# 9 SAND AND FLUIDS MANAGEMENT AT THE SURFACE

## 9.1 Stocktanks (Vertical Gravity Separators)

Vertical gravity separators, referred to as stocktanks, are used at the well site to separate phases in the produced slurry (Figure 9.1). Four or five distinct density phases exist in the CHOPS slurry

- Gas, which is of low density and evolves from the liquids in the stock tank;

- Oil (heavy crude oil), generally in the range of $\rho$ = 0.92-0.98 g/cm$^3$ @ STP with the gas evolved (gas in solution reduces the density);

- Formation water, containing about 50-60,000 ppm NaCl, with a density of approximately 1.04 g/cm$^3$; and,

- Sand, >95% quartz, feldspar and siliceous volcanic shards, all with grain densities of ~2.65 g/cm$^3$, with <5% clay and mica

There is also a "fifth phase" generated partially as the result of the flow and pumping action in CHOPS wells: a stable crude oil and formation water emulsion, which can be either lighter or heavier than the water phase, depending on the quantity of clay and other fine-grained minerals, as well as the proportion of asphaltenes present.

**Standard Stocktank Design**: Stocktanks are typically ~7-10 m high, 3.5-4.5 m in diameter, insulated with 20-30 mm sprayed polyurethane foam, painted black, and heated using a horizontal U-shaped fire-tube that is located at ~40% of the height of the tank (to avoid the gas zone, it should not be too high; to avoid the sand zone, it should not be too low). Stocktanks have a series of standard 3″ diameter hammer-union ports for withdrawal of fluids from various levels as well as some mechanism to withdraw sand (usually some type of a union to hook on a vacuum truck hose or a sand auger). Several stocktank designs are used, and small improvements in design take place regularly. Typical sizes available are 500, 750 or 1000 bbl, but special size vertical stocktanks of up to 2000 bbl capacity are available from local manufacturers. The standard stocktank is equipped with two ports at the base, one to introduce a small pipe that is called a "stinger" to agitate and slurry the sand and another to link to a vacuum truck to withdraw the sand slurry.

**D-Ring Stocktank**:  A design introduced in the early 1990's that has some success when combined with a cone-shaped tank (see below) has a permanent jetting ring called a D-ring (a de-sanding ring) installed at the base of the tank to facilitate suspension of the sand so that it can be directly removed using a vacuum truck.  Unsatisfactory performance of the D-ring design with flat-bottomed stocktanks almost led to this design being abandoned: the jets in the ring are of fixed location and, with multiple jets, the lower shear rates reduce the effectiveness in generating a sand-water slurry.  However, with the cone tank, apparently the D-ring design is becoming more widely used.  The internal jetting tanks are reported to be more effective in fields that produce fine-grained sand, as coarse-grained sand, is more difficult to suspend in a slurry.

**Hopper (Cone) Stocktank**:  Conventional cylindrical hopper stocktanks (cone stocktanks) are widely used since sand is easier to remove  from the base by jetting because of the inclined walls of the lower ¼ or ⅓ of the tank (Figure 9.2).  Design improvements are being made to increase the efficiency of sand suspension using fixed internal jets, with view to the possible elimination of one of the two truck units used to clean stocktanks.

**Auger-Hopper Stocktank**:  Developed in the mid 1990's, this is a tank with the lower portion designed as a planar (linear) hopper, rather than a cone-shaped hopper (Figure 9.2).  A heavy-duty sand auger with a hydraulic drive is installed in the linear bottom portion of the hopper. When sand is removed, the port is opened and an auger truck links to the port with additional augers, also supplying hydraulic power to all the auger units.  Sand is loaded directly by the augers into a sealed tub haulage truck (LHD unit).  The newest version of the auger-hopper stocktank allows the external insertion of an auger only when sand extraction is to take place; this reduces the cost of having all tanks equipped with permanent augers in the base.  A special port allows a 3 to 4 m long auger to be "screwed" into the sand in the base of the tank for sand removal without spilling any tank contents.

**Enviro-Vault Stocktank**:  A standard or a hopper tank design may be enhanced by placing access ports and as many of the connections as possible inside a chamber at the base of the tank. This reduces damage during moving, and in the cold Canadian winters it provides a guarantee that tank heat keeps all valves operational and ports freely accessible.

The produced heavy oil slurry is fed directly into the water zone in the tank to facilitate sand separation.  The heating tube maintains a high temperature (usually ~60-80°C) and gas is

released relatively rapidly. The oil viscosity drops, and gravitational segregation of the phases takes place. Residence time for a unit of crude oil in the stock tank is approximately 3-5 days for an average well producing 60 b/d of oil, 20 b/d of water, and 4 b/d of sand, but it is believed that 99% of the segregation takes place with 24 hours. Obviously, a large tank manifolded to several wells will require more aggressive heating to maintain temperature, and the residence time may drop to about one day, which should still suffice for efficient separation. However, most field operators with multiple wells on a site will have two or more stocktanks to increase residence time and to avoid having to slow well production rates if trucks are temporarily unavailable.[55] Also, if wells are manifolded onto a single large tank, there are relatively stringent conservation authority requirements for placing each individual well on test separators each month, which complicates the operation of a manifolded system involving many producing wells.

At the present time (2002), only stocktank separators have proved effective, and there appear to be no other emerging technologies for large-scale sand separation.

## 9.2 Produced Materials Management

Materials management at the stocktank is achieved simply by monitoring the liquid and sand levels in the stocktank, using the simplest of technology. The field operator uses a total level gauge and small sample cups on a long pole inserted into the tank to determine the levels of the liquids and the sand. (Note that because of the possible angle of repose of sand in the base of the tank after partial cleaning and because of the shape of the tank bottom, it is best to measure the sand level in the center of the tank all the time.). No company has yet developed a cheap and reliable fluid level measurement system for stocktank management that can withstand the climate (-40°C to +30°C) and cope with the different materials in the stock tank reliably. Three types of systems have been tested and abandoned: float systems with level indicators, external sight tube systems, and electronic resistivity and capacitance systems with digital read-out.

Different companies have somewhat different operational guidelines for their field operators to determine the maximum amount of water that should be in the tank, the minimum free head-space for gas, and the maximum sand accumulation before sand cleaning. When there is

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[55] Is this necessary considering the intended audience?In the cold Canadian climate, there is a period in the spring referred to as "break-up" when road travel by loaded trucks is carefully limited to avoid road deterioration. Battery stocks and upgrader stocks are maximized before this period, and tanker trucks are limited to partial loads.

sufficient oil to fill a 30 m³ tanker, it is withdrawn and sent directly to the battery. There are only a few cases in the Canadian heavy oil industry where a number of wells have been directly linked through flowlines to a central battery facility so that economies of scale in oil separation and reduction of trucking costs can be achieved. This is an area to monitor in the future, and is an area where, in a new non-Canadian heavy oil development project, substantial economies could be effected.

### 9.2.1  Water Management

When the water level exceeds the maximum limit, it is withdrawn and trucked or sent down a local flow line to a holding tank. Single wells are usually serviced by truck unless the water cuts are high. A single water holding tank is used to service a group of wells on one site. In a large water holding tank, a short residence time is sufficient to permit suspended solids and oil or emulsions to segregate. The partially clear water is trucked or sent by small diameter flow line to a disposal well (any oil is periodically skimmed off for shipment to the local battery). Different formations are used for deep well water disposal in different locations, but throughout the Canadian HOB, there is no shortage of suitable formations into which produced water can be injected. The cost of water disposal is an issue that will be revisited when various sand disposal options are examined.

### 9.2.2  Gas Management

The gas that evolves from the heavy oil in the heated stocktank is the solution gas present in the formation at depth. This formation solution gas varies in amount from as little as 30 scf/b[56] for shallow or underpressured reservoirs, or for reservoirs with an anomalously low bubble point (occasionally, a bubble point of as low as 60% of the pore pressure is found, but generally, $p_b \approx$ 0.9 to 1.0 $p_o$), to over 80 scf/b for deeper reservoirs (800-850 m deep). In addition to stocktank

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[56] Despite metrification, the amount of gas that is in solution in reservoir oil or that is produced along with the oil during CHOPS continues to be expressed in terms of "standard cubic feet per stocktank barrel of oil". Gas volumes are at STP conditions. In general, if the pressure is known and the data are carefully quality controlled, calculations show that the Henry solution gas constant in Canadian heavy oil is ~0.20 atm⁻¹ (i.e. 0.20 volumes of gas per unit volume of oil per atmosphere pressure). This figure is quite consistent for asphaltenic heavy crude oils (<20°API) elsewhere in the world.

gas, the well annulus is usually extremely gassy (this varies from well-to-well and reservoir-to-reservoir), particularly if the well is operated at very low annular fluid levels.

During 1970-1998, much of the gas evolved in the stocktank was simply exhausted to the atmosphere through a short stack on the stocktank, and not even flared, giving concerns because $CH_4$ is 20 times more powerful as a greenhouse gas than $CO_2$. Most operators have developed methods to burn produced annulus gas (but not gas evolved in the stocktank) in the in-tank fire tube used to heat the stocktank fluids. This method helps conserve the resource through use, but there is still a lot of wastage, particularly of the gas evolved in the stocktank.

Many companies use produced annulus gas to operate the prime mover on site that provides power to the well pump. A natural gas engine driving the hydraulic power units for PC reciprocating pumps requires approximately 150-200 scf/hr of $CH_4$, therefore steady oil production of at least 50-80 b/d is required to maintain gas delivery. The difficulty that sometimes arises with using lease gas is that the right amount is seldom available from a single well or the supply is erratic because the oil production is erratic. If there is a surplus of gas, the excess is simply sent to the natural gas burner that heats the stocktank. Although it seems logical to do so, no company appears to combine the gas from the annulus with the gas from the stocktank, perhaps because this would require more complex plumbing, compression, and metering. Clearly, on a single pad with many wells (4 to 10), fluctuations in the amount of gas available are far less, and efficient natural gas management for lease use is straightforward.

In the 1990's, concern over energy conservation and greenhouse gas emissions led to stringent regulations and guidelines on gas emissions (see recent Alberta Energy Utilities Board Guides). A tentative schedule has been published to reduce emissions to almost zero levels, and as a result new gas management approaches are being developed, often through superior site management and low-pressure collector flowlines.

If the quantity of gas exceeds what is needed for both motive power and for stocktank heating, it is not economical to pipeline it to a central collection location because of the small volumes. The advent of small, high-efficiency, low-pressure gas turbines that generate electricity that can be fed directly into the local power grid may provide a means of profitably exploiting this low concentration but widely distributed source of natural gas. Given that the industry is becoming more and more electrified, local generation and use makes sense economically and

environmentally. There will be a number of incremental developments in this area in the next decade, as the industry responds to the inevitable arrival of a zero emissions policy.

### 9.2.3  Sand Extraction from Stocktanks

Stocktank sand is extracted in several ways, but "standard" methods are changing because of evidence that minimizing turbulence during sand extraction reduces the generation of stable emulsions. It is not necessary to clean out the sand completely during an individual tank-cleaning episode; rather, the tank should be only partially cleaned to reduces the amount of water and oil trapped in the withdrawn material and to avoid unnecessary shear turbulence that may generate more emulsion.

The standard method for many years has been "stinging" the bottom of the tank. Once most of the liquids have been removed from the tank, a narrow probe (the "stinger") connected to a high-pressure water source from a pressure truck is inserted into a port. Another larger basal port is linked to the suction line of a vacuum truck, and as the sand-water slurry is generated, it is withdrawn into the sealed vacuum truck tank. The sand must be in the form of a slurry for the vacuum truck to aspire it. The liquid-sand volume ratio aspired will be between 1.5:1 and 3:1, depending largely on the skill of the stinger operator. The stinger can be pushed in and out, but is generally not articulating. The high-pressure water jet tends to create a condition of high shear, suspending the sand but also generating additional amounts of stable emulsion (Note that it is not possible to remove all the oil and oily sludge during fluids draw-off, and it is this material that becomes emulsified).

Stocktanks with internal jets, are linked to a high pressure water source when the tank is to be cleaned. The resulting sand slurry is aspirated through a basal port by a vacuum truck. In flat-bottomed tanks this method has not proven satisfactory, generating excessively large volumes of dirty water for the amount of sand removed. In cone-shaped hopper tanks, internal jets can suspend the sand, and if a sand pit is locally available at a lower elevation, the sand slurry can be directly voided into the pit, and the excess slops water recycled. After water drains from the sand in the pit, the sand can be directly sent for disposal. This option, which appears to be the most economical way of sand management in tanks, is generally available only at more central sand management sites.

Several trips may be required to unload the sand from a large stocktank. A large vacuum truck has a capacity of 17-20 m$^3$. If it is loaded with liquid only, it can be filled to capacity; however, the vacuum truck may be limited to 12-13 m$^3$ of sand (the rest liquid) by road weight allowances.[57] When loaded, the vacuum truck may visit a liquids tank where as much liquid as possible is withdrawn, including any stable emulsion. Then the sand is deposited in a sand stockpile or a sand disposal site ; the wet mass is generally about 25-35% by weight liquid and 65-75% sand. Excess liquids run off and are collected in peripheral ditches.

Stocktanks designed with a built-in, heavy-duty sand auger in a linear (planar) hopper can be emptied without water jetting. Two trucks are required, a unit that has an articulating set of augers and a LHD sealed-tank truck. The auger truck also has a hydraulic power source that is linked to the tank auger drive unit and other augers. The articulating augers that link with the tank auger through the basal port transport the sand to the LHD truck. Apparently there is no difficulty in starting the tank auger despite the large frictional forces that it has to overcome. The sand is spewed into the LHD truck as a "solid" wet mass, rather than as slurry. Setting aside issues of costs, there are several advantages to this procedure:

- Little additional stable emulsion is generated because high-shear water jetting is not needed.

- A single LHD truck using this method can carry more sand (up to 20 m$^3$ or ~35 tonnes, depending on road limits) than a vacuum truck (typically from 5 to 10 m$^3$ of wet sand).

- No extra water is added, eliminating the need for an intermediate liquids storage tank, and reducing the amount of liquid in the waste at the disposal site.

Many companies continue to use the stinger method because it is reasonably effective, because the existing capital investment in flat-bottom stocktanks is large, and because the cone stocktank and linear hopper-auger stocktank are relatively new. Cone-bottom stocktanks with D-rings to suspend sand are more expensive, and operator skill is important. [58] In 1999, an articulating stinger arm was introduced in Lloydminster, increasing the effectiveness of the stinger method,

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[57] Local roads are maintained by counties and municipalities: load limits per truck axle are published and enforced (although the level of enforcement is not high).

[58] Skilled operators who can clean stocktanks without including excess quantities of liquid can effect substantial savings; sand trucks can go directly to the sand disposal site.

but still generating more stable emulsion than low-shear methods.  Finally, one may note that efficient stocktank cleaning is in a state of dynamic improvement, and costs are likely to drop. For example, elevated tanks requiring only one truck(Figure 9.3), or combined pressure/LHD units might help reduce sand management costs.

### 9.2.4  Stable Emulsion Management

Most of the stable emulsion phase in the stocktank is removed with the sand; a small amount may be removed with the oil when it is withdrawn.  After the emulsion separates at the battery, in the slops tank, or at the sand stockpile, it is collected and shipped for treatment or direct disposal.

## 9.3  Treatment of Fluids

### 9.3.1  Solids Separation at Local Batteries

The dead (gas-free) heavy oil arriving at local batteries typically contains up to 5% chloride-rich formation water and a small percentage of fine-grained minerals (<50 μm in size).  There may also be a small amount of stable emulsion, but as this material cannot be pipelined and also causes problems in the battery operations, care is taken to minimize the amount of emulsion when withdrawing oil from stocktanks.

Tanker trucks (all oil delivery to local batteries is by truck) are weighed before and after delivery, and "truck tickets" are issued stating the volume delivered, using the density of the oil from the particular field to calculate the volume.  These truck tickets, perhaps adjusted slightly for the quality of the oil (water content), constitute the statement of production from the site, and the oil company uses this as primary information to determine the oil production rate from the lease.

To be accepted by pipelines or local upgrading facilities, the water, salt, and solids content of the heavy crude oil must reduced to levels stipulated by the pipeline or the upgrader owners.  If emulsion is present, the majority of the water and fine-grained minerals is usually found in the emulsion phase; this material is not acceptable in pipelines or upgraders.

Most oil treatment methods at local batteries are designed to take advantage of density differences and achieve gravitational separation:

- Extended storage in a heated primary separation tank;

- Chemical treatment, usually accompanied by low-shear mechanical agitation;

- High-speed centrifuge treatment (generally used for emulsion and treater residues);

- Washing with fresh water to remove salts and other soluble phases; and,

- Electrically or acoustically enhanced separation using electrostatic or vibrationally-induced coalescence.

The first phase of the battery treatment pumps the dead, warm oil to a large heated tank (70-90°C). Solids separate out, and residual emulsion and free water segregate into layers, just as in the lease stocktanks. Because what is delivered to the large tank is always >90% oil (usually > 95% oil), the large tanks are relatively easy to manage. Water and solids (tank bottoms) slowly accumulate at the base of the tanks over many months before the tanks are cleaned. The residence time will vary from battery to battery, depending on the viscosity, quantity and quality of the feedstock, and also on the demand and storage capacity for pipelining. Probably, one to three days is a typical residence time; current practice is simply the result of years of practical and on site optimization, as there are no published scientific studies of residence time.

At this point, standard battery oil treaters remove residual water (usually 1-2% by now), by thermal treatment and salt by physico-chemical separation. The use of electrostatic heater-treaters to accelerate the separation of water and to reduce temperatures required is relatively common but not standard. The efficiency of such techniques decreases substantially for the heavier crude oils because the high viscosity impairs the velocity of the small water droplets in the oil phase, slowing electrostatically induced coalescence.

Once the treated oil meets pipelining standards it is pumped to a clean oil tank to await shipment. Some smaller and more remote batteries use clean-oil tanker trucks to haul to either a pipeline terminal or directly to the upgrader; otherwise, it is mixed with ~15% by volume diluent (naptha, a mixture of $C_6H_{14}$ to $C_9H_{20}$,) for pipelining to regional tereminals. Local pipelines (such as the ~110 km, small diameter line from Elk Point) also deliver the oil to the Lloydminster Regional Upgrader. A much smaller parallel pipeline returns diluent to the Elk Point terminal.

Canada produces far more heavy oil than can be upgraded to synthetic oil (there is a serious deficiency in upgrading capacity); therefore diluted oil is pipelined to the mid-western United

States (Kansas City, Minneapolis, Chicago) via much larger international pipelines, using slug methods to separate diluted heavy oil from other crude oil.

### 9.3.2 Stable Emulsion Treatment

The emulsion generated during CHOPS is a remarkably stable substance. If substantial quantities of emulsion are included in the untreated crude oil shipped to local batteries, the thermal treatment process degrades because of the high $H_2O$ (hence NaCl as well) and solids content. Therefore the quantity of emulsion shipped is minimized. There are no figures available for volumes of emulsions generated in the Canadian heavy oil industry because emulsions are often reported as "slops", mixed with sand for disposal by deep well injection, or treated locally at a battery with any oil extracted simply added to the inventory. It is estimated that the amount of emulsion treated is around 4,000 to 8,000 b/day in Alberta and Saskatchewan.

Analysis shows that emulsions are disproportionately rich in asphaltenes. These molecules are highly polar and serve as the lyophilic/hydrophilic bonding agent that stabilizes the emulsion. The high asphaltenes content also means that the oil phase in the emulsion is more viscous than the bulk reservoir oil. Asphaltenes are thought to be the residues of the polysaccharides that formed the cell walls of the bacteria that degraded the heavy oil. Biodegradation increased the oil viscosity through consumption of the lighter hydrocarbons and accompanying molecules, combined with generation of $CH_4$.

Emulsion is perhaps most commonly treated thermally (in "flash treaters") to drive off the water; this gives a product with a considerable amount of solids. The viscous residue from a flash treater can be diluted, and the solids removed while the less viscous mixture is hot. Otherwise, the viscous oil residue can be added directly to the battery hot oil tank where the solids may segregate gravitationally, and the asphaltene-rich oil incorporated into the heavy oil delivered directly from leases.

For two decades, various types of emulsion breakers used in thermal and non-thermal treaters have been tried, but even those approaches that show some measure of success appear not to be economically viable because of the cost of the breaker chemicals, given the concentrations that have to be used to achieve neutralization of the natural emulsifiers.

If the oil is treated in a flash treater or cold treater, the tarry residues are usually sent to a contract waste treatment company (e.g. Anadime Corp., now in receivership) for high-speed centrifugal separation and final disposal of the waste phases.

Corlac Industries in Lloydminster has developed a truck-transported inclined thermal separator (~7 m long, 1.5 m diameter, inclination angle of about 15°, called the SCUD) that can be used with emulsion-breaking chemicals. The company claims that it is extremely effective for separation of produced fluids and somewhat effective for emulsion breaking; the device is now in limited service in the heavy oil industry in Canada, especially in fields with high water cuts, where it seems particularly effective.

In the period 1996-1997, the favored disposal method fort emulsions was to incorporate the emulsion with produced sand to be disposed by deep injection or salt cavern placement. Large volume salt caverns are highly effective for liquids and solids treating and separation; slops and emulsions apparently separate well over the long residence time in the caverns, and the supernatant oil can be easily removed through the wellbore. The mechanisms that aid separation in a salt cavern are the following:

- The aqueous phase becomes NaCl saturated, achieving a density of 1.19 g/cm$^3$ thus enhancing gravitational separation ($\Delta\rho$ = 0.22 rather than 0.07 g/cm$^3$).

- A stable environment at a temperature of 30-35°C is conducive to slow separation; the slow liquid movements that are generated thermally and through density differences aid the separation process. (Note that at the surface much higher temperatures are used to accelerate segregation.)

- It is also possible that saturating the aqueous phase with NaCl may reduce the stabilizing (emulsifying) effect of the polarity of the asphaltenes. (This is the author's speculation, without supporting evidence).

Direct use or direct disposal of emulsions at the surface is not feasible. Given the high concentration of aromatic molecules in the emulsion, spraying this substance on roads for dust suppression (for example) is not advised. Disposal by spreading in small concentrations in fields does lead to biodegradation, but high molecular weight aromatic molecules are difficult to break down bacteriologically. In these approaches to emulsion disposal, there is the risk of

groundwater contamination, offensive odors, and the generation of intermediate products that may be toxic. The heavy metal content and chloride content in the emulsion may make these disposal methods environmentally unacceptable. Finally, note that the material cannot be accepted in landfills because it is in a liquid state.

With the exception of direct disposal, emulsion treatment is costly, and it has historically been unusual that the value of the oil recovered pays for the cost of its recovery. However, the value of the additional oil may defray part of the treatment costs, perhaps allowing treatment to compete favorably with direct disposal methods.

There is a definite possibility for new developments in emulsion treatment. Given that the oil content is from 15-50%, oil recovery may pay for the process when heavy oil prices are high. Also, the emulsion may be used as a part of boiler fuel or cement kiln fuel, provided that boilers are modified to accommodate high solids content, and that the SOx gas emissions could be kept low (difficult given the high sulphur content of the oil).

### 9.3.3  Other Approaches Used in the Past

The high viscosity of the heavy oil and the relatively small density difference between the oil and the water seriously impair the performance of a standard cyclone separator. Because of the high viscosity and the presence of a foamy phase as the oil comes out of the well, sand separation at the producing wellhead is not feasible. The author knows of no successful field-scale cases of direct cyclone separation. Three-phase centrifugal separation at waste treatment sites is carried out on a small scale, and this high-speed centrifugation appears to be effective for stable emulsions, even after they have been partially cold treated by the oil company.

In the 1970's, several designs of horizontal separators using baffles, low flow rates, and sometimes heat, were tried at a field scale to separate materials directly at the wellhead. Despite repeated efforts with de-foaming agents and various modifications, these attempts were not economically successful and are not used today in the Canadian heavy oil industry.

Direct pipelining of the produced sand-oil-water-gas slurry to large capacity tanks has been tried, but viscosity problems in the flow lines and other cold weather difficulties led to abandonment of these efforts for CHOPS.

Small-scale (local) separation is carried out at several liquids treatment plants (e.g. Anadime Corp. and Canadian Crude Separators Inc. waste centers) that accept small amounts of oily sand, stable emulsion, and fluid mixes (slops).  This is of limited scale only, amounting to only a few percent of the total volumes that are generated, and is far too costly for general use.  Those sites that accept wastes are generally prepared to treat only small-volume, locally generated wastes from lease clean-up or from other limited volume activities such as treater residues.  Other technologies are required for the treatment and disposal of large volumes of oily produced sand.

## 9.4  Materials Management for an Integrated CHOPS Project

Figures 9.4 and 9.5 are materials management diagrams for a hypothetical CHOPS project for a heavy oil property to produce 100,000 – 200,000 b/d.  The approaches presented are modifications of current Canadian CHOPS practices:

- For power, treatment, and transportation efficiency, field development is based on clusters of five to ten wells on a single pad.

- Each well cluster is manifolded into a primary production tank; there is a smaller test separator tank (or a mobile test separator) to which production of the individual wells can be directed occasionally to track individual well behavior.

- An option is included to add diluent at the manifold to accelerate gravitational separation and facilitate later flow line transport; this would require installation of a small diluent line to each production cluster.

- The primary production separation tank is a 11 m high, 6 m diameter (~300 m$^3$) tank giving a minimum residence time of approximately 24 hours for 6 wells producing at 50 m$^3$/well/d.

- The insulated primary tank is heated to 75-95°C using co-produced natural gas.  Excess gas could be entrained in the diluted oil using a multiphase pump and compressor system before pipelining the oil to the central treatment facility.

- Sand is removed from the heated stock tank and trucked directly to the disposal site without using an intermediate stockpile (Figure 9.6).  An auger withdrawal system allows low liquids content sand to be withdrawn, reducing transport costs.

- Option 1: Only oil goes to the secondary separation tank, where it may be mixed with more diluent, then shipped; water is removed from the primary tank and pipelined directly to the water disposal facilities for disposal (perhaps co-disposal with injected sand).

- Option 2: Water and oil together either go to the secondary separation tank, or are shipped together from the primary tank to a regional battery through a flow line for separation and treatment.

There are many modifications possible; the example shown is for conditions where flowlines could be used. Also, the well cluster concept and manifolded production were chosen to reduce drilling and transportation costs. Treatment batteries are centrally located in the CHOPS field, and the Waste Materials Disposal Facility is also centrally located. The possibility of a small slurry pipeline to transport produced sand and produced water slurry to the sand disposal site must be evaluated and perhaps rejected if the sand wastes are too coarse-grained, leading to flow line blockage problems.

**Figure 9.1:  Produced Fluids Separation in the Stocktank**

vent, flare, or collect evolved $CH_4$

tank heated to ~60-80°C
with annulus gas

$CH_4$

evolved gas

heavy oil (~0.92-97 specific gravity)

8 m

clay-oil-water emulsion

water layer (~1.02-1.04, NaCl brine)

clay-oil-water emulsion

sedimented sand

4 m
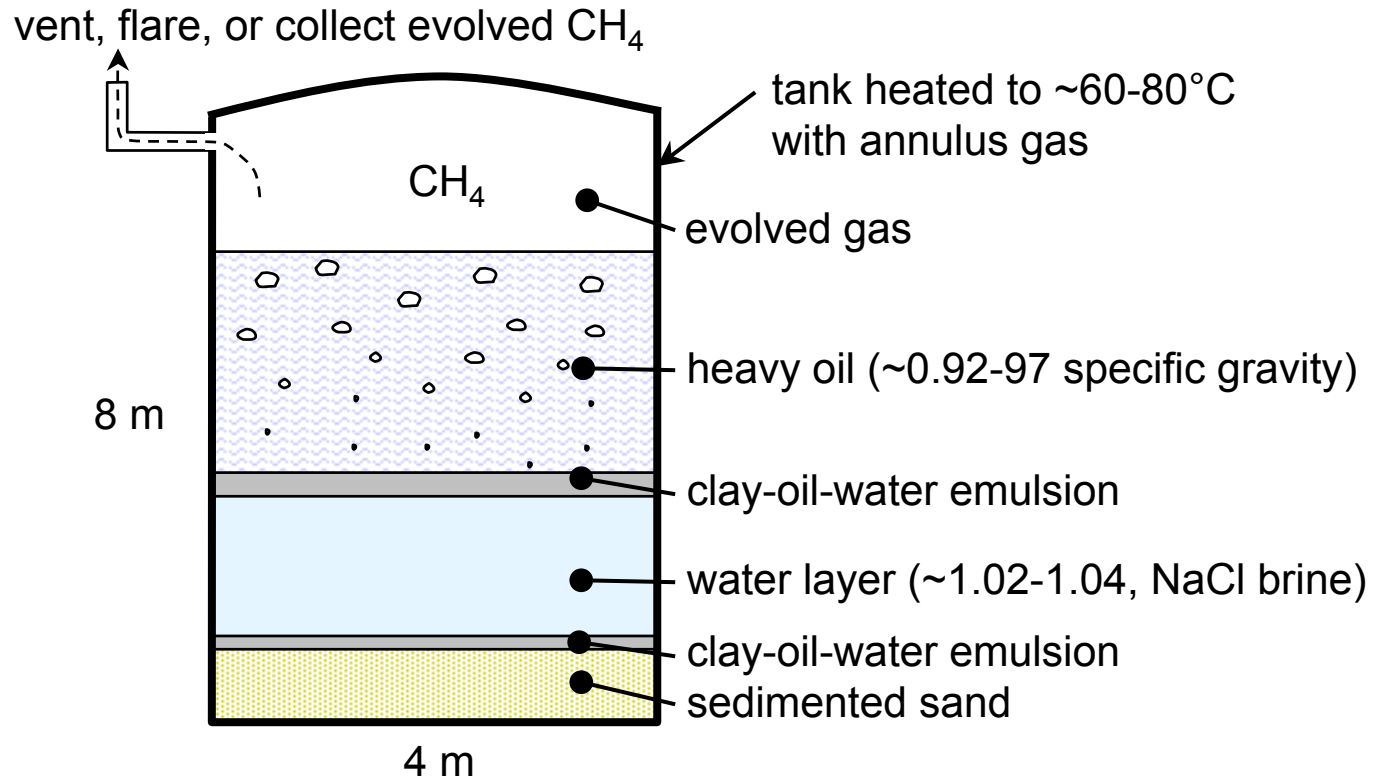
# Figure 9.2: Tank Designs and Cleaning Methods



**Style 1** — "stinger" — Flat bottom tank

**Style 2** — conical section, pressure jets, pressure truck high pressure — Cone-bottom tank, axisymmetric

**Style 3** — X-section A-A', V-hopper, auger, tank, To sand disposal — V-bottom auger tank, parallel flat sides
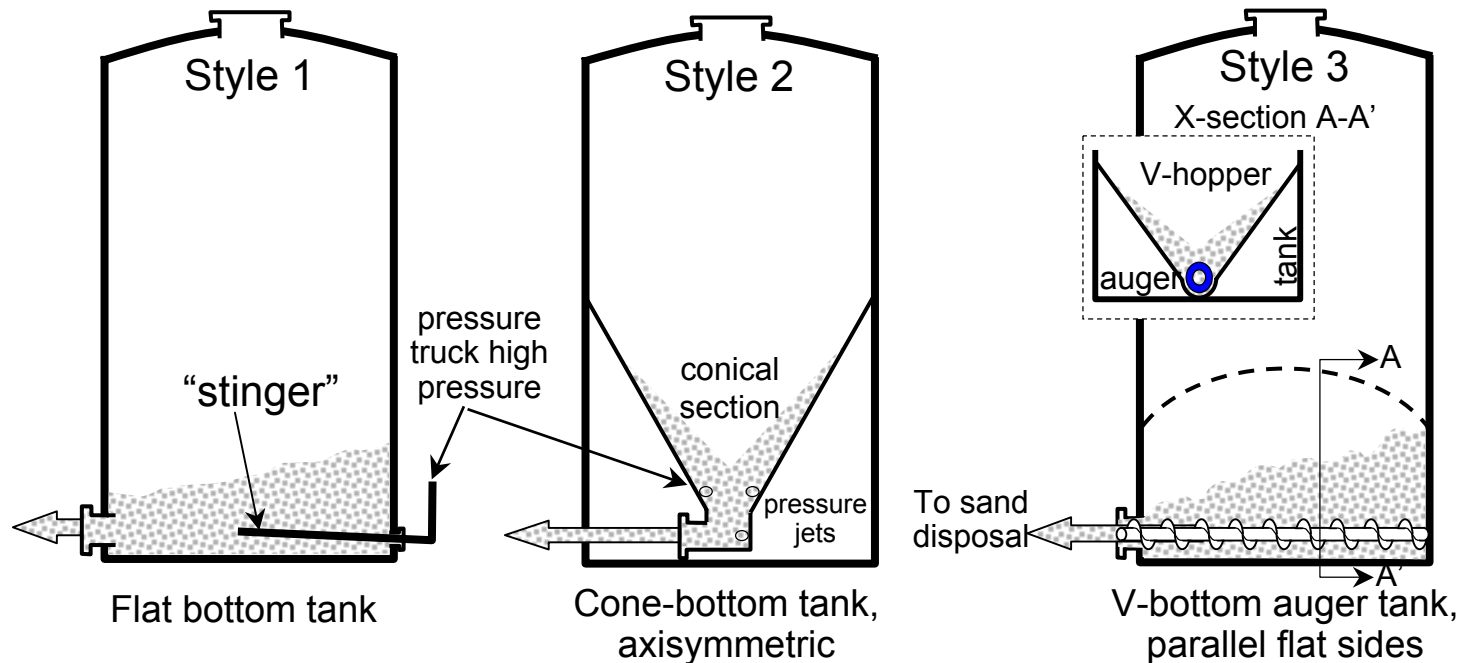
1: A pressure truck and a vacuum truck are used to remove  7-13 $m^3$ sand
2: A vacuum truck may suffice if local high pressure is available for jets
3. An auger/power truck and a LHD truck are needed to remove ~17 $m^3$

**Figure 9.3: Elevated Tank to Facilitate Cleaning**

Cone-bottom tank

Evolved gas

oil

produced water

emulsion

sand

pressure jets

Sand management represents a substantial cost factor in CHOPS. There are incentives to reduce costs through more efficient sand handling, transportation and disposal methods.
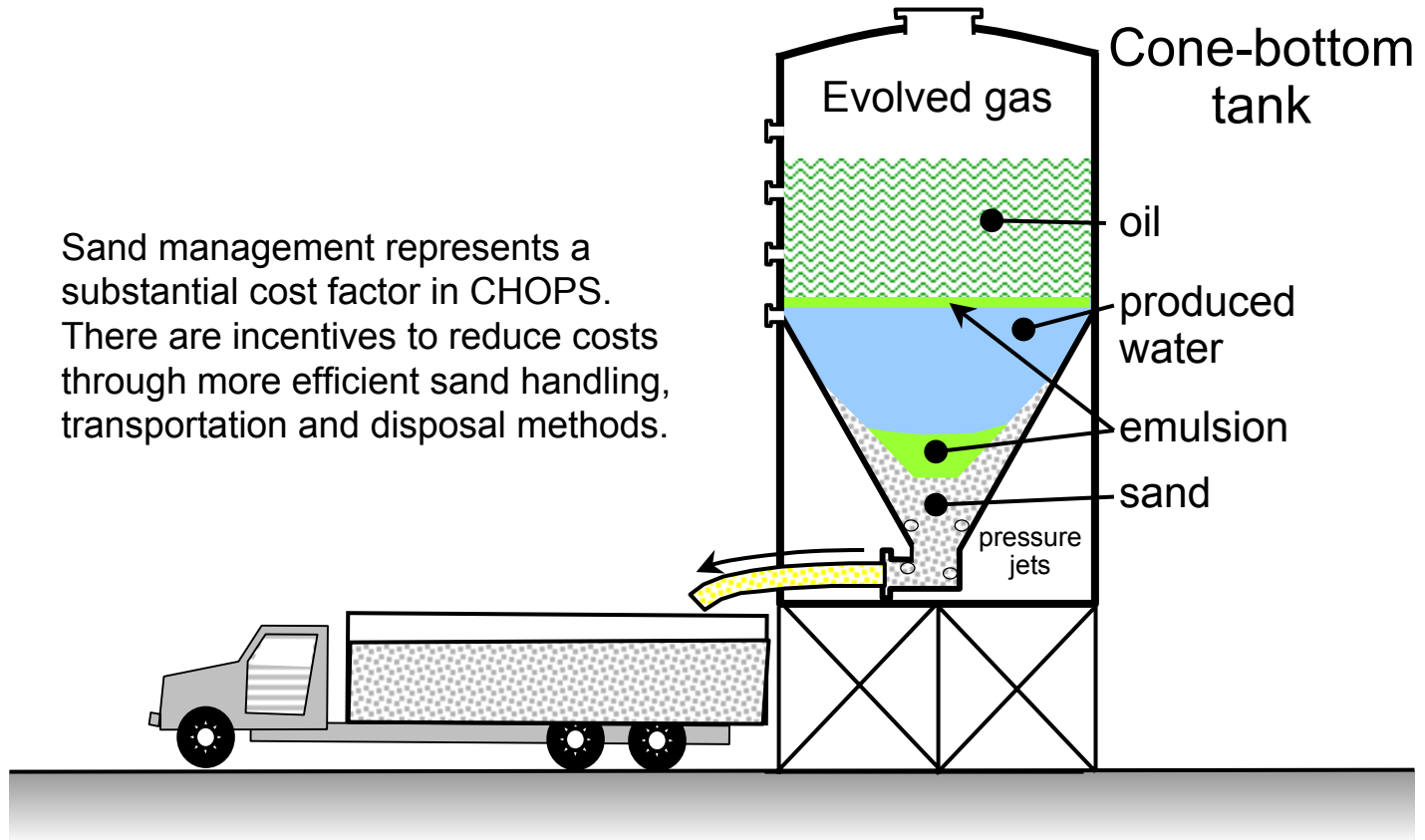
# Figure 9.4: Materials Management for an Integrated CHOPS Project - A



Tank #1, 300 m$^3$

Evolved production gas

Oil to Tank #2

Liquid ports

Oil plus diluent, heated if needed

Oil, $\rho \sim 0.97$

$H_2O$, $\rho \sim 1.02$

Sand

To sand disposal

Fire tube
Sand auger

compressor

To Tank #2

To Tank #2, when needed

Diluent added, if necessary

Annulus gas

Single well

Manifold

Test separator

## Output management:

| | |
|---|---|
| Gas: | collected and burnt for heating or shipped out |
| Oil: | pumped to main |
| $H_2O$: | pumped to disposal |
| Sand: | augered from tank, trucked to disposal |

**Figure 9.5: Materials Management for an Integrated CHOPS Project - B**



Tank #2: same specs as Tank #1, 300 m³

Multiphase fluid pump

To main station

Diluent flowline

Heating tube

Heating gas from Tank #1

Oil from Tank #1
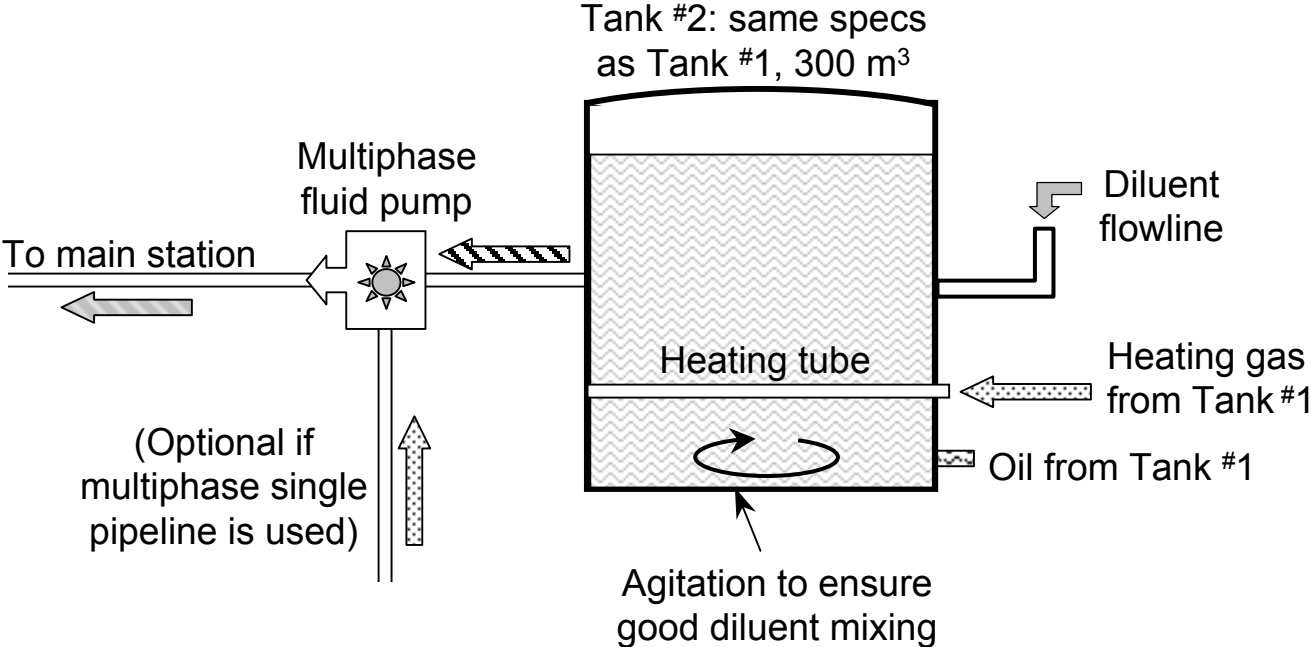
(Optional if multiphase single pipeline is used)

Agitation to ensure good diluent mixing

# Figure 9.6: Flow of Various Streams



**Waste Disposal Facilities**

SFI, salt cavern, landfill

Water tanks and sand pit

Deep well $H_2O$ disposal

**Main Station**

Produced Water

**Central facilities**
- Oil processing
- Dilution & shipping
- Water treatment
- Utilities
- Power generation
- Infrastructure

Sand

Other solid waste

Collected gas

Oil and water 100°C line

7 wells

2 prod tanks + 1 test tank

**Well Clusters**

coke

power?

sulphur

Oil pipeline