Paper #2-18

OIL PRODUCTION TECHNOLOGY

Prepared by the Technology Subgroup
of the
Operations & Environment Task Group

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

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

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

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

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ABSTRACT

There are three main categories of hydrocarbons which are liquid phase in their native-state underground reservoirs: conventional oil, heavy oil, and bitumen. That sequence of categories represents substantial increases in density and viscosity and therefore in the amount of effort required to produce the petroleum from its reservoir. Conventional oil typically is produced, at least initially, using the natural drivers of flow that are native to the reservoir, including gas pressure or geologic formation pressure. In contrast, heavy oil is resistant to flow, and bitumen typically does not flow, without significant artificial intervention by engineering techniques.

The developmental techniques used for oil production recognize the category of petroleum to be produced as well as the maturity stage of the reservoir to be developed. The three established developmental categories are: primary recovery, secondary recovery and enhanced oil recovery (EOR). Primary recovery denotes initial stages of production whereas secondary recovery and EOR denote increasing levels of effort to re-work previously produced reservoirs.

Specific findings are:

- Technologies are well-established for producing a variety of petroleum categories (conventional oil, heavy oil, bitumen) through a succession of production stages (primary recovery, secondary recovery, enhanced recovery). For every type of petroleum deposit, there exist technologies to produce at least some fraction of the recoverable oil.

- Likewise, long-proven technologies exist for separating the oil, gas and water streams that are the typical outputs from petroleum wells. Those technologies include methods for upgrading bitumen to be more transportable and marketable and for making heavy oils easier to refine.

- Enhanced oil recovery (EOR) has been accomplished through several different variations, including polymer water flooding, CO2 flooding and solvent flooding in addition to steam flooding and other thermal methods. Significant industry experience has been accumulated through tailoring EOR technologies and practices for individual petroleum reservoirs.

- Non-conventional petroleum deposits, including oil shales and gas hydrates, comprise the most conspicuous challenges for development of new technologies for safe, sustainable and economical recovery of the subject hydrocarbon resources. Retorting of oil shales can be viewed as already operational although the techniques require additional research to reduce input-energy requirements and environmental footprints. In contrast, production of gas hydrates remains highly experimental and significantly distant from operational status.

PETROLEUM CATEGORIES

Petroleum which is not naturally in the gaseous state as found in the reservoir will be divided into three categories for the purposes of this discussion. They are based upon definitions developed by an international study group over a period of 7 years and presented in a final report at the 12th World Petroleum Congress in 1987. They are:

- Conventional Oil. Petroleum with a viscosity less than 100 centipoise at atmospheric pressure and original reservoir temperature, on a gas-free basis. If viscosity data are not available, crude oil with an API gravity greater than 22º API.

- Heavy Oil. Petroleum with a viscosity between 100 and 10,000 centipoise at atmospheric pressure and original reservoir temperature, on a gas-free basis. If viscosity data are not available, crude oil with an API gravity between 10º and 22º API.

- Bitumen Petroleum in the semi-solid or solid phase in natural deposits. It has a viscosity greater than 10,000 centipoise at atmospheric pressure and original reservoir temperature, on a gas-free basis. If viscosity data are not available, petroleum with an API gravity less than 10º API.

The above definitions were specifically developed for resource characterization/classification and to satisfy the need to define a “bright line” differentiation (particularly in the case of the United States with respect to regulatory issues). Venezuela is relatively unique in that it has significant petroleum resources with API gravities of less than 10o but with viscosities which are less than 10,000 centipoise at original reservoir temperature and atmospheric pressure. Because these resources would fit the classification of heavy oil based on viscosity, yet present surface handling and processing difficulties more akin to bitumen, an additional term Extra Heavy Oil was coined. Since little of the North American resource base fits the Extra Heavy Oil criterion, this discussion will focus on the original three resource categories.

OIL PRODUCTION TECHNOLOGIES

Oil production technologies are categorized based upon the source of the “driving force” used to mobilize the oil in a subsurface reservoir to flow into a wellbore for subsequent production to the surface. There are three categories. These may or may not be used sequentially.

A. Primary Recovery

“Primary recovery is oil recovery by natural drive mechanisms…” (Lake, 1989). Production by primary recovery depends upon the natural energy within the reservoir to drive oil through the pore network within the reservoir rock to producing wells. The sources of this natural energy include:

- Liquid expansion and evolution of dissolved gas from the oil as reservoir pressure decreases during production.
- Expansion of a gas cap or of the gas evolved during pressure depletion.
- Influx of water from a contiguous aquifer.
- Gravity.
- Combinations of the foregoing.

(1) Historical Development and Applicability

Since primary recovery is based upon the use of natural reservoir energy, it has been applied since the earliest days of oil production. However, in the earliest days there was little understanding of the physics of oil production and focus was solely upon maximum production rate resulting in significant waste of the resource. With the development of petroleum engineering as a discipline, early identification of the main primary drive mechanism became possible and well production rates and locations began to be optimized to minimize waste of natural reservoir energy. Examples would include reduced reservoir voidage rates to minimize water or gas coning, limits on producing gas/oil ratios to avoid “blow down” of reservoirs having gas cap drives. Since primary production utilizes natural energy, it is applicable to all reservoirs except those containing the most viscous oils or bitumen, in which the hydrocarbons are essentially immobile in their native state. In reservoirs with low permeability, it is frequently necessary to employ acidization and/or fracturing technologies (discussed in a separate topic paper) in order to enable an economic flow rate.

(2) Environmental and Economic Impacts

Primary recovery operations typically will have the least cumulative environmental impact, but also lower recovery factors than other oil recovery mechanisms. Major improvements in environmental impact over the years have come from better application of engineering and geologic knowledge with respect to selecting the well spacing. No longer does one see the extremely close well spacing of primary recovery wells often present in the very early days of the industry. Compared to earlier times, appropriate well spacing reduces the number of wells, with corresponding reductions impact in areas such as surface usage, drilling water usage, and traffic. Development of directional and horizontal drilling technology has, in many cases, permitted the use of multi-well drill pads. This lowers the total surface area impacted by pads, roads and in-field pipelines, as well as reducing miles travelled by personnel responsible for daily well operations. Development of automated monitoring and control capabilities has improved the risk profile for adverse consequences of equipment failures, while coupling these systems with remote monitoring helps reduce vehicular traffic.

The use of directional or horizontal drilling increases drilling costs, which may or may not be balanced by potential savings in drill pad and other costs. Similarly, the use of automation/remote monitoring increases costs and must be balanced against anticipated savings.

B. Secondary Recovery

"Secondary recovery refers to techniques, such as gas or water injection, whose purpose, in part, is to maintain reservoir pressure" (Lake, 1989). When the natural drive energy of a reservoir is depleted or has become insufficient to maintain desired production rates, energy must be added to supplement the primary recovery energy. Secondary recovery is the injection of water or a gas at nominally ambient temperatures to supply additional reservoir energy, with negligible mass or heat transfer between the injected fluid and the reservoir oil. Separate wells are used for injection and production, with the injected fluids either maintaining reservoir pressure or repressuring the reservoir following primary depletion. The injected fluid displaces a portion of the remaining oil toward producing wells. On a microscopic scale, the displacement process mimics that of natural water influx or gas expansion.

The principal method of secondary recovery is waterflooding. In a waterflood, water is injected through dedicated injection wells, either on the periphery of the oil reservoir or in a pattern of wells distributed throughout the reservoir. Produced water is used for reinjection, but additional volumes of water are generally required during the early phases of a waterflood. The additional water may come from other oil reservoirs, source wells producing non-potable saline water, treated domestic waste water, or fresh water sources.

The use of natural gas injection in the United States is limited by the market value of the gas. However, gas pressure maintenance can be highly efficient under certain limited reservoir conditions.

(1) Historical Development and Applicability

The first pattern waterfloods occurred in the Bradford field in Pennsylvania in 1924, although the general applicability of waterflooding was not recognized until the early 1950s (Craig, 1971). It is very widely applied in conventional oil reservoirs, and today is frequently initiated very early in the productive life of a newly discovered reservoir. It is less beneficial when used in heavy oil reservoirs (Hoang et al., 2005) and is not applicable to immobile bitumen.

The first deliberate injection of natural gas into an oil reservoir to stimulate recovery reportedly was in Macksburg field, Ohio, in 1903 (Muskat, 1949). This process is applicable to conventional oil reservoirs, most beneficially in those with high API gravities and gas caps or high structural relief. Due to the value of natural gas in North America, application in oil reservoirs is now generally limited to remote areas where there is not a ready market for natural gas.

(2) Environmental and Economic Impacts

Secondary recovery projects generally create a slightly larger surface footprint than primary recovery operations in the same field due to the need for injection facilities and, in the case of waterflood, increased oil/water separation capacity. Energy requirements also increase, primarily due to increased volumes of produced fluids. Vehicular traffic increases during new facilities installation. However, the effects are balanced by the increased oil recovery which defers the need to develop new fields. Implementation of a secondary recovery project early in the primary life of a field shortens its ultimate lifespan. Implementation of gas injection in remote fields (e.g., Alaska North Slope), preserves the gas resource for potential future use when a market develops.

C. Enhanced Oil Recovery

Oil which is not recoverable using primary or secondary recovery processes may be recoverable through the use of Enhanced Oil Recovery (EOR) techniques. Like secondary recovery, EOR involves the addition of energy to the reservoir through fluid injection. However, there is a critical distinction – secondary recovery uses injected water or gas at nominally ambient temperatures to supply additional pressure energy to the reservoir with negligible mass or heat transfer between the injected water or gas and the reservoir oil. In contrast, EOR is the use of recovery methods that seek to improve recovery of oil beyond that which might be achieved by merely supplementing reservoir pressure:

> Enhanced oil recovery (EOR) is oil recovery by the injection of materials not normally present in the reservoir. This definition embraces all modes of oil recovery process (drive, push-pull, and well treatments) and covers many oil recovery agents. Most important, the definition does not restrict EOR to a particular phase (primary, secondary, or tertiary) in the life of a reservoir (Lake, 1989).

These processes focus on the rock/oil/injectant system and on the interplay of capillary and viscous forces (Stosur et al., 2003).

Improved oil displacement or improved oil flow rates in the reservoir are most often induced by the addition of heat, addition of chemicals which alter microscopic displacement efficiency, or by injection of fluids under conditions designed to result in significant mass transfer between the injected fluids and the reservoir oil.

(1) Thermal EOR

In thermal EOR processes the physical conditions of the reservoir fluids are altered by the addition of heat. Most often, the main objective is to reduce the viscosity of the petroleum in the reservoir, thus increasing both the rate of production and ultimate oil recovery. In some instances, thermal EOR has had the objective of producing a significant amount of distillation and transport of lighter hydrocarbons within the reservoir (e.g., steamflooding a light oil reservoir) (Konopnicki et al., 1979). There are two main categories of thermal recovery processes – steam injection and in-situ combustion.

Steam injection for EOR is practiced either as cyclic steam injection or as continuous injection. Continuous steam injection may be further subdivided into two subcategories: conventional steam flooding and steam-assisted gravity drainage (SAGD).

In cyclic steam injection, steam is periodically injected into a production well and the well subsequently placed back on production. In steamflooding, steam is continuously injected into dedicated injection wells with other wells acting as producers. Cyclic steam stimulation of producers is generally practiced in addition to continuous steam injection during a steamflood.

Conventional cyclic and steamflood methods are applicable in some bitumen reservoirs, but it is not applicable when the bitumen is immobile. In 1978 the concept of Steam Assisted Gravity Drainage (SAGD) was demonstrated at Cold Lake, Alberta (Butler, 1994). SAGD requires two closely spaced horizontal wells placed one above another. It begins with a period of steam circulation within the wells to create a zone of heated, mobile bitumen before production and steam injection is initiated. Application of SAGD has only recently undergone significant growth beyond pilot-scale projects due to factors such as the need for improved horizontal well technologies, oil prices and ability for the market to absorb increased volumes of bitumen.

The generally accepted first application of cyclic steam was in the Mene Grande Field, Venezuela, in 1959 (Prats, 1982). Due to dramatic and rapid production response achievable when cyclic steam is first applied in a reservoir, it was rapidly implemented in suitable reservoirs, such as the heavy oil fields of California (Hanzlik and Mims, 2003). Steamflood efforts date from at least as early as 1931-32 (Prats 1982). However, widespread field application did not begin until the late 1960's (Hanzlik and Mims, 2003). Worldwide, steam EOR processes are, with minor exception, limited to heavy oil and bitumen reservoirs. Currently, it is the only recovery process producing large volumes of bitumen via wells.

In-Situ Combustion processes are based upon injecting an oxygen-containing gas (generally air, although oxygen-enriched air and pure oxygen have also been used) into the reservoir where it reacts with in-place fuels to produce heat. This heat then generates steam from water which resides in the reservoir and also acts to distill the in-place oil and thermally crack residual oil near the combustion front. Thus, one can expect some degree of upgrading of heavy oils or bitumen in an in-situ combustion project. There are two general categories of in-situ combustion – dry and wet. In dry combustion, only the oxygen-containing gas is injected. However, this can lead to high oxygen requirements, particularly with heavy oils. The method of wet combustion was developed in order to reduce the amount oxygen required. In wet combustion, water is injected in addition to the oxygen-containing gas. This is frequently done by alternate injection of slugs of gas and water. The injected water both reduces the oxygen requirement and increases the volume of steam created within the reservoir.

The first attempt at a purposeful in-situ combustion project in an oil reservoir was a test in Russia in 1934, and significant in-situ combustion research in the United States began in the early 1950's (Prats, 1982). Although numerous field tests have been conducted, only a handful of projects have been commercial. In-situ combustion was initially believed to have great potential for recovering heavy oils and bitumen. However, the process is difficult to control and significant operational, environmental and cost issues have relegated it "niche" status with respect to EOR processes. In the latest Oil & Gas Journal EOR survey (Oil & Gas Journal, 2010) there is only one reported US heavy oil in-situ combustion project, producing 240 barrels of oil per day (BOPD). The method's current application in North America is primarily limited to deep, conventional oil reservoirs.

(2) Environmental and Economic Impacts of Thermal EOR

Surface footprints increase as a consequence of thermal recovery processes requiring close well spacing and significant additional surface equipment compared to primary oil recovery. Major additions to surface equipment for steam projects are water-softening equipment to treat feedwater and steam generation equipment. In locations where the produced water has low salinity, produced water is treated and recycled to the steam generation equipment. If the produced water is very fresh, excess produced water may be used for agricultural purposes following oil/water separation treatments (e.g., Kern River Field, California) (Waldron, 2005).

Air emissions are significant for steam injection processes. However, current technology for steam generators is much improved compared to earlier operations. Modern one-pass steam generators use staged combustion burner designs, exhaust gas recirculation and fully automated burner management. In larger thermal operations, all steam generator operations in a geographic region may be monitored and controlled from a central control room. Beginning in the early 1980s, base load steam for thermal recovery projects began to be supplied from cogeneration plants which produce both electricity and steam for thermal recovery. In 2008, installed cogeneration plants in California had a steam generating capacity equal to approximately 40% of the total steam used in that state's thermal recovery projects (California Department of Conservation, 2009).

Fuel for steam generation is a major cost factor. However, steam injection operations have a major positive economic impact, greatly increasing both the rate and ultimate recovery of heavy oil. For example, 55% of on-shore oil production in California in 2008 came from steam injection operations (California Department of Conservation, 2009).

(3) Chemical EOR

In chemical EOR, the injected fluids contain chemical additives which act to alter oil displacement characteristics compared to those which exist between native reservoir fluids. Examples of the alterations sought are changes in the viscosity ratio between oil and water, or the interfacial tensions between the oil and water phases. Due to variations in oil, water, reservoir mineralogy and temperature between reservoirs, chemical EOR fluids must be "tailored" to fit each reservoir. The following paragraphs provide an outline description of the major processes. For greater depth, one may refer to Lake (1989).

Polymer Flooding is a variety of chemical EOR, which is applied to oils having in-place viscosities greater than water, in which the efficiency of waterflood may be increased by adding polymers to increase the viscosity of the injected water. The net effect is improvement of volumetric sweep efficiency. Most of the commercially attractive polymers fall into two generic classes: polyacrylamides and polysaccharides (biopolymers). Viscosity of the polymer solution is sensitive to water composition, thus a typical polymer flood injection sequence would be:

- Pre-flush of water with a specified salinity.
- Polymer solution of specified viscosity for mobility control.
- A volume in which the concentration of polymer is gradually reduced.
- Post-flush of water with a specified salinity.
- Water.

Surfactant Processes refers to application of chemical EOR through amendment of capillary forces involved in the interfacial tension between oil and water phases and which resists externally applied viscous forces. It has long been recognized that capillary forces cause large quantities of oil to be left behind in well-swept zones of waterflooded oil reservoirs. Lowering the interfacial tension recovers additional oil by reducing the capillary forces. Oil-water interfacial tension is reduced through the use of surfactants. In limited instances, surfactants may be generated in-situ from the injection of alkaline materials which, given favorable conditions and suitable oil properties, react with acidic components in the oil. However, one generally would inject a surfactant and other chemicals which have been selected for a specific reservoir. The usual sequence of injection for a surfactant flood would be:

- Pre-flush with a specified salinity, frequently containing a sacrificial agent to lessen the subsequent retention of surfactant due to adsorption on rock surfaces.
- Surfactant slug.
- Mobility buffer containing polymer to create a desired viscosity.
- A volume in which the concentration of polymer is gradually reduced.
- Water.

(4) Environmental and Economic Impacts of Chemical EOR

Significant research activity and initial field trials of chemical flooding technologies occurred in the early 1960s (IOCC, 1974). There were a large number of field projects in the early 1980s, but presently there are only two significant chemical EOR (polymer) projects in North America which are reported in the biennial Oil and Gas Journal EOR survey (Oil & Gas Journal, 2010).

Chemical EOR, particularly surfactant flooding, is most applicable to conventional oils, but polymer flooding can be applicable in some heavy oils.

Surface footprints of chemical EOR are similar to waterflooding, with minor expansion to provide for chemical mixing facilities. Power requirements are somewhat greater, as the injected solutions are more viscous than water. Due to the need for controlled salinities, there may be additional demand for fresh water during certain phases of the operation. Chemical EOR has the potential to both increase recovery (primarily when using surfactant systems) and accelerate recovery (polymer flooding). A major economic factor is the cost of the required chemicals. The linkage between chemical costs and petroleum prices should be noted as the both the commonly used surfactants and the polyacrylamide polymers are petroleum-based.

(5) Solvent EOR

Solvent flooding refers to techniques whose main oil recovering mechanism involves extraction, dissolution, vaporization, solubilization, condensation or some other phase behavior change involving the crude oil. Other mechanisms which improve oil recovery (e.g., viscosity reduction) also occur (Lake, 1989). Although there are many potential solvents, most field applications have involved injecting hydrocarbon gases or carbon dioxide (CO_2) under conditions of pressure and composition which achieve miscibility with the oil in the reservoir. The conditions required for miscibility limit the number of prospective reservoirs as does the availability of injectants in sufficient volume and at economic prices.

(6) Environmental and Economic Impacts of Solvent EOR

Hydrocarbon-miscible processes received extensive field testing in the 1950s and 1960s in the United States (Stalkup, 1983). However, due to the value of the hydrocarbons, hydrocarbon-miscible projects are now generally limited to remote locations such as Alaska. Most miscible production in North America now is produced using CO_2 injection (Oil & Gas Journal, 2010). It is applicable to light oils, but it must be noted that the minimum required operating pressure for miscibility is a function of oil composition and reservoir temperature, as well as injectant composition. Reservoirs which have had their pressures depleted below the miscibility pressure require repressuring. Impurities in the injected CO_2 can significantly increase the pressure required for miscibility. CO_2 injection under immiscible conditions is also practiced, but to a lesser degree.

Used under favorable reservoir conditions, miscible processes can greatly increase ultimate oil recovery. If implemented early in reservoir life, they decrease the lifetime of the production operation. Implemented later in life, such as many CO_2 floods in West Texas, they both increase ultimate recovery and provide economic stimulus to the local community. The surface footprint of operations is slightly greater than primary production due to the need for additional compressors and facilities to reclaim and recycle the valuable injectants.

PRODUCTION TECHNOLOGY USE BY PETROLEUM CATEGORY

A. Conventional oil production

Deposits of conventional oil initially begin production using primary recovery methods. Historically, primary recovery was continued until the natural drive mechanism was nearly depleted prior to initiating other methods. In more recent decades, other recovery processes frequently have been begun at earlier stages of primary depletion. The reservoir is produced on primary production for a time sufficient to determine the natural drive mechanism (e.g., depletion gas drive, water influx) following which a determination is made on an additional process to be applied to increase ultimate economic recovery. Most commonly, this is water injection, but it may also be gas pressure maintenance, miscible gas injection, or potentially other EOR processes if local conditions and economics are favorable. Due to the long history of oil production in North America, chemical EOR processes and CO2 injection processes have typically not been applied until after water injection. Initiation of those processes at earlier times in the reservoir production history can have both economic and environmental advantages. Economically, the ultimate recovery from the reservoir is achieved earlier, and environmentally, the period of time during which the surface is occupied by operations is reduced, thus reducing overall impact.

Steam injection is not typically applied to conventional reservoirs, although there have been some tests (Konopnicki et al., 1979). Similarly, in-situ combustion has not been generally applied to conventional reservoirs. However, under specific conditions it may be applicable, as shown by the production of approximately 17,000 barrels per day of incremental conventional oil from eleven projects in Montana, North Dakota and South Dakota (Oil & Gas Journal, 2010).

B. Heavy oil production

Most heavy oil reservoirs are capable of primary production. However, the recovery factors for heavy oil reservoirs under primary recovery are significantly lower than for conventional oil reservoirs. This is because heavy oils have higher viscosity and typically are in reservoirs found at shallower depths (leading to lower reservoir pressure and lower volumes of dissolved gas). This combination of higher viscosity and lower reservoir energy leads to both lower production rates and ultimate recovery factors under primary production. In some instances where the primary production rates from conventionally completed vertical wells in unconsolidated sand reservoirs are too low for economic production, wells may be completed to deliberately encourage massive sand influx and a combination of oil and sand are produced. This method is commonly referred to as "CHOPS" (Cold Heavy Oil Production with Sand). The produced fluids and sand are separated on the surface and the sand disposed of in accordance with local regulations. In North America CHOPS is principally practiced in Canada.

Similarly, the high viscosities of heavy oil lead to poor incremental performance when waterflooded (Hoang et al., 2008). Attempting to "drive" the viscous oil with less viscous water results in water "fingers." Water rapidly reaches producing wells, leaving much oil behind. Although the use of polymer flooding can improve performance, the high oil viscosities require larger quantities of polymer than needed for conventional oils. This, coupled with the lower value of heavy oil has limited the application of polymer flooding. Similar constraints apply to surfactant flooding.

Thermal recovery processes are most commonly applied to heavy oil reservoirs following an initial period of primary production. Although in-situ combustion has theoretical attractiveness, it is generally difficult to control and it causes more production operational problems than steam injection processes. Thus, steam processes are most common.

Steam thermal recovery in a reservoir generally begins with the use of cyclic steam stimulation. This provides a quick production response as well as some initial reservoir heating near production wells. In suitable reservoirs, operations are subsequently converted to continuous steam injection with dedicated injection wells. Cyclic steam stimulation of production wells generally continues during steamflooding operations. Ultimate recovery from a heavy oil reservoir is significantly increased through successful steamflooding. Where a heavy oil reservoir may have had a primary recovery factor of 10% or less, successful steamflood recovery may be on the order of 60-70% of the remaining oil in place. (IOCC, 1984), (CA Dept. of Conservation, 1960, 2008)

C. Bitumen (oil sands) production

Bitumen is immobile, or essentially so, at ambient reservoir conditions. Thus, it is not capable of economic primary production by normal methods. It is found in North America in both surface/near surface deposits and in subsurface reservoirs.

<u>Surface/Near Surface Bitumen Production</u>. Natural bitumen deposits in the Canadian Athabasca region can be mined from the surface to depths of approximately 250 feet where the deposit is sufficiently rich and thick (World Energy Council, 2010). The bitumen is separated from the sand by hot water processes and then upgraded to a marketable syncrude. The upgrading may occur either on-site or the bitumen diluted with a light hydrocarbon and shipped to an off-site upgrading facility.

The hot water process used in Canada has not generally been found to be successful when tested with US oil sands. Development testing of minable US deposits most commonly has considered either solvent-based or retorting methods of bitumen separation from the mined oil sand material.

<u>Subsurface Bitumen Production</u>. Where the deposit is deep enough and has suitable overburden rock to maintain confinement of steam at desired processing temperature and pressure, wells and thermal recovery methods are employed for bitumen recovery. If the bitumen has some degree of mobility at ambient reservoir conditions (e.g., Cold Lake, Alberta), cyclic steam thermal recovery may be employed. Where the bitumen is immobile at ambient reservoir conditions, the SAGD thermal recovery process is employed. Bitumen production is generally diluted with a lighter hydrocarbon and shipped to an offsite facility for upgrading.

D. Future resources

Oil Shale. Oil shale is a generic term covering a range of materials. An early definition commonly cited is "compact laminated rock of sedimentary origin, yielding over 33% of ash and containing organic matter that yields oil when distilled, but not appreciably when extracted with ordinary solvent for petroleum" (Gavin, 1924). In his discussion, Speight (1990) considers oil shale "to denote an organic-rich rock that contains little or no free oil." Lithologically, oil shales can be categorized into three groups: 1) carbonate-rich shale; 2) siliceous shale; and 3) coaly shale, often called cannel shale (Lee, 1991). The insoluble hydrocarbon material in oil shale is termed kerogen. Production of liquid syncrude and gaseous hydrocarbons from this material requires destructive distillation, or retorting. The retorting may occur either ex-situ or in-situ.

In Ex-Situ Retorting, the oil shale is mined, crushed and then sent to a retort in which it is subjected to temperatures ranging from 500º to 550º C. At these temperatures, the kerogen is rapidly pyrolyzed yielding simpler and lighter hydrocarbon molecules. The advantages and disadvantages of ex-situ retorting include (Lee, 1991):

- Recovery of organic material is high, up to 70-90% of the organic material of the retorted shale.
- Control of process variables is possible and relatively easy.
- Product recovery becomes easy once it is formed.
- Operating cost is normally high since the material has to be mined, crushed, transported and heated.
- Spent shale disposal, potential water contamination, and re-vegetation issues are significant.
- Capital investment for large-scale units is high.

In-Situ Retorting is applied to oil shale underground. Most in-situ processes which have been field tested involve fracturing the shale by either explosive or hydraulic means and then initiating combustion to provide the required heat through burning a portion of the organic matter. Other methods of providing the required heat include conductive heating from a wellbore or use of radio frequency energy or electric currents through the shale. The advantages and disadvantages of in-situ retorting include (Lee, 1991):

- Oil can be recovered from deep deposits of oil shale.
- Mining costs can be avoided or minimized.
- Minimal solid waste disposal issues.
- Potentially more economic and applicable to leaner shales.

- Difficult to control process conditions.
- Drilling costs are high due to very close well spacing.
- Recovery efficiencies are lower.
- Concern over potential contamination of aquifers.

Good summary discussions of various historic retorting processes can be found in Speight (1990, 1991) and Lee (1991). Most recent research work appears to be focused on in-situ methods due to the potential for less environmental impact.

Gas Hydrates. Gas hydrates are crystalline compounds in which individual gas molecules reside within cages of water molecules, and are formed when a hydrocarbon gas such as methane comes in contact with liquid water at high pressure and low temperature. They are solids and have physical properties similar to those of regular ice. Methane hydrates are a very large potential resource of natural gas for the future. An extensive discussion may be found in a recent report by the National Research Council (NRC, 2010). Gas recovery from hydrates presents technical challenges, since the gas is bound in a solid form and is found in hostile environments such as the arctic. In addition, it may be found in different reservoir settings which are likely to require different development strategies. Three primary production concepts have been advanced:

- Depressurization
- Thermal stimulation
- Chemical stimulation

In each method the goal is to alter the stability of the hydrate and induce in-place dissociation to release free gas. Very limited field testing has been done for depressurization and thermal stimulation. Chemical stimulation concepts have been based upon methods used to deal with hydrate blockages in pipelines, but face issues of cost and challenges in placing the inhibitor in the formation. A novel concept involves injecting another gas into the reservoir which would exchange with the methane in the hydrate structure. This concept is based on laboratory observations and thermodynamics.

PRODUCED OIL PROCESSING

Typical oil wells produce a mixture of gas, oil and water. Portions of the oil and water are frequently in the form of emulsions. Processing of production at a lease/field level primarily consists of separating the produced fluids into gas, water and oil streams. The gas and oil streams receive sufficient on-site treatment to meet the local specifications for sales and the water receives treatment for disposal. It should be noted that the following description represents a generalized on-shore operation, and that numerous variations exist as needed to fit local conditions.

A. Gas

The majority of the produced gas is separated from the produced liquids using "gas traps" which operate on the difference in density between the gas and liquid phases, the less dense gas flowing from the top of the vessel and the liquids flowing from the bottom of the vessel. Depending on fluid properties, there may be more than one stage of separation which operate at different pressures. Smaller volumes of gas evolve and are collected during subsequent processing of the produced liquids. Following separation from the produced liquids, gas is next dehydrated. Some portion of the gas production is likely to be used as fuel on the lease, with the remainder compressed and sold into pipeline systems for ultimate delivery to an end user. If a local market does not exist (e.g., Alaska North Slope) gas may be reinjected into the oil reservoir for pressure maintenance and storage until a market is available. The gas associated with oil production usually contains liquid petroleum gases (LPGs), such as propane and butane, which are recovered by processing in a gas plant. On large properties LPG separation may occur on the lease prior to the gas sales point, while on smaller properties separation generally occurs in a central gas plant serving a number of separate properties. Details on gas dehydration, compression and LPG recovery may be found in a separate topic paper on gas production.

B. Water and Oil

From the gas trap(s), the produced liquids (oil and water) undergo additional separation processes. Produced water is subsequently returned to the oil reservoir via injection for secondary recovery or EOR recovery projects or is sent to disposal (see white paper on "Water Management" for details on treatment/disposal methods). The water content of the oil is reduced to a level which meets local pipeline specifications, the oil is metered for custody transfer/sale and then enters the crude oil pipeline system either directly or via trucking to a terminal. In a limited number of areas, it may be transported by train. Three main steps are as follows:

- Free Water Knock-Out. Following the initial gas/liquid separation in the gas trap, the liquids are sent to what a free water knock-out vessel. This may be either an atmospheric pressure tank or a low pressure horizontal vessel. In this vessel, the unemulsified water separates by gravity from the lower density oil and oil/water emulsion. The size and retention time in this vessel is a function of the oil properties. Some additional gas evolves and is collected at this point. The water is drawn from the bottom of the vessel and sent to the waste water facility. Oil and emulsion are drawn from the upper level of the tank. De-emulsifying chemicals are added at this point if they have not been added earlier.

- Heater Treater/Wash Tank. The oil and emulsion next flow to a heater treater or a wash tank. In each instance, the oil and emulsion is heated to assist in breaking the emulsion into separate oil and water phases, with the water being drawn off the bottom of the tank or treater and sent to a waste water system for recycle as part of an oil recovery process (e.g., waterflooding) and/or disposal. Sales-quality oil is drawn from the upper portion of the vessel. The heat input required and the required vessel size and retention time is a function of the oil and emulsion properties. Again, small additional volumes of gas are collected at this point. In some instances, electrostatic coalescers may also be used as part of the emulsion treatment.

- Shipping Tanks. From the heater treater or wash tank pipeline quality oil is stored in shipping tanks until metered and shipped to sales.

C. Crude Oil Upgrading

Production of bitumen generally requires the addition of a lighter hydrocarbon diluent to facilitate oil/water separation and to reduce oil viscosity to a level which allows transportation. If sufficient light hydrocarbons are available from other nearby production operations, they may be used as the diluent and the combined stream sold as a blend. If sufficient light hydrocarbons are not readily available from nearby production, they are generally supplied by having the bitumen/diluent blend dedicated to processing by a single facility, with the diluent recovered and recycled to the field. In some instances the processing facility may be a refinery which produces finished petroleum products, while in other instances the facility is an "upgrader" which is dedicated to producing synthetic crude which then enters the conventional crude oil marketing system. Two main processes are applied to bitumen:

- Visbreaking. Visbreaking is a mild thermal cracking operation used to reduce the viscosity of a heavy hydrocarbon (Speight, 1991). When used to upgrade heavy oil or bitumen, the objective is to achieve a minimally upgraded product that has a viscosity low enough to permit transportation. In a typical application, 8-10º API bitumen might be upgraded to a 16º API syncrude which is transportable and is then sold to refineries having the capability to handle heavy oils.

- Coking-Based Processes. When a more broadly marketable syncrude is desired the most common form of upgrading involves improving the carbon/hydrogen ratio of the oil by carbon rejection through coking. Coking is a thermal cracking process under somewhat more severe heating than used in a visbreaker (Speight, 1991). The delayed coking process currently is most often used. If a syncrude having a full range of distillation products similar to a crude oil is desired, a typical process scheme consists of atmospheric and vacuum distillation units, coker, hydrotreater, and hydrocracker units. The residue from the vacuum distillation unit is split into two streams, with only a portion going to the delayed coker for carbon rejection. The remainder of the vacuum residue bypasses further processing and is blended into the final syncrude product to create a syncrude with a full distillation range. The other streams from the coker, atmospheric and vacuum units are sent to be hydrotreated or hydrocracked (depending on the properties of the individual stream). Finally, the products from the hydro processing units are blended with bypassed vacuum residue to form one or more syncrudes for sales. By varying the upgrader design and the volume of vacuum residue bypassing the coker, the API gravity of the syncrude may be varied to fit a desired market. For example, upgraders for three major Venezuelan projects produce syncrude streams having API gravities ranging from 20-32º API.

FINDINGS

Technologies are well-established for producing a variety of petroleum categories (conventional oil, heavy oil, bitumen) through a succession of production stages (primary recovery, secondary recovery, enhanced recovery). For every type of petroleum deposit, there exist technologies to produce at least some fraction of the recoverable oil.

Likewise, long-proven technologies exist for separating the oil, gas and water streams that are the typical outputs from petroleum wells. Those technologies include methods for upgrading bitumen to be more transportable and marketable and for making heavy oils easier to refine.

Enhanced oil recovery (EOR) has been accomplished through several different variations, including polymer water flooding, CO2 flooding and solvent flooding in addition to steam flooding and other thermal methods. Significant industry experience has been accumulated through tailoring EOR technologies and practices for individual petroleum reservoirs.

Non-conventional petroleum deposits, including oil shales and gas hydrates, comprise the most conspicuous challenges for development of new technologies for safe, sustainable and economical recovery of the subject hydrocarbon resources. Retorting of oil shales can be viewed as already operational although the techniques require additional research to reduce input-energy requirements and environmental footprints. In contrast, production of gas hydrates remains highly experimental and significantly distant from operational status.

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