Technical Overview

Nigeria's Bitumen Belt and Development Potential

Ministry of Solid Minerals Development

March 6, 2006

Section 1: Historical Background

Nigeria History of Bitumen and Heavy Oil Development

Tarsand outcroppings and bitumen seeps have been present in western Nigeria since pre-historic time. Although this bitumen has been used locally for roads and housing, it has never been exploited commercially on a large scale. Over the past century, several scientific and commercial investigations have addressed these deposits. These efforts have sought to delineate the deposits, to understand their relation to subsurface petroleum accumulations in the region, and to demonstrate their commerciality as a minable resource. The following sections summarize in approximate chronological order this prior activity by successive separate organizations.

Mineral Survey of Southern Nigeria

In 1905, sixteen shallow boreholes were drilled under the authority of the Mineral Survey of Southern Nigeria. These boreholes were located near the western part of the Tarsand outcrop belt, near Mafowoku and Eregu Valley, and demonstrated the presence of bituminous deposits at shallow depths (4-9 meters).

Nigeria Bitumen Corporation

Between 1907 and 1914, a more ambitious series of fifteen boreholes was drilled by a German venture, the Nigerian Bitumen Corporation (NBC). These boreholes were distributed mainly along a trend beginning at the outcrop belt northeast of Lekki Lagoon in Ogun State, and extended toward the southeast in Ondo State. The NBC boreholes generally penetrated the entire sedimentary section and varying thicknesses of underlying crystalline basement rocks. Total depths range from 330 feet to 2270 feet. Extant data include lithologic designations; depths of occurrence of bitumen and other minerals such as sulfur and pyrite; oil shows; and flowing aquifers. Although no precise data on bitumen saturation are available, inferred thicknesses of bitumen sands occur in all but one of the boreholes. One borehole (NBC-7) located in Agbabu village remains open to the surface and periodically flows heavy oil.

Because of their depth and distribution, the NBC boreholes are a valuable source of information on the size and extent of the bitumen resource.

Shell d'Arcy

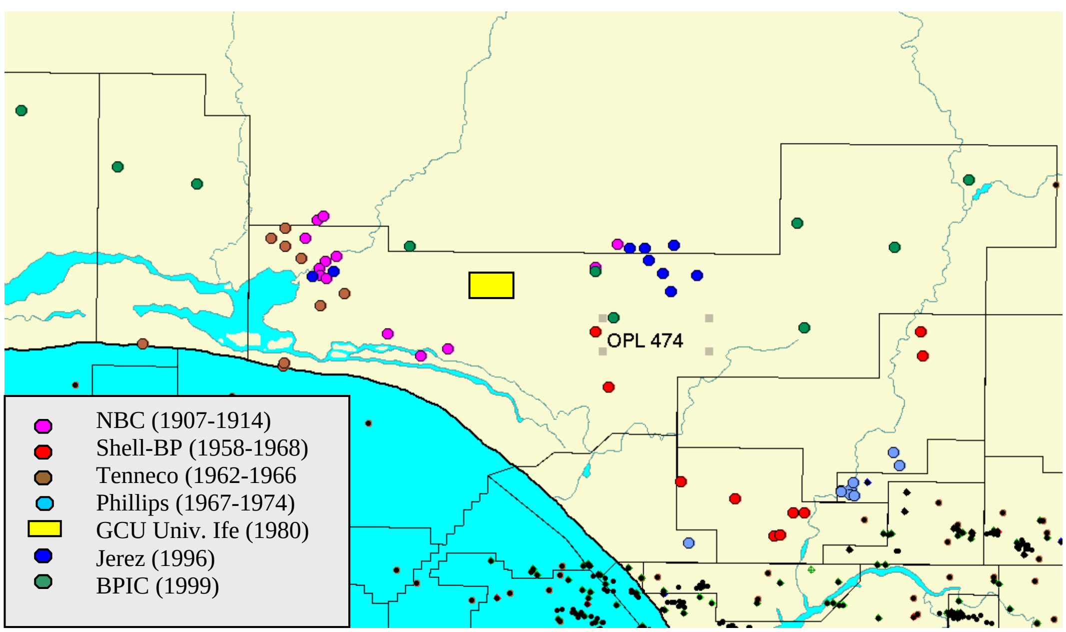
A comprehensive program of geological and geophysical investigations throughout southwestern Nigeria was begun by Shell d'Arcy in 1922. Shell's surface geologic mapping, structural interpretation, and stratigraphic definition contributed significantly to the geological maps and monographs compiled and published by the Nigerian Geological Survey during the mid-twentieth century. Additional unpublished materials include geophysical investigations involving land-based seismic, gravity, and magnetic surveys. Activity was suspended during World War II, but resumed thereafter.

Shell BP

Shell BP Petroleum Development Company of Nigeria Ltd. conducted petroleum exploration activity near the Tarsand outcrop belt for more than a decade following World War II. Shell BP drilled a series of six exploration wells in the general region of the Benin Flank. Although none of these was commercially successful, the wells all contributed to a geological interpretation of the subsurface petroleum system linking the surface seeps of bitumen to deeper petroleum-generating zones to the south and east. Cross sections through these wells (Araromi-1, Gbekebo-1, Benin West-1 to the SSE of the outcrop belt; Benin-1, Owan-1, Egoli-1 to the east) have been widely reproduced as illustrations of the subsurface stratigraphy of the sedimentary units of Cretaceous and Tertiary age that host the bitumen sands.

Additional work by Shell BP, in conjunction with and support of this drilling activity, included continued subsurface mapping of geological horizons and of the crystalline basement via a combination of seismic and gravity data. This work included an attempt to integrate the stratigraphic and structural history of the area. More modern work builds upon this through incorporation of global tectonics and a wider context for understanding the evolution of basins along rifted continental margins such as those along the South Atlantic.

Figure 1
Historical Well and Borehole Data, Block 474 Vicinity



Gulf Oil

A report by Crockett and Wescott of Gulf Oil Corporation in 1954 summarized analyses of Tarsands in Ondo State, finding the bitumen suitable for road surfacing.

Mobil Oil

Mobil Exploration Nigeria and Mobil Producing Nigeria conducted an extensive petroleum exploration program in the region to the west of Block 474. Although not directly related to bitumen sands and their exploration, it provides some additional geological understanding of the stratigraphy and petroleum geology of the more central part of the Benin Basin, near the national border with Benin. Seismic data were collected, four wells were drilled in 1960-1961: Afowo-1, Ojo-1, Ileppaw-1, Bodashe-1. All were plugged and abandoned as dry holes.

Tennessee Nigeria Inc. (Tenneco)

Tenneco conducted seismic acquisition and exploratory drilling for petroleum in 1962-1963. The area of operations included parts of Ondo and Ogun States, south of the western part of the belt of outcropping bitumen sands. Ise-1 and Ise-2 were drilled near the coastline and are stratigraphically notable for having penetrated a great thickness of Lower Cretaceous strata, including potential oil source beds.

Tenneco resumed operations in 1966 on OML 47 along the eastern side of Lekki Lagoon, in the general area explored by Nigeria Bitumen Corporation some 50 years earlier. Borehole lithology logs exist for 6 of 10 core holes attempted.

University of Ife (Obafemi Awolowo University)

From 1974 to 1980 the Geological Consultancy Unit (GCU) at the University of Ife (now Obafemi Awolowo University) conducted a major program of investigation of the bitumen sands and their potential for extraction by mining. Initial efforts demonstrated the subsurface extent of bitumen sands by drilling between previously known outcroppings; results were published in a 1976 report. Further boreholes near the towns of Ilubirin and Agbabu in Ondo State led the GCU in 1978 to propose an evaluation of a site for open-pit mining. This proposal was funded by Ondo State Government of Western Nigeria and resulted in a series of 44 boreholes over a 17 square kilometer area. Bitumen content and thickness of sands in these boreholes, and the resulting estimation of extractable volumes of bitumen in Ondo State, were published in a two-part report in 1980.

The GCU study area was found to contain 1.1 billion barrels of extractible bitumen. By extrapolation of this as an average thickness of bitumen sand, the entire tarsand trend was claimed to contain some 43 billion barrels, a figure cited in numerous reports and publications over the succeeding two decades.

Nigerian National Petroleum Corporation

In 1987, the Nigerial National Petroleum Corporation (NNPC) is reported to have gathered 150 km of seismic data in portions of the bitumen sand area. The entire tar sand trend was found to contain some 43 billion barrels.

Jerez Energy

In 1996, ten boreholes were drilled to approximately 1000 feet by Jerez Energy, a Canadian corporation that was attempting to demonstrate commerciality of heavy oil in the area of this study. Data generated from these boreholes are to be found with the company; most encountered oil sands, and one flowed oil to the surface.

Bitumen Project Implementation Committee (BPIC)

The Bitumen Project was instituted in 1989 under the guidance of an Implementation Committee. Following establishment of the Ministry of Solid Minerals by the Government in 1995, the BPIC was placed under the authority of the Ministry.

The Ministry has received authority from the Government to grant licenses for bitumen extraction in the entire belt, which has been set aside by the Department of Petroleum Resources for this purpose. The BPIC in 1999 specified and supervised the drilling of 10 boreholes to further delineate the subsurface extent of bitumen sands in this area. Recently, the Implementation Committee also drilled some 16 core holes and generated core logs that have provided additional resource data for two newly demarcated blocks 1 and 2.

Historical Analysis Conclusions

Analysis of worldwide and local historical projects seems to suggest that the critical success factor for viscous oil and bitumen development is to fit the extraction technology to the resource to yield the best commercial result. For Nigeria's hydrocarbons in the Benin Basin that range from oil sands in the up-dip outcrop area to more mobile heavy oil in the down-dip areas. Open cast extractive techniques are recommended for the up-dip outcrop areas while in-situ enhanced oil recovery techniques are recommended for the more mobile heavy oil in the down-dip areas.

Section 2: Subsurface Reservoir Characterization

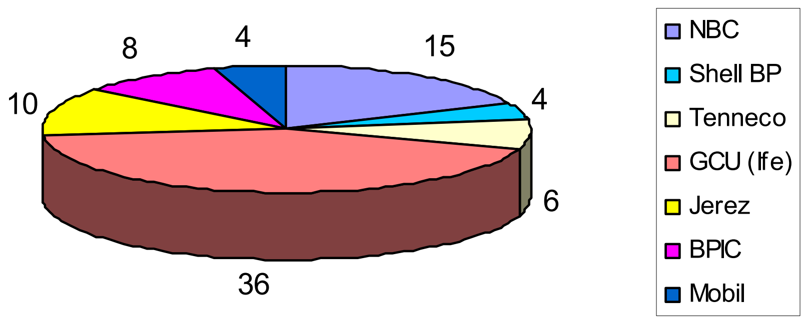
Identification of Available Data

Well Data

Eighty-three wells were loaded digitally and correlated in this study. Figure 1 is a summary of the well operators and proportionate number of wells.

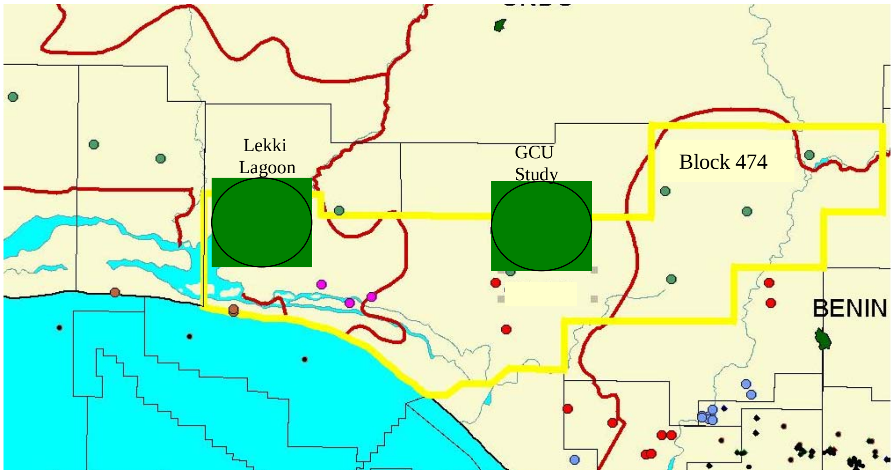
Figure 1

Summary of Well Operators and Proportionate Number of Wells



A large portion of the wells (90%) were only available as lithology data, the remaining wells (10%) contained vintage wireline log data. The University of Ife GCU study from 1980 provided a wealth of quality data for 36 lithology logs, as well as the associated report. All data have been converted into digital format and loaded into Landmark Petroworks and Stratworks software. Well data is predominately in the shallow depths of less than 200 feet; sparse well control exists over Block 474 beyond this depth range. The largest concentration of well data is located in the Lekki Lagoon area and the vicinity of the GCU Pilot area (Figure 2).

Figure 2



Two Focal Areas of Well Control

Regional Geologic Setting - Structure and Tectonics

The tarsands of southwestern Nigeria lie inland near the boundary between the coastal plain and the uplands. In geologic terms, the tarbelt straddles the Ilesha Spur or Okitipupa High, a structural and slight topographic divide. To the west are plains and uplands of the Benin Basin; to the east are the valley and delta of the Niger River system that is developed above the subsurface Anambra Basin.

The coastal plain, underlain by sedimentary strata, forms a land surface of generally low relief. Drainage is moderately integrated but most rivers are relatively small and have drainage basins either within the coastal plain or the adjoining uplands. Much of the land surface has a well-developed lateritic soil cover, and bedrock is not generally exposed except in artificial cuts or excavations. The northern part of the coastal plain lies atop sands and clays of Cretaceous and Tertiary age, some of which are relatively unconsolidated. The southern part of the coastal plain is a coastal lowland band, widening slightly to the east, dominated by marsh and beach-ridge topography. Alluvial valley deposits of Quaternary age border the larger rivers.

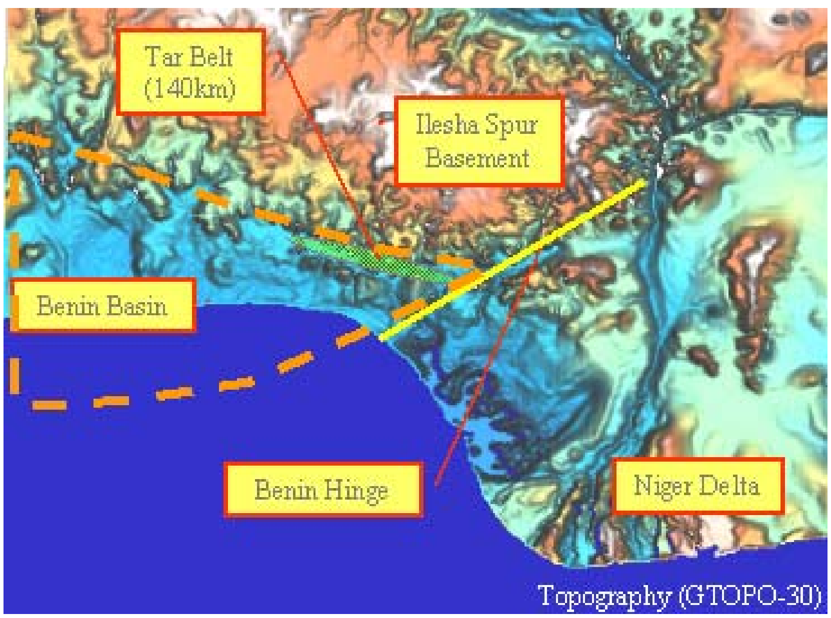
The uplands, to the north of the tarbelt, constitute a region of more elevated topography underlain by basement rocks. Gneiss, quartzite, granite and schist dominate this suite of igneous and metamorphic rocks of Precambrian age. In a few places, sedimentary strata atop hills of basement rock indicate the tendency for strata to onlap the basement surface as it rises toward the north. To the south, basement underlies the sedimentary succession at progressively greater depths.

The Benin Basin is named for the nation that borders Nigeria to the west. It has also been called the Dahomey Basin and the Cotonou Basin. The basin is a post-rift basin in a marginal position; it developed in a shallow embayment of the coastline of western

Africa following the opening of the equatorial Atlantic Ocean during Early Cretaceous time. The Benin Basin is elongate in an east-west direction, parallel to the coastline, extending from the Ilesha Spur and the tarbelt in the east to the coastal lowlands of Ghana in the west. The northern edge of the basin is marked by basement exposure, which is located as much as 130 km from the coast along the central axis of the basin near the Nigeria-Benin border. The southern limit of the basin is poorly defined and lies beneath the seafloor beyond the continental shelf.

The Anambra Basin to the east of the tarbelt is the geologic region underlying the western onshore part of the Niger Delta. Like the Benin Basin, it originated in the Early Cretaceous as a rift structure; it differs by being elongate toward the northeast as one of a series of structural troughs caused by crustal thinning along a failed rift axis perpendicular to the mid-Atlantic spreading center. The most relevant part of this system is the Benin Hinge, the distinct northeast-trending structure where the northwestern flank of the basin meets the Ilesha Spur (Figure 3). This structure is clearly shown in seismic lines and borehole stratigraphy as the top of basement dips southeast in a series of terraces between high-angle normal faults.

Figure 3
Key Structural Elements



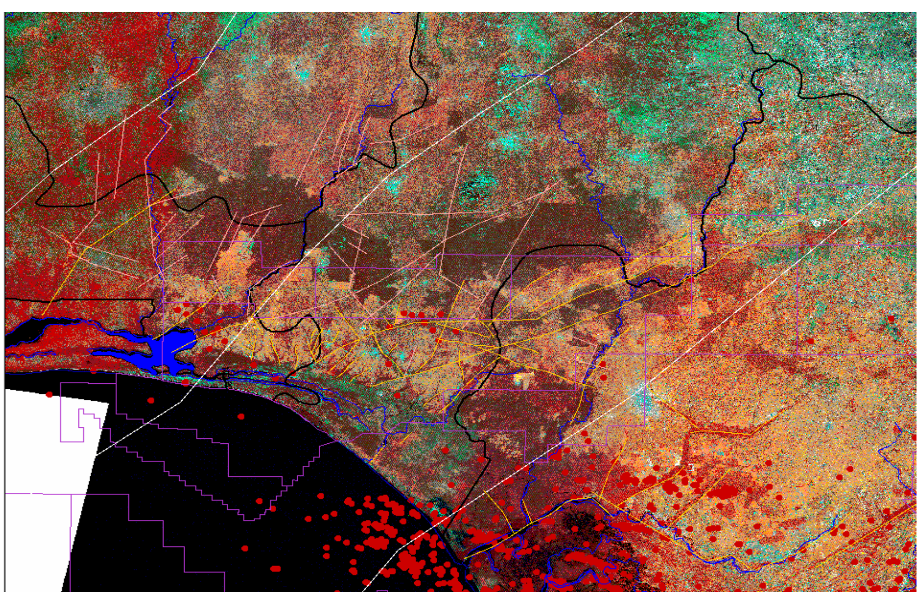
The history of structural development reflects the passive-margin tectonic setting of the tarbelt. Principal basement structures in the Benin Basin are those associated with Early Cretaceous rifting and are dominated by generally east-west trending normal faults bounding a series of linked half-grabens. The trend of these faults can be expected to follow the basin outline, swinging slightly southeast in the narrowing eastern part of the Benin Basin. In this area also a set of east-northeast-trending structures, parallel to the Benin Hinge, also becomes evident. The major structures appear to have formed in the Neocomian to Barremian. They were generally inactive during the Late Cretaceous and Cenozoic and are draped by strata of these ages. Available geologic maps of the coastal plain delineate few faults or folds at the surface, although some small-scale structures are inferred from sparse subsurface data. These are likely the result of compactional effects in the irregular stratal wedge above the rifted basement surface. Some, however, could be the result of basement reactivation, either during the late stages of thermal subsidence, or of wrenching during changes in movement of the African plate during continued Atlantic spreading. Additionally, sediment loading to the southeast during the Neogene development of the Niger Delta probably reactivated structures associated with the Benin Hinge.

Surface lineaments suggest a possibly complex and extensive set of faults and fractures in the tarbelt and vicinity. A preliminary analysis of lineaments have been made from a combination of LANDSAT TM imagery and SAR radar mapping of topography (Figure 4). The importance of these features lies in (1) their ability as discrete permeability barriers or baffles to compartmentalize oil reservoirs; (2) their possible role as oil-trapping structures; and (3) their influence, if present in underlying basement, on sand distribution by controlling paleotopography and sediment transport fairways.

The first order of features is a set of SW-NE trends that appear to align with offshore seafloor transforms. Some workers have adopted this trend as a model for the orientation of rift horsts and grabens in the eastern Benin Basin. Although it is doubtful that seafloor transforms would have propagated landward of the oceanic spreading axis, this lineament appears real. An alternative tectonic explanation is that such trends are related to the high-angle faults of the Benin Hinge region.

Additional sets of smaller lineaments trend variably E-W and NW-SE. These may be subsidiary to the longer lineaments, reflecting local stress anomalies at various intervals of geologic time. Their full significance is unclear but could be the subject of further more detailed analysis.

Figure 4
LandSat Imagery and Surface Lineaments

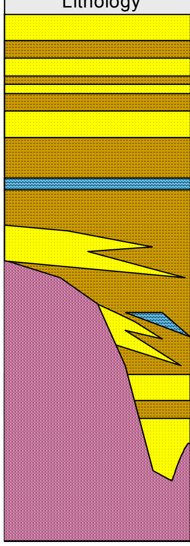


Stratigraphy

Strata of the eastern Benin Basin and Ilesha Spur range in age from Cretaceous to Recent. Surface distributions of basic lithostratigraphic units have been mapped across the region, and a basic stratigraphic framework has been erected (Figure 5). This framework utilizes surface exposures and subsurface borehole information. Some stratigraphic nomenclature is from subsurface usage, whereas other is based on outcrop descriptions. To avoid terminological confusion and complication, only a simplified stratigraphic scheme is used in subsequent descriptions of the tarsands and oil sands. The section below is a brief summary intended only to provide regional context.

The oldest strata exposed in outcrop in the tarbelt are sands and shales of Maastrichtian (Late Cretaceous) age. These units are commonly designated the Abeokuta Formation (formerly "Ijebu Beds"). At its type locality to the west of the tarbelt, the Abeokuta Formation is approximately 600 feet thick, but becomes somewhat thinner eastward. Detailed studies in the tarbelt demonstrate that individual sands are somewhat impersistent; nonetheless, the general pattern is of basal sands and conglomerates followed by a sand-shale interval of a few hundred feet that is succeeded by a dominantly shaly upper section.

Figure 5
Generalized Stratigraphic Column



Generalized Lithology	Formation	Age		Thickness (feet)	Comments
	Benin Fm., Coastal Plains Sands	Tertiary	Pleistocene - Oligocene	0 – 1600	coastal-plain clastics
	Oshosun – Ilaro – Ameki Fms.	Tertiary	Eocene	200 – 1000	fluvial and marine sands and clays
	Ewekoro Fm.	Tertiary	Paleocene	400 – 1000	marine shale, limestone
	Araromi Fm. Abeokuta Fm.	Cretaceous	Maastrichtian	500 – 1000	coastal sand, shale; marine shale
	Afowo Fm. Turonian Sst. Albian Sst.	Cretaceous	Campanian - Aptian	0 – 800	marine sandstone, shale, limestone
	Ise Fm.	Cretaceous	Barremian - Neocomian	0 – 6000+	continental and lacustrine rift-basin fill
	crystalline basement (undifferentiated)	Cambrian - Precambrian			metamorphic and igneous complex

Older Cretaceous units are present in outcrop in other parts of Nigeria, particularly east of the Niger Delta, as well as in the subsurface in onshore and offshore wells downdip of the tarbelt. These include various sands, sandstones, and shales of Turonian to Campanian (Senonian) age ("Turonian Sandstone"), carbonates and clastics of Aptian-Albian age ("Albian Sandstone"), and mixed clastics of Lower Cretaceous age (Ise Formation). The regional pattern of distribution of these units reflects the evolution of the Benin -

Anambra rift basins, beginning with deposition of thicknesses of 2 km or more of coarse continental clastics and lacustrine fines in linked and isolated rift basins during the Neocomian-Barremian (Early Cretaceous). This system was followed by restricted-marine, coastal, and transgressive-marine deposition during the remainder of the Cretaceous. The Afowo and Araromi Formations are bathyal marine deposits that are approximately equivalent in age to the Abeokuta of the tar-sand belt, but indicative of offshore conditions that were both oxygen-poor because of oceanic circulation and sand-poor because of shoreline retreat.

Overlying the Maastrichtian tarsands and shales of the Abeokuta Formation are a succession of stratal units of Tertiary age. Their surface extents are mapped as bands parallel to the basement outcrop limit, stepping progressively seaward. The Ewekoro Limestone, reflecting continued marine transgression, represents the Paleocene. The Ewekoro is temporally equivalent to the Imo Shale of eastern and offshore areas. Limestones of the Ewekoro are relatively thin and discontinuous across Block 474, judging by the boreholes and wells from which data were obtained in this study. This succession is unconformably overlain by a clastic complex of Eocene age, locally designated as either the Oshosun Formation or the Ilano Formation, identifiable in wells as a generally sandy interval. The Oligocene is poorly represented, owing to a regional unconformity of nondeposition and erosion. Miocene strata are locally present near the coastal lowlands, and thicken markedly to the east across the Benin Hinge zone as a result of the Neogene development of the Niger Delta. Plio-Pleistocene strata occur as alluvial valley deposits along the major rivers, and as beach ridges in the coastal lowlands. The Benin Formation is commonly applied (particularly in seismic stratigraphy) to the undifferentiated Neogene coastal-plain succession west of the Niger Delta.

Hydrocarbon Type and Quality

The high viscosity, API gravity, and chemical properties of the Block 474 tar and oil are a result of degradation of conventional oil in a near-surface environment. Nearly all tar and heavy oil accumulations are the result of such degradation, which may result from microbial biodegradation, segregation by aquifer contact, or both. The original generative source for the oil would have required sediment with high total organic content (TOC) to have been buried deeply at elevated temperatures sufficient for the generation of liquid hydrocarbon, which would then have migrated upward through permeable formations until reaching the surface.

The Benin Basin tarbelt and offshore Aje-1 oils are probably derived from Neocomian-Albian (Lower-Middle Cretaceous) source rocks similar to those penetrated in the Ise-2 well (500 feet interval). Reports correlate Aje-1 oil to the Benin tarbelt oils due to high gammacerane content. Samples are isotopically heavy which suggests a restricted marine to lacustrine source. The total organic content (TOC) ranges between 2% and 3.5% and the hydrogen index (HI) is 300 mg/gTOC (B-1, Baba-1 and Ise-1 offshore wells). Alternatively, Cenomanian-Turonian or Maastrichtian-Paleocene source rocks may also contribute oils from a marine shale origin; in this case, the composition of the oil would have been significantly modified by biodegradation.

Oil and Bitumen Distribution Plays

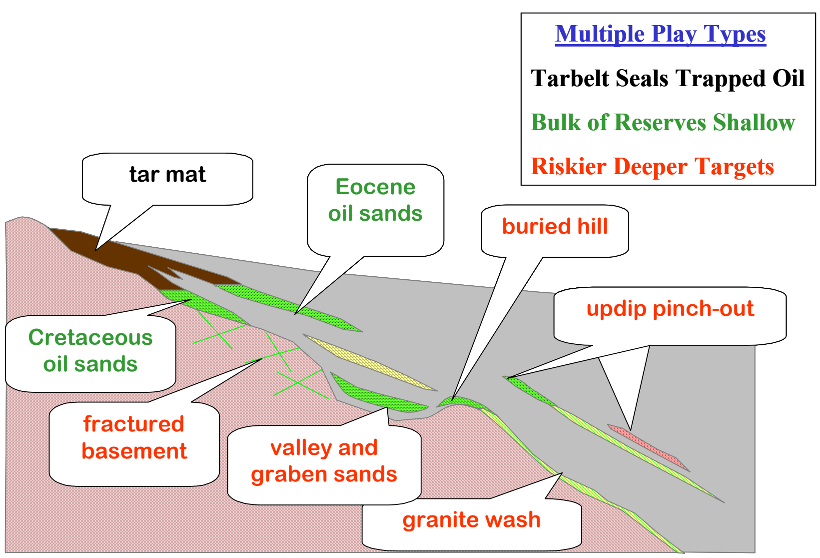
Surface Bitumen Play

The area encompassed by the Surface Bitumen Play extends from basement outcrop on the north, to a line south of which oil sands are deeper than 1500 feet. The east-west extent of the play, defined by known surface occurrences of tarsands, is some 135 km from near Ijebu-Ode in the west to near Onishere in the east.

Within the play area, both bitumen and heavy oil are known to occur. Most previous work focused on bitumen and its potential as a minable resource. However, flowing oil from this depth range (NBC-7, NBC-10, NBC-12 wells) proves the presence of heavy oil. The principal trapping mechanism is the surface tar. The possibility exists that some heavy oil in this region is trapped stratigraphically as well. Multiple separate oil sands and intermediate water sands are found in some boreholes, and it is doubtful that there is a single extensive oil-water contact, although local contacts are indeed possible.

Individual reservoir units in this play include fractured basement, basal sands and conglomerate (granite wash), Maastrichtian sands interbedded with shales, and Eocene sands (Figure 10). Insufficient data were obtained for volumetric estimation of oil and bitumen in fractured basement. Volumes of oil and bitumen in the basal layer and the Maastrichtian sands are combined as "Cretaceous oil." Volumes in shallower sands are tabulated as "Eocene oil."

Figure 6
Possible Hydrocarbon Play Types on Block 474



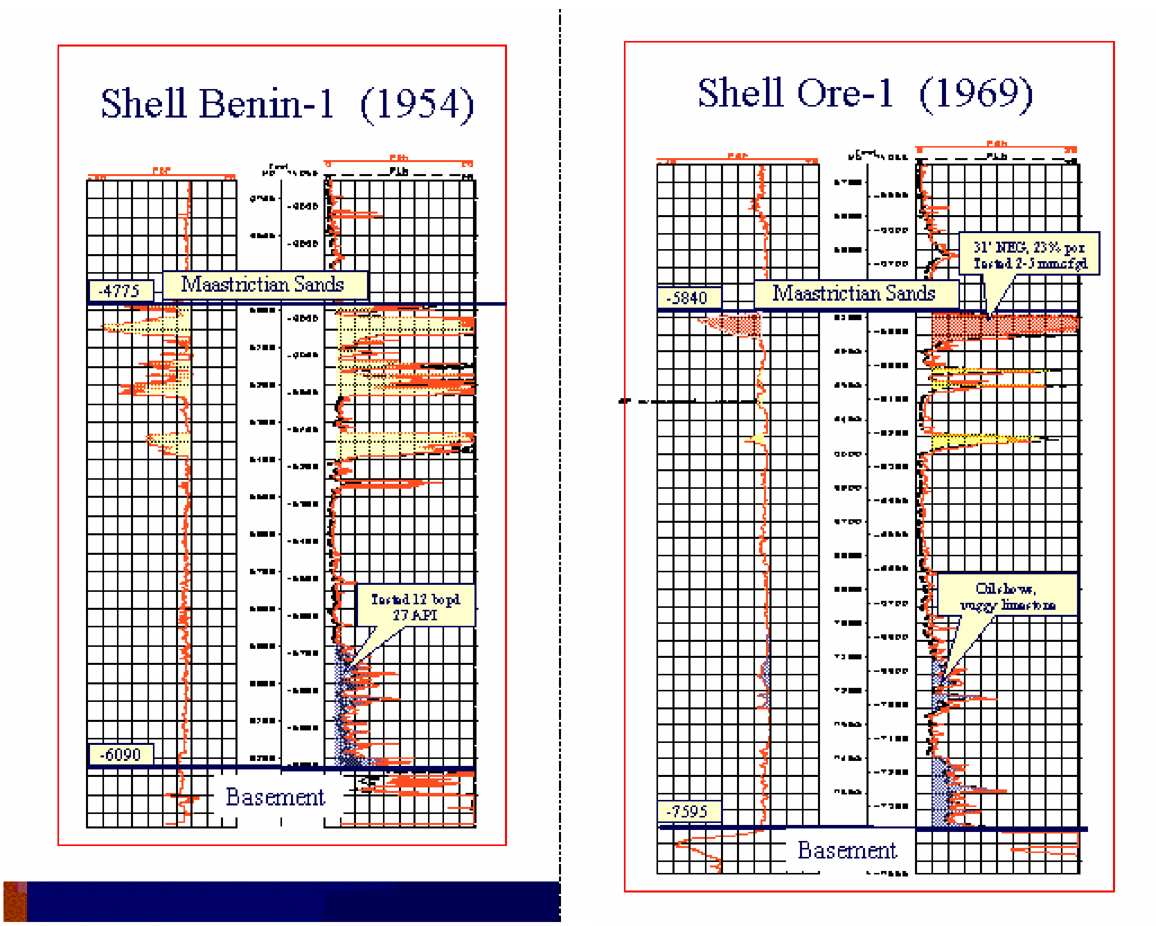
Cold Horizontal Production Play

A significant portion of the tar belt acreage contains the potential for hydrocarbons below the 1500 feet depth, the minimum depth feasible for production from cold horizontal wells. Extraction could be from several potential exploratory target reservoirs. Those considered in this study are Maastrichtian sandstones, Upper Cretaceous limestones, basal clastics, weathered basement and fractured basement (Figure 6). Hydrocarbons migrating from the source rocks immediately basinward of tar belt could be trapped in whatever type of feature that retards their up-dip movements. If structural relief is low and permeability barriers exist, the migrating oil will rest in nonstructural traps.

Upper Cretaceous Maastrichtian Sandstones Stratigraphic Trap

Two wells drilled by Shell/BP slightly off the tar belt to the east, the Benin-1 (1954) and Ore-1 (1969), contain multi-lobe channel shaped sandstones possibly age equivalent to the "False River Sandstone" (Figure 7). The primary trap type would be an up-dip stratigraphic truncation, although localized small-scale faulting may be present.

Figure 7
Potential Upper Cretaceous (Maastrichtian) Sandstone Reservoirs



The Ore-1 well encountered gas in an upper 31 feet lobe of a three-lobe sandstone package. This zone tested 2-5 MMSCFD of dry gas. The production rate potential was estimated to be 10-20 MMSCFD. Porosity was 23% at a depth of –5840.

Gas shows were also reported in the Benin-1 well but no tests were undertaken from False River Sands equivalents. Despite encountering thicker sands than the Ore-1 and being in a higher structural elevation by 1065 feet (-4775) to the northwest, the Benin-1 was not tested. No oil tests were reported in either the Benin-1 and Ore-1 wells, but oil shows were observed in deeper marine shales and limestones (27° API). Other deep wells in the region, the Benin West-1, Gbekebo-1 and Araromi-1, did penetrated marine shales but no sands within the Maastrichtian. The Upper Maastrictian sands, where they occur, are encased in thick shales providing sufficient topseal and bottomseal in the southeastern area of Block 474, barring they do not extend to the outcrop tarbelt. A risk exists that the oil migration through lower basal clastics and fractured basement “carrier beds” may have bypassed these sands. The Maastrichtian sands in the Benin-1 and Ore-1 wells are approximately 400 feet to 600 feet above known oil-bearing shales and limestones).

Section 3: Asset Development Concepts For Heavy Oil and Bitumen

Bitumen and Heavy Oil Development Practices

Because bitumen and heavy oil have very limited mobility, conventional oil recovery methods are not generally suitable for development of these heavy hydrocarbon resources. Instead, specialized technology is needed.

Heavy oil operations are extensive in Canada, China, Venezuela, and the USA. Technology normally considered for heavy oil development can also be applied in medium gravity reservoirs such as has been done in the Duri Field Steam Flood in Indonesia and an older, In-Situ Combustion (ISC) project in Romania. The California USA heavy oil projects have generally involved steam injection as exemplified in the giant Kern River Field. The Venezuelan projects also have used steam injection around the shores of Lake Maracaibo, and more recently have included some major long horizontal well developments in the vast heavy oil belt north of the Orinoco River. The Faja del Orinoco contains an estimated 1.2 trillion (1.2 x 10^{12}) barrels of oil originally in place (OOIP). The Canadian heavy oil operations are mostly in the Province of Alberta with some in the neighboring Province of Saskatchewan. The Canadian projects employ a variety of extraction processes that range from open pit mining and steam injection to cold horizontal well developments. More recently, the concept of Steam Assisted Gravity Drainage (SAGD) is being applied in Canada. Most of the Canadian projects are associated with the huge Athabasca, Peace River, and Cold Lake resources that contain an estimated 2.4 trillion (2.4 x 10^{12}) barrels of OOIP.

Heavy oil In-Situ Combustion projects ranging in size from pilot to modest scale have been attempted in Canada, Venezuela, and the USA, but these projects generally produced poor commercial results due to high operating costs.

A novel concept that uses mining for access coupled with horizontally drilled gravity drain holes has been tested in Russia, the USA, and Canada. All of these have been relatively small-scale pilot projects. The Russian project involved steam injection and gravity drainage. The Canadian tests by AOSTRA pilot tested SAGD at a semi-commercial scale. The tests in the USA were small-scale cold gravity drainage projects. None of these led to commercial use of cold gravity drainage of heavy oil suggesting sub-economic results. SAGD, on the other hand, is proliferating.

Factors Restricting Heavy Oil and Bitumen Production

Heavy oil and bitumen production is generally restricted by three dominating factors: high fluid viscosity at reservoir conditions, low reservoir pressure, and high residual oil saturation (low recovery factor) when using conventional oil extraction methods.

High oil viscosity restricts oil mobility in the reservoir and sets heavy oil and bitumen extraction apart from conventional oil production operations. Therefore heavy oil and bitumen technology often focuses on reducing hydrocarbon viscosity by heating or by compensating for the high viscosity in some other way.

Low pressure related to shallow reservoir depth is another important parameter common to many heavy oil accumulations. Low reservoir pressure means that less drive energy is available to force fluids through the reservoir rock toward the producing well while at the same time high viscosity requires greater pressure differential to move the fluids. For low pressure reservoirs it is critical to achieve very low producing well bottom hole pressure in order to minimize backpressure on the reservoir and maximize the limited drive energy. This is further complicated because the viscous oil is sluggish and does not easily flow through the downhole piping and pump equipment and requires much more energy to pump than lighter oil.

In addition to high viscosity and low pressure, heavy oil is very difficult to efficiently recover from the reservoir rock by conventional production methods because heavy oil tends to "stick" to the rock surface like tar, or because its surface tension does not allow the oil to easily deform to pass through the narrow pore throats between grains of rock in the reservoir matrix. The result is a relatively high residual oil saturation, or low recovery factor, compared to conventional oil operations.

Hydrocarbon Extraction Technology Considered

Heavy oil extraction technology generally focuses on overcoming high viscosity, low pressure, and high residual oil saturation. Eight different concepts for bitumen and heavy oil extraction have been evaluated for application in Block 474. These range from "in commercial use" to "unproven technology." Each concept addresses the viscosity, pressure, and recovery factor restrictions differently.

- **Cold Horizontal Well (CHW) technology is a conventional oil production method applicable to oil with reasonable mobility.**

The horizontal well helps compensate for limited oil mobility in two ways. First, vertical wells have a radial flow character that results in a high drop in pressure near the wellbore. As oil converges toward the drainage point this pressure drop, which is necessary to sustain a commercial rate, does not allow full pressure depletion in portions of the reservoir farther from the well. Vertical well operators compensate for this limitation in viscous oil reservoirs by using very close well spacing. The horizontal well is very long relative to the thickness of the reservoir and spreads out this convergence effect near the drainage point (or, more appropriately, drainage line). The same production rate can be achieved in a long horizontal well with a much lower pressure drop near the wellbore than can be achieved with a vertical well. This allows for greater pressure depletion throughout the reservoir with the horizontal well than with the vertical well for a given spacing between wells.

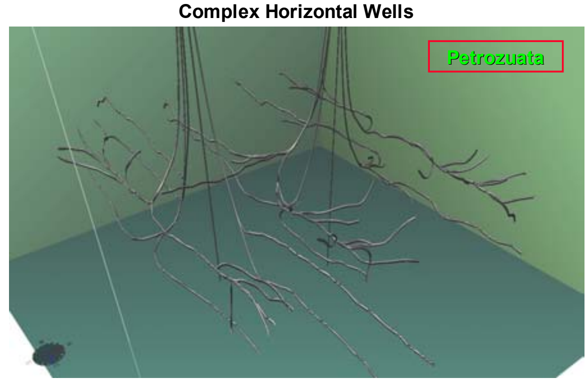
Second, the horizontal well provides much more flow area into the well than does the vertical well. Due to its low mobility heavy oil moves relatively sluggishly through the reservoir. But a vertical well depends on radial flow convergence and accelerating speed of the oil as it approaches the wellbore. The flux, or the mass flow rate per unit of cross-sectional flow area is high for the vertical well just at the time that oil viscosity is increasing due to loss of pressure and lighter components near the wellbore. The horizontal well, on the other hand, provides a very large entry area by virtue of its long completion length in the reservoir. This allows the oil to "ooze" into the wellbore at a very low flux but, due to the large completion surface area, still achieve a commercial rate.

These same factors allow the horizontal well to outperform the vertical well at lower reservoir pressure. The greater pressure depletion achievable by the horizontal well also allows a slightly higher recovery factor than is possible with the vertical well, but the basic residual oil saturation is still high in either case. Thus, the cold horizontal well achieves higher production rate but does not afford much improvement in overall recovery factor compared to vertical wells. Typical heavy oil recovery factors might range in the 5% to 15% range for cold horizontal wells.

The state of the art cold horizontal well development is exemplified by the complex multi-lateral wells being produced by Petrozuata C.A. in Venezuela. Figure 1 illustrates the way these wells increase flow area and shorten the distance oil must move within the reservoir to reach a drainage point.

Figure 1

Complex Horizontal Wells



- ***Cyclic Steam Stimulation (CSS) overcomes the viscosity restriction by heating the viscous oil with steam.***

This process is also known by the names "Steam Soak" and "Steam Huff'n'Puff". Steam is injected into the well for a period of time from a few days to a few weeks. The well is allowed to sit or "soak" for a period of time that ranges from zero to several days. During this "soak" time the steam condenses and transfers heat to the rock in the near wellbore area. At the end of the "soak" period the well is placed on production until the oil production rate drops to a level that justifies another steam injection cycle.

This process is especially effective for vertical wells where oil mobility exists in the reservoir, but near wellbore effects restrict rate to a low level. Steam is injected to heat the rock that surrounds the wellbore. Much of the oil is displaced away from the wellbore during the steam injection cycle; the oil viscosity is reduced by two or more orders of magnitude by the heat from the rock as the oil flows through the near wellbore area. The reduced viscosity oil can flow very easily at high rate into the wellbore. Over time the oil that flows through the rock around the wellbore cools the rock by convection, and the viscosity starts to increase and rate declines. The production cycle may last from a few months to a few years before another steam cycle is required.

Cyclic Steam Stimulation overcomes the viscosity limitation near the wellbore with artificial heating. Since it does not heat the reservoir in depth, the oil must be mobile within the reservoir for this mechanism to work. Like Cold Horizontal Wells, Cyclic Steam Stimulation achieves greater reservoir pressure depletion by overcoming the near wellbore pressure restriction; but it does not significantly change the residual oil saturation in the largest portion of the reservoir that remains unheated. Some of the injected steam condensate may stay in the reservoir rather than being immediately produced at the beginning of the production cycle. When this happens it adds some pressure support and displaces some oil that is replaced by water. This can add another 1 to 5% to the 5 to 15% recovery factor expected for CHW. Often Cyclic Steam Stimulation evolves into Steam Flood when the cycle time between heating and production becomes less effective as reservoir pressure depletes.

Cyclic Steam Stimulation recovery factors might range between 5% and 20%. Cyclic Steam Stimulation can improve horizontal well performance as well as vertical well performance, however, the benefit for horizontal wells will be less dramatic since flow restrictions are less severe in horizontal wells.

❖ ***Steam Flood (SF) is the continuous injection of steam into certain wells and the continuous production of fluids from other wells.***

Steam Flood, as illustrated in Figure 2, reduces oil viscosity by increasing temperature throughout much of the reservoir rather than just near the wellbore. In addition to increasing temperature, the injected steam also supplies continuous pressure support and fluid displacement. The Steam Flood method is also known as "Steam Drive", and addresses all three of the major factors that tend to limit heavy oil production: low oil mobility, low reservoir pressure, and low recovery factor.

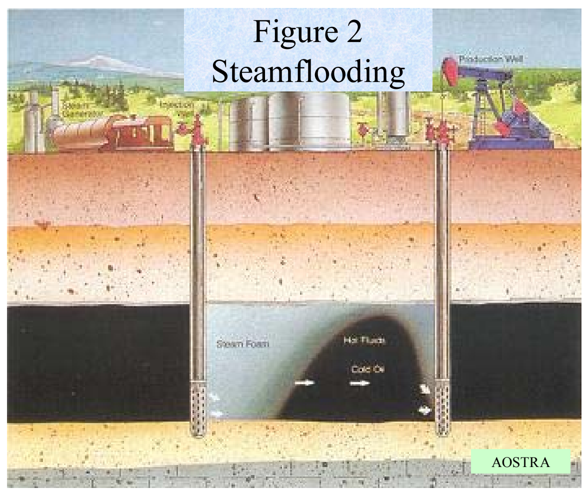


Figure 2
Steamflooding

Steam Flood can be used to recover bitumen to a much greater extent than either Cold Horizontal Wells or Cyclic Steam Stimulation. The reason for this is that the reservoir is heated in depth; however it is rarely practical to heat 100% of the reservoir. For this reason, Steam Flood works best when there is some initial oil mobility at reservoir conditions to allow oil from the colder parts of the reservoir to migrate into the heated areas.

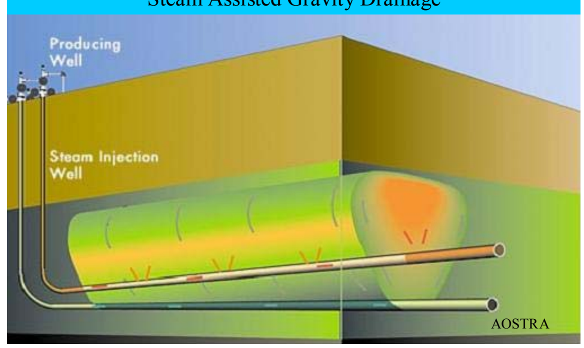
Steam Flood is expensive due to high energy consumption. A 100 MBOPD steamflood typically would consume between 200 and 350 MMSCFD of fuel gas. However, this process can achieve high recovery factors that range between 30% and 70%. Steam Drive can be used with vertical wells, horizontal wells, or combinations.

- ***Steam Assisted Gravity Drainage (SAGD) is a highly specialized case of the Steam Flood process coupled with gravity drainage.***

The Steam Assisted Gravity Drainage process can be used for bitumen or heavy oil and may have some greater benefit with bitumen. The SAGD process is generally implemented as two horizontal wells: one well vertically above and parallel to the other as illustrated in Figure 3. The upper well is used for steam injection while the lower well is used for production. The production well is ideally located very close to the bottom of the reservoir. The injector is located about 5 meters above the producer. Steam injected into the upper well tends to rise toward the top seal of the reservoir. As the steam rises, it heats the oil and rock and then condenses. The

Figure 3

Steam Assisted Gravity Drainage



condensed steam and heated oil drain by gravity toward the producing well. SAGD is a delicate process. Careful control of injection, production, and steam chamber pressure is required. Over injection will short circuit steam into the producer. Under injection will quickly limit production rate and recovery factor. Careful control of the well geometry is important to avoid hot spots (short circuits) between the wells and localized undulations that can restrict overall rates by introducing liquid traps and irregular pressure distribution in the wells.

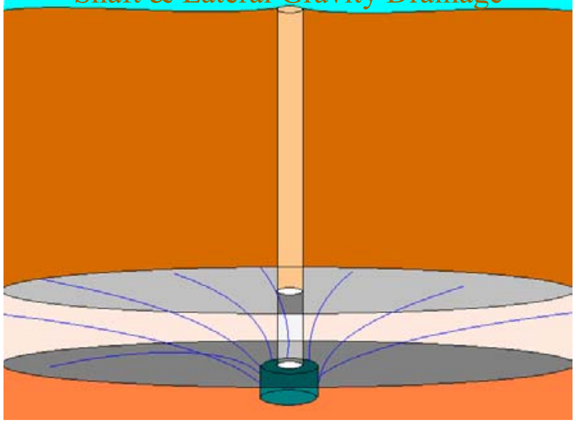
The SAGD method addresses low oil mobility, low reservoir pressure, and low recovery factor. The entire reservoir tends to be heated to reduce oil viscosity. Reservoir pressure is maintained by continuous steam injection, and residual oil saturation is reduced by steam displacement. A fourth factor, gravity segregation and drainage, promotes very high displacement efficiency when compared to other processes. Because the process requires large amounts of steam, energy costs are high. Higher costs may be somewhat justified by the higher recovery factors that range between 50% and 80%.

- ***Shaft and Lateral Gravity Drainage (S&LGD) combines underground mining access with horizontal well technology.***

The Shaft and Lateral Gravity Drainage method of heavy oil production is also known as "Drainage from Underground Access". A shaft, mine adit, or other access to the reservoir, is installed. Horizontal wells are drilled from the underground access to allow oil to drain by gravity into a collection point. From the collection point the oil is pumped to the surface. This concept does not directly address oil mobility. The oil must be mobile at reservoir conditions to flow into the cold horizontal laterals. S&LGD does not generally use heat, but it can. The concept is illustrated in Figure 4.

The Shaft and Lateral Gravity Drainage method indirectly addresses low reservoir pressure. Laterals are nearly horizontal, or even inclined upward from the underground access, to allow gravity drainage with essentially zero backpressure. Other processes rely on artificial lift or flowing systems that impose backpressure on the reservoir. In the absence of imposed backpressure on the reservoir, the S&LGD method can achieve the lowest pressure depletion compared to the other methods of heavy oil production.

Figure 4
Shaft & Lateral Gravity Drainage



S&LGD can also achieve a higher recovery factor than most cold well processes because gravity drainage allows segregation of oil and gas in the reservoir. This is much more efficient than injection methods that tend to bypass large portions of the oil.

S&LGD is conceptually simple but it must be regarded as an unproven technology until some larger commercial applications are demonstrated. Recovery factors may range between 15% and 50%. Note that S&LGD is not applicable to immobile bitumen unless combined with one of the heating processes.

- ***In-Situ Combustion (ISC), also known as "Fireflood", is the injection of air or oxygen to initiate a combustion reaction to heat the viscous oil.***

The In-Situ Combustion method creates heat and addresses low oil mobility, low reservoir pressure, and low residual oil saturation. ISC may offer an additional benefit by upgrading the hydrocarbon by selectively removing carbon, which can increase the hydrogen to carbon ratio and the API gravity. The concept is illustrated in Figure 5.

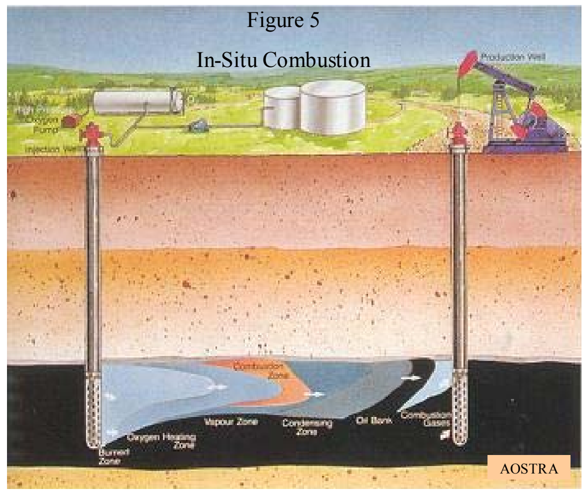


Figure 5
In-Situ Combustion

The injected oxygen reacts with the residual hydrocarbon and burns in a manner similar to a glowing coal. Oxygen that reacts with any hydrogen forms water of combustion, and oxygen that reacts with any carbon forms carbon dioxide or carbon monoxide. The heat generated by combustion vaporizes the connate water to produce steam and thermally alters the residual hydrocarbon. In essence, before oxygen reaches the combustion front, the reservoir is swept by banks of nitrogen, carbon monoxide, carbon dioxide, volatized hydrocarbon gases, condensed hydrocarbon liquids, cold water, hot water, steam vapor and superheated gases.

The air that moves from the burned out zone into the combustion zone is preheated as it scavenges the heat from the rock. This very hot air reacts with hydrocarbon that it encounters, but the very hot combustion gases that travel ahead of the burn front are depleted of oxygen and only preheat the rock and hydrocarbon ahead of the front. The temperatures are so high that all volatile hydrocarbons are vaporized and heavy hydrocarbons are cracked into lighter chains and driven ahead. The hydrocarbon that is left is coked residue that acts as the fuel that reacts with the oxygen. When oxidation occurs, it is almost entirely a carbon and oxygen reaction. Ideally, ISC can be very thermally efficient compared to steam displacement because only a fraction of the reservoir is maintained at high temperature and heat from the depleted areas is scavenged for beneficial use closer to the combustion front. Steam Flood and SAGD both require heating a large volume of rock and maintaining that volume at high temperature for the duration of the process; that large heat volume is largely un-recovered.

In-Situ Combustion generally works better with the lighter end of the heavy oil gravity spectrum and perhaps medium to light oil gravity as well. It seldom is considered for bitumen and very low mobility oil for two reasons: low recovery factor and extremely high oxygen consumption. The best cases usually benefit from a gravity stabilized drive where reservoir dip exceeds 30 degrees or where some other top-down process can be induced.

ISC is not without operational problems. These can include corrosion problems and thermal failures in well equipment. Oil that is too heavy tends to "lay down" excessive coke that consumes extra oxygen that increases cost by requiring more compression capacity and fuel as well as generating higher than desired temperatures. Oil that is too mobile does not lay down enough fuel to sustain the process. Attempts to quench combustion by injecting water do not overcome the high fuel lay-down problem, but quenching can reduce air requirements. The process is hard to control and rarely achieves high efficiency in reducing air requirements. Commercial success with ISC is very limited and where it has succeeded it has been in the lighter end of the heavy oil gravity spectrum rather than the bitumen and extra heavy gravity range.

The recovery factor might fall between 30% to 50% or higher in the ideal application.

- ***Open Pit Mining (OPM) is a surface excavation method to remove oil sand, which is then processed to separate the hydrocarbons from the solids.***

Open Pit Mining is not restricted by low oil mobility, low reservoir pressure, and low residual oil saturation that impact the wellbore extraction methods. It has been commercially proven on a very large scale in the Athabasca Oil Sands of Alberta, Canada but has not been applied on a commercial scale in any other area of the world. Figure 6 is a picture of a 240-ton mining truck used by Syncrude of Canada. OPM has potentially greater adverse environmental impacts due to land disturbance than most other oil operations and is restricted to shallow depths and certain overburden to oil content ratios. OPM probably is not suitable for oil that is relatively mobile. Oil mobility can be expected to increase handling and processing difficulties. For these reasons, OPM is generally restricted to outcrop or tarbelts with less than 200 feet of total depth.

Figure 6
240 Ton Mining Haul Truck

Although mining oil is a relatively high cost operation, it can be applied to bitumen with recovery factors up to 95%. No other extraction process comes close to this recovery potential. This high recovery factor can make the unit cost competitive with other heavy oil and bitumen extraction processes.

❖ ***Oil Sands Underground Mining (OSUM) integrates a tunneling machine and oil sand processing into a single operation.***

Oil Sands Underground Mining is an emerging technology that has not been demonstrated to date. It is not likely to be as economical as Open Pit Mining in the outcrop and shallow areas. OSUM targets those reservoir depths that are too deep for open pit mining and too shallow for the thermal and wellbore extraction processes.

Figure 7
English Channel Tunneling Machine

The concept uses a tunnel-boring machine that has its own integrated oil-sand separation equipment. The basic drilling machine is illustrated in Figure 7 from Euro Tunnel.

Tailings are left in the ground behind the machine as it “chews” its way through the reservoir. The promoter of this technology claims a 14-meter diameter machine could produce 20 MBOPD from an Athabasca resource in Alberta, Canada. The machine would dig through the reservoir, use diluent and cyclones to separate the sand from the oil and send the diluted oil through an umbilical pipeline back to the surface for collection. The de-oiled sand would be packed into the tunnel behind the machine. A small cement lined tunnel is created behind the Underground Tunneling Machine (UTM) in the tailings-filled area to allow workers to access the equipment and to provide the path for the umbilical to the surface.

Recovery factor is projected to be a little lower than the Open Pit Mining because the underground separation system would not be as elaborate as that used with OPM. However, this process targets oil that would not be available for OPM or thermal processes. Recovery factor could approach 90% for the area actually processed; bypassed areas would have to be deducted from this recovery factor. A great deal of technology development will be required to introduce this concept into commercial operation.

Recovery Process Keyed To Depth

Beginning with the exposed outcrop of the oil belt and going down dip, the following broad guidelines are used to define the appropriate extraction process to develop various portions of Block 474. The depth ranges for each process are illustrated graphically in Table 1.

- Open Pit Mining (OPM) applies from the outcrop down to a total overburden depth of about 100 feet. This depth depends on pay thickness and bitumen content.

- Oil Sands Underground Mining (OSUM) applies from the deeper limit for open pit mining to the shallower depth for steam operations - from 100 to 400 feet.

- Shaft and Lateral Gravity Drainage (S&LGD) may apply to depths greater than 100 feet. This depends on oil mobility. For this study S&LGD applies to depths greater than 200 feet because oil mobility is expected to be unacceptably low for shallower depths.

- Steam Assisted Gravity Drainage (SAGD) applies to depths greater than 400 feet.

- Steam Flood (SF) and Cyclic Steam Stimulation (CCS) are generally restricted to depths greater than about 400 feet and less than 4000 feet. Oil mobility is expected to be high enough that steam would be unnecessary below 2500 feet in Block 474.

- Cold Horizontal Well (CHW) production is likely to be controlled by oil mobility and is applicable at depths greater than 1500 feet.

- In-Situ Combustion (ISC) may be restricted to depths greater than 200 feet, but will be more determined by oil and rock properties than by depth.

Note that the depth boundaries for each process are not precise and may overlap significantly. The optimal process selection should consider all available information. Operating outside the boundaries suggested here will likely result in higher unit cost per barrel. Technology screening done within these boundaries should represent the lowest expected cost of development for each process.

Table 1

Heavy Oil Recovery Processes versus Reservoir Overburden Depth

Depth, feet->	0-100	100-200	200-400	400-800	800-1500	1500-2500	2500-4000
OPM	X						
OSUM		X	X				
S&LGD			X	X			
SAGD				X	X		
SF				X	X		
CSS				X	X	X	
CHW						X	X
ISC			X	X	X	X	X