Oil Sands Technology

Past, Present, and Future

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About This Report

Purpose. Since the inception of the first commercial oil sands facilities, the industry has established a track record of ongoing technical innovation—reducing costs, increasing recovery, increasing efficiency, and reducing its environmental intensity. This report identifies and quantifies these past innovations, while analyzing the potential and challenges in achieving further gains. The oil sands industry is increasingly under pressure—from the public, the government, regulators, and its only export market, the United States—to further reduce its environmental impact. Ability to demonstrate improvements will be a critical factor shaping the economic and political playing fields for Canadian oil sands.

Context. This is the third in a series of reports from the IHS CERA *Canadian Oil Sands Energy Dialogue*. The dialogue convenes stakeholders in the oil sands to participate in an objective analysis of the benefits, costs, and impacts of various choices associated with Canadian oil sands development. Stakeholders include representatives from governments, regulators, oil companies, shipping companies, and nongovernmental organizations. The 2010 Dialogue program and associated reports cover four oil sands topics:

- the role of Canadian oil sands in US oil supply
- oil sands, greenhouse gases (GHG), and US oil supply: getting the numbers right
- oil sands technology: past, present, and future
- oil sands and GHG policies

These reports and IHS CERA's 2009 Multiclient Study *Growth in the Canadian Oil Sands? Finding the New Balance* can be downloaded at www2.cera.com\oilsandsdialogue.

Methodology. This report includes multistakeholder input from a focus group meeting held in Calgary on August 10, 2010, and participant feedback on a draft version of the report. IHS CERA also conducted its own extensive research and analysis both independently and in consultation with stakeholders. IHS CERA has full editorial control over this report and is solely responsible for the report's contents (see the end of this report for a list of participants and the IHS CERA team).

Structure. This report has five major sections, including the Summary of Key Insights:

- Summary of Key Insights of IHS CERA's Analysis
- **Part I: The Evolution of the Oil Sands Industry.** What factors have shaped the history of innovation? What are the technologies for extracting oil sands today?
- **Part II: Benchmarking Environmental Change, Past to Present.** How have GHG emissions and water consumption per barrel produced changed over time? What technologies have shaped these improvements?
- **Part III: Future Technology Drivers for Oil Sands.** How could technology further reduce environmental intensities—and what are the challenges to realizing these benefits? What are the emerging technologies?
- **Part IV: Where Is the Industry Headed?** In aggregate what level of environmental improvement is ultimately possible? How is future research and development being supported?

OIL SANDS TECHNOLOGY: PAST, PRESENT, AND FUTURE

SUMMARY OF KEY INSIGHTS OF IHS CERA'S ANALYSIS

A track record of ongoing, continuous technical improvement has enabled oil sands growth. At the same time, innovation has improved the environmental performance of production, lowering the average amount of greenhouse gases (GHGs) emitted per barrel of output. Since 1990 the intensity of GHG emissions per barrel of output for mining and upgrading operations has fallen by 37 percent on a well-to-retail pump basis. Since the inception of steam-assisted gravity drainage (SAGD) a decade ago, well-to-retail pump emissions have declined 8 percent per barrel. Mining and SAGD account for close to 70 percent of total oil sands supply. For cyclic steam stimulation (CSS)—which produces 16 percent of oil sands output—GHG intensity has increased.

The trend of declining GHG emissions intensity is expected to continue, but the absolute level of GHG emissions will grow as oil sands production volumes increase. A scenario with rapid technical innovation and relatively moderate oil sands growth—3.1 million barrels per day (mbd) by 2030 from 1.35 mbd in 2009—would reduce the GHG emissions per barrel of production by over 30 percent, but total GHG emissions from oil sands upgrading and production would still grow, from 5 percent of Canada's emissions to about 10 percent. However, in the absence of new oil sands supply, global oil demand is still projected to grow, and substituting oil sands supply for another source still results in emissions growth.

Deployment of new technology and methods has reduced the water use intensity of production, particularly the use of fresh water. The original SAGD operations required over 1 barrel of fresh water per barrel of bitumen produced. Today, on average, SAGD operations consume 0.7 barrels of water per barrel of bitumen produced, with 60 percent from nonpotable brackish water sources. For CSS water use has decreased from over 3 barrels of fresh water per bitumen barrel produced to less than 0.6 barrels. For mining operations the water consumed per barrel of bitumen extracted has not declined substantially, but because of improved water management practices the amount of water withdrawn from the Athabasca River has been reduced, from 3.5 barrels of water per barrel produced a decade ago to 2.5 barrels currently.

The oil sands industry is continually evolving; past innovations have centered on improving the economics of recovery. Over the coming decades new technologies must meet both economic and environmental goals. Improvement on both fronts is expected, but the pace and ultimate size of future gains is uncertain. For SAGD developments ongoing efficiency improvements and new hybrid steam-solvent technologies could reduce well-to-retail pump emissions by 5 to 20 percent per barrel produced, and water consumption could potentially decline by 10 to 40 percent per barrel. For the more mature mining operations GHG emissions gains are projected to be smaller. GHG intensity could decline

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5 percent (well-to-retail pump), plus there are prospects for decreasing water consumption. However, new technologies must overcome economic and environmental hurdles; if not, widespread adoption is unlikely. A second factor is reservoir quality. Generally the first generation oil sands projects selected some of the best parts of the oil sands deposit—those with characteristics that allow the most efficient recovery. The next phase of oil sands projects involves lower quality resources. Without new techniques, some of the new sites could require more energy compared to today's developments.

Past oil sands innovation has most often been the product of collaboration and partnership between industry and government. This trend is growing and is preferable to operating in research silos. There is a growing appreciation that collaboration among industry players and government is beneficial—both to the speed of innovation and to the potential benefits of new technology in diminishing environmental impacts. Numerous initiatives are developing new technology through cooperative funding and research. The industry itself is cooperating more through various oil sands groups; a recent example includes the sharing of new environmental technologies with competitors without fees or royalties.

Beyond the next two decades, new methods of extracting oil sands are likely to lead to more reductions in GHG intensity and environmental impacts, but these trends are not inevitable. More research and development is needed. Ideas for new methods to extract bitumen include electric heating, solvents, in-situ combustion, and underground tunnels. These methods have the potential to decrease the environmental footprint of production while unlocking new parts of the oil sands deposit—oil that is currently not recoverable. Because of the time lag between a successful pilot and broad commercial deployment, the potential benefits from these revolutionary technologies are probably 15 to 20 years away.

Carbon capture and storage (CCS) efforts are enhanced by government engagement, but it is a high-cost activity. Given the Alberta and Canadian government's significant investment in CCS, it is probable that at least one project will be operating in the oil sands. It will be installed at the lowest cost point of capture—the concentrated carbon dioxide (CO_2) sources found at the upgraders in proximity to geologic storage (central Alberta). Capturing these emissions reduces the GHG intensity of oil sands production by 11 to 14 percent (well-to-retail pump). CCS for upstream facilities will take much longer to develop (if it happens at all). Here the CO_2 comes from dilute combustion streams, and capturing these emissions is both expensive and energy intensive; and added to this is the fragmented nature of the upstream extraction facilities and the lack of geological carbon storage in the Fort McMurray region.

—January 2011

OIL SANDS TECHNOLOGY: PAST, PRESENT, AND FUTURE

Technical innovation is at the heart of the Canadian oil sands story. "Cracking the code" of more efficient production has enabled the oil sands to become one of the most important sources of global supply growth, while also strengthening North American energy security. The oil sands will soon become the largest source of US oil imports. Innovation has focused on increasing the economic viability of oil sands in the global market, but it has also led to an improved environmental performance. Further challenges face the industry, especially since concerns about climate change have intensified the worldwide debate about oil resource development.

Innovation remains the key to helping oil sands meet environmental and economic objectives. This report discusses new and evolving technologies that have the potential to further reduce the environment impact of oil sands activity, including shrinking greenhouse gas (GHG) intensity of the production process and reducing water use intensity. Ongoing improvements in oil sands extraction and upgrading are expected but not guaranteed, given the countervailing challenges of decreasing reservoir quality and the need for new technologies that are both environmentally sustainable and economic.

This report has four main parts:

- The first part focuses on understanding the historical context of innovation and technological development. This provides a framework on how the industry got started and how it has evolved to its present state of operation and production.
- The second section benchmarks environmental changes from the past to current.
- The third part focuses on how the application of new technologies could reduce water consumption and GHG emissions intensity. We explore a wave of innovation at work and a wide diversity of paths of innovation at various stages of development.
- The final section assesses what the past, present, and future of innovation mean for the oil sands and identifies what is potentially achievable in reducing environmental impacts in the aggregate.

PART I: THE EVOLUTION OF THE OIL SANDS INDUSTRY

A BRIEF HISTORY OF OIL SANDS DEVELOPMENT

The century following the 1884 mapping of the Canadian oil sands deposit was marked by great potential held in check by technological challenges. For much of this time oil sands were simply was too expensive to process and ship to market. But over the past several decades pivotal advances were made that enabled the oil sands to become one of the top sources of global oil supply growth. Production more than doubled, from 0.6 mbd in 2000 to 1.35 mbd in 2009. By 2020 oil sands output is likely to double again and could be higher than the national production from several OPEC member states.

The "oil" in the oil sands comes from bitumen, which is extra-heavy oil with high viscosity. In others words it has the feel of what some might call a sticky hockey puck. The thick, heavy oil does not flow at reservoir temperatures, making attempts to produce it using conventional methods futile. It was 1925 before the first major innovation was made in producing the oil sands. In that year Dr. Karl Clark of the Alberta Research Council demonstrated the first separation of oil from the sands using hot water and caustic soda. The process was patented in 1928 and still forms the basis of oil sands mining extraction.

At the same time a Nova Scotia entrepreneur began construction of a plant at the Bitumount, Alberta, site. Here oil sands were surface mined, and the bitumen was extracted using the hot water process. After a checkered history of experimentation, including numerous bankruptcies and one government bailout, the plant was officially closed in 1958. Meanwhile a separate company, Abasand Oils, built a processing plant in 1935 to produce diesel. After a decade of tribulations in processing oil sands—including numerous fires—this plant was also closed down.

As in any process of innovation the road to commercial development is often rocky and full of setbacks and pitfalls. Getting to commercial development in oil sands has been no exception.

Surface Mining: Commercial Production Gains a Foothold

A key step in commercialization took place in 1953 with the formation of the Great Canadian Oil Sands (GCOS), a consortium led by Sun Oil, a predecessor of today's Suncor Energy. After a vast investment of over C$1.6 billion in today's dollars, the first lasting mining and upgrading operation came into production in 1967.* The GCOS plant had to overcome many operational problems, unsurprising given this was the first attempt at commercial oil sands production. Numerous problems were encountered in scale-up. The hot water extraction process struggled with the variability in ore grades, the massive bucket-wheel excavators had productivity issues, and the conveyors regularly needed repair. However, this first plant proved an invaluable learning experience for the mining oil sands business. Continuous

*The original investment of C$250 million was estimated in today's dollars. At the time, this was the largest private investment ever made in Canada (source: Suncor website).

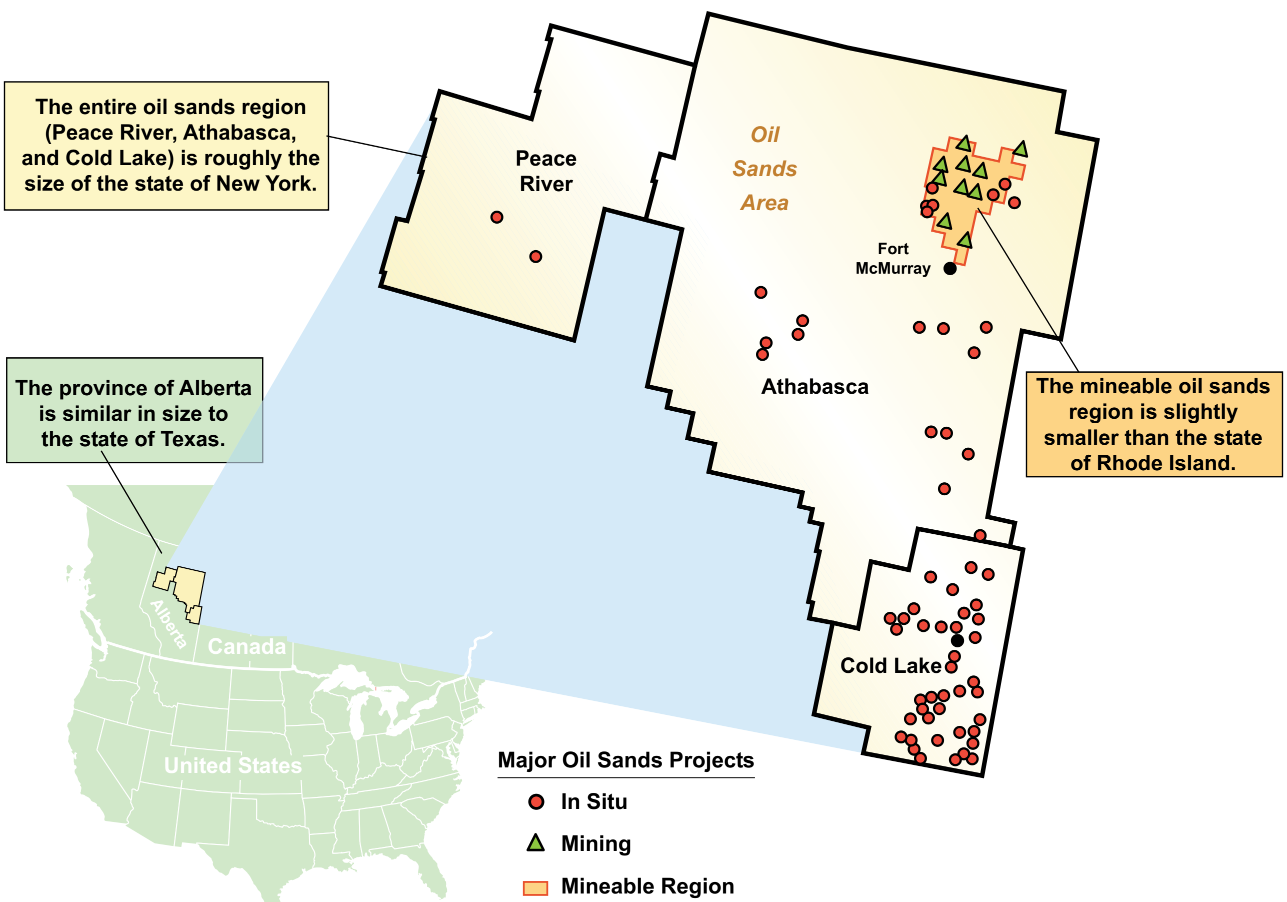
innovation over an extended period has borne fruit in the productivity and economics of today's mining operations.

But confidence in the operation of the GCOS plant was growing. The next major step was the development of the Syncrude operation. Syncrude's new oil sands surface mine and upgrader opened in 1978 amid rising oil prices and growing energy security concerns.

Although extracting oil sands from surface mining was gaining considerable momentum, new methods were required to access the much larger nonminable part of the oil sands—deposits buried too deep to surface mine. The oil sands deposit is concentrated in three major areas: the Peace River, Cold Lake, and Athabasca deposits. By far the largest deposit is the Athabasca, with over 80 percent of the oil in place. Within the Athabasca deposit a small area (less than 3 percent of the total oil sands area) is close enough to the surface for mining (see Figure 1).

Figure 1

Location of Canadian Oil Sands Resources



Source: IHS CERA.
Note: Comparisons to US states are to the total areas of the states, including land and water.
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Going Underground: In-situ Production

Imperial Oil made the first steps in producing bitumen from the deeper deposits by patenting the CSS process in 1966. After 20 years of improving the process commercial production was achieved in 1985. Although Imperial's cyclic steam stimulation (CSS) method was successful, it is a high-pressure process best suited for operations in the relatively small Cold Lake and Peace River oil sands deposits.* New lower-pressure techniques were required to produce bitumen from the much larger, shallow Athabasca deposit. The government's support and participation played a key role in finding the solution for unlocking bitumen from the massive Athabasca deposit. In 1974 the Alberta government, under the leadership of Peter Lougheed, was instrumental in the creation of the Alberta Oil Sands Technology and Research Authority (AOSTRA). AOSTRA became the crucible of oil sands research, especially for the vast tract of oil sands resources too deep for surface mining.

Imperial Oil was the first to pilot the SAGD recovery process at Cold Lake in the late 1970s, patenting the technique in 1982. Later, Roger Butler from the University of Calgary (formerly an employee of Imperial) proposed to AOSTRA to pilot the SAGD concept in the more shallow Athabasca deposit, which resulted in the 1984 Underground Test Facility pilot. Initially the Alberta government funded the project alone, but eventually the industry partnered in the investment. It took a further 15 years for true commercial development, but a major innovation that could extract bitumen at low pressures and access a larger part of the deep oil sands deposit was born.

Over its 25 years in existence AOSTRA through the Alberta government partnered with industry on 16 field trials. In addition to promoting the eventual commercialization of the SAGD process, the AOSTRA field trials provided a wealth of data and lessons on alternative production techniques. In the first 15 years of AOSTRA the Alberta government and industry jointly invested over C$2 billion (current dollars) in research and development (R&D).** Although AOSTRA was dissolved in 1995, the Alberta government remains actively engaged in oil sands R&D through current initiatives such as Alberta Innovates—Energy and Environmental Solutions (formerly AERI) and the Climate Change and Emissions Management Corporation (CCEMC) (see Part IV for more details on research).

These first oil sands developments—the "learning projects"—involved large, high-risk investments and formed the foundation of the advances in extraction processes that dominate the industry today. Without risking significant sums of up-front capital—often shared by government, industry, and the capital markets—it is unlikely that production from oil sands would be where it is today.

*In the smaller Peace River and Cold Lake deposits the reservoir is deep, allowing bitumen to be extracted at higher pressures. Additionally the smaller deposits are generally not in contact with thief zones—water or gas zones that steal heat—characteristics that are common in the Athabasca deposit.
**Source, AOSTRA, *A 15 Year Portfolio of Achievement.* Original spend was C$1 billion.

OIL SANDS TODAY

The Alberta oil sands are an immense resource. Current estimates of economically recoverable oil are 170 billion barrels—the second largest in the world after Saudi Arabia.* Today four commercial technologies are used to produce oil sands (see Table 1).

Cold Flow and Enhanced Recovery

Some areas of the oil sands resource, comprising slightly less viscous oil, are amenable to "cold flow" methods. The "nonsteam" production methods include cold heavy oil production with sand (CHOPS) and production from horizontal wells; enhanced recovery methods such as water or polymer flooding are also used.** In 2009 cold flow production constituted 15 percent of oil sands production; it is projected to decline to less than 5 percent of production by 2030.

Mining

About 20 percent of currently recoverable oil sands reserves lie close enough to the surface to allow open-pit mining (see Figure 2). The bitumen is produced using a strip mining process similar to that for coal mining. The overburden (primarily soil and vegetation) is removed, and a layer of oil sands is excavated using massive shovels and moved by pipeline or truck to a processing facility where the bitumen is extracted using the hot water technique. Today all sites are integrated mine/extraction-upgrading operations; these operations extract the heavy bitumen and upgrade it to a light crude oil called synthetic crude oil (SCO).*** The first mining/extraction-only operation (Imperial's Kearl Mine) is now under construction. This project will not upgrade its product; rather the extracted bitumen will be shipped as a diluted bitumen blend (dilbit) by pipeline to refineries in Canada or the United States for upgrading to petroleum products.

Table 1

Breakdown of Oil Sands 2009 Production by Extraction Method

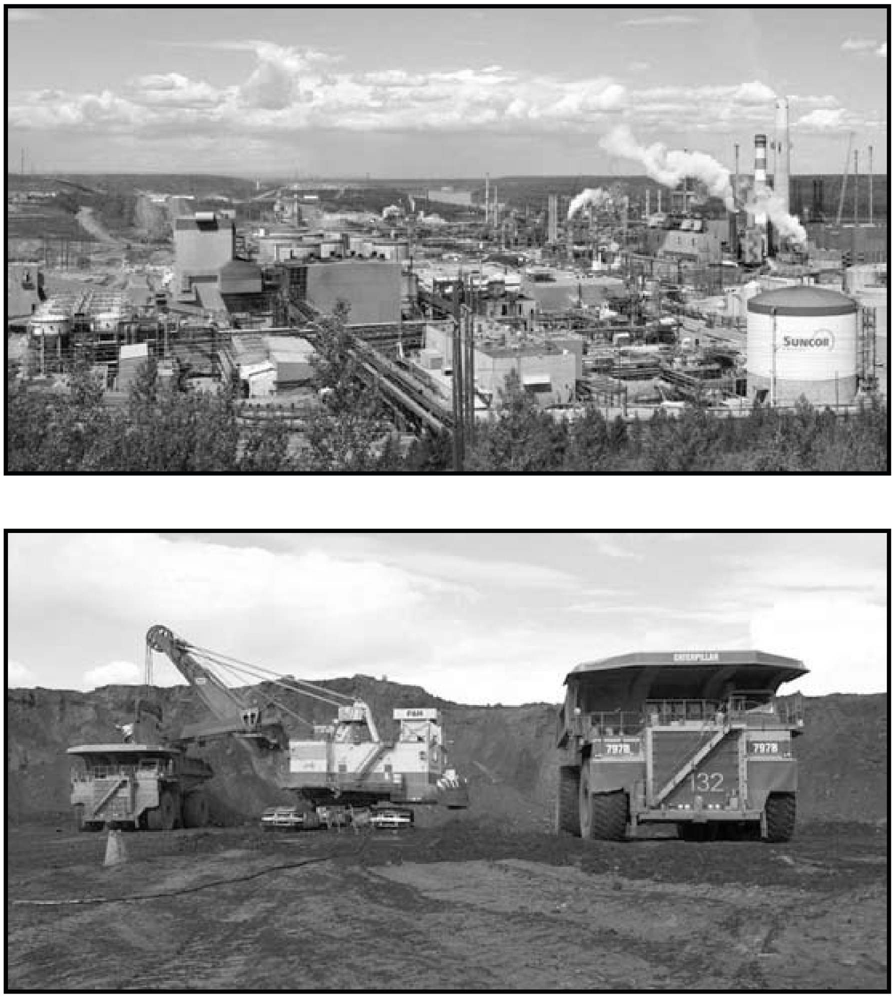
	2009 Production (bd)[1]	Percent of Oil Sands Production
Cold flow and enhanced recovery	206,941	15 percent
Mining	690,154	51 percent
In-situ—CSS	213,860	16 percent
In-situ—SAGD	242,794	18 percent

Source: ERCB Alberta's Energy Reserves and Supply Outlook, June 2009.
1.Barrels per day.

*Alberta Energy Reserves 2009 and Supply/Demand Outlook 2010-2019, Alberta Energy Resources Conservation Board (ERCB).
**In producing bitumen using the CHOPS method, both sand and oil are recovered using progressive cavity pumps. Significant volumes of sand are produced and sand disposal is required. To produce bitumen using enhanced recovery methods such as water and polymer flooding, water or polymer is injected into the reservoir to displace the bitumen into the production wellbores.
***An oil sands upgrader is akin to a refinery, converting the heavy bitumen to a lighter crude oil product.

Figure 2

Mining Extraction and Upgrading Facility



Source: Suncor Energy.
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Although the minable part of the oil sands is just 20 percent of the total resource, it is still large—34 billion barrels of bitumen recoverable. Production from mining operations is expected to keep growing, and thus mining is likely to maintain its position at nearly half of the oil sands production for the next 20 years.

In-situ Thermal Processes

About 80 percent of the recoverable oil sands deposits are too deep for surface mining and are recovered using drilling techniques combined with thermal transfer. In-situ thermal methods inject steam into the wellbore to lower the viscosity of the bitumen, allowing it to flow and be pumped to the surface. Two thermal processes are in commercial use today: CSS and SAGD.

CSS

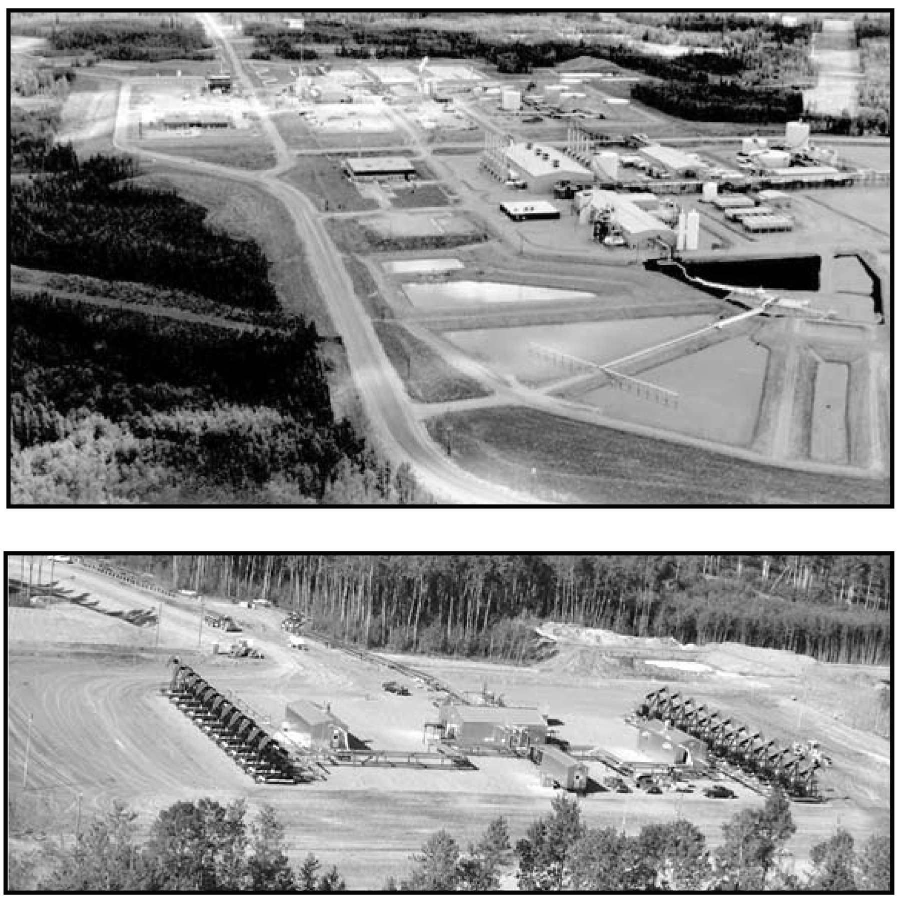
CSS, also called huff and puff, is a three-stage steam injection process that uses vertical, deviated, and horizontal wells. This was the first process used to commercially recover oil sands in situ (see Figure 3). CSS production volumes are projected to decline from 16 percent currently to less than 10 percent of oil sands by 2030, as SAGD production from the larger Athabasca oil sands deposit continues to grow.

SAGD

SAGD is the technique advanced by AOSTRA in the early 1980s. In this process two parallel horizontal wells—vertically separated by about 5 meters—are drilled in the oil sands formation. The upper well is used for steam injection, which heats the reservoir and bitumen, allowing it to flow into the lower well (see Figure 4). Production from SAGD currently makes up 18 percent of production and is projected to increase to more than 40 percent of total production by 2030.

Figure 3

CSS Well Pad and Central Facility



Source: Imperial Oil Resources—Cold Lake.
01212-6

Figure 4

SAGD Well Pad and Central Facility

Source: Cenovus Energy—Foster Creek.
01212-5

PART II: BENCHMARKING ENVIRONMENTAL CHANGES, PAST TO PRESENT

Historical analysis indicates that deployment of new technologies often follows an S-shaped curve. Initial progress is often slow, but when the technology "crosses the chasm," learning reaches a critical stage and takeoff is rapid. The stage of rapid commercialization results in gains in efficiency and productivity, lower materials use, and lower energy use. This section of the report measures improvements in the overall efficiency of converting the oil sands resource into a barrel of bitumen or SCO over time. We first discuss the history of changes in mining and upgrading and then turn to SAGD, the second most-used method of oil sands extraction. We end this section by reviewing the third major method of oil sands production, CSS.

MINING AND UPGRADING

Established over 40 years ago, the main method of oil sands production, mining, and upgrading has improved its environmental performance per barrel produced.

Energy Consumption and GHG Emissions

Over the past two decades mining operators have learned how to produce bitumen more efficiently, reducing GHG emissions per barrel by 37 percent on a well-to-retail pump basis (see Figure 5).* Major drivers of reduced GHG emissions include the following:

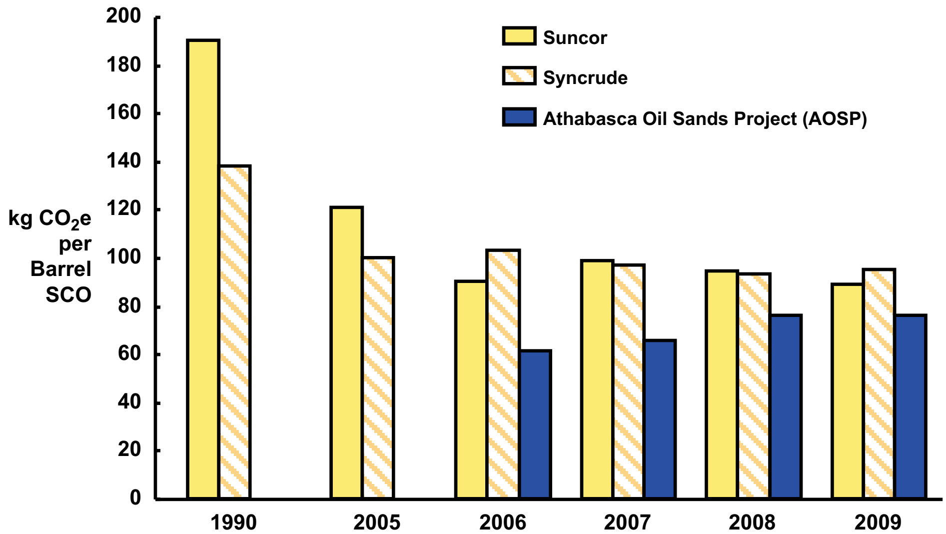
- **Hydrotransport and improvements in bitumen extraction.** More than half of the energy savings in mining operations has resulted from improvements in extracting the bitumen from the sands. The initial Clark hot water process required temperatures of 80 degrees Celsius (°C), and today ranges between 40 and 50°C. The chief enabler of the reduced temperature was the discovery of hydrotransport, a method of fluidizing the bitumen-laden ore and transporting it by pipeline to the extraction vessel, as opposed to moving it by conveyer belt. By using a pipeline the bitumen-sand slurry is mixed while transported, and the bonds between the bitumen and the sand start to break down before entering the extraction process. As a result lower temperatures are needed to extract the bitumen. Other significant extraction energy reductions have come from improved heat integration (recovering more waste heat from the extraction waste stream) and increasing the recoveries of bitumen.

- **Shifting to natural gas cogeneration for electricity and steam.** The first oil sands operations generated electricity primarily from fuels produced on site. For example Suncor's original plant used some petroleum coke for generating both electricity and steam. Syncrude generated energy from upgrader off-gas. Over time both operations have shifted to supplying increasing portions of electricity and steam from lower–carbon emitting natural gas cogeneration.

*The production-weighted average GHG intensity was calculated across all projects at each period (Suncor, Syncrude, and Athabasca Oil Sands Project [AOSP]).

Figure 5

Mining and Upgrading Oil Sands: GHG Emissions per Barrel of SCO



Sources: Syncrude 09/10 Sustainability report, Suncor Energy Sustainability reports and company data, AOSP—Muskeg River Mine and Scotford Upgrader Shell Sustainability Report 2009. (Note: AOSP is a joint venture project operated by Shell; partners are Shell Canada, Marathon Oil Canada, and Chevron Canada.)
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- **Upgrading efficiency improvements**. Over time upgraders have been optimized and energy consumption has been reduced. Improvements have stemmed from numerous initiatives, some of the largest gains have resulted from improved heat integration (recovering more heat from process streams).

- **Improvements in new operations.** The most recent oil sands mining projects have the advantage of "starting from scratch" and taking advantage of the latest techniques and equipment (new projects are Horizon plant of Canadian Natural Resources Limited (CNRL) and the AOSP).* These new operations have implemented ideas learned from the original operations plus new energy-saving techniques. Because the new plants are more efficient, the GHG emissions are 15 to 25 percent lower than those from the original operations.** Phase 1 of AOSP, which started operations five years ago, deployed a number of energy-saving ideas. One improvement was in extracting the heaviest component of the bitumen—asphaltenes—before upgrading. By removing the highest-carbon component of the bitumen barrel, the emissions from upgrading are lowered. Most operations send hot water from the extraction process to tailings ponds

*AOSP is a joint venture operated by Shell; partners are Shell Canada (60 percent), Marathon Oil Canada (20 percent), and Chevron Canada (20 percent).
**Source: AOSP Muskeg River Mine and Scotford Upgrader, Shell Sustainability Report 2009; emissions are about 25 percent lower than established operations. CNRL 2010 Horizon report to stakeholders, emissions projected to be 15 percent lower than comparable operations.

to cool, but the AOSP project is more efficient and recycles a small portion of the hot water back immediately, thereby reusing some of the heat.

Water Consumption

Approximately 12 to 14 barrels of water are used to extract a barrel of bitumen from mined oil sand ore, and about 70 percent of this water can be recycled. The remaining water, about four barrels, is trapped in the mining waste—a mixture of water and fine clay and silt about the consistency of yogurt. As water does not separate naturally from this material, the mining waste is stored in tailing ponds. To account for the water lost to the tailings, additional water is required. Part of this water comes from the Athabasca River, and part is collected from site runoff and mine dewatering. For integrated oil sands mining and upgrading facilities the water supplied from the Athabasca River ranges from 2 to 2.5 barrels of water per barrel of SCO produced; this is about 1 barrel less than ten years ago.

SAGD PRODUCTION

Established just over a decade ago, the second largest and fastest growing method of oil sands production is SAGD. Today's SAGD production has reduced its environmental intensity compared with the original operations.

Energy Consumption and GHG Emissions

Just over a decade ago the first in-situ SAGD development—Foster Creek—started operation. Four other first generation projects followed, commencing operations in the early 2000s.*

The steam-oil ratio (SOR) is a critical measure of the efficiency of thermal in-situ production. It measures the average volume of steam—generally produced using natural gas as a fuel—needed to produce one barrel of bitumen. There are two ways to measure SOR:

- **Cumulative steam-oil ratio (CSOR).** This method measures the average volume of steam—over the entire life of the operation—required to produce one barrel of bitumen. A CSOR of 3.2 means that since the start of operations, on average 3.2 barrels of steam were required to produce one barrel of bitumen.

- **Instantaneous steam-oil ratio (ISOR).** This measures the current or instantaneous rate of steam required to produce a barrel of bitumen. For example an average ISOR of 3.0 means that currently the operation needs three barrels of water to be vaporized to steam to produce one barrel of bitumen. The ISOR is lower than the CSOR because the ISOR does not account for the steam injected to warm the reservoir prior to first production.

Comparing the CSOR from the first years of the projects to the current values shows a steady decline in steam (and hence energy) use per barrel of bitumen produced. Today the average CSOR across the first generation projects has dropped 0.6—from 3.4 in the early

*First generation commercial projects include today's Cenovus/Conoco Phillips Foster Creek (1997), JACOS Hangingstone (1999), Cenovus/ConocoPhillips Christina Lake (2002), Suncor Energy MacKay River (2002), and Suncor Energy Firebag (2004).

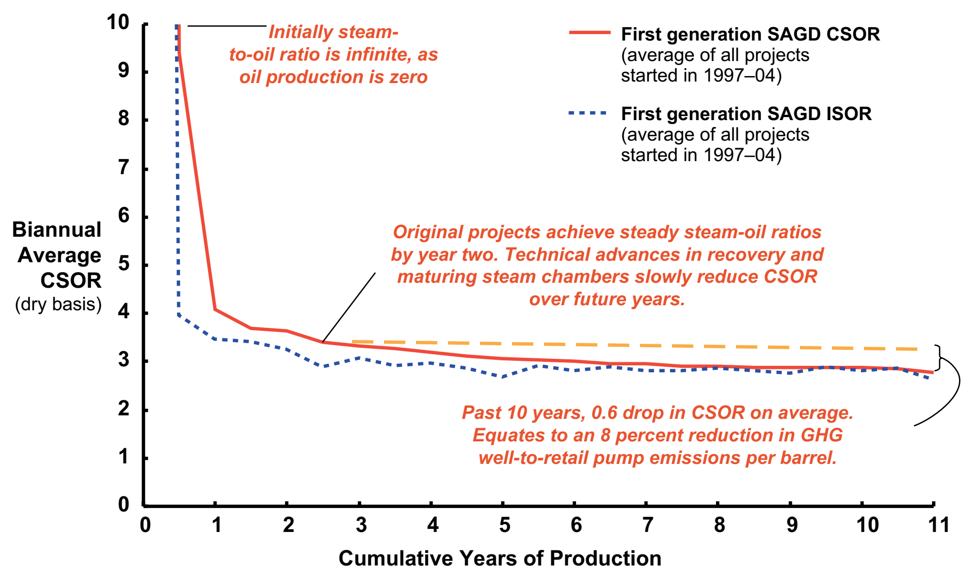
years of each project to 2.8 today. This equates to about an 18 percent reduction in GHG emissions for producing a barrel of bitumen with SAGD over the past decade, or equivalent to an 8 percent reduction on a well-to-retail pump basis (see Figure 6).*

For SAGD production it is still relatively early days, and longer-term SOR trends are somewhat uncertain; so far the historical trend is one of declining steam requirements per barrel of output. For an individual well pair, the SOR is expected to start out high and then decrease sharply over the first 18 months, followed by slighter declines as the steam chamber matures. Late in the life of a field, after most of the recoverable oil has been produced, the SOR increases. Production will stop when the steam rate becomes too high for economic production. A given oil sands operation has numerous well pairs, all at different stages of this life cycle.

Considering this life cycle, the measured 0.6 improvement to date in CSOR is partly from the advancing maturity of the steam chamber (SOR declines slightly as the steam chamber matures) and partly from technical advancements in SAGD production. Since the start-up

Figure 6

First Generation SAGD Projects:
Progression of Steam-to-oil Ratios



Source: IHS CERA.
Notes: First generation projects included in average are Cenovus/ConocoPhillips Foster Creek (1997), Cenovus/ConocoPhillips Christina Lake (2002), Suncor Energy MacKay River (2002), Suncor Energy Firebag (2004), JACOS Hangingstone (1999). The production-weighted average CSOR was calculated across all first generation projects. The average CSOR between year two and three was compared to the average CSOR in the past six months. Data source ERCB, IHS.
01212-2

*The production weighted average CSOR was calculated across all first generation projects. The average CSOR between year two and three for each was compared with the average CSOR in the past six months. The GHG savings do not account for GHG reductions from electricity cogeneration.

of the first generation projects less than a decade ago, three major energy-saving technical innovations have been applied in SAGD operations:

- **Improved reservoir characterization and wellbore placement.** The level of understanding of the behavior of the SAGD reservoir has increased sharply since the first operations. Most likely this has been the largest contributor to reduced energy in SAGD production. Operators are now able to visualize the reservoir using data from observation wells and advanced seismic data. New drilling technologies and techniques allow operators to accurately place the wells in optimal locations.

- **Electric submersible pumps (ESPs).** The original SAGD operations used a gas-lift technique to lift fluids to surface. The operator would have to operate SAGD at high reservoir pressures for gas-lift to perform effectively. This resulted in nonoptimal SOR and costly heat loss to nonbitumen zones. With ESPs capable of handling high temperatures, the operators are able to reduce the SAGD operating pressure, which reduces steam losses, energy usage, and the overall SOR.

- **Wellbore liner improvements.** Oil sands bitumen is found in deposits of unconsolidated sands. Loose sands create difficulties for bitumen production. Sand tends to enter and plug the well liner, leading to operational problems in downstream facilities and nonoptimum use of steam. Operators are learning the most optimal configurations of liners for each well, resulting in both increased operational time and reduced energy losses from uneven steam distribution.

Taking into account these improved practices, how have the second generation SAGD projects—projects that have commenced production after 2006—fared in energy efficiency?*

The average CSOR for the group of second generation SAGD projects is 4—higher than the first generation projects (see Table 2). The higher SORs stem from numerous factors: operational challenges in start-up, more difficult reservoirs, projects that are still ramping up to nameplate capacity, and learning by first-time operators. It is important to note that the majority of second generation projects have not required significantly more energy compared with their first generation counterparts; the average CSOR for the top four projects (representing over 70 percent of second generation production) is 3.1.

A significant factor dictating the absolute SOR level for an operation is reservoir quality. Generally, the first generation SAGD projects had high quality reservoirs: thick continuous pay zones, high porosity, and high oil saturations. These qualities allow for more energy efficient production.

The higher CSOR on some of the second generation sites highlights a risk in maintaining the ongoing track record of efficiency when moving to different oil sands leases or areas of the same lease that are lower quality. However, even operations with elevated SORs, without the lessons from the first generation projects' higher SORs likely would have resulted. The

*Second generation projects include Husky Energy Tucker (2006), ConocoPhillips/Total Surmont (2007), MEG Energy Christina Lake (2009), Connacher Oil & Gas Great Divide (2007), Nexen Long Lake (2007), Devon Canada Jackfish (2007), and Shell Orion (2007).

Table 2

SAGD Project Level CSOR and ISORs (January to June 2010)

Project	Project Generation	ISOR	CSOR	Average Daily Production
First generation average (production weighted)	First	2.61	2.78	211,218
Second generation average (production weighted)	Second	3.71	4.03	101,136
All projects average (production weighted)	All projects	2.97	3.19	312,354

Source: IHS CERA.

majority of second generation projects are also still relatively early in their life cycle, and SORs are projected to decline further as the operations continue to mature.

Water Consumption

Today groundwater is the primary water source for SAGD oil sands production. The amount of fresh water used for SAGD production has been decreasing over time. A decade ago operations used only fresh water, consuming more than one barrel of water per barrel of bitumen produced.* Currently the use of nonpotable salty water from deep aquifers, known as brackish groundwater, has become common.

To understand current water demands, we surveyed ten SAGD sites representing 97 percent of total production.** On average the group of SAGD operations consumed 0.7 barrels of water per barrel of bitumen produced, with 60 percent of the water consumed from brackish sources. The operations were recycling 75 percent of the water they produce. Not all sites are average; some operations use only brackish water, while others use only fresh water because they have no on-site brackish water source.

The type of technology used for steam generation is an important factor in determining the recycle rate and consequently the volume of water consumed. The various technologies deployed are

- **Once-through steam generators (OTSG).** Currently OTSGs are the most common technology for steam raising. Before entering the steam generator, water is treated with water softening chemicals to prevent solids from fouling the boilers. In the OTSG about 75 to 80 percent of the feed water is vaporized. The remaining wastewater (having high silica, hardness, and solids) is injected into deep disposal wells or salt caverns. This wastewater, often called blowdown, has been the limiting factor in further reducing net water use. Using an OTSG for a typical SAGD project consumes about 0.9 barrels of blowdown water per barrel of bitumen produced.***

*Although in-situ production uses some surface water, most of the fresh water comes from deep wells. The groundwater termed "fresh water" is typically not drinkable because of its high solids content—well above the 500 parts per million limit for drinking water.
**Source 2009 ERCB operator progress reports and IHS.
***Assumes SOR of 3.

- **Evaporators with drum boilers.** An alternative steam generation method—which is becoming more common for new developments—is to combine evaporators with drum boilers. The benefit of evaporators compared to water softening chemicals is they remove solids and hardness before the water enters the boiler. With cleaner feed water, more energy-efficient drum boilers can be deployed (instead of OTSG). An evaporator–drum boiler on a typical SAGD project consumes 0.4 to 0.5 barrels of water per barrel of bitumen produced.*

- **Zero liquid discharge (ZLD).** A small number of sites go even further, completely eliminating the waste stream, crystallizing the waste solids and recycling the resulting water; usually such ZLD sites do not have the option of deep-well disposal on their lease and therefore choose this option. For these sites water consumption can be lower than 0.2 barrels of water per barrel of bitumen produced.**

CSS PRODUCTION

Established 25 years ago, the third largest method of oil sands production, CSS, has benchmarked reductions in water intensity although GHG emissions per barrel have increased, mostly in the past decade.

Energy Consumption and GHG Emissions

Analyzing the annual average CSOR for each year of CSS production from the mid-1980s shows a slight increase in the energy required to produce bitumen; today's average ratio is about 3.6 compared with ratios of around 3.2 in earlier years of commercial CSS production. For the first 15-plus years the annual average CSORs stayed relatively constant between 3.2 and 3.3. Over the past six years the CSOR has increased to 3.6. This change equates to a 12 percent increase in producing a barrel of bitumen with CSS, or a 6 percent increase on well-to-retail pump basis (see Figure 7). *** It is important to note that with CSS the steam is not the same quality as for SAGD—it is higher pressure and wet (containing both water and vapor). Therefore care must be taken when comparing absolute CSORs between the SAGD and CSS processes, as they are not necessarily equivalent on an energy input basis.

The CSS projects are more mature plays than SAGD, and over time the amount of energy required to produce a barrel of bitumen is increasing. However, with the deployment of new techniques the trend of increasing energy consumption can be slowed. For instance Imperial Oil Cold Lake has a cumulative steam-oil ratio of about 3.3—notably lower than the average of other CSS operations, which are about 4.5. Furthermore the Imperial CSOR has remained relatively constant over the past eight years. An important driver of the lower energy use per barrel for this operation has been the combination of a relatively good quality reservoir and the application of advanced reservoir modeling techniques coupled with the implementation of followup recovery technologies.

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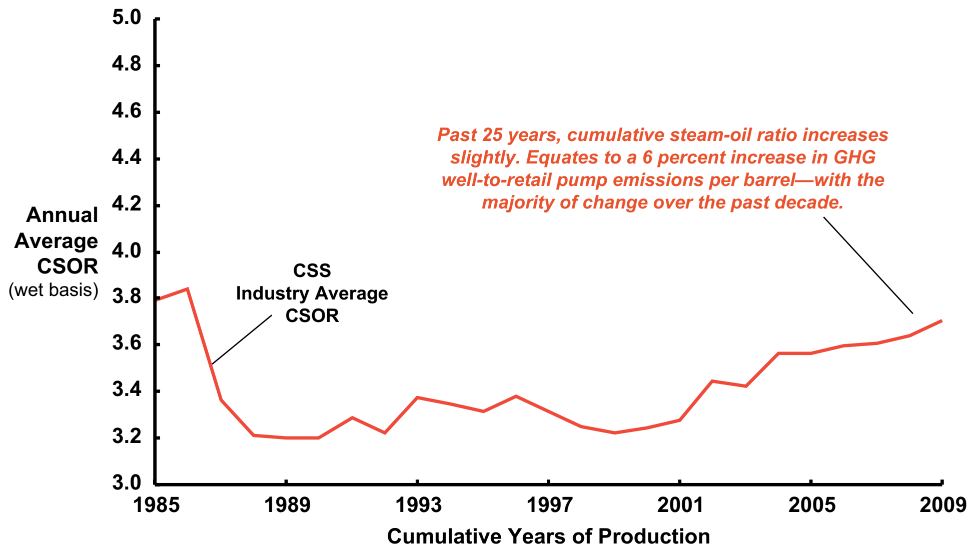
*Assumes SOR of 3.

**Assumes SOR of 3.

***The production-weighted annual average CSOR was calculated across all CSS projects. The average CSOR between years three and six was compared with the average CSOR in the past four years. The GHG emissions do not account for electricity cogeneration.

Figure 7

CSS Projects: Progression of Cumulative Steam-to-oil Ratio



Source: ERCB, IHS.
Notes: Projects included in average are Imperial Oil Cold Lake (1985), CNRL Primrose/Wolf Lake (1985), and Shell Canada Peace River (1996). The production-weighted annual average CSOR was calculated across all CSS projects. The average CSOR between years three and six was compared with the average CSOR in the past four years.
01212-3

Water Consumption

Originally CSS operations used as much as three barrels of fresh water per barrel of bitumen produced, all from fresh surface water sources. In the early 1990s new practices for storing produced water and using brackish water were adopted which reduced water demand.

Currently net water use per barrel averages about 0.6 barrels of fresh water per barrel of bitumen. About 10 percent of the water consumed comes from brackish sources. For the past five years over 95 percent of the produced water has been recycled.*

*Data for Imperial Cold Lake operation only, about 70 percent of total CSS production.

PART III: FUTURE TECHNOLOGY DRIVERS FOR OIL SANDS

Discovery consists of seeing what everybody has seen and thinking what nobody has thought.

–Albert von Szent-Gyorgy

The emergence of oil sands as a commercially competitive resource is the result of innovation. Challenges remain, such as reducing the environmental footprint of oil sands production. This section reviews the breadth of innovation being applied within the industry to further improve the efficiency of converting the oil sands resource into a barrel of bitumen or SCO, along with other factors with the potential to push back on future improvements. The challenge is to relieve the environmental intensity while maintaining or improving the economic viability of oil sands production.

THE DYNAMICS OF OIL SANDS RESERVOIR QUALITY

It is important to recognize that external factors are apt to push back on part of the technical gains described in this section. The first generation oil sands projects selected the very best parts of the oil sands deposit, with characteristics that could provide the most profitable recovery. For mining projects the first operators picked locations with oil sands that were close to surface and rich with bitumen. The next phase of mining projects generally involves lower quality resources (see Figure 8).

For the remaining economically recoverable in-situ oil sands resource the trend is also toward lower quality reservoirs. However, the in-situ reserves are bigger than mining, measuring 135 billion barrels, or enough bitumen to sustain production levels of 4 mbd for close to 100 years.* With a resource this immense, there will surely be a mix of higher and lower qualities reservoirs developed over the coming decades. However, considering the combination of aging first generation projects and the tendency for the best parts of the reservoir to be developed first, a general future trend toward lower-quality reservoirs is expected.

Considering the effect of lower reservoir quality for new mining and in-situ projects, if all other things are equal, the average energy consumption per barrel produced would increase. However, the critical question is, will all things be the same? Technology offers the chance to offset this trend to varying degrees.

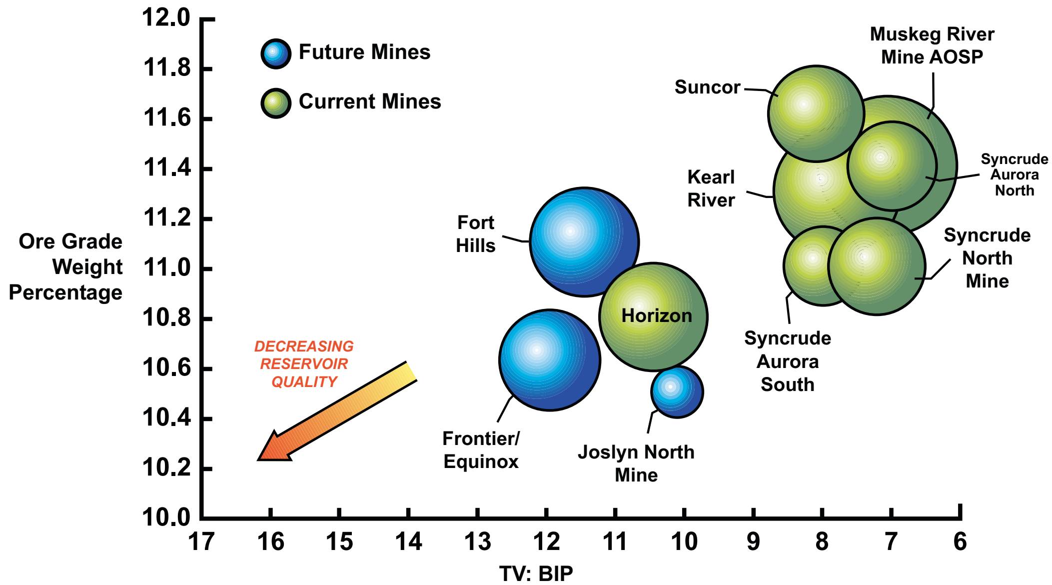
NEW TECHNOLOGY’S POTENTIAL TO FURTHER IMPROVE ENVIRONMENTAL PERFORMANCE

A wide range of technologies is under development in the oil sands. Not all of the technologies highlighted here will become commercial; many face significant technical and commercial challenges. However, the process of innovation and experimentation is likely to help improve the efficiency of converting the oil sands resource into a barrel of bitumen

*Alberta Energy Reserves 2009 and Supply/Demand Outlook 2010-2019, Alberta ERCB.

Figure 8

Changing Reservoir Quality: Mining Projects



Source: IHS CERA.
Data sources: Oil Sands Review August 2010, & Macquarie Securities and companies websites, investor materials.
Notes: Frontier and Equinox are based on high estimate of recoverable reserves.
00807-1_0510

or SCO over time—decreasing GHG emissions intensity, natural gas demand, and water intensity. The potential benefits quantified here do not consider the possible effects from lower reservoir quality.

GHG Emission Intensity

One of the key pressure points in oil sands developments is GHG emissions. Over the next two decades there will likely be two main methods of reducing emissions per barrel produced—one is to increase the energy efficiency of oil sands production, the other is CCS. Longer term, radically new methods of producing oil sands or generating steam more efficiently could take hold.

Evolutionary Methods: Improving Efficiency

Through a process of continuous improvement, down-hole production, mining extraction, and surface facilities will evolve. The incentive to reduce energy use is large; reducing energy consumption notably improves both oil sands economics and reduces GHG emissions—a win-win scenario. Over the next two decades potential well-to-retail pump GHG intensity reductions of around 5 percent for mining and 5 to 20 percent for in-situ production are possible.

See the box “Evolutionary Mining and In-situ Technologies” for more details on the technologies that could further reduce GHG emissions for oil sands production.

Evolutionary Mining and In-situ Technologies

Mining and Upgrading Operations—5 Percent GHG Intensity Reduction (well-to-retail pump)

Although mining is the most established oil sands recovery technology, more environmental improvements are expected. Potential energy-saving improvements include

- **Improved extraction.** The newest phases of mining projects are deploying more efficient variations of the asphaltenes extraction process first used in the AOSP phase 1. For mining and upgrading operations this technology is projected to reduce the emissions per barrel a further 2.5 percent (well-to-retail pump).
- **Heat integration.** Energy savings from increasing the heat recovery are probable. The goal is to recycle and recover more of the energy from the hot water postextraction, instead of sending the valuable heat directly to tailings ponds.
- **Mobile crushing units.** Another innovation is to use mobile crushing units to prepare the ore and bitumen mixture for transportation via pipeline at the mine face, instead of using large trucks; by eliminating the trucks, energy is saved. Commercial-scale trials have been under way for over three years and have led to changes in crusher designs. However, no operation has yet announced a large-scale transition to this technology. By eliminating most of the mining trucks, mining emissions per barrel from upgrading and mining operations could be reduced by 2.5 percent (well-to-retail pump).[1]

In-situ Production—5 to 20 Percent GHG Intensity (well-to-retail pump)

Improvements to in-situ recovery have the potential to make a noteworthy dent in GHG emissions per barrel produced.

- **Improved efficiency.** Today's in-situ production methods have the potential to reduce GHG emissions per barrel by 5 to 10 percent (well-to-retail pump). Improvements now emerging that help support these reductions include more robust electrical submersible pumps (able to better withstand the harsh wellbore conditions), in-fill wells, improved reliability, more heat integration in steam facilities, more advanced reservoir modeling and management (for instance, improving steam chamber optimization), and the potential for even lower-pressure operations.
- **Hybrid solvent-steam technologies.** Now undergoing trials in both SAGD and CSS operations, these methods inject solvent and steam into the reservoir. These techniques have the potential to reduce GHG emissions per barrel by more than 10 percent (well-to-retail pump). Solvent-aided SAGD is being used in some SAGD wells at the Cenovus/Conoco Phillips Christina Lake operation. Initial results are impressive. With only a minimal amount of solvent makeup required (0.05 barrels of butane per barrel of bitumen), a 30 percent increase in the production rate has been recorded—reducing both the steam-oil ratio and the GHG emissions per barrel of bitumen produced.[2]

  Solvent addition has also been successful in the CSS process at Cold Lake. Imperial Oil has now entered the commercial phase of solvent addition after two successful pilot cycles. Imperial's Liquid Addition to Steam to Enhance Recovery (LASER) process injects 3 to 8 percent diluent with the steam, and a 25 percent reduction in GHG emissions per barrel produced has been recorded.[3]

Evolutionary Mining and In-situ Technologies (continued)

Solvents have potential; however, the key to industrywide adoption will hinge on economics. To work economically, solvent use must be minimized—it is an expensive additive. The recovery must be maximized—most of the solvent injected into the reservoir needs to be recovered and reused—and in some field trials solvent recovery has been a challenge. On Suncor's Firebag pilot, just 8 to 41 percent of the solvent injected was recovered.[4] Finally, operators need to acquire solvent supplies at reasonable prices. If solvent technologies are adopted widely, this could lead to supply shortages, higher solvent prices, and more pressure on solvent economics.

1. The AOSP project (starting up in 2010) and the Imperial Kearl mining project (now under construction) are both deploying lower-energy variations of the AOSP phase 1 paraffinic froth treatment process. This process reinjects a fraction of the asphaltenes in the bitumen. Shell Canada's 2006 Sustainability Report states that the new, lower energy paraffinic froth treatment technique is expected to reduce energy use per barrel extracted by 10 percent, or 2. 5 percent well-to-retail pump, for mining and upgrading operations.
2. Source: Cenovus Presentation, Barclays Capital 2010 CEO Energy-Power Conference, September 16, 2010.
3. Imperial Presentation, Responsible Development of Canada's Oil Sands, Toronto Board of Trade, May 26, 2010 and ERCB report on LASER, April 16, 2010.
4. Source: ERCB, operator progress reports, Athabasca Suncor Firebag, April 30, 2008.

New Production Methods

Longer term, completely new methods of producing oil sands offer the possibility of greater reductions in GHG emissions per barrel produced. In-situ offers the most potential for revolutionary new production methods, as many methods are under development. Some new production techniques use alternatives to steam for mobilizing the bitumen including warm solvents, electricity, and even creating a fire within the reservoir.

Although the potential environmental benefits from these methods are still somewhat uncertain, considering the spectrum of new methods under development GHG emissions intensity reductions in the range of 20 percent or greater are possible (well-to-retail pump).

See Table 3 in the next section for specific examples of potential new oil sands production techniques and benefits.

Carbon Capture and Storage

In the oil sands the lowest-cost CO_2 capture opportunity is at the upgrader; at either the hydrogen plant or the gasifer. Capturing CO_2 at the upgrader hydrogen plant reduces GHG emissions per barrel by between 11 to 14 percent (well-to-retail pump).*

Implementing carbon capture and storage (CCS) increases capital and operating costs substantially. Capture and storage of CO_2 at the hydrogen plant is estimated to cost between \$500 and \$700 million for a 100,000 barrels per day upgrading facility, and equipping a

*IHS CERA assumes that parasitic load from the CCS equipment increases energy use by about 30 percent, thus decreasing the impact of CO_2 capture. For the hydrogen plant retrofit we assume that after parasitic losses are considered, 40 percent of the emissions associated with the upgrading portion of the value chain are captured with CCS.

gasification plant for CCS is likely to exceed $1 billion, in addition to the $1.5–$2 billion cost of building the plant. Translating these capital costs into dollars per ton of GHG abatement costs suggests that CO_2 prices (or taxes) would need to exceed $50 per metric ton of CO_2 for capture at the hydrogen plant and nearly $100 per metric ton of CO_2 for CCS on a gasification plant to economically justify the additional expenses. Some studies find even greater carbon capture costs—in excess of $150 per ton.

Longer term, capture of postcombustion CO_2 emissions in oil sands provides the possibility of reducing emissions beyond the upgrader. However, at present capture of postcombustion GHG emissions (which are low pressure and dilute) is considerably more expensive (both capital and operating costs are higher). Significant energy and equipment are required to separate and compress the CO_2, which makes the process costly and, depending on the power generation source used for capture, reduces the net GHG emissions benefit of the abatement.

Although costs are currently high and in the medium term wide-scale of CCS seems unlikely, globally and across many industries research into CCS is under way. Over a longer time horizon and through these efforts, we expect the cost of CCS to decline. In total the Alberta and Canadian federal governments have placed C$3 billion of investment in demonstration projects aimed at proving up the carbon capture technologies from both technical and economic perspectives. The effort remains a linchpin in the government's efforts to curtail CO_2 emissions from the oil sands industry and other industries in Alberta over the longer term. With government support, in the next decade it is probable that at least one CCS project will be operating in the oil sands. See the box "CCS Technologies and Projects" for details.

Reducing Natural Gas Demand

Natural gas is the primary fuel used for steam generation in oil sands processes. Using less natural gas lowers costs and reduces GHG emissions. Oil sands currently account for just over 20 percent of Canadian natural gas demand. Under a moderate oil sands growth scenario this could increase to 25 percent, and under a "stretch case" scenario this could grow to 40 percent of Canadian gas demand by 2035.*

Periods of high gas prices have led to the pursuit of alternative fuels such as gasifying petroleum coke or bitumen bottoms (by-products of oil sands upgrading) or burning a portion of the produced bitumen to raise steam. But today the industry has moved into a new era of expanding domestic gas supply and low gas prices. The "shale gale" is the result of a technological breakthrough in the commercial exploitation of massive shale gas deposits in North America, and this has changed expectations about the future cost profile of North American natural gas (see the box "Natural Gas Raises the Bar for Competing Fuels"). With expectations of low natural gas prices, the economic bar that alternative fuels must overcome to compete with natural gas is high. Using bitumen (or by-products) for fuel is not only challenged on the economic front, it is also tested on environmental grounds, as options that use bitumen or its by-products generate about double the GHG emissions

*The high growth scenario is a stretch case for oil sands growth, with production of 6.3 mbd by 2035. The moderate growth case assumes oil sands production of 3.1 mbd by 2035.

CCS Technologies and Projects

Oil Sands Upgrader CCS—Potential of 11 to 14 Percent Reduction in GHG Intensity (well-to-retail pump)

There are two CCS projects under consideration for oil sands upgraders, both in the Edmonton area. Edmonton is home to 25 percent of oil sands upgrading capacity—the remainder is more than 400 kilometers (km) away, near Fort McMurray.[1] One CCS project is in the planning phases, while the other is at a conceptual stage. Both projects have sizable financial commitments from the Alberta government.[2]

Beyond the Edmonton upgraders, the challenges of CCS are more formidable. There are no geologically suitable carbon storage locations in the Fort McMurray region—therefore a pipeline to transport CO_2 from the oil sands region to more suitable storage locations (200 to 400 km away) is required. Central Alberta provides a plethora of opportunities for using CO_2 for enhanced oil recovery (EOR), a method to improve recoveries of conventional oil. Although there are numerous large CO_2 sources in central Alberta, which are much closer to the potential EOR opportunities than the Fort McMurray upgraders, the construction of a CO_2 pipeline is not outside of the realm of possibly. A pipeline project currently being advanced aims to transport CO_2 from the Fort McMurray region; transportation of GHG emissions over this distance has been estimated to add in the range of $10 to $20 per metric ton of CO_2 to the cost of CCS.[3]

CCS from Dilute Postcombustion Exhaust Streams

Postcombustion exhaust streams are dilute (only 5–15 percent CO_2) and low pressure. Even with a hypothetical high cost of carbon, the economics are unfavorable because of the high capital, operations, and energy costs of CCS for dilute streams. Numerous technologies are now under development with potential to lower both the cost and the energy required for capture and compression, but no clear winner exists today. These technologies include

- **Postcombustion recovery using new stripping agents.** Today mine scrubbers can capture the dilute combustion streams technically, but high parasitic losses associated with regeneration of the amine stripping agent make for questionable economics. Current research is under way to develop new stripping agents, such as chilled ammonia or advanced amines, that could be more efficient and potentially more cost effective.
- **Oxy-fuel combustion.** A precombustion process that uses pure oxygen for combustion instead of air results in a combustion stream that is 95 percent or more CO_2—obviously much more amenable to separation than a dilute stream. The main detractor for this option is the requirement for a capital- and energy-intensive air separation plant to produce oxygen. In 2012 a test of oxy-fuel combustion is planned for an in-situ oil sands site; this is a joint industry and government initiative that is testing capture only—the project does not include CO_2 storage.[4]
- **Integrated gasification combined-cycle.** This is a variation of traditional gasification. Instead of air, this process uses oxygen as a combustion medium that produces a more pure CO_2 stream; but this is at the expense of large parasitic energy losses.
- **Chemical looping.** This process involves a reactor that uses an oxygen carrier to create a postcombustion stream of pure CO_2. This process is now being demonstrated at pilot scale.

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1. Two upgraders near Edmonton are AOSP phase 1 and phase 2. Phase 2 is currently under construction and slated for start-up in early 2011.
2. The AOSP CCS project, called Quest, has C$745 million of funding under the Alberta government's C$2 billion dollar Carbon Capture and Storage Fund. The Northwest upgrader, which has not yet commenced construction, has signed a letter of intent for a CCS project valued at C$495 million.
3. http://www.ico2n.com/what-is-ccs/ccs-economics/transport-economics.
4. This project is part of the CO_2 Capture project, a partnership of energy companies, academia, and government.

Natural Gas Raises the Bar for Competing Fuels

The North American natural gas industry has undergone a metamorphosis in the past five years. IHS CERA calls this the shale gale.

Around the middle of the past decade natural gas supplies seemed under severe pressure from declining North American conventional gas supplies and high and volatile pricing, aggravated by a series of severe hurricanes in the Gulf of Mexico. Common expectations for future natural gas prices were $8–10 per million British thermal units (MMBtu)—a level at which alternatives become attractive in the oil sands, especially in-situ projects. Concerns about gas supply at that time led to a build of regasification capacity in the United States for an expected wave of liquefied natural gas imports.

How times have changed. Unconventional gas in the form of shale gas has boosted supplies, driven by major technological advances in directional drilling and fracturing technologies. There is now a longer-term prospect that almost 15 billion cubic feet per day (Bcf) of US base-load regasification facilities will lie idle for a very long time.

Unconventional gas resources have been known for a long time, but only with recent technology advances can they now be exploited economically. Indeed most current shale plays are more economical than conventional gas plays: hence the downward pressure on natural gas prices in recent years as almost 10 Bcf per day, or almost 20 percent of US gas supply, has come into production since 1997. These shale plays are common in North America; they extend all the way from Texas along the Appalachians to New York and continue into eastern Canada. In addition at least two large economic shale plays have been discovered in Alberta and British Columbia—the Montney play and the Horn River play.

The result is that the outlook for natural gas supply and price has changed dramatically in recent years, with long-term gas prices now estimated to remain in the $5–6 per MMBtu range.

compared with natural gas. High GHG emissions and the shale gale have diminished the likelihood of alternatives' displacing natural gas in the coming decades.

The outlook for low natural gas prices has also raised the economic bar for some new oil sands production methods. For example use of new hybrid solvent-steam technologies for in-situ production results in extra costs for purchasing, handling, and recycling solvents. This is offset by reduced demands for natural gas that result from lower SORs when using solvents. However, if the cost of natural gas is low, the economics for hybrid solvent are more challenged as the economic advantage of reducing natural gas demand is diminished. A similar problem exists for other production methods that do not use natural gas.

Using zero carbon–emitting technologies as an alternative to natural gas still holds appeal. Small nuclear plants have the highest potential to achieve the vision of no carbon emissions for oil sands production. But even with the most optimistic development scenario and assuming the technology is both economic and practical, deployment is more than 20 years away.

Reducing Water Consumption

For both oil sands mining and in-situ operations, the volume of water required to produce a barrel of bitumen is projected to decline.

Mining Water

There is potential for incremental declines in mining water intensity. For instance, the next phase of mining projects are deploying a more efficient oil extraction and froth treatment process expected to reduce water consumption per barrel by 10 percent.*

Still, the biggest prospect for reducing water consumption in mining operations comes from liberating the water trapped in the tailings. About four barrels of fresh water are consumed for each barrel of bitumen extracted. This water is trapped in the tailings ponds, tightly bonded with fine sands. Two new tailings technologies have been announced in the past year, and both offer the potential to recover some of the water from tailings. Suncor has introduced Tailings Reduction Operations and Shell has also announced a new tailings treatment process. However, even if the tailings water is recovered, it must still be treated and cleaned before it can be reused for mining extraction. Today, water-treatment technologies for cleaning the water exist, but they are expensive. An alternative to reusing the water in the mining operations is to use the tailings water for in-situ production; here the processes can handle less pure water.

In the longer term (20 years and beyond) the future for mining could lie in nonaqueous extraction methods. At present these techniques are in the research and developmental stage.

In-situ Water

The biggest driver for reducing water demand for in-situ production is to lower the SOR—the same driver as with GHG emissions. With improved efficiency in the existing in-situ processes, SOR (and thus water demand) could be reduced by 10 to 20 percent per barrel produced. If hybrid steam solvents are used for in-situ production, a further 25 percent or more reduction in water demand is possible.

Another way to reduce water demand is to further improve the amount of produced water that is recycled. Already some new sites are deploying the combination of evaporators and drum boilers, or ZLD systems—here recycle rates between 90 and 95 percent are achievable. However, for sites already installed with the more established OTSG technology, there is still potential for further improvements. For instance a new technique is being trialed that could theoretically reduce OTSG net water use from 0.9 barrels of water per barrel of bitumen produced to 0.3—equivalent to a 90 percent recycle rate.**

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*The AOSP project (starting up in 2010) and the Imperial Kearl mining project (now under construction) are both deploying lower-energy variations of the AOSP phase 1 paraffinic froth treatment process, which is expected to save energy and water for extraction.

**Assumes SOR of 3. The technique involves rerunning the OTSG blowdown or wastewater stream through a second boiler, generating more steam and decreasing the size of the blowdown.

Over the past decade the industry has shifted from consuming mostly surface and fresh groundwater to using increasing volumes of brackish water. Ultimately reducing water consumption and increasing volumes of brackish water is a trade-off between energy use and fresh water consumption. The use of brackish water generally results in higher water treatment costs, greater energy consumption (as much as 10 to 30 percent more energy for the water treatment step), and more waste.* Although using larger volumes of brackish water typically requires more energy, it's important to keep the energy consumption in perspective—more than 90 percent of the energy consumed in producing a barrel of bitumen comes from generating steam to inject into the reservoir, not from water treatment.

In the next 15 to 20 years a number of the revolutionary new production methods, including in-situ combustion and warm solvents, offer the possibly of producing in-situ oil sands with no water use (see Table 3 for details on revolutionary new production technologies).

REVOLUTIONARY PRODUCTION TECHNOLOGIES

This section highlights a spectrum of completely new in-situ oil sands production techniques that are in various phases of development. The technologies highlighted in Table 3 are not exhaustive. All of the technologies listed must still achieve commercialization—overcoming economic, technical, and environmental hurdles. The potential environmental benefits from these methods are still somewhat uncertain, however. Considering the number of ideas under development, some of these ideas are likely to take hold, helping to decrease the environmental footprint of production while unlocking new parts of the oil sands deposit—bitumen that is currently not recoverable (see the box "Unlocking More of the Massive Oil Sands Resource").

*The exception to this general rule is in shifting steam generation technology from OTSG/lime water treatment to the evaporator/drum boiler combination. With the higher efficiency of drum boilers, the overall energy consumption can be reduced.

Table 3

Examples of Revolutionary In-situ Technologies

Technology	Potential to Unlock New Parts of the Oil Sands Deposit	Status
In-situ combustion technology produces bitumen using heat generated within the reservoir from combustion—effectively burning about 10 percent of the bitumen to recover the rest. The heat from combustion reduces the bitumen's viscosity and mobilizes the bitumen. Due to the combustion, the product is partly upgraded. After initial start-up, the process does not require an external source of heat to mobilize the bitumen. Potential benefits over today's SAGD include low water demands and lower GHG emissions intensity. Examples of firms pursuing variants of this process include Petrobank's THAI™ with a field pilot under way—this project is already producing bitumen—and Petrobank has four other projects planned. Athabasca Oil Sands Corporation (formerly Excelsior Energy) is developing a second variant called combustion overhead gravity drainage—a pilot is planned for 2011. In-situ combustion is also being researched at Calgary Center for Innovative Technology at the University of Calgary.	Reservoirs that are too thin	Field pilot
Pure solvent technology involves injection of pure solvents (not steam) to mobilize the bitumen. The solvents are injected warm and result in partial deasphalting of the bitumen, creating a lighter product. Potential benefits include notably lower GHG emissions and no requirement for water. The process could require significant volumes of solvent. An example of a firm pursuing this concept is N-Solv Corporation. The N-Solv process is low energy; it operates at 40°C (much lower than current in-situ methods which are often over 200 °C).	Access reservoirs without cap rock, too thin, with low pressure gas cap, and at intermediate depth	Conceptual
Electric heating processes, energy is transferred to the bitumen by electricity. Depending on the electrical current applied, the energy can be transferred numerous ways—dielectric heating, resistive heating, or inductive heating. Some methods require water (to transfer the heat). One potential sweet spot for this technology is areas of the oil sands deposit that are too deep for mining but too shallow for thermal in-situ processes.	Access intermediate depth reservoirs, insufficient cap rock, and low pressure gas cap, and carbonates	2010 field tests planned

Table 3

Examples of Revolutionarily In-situ Technologies (continued)

Technology	Potential to Unlock New Parts of the Oil Sands Deposit	Status
Electric heating processes (continued). It is still uncertain if electric heating technology can provide lower GHG intensity compared with today's SAGD. Although the reservoir temperature is notably lower (potentially less than 100°C), depending on the fuel used to generate electricity, the GHG intensity could still be comparable with today's SAGD. Depending on the technique, water use should be lower than today's SAGD. A number of electric heating processes are under development, one method is being developed by ET Energy. In the ET process, electrodes are arranged in a close-knit grid with extraction wells at the center of each grid. A second technique is being developed by Siemens—it uses electric heaters. The Siemens heaters could possibly be combined with SAGD in a hybrid process called EM-SAGD. Shell has also conducted research and pilots using electric heating concepts. Recently, Athabasca Oil Sands Corporation announced an electric technology called thermal assisted gravity drainage—they plan to pilot the use of electric heat for bitumen extraction in the carbonate reservoirs.		
Hybrid solvent extraction and electric heating technology combines the electric heating and pure solvent extraction methods. The process is low energy, operating at about 50°C, and does not require water. Potential benefits over today's SAGD include lower GHG emissions and no water requirement. The process could need significant volumes of solvent. This technology is being developed in partnership between operators and technology providers including Nexen, Laricina Energy, Suncor Energy, and Harris Corporation. This technique is called enhanced solvent extraction incorporating electromagnetic heating.	Access reservoirs without cap rock, too thin, with low pressure gas cap, and intermediate depth	Field pilot planned (2+ years)
Underground tunnels technique targets reducing the surface disturbance from development while increasing operating and thermal efficiency. The tunnel includes a main shaft for surface access, combined with branching tunnels which are drilled beneath the target formation. Conventional SAGD wells are drilled from the tunnel up into the formation. With this approach, the oil is drained downward from the formation and therefore operations can be conducted at very low pressures—leading to numerous process efficiencies. Further the gathering system is not exposed to the atmosphere, which reduces thermal losses. This method was used for AOSTRA's first SAGD pilot.	Access carbonate reservoirs, intermediate and shallow depth, and areas with surface restrictions	Conceptual

Table 3

Examples of Revolutionarily In-situ Technologies (continued)

Technology	Potential to Unlock New Parts of the Oil Sands Deposit	Status
Underground tunnels (continued). Advantages are expected to include lower SORs and correspondingly lower water and energy requirements. Land disturbance should be significantly less. This technology is currently being developed by OSUM Oil Sands Corporation. OSUM is proposing this method for recovering bitumen from the carbonate reservoirs.		
Gas cap combustion is a new method being tested to produce bitumen that is in communication with a low pressure gas zone. Air is injected into the gas reservoir, and a combustion zone is initiated; the resulting heat is transferred to the bitumen below, mobilizing it. Cenovus plans to pilot test this concept in 2012.*	Communication with low pressure gas cap	Field pilot planned (2012)

Source: IHS CERA.
*Cenovus Presentation, Barclay Capital 2010 CEO Energy-Power Conference, September 16, 2010.

Unlocking More of the Massive Oil Sands Resource

Using today's surface mining, SAGD, and CSS methods, only 10 percent of the bitumen-in-place is expected to be recovered. A study by the Petroleum Technology Alliance Canada (PTAC) estimated that more than half of the bitumen-in-place (1 trillion barrels) is not accessible at all with current production methods.* The following list highlights the reservoir types that currently cannot be produced. The revolutionary new oil sands production technologies under development—shown in Table 3—have the potential to extract bitumen from these more challenging reservoir types.

- **Thin reservoir.** About 410 billion barrels of bitumen-in-place is found in sand deposits that are too thin for economic SAGD production (less than 10 meters [m] in thickness); the thin reservoirs result in costly heat loss into other formations. Moreover it is technically difficult to "fit" the stacked SAGD well pairs into these thin pay zones.
- **Carbonate rock.** About 477 billion barrels of bitumen-in-place is found in carbonate rocks or limestone, not sand. The carbonate rocks have discontinuities and fractures; these can make the containment of steam a challenge, but these fractures can also provide benefits, increasing the porosity and permeability of the reservoir. A number of pilots ran in the 1980s with varied success, but now this resource is being revisited, with a number of new pilots planned.
- **Insufficient cap rock.** Around 36 billion barrels of bitumen-in-place is in sand deposits that lack an overlying cap rock that seals the top of the deposit. Without a cap rock the steam escapes and transfers energy to non–bitumen-bearing formations.
- **Intermediate depth.** About 28 billion barrels of bitumen-in-place are contained in pay zones that are too deep for mining and too shallow for thermal recovery (defined as oil sands at depths between 40 m to 75 m).
- **Communication with low pressure gas cap.** Around 14 billion barrels of bitumen-in-place are overlain and in communication with shallow gas reservoirs. This bitumen is difficult to produce with SAGD methods as the steam can escape to the low pressure gas zone above.

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*Source: *Expanding Heavy Oil and Oil Sands Resources While Mitigating GHG Emissions and Increasing Sustainability,* PTAC, May 2006.

PART IV: WHERE IS THE INDUSTRY HEADED?

New ideas in oil sands extraction are not in short supply, and ongoing improvements from deploying new technologies are likely. But what do these individual improvements mean for the industry as a whole? How can the successful deployment of new technologies (or tweaks to existing processes) change the cumulative impacts from the oil sands industry over the next two decades and beyond? Where will future innovations come from and who will fund this research?

NEW TECHNOLOGY: SLOW RAMP-UP TO INDUSTRYWIDE BENEFITS

Economic evolutionary technologies that can be applied to existing oil sands facilities are often rapidly adopted. The pace at which revolutionary technologies are adopted, however, is slower.

Even when revolutionary technologies can navigate the difficult and lengthy hurdles to commercialize the first facility (starting with initial success in the laboratory, then gaining access to an oil sands lease for a field pilot, then successfully raising hundreds of millions of dollars to fund the multiyear process of regulatory approval construction and operation of the pilot), there is a further time lag before the industry adopts these technologies and industrywide benefits become evident.

The most recent revolutionary development in oil sands extraction, SAGD, presents an example. After successful pilots in the mid-1980s, it took 15 more years before the first commercial project started and a further 5 years before the production from SAGD reached 5 percent of total oil sands production (see Figure 9). Thus it took more than 20 years to go from field pilot to having a substantive affect on the industry as a whole. Undoubtedly part of this was the result of a decade of relatively weak oil prices following the discovery of SAGD combined with the need for advancements in horizontal drilling—a technique that was only first introduced in its present form in the mid- to late 1980s.

The lag between the invention of a commercial technology and the realization of substantive environmental benefits is highlighted by one of the IHS CERA oil sands future scenarios—New Social Order.* In this scenario strong government policies limit GHG emissions, and oil sands growth is moderate, leveling off at around 3.1 mbd by 2020.**

In this scenario, a true stretch case for oils sands innovation, technology enables a paradigm shift for oil sands. Highlights of major innovations are

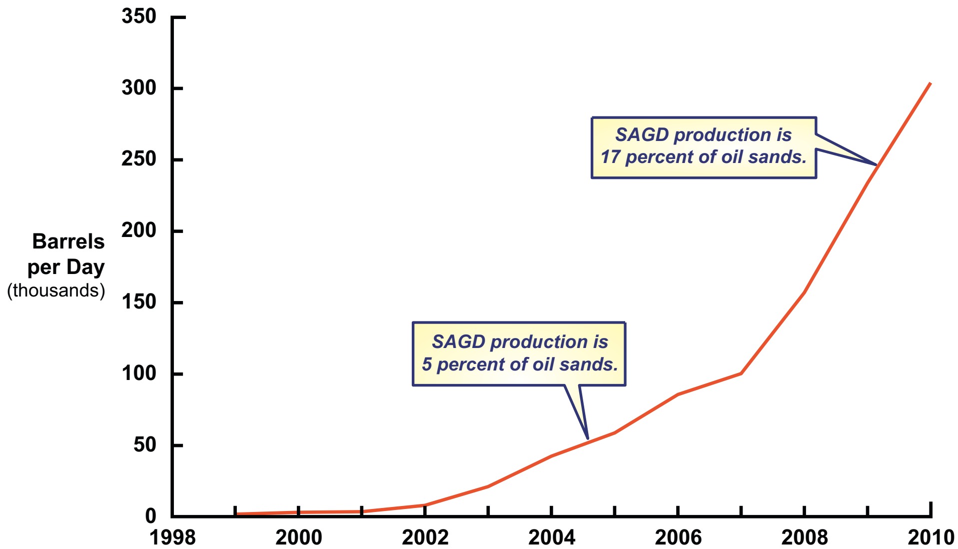
- **In 2020 the industry and government collaborate to fund the construction of a network of gathering pipelines to aggregate CO_2** and transport it via pipeline to Central Alberta for use in EOR projects.

*For more information on IHS CERA's future scenarios see the IHS CERA Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance.*

**A high price for emitting carbon is one factor driving innovation, but it is not the only one. By 2020 carbon costs reach $100 per metric ton (constant 2008 dollars).

Figure 9

SAGD Production Growth



Source: IHS CERA.
Note: 2010 average production January to May 2010, Athabasca deposit production only.
01006-6

- **By 2035 more than half of all upgraders capture CO_2 (at the hydrogen plant or gasifier).** Economic postcombustion technologies on upstream facilities are not developed in this time frame.

- **New, low-emission, revolutionary, in-situ extraction technologies just start to be deployed commercially post-2030.**

- **Small nuclear plants are used on the first SAGD site as an alternative to natural gas for steam and electricity generation in 2030.**

- **By 2035 the aggregate SOR for SAGD is reduced to 1.8 though a combination of ongoing efficiency improvements and successful industrywide implementation of hybrid steam-solvent technologies.** Technology effectively dampens the effects of lower reservoir quality and provides major gains in SAGD efficiency.

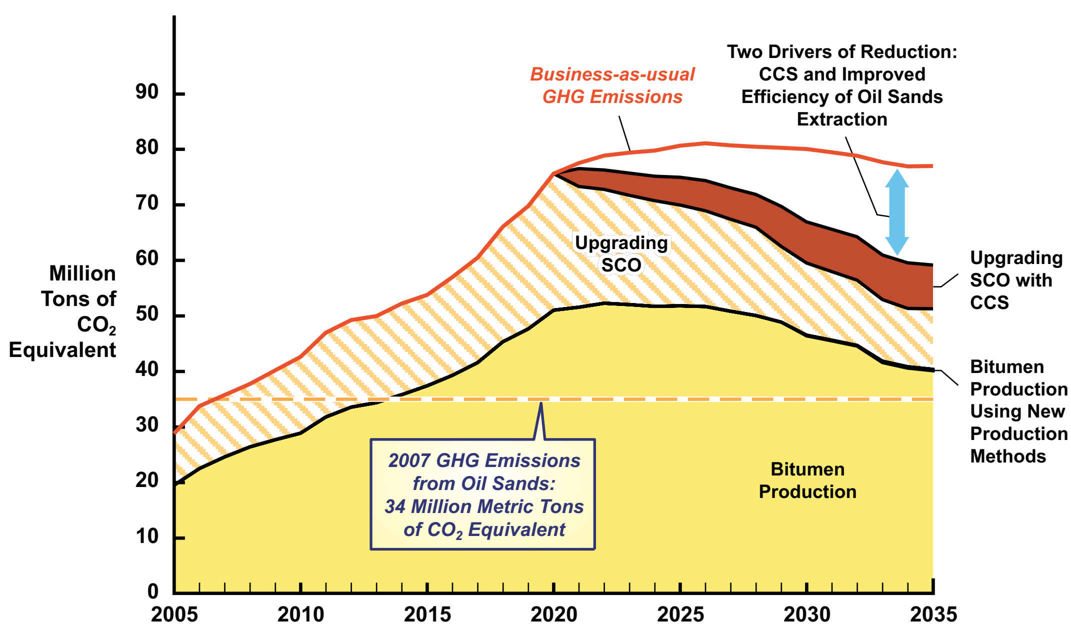
- **By 2020 new methods allow mining operations to reduce GHG emissions by 10 percent compared with 2010 levels.** These gains are maintained despite lower-quality mining reservoirs.

How does this aggressive technology scenario affect the GHG emissions from oil sands upgrading and extraction? Emissions grow in sync with production, both nearly doubling from the current level by 2020 when oil sands growth plateaus. Post-2020 major innovations start to chip away at the aggregate emissions. Over the next 15 years industrywide emissions from producing and upgrading oil sands are down 23 percent from peak, and GHG intensity per barrel produced is down even more—over 30 percent (see Figure 10). Nearly all of the GHG reductions stem from two areas: increased energy efficiency in oil sands extraction (two thirds of the improvement) and using CCS on oil sands upgraders (one third). By 2035 other, more revolutionary innovations are just starting to be deployed more widely—but they do not yet have a material impact on the industry in aggregate. Nuclear is deployed for 3 percent of the production in 2035, and low energy (nonsteam) in-situ extraction technologies also account for 3 percent. Now these newly commercial, revolutionary technologies are becoming established and setting the stage for major improvements over the following decades. In this, a stretch case for oil sands innovation, although the emissions per barrel decline significantly, oil sands production more than doubles, and aggregate emissions from oil sands still grow. Compared with today, emissions from oil sands grow from about 5 percent of Canada's emissions (40 million metric tons [mt] of CO_2-equivalent for 1.35 mbd of oil sands production) to about 10 percent by 2035 (60 mt of CO_2-equivalent for 3.1 mbd of oil sands production).

Although emissions grow, clearly extraction of any oil takes energy. Substituting oil sands supply for another source still results in emissions. For instance, producing 3.1 mbd of the average crude consumed in the United States results in GHG emissions of 44 mt of CO_2-equivalent.*

Figure 10

New Social Order Future Scenerio—Oil Sands GHG Emissions



Source: *Growth in the Canadian Oil Sands: Finding the New Balance*, New Social Order scenerio.
01006-8

*Emissions for production of the average crude consumed in the US (2005 baseline). See the IHS CERA Special Report *Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right.*

THE FUTURE OF RESEARCH AND DEVELOPMENT

Ongoing investment in research is critical to the future health of the oil sands industry—and the future could be lengthy. Just considering established reserves and assuming an oil sands production rate of 5 mbd, it would take more than 100 years to exhaust the currently recoverable resource. Consequently R&D should be a combination of both new breakthrough, revolutionary ideas that affect 20 years and beyond and the evolutionary improvements that shape both the short and the long term.

Who Should Invest in R&D?

This is not an either/or question. Both publicly funded and privately funded research is critical to the future health of the oil sands industry. Research funding is a multitiered process ranging from fundamental academic research to demonstration trials through to applied research and pilot plants. Most fundamental research occurs in universities and some government laboratories. Applied research is conducted mostly by private companies (both oil companies and the service sector) but also to some extent by government agencies.

Many potential breakthroughs will require relatively high-risk, low-probability fundamental research that is by definition very long term. Basic research is essential for creating the building blocks for new solutions—concepts with potential for applications across a spectrum of industries. Individual companies do not have the resources or incentives to conduct this type of broadly applicable research; government investment is required. Advancement of these fundamental building blocks could position the oil sands industry (as well as other industries) for radically new approaches in the long term; research in areas such as nanotechnology, photonics, and biological systems all have potential application for oil sands (see the box "Looking in the Crystal Ball").

Examples of Collaborative Public and Private Research

Investment is moving more into the realm of collaborative research. This strategy is preferable to operating in research silos. This not only avoids duplication of research and field pilot endeavors, it also leads to cross-fertilization and sharing of ideas. There are many encouraging signs of R&D collaboration within the oil sands industry—partnerships covering the spectrum of industry, academia, and government (both federal and provincial). The following list is not exhaustive but highlights some of the numerous initiatives under way:

- **Oil Sands Leadership Initiative** (OSLI). This is a collaborative research network between Conoco Phillips, Nexen, Statoil, Suncor Energy, and Total. The focus is to improve sustainability of oil sands development. Examples of current projects include research in synthetic biology and investment in sustainable communities.

- **Natural Sciences and Engineering Research Council of Canada (NSERC).** Research is a partnership between the Canadian government, industry, and academia. NSERC has a broad mandate to invest in research; specific oil sands research includes study of water quality for oil sands extraction and engineering fundamentals of extraction.

Looking in the Crystal Ball

The oil sands future is likely to be long. How could innovations in more broadly applicable fundamental research play a role over the very long term?

Nanotechnology. The manipulation of materials at the molecular level to create stronger, cheaper, and higher-performance materials, nanotechnology is already emerging from the laboratory to affect a range of commercial products. Ultimately nanotechnology could have an impact on many facets of oil sands extraction and processing, from the reservoir, water treatment, and reduction in oil viscosity to boiler designs, upgrading technologies, and improved recoveries of pollutants.

NanoAlberta is a provincially funded center for nanotechnology R&D and commercialization.

Biological engineering. Major advances in biotechnology and genomics in recent years are leading to renewed interest in biological solutions in resource industries and environmental remediation. These innovations could transform how oil sands are extracted and upgraded and could even destroy oil sands waste streams.

Application examples include bacteria that could eat the oil in the deposit, producing lighter hydrocarbons or even methane from the bitumen. Microbes could also upgrade the bitumen or destroy wastes. Microorganisms could consume wastes, eating CO_2 and turning it into valuable product such as food or fuel—a game changer compared to the prospect of long-term carbon storage.

Photonics. Using light in the application, examples include fiber optic telecommunications and medical lasers. Advancements in photonics could lead to improvements in oil sands observation and detection, allowing operators to more accurately visualize reservoir operations, optimize energy use, and maximize production.

- **Canadian Oil Sands Network for Research and Development (CONRAD).** The CONRAD research partnership involves about 30 organizations, including companies, government, and academia. The research focus is to advance oil sands technology.

- **Petroleum Technology Alliance Canada (PTAC).** This not-for-profit association facilities collaborative research in the energy sector. The current membership includes 26 oil and gas producers. PTAC conducts research oil sands as well as in the oil and gas sector overall.

- **CCEMC.** Under a government initiative, CCEME capital is raised by a levy on Alberta companies that emit more than a specified amount of GHG emissions.* In the first two years over C$120 million has been paid into the fund and will be invested collaboratively with industry and government on research into cleaner technologies.

- **Alberta Innovates—Energy and Environment Solutions (previously AERI).** Created recently as a central clearinghouse for publicly funded research within the province, historically its budget has been about C$16 million per year. Part of that is allocated to joint investments with industry on oil sands research.

*One compliance option is to pay the CCEMC fund C$15 for each ton of CO_2 emitted over baseline.

- **Carbon Capture and Storage Fund.** In 2010 the Alberta Department of Energy has approved four major CCS projects in Alberta for total funding of C$2 billion over four years.

- **The Innovative Energy Technology Program (IETP).** This program is administered by the Alberta Department of Energy. If fully subscribed, total spending by industry and government through IETP over more than eight years could exceed C$800 million, only part of which is focused on oil sands.

There is now a much broader acceptance within the industry and government that collaboration is beneficial—not only at the individual corporate level but also at the industry level. In an era of instant dissemination of information, a mishap at one operation can lead to a detrimental impact on the whole industry. The significance of this is not lost on the industry, as illustrated by an announcement by Shell about an environmental tailings reclamation technology. In its announcement, Shell reiterated that this technology would be made available at no cost to other industry producers—no fees, no royalties. Further to this announcement, other oil sands producers have publicized efforts to "join forces" and collaborate on advancing tailings technology development—pledging to remove both intellectual property and monetary barriers to sharing technology.*

CONCLUSIONS: ONGOING IMPROVEMENT CREATING BENEFITS

The industry has established a track record of ongoing, continuous improvement, leading to better economics and lower environmental intensity. The historical pattern of successful oil sands innovation has always been a two-pronged approach: ongoing improvements to the existing processes combined with the periodic breakthroughs. The breakthroughs have not been accidental but do tend to be unpredictable and have been the result of large, up-front capital investments over the long term. Most often the large investments required for these breakthroughs have been a combination of public and private funding. Current investment in the oil sands is continuing this trend.

In a global context oil sands is a high-cost but competitive oil resource. Its growing role in world oil markets owes much to this process of continuous innovation. Mining methods have incorporated more conventional truck and shovel mining techniques, hydrotransport, and lower-temperature extraction processes. All have boosted productivity while reducing unit costs. New in-situ techniques have been developed, including SAGD. Currently hybrid steam-solvent processes are poised to have an impact on both the productivity and costs of SAGD and CSS extraction processes.

There is a growing appreciation that collaboration among industry players is beneficial—both in increasing the speed of innovation and in sharing the effects of new technology on reducing industrywide environmental impacts. This should help to increase technology development and the possible pace of implementation across the industry. There is increasing recognition that stakeholders view oil sands in the aggregate rather than as individual projects.

*Companies are Syncrude, CNRL, Imperial Oil, Shell, Suncor Energy, Teck Resources, and Total.

Ongoing environmental and economic improvements in oil sands extraction and upgrading are likely, but not inevitable. Any benefits must resolve the countervailing challenges of decreasing reservoir quality and the requirement for new methods to meet both economic and environmental goals. Ongoing, consistent funding of research and development is required. Yet if history repeats itself, the industry will continue to make strides—potentially significant ones—toward increasing resource frugality. The seeds have already been planted in a plethora of new extraction processes being deployed at the pilot scale level. The potential for the future is a lower environmental footprint per barrel extracted.

REPORT PARTICIPANTS AND REVIEWERS

IHS CERA hosted a focus group meeting in Calgary (August 10, 2010) that provided an opportunity for oil sands stakeholders to discuss perspectives on the key issues related to oil sands technology. Additionally, a number of participants reviewed a draft version of this report. Participation in the focus group or review of the draft report does not reflect endorsement of the content of this report. IHS CERA is exclusively responsible for the content of this report.

Alberta Department of Energy

American Petroleum Institute—API

BP Canada

Canadian Association of Petroleum Producers—CAPP

Canadian Oil Sands Trust

Cenovus Energy Inc.

ConocoPhillips Company

Deborah Yedlin, Calgary Herald

Devon Energy Corporation

Energy and Environmental Solutions, Alberta Innovates

Energy Resources Conservation Board (Alberta)—ERCB

General Electric Company—GE

Imperial Oil Ltd.

In Situ Oil Sands Alliance—IOSA

Marathon Oil Corporation

Natural Resources Canada

Nexen Inc.

Pembina Institute

Petroleum Technology Alliance of Canada (PTAC)

Shell Canada

SilverBirch Energy Corporation

Statoil Canada Ltd.

Strategy West

Suncor Energy Inc.

Total E&P Canada Ltd.

TransCanada Corporation

University of Alberta

US Department of Energy

IHS CERA TEAM

David Hobbs, Chief Energy Strategist

David Hobbs, IHS CERA Chief Energy Strategist, is an expert in energy industry structure and strategies. He previously managed IHS CERA's energy research activities. Mr. Hobbs is a principal author of the major IHS CERA studies *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda,* a comprehensive examination of the impact of the changed natural gas supply outlook on energy markets, power generation technology choices, and the challenges in achieving a low-carbon future; *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosures* and *Modernizing Oil and Gas Disclosures,* comprehensive analyses of the problem of assessing oil and gas reserves and resulting proposed solutions; *"Recession Shock": The Impact of the Economic and Financial Crisis on the Oil Market,* a major IHS CERA assessment of the world economic crisis; and the IHS CERA Multiclient Study *Harnessing the Storm—Investment Challenges and the Future of the Oil Value Chain.* He was a project advisor to the IHS CERA Multiclient Study *Crossing the Divide: The Future of Clean Energy.*

Mr. Hobbs is IHS CERA's representative on the management board of the Global Energy Executive MBA program run jointly by the Haskayne School of Business and IHS CERA. He is also a member of the Scientific Advisory Board of the Fondazione Eni Enrico Mattei. Prior to joining IHS CERA Mr. Hobbs had two decades of experience in the international exploration and production business. He has directed projects in Asia, South America, North America, and the North Sea and has led major international investment and asset commercialization operations. Based in Cambridge, Massachusetts, Mr. Hobbs holds a degree from Imperial College.

James Burkhard, Managing Director

James Burkhard, Managing Director of IHS CERA's Global Oil Group, leads the team of IHS CERA experts that analyze and assess upstream and downstream market conditions and changes in the oil and gas industry's competitive environment. A foundation of this work is detailed short- and long-term outlooks for global crude oil and refined products markets that are integrated with outlooks for other energy sources, economic growth, geopolitics, and security. Mr. Burkhard's expertise covers geopolitics, industry dynamics, and global oil demand and supply trends.

Mr. Burkhard also leads the IHS CERA Global Energy Scenarios effort, which combines energy, economic, and security expertise across the IHS Insight businesses into a comprehensive, scenario-based framework for assessing and projecting global and regional energy market and industry dynamics. Previously he led the IHS CERA study *Dawn of a New Age: Global Energy Scenarios for Strategic Decision Making—The Energy Future to 2030,* which encompassed the oil, gas, and electricity sectors. He was also the director of the IHS CERA Multiclient Study *Potential versus Reality: West African Oil and Gas to 2020.* He is the coauthor of IHS CERA's respected *World Oil Watch,* which analyzes short- to medium-term developments in the oil market. In addition to leading IHS CERA's oil research, Mr. Burkhard served on the US National Petroleum Council (NPC) committee that provided recommendations on US oil and gas policy to the US Secretary of Energy. He led the team that developed demand-oriented recommendations that were published in the 2007 NPC report *Facing the Hard Truths About Energy.* Before joining IHS CERA Mr. Burkhard was a member of the United States Peace Corps in Niger, West Africa. He directed infrastructure projects to improve water availability and credit facilities. He was also a field operator for Rod Electric. Mr. Burkhard holds a BA from Hamline University and an MS from the School of Foreign Service at Georgetown University.

Jackie Forrest, Director

Jackie Forrest, IHS CERA Director, Global Oil, leads the research effort for the IHS CERA *Oil Sands Energy Dialogue*. Her expertise encompasses all aspects of petroleum evaluations, including refining, processing, upgrading, and products. She actively monitors emerging strategic trends related to oil sands, including capital projects, economics, policy, environment, and markets. She is the author of several IHS CERA Private Reports, including an investigation of US heavy crude supply and prices. Additional contributions to research include reports on the life-cycle emissions from crude oil, the impacts of low-carbon fuel standards, and the role of oil sands in US oil supply. Ms. Forrest was the IHS CERA project manager for the Multiclient Study *Growth in the Canadian Oil Sands: Finding the New Balance,* a comprehensive assessment of the benefits, risks, and issues associated with oil sands development. Before joining IHS CERA Ms. Forrest was a consultant in the oil industry, focusing on technical and economic evaluations of refining and oil sands projects. Ms. Forrest is a professional engineer and holds a degree from the University of Calgary and an MBA from Queens University.

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Roger J. Goodman, IHS CERA Senior Consultant, is an authority on natural gas, coal, and electricity market trends. He specializes in strategy, scenario planning, technology, marketing, and business development. For nearly 15 years Dr. Goodman was employed in a variety of senior management positions with Shell Canada Limited in strategic and scenario planning, business development, and marketing, especially in natural gas, electricity, sulfur, and liquids. Prior to his career at Shell he was employed at Crows Nest Resources Limited as Manager, International Coal Marketing, responsible for markets in North America, Europe, and Africa. He has also held senior management positions in the Canadian government in the areas of trade promotion, metals, minerals, and energy specialist and headed Canadian delegations as a technical expert at international meetings of United Nations Conference on Trade and Development, United Nations Industrial Development Organization, and the OECD. He is a founder and President of Kernow Enterprises Inc., a consultancy practice specializing in business trends and strategic and scenario analysis. Dr. Goodman is the author of several IHS CERA reports, including analyses of coal commoditization; power generation; fuel cells; hydrogen; Canada's Kyoto compliance strategies; and Canada's electric power and fuels sectors including nuclear, hydro, natural gas, and coalbed methane. Dr. Goodman holds a BA from Carleton University, a BSc (Honors) from the University of Wales in Cardiff, and a DPhil from Oxford.

Judson Jacobs, Director

Judson Jacobs, IHS CERA Director, is a Research Director in IHS CERA's Upstream Technology practice. In this role he studies the strategic implications of digital and oilfield technologies in the exploration and production (E&P) sector. He was the primary contributor to IHS CERA's *Digital Oil Field of the Future* (DOFF) Multiclient Study and continues to examine technology issues related to production activities in leading IHS CERA's DOFF Forum service. Other recent research includes information technology externalization in E&P, the expanding role of seismic, and industry knowledge management trends. Prior to joining IHS CERA Mr. Jacobs worked at the Mitchell Madison Group, a strategy consulting firm, where he served the energy and financial services sectors. His background in the upstream oil and gas industry includes engineering positions with Schlumberger Wireline Services and work as an exploration geologist in Anadarko Petroleum Corporation's international division. Mr. Jacobs hold a BSE from Princeton University and an MS in Geology from Stanford University.