes it difficult to quantify and/or verify reports of tight oil production in many of the identified plays. North Dakota is a notable exception, with annual production data for each oil-producing formation in the state being available on the North Dakota Department of Mineral Resources website. A summary of the recent production history of the Bakken Formation in North Dakota may shed light on what may be anticipated to occur in other plays that are in the early stages of development.

During the first Williston Basin oil boom, many wells in the 1950s and early1960s were perforated both in the Bakken Formation and more conventional carbonate reservoirs of the overlying Madison Group. These early attempts at Bakken exploitation were through vertical wells, resulting in IP values ranging from 150 to 450 B/D and typical cumulative production of 85,000 B/well[120]. These statistics indicate that most early Bakken wells had productive lifetimes of less than 2 to 3 years. By the mid-60's the Bakken's reputation for quickly "running dry" precluded it from being a zone worthy of testing for most operators. As such, very little oil was produced from the Bakken throughout most of the productive history of the Williston Basin.

In the early 1990's the advent of horizontal drilling technology brought new interest to the Bakken, and IP values were increased to 230 to 500 B/D, with typical cumulative production also increasing to 145,000 B/well. However these improvements in production were not enough to economically sustain wide-scale exploitation of the Bakken and by the late 1990's the Bakken was once again considered an economically unattractive resource. In the early to mid-2000's a combination of high oil price environment, improved understanding of the geology of the Bakken, and improvements in well drilling, completion, and stimulation technologies sparked renewed interest in Bakken exploitation. Since 2005 reports of IPs over 1500 B/D are not uncommon, and while it is too early to make definitive statements about cumulative production on a per-well basis, estimates of 500,000 B/well have been speculated[121] . According to the North Dakota Department of Mineral Resources (NDDMR) – Oil and Gas Division, production from the Bakken Formation in North Dakota has increased from approximately 20,300 B/D in 2007 to over 220,000 B/D in 2010. From the information that was available at the time of this study, the Bakken appears to account for a vast majority of the current tight oil production. However recent reports of success and active development within the Niobrara and Eagle Ford plays suggest that their productivity may be comparable to that of the Bakken within just a few years.

Economic and Government Policy

No state or federal government policies were identified that specifically focused on incentivizing or otherwise supporting the development of tight oil resources. While the US Federal tax code has included tax credits for tight gas production and thermally processed shale oil production as recently as 2007, tight oil resources as defined in this study are not eligible for such tax credits[122] .

Production Technologies

In many respects the fundamental technologies used to successfully drill, complete, stimulate and produce oil from a well in a tight oil-bearing formation are essentially the same as those used for many conventional oil resources. Horizontal drilling technology combined with advancements in well completion and hydraulic fracture stimulation methods, has opened up domestic tight oil production in North America. Most importantly production methods for tight oil are driven by technology, and therefore evolve according to the technical aspects of the play and specifics of the location. Any given technology will be chosen based on the technical aspects of the resource given current economics, technology options, availability, and geologic constraints. The successful production of tight oil relies heavily on a detailed understanding of the potential pathways to unlock hydrocarbons from a low permeability and low porosity formation that may contain natural fracture networks. It is the understanding of the geologic context of the natural fracture system, the relative location of oil within formation, formation pressure, and regional stresses that will enable petroleum engineers to properly design the well path, fracture stimulation treatment, and completion technologies to affect the largest possible drainage area and achieve the best potential oil recovery.[123]

While the basic approach toward developing a tight oil play are expected to be similar from area to area, the application of specific strategies, especially with respect to well completion and stimulation techniques, will almost certainly differ from play to play, and often even within a given play. It is often quoted that there are as many well completion techniques as there are operators within a given basin. The differences are not only a function of different operators preferring different approaches, but also depend on the geology (which can be very heterogeneous, even within a play) and reflect the evolution of technologies over time with increased experience and availability. The Bakken is a good example of this. The exploitation approach for the Bakken evolved from early vertical wells perforated across the entire thickness of the formation to horizontal drilling of the upper shale, then to the horizontal drilling of the middle Bakken (which is not typically shale, but may be composed of silts, sands, or carbonates) utilizing single stage fracturing, to the current trend of horizontal drilling with multi-stage fracturing of the middle Bakken. The horizontal drilling approaches in the Bakken have also included a host of multi-lateral well types drilled in various orientations in attempts to optimize the influence of natural fracture networks and natural stress and strain forces on productivity. The current trend in the Bakken is a move towards single well pad locations with various horizontals (up to 12) drilled from one location covering two 1280 acre spacing units[124] .

The following examples are provided to illustrate the various techniques being used to produce tight oil in the Bakken.

Recent single and multi-stage completions in the middle Bakken of North Dakota: Since 2005 drilling in the Bakken play has included drilling vertically to depths of approximately 9,000 to 10,000 ft and horizontally an additional 4000 to 11,000 ft. Since 2005 horizontal completion techniques in North Dakota have included open holes, uncemented liners, and cemented liners. Recently, completion techniques have progressed to utilization of sliding sleeve liners with swellable packers in the open-hole to separate and isolate different intervals along the length of the horizontal well-bore. These isolated intervals are then individually and sequentially subjected to a hydraulic fracturing operation (sometimes referred to in literature and media reports as “fracking”), with each interval and its associated fracturing operation being referred to as a “stage.” The number of stages can range from a single stage operation, where the entire length of the horizontal well-bore is hydraulically fractured in one operation, to multi-stage operations that can have up to as many as 40 stages. Generally, staging has been equally spaced; however the use of fracture mapping and monitoring technologies can provide more precise information to determine stage location, and potentially improve the distribution of induced fractures in patterns along the well-bore that are more conducive to production. Typically, during hydraulical fracturing, operators inject sand to help keep the fracture open. As an alternative to sand, operators are now increasing the use of ceramic proppants which have greater strength than sand. Typically, fracture stimulations are pumped at high rates and pressure to provide sufficient fracture growth and proppant placement. Such high-rate, high-pressure stimulation operations require specialized pumping units, and the great depth and lateral extent of these Bakken wells requires large amounts of hydraulic fracturing fluid that is typically a water-based mixture of proppants and proprietary chemicals. Fracturing-fluid volumes can range from 500,000 gallons up to 3,000,000 gallons per well, depending on the length of the horizontal well-bore and the number of stages. The general strategy for production from the Bakken play in North Dakota may be a good analog for exploitation of tight oil plays that might have similar geological attributes, particularly with respect to depth and the presence of zones of non-shale rock interbedded within oil-rich shales.

Environment

Aside from the environmental issues typically associated with conventional oil and gas exploration and production, the exploitation of tight oil resources may include its own unique set of environmental issues. The issues that may be associated with tight oil exploration and production are described below. Also described below are approaches that are either currently being employed or may be employed to mitigate the environmental issues associated with tight oil production.

- **Water:** Conducting multiple-stage hydraulic fracturing operations in horizontal laterals that can extend up to 10,000 ft can result in the need for up to 3,000,000 gallons (approximately 72,000 B) of water per well. In areas with an arid or semi-arid climate the use of water for hydraulic fracturing operations may come under scrutiny from local regulators and/or other users including agricultural producers, municipalities, rural water associations, and other industries. Such concerns have been raised in western North Dakota as the exploitation of the Bakken has increased. The use of multi-stage hydraulic fracturing operations is a recent enough development that there is little information on the cumulative oil production of wells that have been hydraulically fractured using these methods. Therefore, it is not possible to accurately calculate the amount of water needed per barrel of oil produced. However, a study by Stepan et al. (2010) compared volumes of water for a typical Bakken hydraulic fracturing operation to other common uses of water in North Dakota and found that the approximate volume of water used to irrigate a quarter-section of land using a center-pivot operation is 1,380,000 gallons per day, and that typical water use for a Midwestern city of 50,000 residents is 10,000,000 gallons per day. While the volumes of water needed for an individual hydraulic fracturing operation may be on par or less than other common uses, the industry in North Dakota is examining ways to reduce the amount of water taken from sources that may also be used by other stakeholders. Potential mitigation approaches include the use of marginal-quality groundwater that is not a potential underground source of drinking water (USDW) and the treatment of non-potable groundwater to a level that is suitable for hydraulic fracturing fluids[125].

- **Hydraulic fracturing fluid chemicals contaminating drinking water sources:** The hydraulic fracturing fluids also may contain chemicals that have become the subject of some public concern with respect to potential contamination of USDW. While there is a push from some members of the community to make the chemical composition of hydraulic fracturing fluids a matter of public record, many of the mixtures are considered to be proprietary and current law related to proprietary materials supports the maintenance of confidentiality with respect to the composition of those fluids. It should be noted that regardless of the chemical composition of a particular hydraulic fracturing fluid, the application of proper well design, completion, operations and monitoring according to rules and regulations that already exist in most states and provinces will ensure that fracturing operations do not negatively impact either the subsurface or surface environment.

- **Over pressuring of the reservoir results in leaking:** Public stakeholders have expressed concern that overpressured hydraulic fracturing operations may result in overlying formations becoming fractured, possibly serving as conduits for leakage of formation fluids and fracturing fluids into overlying formations, including aquifers. This concern is largely the basis for a moratorium on drilling and hydraulic fracturing for shale gas in the state of New York. Concerns have also been expressed that overpressured hydraulic fracturing operations could result in rapid upward leakage through the borehole into overlying formations, including aquifers and possibly even to the surface. The application of proper well design, completion, operations, and monitoring according to rules and regulations that already exist in most states and provinces will ensure that hydraulic fracturing operations do not negatively impact either the subsurface or surface environment. A recent case in North Dakota demonstrates that attention to existing protocols for well design, operation, and monitoring are effective means of protecting the environment. Specifically, in August, 2010, after thousands of Bakken wells had been drilled and hydraulic fracturing without incident, the first incident of fracturing -related leakage through a borehole occurred. The cause of the leakage was quickly identified and stopped within a few days, during which time actions were taken to minimize the introduction of wellbore fluids to the surface and shallow subsurface environments. The result of those mitigation efforts was that there was no quantifiable impact to local groundwater resources. The incident served to demonstrate the effectiveness of the existing statutory requirements and vigilant regulatory authorities at protecting the environment.

- **Changes in land use:** Industry projections of the need for thousands of new wells to be drilled over the coming decades may lead to the construction of thousands of new well pads and thousands of miles of new access roads. The projected increase in roads has led some to be concerned about adverse effects of roads on ecosystems in areas of tight oil development. One way of mitigating this potential environmental issue is the increased use of "Ecopads", which allows for the drilling of multiple wells from a much smaller surface area, thereby reducing the number of well drilling pads and access roads that would need to be constructed during the development of these plays.

- **Bakken produces light crude**: On a positive environmental note, the Bakken produces light, sweet crude oil. The refining of lighter gravity crude oils has a smaller GHG footprint than heavier crude oils. Also the lack of sulfur content, which makes it sweet, means that this tight oil resource will have smaller H_2S and SO_X footprint. However, not all crude oils produced from tight oil plays are likely to be like the Bakken crudes - it is likely that some of the produced crude oils could be heavier than conventional crudes.

Productive Capacity Projection

Projection to 2035

Table TO2 – Projected Tight Oil Supply

	2009 Actual (B/D)	2035 Low (B/D)	**2035 Likely (B/D)**	2035 High (B/D)
Tight Oil	**265,000**	600,000	**2,000,000**	3,000,000

Table TO2 presents an estimate of tight oil production in 2009 being approximately 265,000 B/D. It is worth noting that recent reports indicate that tight oil production is rapidly increasing, with data suggesting that tight oil production during the summer of 2010 was at least 365,000 B/D.

Low Case assumes that restrictions on hydraulic fracturing are put into place by state and/or federal regulatory agencies; that the availability of water for hydraulic fracturing is limited; and that changes in the tax rules for oil exploration and production activities reduce the financial incentive to produce tight oil resources. Barriers to development in this scenario include limited access to water sources, including federally managed lakes and reservoirs, that serve other stakeholders, and increased production costs associated with compliance to new regulations and tax rules.

Likely Case. When considering potential tight oil production rates in 2035, it is once again instructive to look at the Bakken. In many ways the Bakken play has been the proving ground for some of the most effective engineering advancements in tight oil plays. The application of knowledge gained during the highly successful development of the Bakken towards other tight oil plays will almost certainly lead to significant increases in tight oil production over the coming decade. The North Dakota Department of Mineral Resources predicts Bakken production from North Dakota alone to be as high as 450,000 B/D by the year 2012, and projects that level of production to be maintained for at least a decade, with production outlooks ranging from 300,000 to 600,000 B/D in 2035. Further, some analysts have forecasted the Eagle Ford play alone could ultimately reach 800,000 B/D. If levels of Bakken production from Saskatchewan and Montana are each only half the North Dakota production, and similar productivity is realized from just three other large tight oil plays (for example the Eagle Ford, Niobrara, and Cardium) then over 2 M/D of production from tight oil formations in North America in 2035 is likely.

High Case. These projections may be considered to be conservatively low because they assume only a few of the many tight oil formations in North America will be exploited by 2035 and they do not account for continued improvements in recovery technologies. History suggests that both of these assumptions are unrealistic, and barring major policy changes that impede the development of these resources the unconstrained estimates of future production rates of 3 MB/D are possible.

A View to 2050

Based on current knowledge of resources, technologies, and price environments a qualitative view of tight oil production over the next 40 years would suggest that development of this resource in North America would likely peak in the 2015 to 2025 timeframe. The NDDMR has projected that production rates from the Bakken system in North Dakota will be between 250,000 and 350,000 B/D in 2050[126]. Applying this rate of decline to other tight oil plays that would be assumed to be in production mode suggests that while total production from tight oil will be on the decline in 2050, it could still realistically account for between 1,000,000 and 2,000,000 B/D.

Factors that could slow growth

While robust production from the Bakken is expected to continue over the coming decades, the magnitude of that production and the development of other tight oil plays in North America will be dependent in no small part on a variety of policy-related factors. While success rates in the Bakken are high - greater than 90 percent by some reports - that success is based on the application of relatively capital-intensive technologies. Additional costs that are associated with compliance to government regulations and/or tax programs could have significant impacts on the economic viability of a tight oil plays, and thus the ultimate productive capacity possible. These impacts are described below.

Future Government Policy

As described above, successful production of tight oil resources has been dependent on the development of drilling, completion, and stimulation technologies and detailed understanding of the geological characteristics of each given play. There is a high degree of variability in geological conditions between tight oil plays that require play-specific modifications to key production technologies and play-specific geological characterization studies. In the Bakken play, many of the technology development and geological characterization activities that were critical to successful production were conducted as part of research efforts either paid for entirely by industry or jointly funded by industry and government-funded research programs, such as the Department of Energy's Office of Fossil Energy and the Research Partnership to Secure Energy for America (RPSEA). Past federal tax codes have allowed oil companies to write-off expenses related to their participation in research programs[127]. Changes to the tax code that result in companies no longer being able to write-off those expenses will provide a substantial disincentive to fund research that may be critical to the development of emerging and underexplored tight oil plays, and will ultimately hamper the timely development of those plays.

Ineffectual regulatory policies can also impede the progress of tight oil development. The Environmental Protection Agency (EPA) is currently reviewing hydraulic fracturing technologies, methods, and operations with an eye towards potentially developing new federal regulations for the design, operation, and monitoring of hydraulic fracturing. Because each tight oil play will be unique, what may be a safe and appropriate technique in one area of the country may not be in another. A corollary of this is that rules and regulations for hydraulic fracturing should be geared towards addressing local conditions. If the EPA takes a strict "one-size-fits-all" approach to regulating fracking operations, then it is likely that restrictions and/or requirements and their associated added costs will be applied to areas where they are not only unnecessary but can make the play uneconomic.

Policy decisions can also have positive impacts on the development of tight oil resources. Policies that streamline leasing and permitting processes can facilitate timely development of a play. Adequately funded regulatory agencies can maintain the staff necessary to evaluate and process applications in a thorough but timely manner. The maintenance of adequate staffing can also ensure that current regulations that are intended to protect the environment are enforced. Investment in the development of digital resources and infrastructure for regulatory agencies can also improve the efficiency of both the regulatory process and technology transfer.

8. Acronyms and Abbreviations

CCEMC - Climate Change Emissions Management Corporation. Alberta fund that reinvests money collected from Alberta's carbon price to new technology development.

AERI - Alberta Energy Research Institute

AOSTRA -Alberta Oil Sands Technology and Research Authority

BB - Billion Barrels

BB/D - Billion barrels per day

BLM - Bureau of Land Management

CCEMC- Climate Change Emissions Management Corporation. Alberta fund that reinvests money collected from Alberta's carbon price to new technology development.

CCS - Carbon Capture and Storage

Dilbit blends - Use condensate from field production at a ratio of 30 percent diluent/70 percent bitumen to yield a pipelinable product from extra heavy oil or bitumen.

EIA - US Energy Information Administration

EPACT 2005 - Energy Policy Act of 2005

FACA - Federal Advisory Committee Act

GDP - Gross Domestic Product

GHG - Greenhouse gases (primarily carbon dioxide, methane, nitrous oxide, and ozone).

IEA - International Energy Agency

Insitu - producing unconventional oil in place, usually using drilling methods to access the oil similar to conventional production.

MB/D - Million barrels per day

NAs - Naphthenic acids

Oil in place - an estimate of both the discovered and undiscovered oil – how much oil is in the ground.

OPEC Organization of the Petroleum Exporting Countries

PAHs - polycyclic aromatic hydrocarbons

RD&D - Research, Development and Demonstration

Reserves - a sub-set of the oil in place, just the oil that can be produced economically with current technology.

Resources – Include both Reserves, and oil that is thought to be recoverable in the future but is not economic at the time of estimation.

S&T - Science and Technology research

SAGD - Steam Assisted Gravity Drainage

SCO - Synthetic Crude Oil

SPE - Society of Petroleum Engineers

STSA's - Special Tar Sand Areas for US Oil sands production

TV/BIP - Total Volume / Bitumen in Place, a ratio for measuring the quality of mining ore.

Ultimate potential - an educated guess of the amount of oil that could be recoverable if economic techniques were discovered

TB – Trillion barrels

WTI - West Texas Intermediate

9. References

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2 Compare 2009 unconventional production with EIA 2009 liquid fuels demand in the United States - 19.7 MB/D
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11 Assuming a 5 percent per year decline rate from current global production of 86.4 MB/D provided by current production provided by August 2010 International Petroleum Monthly contrasted against the IEA WEO2010 Current Policies Scenario 2035 demand projection of 107.4 MB/D.
12 The aggressive alternatives scenario is the IEA 450 case, here greenhouse gas emissions are capped to a level of 450 ppm. Assuming a 5 percent per year decline rate from current global production of 86.4 MB/D provided by current production provided by August 2010 International Petroleum Monthly contrasted against the IEA WEO2010 450 Scenario 2035 demand projection of 81 MB/D.
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