

TOPIC PAPER #22

HEAVY OIL

On July 18, 2007, The National Petroleum Council (NPC) in approving its report, *Facing the Hard Truths about Energy*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the Task Groups and their Subgroups. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

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

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

The attached Topic Paper is one of 38 such working document used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix E of the final NPC report provides a complete list of the 38 Topic Papers and an abstract for each. The printed final report volume contains a CD that includes pdf files of all papers. These papers also can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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Heavy Oil, Extra-Heavy Oil and Bitumen

Unconventional Oil

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I. Executive Summary

There are huge, well-known resources of heavy oil, extra-heavy oil, and bitumen in Canada, Venezuela, Russia, the USA and many other countries.¹ The resources in Canada and the USA are readily accessible to oil companies, and the political and economic environments are stable. While these resources in North America only provide a small percentage of current oil production (approximately 2%), existing commercial technologies could allow for significantly increased production. These unconventional oils can be profitably produced, but at a smaller profit margin than for conventional oil, due to higher production costs and upgrading costs in conjunction with the lower market price for heavier crude oils.

Canada, Venezuela, and the United States are leading producers of these unconventional oils. In Canada, open-pit mining of shallow oil sands provides approximately 50% of the nation's heavy oil production. In situ production of heavy oil with sand and thermal production using injected steam provide the remainder of Canada's production. In particular, steam assisted gravity drainage (SAGD) production is rapidly growing. In Venezuela, cold production with horizontal and multilateral wells predominates. In the USA, thermal production using steam is the primary production means.

However, there are several barriers to the rapid growth of heavy oil, extra-heavy oil, and bitumen production. Open-pit mining has a large environmental impact and

¹ See the Discussion section for the definitions of heavy, extra-heavy oil, and bitumen.

can only exploit resources near the surface. Open-pit mining is a mature technology and only evolutionary improvements in technology are likely. By contrast, there are several commercial in situ production technologies, and several more in research or pilot phase. Many of the in situ production methods require an external energy source to heat the heavy oil to reduce its viscosity. Natural gas is currently the predominant fuel used to generate steam, but it is becoming more expensive due to short supply in North America. Alternative fuels such as coal, heavy oil, or byproducts of heavy oil upgrading could be used, but simply burning them will release large quantities of CO₂, a greenhouse gas. One option is gasification with CO₂ capture and sequestration to minimize greenhouse gases. Nuclear power has also been proposed, but faces societal opposition. Another fuel option is using the unconventional oil itself by injecting air into the reservoir for in situ combustion.

Other in situ methods undergoing pilot testing are using a solvent to reduce heavy oil viscosity by itself or combined with steam. These could reduce energy requirements and possibly open resources that otherwise are too deep, in arctic regions, or offshore where steam injection is difficult. Other options are generating steam downhole, or directly heating the formation with some form of electricity such as resistance, induction, or radio-frequency heating. Research indicates that some in situ upgrading may also be possible with heat, combustion, solvents, or catalysts.

Heavy oil, extra-heavy oil, and bitumen projects are large undertakings and very capital intensive. In addition to the production infrastructure, additional upgrading, refining, and transportation facilities are needed. Pipelines for heavy oil and possibly for CO₂ sequestration would be needed. Another issue is obtaining a sufficient supply of diluent for pipelining heavy oil. These projects also have long operating and payback periods, so unstable oil prices can deter long-term investments.

Technologies that upgrade value, drive down costs, and reduce environmental impacts will have the greatest effect on increasing the production of heavy oil, extra-heavy oil, and bitumen. There are a large number of technologies that can have an impact, but there is no single silver bullet, owing to the tremendous variety of heavy oil, extra-heavy oil, and bitumen resources. In recent years there has been a renewed interest within oil companies, research institutions and universities to develop such

technologies. The challenges are huge and will require collaboration between the oil industry and governments.

II. Overview of Methodology

This report is based on a review of public documents concerning heavy oil, extra heavy oil, and bitumen. There are extensive reports available; a bibliography can be found in Appendix 1. Discussions were held with university and oil industry personnel in the United States and Canada (Appendix 2). Mining and several in situ production sites were visited, including cyclic steam stimulation, steamflood, cold heavy oil production with sand, steam assisted gravity drainage, solvent assisted gravity drainage, and upgrading facilities.

III. Background

Heavy oil, extra-heavy oil, and bitumen are unconventional oil resources that are characterized by high viscosities (i.e. resistance to flow) and high densities compared to conventional oil. Most heavy oil, extra-heavy oil, and bitumen deposits are very shallow. They originated as conventional oil that formed in deep formations, but migrated to the surface region where they were degraded by bacteria and by weathering, and where the lightest hydrocarbons escaped. Heavy oil, extra-heavy oil, and bitumen are deficient in hydrogen and have high carbon, sulfur, and heavy metal content. Hence, they require additional processing (upgrading) to become a suitable feedstock for a normal refinery.

There are very large heavy oil, extra-heavy oil, and bitumen resources whose extent and locations are well known. The International Energy Agency (IEA) estimates that there are 6 trillion ($6 \cdot 10^{12}$) barrels in place worldwide; with $2.5 \cdot 10^{12}$ bbl in Western Canada, $1.5 \cdot 10^{12}$ bbl in Venezuela, $1 \cdot 10^{12}$ bbl in Russia, and 100 to $180 \cdot 10^9$ bbl in the United States.² Heavy oil and bitumen resources in Western

² *Resources to Reserves—Oil and Gas Technologies for the Energy Markets of the Future*, International Energy Agency, Paris (2005): 75. Available at www.iea.org/Textbase/publications/free_new_Desc.asp?PUBS_ID=1568.

Canada and the United States could provide stable and secure sources of oil for the United States. Most of these resources are currently untapped.

Exploration technology is of minor importance, since large resources have already been discovered, but optimizing production technology is important. Because heavy oil, extra-heavy oil, and bitumen do not flow readily in most reservoirs, they require specialized production methods. Very shallow oil sands can be mined. Slightly deeper deposits can be produced by increasing reservoir contact with horizontal wells and multilaterals, producing the oil with large amounts of sand, or by injecting steam, which lowers the viscosity and reduces the residual oil saturation, thus improving recovery efficiency. In situ combustion has also been used to heat the reservoir, but it has faced several technical and economic challenges that have limited its application. A few reservoirs are sufficiently hot that heavy oil can be produced with essentially conventional methods.

Historically, bitumen outcrops have been used as sources of fuel, asphalt, and water sealant. The modern version is mining the bitumen in oil sands, which accounts for over half of Canada's current unconventional oil production.³ The overburden is stripped, and the oil sands are mined, transported, and mixed with water to separate the oil. The recovery factor is up to 90% of the original oil in place.

Conventional or "cold" production of heavy started in California in the early 20th century. Indonesian and Venezuelan heavy oil fields were also using cold production by mid-century. Cold production has a low recovery factor, typically 5% to 10%. Water floods in a few limited cases have been used with heavy oil to enhance formation pressures and help displace the heavy crude.

In the 1960s, operators began to inject steam to reduce the heavy oil viscosity and increase recovery. In cyclic steam stimulation (CSS), steam is injected into a well for a time period from several days to several weeks. The heat is allowed to soak into the formation surrounding the well for an additional time (weeks). The oil is then produced (possibly for up to a year) until the rate drops below an economic limit. A steamflood may follow CSS to sweep oil between wells. Steam is injected in one well and oil is produced in another well, for example in a 5-spot pattern. Steamflooding

³ Some now refer to the heavy oil produced in Canada as "conventional oil."

operations have produced recovery factors of over 70%, such as in the Duri Field in Indonesia and in several fields in the San Joaquin Valley in California.

Steam assisted gravity drainage (SAGD) was developed recently in Canada and is now one of the fastest growing techniques. Two horizontal wells are drilled parallel to each other and separated by a constant vertical distance, typically 5 m. Steam is injected into the upper well, and oil is produced from the lower well. Predicted recovery factors of 50% to 70% are reported.

In situ combustion of heavy oil has been tried with modest success only in special situations. Currently, in situ combustion is only used in Eastern Europe. However, there is ongoing research and development for in situ combustion using a combination of vertical and horizontal wells.

The production of heavy oil, extra-heavy oil, and bitumen is economic at current oil prices with existing production technologies. However, heavy oil, extra-heavy oil, and bitumen sell at a lower price than conventional oil because of the difficulty in processing the heavier crude to create refined products, and because fewer refineries have the capability to process it. In addition, production is more costly than for conventional oil, so the profit margin is less. If an oil company has equal access to conventional oil and to heavy oil, then economics would favor conventional oil. However, gaining access to conventional oil resources is becoming more difficult in many countries. On the other hand, heavy oil deposits are both abundant and well known, which means very little or no exploration costs are required. This has motivated oil companies looking to increase their reserves to move into heavy oil. Because Canada has stable political and economic environments and a very large unconventional resource, companies are racing to take positions. There is a boom economy in the oil fields of Western Canada with consequent price inflation.

There are no purely technical reasons why heavy oil and bitumen production cannot be increased dramatically. For example, Canada produced approximately 1 million barrels of heavy oil and bitumen per day (BOPD) in 2005, and production is forecast at 4 million BOPD by 2020. With 175 billion barrels of reserves, given existing technology, Canada could produce 4 million BOPD for over 100 years. The International Energy Agency's World Energy Outlook projects that heavy oil and bitumen production from Canada and Venezuela together could reach 6 million

barrels per day by 2030.⁴ Given sufficient incentives, heavy oil and bitumen production rates could be far greater.

However, there are several issues that must be addressed if production is to be increased significantly.

First, very large capital investments must be made to increase the extraction, upgrading, transportation (pipeline and trucking) facilities, and infrastructure. While production from a heavy oil well may last for many years, the production rate may be low compared to that for a well producing light oil. This can result in a relatively long payback period. This increases risks due to potentially low oil prices in the future, and to potentially higher future operating costs (e.g. from natural gas), or to increased restrictions (e.g. CO₂ quotas).

Second, a greatly expanded workforce will be needed, especially in northern Canada. Community infrastructures, such as schools, housing and social services are inadequate to absorb a large population increase. The impact on the aboriginal society must also be considered.

Third, producing and upgrading heavy oil, extra-heavy oil, and bitumen require considerable energy input. Currently, natural gas provides most of the energy for steam generation, as well as providing a source of hydrogen for upgrading. There are insufficient quantities of natural gas in North America to sustain the planned expansion of heavy oil, extra-heavy oil, and bitumen production.

Alternative fuels such as coal, coke, and heavy ends could be used, but burning them will increase CO₂ emissions. If a carbon tax is enacted, then the energy costs will increase. Nuclear power could provide energy and hydrogen without CO₂, but faces public resistance.

Fourth, increased heavy oil, extra-heavy oil, and bitumen production could have a major impact on the environment if only current technologies are used. Increased emissions of carbon dioxide are the most immediate concern, especially if carbon-intensive alternative fuels are burned. Gasification combined with CO₂ capture and sequestration could mitigate this problem. Mining operations have greater environmental issues than in situ techniques. These include water usage, footprint,

⁴ *Energy Technology Perspectives 2006, Scenarios and Strategies to 2050*, International Energy

land reclamation, reforestation, and the disposal of byproducts such as sulfur, fine tailings, acid, and heavy metals.

While heavy oil, extra-heavy oil, and bitumen production could be increased using commercial methods, advances in technology could mitigate all of the issues listed above. The potential impact of new technologies on economics, recovery factor, environmental effects, and manpower requirements could be substantial.

The Canadian government has sponsored research and development activities for heavy oil, extra-heavy oil, and bitumen production for many years. This has resulted in many advances that have been instrumental in advancing the industry. A similar model has been suggested for the United States to develop the large shale oil deposits in the West.

IV. Tables of advances

Heavy oil, extra-heavy oil, and bitumen resources are complex and greatly varied. To analyze the technology needs, it is necessary to categorize the resources, the production methods, and the applicable technologies. Tables IV.1, IV.2, and IV.3 list the major production methods. Table IV.4 lists production method versus resource properties. Table IV.5 lists the relevance of specific technologies versus production method. There are fourteen production methods and twenty-nine technologies in the latter tables.

Method	Current usage	Comment
Open-pit mining	Used in Canada for shallow oil sands	High recovery factor, but high environmental impact
Cold production using horizontal wells and multilateral wells	Used in Venezuela, some use in North Sea	Low recovery factor, may use water drive (North Sea)
Cold heavy oil production with sand (CHOPS)	Used in western Canada to exploit thin layers	Low recovery factor, needs good gas/oil ratio (GOR), unconsolidated sands
Cyclic steam stimulation (CSS)	Used in USA, Canada, Indonesia, many others	Reduce viscosity of heavy oil, needs good caprock, fair-to-good recovery factor
Steamflood	Used in USA, Canada, Indonesia, many others	Follow-up to CSS for interwell oil, good-to-high recovery factor
Steam assisted gravity drainage (SAGD)	Used in Canada	Allows production from shallower sands with weaker caprock

Table IV.1 Major commercial production methods.

Method	Description	Comment
Vapex	Use solvent rather than steam in SAGD-type wells	Lower energy consumption, low production rates. In situ upgrading
Hybrid	Solvent plus steam in SAGD, CSS and steamflood wells	Lower energy consumption, increased production, in situ upgrading
In situ combustion with vertical and horizontal wells	Uses heavy oil in reservoir and injected air	Eliminate need for natural gas for steam generation, in situ upgrading
Gasification of heavy ends	Used for steam generation and hydrogen production	Eliminate need for natural gas
Downhole heating with electricity	Resistance, induction, radio-frequency (RF)	Offshore, deep and arctic regions, in situ upgrading

Table IV.2 Major production methods in pilot phase, possibly ready for commercial use by 2010.

Method	Description	Comment
Alternative fuels with gasification and CO ₂ capture and sequestration	Uses coal, coke, or heavy ends for energy and hydrogen	CO ₂ limited world
Nuclear power plant fit-for-purpose	Small scale for energy and hydrogen production	CO ₂ limited world, safety, proliferation, fuel disposal, societal concerns
Downhole steam generation	Possible options include generating heat downhole from either electricity or combustion of fuel	Arctic, offshore, deep formations
Combination sub-surface mining and well production techniques		Arctic and extremely restricted surface footprint environments

Table IV.3 Major production methods possibly ready by 2020/2030 for commercial use.

Heavy oil, extra-heavy oil, and bitumen resources can be subdivided into a number of different categories based on their location, environment, and characteristics. The following categorization is not unique, but meant to illustrate the great variety among heavy oil resources. The properties of the heavy oil (composition, viscosity, etc.) are equally important but not used in the following tables. The categories are:

- Shallowest resources (<50 m)
- Shallow resources (50 to 100 m, too deep for mining but no caprock seal)
- Medium-depth resources (100 to 300 m, caprock seals pressures <200 psi)
- Intermediate-depth resources (300 to 1,000 m, seal for pressure >200 psi)
- Deep resources (>1,000 m)
- Arctic resources (permafrost)
- Offshore resources
- Carbonate resources (difficult petrophysics, tight rocks, dual porosities)
- Thinly bedded resources (<10 m thick)
- Highly laminated resources (low vertical permeability, possibly due to shale layering)

These resource categories are cross-referenced to the following production methods:

- Open-pit mining

- Cold-production horizontal wells & multilaterals
- Waterflood
- Cold production with sand (CHOPS)
- Cyclic steam stimulation (CSS)
- Steamflood
- SAGD
- Solvent without heat or steam (e.g. Vapex)
- Solvent with heat or steam
- Fire flood with vertical wells (~20 API oil only)
- Fire flood with vertical and horizontal wells
- Downhole steam generation (CSS, flood, SAGD)
- Electric, induction or RF heating
- Supercritical fluids (e.g. CO₂)
- Biotechnology

Table IV.4 contains estimates of which production method applies to each resource. Table IV.4 is split into sub-tables to fit onto the pages. There is no implied hierarchy in the order of the production methods.

Production method or resource	Open-pit mining	Cold-production horizontal wells & multilaterals	Waterflood	Cold production with sand (CHOPS)
Status	Commercial	Commercial	Commercial	Commercial
Shallowest (<50 m)	Only solution	No	No	No
Shallow (50 to 100 m)	Possible but economically limited	No	No	No
Medium depth (100 to 300 m)	No	Unlikely unless very low viscosity or high solution gas along with high permeability	Unlikely unless very low viscosity and high permeability	Unlikely, may require solution gas, but may be possible
Intermediate depth (300 to 1,000 m)	No	Requires low viscosity with solution gas or high formation temperature and high permeability	Requires low viscosity and/or high formation temperature	Requires unconsolidated formation and generally requires solution gas
Deep (>1,000 m)	No	Requires low viscosity with solution gas or high formation temperature and high permeability	Requires low viscosity and/or high formation temperature	Unlikely because requires unconsolidated formations
Arctic	No	Maybe	Maybe	Disposal of sand and water an issue
Offshore	No	Maybe	Yes, North Sea	Disposal of sand and water an issue
Carbonates	No	No	No	No
Thin beds (<10 m thick)	Can be mined if near surface and thin overburden	Maybe	Maybe	Yes
Highly laminated	Can be mined if near surface and thin overburden	Yes, if multilaterals can penetrate multiple layers	Maybe for vertical wells	Yes

Table IV.4a. Production method versus heavy oil resource.

Production method or resource	Cyclic steam stimulation (CSS)	Steamflood	SAGD	Solvent without heat or steam
Status	Commercial	Commercial	Commercial	Pilot test
Shallowest (<50 m)	No	No	No	No
Shallow (50 to 100 m)	No	No	No	Possible, but unproven
Medium depth (100 to 300 m)	No, unless good sealing caprock	No, unless good sealing caprock	Yes, if good vertical and horizontal permeability and payzone > 10m	Unproven, needs good vertical and horizontal permeability
Intermediate depth (300 to 1,000 m)	Yes, but deep zones need higher temperature steam & are less economic	Yes, but deep zones need higher temperature steam & are less economic	Yes, but deep zones need higher temperature steam & are less economic	Unproven, needs good vertical and horizontal permeability
Deep (>1,000 m)	No, needs high temperature and high-pressure steam and too much heat losses to overburden through injection wellbore	No, needs high temperature and high-pressure steam and too much heat losses to overburden through injection wellbore	No, needs high temperature and high-pressure steam and too much heat losses to overburden through injection wellbore	Possible, but unproven
Arctic	Maybe if permafrost can be managed	Maybe if permafrost can be managed	Maybe if permafrost can be managed	Possible, but unproven
Offshore	No, too much heat loss in riser to ocean water	No, too much heat loss in riser to ocean water	No, too much heat loss in riser to ocean water	Possible, but unproven
Carbonates	No	No	No	Unknown
Thin beds (<10 m thick)	Possible with horizontal wells	No, needs at least 10 m bed, heat losses to overburden are too great	No, need at least 10 m bed	Possible, but unproven
Highly laminated	Possible with horizontal wells	May be possible with horizontal wells, but unproven	No, need at least 10 m bed	Unlikely

Table IV.4b. Production method versus heavy oil resource.

Production method or resource	Solvent with heat or steam	Fire flood with vertical wells (~20 API oil only)	Fire flood with vertical and horizontal wells	Downhole steam generation (CSS, flood, SAGD)
Status	Pilot test	Commercial	Pilot test	Experimental
Shallowest (<50 m)	No	No	No	No
Shallow (50 to 100 m)	Unknown	No	Unknown	No
Medium depth (100 to 300 m)	Unproven, needs good vertical and horizontal permeability	Possible	Unknown	Tested but commercially unproven
Intermediate depth (300 to 1,000 m)	Unproven, needs good vertical and horizontal permeability	Yes	Possible	Possible, but unproven
Deep (>1,000 m)	Unknown	Possible	Possible, but unproven	Unknown, greater depth means need high steam pressure & temp
Arctic	Unproven, must manage permafrost issue	Possible, but unproven	Possible, but unproven	Possible, but unproven
Offshore	Unlikely	Possible, but unproven	Possible, but unproven	Possible, but unproven
Carbonates	Unknown	Unknown	Unknown	Possible, but unproven
Thin beds (<10 m thick)	Possible, but unproven	Unknown	Unlikely	Possible, but unproven
Highly laminated	Unknown	Unknown	Unlikely	Possible, but unproven

Table IV.4c. Production method versus heavy oil resource.

Production method or resource	Electric, induction or RF heating	Supercritical fluids (e.g. CO ₂)	Biotechnology
Status	Pilot test	Experimental	Research
Shallowest (<50 m)	No	No, needs higher reservoir pressure	Unknown
Shallow (50 to 100 m)	Possible, limited field successes in isolated cases	No, needs higher reservoir pressure	Unknown
Medium depth (100 to 300 m)	Possible, limited field successes in isolated cases	No, needs higher reservoir pressure	Unknown
Intermediate depth (300 to 1,000 m)	Possible, but unproven	Unknown	Unknown
Deep (>1,000 m)	Possible, but unproven	Unknown	Unknown
Arctic	Possible, but unproven	Unknown	Unknown
Offshore	Possible, but unproven	Unknown	Unknown
Carbonates	Possible, but unproven	Unknown	Unknown
Thin beds (<10 m thick)	Possible, but unproven	Unknown	Unknown
Highly laminated	Possible, but unproven	Unknown	Unknown

Table IV.4d. Production method versus heavy oil resource.

Open-pit mining and subsurface production are significantly different and treated separately. The required mining advances have been extensively described in the “Oil Sands Technology Roadmap” as continuous improvements in such areas as material handling, reduced sensitivity to process temperature, extended component life, reduced maintenance costs, faster dewatering of tailings, lower labor costs, reduced water usage, mobile crushing, improved primary separation and froth treatment, etc.⁵ Step-out technologies include processing the ore at the mine face to extract bitumen, or tunnel mining to exploit the bitumen deeper than about 50 m.

The focus in this report is on subsurface resources (i.e. deeper than 50 m) which constitute 90% of Canada’s heavy oil resources, and 100% of the United States and Venezuela’s resources. The table contains estimates of the potential impact of specific technologies on various subsurface production methods. The potential impacts have

been rated “high”, “medium”, “low”, and “unknown.” Given the large number of technologies and the great variety of resources, it is very difficult to force rank the technologies. There is no implied hierarchy in the sequence that the technologies are listed.

⁵ *Oil Sands Technology Roadmap*, Alberta Chamber of Resources (January 2004). Available at www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf.

Technology or production method	Simulations and modeling	Geomechanics	Downhole sampling	In situ viscosity	Fluid characterization
Cold-production horizontal & multilaterals	High	High	High	High	High
Waterflood	High	Medium	High	High	High
Cold production with sand (CHOPS)	Medium	High	High	High	High
Cyclic steam stimulation (CSS)	High	High	High	High	High
Steamflood with surface burners	High	High	High	High	High
SAGD	High	High	High	High	High
Solvent without heat or steam	High	High	High	High	High
Solvent with heat or steam	High	Medium	High	High	High
Fire flood with vertical wells (~20 API oil only)	High	High	High	High	High
Fire flood with vertical and horizontal wells	High	High	High	High	High
Downhole steam generation (CSS, steamflood, SAGD)	High	High	High	High	High
Electric, induction, or RF heating downhole	High	High	High	High	High
Supercritical fluids	High	High	High	High	High
Biological	Unknown	Unknown	High	High	High

Table IV.5a. Technology versus production method.

Table IV.5a technology descriptions:

- Simulations and modeling. Being able to simulate production rates, recovery factor, energy requirements, etc., is critical to selecting the production method, number and placement of wells, surface facilities, and project economics. Simulators must be able to handle multi-physics interactions, possibly including multiphase flow in porous media (oil, water, natural gas, steam, and solvents), multiphase flow in tubulars (water, oil, natural gas, steam, solvents, and sand), chemical reactions, diffusion, temperature, pressure, thermal effects (heat propagation, matrix expansion, viscosity, chemical reactions, and completion hardware), combustion process

and effects (flue gases), geomechanics (borehole stability, fracturing, sanding, overburden integrity, compaction, and permeability reduction), etc. The simulators require accurate laboratory data on the properties of the relevant fluids and formations at the appropriate downhole conditions (pressure, temperature, during combustion, etc.). There are few laboratory facilities capable of making these measurements.

- Geomechanics. Measuring and understanding the formation and overburden mechanical properties under drilling and production conditions is required for optimum field performance. Borehole stability is an issue when drilling horizontal wells in unconsolidated formation (e.g. for SAGD). CHOPS requires sand production (weak formation strength) and possibly gravity drive on the formation. Fracturing the formation may be desirable or undesirable depending on the process. For example, fracturing the overburden and allowing steam to escape would adversely affect SAGD, CSS, or steamflood operations.
- Downhole sampling. Recovering fluids in situ (oil, water, and natural gas) without contamination, loss of constituents, or degradation is needed for laboratory measurements (e.g. PVT, viscosity, and composition), and for planning production. Since heavy oil is viscous and may not be mobile without steam, solvent, or heat, this is a difficult technical challenge.
- In situ viscosity. There can be very large variations in viscosity (several orders of magnitude) in heavy oil deposits, making such highly heterogeneous resources a challenge to produce. A method of measuring the variation of viscosity in situ is needed. Magnetic resonance well logging is one possible approach, but would be difficult above approximately 100 cp.
- Fluid characterization. Fluid typing, heavy oil composition, gravity, viscosity, solution gas, asphaltenes and mineral content are important in planning the production method. This requires good laboratory data on representative fluid samples as input parameters to the reservoir simulator. Laboratory data obtained at representative (i.e. high) temperatures and pressures are needed, possibly also in the presence of solvents, or during combustion.

Technology or production method	Flow assurance	Drilling	Well placement	Multilaterals	Cementing
Cold-production horizontal & multilaterals	High	High	High	High	Low
Waterflood	High	Medium	Medium	Low	Low
Cold production with sand (CHOPS)	High	Low	Low	Low	Low
Cyclic steam stimulation (CSS)	High	Medium	Low	Medium	High
Steamflood with surface burners	High	Medium	Medium	Low	High
SAGD	High	High	High	Low	High
Solvent without heat or steam	High	High	High	Low	Low
Solvent with heat or steam	High	High	High	Low	Medium
Fire flood with vertical wells (~20 API oil only)	High	Medium	Low	Low	High
Fire flood with vertical and horizontal wells	High	High	High	Low	High
Downhole steam generation (CSS, steamflood, SAGD)	High	Medium	Low to High	Medium	High
Electric, induction, or RF heating downhole	High	High	High	Low to Medium	High
Supercritical fluids	High	Medium	Unknown	Unknown	High
Biological	High	Medium	Unknown	Unknown	Low

Table IV.5b. Technology versus production method.

Table IV.5b technology descriptions:

- Flow assurance. This is needed to guarantee the transport of heavy oil possibly mixed with sand, water, natural gas, and/or solvents, in pipelines or horizontal wells. Sand may drop out and block flow in pipelines or long horizontal wells. Deposition of asphaltenes in the well tubing or pipeline is possible. Lower temperatures (in the overburden, in arctic regions, subsea, and northern pipelines) may require heating elements, addition of solvents, insulated tubing, and other flow assurance methods.
- Drilling. Advances in drilling technology can lower the cost of heavy oil wells and expand the resource base. Directional-drilling technologies such as

steerable systems, measurement while drilling (MWD), and logging while drilling (LWD) have had a large impact on conventional oil and natural gas production. Horizontal wells are an example of how technology can lower development costs while accessing previously uneconomic resources. Slant rigs allow operators to drill very shallow horizontal wells for SAGD.

- Well placement. Optimum placement of horizontal and multilateral wells is required to maximize reservoir contact, minimize exposure to bottom water or gas caps, and to remain in the most productive zone of the reservoir. For example, in SAGD wells, no heavy oil can be produced that lies below the producing (lower) well. If the heavy oil zone is 10 m thick, but the producer well is 3 m off bottom, then 30% of the oil lies below the producer and is not recoverable. Similarly, the injector well must be accurately positioned above the producer (typically 5 ± 1 m). Directional drilling, MWD and LWD technologies are critical for positioning wells with respect to the geology (“geosteering”).
- Multilaterals. Multilateral wells have several branches from a central or main wellbore. Multilaterals maximize reservoir contact while minimizing the surface and intermediate well construction. Multilateral junctions may be difficult to construct for high temperature environments, maintaining wellbore and hydraulic integrity.
- Cementing (high temperature, chemical attack). Thermal production methods require cement capable of surviving high temperatures ($>200^{\circ}\text{C}$) and the resulting thermal expansion. A supercritical fluid, such as CO_2 , can attack the cement and cause the loss of hydraulic isolation.

Technology or production method	High-temperature completions	High-temperature, long-life pumps	Pumps with high sand and solids capability	Sand control	Monitoring and control
Cold-production horizontal & multilaterals	Low	Low	High	High	High
Waterflood	Low	Low	Medium	High	High
Cold production with sand (CHOPS)	Low	Low	High	Low	Medium
Cyclic steam stimulation (CSS)	High	High	Medium	High	High
Steamflood with surface burners	High	High	Medium	High	High
SAGD	High	High	Medium	High	High
Solvent without heat or steam	Medium	Low	Medium	High	High
Solvent with heat or steam	High	Medium	Medium	High	High
Fire flood with vertical wells (~20 API oil only)	High	High	Medium	High	High
Fire flood with vertical and horizontal wells	High	Medium	Medium	High	High
Downhole steam generation (CSS, steamflood, SAGD)	High	High	Medium	High	High
Electric, induction, or RF heating downhole	High	High	Medium	High	High
Supercritical fluids	High	High	Medium	High	High
Biological	Low	Low	Medium	High	High

Table IV.5c. Technology versus production method.

Table IV.5c technology descriptions:

- High-temperature completions. Thermal production methods can stress completions. In particular, the packers must be able to survive high temperatures and thermal expansion. Some wells utilize slip joints between tubulars. High-temperature steam can corrode steel tubing. In situ combustion creates even greater thermal stresses on the completions.
- High-temperature, long-life pumps. Heavy oil wells usually require artificial lift. Progressive cavity pumps (PCPs) and electric submersible pumps (ESPs) are commonly used. The rubber in PCPs is vulnerable to high

temperatures, requiring pumps to be replaced periodically. ESPs are also subject to shortened lifetimes at high temperatures.

- Pumps with high sand and solids capability. Many heavy oil wells produce sand, since they penetrate poorly consolidated sand formations. In CHOPS wells, a relatively high percentage of sand production is desirable. Pebbles and mineral nuggets as large as 1 cm in diameter may be produced in CHOPS wells.
- Sand control. Sand production is undesirable in many heavy oil wells, and slotted liners, screens, and gravel packs are often used to prevent this. Knowledge of the grain-size distribution is needed to design slotted liners and screens. Reducing the drawdown pressure, for example with horizontal wells, also reduces sand production.
- Monitoring and control. Any production method involving heat, steam, solvent, or waterflood will benefit greatly from the ability to monitor and control the process. For example, creating steam is the greatest operating cost for thermal production methods such as SAGD, CSS, and steamflood. Monitoring the steam chamber, the distribution of heat, and the location of the remaining heavy oil could allow one to select the regions to target steam.

Technology or production method	Devices for downhole flow control	Distributed temperature	Downhole pressure	High-temperature electronics & sensors (>200°C)	Downhole multiphase flow sensors
Cold-production horizontal & multilaterals	High	Low	Medium	Low	High
Waterflood	High	Low	High	Low	High
Cold production with sand (CHOPS)	Low	Low	Low	Low	Low
Cyclic steam stimulation (CSS)	High	High	High	High	Medium
Steamflood with surface burners	High	High	High	High	High
SAGD	High	High	High	High	Low
Solvent without heat or steam	High	High	Medium	Low	Low
Solvent with heat or steam	High	High	High	Medium to high	Low
Fire flood with vertical wells (~20 API oil only)	Medium	High	High	High	Low
Fire flood with vertical and horizontal wells	Low	High	High	High	Low
Downhole steam generation (CSS, steamflood, SAGD)	Low	High	High	High	Low
Electric, induction, or RF heating downhole	Low	High	High	High	Low
Supercritical fluids	Unknown	High	High	Medium	High
Biological	Unknown	Low	Low	Low	Unknown

Table IV.5d. Technology versus production method.

Table IV.5d technology descriptions:

- Devices for downhole flow control. This includes controllable pumps, valves, sliding sleeves, and expandable packers.
- Distributed temperature. Currently, fiber-optic based systems are used to monitor temperature along the wellbore. Survival at high temperatures and corrosive environments is an issue.
- Downhole pressure. Currently limited to point pressure measurements, but distributed pressure measurements would be beneficial.

- High-temperature electronics & sensors ($>200^{\circ}\text{C}$). Steam, in situ combustion, and electric heating produce temperatures above 200°C . There are very few electronic components or sensors that work at these temperatures. Wireline logging tools can survive brief periods above 200°C by using flasks. Permanent sensors cannot be flaked.
- Downhole multiphase flow sensors. Sensors are needed to measure oil, water, natural gas, steam, solvent, and sand production from different portions of the well. The need includes sensors for individual branches of a multilateral well, and sensors along a horizontal well.

Technology or production method	Microseismic while fracturing	Cross-well EM for fluid saturation	Cross-well seismic for gas saturation	Through-casing fluid monitoring	Composition monitoring for in situ upgrading
Cold-production horizontal & multilaterals	Low	Low	Low	Low	Low
Waterflood	Low	High	Low	Medium	Low
Cold production with sand (CHOPS)	Low	Low	Medium	Low	Low
Cyclic steam stimulation (CSS)	Medium	Medium	High	High	Low
Steamflood with surface burners	High	High	High	High	Low
SAGD	Medium	Low	Medium	Low	Low
Solvent without heat or steam	Low	Low	Medium	Low	Medium
Solvent with heat or steam	Medium	Low to High	High	Medium	Medium
Fire flood with vertical wells (~20 API oil only)	Low	Unknown	High	Medium	High
Fire flood with vertical and horizontal wells	Low	Unknown	High	Medium	High
Downhole steam generation (CSS, steamflood, SAGD)	Medium	Low to High	High	Low to Medium	Low
Electric, induction, or RF heating downhole	Low	Unknown	Low	High	High
Supercritical fluids	Medium	Unknown	Unknown	High	High
Biological	Unknown	Low	Low	High	High

Table IV.5e. Technology versus production method.

Table IV.5e technology descriptions:

- Microseismic while fracturing. Microseismic measurements might be used to monitor fracturing in a high temperature well.
- Cross-well EM for fluid saturation. Time-lapse electromagnetic-induction measurements can be made between monitoring wells to monitor water saturation, and to locate bypassed oil zones. Challenges are inversion of the electromagnetic data and obtaining high spatial resolution. The cost of monitor wells is also a limiting factor.

- Cross-well seismic for gas saturation. High frequency seismic measurements between monitor wells can be made to locate the steam chambers, since there is a large acoustic contrast between steam and oil or water.
- Through-casing fluid monitoring. Nuclear through-casing resistivity logging tools can be used to monitor the water-oil or steam-oil contacts. Nuclear devices measure very shallow, penetrating only a few inches into the formation, while resistivity devices can see several feet into the formation.
- Composition monitoring for in situ upgrading. There is an unsatisfied need to monitor the changes in oil composition during in situ upgrading. A fallback approach is to measure the produced fluids, but the best approach would be a method for monitoring the fluids in situ, either with cased-hole logging, downhole fluid sampling, or permanent sensors.

Technology or production method	Surface multiphase flow sensors	4D surface seismic	Fluids separation and disposal	Produced-solids separation
Cold-production horizontal & multilaterals	High	Medium	High	Medium
Waterflood	High	High	High	Medium
Cold production with sand (CHOPS)	High	Medium	High	High
Cyclic steam stimulation (CSS)	High	High	High	Medium
Steamflood with surface burners	High	High	High	Medium
SAGD	High	Medium	High	Medium
Solvent without heat or steam	High	Medium	High	Medium
Solvent with heat or steam	High	Medium	High	Medium
Fire flood with vertical wells (~20 API oil only)	High	High	High	High
Fire flood with vertical and horizontal wells	High	High	High	High
Downhole steam generation (CSS, steamflood, SAGD)	High	Medium	High	Medium
Electric, induction, or RF heating downhole	High	Medium	High	Medium
Supercritical fluids	High	High	High	Medium
Biological	High	Low	Unknown	Medium

Table IV.5f. Technology versus production method.

Table IV.5f technology descriptions:

- Surface multiphase flow sensors. The surface production stream can include oil, water, steam, natural gas, solvents, and sand. In multi-well situations (e.g. SAGD), it would be very beneficial to measure the production from each well before the streams are combined. The equipment must be able to handle high-temperature and possibly high-pressure flow streams.
- 4D surface seismic. Time-lapse surface seismic could be used to monitor the steam chambers, for example for steamflood or SAGD wells. Issues are cost of the service and how frequently the measurement could be made.
- Fluids separation and disposal. A cost-effective means for separating oil, water, steam, and solvent is needed.

- Produced-solids separation. Sand and fines need to be removed from the fluid stream.

V. Discussion

Heavy oil and bitumen are characterized by high viscosities (i.e. resistance to flow measured in centipoises or cp) and high densities compared to conventional oil. The World Petroleum Congress defines heavy oil as oil whose gas-free viscosity is between 100 cp and 10,000 cp at reservoir temperature. By comparison, ketchup has a viscosity of approximately 30,000 cp. Heavy oil is slightly less dense than water with API gravity between 10° and 20°. Heavy oil can flow in some reservoirs at downhole temperatures and/or with in situ solution gas, but at the surface, it is a thick, black, gooey fluid. Bitumen has a viscosity greater than 10,000 cp, and may be as high as 10,000,000 cp, the viscosity of chocolate. Bitumen is predominantly defined as those crude oils with a dead-oil viscosity >10,000 cp. If no viscosity data are available, then crude oils with an API of <10° are sometimes referred to as bitumen. Extra-heavy oil is that heavy crude with an API <10° and a dead-oil viscosity <10,000. For comparison, oil with an API of <10° is denser than water. (It should also be noted that the term “Oil Sands” was created for incentive tax purposes in Canada for those heavy crude oils found above a certain latitude where the infrastructure was almost non-existent.) For simplicity, hereafter “heavy oil” will often be used as a shorthand notation for heavy oil, extra-heavy oil and bitumen.

Heavy oil was originally conventional oil that migrated from deep source rocks or deep reservoirs to the near surface, where they were biologically degraded and weathered by water. Bacteria feeding on the migrated conventional oil removed hydrogen and produced the denser, more viscous heavy oil and bitumen. Lighter hydrocarbons may also have evaporated from the shallow, uncapped formations.

Because heavy oil is deficient in hydrogen compared to conventional crude oil, either hydrogen must be added to the molecules (by hydroprocessing), or carbon removed (by coking or cracking) to render it useful as a feedstock for a conventional refinery. Heavy oil may also contain heavy metals and sulfur, which must be removed. These processes are used in more complex refineries to create products but

can also be used upstream of refineries to upgrade heavy oil to syncrude (synthetic crude oil) that can be processed by simpler refineries.

Heavy oil viscosity decreases rapidly with increasing temperatures, therefore external heat may be required for production. High-temperature steam is commonly used to deliver heat to the formation; water being readily available and having a high latent heat of vaporization. The steam oil ratio (SOR) or fuel oil ratio is an important measure of the energy required to produce heavy oil.⁶



Figure V.1. Heavy oil flowing slowly from a beaker
(Source *Oilfield Review* [reference 15]).

Heavy oil deposits may also contain water, clay, and minerals containing sulfur, titanium and heavy metals such as nickel, vanadium and molybdenum. Heavy oil deposits are usually shallow, generally no deeper than two or three thousand feet, and often lie within feet of the surface. There are unconsolidated heavy oil deposits (i.e. the bitumen holds the quartzite grains together rather than cementation) in Alberta and Saskatchewan provinces in Canada, in California, in Northern Mexico, and in Venezuela.

Most current heavy oil production comes from quartzite sandstone formations, but heavy oil also exists in carbonate formations. Carbonate formations are much more complex than sandstone formations, and often have extensive fracturing and vugs, in addition to intergranular porosity. Iran, Oman, and Mexico have extensive carbonate heavy oil deposits that are being developed and produced, they are just not

as successful as the sandstones and appropriate technology needs to be developed to increase recovery in these formations.

The IEA estimates that there are 6 trillion barrels of heavy oil worldwide, with 2 trillion barrels ultimately recoverable.⁷ Western Canada is estimated to hold 2.5 trillion barrels, with current reserves of 175 billion barrels (BBO). Venezuela is estimated to hold 1.5 trillion barrels, with current reserves of 270 billion barrels. Russia may also have in excess of 1 trillion barrels of heavy oil. In the United States, there are 100 to 180 BBO with large resources in Alaska (44 BBO), California (47 BBO), Utah (19 to 32 BBO), Alabama (6 BBO), and Texas (5 BBO). Heavy oil has been produced in California for 100 years, with current production of 500,000 BOPD. Heavy oil resources in Alaska are being developed on a small scale with less than 23,000 BOPD in 2003.⁸ Heavy oil is also located and being produced in Indonesia, China, Mexico, Brazil, Trinidad, Argentina, Ecuador, Colombia, Oman, Kuwait, Egypt, Saudi Arabia, Turkey, Australia, India, Nigeria, Angola, Eastern Europe, the North Sea, Rumania, Iran, and Italy.

There is not a great need to explore for heavy oil since the locations of very large resources are already known. Exploration techniques might be developed to locate smaller resources. However, the main challenge for technology is to optimize heavy oil production with cost-effective and environmentally sound methods.

Several very different production technologies have been developed for commercial exploitation of heavy oil; there are more techniques in research or pilot development.

Heavy oil, extra-heavy oil, and bitumen resources can be markedly different in their characteristics. Hence, each production method must be tailored for the particular resource and for its fluid properties. A method that works in one situation may fail utterly in a different one. Hence, it is essential that the properties of the resource be fully understood before selecting a production scheme. Essential properties include the geological setting; the depth, areal extent, and thickness of the

⁶ A SOR of 3 means that three barrels of water (converted to steam) are needed to produce one barrel of oil.

⁷ *Resources to Reserves*: 75 [reference 2].

⁸ "Undeveloped Domestic Oil Resources: The Foundation for Increasing Oil Production and a Viable Domestic Oil Industry," *Advanced Resources International* (February 2006): 12, 18.

resource; oil composition, density, viscosity, and gas content; the presence of bottom water or top gas zones; petrophysical and geomechanical properties such as porosity, permeability, and rock strength; the presence of shale layers; vertical and horizontal permeabilities; and the variation of these properties across the reservoir.

A. Deep, Arctic, and Subsea Heavy Oil Resources

The United States has 35 billion barrels of heavy oil less than 3,000 ft deep that may be accessible by thermal methods. There are 42 billion barrels of heavy oil that are deeper than 3,000 ft that might not be recovered with thermal means.⁹ In addition, the thermal production of heavy oil in the Alaskan arctic is problematic. Injecting steam and producing hot heavy oil through the tundra and permafrost both would be costly and might impact the arctic environment. Another situation where heavy oil is inaccessible to thermal production is offshore, where water temperatures and water depths preclude the use of steam for production, for example offshore Brazil.

Technologies that could convert such resources to reserves might include: downhole steam generation, electric heating, radio-frequency heating, in situ combustion, or the use of solvents. In addition, heated or insulated pipelines could be used for flow assurance.

B. Production Methods

Production methods can be classified as surface mining or well production. Primary subsurface production methods include cold production (horizontal and multilateral wells, water flood, and cold heavy oil production with sand) and thermal production (cyclic steam stimulation, steamflood, and steam assisted gravity drainage).

In addition, there is ongoing research and development of new in situ production methods that are not yet commercial. These include the use of solvents, hybrid methods with mixed steam and solvent, in situ combustion using vertical and horizontal wells, supercritical fluids, electric resistance, induction and radio-

⁹ “Undeveloped Domestic Oil Resources”: 15 [reference 8].

frequency heating, downhole steam generation, alternative fuels to natural gas, and in situ upgrading.

C. Open-pit Mining

There are large oil sand resources near Fort McMurray, Alberta, currently being mined. If the resource lies within 50 to 75 m of the surface, then open-pit mining is the only commercial production method. Approximately 10% of the heavy oil and bitumen in Western Canada can be recovered by this method.¹⁰ Mining of Canadian oil sands produced 552,000 BOPD in 2005, and will grow to 2,270,000 BOPD by 2020. By comparison, subsurface production of Canadian heavy oil was 438,000 BOPD in 2005, and will grow to 1,724,000 BOPD by 2020.¹¹ Hence, mining will produce a significant portion of Canada's heavy oil production for the foreseeable future.

In open-pit mining, trees and other vegetation are first removed; then the overburden is excavated and either used to build retaining dykes for ponds or stockpiled for later land reclamation. Large shovels and trucks are used to load and transport the unconsolidated oil sands from the mine face to an ore crusher. After being crushed into 12 inch or smaller chunks, the ore is slurred with water in a cyclofeeder. The slurry is sent by pipeline (hydrotransported) to a central processing facility for upgrading. The bitumen, sand and water mixtures create emulsions which are extremely difficult to separate, and the process of separating oil from the sand particles begins during hydrotransport. This process is continued in the primary separation vessel (PSV) at the central facility. Bitumen froth (60% bitumen, 30% water, 10% fine solids) is removed from the PSV and then is either processed with naphtha or paraffinic solvents to remove water and fine solids. The paraffinic solvent process results in bitumen with less than 0.1% water and fines remaining. Clean sand from the PSV is removed and stockpiled. A combination of mixed bitumen and water, fine particles and clay (fine tailings) is transported to a holding pond. The fine tailings take a very long time to dewater.

¹⁰ *Oil Sands Technology Roadmap*, Alberta Chamber of Resources (January 2004): 22.

¹¹ *Canadian Crude Oil Production and Supply Forecast 2006-2020*, Canadian Association of Petroleum Producers (May 2006): 3.

Because current mining practices recover approximately 90% of the bitumen in place, large reserves can be obtained from relatively small areas. For example, a 50-m thick oil sand with 30% porosity and 85% bitumen saturation contains 80 million barrels of bitumen per square kilometer. This corresponds to 72 million barrels of reserves per square kilometer. Since 1978, the Syncrude plant in Fort McMurray has produced more than 1 billion barrels of bitumen from a few square kilometers, and has several billion barrels of remaining reserves.

Operating costs for bitumen mining and extraction in Canada are estimated at \$16 to \$18, and integrated mining, extraction and upgrading costs are estimated at \$32 to \$36.¹²

Surface mining of bitumen has been used commercially for over 40 years and is now a mature technology. Evolutionary improvements are possible, but no major technological breakthroughs are anticipated. Technical opportunities for improvement include: sensors for real time process control, equipment monitoring, faster dewatering of the fine tailings, increased bitumen recovery, reduced water usage, and moving the slurry process to the mine face. Recovering metals such as titanium from the mined ore could provide a new revenue stream and improve economics.

The main challenges for the surface mining process are minimizing the environmental impact, land reclamation, and forest restoration. For every cubic meter of synthetic crude produced, 6 cubic meters of sand and 1.5 cubic meters of fine tailings must be transported.¹³ Stockpiled overburden, sand, and tailing ponds can occupy a significant area of the mine, and may have to be moved to access oil sands beneath them. Land reclamation has only started on a small scale. Bitumen contains approximately 5% sulfur, which is removed in the upgrading process. Because the market cannot absorb the large sulfur stream; pure sulfur is stockpiled in large mounds on site. Large quantities of water have to be captured during spring flood and stored in reservoirs for use during the low water months of the year. Large quantities of coke produced during the upgrading process must also be stored and eventually disposed.

¹² *Canada's Oil Sands Opportunities and Challenges to 2015: an Update* (June 2006): 3. Converted with \$1CAD = \$0.89 U.S.

¹³ *Oil Sands Technology Roadmap*: 3 [reference 10].

D. Subsurface (Well) Production

There are a variety of production methods for resources that are too deep for open-pit mining. However, if the resource lies between approximately 50 and 100-m depth, there is no current commercially viable production method. If the resource is between about 100 m and a few hundred meters deep, and if it has an impermeable caprock, then thermal production is possible. Some resources can be produced by allowing both oil and sand to be produced. Other resources may flow without external heat if the reservoir is hot enough and if the heavy oil viscosity is low enough. In sum, the production method must be tailored to the particular characteristics of the resource.

E. Cold Heavy Oil Production

The Faja del Orinoco belt in Venezuela is the world's largest heavy oil accumulation at 1.2 trillion barrels. Heavy oil production from this belt is expected to last for 35 years at 600,000 BOPD.¹⁴ There are a few factors and technical advances that allow this heavy oil to be produced.¹⁵ First, the viscosity is low enough with the existing solution gas that the heavy oil can flow at reservoir temperatures. Second, horizontal wells up to 1,500 m long allow the heavy oil to be produced at economic rates while maintaining sufficiently low drawdown pressures to prevent extensive sand production. More complex well geometries are being drilled with several horizontal branches (multilateral wells). Third, the horizontal legs are placed precisely in the target sands using logging while drilling (LWD) and measurement while drilling (MWD) equipment, enabling more cost effective placement of the wells. Fourth, in some locations, sand production from the unconsolidated formation is minimized using slotted liners and other sand-control methods. A low drawdown pressure in a long multilateral can also reduce the need for significant sand control. Finally, progressive cavity pumps (PCPs) and electric submersible pumps (ESPs)

¹⁴ Meyer RF and Attanasi ED: "USGS Fact Sheet 70-03, Heavy Oil and Natural Bitumen—Strategic Petroleum Resources," (August 2003). Available at <http://pubs.usgs.gov/fs/fs070-03/> (accessed 2/15/07).

¹⁵ Curtis C, Kopper R, Decoster E, Guzmán-García A, Huggins C, Knauer L, Minner M, Kupsch N, Linares LM, Rough H and Waite M: "Heavy-Oil Reservoirs," *Oilfield Review* 14, no. 3 (Autumn 2002): 42-46.

have been developed to move heavy oil. A diluent such as naphtha or light oil may be injected near the pump to reduce the viscosity of the heavy oil and allow it to be more easily pumped. Alternatively, diluent may be added at the surface to facilitate pipeline transport.

Waterflooding can also be used in some heavy oil reservoirs to maintain pressure during cold production. The Captain Field in the North Sea uses horizontal wells with specially designed ESPs for the heavy oil production, and horizontal wells for water injection.¹⁶ The horizontal injectors provide more uniformly distributed pressures and a more efficient line-water drive. Since water viscosity (~1 cp) is much lower than the heavy oil (80 to 100 cp), care must be taken to avoid water fingering from the injecting wells to the producing wells.

Cold production of heavy oil in Canada is estimated to cost \$13 to \$16 per barrel.¹⁷

The main issue for cold production is the low recovery factor, typically 6% to 15%, for primary production. Fields are not being developed with future, secondary processes in mind. For example, wells, cement, and completions are not designed for high temperatures encountered in steam injection and other thermal recovery processes. Horizontal and fishbone wells should be drilled in the optimum location with regard to permeability, porosity, oil composition, and distances above water or below gas, and the length of the laterals. Characterizing the formation and hydrocarbons in real time while drilling is essential for well placement. Drilling, measurement-while-drilling, and logging-while-drilling technologies are key enablers for this. In horizontal wells and multilateral wells, being able to monitor, understand, control, and ensure the flow from different sections of the well will improve production and reduce unwanted water and/or natural gas production. In Orinoco, natural gas production is interfering with progressive cavity pumps' ability to lift the heavy oil.

¹⁶ Etebar S: "Captain Innovative Development Approach," SPE 30369 (September 1995).

¹⁷ "Canada's Oil Sands, Opportunities and Challenges to 2015: An Update," An Energy Market Assessment, National Energy Board (NEB), Calgary (June 2006): 3. Available at www.neb-one.gc.ca/energy/energyreports/ema oilsandsopportunitieschallenges2015_2006/ema oilsandsopportunities2015qa2006_e.htm.

F. Cold Heavy Oil Production with Sand (CHOPS)

CHOPS is used for thin subsurface oil sands (typically 1 to 7 m thick) in Canada, provided the oil sand is unconsolidated and provided the heavy oil contains sufficient solution gas to power the production process. To have any natural gas in solution, the oil sand must be at least a few hundred meters deep. For example, there are a large number of CHOPS wells located near Lloydminster, Alberta. In fact, today CHOPS is the only commercial method for exploiting these thin oil sands. CHOPS wells (by definition) require sand production. Foamy oil production may occur without sand production in other areas, such as in the Faja belt, Venezuela. Alternatively, oil may be produced with sand, but without solution gas in still other areas. This section deals with CHOPS as developed and used in Canada.

It is believed that CHOPS production occurs with the formation of “wormholes,” tunnels that may extend some distance into the formation. There are no current methods for predicting the distribution, location, length, or diameter of wormholes, and there are very limited means of measuring them once formed. Surface seismic may give an indication of their distribution and density. Hence, there is considerable uncertainty about the behavior of CHOPS wells.

CHOPS wells are vertical or slightly deviated wells; they are cased and perforated, and a downhole pump is deployed to create an aggressive pressure differential between formation and wellbore pressures. This causes natural gas to break out of solution from the heavy oil, resulting in “foamy oil.” Gas bubbles evolving at the wormhole-sand interface destabilize sand grains and the expanding gas helps move the mixture through the wormholes. Gravity drive on the unconsolidated sands also provides energy for production. At the start-up of production, up to 10% sand by volume is produced along with oil, water, and gas. Sand production eventually falls to under 2% during the well lifetime.

The recovery factor for CHOPS wells is low, typically less than 10%.¹⁸ Hence, the well must be drilled, completed, and operated as economically as possible.

¹⁸ *Oil Sands Technology Roadmap*, Alberta Chamber of Resources, Edmonton (January 2004): 28. Available at http://www.acr-alberta.com/ostr/OSTR_report.pdf.

Extraction costs are currently estimated at \$14 to \$17 in Canada.¹⁹ A large number of CHOPS wells are shut in, having stopped producing oil. There are many possible reasons. A well may water-out if a wormhole reaches a water zone, since water flows preferentially due to its much lower viscosity. The wormhole may reach a region where there is insufficient natural gas in the oil to break off sand grains. The sand face may become too strong to allow the wormhole to grow. The wormhole may migrate and interact with wormholes from other wells which have stopped producing. The wormhole may collapse. Infill drilling a well for CHOPS may result in a non-productive well surrounded by nearby productive wells. Alternatively, an infill well may encounter severe lost circulation problems if it intercepts an existing wormhole.

The surface footprint for CHOPS wells is small, only requiring space for the wellhead, a storage tank, and a small doghouse. Any produced gas is used on site to power equipment or to heat the storage tank. Because a large volume of sand is produced, pipelines cannot be used for transportation. Instead, trucks are required to move oil, water, and sand for processing or disposal. During spring break-up, the CHOPS wells in Alberta must be shut in since trucks cannot navigate the roads.

The technical challenges for CHOPS wells include a better understanding of their behavior and more predictive performance models. Progressive cavity pumps have increased production rates, but increased reliability and longer maintenance-free periods would improve economics. A method for water shut-off would bring some unproductive wells back to life. A major breakthrough would be a secondary recovery method to tap the remaining approximately 90% of the original oil in place. Two possible secondary recovery methods are in situ combustion and solvent flood. Neither has been demonstrated in a commercial operation. A primary production method that has a higher recovery factor would also have a significant impact. A high recovery factor and oil production without sand might replace trucking with pipelines, thus reducing CO₂ emissions and manpower costs, and allowing year-around production.

¹⁹ “Canada’s Oil Sands, Opportunities and Challenges to 2015: An Update”: 3 [reference 17], converted at \$0.89 US\$ per \$CAD.

G. Cyclic Steam Stimulation (CSS) and Steamflood

CSS is often the preferred method for production in heavy oil reservoirs that can contain high-pressure steam without fracturing the overburden. In Canada, the minimum depth for applying CSS is 300 m even though there are some limited locations in other areas where steam injection has been successful at depths between 200 and 300 m.²⁰ Extraction costs are estimated at \$18 to \$21 in Canada.²¹ CSS works best when there are thick pay zones (>10 m) with high porosity sands (>30%). Shale layers that reduce vertical permeability are not a problem for vertical wells that penetrate thick pay zones. However, good horizontal permeability (>1 darcy) is important for production. Recently, CSS has been applied to wells with multilateral horizontal legs.

There are three phases in CSS. First, high-temperature, high-pressure steam is injected for up to one month. Second, the formation is allowed to “soak” for one or two weeks to allow the heat to diffuse and lower the heavy oil viscosity. Third, heavy oil is pumped out of the well until production falls to uneconomic rates, which may take up to one year. Then the cycle is repeated, as many as 15 times, until production can no longer be recovered. Artificial lift is required to bring the heavy oil to surface. Typical recovery factors for CSS are 20% to 35% with steam-to-oil ratios (SOR) of 3 to 5.²²

Steamfloods may follow CSS. While CSS produces the heavy oil around a single wellbore, steamflood recovers the heavy oil between wells. For example, a five-spot pattern with four producing wells surrounding a central steam injection well is a common configuration. The well spacing can be less than 2 acres for a field in steamflood. The steam heats the oil to lower its viscosity and provides pressure to drive the heavy oil toward the producing wells. In most steamflood operations, all of the wells are steam-stimulated at the beginning of the flood. In a sense, CSS is always the beginning phase of a steamflood. In some cases, even the steamflood injection wells are put on production for one or two CSS cycles to help increase initial project production and pay-out the high steamflood capital and operating costs.

²⁰ *Oil Sands Technology Roadmap*: 28 [reference 18].

²¹ “Canada’s Oil Sands, Opportunities and Challenges to 2015: An Update”: 3 [reference 17].

CSS and steamfloods are used in California, Western Canada, Indonesia, Oman, and China. California's Kern River production rose from less than 20,000 barrels per day in the late 1950s before CSS, to over 120,000 barrels per day by 1980 after the introduction of CSS.²³ The Duri field in Indonesia is the world's largest steamflood and produces 230,000 BOPD with an estimated ultimate recovery factor of 70% in some locations.

Technical challenges for CSS and steamflood are primarily related to reducing the cost of steam, which is generated in most locations using natural gas. The economics may be improved by also generating and selling electricity, and by using waste heat for co-generation. Alternative fuels (coal, heavy ends, coke) are discussed separately below, but could also reduce the cost of steam generation. Monitoring and controlling the steam front could also reduce costs by redirecting steam to zones where the heavy oil has not been produced. Steam could then be shut-off from zones that have been successfully swept and directed toward unswept regions. Gravity override (see Figure VG.1) is a natural occurrence in every steamflood. The steam breaks through to the producers, at which time the process turns into a gravity drainage process. The steam chest at the top of the formation expands downward and the heated heavy oil drains by gravity to the producing wells. Although the geometry configuration is totally different than SAGD (described later), the basic physics is the same.

Measuring the produced fluids (oil, water, and natural gas) at surface for each well can be used to optimize production by adjusting artificial lift rates and steam-injection rates. Downhole fluid-flow measurements could be used to identify which zones are producing oil, water, or gas in a producing well.

Monitoring may involve drilling observation wells where permanent sensors may be deployed, or where logging can be periodically performed. Downhole temperature and pressure sensors may use fiber-optic or wireline technology. Water and steam saturation outside the observation well's casing can be measured with nuclear spectroscopy logs. Time-lapse, cross-well electrical imaging can be used to identify bypassed heavy oil zones between closely spaced (500 m) observation wells. Cross-

²² *Oil Sands Technology Roadmap*: 28 [reference 18].

well seismic and surface seismic measurements might be used to locate steam fronts. However, high-resolution imaging of the formation and the fluid saturations before completing the wells and during production is an open technical challenge.

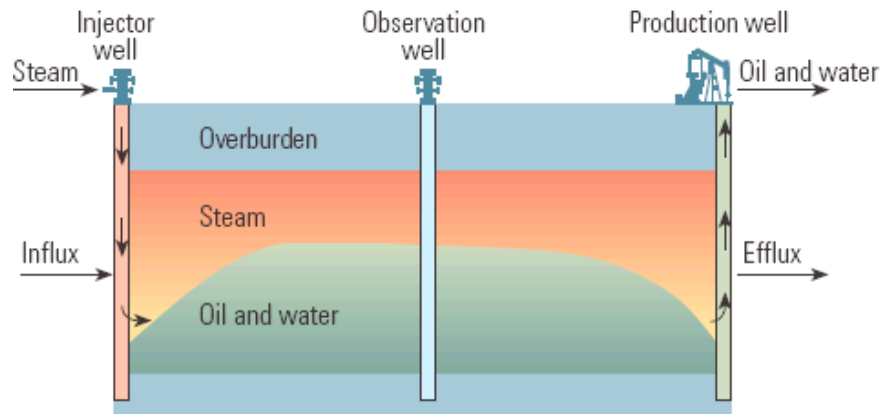


Figure VG.1. Gravity override in a steamflood
(Source *Oilfield Review* [reference 15]).

Technologies must be reliable and have long operating periods between service periods. High temperature (up to 300°C) and corrosion-resistant equipment including pumps (artificial lift), cements, completions, liners, packers, valves, electronics, and sensors are needed. Thermal expansion of the formation can also cause the casing to fail.

Most CSS and steamflood wells have been vertical wells. More recently, vertical wells with multilateral braches and horizontal wells are being tried for CSS and steamflooding. The advantage is a reduced footprint while tapping large subsurface regions. Optimal control and configuration of these wells for CSS and steamflood recovery processes are still being developed.

H. Steam Assisted Gravity Drainage (SAGD):

SAGD is a more recent development than CSS or steamfloods. SAGD is expanding rapidly in western Canada due to its ability to produce heavy oil from formations too shallow for conventional steam injection methods. Because SAGD

²³ Curtis, et al: 50 [reference 15].

wells operate at lower steam pressures than CSS or steamflood wells, less overburden steam containment is required. SAGD wells can exploit formations from 100 m to a few hundred meters deep.

In SAGD, two wells with horizontal sections are drilled with one well directly above the other well. The two wells maintain a constant vertical separation of typically 5 m, but 3 to 7 m could be used depending on the oil viscosity. The horizontal sections are typically are 500 to 1,500 m long, and are completed with slotted liners to reduce sand production and increase oil productivity. In the start-up phase, steam is injected in both wells to reduce the heavy oil's viscosity. In the production phase, steam is injected in the upper well and heavy oil is produced from the lower well.

Ideally, a steam chamber is formed above the injection well, but does not break through to the lower well (Figure VH.1). Heat travels by convection of the steam to the edge of the steam chamber, where the steam releases its heat of vaporization to the heavy oil and formation, and condenses into water. The heated oil and hot water drain into the producing well. Because gravity provides the drive rather than steam pressure, the steam injection pressure is lower than that for CSS or steamflood. Artificial lift is required to move the viscous oil to surface. Gas lift is the least expensive approach; progressive cavity pumps and electric submersible pumps are more effective, but must survive high temperatures.

Production from a pair of SAGD wells is anticipated to last from 7 to 12 years with a relatively constant output over that time. A SAGD well can produce from 500 BOPD up to several thousand BOPD. Recovery factors of 50% to 70% are theoretically predicted for SAGD, with SOR values in the range of 2 to 3. At this time there are not enough mature, completed SAGD projects to determine ultimate recovery factors. Extraction costs for SAGD are \$16 to \$18.²⁴

²⁴ "Canada's Oil Sands, Opportunities and Challenges to 2015: An Update": 3 [reference 17], converted at \$0.89 US\$ per \$CAD.

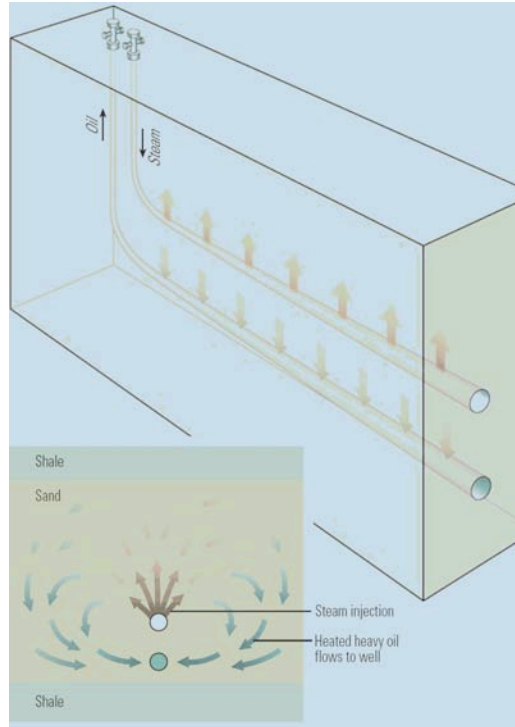


Figure VH.1. Steam assisted gravity drainage (SAGD configuration (Source *Oilfield Review* [reference 15]).

For SAGD to be effective the heavy oil zone must be at least 10 m thick; preferably it is thicker. The formation must have good vertical and horizontal permeabilities; if there are shale layers, the steam chamber cannot form properly. Hence, evaluation of the vertical permeability is important before using SAGD to develop a resource. Gas zones above the heavy oil, or water zones below, may result in heat loss and higher energy costs. A depleted gas zone is a major heat thief; the Canadian government has placed restrictions on gas production above heavy oil layers until after the heavy oil has been produced.

Several SAGD pairs can be drilled from a central pad so that they share facilities, steam generation equipment, production equipment, transportation (pipelines and roads), and upgrading. SAGD well pairs are typically placed 40 to 200 m apart, depending on reservoir properties. When well pairs decline, additional well pairs can be brought on-line to maintain the optimum production rate for the surface equipment.

A SAGD pad might exploit an underground resource 1,000 to 3,000 m in diameter from a much smaller surface footprint. Site preparation involves removing

trees and leveling the ground, but does not involve extensive excavation, so land reclamation and reforestation is simpler than for mining. Water used to produce steam can be recovered (90%) and recycled so the volume of water is much less than for other methods. Water can even be drawn from subsurface reservoirs and eventually disposed in wells, so that surface water is not used or affected. Except for CO₂ emission, SAGD wells have a much smaller environmental impact than mining.

Many of the same issues occur for SAGD as for CSS and steamflood, such as the energy costs. Monitoring and controlling the steam front is critical for reducing steam usage and for optimizing production. The steam chamber should extend from the heel to the toe of the injection well without breaking through to the producing well. Fiber-optic sensors are used to monitor well temperatures and downhole pressure gauges can be used to monitor the steam chamber pressures. Other technical challenges are similar to those for CSS and steamflooding.

I. Technologies in Development

There are several technologies in research, development, or pilot phase which are not yet commercial.

1. Vapor Assisted Petroleum Extraction (Vapex)

Vapex is a non-thermal solvent-based technology that is undergoing pilot field tests.²⁵ As with SAGD, two parallel horizontal wells are drilled with about a 5 m vertical separation. Rather than injecting steam in the upper well, a solvent consisting of propane, butane, naphtha, methane, or a mixture is injected as a vapor into the upper well. A vapor chamber is formed, and the vapor travels to the bitumen face where it condenses into a liquid. The solvent mixed with the bitumen flows to the lower well and is pumped to the surface. This is a relatively cold (40°C), low-pressure process that does not involve depositing significant amounts of energy into the formation. Vapex reduces the need for natural gas and water. However, vapex is a slow process and does not appear to be economic at present. The biggest economic

²⁵ Mokrys IJ and Butler RM: "In situ Upgrading of Heavy Oils and Bitumen by Propane Deasphalting: The Vapex Process," SPE 25452 (1993).

concern with vapex is the extremely high cost of the solvent and the ability to recover a high percentage (>90%) of the valuable injectant.

2. Hybrid Solvent and Steam Processes

By combining a solvent with SAGD, the energy requirements may be reduced, production rates increased, and recovery factor increased. In addition, capital investment, CO₂ emission, water and natural gas usage may be reduced.²⁶ The solvent is injected as a vapor with the steam. Mixed with the heavy oil, it reduces the viscosity and may even provide some in situ upgrading. Pilot testing is underway in a few locations in Canada. Again, high cost and recovery of the solvent are critical to success.

3. In Situ Combustion

Downhole combustion of heavy oil can provide the heat to mobilize the heavy oil and can provide some in situ upgrading. This process is also known as fire flooding. Either dry air or air mixed with water can be injected into the reservoir. Ideally, the fire propagates uniformly from the air injection well to the producing well, moving oil and combustion gases ahead of the front. The coke remaining behind the moved oil provides the fuel. Temperatures in the thin combustion zone may reach several hundred degrees centigrade, so that the formation and completion hardware can be severely stressed. Except in special situations (the Bellvue field in Louisiana, multiple fields in Romania, and India), in situ combustion has not been successfully applied. The fire front can be difficult to control, and may propagate in a haphazard manner resulting in premature breakthrough to a producing well. There is a danger of a ruptured well with hot gases escaping to the surface.

The produced fluid may contain an oil-water emulsion that is difficult to break. As with output from many heavy oil projects, it may also contain heavy-metal compounds that are difficult to remove in the refinery. In situ combustion eliminates the need for natural gas to generate steam, but significant energy is still required to compress and pump air into the formation.

²⁶ Gupta SC: "Unlocking The Planet's Heavy Oil And Bitumen Resources—A Look at SAGD," SPE 108799-DL (March 2005).

Conventional fire-flood projects have used vertical wells for injecting and producing oil. A pilot project is underway where the air is injected in a series of vertical wells and produced in a number of parallel horizontal wells.²⁷ The objective is better control of the fire front by reducing the distance the moved oil has to travel to the producer. Since the horizontal producer lies directly below the combustion front, the mobile heavy oil can drain into the producer. Combustion gases rise to the top of the oil zone, and therefore do not breakthrough into the producing well. A variation is to place a catalyst in the producing well to enhance the upgrading process.²⁸

4. Alternative Fuels

Natural gas is used extensively to generate steam for heavy oil production and as a source of hydrogen via steam methane reforming for upgrading heavy oil. Many projects have historically used the produced heavy crude as fuel. However changes in emission constraints, more efficient boilers, and cogeneration of steam and electricity with turbines have changed the fuel of choice. Approximately 1,000 cubic feet of natural gas are required to produce the steam to recover 1 barrel of heavy oil via thermal processes. Upgrading requires approximately 500 cubic feet of natural gas to produce 1 barrel of synthetic crude.²⁹ For business as usual, the Canadian oil sands will consume 2,000 Tcf of natural gas by 2030.³⁰ With the pending shortage of natural gas in North America, the availability and cost of natural gas will require the use of an alternative fuel. These alternative fuels include coal, heavy ends (asphaltenes), coke, and nuclear. The three fossil fuels contain large amounts of carbon compared to natural gas, and raise concerns about increased greenhouse gas emissions, especially with increased heavy oil production.

One approach undergoing pilot field test is integrating SAGD with on-site upgrading and gasification.³¹ The produced bitumen is upgraded to synthetic crude

²⁷ Collison M: "Hot About THAI," *Oil Week* (March 1, 2004): 42-46.

Greaves M, Xia TX, and Ayasse C: "Underground Upgrading of Heavy Oil Using THAI—'Toe-to-Heel Air Injection,'" SPE 97728 (2005).

²⁸ "Unleashing the Potential Heavy Oil", *E&P Oil and Gas Investor* (July 2006): 15.

²⁹ *Oil Sands Technology Roadmap*: 14 [reference 18].

³⁰ *Oil Sands Technology Roadmap*: 14 [reference 18].

³¹ See Nexen OPTI Long Lake at <http://www.longlake.ca/> (accessed 11/06).

oil, and the residual heavy ends are used to produce the steam and hydrogen via gasification. This eliminates the need for natural gas and should reduce costs. The syncrude can be transported by pipeline without the need for a diluent. Carbon dioxide is still released to the atmosphere, but it could potentially be captured and sequestered.

Coke is a byproduct of the upgrading process and could also be used to generate steam via combustion or steam and hydrogen via gasification. Coal is abundant and inexpensive in North America, and could also be used in the same manner. It is even possible to use some of the produced heavy oil as a fuel stock. However, possible future restrictions on CO₂ emissions or a CO₂ tax could favor gasification with CO₂ capture and sequestration over simple combustion. Since gasification produces a stand-alone CO₂ stream, it is easy to capture. In contrast, normal combustion techniques produce CO₂ mixed with many other flue gases, making it more difficult to separate and capture CO₂. The main concern with gasification is the extremely high capital cost for the available gasifier technology. For the Canadian oil sands, CO₂ sequestration will probably require a dedicated pipeline system for transportation to deep aquifers or hydrocarbon reservoirs. The bedrock underlying the Canadian oil sands is not a likely sequestration site. The economics for CO₂ capture and sequestration are estimated to add about \$5 per barrel for SAGD.³²

Nuclear power has been proposed for the Canadian oil sands to produce electricity, steam, and hydrogen via electrolysis.³³ The nuclear option faces societal concerns about safety, nuclear waste disposal, and proliferation. Additionally, a small reactor would be needed to match the requirements for a SAGD site.

5. In Situ Upgrading

In situ upgrading can reduce the viscosity of heavy oil by cracking long hydrocarbon chains, and can improve oil quality by reducing or removing asphaltenes and resins. Asphaltenes may contain iron, nickel, and vanadium, which are damaging

³² *Energy Technology Perspectives, Scenarios and Strategies to 2050*, International Energy Agency (2006): 266.

³³ Gauthier-Villars D: "Total May Use Atomic Power At Oil-Sand Project," *Wall Street Journal* (September 28, 2005): B6.

to refineries. Excess carbon, in the form of coke, may be left in the reservoir. The upgraded oil will flow more readily into the wellbore (increasing recovery factor), is easier to lift to surface, and may eliminate the need for a diluent for pipeline transportation. Furthermore, in situ upgrading might eliminate the need for surface upgrading facilities, thus reducing capital investments. In a conventional thermal process (e.g. SAGD), the heavy oil is heated in situ, but may cool after being produced to surface. It then has to be reheated for upgrading. In situ upgrading may be more energy efficient as well.

Heavy oil molecules can be pyrolyzed into lighter hydrocarbon molecules at high enough temperatures and pressures. In the pyrolysis of heavy oil, carbon-carbon bonds in the hydrocarbon chain are broken by heat; essentially the vibrational energy exceeds the chemical energy in the C-C bond. Pyrolysis occurs in the absence of oxygen or a catalyst, although steam may be present. For example, steam cracking and thermal cracking are done in refineries at temperatures at or above 800°C. While such high temperatures are difficult to achieve in the reservoir, pyrolysis can still occur at lower temperatures, but at much, much slower rates.

There are three main approaches for heating the reservoir: steam injection, in situ combustion, and electric heating. Steam injection pressures are limited because most heavy oil deposits are relatively shallow. Hence, the maximum steam temperature is limited by the ideal gas law. For example, at 1,000-m depth, the formation pressure will be approximately 10 MPa, permitting a steam temperature of approximately only 300°C. This is too low to provide significant upgrading on a short time scale. In situ combustion is capable of much higher temperatures (approximately 700°C),³⁴ which should allow significant upgrading. Electric heating (resistance, induction, or RF) should also be able to achieve the high temperatures required for in situ upgrading.³⁵

³⁴ See www.petrobank.com/webdocs/news_2006/2006_09_12_WHITESANDS_Update.pdf (accessed 11/06).

³⁵ Mut S: "Oil Shale and Oil Sands Resources Hearing" (April 12, 2005). Available at energy.senate.gov/public/index.cfm?FuseAction=Hearings.Testimony&Hearing_ID=1445&Witness_ID=4139 (accessed 11/06).

"Venezuela Looks to Shell's ICP Technology for the Orinoco," *MarketWatch* (August 11, 2006). Available at http://www.tellshell.net/blog/MarketWatch/_archives/2006/8/12/2223600.html.

Adding a catalyst (such as iron) to a thermal process may enhance in situ upgrading, even at the lower temperatures for steam injection.³⁶ Laboratory experiments combining in situ combustion with a catalyst in a horizontal producing well produced significantly upgraded oil. Thermal cracking occurred in the combustion zone, and additional upgrading was achieved by catalytic cracking in the production well.³⁷

Biotechnology is a very active area of research, and it is natural to expect that some discoveries will spill over into the oil and natural gas technology. Microbiological enhanced oil recovery (MEOR)³⁸ has been the subject of research since the 1980s, primarily to reduce pore blockage in the near wellbore area, or to produce surfactants or solvents in situ.³⁹ Enzymes from some bacteria have proved to be capable of minimal upgrading in controlled surface environments. In addition, some microbially generated surfactants have improved oil recovery in laboratory core floods. However, placing bacteria in situ to upgrade heavy oil has not been achieved. Technical challenges include dispersal into the formation, providing nutrients, competition with existing microorganisms, and not blocking permeability.

Supercritical CO₂ is an effective solvent with very low viscosity that is used in food processing, cleaning, and other industries. CO₂ is supercritical for temperatures above 31°C and pressures above 1,050 psi, so that it cannot be used in the shallowest resources. In supercritical state, it is miscible in hydrocarbons. CO₂ is inexpensive compared to other solvents that might be used for reducing the viscosity of heavy oil and for in situ upgrading. CO₂ produced during heavy oil production or upgrading may be geologically sequestered in a supercritical state, thus achieving two goals simultaneously. However, this has not been demonstrated yet.

³⁶Jiang S, Liu X, Liu Y and Zhong L: "In Situ Upgrading Heavy Oil by Aquathermolytic Treatment under Steam Injection Conditions," SPE (2005).

³⁷ Xia TX, Greaves M, Werfilli WS and Rathbone RR: "Downhole Conversion of Lloydminster Heavy-Oil Using THAI-CAPRI Processes," SPE 78998 (2002).

³⁸ Saxman DB and Crull A: "Biotechnology and Petroleum Production," SPE 13146 (1984).

³⁹ Bailey SA, Kennedy TM and Schneider DR: "Microbial Enhanced Oil Recovery: Diverse Successful Applications of Biotechnology in the Oil Field," SPE 72129 (2001).

J. Research and Development Issues

New technologies for the in situ production of heavy oil require large investments and long times for research, development, testing, and commercialization. Laboratory research into the properties of heavy oil and core samples in realistic conditions is needed to provide input to simulators. For example, few laboratories exist that are capable of making measurements at the high temperatures encountered in steam injection, in mixed steam and solvent environments, or during in situ combustion.

Scaling up from laboratory studies to full scale production is costly and time consuming. Pilot studies are mandatory before undertaking full-scale commercial operations, but pilot studies may cost up to \$100M and last up to 10 years. The high cost limits the number of pilot studies that can be done. Since the purpose is understanding and optimizing a new production technology, there are additional expenses for monitoring wells, extra surface and downhole equipment. The additional operating time for varying parameters is also costly.

Hence, new innovations can be expected to occur on a decadal time scale. Those ideas in laboratory research today will still require a decade of pilot study before commercial operations will start in earnest. Among the most noticeable research institutions working on technologies for heavy oil are the following:

- Alberta Research Council (Canada)
- C-FER (Canada)
- Saskatchewan Research Council (Canada)
- Institut Francais du Petrole (France)
- University of Alberta
- University of Calgary
- Stanford University
- University of Texas
- Texas A & M
- University of Houston
- National and major oil companies.

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