

Pilot Testing of Post-Steam Bitumen Recovery from Mature SAGD Wells in Canada

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Abstract

The world's first Steam Assisted Gravity Drainage (SAGD) wells were operated at the Underground Test Facility (UTF) in the Athabasca Oil Sands near Fort McMurray, Alberta, Canada. The SAGD technology development pioneered at the UTF has led to a revolution in technology for recovery of bitumen and heavy oil in Canada with numerous new projects under way. After 8 years of operation, the SAGD wells at the UTF are now the most mature SAGD wells in the world and are approaching the end of economic recovery with over 55% of the original oil-in-place produced. A new experimental technology is being pilot tested to extend economic recovery from the wells by dramatically reducing or terminating steam injection and continuing production with pressure maintenance through the injection of non-condensable gas. In addition to continued production, the pressure maintenance will test the operation of a new SAGD well pair next to the mature wells to determine if the loss of steam to the depleted area can be controlled. This will reduce or eliminate the need for non-productive buffer areas to provide isolation between new and depleted SAGD operations. The paper provides an overview of SAGD technology development and current operations including partial produced water recycle using new technology and new innovations in drilling, completing and operating SAGD wells.

Major Bitumen Reserves in Alberta

Canada's heavy oil and bitumen resources are extensive totaling more than 280 billion cubic meter (m^3). In Alberta, the major currently exploitable bitumen reserves are Athabasca, Peace River and Cold Lake, which contain about 170 billion m^3 "original-oil-in-place".

About 10% of the Athabasca bitumen deposits or 1.4 billion m^3 are located sufficiently near the surface to allow surface mining of the oil sands and extraction of the bitumen by the modified Clark Hot Water Extraction Process. The oil sands mining projects Syncrude Canada Ltd. and Suncor Inc.

currently produce about 22% of Canada's crude oil production by surface mining down to a depth of about 130 meters.

The remaining deeper oil sands resource can be exploited by using new improved in-situ thermal technologies like the Steam Assisted Gravity Drainage (SAGD) Process applied with twin horizontal wells. In the Athabasca oil sands alone, assuming a 15-meter average pay zone, there are over 140 billion m^3 (900 billion barrels) of original bitumen-in-place. Of this resource, more than 50 billion m^3 (330 billion barrels) are recoverable using the SAGD *in situ* process (Figure 1). This volume of oil could supply the USA and Canada's current crude oil needs for more than sixty years.

Need for Development of Athabasca Reserves

The Alberta Government recognized that the reserves of conventional oil in Alberta regions were dwindling at a rapid rate and the Canadian offshore regions were at that time too expensive to develop. The oil sands resources are comparatively very large and are known to exist, that is, there are very few finding costs involved in development of the oil sands. However, there was a great need to develop new technologies to reduce the capital and operating costs for extracting and upgrading the bitumen. In 1974, the Alberta Government created a crown corporation, the Alberta Oil Sands Technology and Research Authority (AOSTRA). AOSTRA had the specific mandate to develop with industry in a shared funding approach new or improved technologies to economically exploit the huge oil sands reserves in Alberta.

One of the main targets was the Athabasca oil sands region of Alberta where new technologies were required to develop the large reserves too deep for surface mining.

New Technologies are Key to Oil Sands Development

Several predictions would indicate that the world price of crude oil will continue in a range of U.S. \$15–\$24 per barrel for the next 7–10 years. Given that the oil sands reserves are well established and hence require very little “finding” costs, the key to economical oil sands development lies in utilization of improved lower cost extraction and processing technologies.

The breakthrough technology that will probably open up the Athabasca oil sands more than any other *in situ* process will be the Steam Assisted Gravity Drainage (SAGD) process that extracts *in situ* bitumen economically using twin horizontal wells.

Requirements for Successful Oil Sands Development

There are several other key conditions, which have to be met in order to commercially develop the oil sands deposits in northern Alberta, Canada. Today Industry and the Alberta and Canadian governments have worked together to achieve the following goals:

1. Enable increased exports of oil to USA markets.
2. Develop “black oil” pipelines from Fort McMurray to Edmonton.
3. Minimize capital and operating costs by new technology.
4. Utilize existing technical expertise and management know-how.
5. Provide favorable royalties and taxes.

UTF Pilot Project Developed

The Underground Test Facility (UTF) was to test the concept of *in situ* bitumen extraction using the Steam Assisted Gravity Drainage (SAGD) process.

Features of the current UTF Project are shown in Figure 2. It consists of two vertical shafts 3.3 meters (m) in diameter penetrating 140 m of overburden, 20 m of oil sands and 15 m of limestone below which are located horizontal tunnels 5 m wide and 4 m high. The tunnels are in solid limestone and are larger where the wells are located (8 m wide x 5 m high) and smaller (4 m wide x 3 m high) where the tunnels serve only to complete the access and ventilation circuit. From the tunnel walls, horizontal wells were drilled upwards through the limestone and then horizontally into the oil sands pay zone.

In the first, proof of concept test (Phase A), the three well pairs were 60 meters long and 25 meters apart in the oil sands. The test proved highly successful.

The Phase B program consisted of three well pairs spaced 70 meters apart horizontally. Each well pair consists of an injection well (upper) and production well (lower) spaced 3–5 meters vertically apart near the bottom of the pay. The six wells are each 600 meters long of which 500 meters are drilled horizontally in the oil sands pay zone.

Why Tunnel Drilled SAGD Wells?

During the early 1980s, there were very few successful long horizontal wells drilled and/or operating. At an “oil mine” project near Uregea, Russia, oil was being recovered from wells placed horizontally into the oil reservoir from the walls of underground tunnels. A team of industry consultants working together with AOSTRA conceived the Underground Test Facility north of Fort McMurray, Alberta, Canada to extract bitumen from the oil sands by drilling and operating horizontal well pairs from shafts and tunnels excavated in the limestone below the oil sands.

It was not till the early 1990s that horizontal wells from the surface were successfully drilled, completed and commercially operated.

In 1995, the operation of the UTF “B Wells” had successfully proven the operation of the “steam trap” well production control mechanism. Also by this time the well drilling/completion industry had gained much experience in drilling horizontal wells from the surface.

Also during 1995, the UTF Project drilled and completed two horizontal SAGD well pairs from the surface. These wells known as the “D Wells”, are currently in operation.

UTF SAGD Project Location

The UTF demonstration project is located on a 20,000 hectare lease currently owned by the Joint Venture consisting of Northstar Energy Corporation (58 1/3%), Chevron Canada Resources Limited (8 1/3%), CNPC Canada Ltd. (8 1/3%), Gibson Petroleum Company Limited (8 1/3%), Imperial Oil Resources Limited (8 1/3%), and Petro Canada (8 1/3%). It is about 60 kilometers north west of Fort McMurray (Figure 3).

The Steam Assisted Gravity Drainage (SAGD) Process

During the early 1980s, the gravity drainage of steam-heated heavy oil to horizontal wells was investigated and reported in publications by R. M. Butler, then with Imperial Oil Limited. In 1989, N.R. Edmunds, J. A. Haston and G.M. Cordell patented the Steam Assisted Gravity Drainage (SAGD) Process using parallel horizontal wells (at the UTF Project) on behalf of the Alberta Oil Sands Technology and Research Authority.

Steam is injected into the upper well and production comes from the lower well. (Figure 4). Steam, injected just below formation fracture pressure, “melts” the cool, immobile bitumen which flows by gravity to the lower well. The lower production well operates using the “steam trap” technique to prevent steam vapor entering the well bore. This entails throttling the producer well to maintain the temperature of the production stream just below saturated steam conditions. The produced fluids are piped to the surface facilities for treatment and recovery of dry bitumen.

The process is started by circulating steam in both wells to heat the oil sands between them until the bitumen is liquid enough to flow into the lower well. The space in the pores created by the produced bitumen fills with steam that is injected into the reservoir by the upper well. This steam in turn “melts” more bitumen at the periphery of this small steam chamber, which flows to the lower well by gravity. The steam chamber grows as bitumen is produced. When steam from the upper well reaches the lower well, steam circulation is stopped in the lower well and is injected only into the upper well at constant pressure (just below fracture, at about 2,600 kPa) and fluids are produced from the lower well at just below steam saturation temperature (approximately 215°C).

The process continues steadily in this manner until over 55% of the original-bitumen-in-place is removed. Not having to fracture the formation in order to get steam distribution, leads to low steam-oil ratios (SOR ~2.5) and high recovery.

There are no down-hole pumps in the wells because the reservoir pressure is maintained high enough to lift the fluids to surface. In addition, fluid velocities into the well bore are low and no sand production is experienced.

The produced hot fluids are pressured to the surface where the “dry” bitumen is separated and trucked to market. The bitumen produced has a viscosity of 7 centipoise at 220°C, density of 8.7°API and contains 4.8% sulphur. The typical Athabasca-McMurray oil sands reservoir parameters (at the UTF) are shown in Figure 5.

Status of the Three Tunnel Drilled SAGD Well Pairs

The Phase B of the UTF Project was designed to confirm the accurate drilling and completion of commercial length twin horizontal well pairs and the efficient performance of the reservoir.

The three well pairs were successfully drilled and completed from tunnels within technical and cost guidelines. All three well pairs have been operating as predicted since start-up. Each well pair produced about 100 m³/day at its peak and the current production for the three well pairs is steady at a target of 190 m³/day (1,230 BPD).

The cumulative steam-oil ratio is 2.5 average and the ultimate target was 2.3. The dry bitumen is shipped undiluted by

truck to Syncrude, Suncor and south to the Edmonton area markets.

These Phase B tunnel drilled SAGD horizontal well pairs have been operating for over eight (8) years at near predicted production and oil cut and have extracted over 55% of the original-bitumen-in-place. Original-bitumen-in-place was established by reservoir performance computer modeling prior to start-up within pre-set geographic areas of the oil sands reservoir to where the mature steam chamber would grow. These “B” wells have produced over 400,000 tonnes (2,500,000 barrels) of bitumen and are currently in their decline as show in Figure 6.

Surface SAGD vs. Tunnel SAGD

The original concept of twin horizontal wells drilled from tunnels upwards and horizontally into the oil sands pay zone was co-ordinated by AOSTRA in 1980. The tunnel SAGD concept was selected since, during the early 1980s the technology for drilling, completion and operation of long horizontal wells drilled from surface was still in its infancy. Recent commercial plant studies however have indicated that SAGD wells drilled, completed and operated from surface are more economical than those drilled, completed and operated from tunnels. The same reservoir performance is expected in both the tunnel and surface approaches. The major test conditions to be proven with the surface wells will be the “steam trap” control mechanism and gysering effects.

Major strides have been accomplished by the Canadian drilling industry in recent years. The Shell Twin Well Enhanced SAGD Project (ESAGD) in Peace River is designed to prove the technical and economic feasibility of drilling and operating wells of 500 m to 1,000 m long twin horizontal SAGD well pairs at a depth of some 600 meters. This has proven economically feasible and it has lead to Shell expand their Peace River operation using the twin horizontal SAGD well technique instead of the original vertical well pressure cycle steam drive. In contrast, the UTF Athabasca oil sands are located about 140 meters from the surface, are about 20 meters thick and hence require greater “pull down” capability in the drilling rig.

SAGD Horizontal Wells Drilled From the Surface — “D Wells”

In 1995, the decision was made to drill, complete and operate from the surface, two SAGD horizontal well pairs having a length of 750m in the oil sands pay zone. Preliminary analysis indicated that this expansion could double UTF production from 320 m³/d (2,000 BPD) to 640 m³/d (4,000 BPD) and remain within the currently approved net budget funding. The net revenue from bitumen product sales was re-invested into the test program.

The new surface well program consisted of the following:

- a. Two pairs of SAGD horizontal Wells, each pair consisting of an injector well and producer well, 750 m horizontal section in the oil sands pay zone. The injector well is 3 m to 7 m above the production well. A 45% slant drilling rig was used. One well pair (D1) had 219 millimeter (8 5/8 inch) diameter casing and the other (D2) had 178 millimeter (7 inches) diameter casing. Both were fitted with wire-wrapped screens.
- b. Four vertical delineation/observation wells were drilled, cored and logged, for geological control, tie-in to geophysical program and to provide reservoir instrumentation near the mid point and toe of the horizontal section of the well pairs. Figure 7 illustrates the layout of the new surface well pairs “D” in relation to the Phase A and B tunnel drilled wells. Figure 8 illustrates the production forecast.

There were several key features that needed to be confirmed from the new longer commercial length surface drilled SAGD wells. These were:

 - Drilling and completing new design commercial length wells from surface.
 - Good production control, to minimize gysering effects and steam vapor production.
 - No sand production.
 - No requirement for down hole pumps.
- c. The expansion of the surface production and steaming facilities consisted essentially of a new 50 million BTU/hour boiler, increasing the pumping capacity of a boiler feed water pump, a new well head skid located near the wells to control steam to the wells and production from the wells.
- d. New disposal wells have been drilled to handle increased volumes of produced water and boiler blowdown water.

Partial Success With Placement of the “D” Surface Drilled SAGD Wells

The four 750 m long horizontal wells were successfully drilled, however, problems were encountered in placing the two (2) liners in the second well pair (D1). The drilling and completion was done by a slant rig which had to be provided initially with additional pull-down capacity because of the shallow (160 m) total vertical depth of the horizontal wells. (Figure 9).

One well pair was successfully completed to its design length of 750 m with a 178 mm diameter (7 inch) wire wrapped screen. The 219 mm diameter (8 5/8 inch) screens of the second well pair could only be completed for a length of about 300 m for the producer and 180 m for the injector. Both well pairs have been operating since April 1996 with an average daily production of 70 m³/d (440 BPD) of bitumen. In December 1997, the long “D” well pair was re-completed

with modification to instrument tubing string size and location that have resulted in significant production improvement. The current production for the two “D” well pairs is in the order of 200 m³/d (1,260 BPD).

Gysering Effect Controlled at Surface Facilities by Well Parameters

In the surface drilled “D” wells, another foreseen problem known as “gysering” was overcome by integrated control of pressures at the toe of the production well and at the receiver/separator vessel above ground. The concept of the steam trap control is to maintain the production temperature below the saturated steam temperature corresponding to the production pressure. Under these conditions the chance of steam bypassing from the reservoir to the production well is minimized. The method works well for the tunnel “B” wells because the produced fluids flow downwards into the tunnel located well-heads and remain in undersaturated (or subcool) conditions. However, the situation changes for the surface wells. The produced fluids at the wellhead are always at saturated conditions because of decrease in pressure due to friction and reduction in hydrostatic head. In order to utilize the steam trap control, downhole pressure measurements are required. Figure 10 shows the schematic of the control system at the wellhead. Experience indicates that stable flowing conditions can be achieved by maintaining a constant liquid rate at the well head and allowing the bottomhole production temperature to vary within a certain range. This has now been proven to the level of confidence which allows this technique to be used for commercial projects. The “D” wells are now operating according to predictions.

Innovative Design of Surface Production Facilities Produce Dry Bitumen

Figure 11 outlines the process flow diagram for producing dry bitumen from surface drilled SAGD wells.

Essentially, the surface receiver vessel, a high temperature separator, is maintained at sufficient pressure to allow the bitumen to be readily separated and removed from the bottom of the vessel. The bitumen is then passed through a flash vessel wherein the remaining water is flashed off producing a dry bitumen at less than 0.5% BS&W. The dry bitumen is trucked to market in a hot condition without any diluent. Figure 12 shows the UTF Bitumen Specification.

No Significant Sand Production

During initial start-up the new “D” wells did produce minor amounts of sand that created erosion problems at surface piping and bitumen pumps. This problem has since been overcome by better production rate control.

The “E” Wells — Field Tests to Minimize Buffer Zones Between SAGD Well Pairs

The UTF tunnel drilled SAGD wells (“B” wells) are now considered mature or depleted in the sense that more than 55% of the original bitumen-in-place will have been recovered and they will approach a steam-oil-ratio of over 3.2. The objective of the ongoing technology development is to field test the operation of new SAGD wells, which are in communication with mature SAGD, wells.

A new post-steam operating technology will provide an additional economic advantage for SAGD wells in oil sands development and a greater than 55% recovery of bitumen from the reservoir.

The main objective of the E well pair test is to place and operate a new surface drilled horizontal SAGD well pair next to an active depleted SAGD operation (Phase B wells). The recovery of bitumen from the reservoir between the new and existing wells is to be maximized (Figure 7).

SAGD Depletion Optimization and Isolation Methods

The two important design aspects of a SAGD project in later pattern life are optimizing depletion and isolating new undepleted patterns from adjacent old depleted zones.

a) Optimum Depletion

Performance and numerical simulation of the SAGD process at UTF have shown that as the steam chambers in adjacent well pairs reach the top of the oil sands, coalesce and edge chambers begin to expand out of the pattern area, bitumen production begins to decline and the steam bitumen ratio begins to rise. Both of these are as a result of increased heat losses to the overburden and lower bitumen production. In the case of UTF this has been estimated to occur when bitumen recovery reaches 50–60%. Although economics of individual well pairs may support higher steam bitumen ratios, commercial plant economics, strongly affected by steam costs, will dictate that steam will be diverted to patterns with lower steam bitumen ratios. Heat remaining in the reservoir at this time will be in the order of 70% of the original steam heat injected.

Replacement of steam with injection of non-condensable gas and/or solvents are potential methods of maximizing bitumen recovery in the later stage of a SAGD pattern. As a result of numerical simulations by Kisman⁴ in 1995 and GravDrain

Inc. currently in process, it is planned to inject natural gas into the B Pattern at a rate sufficient to maintain reservoir pressure with reduced steam injection.

b) Isolation Method

A unique feature of a steam process particularly SAGD is that when the zone nears depletion and steam injection is discontinued, steam vapor condenses and the reservoir pressure drops. In commercial SAGD development it is envisioned that groups of well pairs will be initially drilled and placed on production in sufficient numbers to fill the plant capacity. As the productivity of these wells decrease and the original area depletes, additional groups of well pairs in adjoining areas will be added. Several methods of isolating new undepleted patterns from old depleted patterns have been considered and are schematically illustration on Figure 13.

The initial approach considered is the use of a buffer zone as shown in A on Figure 13 although this method will isolate the low and high-pressure areas if the buffer zone is large enough and pressure communication will not exist. This will leave areas of the reservoir that will not be recovered. Also more cost will be incurred for additional steam and produced fluids piping to cover the project larger area.

A modification to the buffer area approach, shown in B on Figure 13, involves using the geology of the oil sands where possible and/or gas blunting to control the shape of the unconfined edge of the steam chamber. Numerical simulation conducted by CMG2 predicted that injection of very small amounts of gas (0.01–0.2 mole per cent) with the steam would tend to collect and insulate the bitumen face in the upper portion of the steam chamber and reduce the rate of its forward advance. Controlling the shape of the chamber combined with some buffer area such that the patterns are essentially depleted at the time that the old and new chambers coalesce is considered an improvement over using a buffer area alone.

The preferred method of isolating depleted and undepleted patterns is to inject either natural gas, hydrocarbon gas or flue gas into the depleted pattern to maintain pressure as the steam vapor in the pattern condenses. This method, shown schematically as option C on Figure 13 will be tested in the Dover Project (formerly UTF). Well pair E, drilled offsetting the B Pattern to test this concept, is expected to be started up in mid 1998 and the effectiveness of the concept will be demonstrated over the next few years.

UTF Produced Water Recycle Field Test

Produced water, water treatment backwash and condensate from the steam separators were disposed underground into a thin three meter thick Wabiskaw water sand in the vicinity of the project.

Capacity limitations of the disposal zone and the environmental need to recycle water in commercial project operations

has led to the installation of a partial water recycle water treatment facility which will recycle up to 87% of the produced water for steam generation at UTF. The recycle process offers advantages over the current alternate technologies such as hot lime in that treatment chemical handling is simpler and cheaper, less sludge is produced and the mechanical design is simpler and less expensive. The process concept also has the advantage of pre-treating produced water upstream of existing sodium zeolite water softeners commonly used for “one-way” water treatment. This feature permits easy conversion for water recycle.

As shown in Figure 14 de-oiled water will be blended with raw source water to control the total dissolved solid concentration to less than 2,000 mg/L (the limiting value for use in existing UTF strong acid cation softeners). Warm caustic softening with magnesium oxide addition will reduce silica levels in the blended water to less than 50 mg/L and hardness to less than 50 mg/L (as CaCo₃). The caustic softened water will then be carbonated with carbon dioxide to reduce its pH to a non scaling index for use in the steam generators and will be filtered prior to ion exchange softening in the existing facilities. Start-up of the partial recycle facility is scheduled in March 1998.

Economic Viability of SAGD for In Situ Recovery

There are several factors of the SAGD Technology that contribute to its success as an economically viable *in situ* recovery process. The advantages are low steam-to-oil ratio of about 2.1; successful drilling and completion of long commercial length horizontal well pairs, good operational control of surface drilled production wells and no sand production.

The SAGD in-situ process provides the developer the ability to start with a small plant and “boot strap” the production increase as bitumen market price justifies it.

The economic viability of UTF SAGD commercial project in sizes 1,600, 3200, 9,800, and 6,000 m³/d (10,000, 20,000, 30,000, and 50,000 BPD) has been reviewed on a preliminary basis. Also preliminary studies of surface drilled versus tunnel drilled SAGD well projects have shown the former to be economically more advantageous. This is especially true since the drilling industry has made very significant advances in the past several years in horizontal well drilling, measurement-while-drilling and placement of casings and completions.

Figure 15 shows that a 4,800 m³/d (30,000 BPD) SAGD project would require only 30 SAGD horizontal well pairs initially. Each 750 m well is estimated to produce at a rate of 160 m³/d (1,000 BPD). It would require about one year to heat the reservoir and come up to full operating capacity and each well would have about a 5–year life. During the project life of 25 years, about 152 additional well pairs would be required.

Based upon a study in 1994 for a “grass roots” surface drilled SAGD project, the initial capital for access, utilities,

wells and production facilities would be in the order of C \$265 million. The total capital over the life of the project is estimated to be C \$420 million with an annual operating of about C \$40 million. This represents an operating cost of about C \$26/cubic meter (Figure 16).

Using the definition of supply cost to mean that the cost of producing a cubic meter of bitumen including the payback of capital and operating cost, but excluding royalties and taxes, the supply cost for the above project would be C \$35 per cubic meter.

Figure 17 shows the real social rate of return (ROR) for the price received for bitumen delivered to a local upgrader. It illustrates that a real rate of return of 15% can be achieved if the price of bitumen is C \$57 per cubic meter. (C \$9 per barrel.)

Industry and Government Cooperation — Consortium

The Alberta Department of Energy and the nine Industry Participants operated this project as a consortium during the period 1988–1997 (Phase A and Phase B).

The project funding came from Industry Participants and Government contributions, based upon percentage share ownership in the project, as well as from the revenue from bitumen sales. A total of \$170 million Canadian (C) were expended to the end of Phase B on September 30, 1997. The Alberta Government contributed C \$80 million, Industry contributed C \$50 million and C \$40 million came from bitumen production sales.

Initially, the Alberta Government, through the Alberta Oil Sands Technology and Research Authority (AOSTRA) was the operator and champion of the project from the period 1984 to 1995. By 1992, there were nine Industry Participants, consisting of major and small oil companies.

The energy efficient, low steam-oil ratio, high recovery, low maintenance and environmentally attractive SAGD Process had retained the interest of Amoco Canada Petroleum Co. Ltd., Chevron Canada Resources Limited, CNPC Canada Ltd. (China National Petroleum Corp.), Gibson Petroleum Company Limited, Imperial Oil Resources Ltd., Japex Oil Sands Ltd., Petro-Canada, Shell Canada Limited and Suncor Inc. These nine oil companies currently retain enough leases (48%) in Athabasca that could produce a combined volume of some 25 billion m³ (150 billion barrels) of bitumen by using the UTF SAGD Process. Syncrude Canada was an Associate member and CANMET was involved in supporting the geotechnical aspects of Phase A of the UTF project.

On October 1, 1995, operatorship was handed over to one of the Industry Participants, Gibson Petroleum Company Limited. At this time the Alberta Government felt that the SAGD Technology was sufficiently advanced and that industry were confident enough to carry the pilot project toward commercialization.

Part of the scope of work in Phase B was to establish the costs and economic viability of a commercial size UTF SAGD project at the UTF lease. At the end of Phase B, ten industry participants were granted by AOSTRA world wide licence fee-free use rights to the SAGD Technology for their continued support of the project as well as 8 1/3% of the project assets which include the 20,000 hectares UTF lease in Athabasca where the current demonstration project is built. This lease is estimated to contain 500 million m³ (3 billion barrels) of bitumen.

Government Hands Over to Industry

On September 30, 1997, the Alberta Government sold its remaining three 8 1/3% shares to Northstar Energy Corporation, who at that time had become a new Industry Participant in the UTF Project.

On January 1, 1998, Northstar Energy Corporation took over as Operator and is currently the majority shareholder of the UTF Project. The other remaining participants in the project are Chevron Canada, CNPC Canada, Imperial Oil, Gibson Petroleum and Petro Canada.

This industry joint venture, newly named the Dover Project, will continue the experimental phase of the SAGD Technology by optimizing the depletion of the "B" wells and operating the "E" wells adjacent to the mature "B" pattern.

Industry Forges Ahead with SAGD Pilots

It is a well-established practice that each reservoir has its own peculiar parameters that have to be taken into account when designing a SAGD commercial project. Also, it is prudent for industry to initially prove out the extraction process by use of a pilot having commercial length SAGD horizontal wells.

Very favorable performance at UTF has led to the testing of the process and variations of the process at many other locations in Alberta and Saskatchewan as listed on Figure 18. Including UTF, now known as the Dover project, there are 26 test sites that are underway or in the late planning stage as shown on area map in Figure 19.

Four basic well bore configurations are being used in the current SAGD tests; twin horizontal injection and production wells in a common vertical plane, staggered horizontal injection and production wells, referred to as combination drive drainage (CDD), horizontal production wells with vertical steam injection wells and single horizontal combined injection and production wells.

The most common is the twin horizontal injection and production well configuration with 16 well tests currently underway, followed by 9 single well SAGD well tests and 7 horizontal production/vertical injection well tests. The staggered horizontal injection and horizontal production well combination is being tested at 3 sites.

SAGD technology development is quite recent. Applications are seen to be in a wide variety of heavy oil and bitumen sands at depths ranging from 135m to 805m, thicknesses from 10m to 52m and oil gravity from 930 kg/m³ to 1014 kg/m³. A great deal of learning associated with the SAGD process operation has been gained. This and experience gained over the next two to three years will better define the type of reservoir, well orientation and operating strategy best suited for its application.

Major Impact of SAGD Process on Canadian Oil Reserves

The new SAGD horizontal twin well technology has now made available for economic recovery about 50 billion m³ (315 billion barrels) of bitumen reserves in Alberta, Canada that were previously not commercially exploitable.

Conclusions

The pace of development of the SAGD Technology is considered to have been very rapid. The world's first SAGD wells were started at the UTF in 1987 and it required less than a decade of technical cooperation and a comparatively modest joint expenditure of C \$170 million for the Alberta Government working with the oil Industry to develop the Steam Assisted Gravity Drainage technology. There have been spin-off benefits of major advances in horizontal well drilling/completion techniques by the oil industry and well drilling companies. Also, the enhancements of the SAGD knowledge by the research community and the companies operating in Canada has, established a center of excellence in this field in Alberta.

This last phase of field demonstration of the optimization of the SAGD well depletion and isolation techniques will make significant contribution toward further reducing capital and production costs of the SAGD Process. This will allow more effective and efficient resource utilization. Also, the development of the produced water recycle technology for that area of the province will provide economic and environmental protection advantages.

It should be recognized that the success of the SAGD technology development has essentially completely changed the understanding of the industry on how to recover bitumen from the oil sands.

Acknowledgment

The authors of this paper wish to thank the UTF Industry Participants for their contribution to the project. Much credit is due to the UTF Project personnel who have persevered and dedicated much effort to making the UTF SAGD Project a continued success.

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Athabasca Deposit	140 Billion Cubic Metres
Accessible by SAGD	95 Billion Cubic Metres
Recoverable by SAGD	50 Billion Cubic Metres
Basis: Oil Sands Pay	> 15 Metres
% Bitumen	6% B.W.
Recovery	55%
Overburden	> 30 Metres

Figure 1: Athabasca Reserves Recoverable by Steam Assisted Gravity Drainage (SAGD)

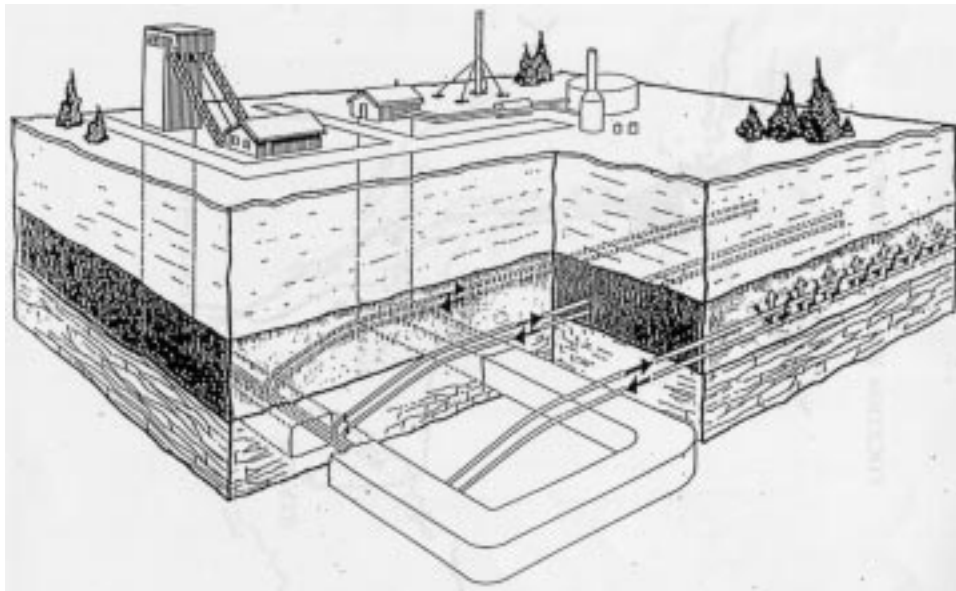


Figure 2: Underground Test Facility – Tunnel Wells

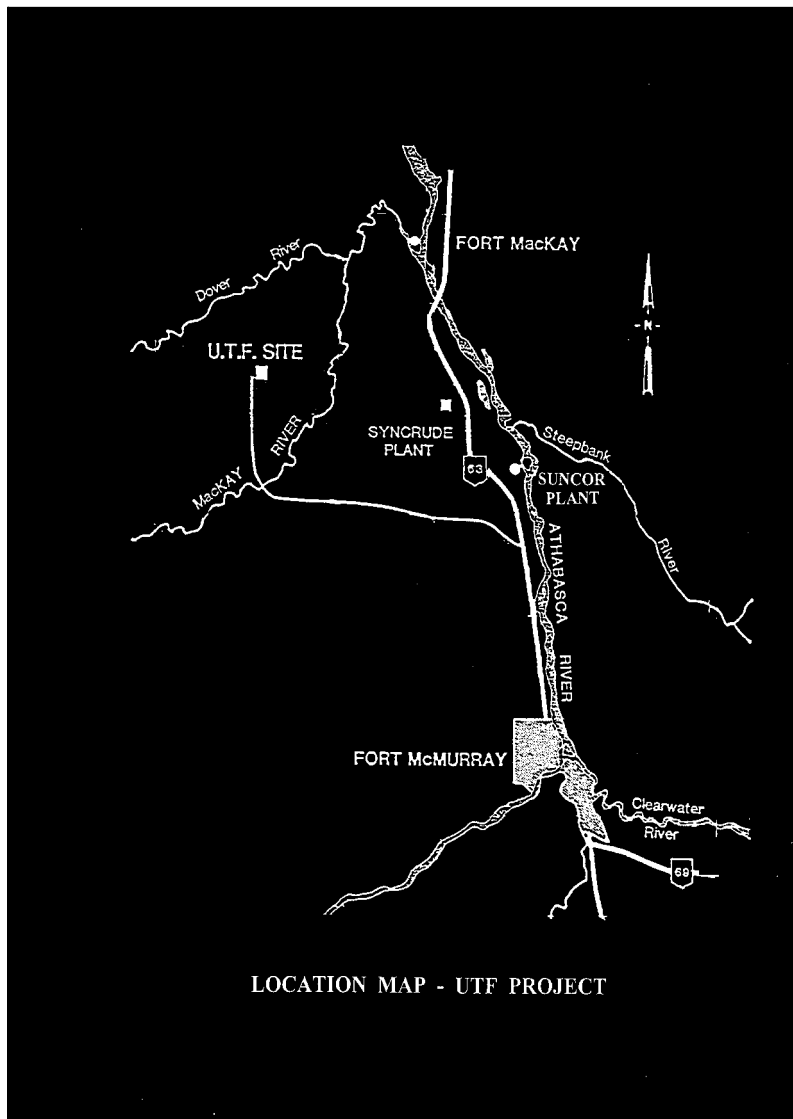


Figure 3: Location Map — UTF Project

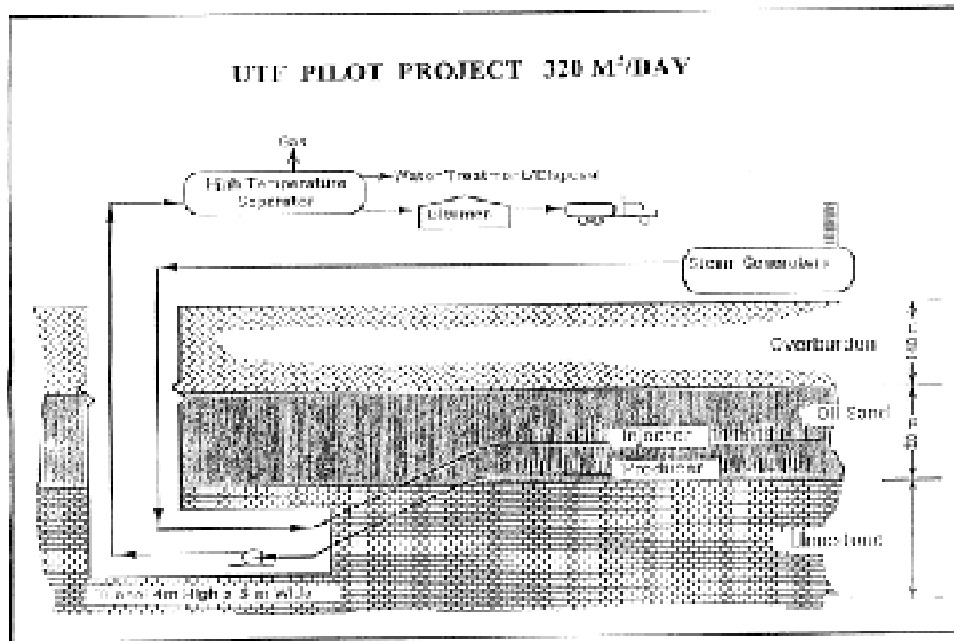


Figure 4: UTF Pilot Project 320 m³/day

Depth	130–150 m
Net Pay	15–20 m
Porosity	35%
Bitumen Saturation	80–85%
Sand Permeability	5–12 Darcy
Initial Pressure	
Initial Temperature	7°C
Bitumen Viscosity (70°C)	5,000,000 cp
Bitumen Viscosity (2200°C)	7 cp

Figure 5: Typical Athabasca — McMurray Oil Sands Parameters at UTF

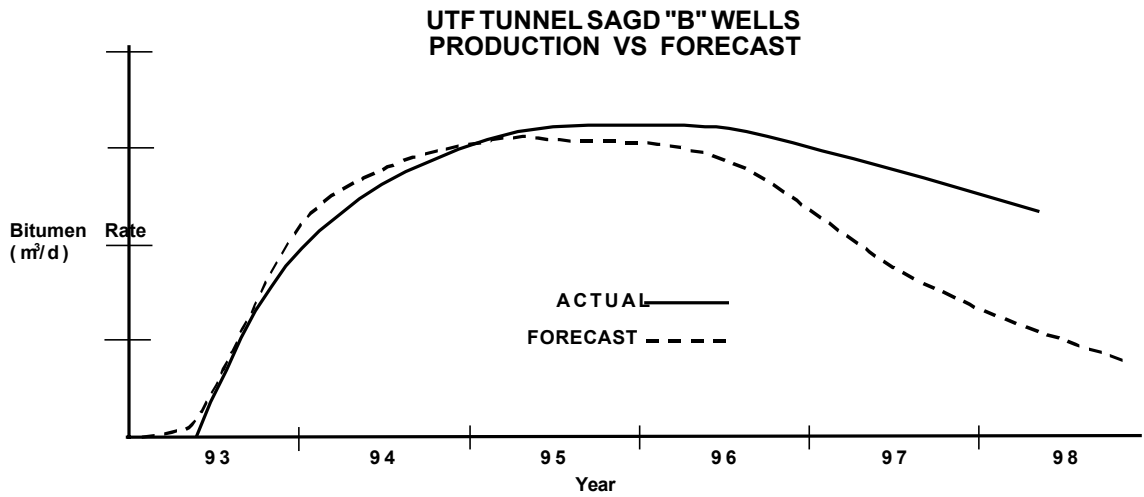


Figure 6: UTF Tunnel SAGD "B" Wells Production vs. Forecast

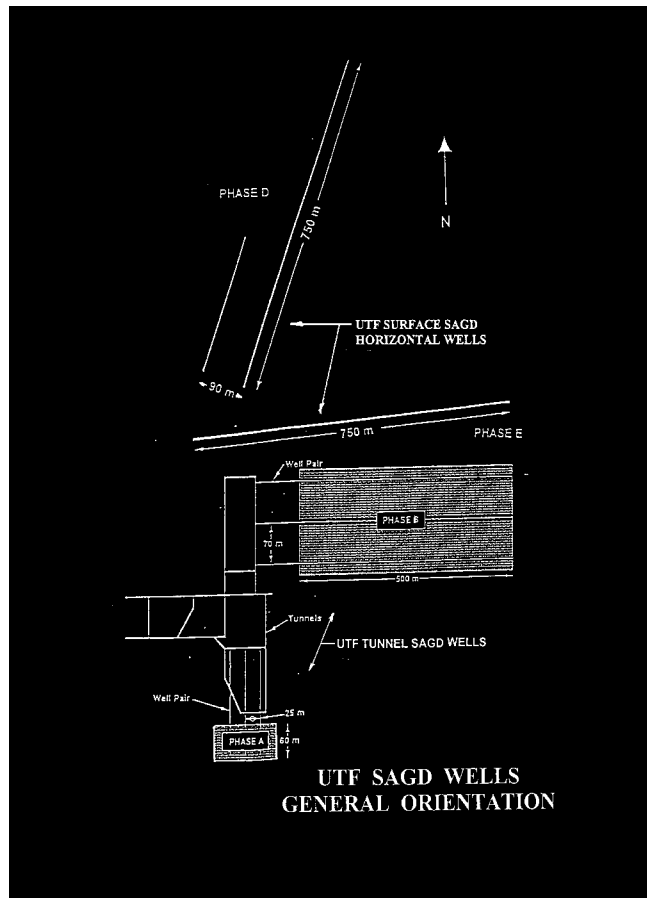


Figure 7: UTF SAGD Wells General Orientation

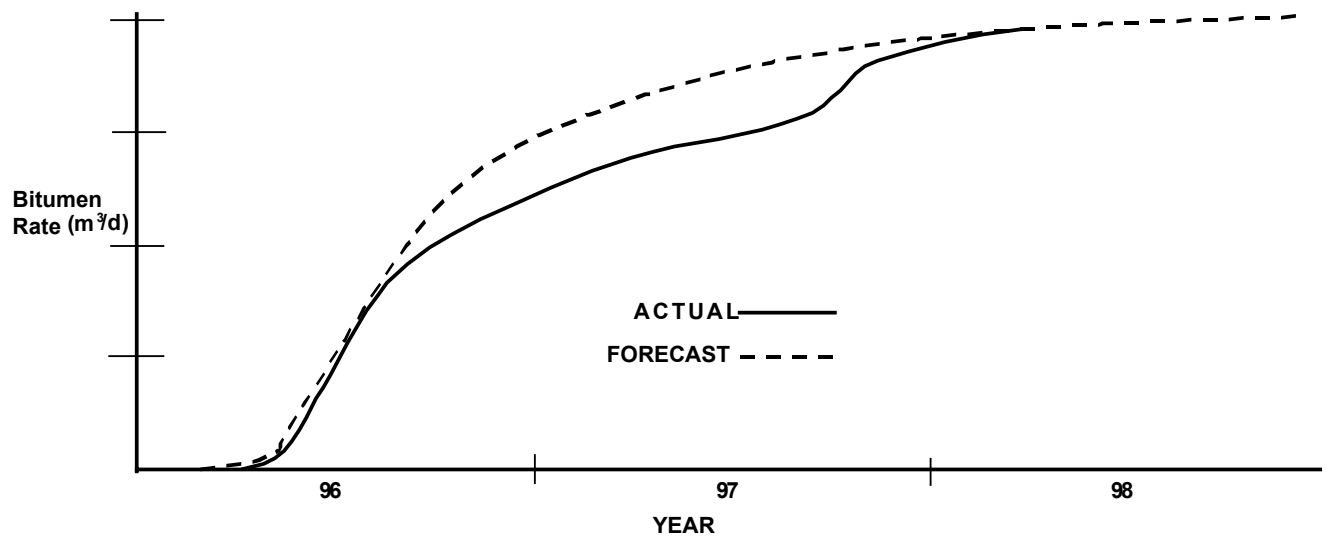


Figure 8: UTF Surface SAGD "D" Wells Production vs. Forecast

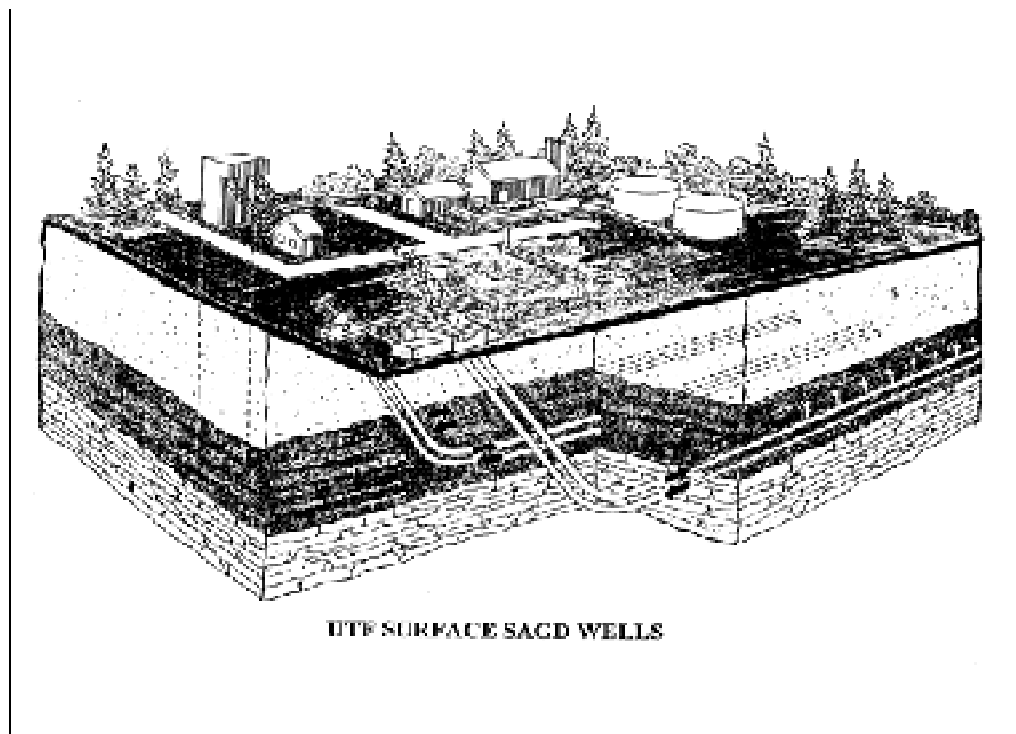


Figure 9: UTF Surface SAGD Wells

SURFACE SAGD WELL CONTROL

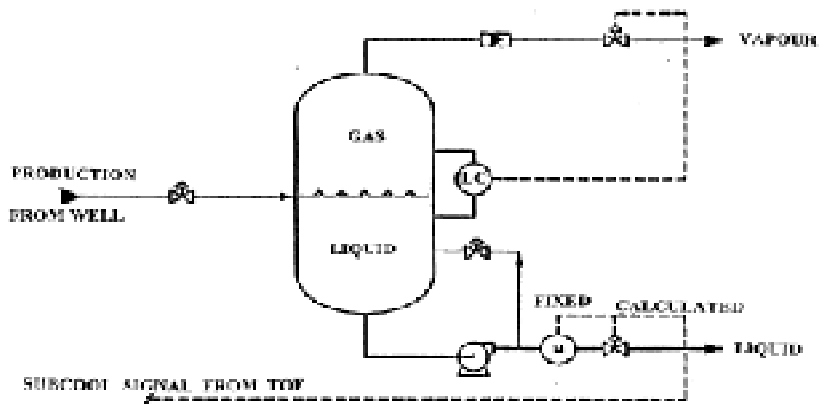


Figure 10: Surface SAGD Well Control

UTFPROCESSFACILITIESSCHEMATIC

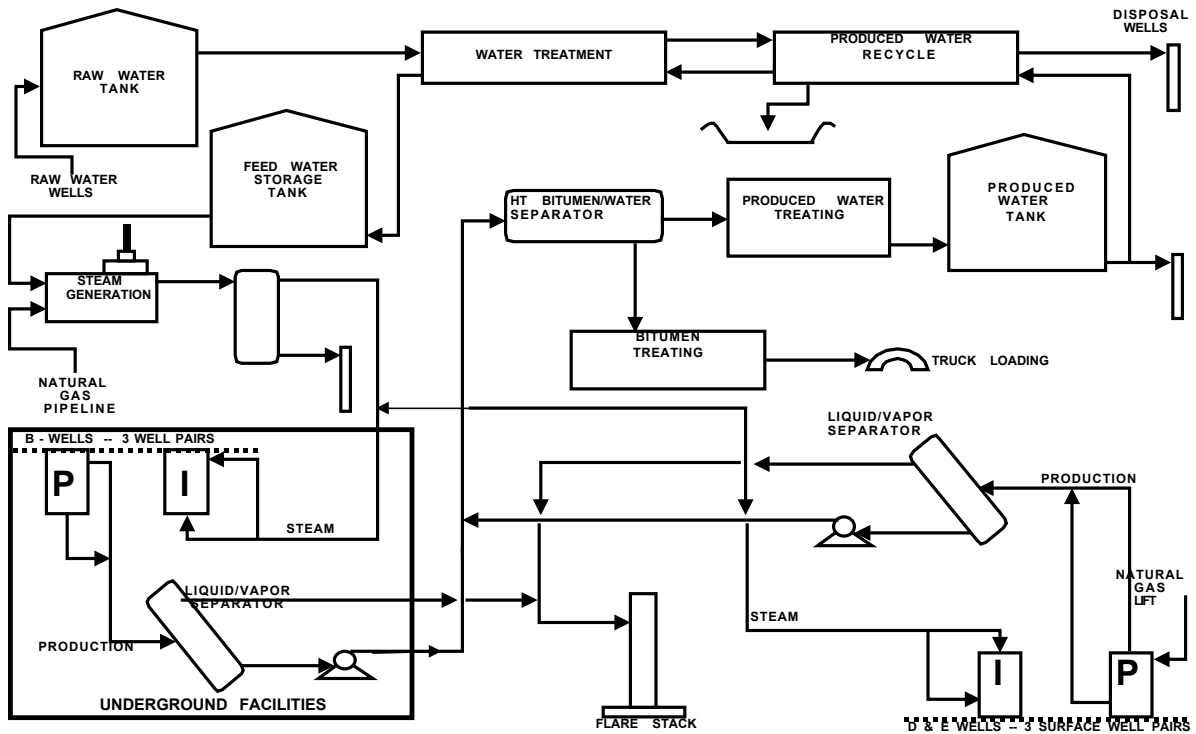


Figure 11: UTF Process Facilities Schematic

UTF PRODUCED WATER RECYCLE PROCESS SCHEMATIC

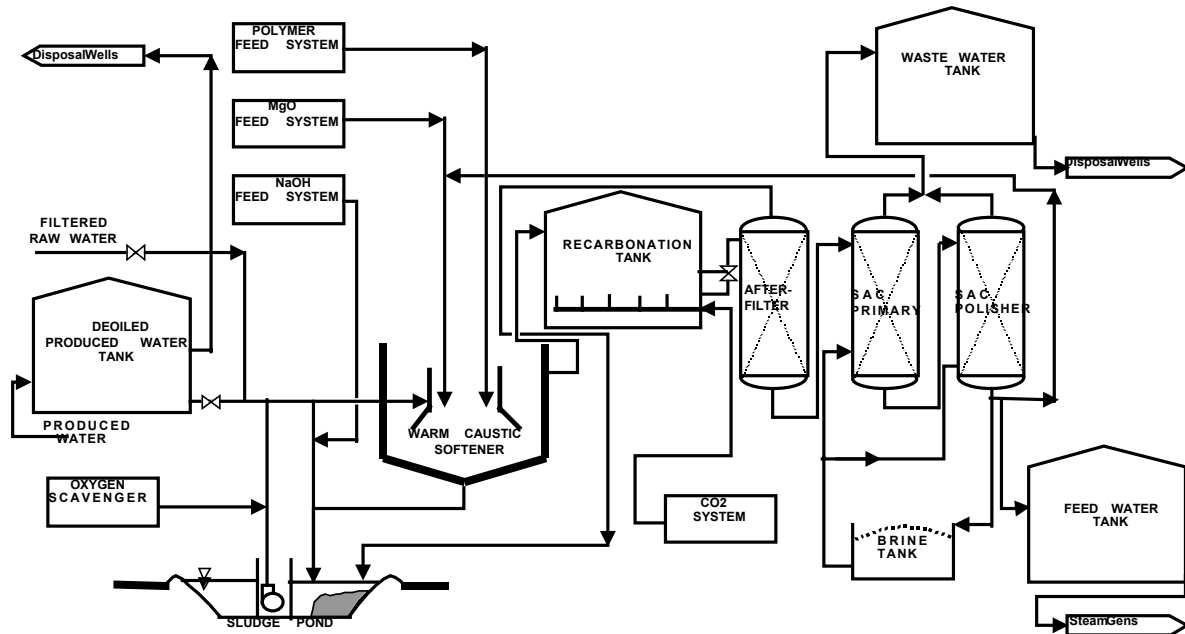


Figure 14: UTF Produced Water Recycle Process Schematic

COMMERCIAL SAGD PROJECT ON DOVER LEASE RETURN ON INVESTMENT FOR 4800 m³/d PROJECT

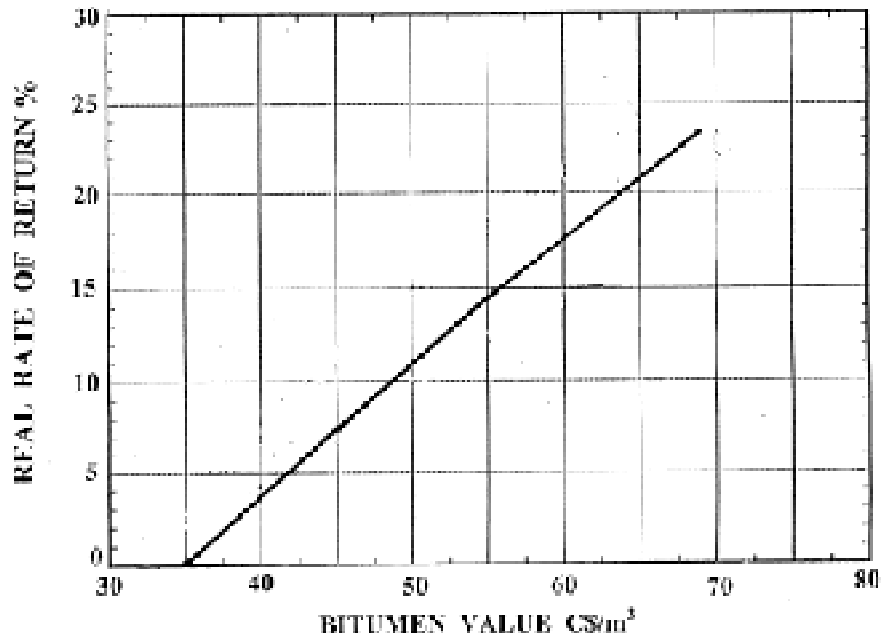


Figure 15: Commercial Project on Dover Lease Surface Drilled SAGD Wells, Preliminary Design Basis

Initial Capital	265
Total Capital	420
Annual Operating	40
Operating Cost	\$26/m³
Bitumen Supply Cost	\$35/ m³

Figure 16: 4,800 m³/d Commercial SAGD Project — Dover Lease – Costs

Plant Capacity – m³/day	4,800
Project Life Basis	25 Years
EPC	3 Years
Operation to Capacity	1 Year
Well Pairs – Start	30
Production Per Well Pair - m³/day	160
Well Pairs – Over 25 Yr. Plant Life	152
Well Pair Life	5 Years

Figure 17: Commercial SAGD Project on Dover Lease Return on Investment for a 4800 m³/d Project

Alberta&SaskatchewanSteam-AssistedGravityDrainageProjects									
ProjectName*	Operator	Formation	No. of Wells producer/injector	Depth (m)	Horizontal Length (m)	Oil Gravity (kg/m3)	Net Pay (m)	Start-up Date	
Alberta									
1 Dover (formerly UTR)	Northstar	McMurray	6H / 6H	135	500 / 750	1014	2.2	Nov-87	
2 Peace River	Shell	Bluesky-Gething	12H / 12H	554	500 / 1000	1012	2.5	Feb-94	
3 Kitscoty	Probe Exploration	Sparky	4H / 5V	570	250	979	2.5	Jul-94	
4 Lindbergh	Murphy Oil	Lloydminster	2H / 6V	505	700	990	2.2	Feb-97	
5 Hilda Lake	Black Rock	Clearwater	1H / 1H	427	900	995	3.0	Sep-97	
6 Wolf Lake	Ranger	Waseca	1-C, 1H / 1H	375	800	970	2.2	Feb-96	
7 South Bodo	Ranger	McLaren	2-C	735	700	950	1.5	Oct-95	
8 Lindbergh	Ranger	Cummings	1-C	590	800	940	1.2	Oct-95	
9 Beaverdam	Ranger	Lloydminster	1-C	465	800	980	1.3	Oct-95	
10 Wolf Lake MWSDD	Amoco	Clearwater	20H / 194V	475	1000	998	2.0	Sep-95	
10 Wolf Lake HWPI	Amoco	Clearwater	1H / 1H	520	750	998	4.0	Sep-94	
10 Wolf Lake BSAGD	Amoco	Clearwater	1H / 1H	400	950	1005	1.5	Jul-97	
11 Wolf Lake	Mobil	G.P.	1H / 3V	380	300	986	1.4	Aug-97 (susp.)	
12 Main Bodo	Norcen	McLaren	2-C	750	750	979	1.3	Jun-96	
13 Primrose	ÆC	McMurray	3H / 3H	480	700	1000	3.0	May-97	
14 Burnt Lake	Suncor	Clearwater	3H / 3H	500	1000	975	2.7	1996	
15 Primrose SAGD	Amoco	Clearwater	1H / 1H	500	600	998	1.2	Apr-98	
15 Primrose CDD	Amoco	Clearwater	3H / 4H	500	600	998	1.0	Apr-93	
15 Primrose SWSAGD	Amoco	Clearwater	1-C	500	600	998	1.8	Nov-95	
15 Primrose MWSDD	Amoco	Clearwater	4H / 35V	500	800	998	1.8	Jan-96	
16 Hangingstone	JACOS	McMurray	2H / 2H	280	500	1000	2.5	Dec-98	
17 Cold Lake	Ranger	McLaren	2-C	330	800	960	2.0	Dec-96	
18 Surmont	Gulf Canada	McMurray	2H / 2H	380	350	1014	5.2	Aug-97	
19 Christina Lake	CS Resources	McMurray	4H / 4H	400	500	1000	3.0	1999	
Saskatchewan									
20 Bolney	Tarragon	Waseca	1H / 1H, 1H / 3V	450	500	980	2.0	Mar-96	
21 Cactus Lake	North Ranger	McLaren	7-C	775	750 - 1000	930	1.2	Jan-95	
22 Celtic	Mobil	G.P.	5-C, 1H / 1H	490	400	980	1.8	Apr-96	
23 Senlac	CS Resources	Cummings/Dina	4H / 4H	750	500	900	1.5	Mar-96	
24 Tangleflags	East Can. Nat. Res.	Lloydminster	4H / 3H	500	1000	980	1.5	Aug-96	
25 Tangleflags	North Can. Nat. Res.	Lloydminster	7H / 15V, 1H / 1H	500	1000	980	2.0	Jun-88	
26 Kerrobert	Gulf Canada	Lloydminster	3H / 2H	805	450 - 550	995	2.5	Sep-97	

Figure 18: Alberta and Saskatchewan Steam-Assisted Gravity Drainage Projects

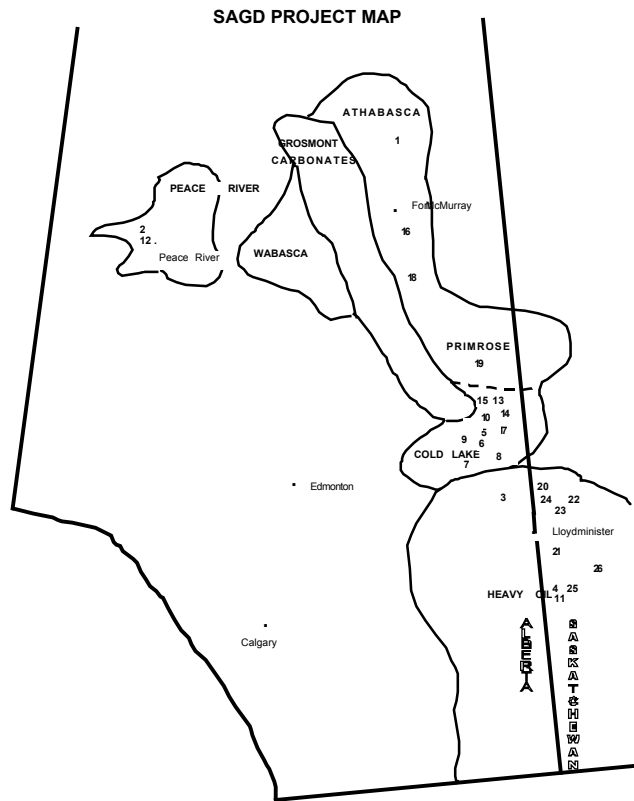


Figure 19: SAGD Project Map