FACILITIES OPTIMIZATION REPORT

for

Existing
Production Process Facilities

A Study Report for

A Major Oil Producer

in

Alberta, Canada

Report No. 21160521

Breakthrough
ENGENUITY

EXISTING FACILITY

Production Facilities Optimization Study Report

1.0 INTRODUCTION

1.10 Serious concern over process equipment designs, chemical treatment philosophies and practice, and surface facilities operations and optimization resulted in a sufficient confidence level for this producer to issue a purchase order for a comprehensive facilities study. The objective of this study is to recommend real-world solutions to ongoing problems in the existing surface facilities in this producer's operations.

2.0 OVERVIEW

2.10 The existing facility consists of two process facilities. Both are similar, though not identical. Each is designed to separate and/or process the produced oil, water, gas, and related solids from the associated production operations.

2.11 We requested and received a set of Piping and Instrument Drawings (P&ID's) for review. In addition, we requested received salient fluids analytical data, as well as chemical treatment information. These drawings and information, and the discussion with this producer are the basis for this report.

2.12 The findings of this are presented in synopsis form in the executive summary which follows. The detailed findings are presented in subsequent sections of this report.

2.13 We are proud to have been selected by this producer for this study, and expresses sincere thanks to this producer for this opportunity to be of service to this producer.

3.0 EXECUTIVE SUMMARY

3.10 The existing facility production processing facilities are difficult to operate. Upsets are common. Causes are difficult to quantify; are more matters of opinion that fact. Resulting problems are costly. So many problems exist they seem overwhelming as a group. Solutions are needed.

3.11 Since initial problem solving discussions began between us and this producer, a consensus between us, This producer engineering, and this producer operations has developed. This consensus is that recycling fluids at the existing facility causes the majority of the upsets. This, ***RECYCLING***, is the key focus of this report. But, as is so often the case, there are many other forces at play in the Existing facility. Each impacts the production processing facilities. Several of these are identified in this report as areas of significant concern.

3.12 With recycling at the top of a list of offenders, the list of other offenders is rank ordered. This offers this producer the opportunity to proceed logically toward practical solutions at Existing facility, in an order that offers the best return for this producer's investment.

3.13 The focal point of this report is to minimize the practice of recycling. The goal of the recommendations section of this report is to offer this producer **proven methods** which can translate into smooth, effective production processing at Existing facility.

3.14 With the support, encouragement, and cooperation of This producer's management team these recommendations can be instituted in an orderly fashion and in a cooperative effort between engineering and production operations, The results are reasonably predictable: fewer upsets, better oil treating, cleaner water to injection, more a proactive, less reactionary, operating posture, a few surprises, a more comprehensive approach to chemical treating, lowered operating costs, and more oil to sales day in and day out.

4.0 REVIEW OF EXISTING OPERATIONS

4.10 Several major problem areas are daily obvious from the review of the data and information provided. While these problem areas are relatively easy to identify, they are far more difficult to resolve. The focus of this report is to identify each of these areas, and to recommend corrective action. These recommendations are divided into "must do" and "should do" categories for ease of interpretation.

4.11 They key major problem areas are as follow:

1. PREVIOUS PRODUCTION OPERATIONS

2. RECYCLING

3. VARYING CHEMICAL TREATMENT RATES

4. PROCESS FLUID RATES CONTROL

5. SOLIDS PROCESSING/TREATING

6. PROCESS VESSEL INTERFACE LEVEL CONTROL

7. OTHER CHEMICAL TREATMENT

8. INSUFFICIENT OPERATIONS DATA

9. PROCESS EQUIPMENT DESIGN

4.12 Each of these problem areas deserves attention in this report so the readers can reach to an objective appraisal of each contributing condition. Understanding is key to problem solving/prevention. What follows is intended to propagate such a level of understanding, hopefully achieving the form of a consensus.

<u>4.13 Previous Production Operations</u>

4.14 It is important to understand that the existing facility has been operated under two different owners, and several production enhancement programs. Husky Oil developed the field, now owned and operated by this producer. Under Husky's ownership, three different types of enhanced recovery were attempted. The scope of these efforts is not fully presented, but suffice it to say that each of the foregoing enhanced recovery efforts has an effect on the current production operations. Let's examine the generic results of each of these previous efforts on today's operation.

4.15 Fire Flooding

4.16 The intent of a fire flood is to decrease the heavy oil viscosity through a direct combustion process in the reservoir in order to increase the ultimate recovery of original oil in place. One residual result is the formation of combustion by-products in the reservoir, such as carbon particulates which range down to less than one micron in particle size. Friable portions of the reservoir are also physically altered during fire flooding, producing additional small particles. These particles are of minimal concern during fire flooding, since they tend to stay in the formation, collecting in the comparatively more permeable strata, and redirecting the fire flood front across a more uniform cross section of the reservoir.

4.17 However, when a fire flood is followed by a waterflood, these ultra-small solids are often carried by the injection water and crude oil to producing well bores where they are then pumped to the surface, if they don't first plug down hole pumps or tubing strings. During the work of pumping these solids to the surface, shearing forces, present in the stages of down-hole centrifugal pumps, and across the discharge check valves in down-hole plunger pumps, intimately mix these solids with the water, oil, and gas phases. This exposure has several potential negative effects on all four phases.

4.18 1. The solids may shear into even smaller particles, making them even more difficult to separate once they reach the surface.

4.19 2. The solids may oil wet. A coating of oil, similar to the shell of an egg, on the solid particle, affects its effective gravity. That is, even a large particle (i.e.: 200 micron), with a specific gravity of 2.5 (compared to water at 1.0) may oil wet with a sufficient oil layer so that it approaches a net specific gravity between the oil and water gravities. This rather common phenomenon results in these particles migrating to the interface layers within the process equipment designed to separate oil and water.

4.20 3. The solids may attach to one or more micro-droplets of natural gas as it evolves from solution in the pressure dropping area of the down-hole pump, or as gas evolves from production during the pressure reduction occurring in its path up the tubing string to the surface. Velocities are comparatively high in the down-hole production facilities as compared to gather headers and process equipment at the surface. This gives the fluids ample opportunity to mix and/or interact.

4.21 4. In a waterflood, if the chloride/potassium content of the connate water and the injection water vary, formation fines in the clay family may be affected. The affect may be either a shrinking of the clay particle size if exposed to a higher potassium concentration, or the hydroxylation and growth of the particle size if the chloride content is lowered.

4.22 In some aspects of oilfield operations, formation clays are "stabilized" with potassium compounds to prevent swelling and formation damage. This, of course, results in smaller particles, which are much more difficult to process if and when they reach the surface facilities. A hard look at drilling/re-drilling/workover procedures with this in mind may result in improved routine oil/water processing.

4.23 Oxygen Fire Flooding

4.24 While the conditions described above certainly apply to this form of fire flooding, compressing oxygen containing air into an oil reservoir adds to downstream processing aggravations. Oxygen depletes in oil bearing formations during the first stages over sedimentary covering, and early in to life of what becomes an oil rich reservoir. Aerobic bacteria present during these early days dies from the depletion of oxygen. But, when oxygen containing is fed into the reservoir (for the intended purpose of maintaining the fire flood fire front) some unique strains of the long-extinct bacteria regenerate and proliferate. These for new biomass solids as a by-product of their life cycles, which ultimately add to migrating formation fines destined for surface production processing facilities.

4.25 In addition, oxidation reactions occur within the reservoir with minerals such as elemental iron, forming, for instance, huge (by comparison) particles of ferric and/or ferrous hydroxide. These solids, like most in oilfield operations, preferentially oil wet. As mentioned above, this has a deleterious effect on solids separation.

4.26 Previous Waterflood

The previous waterflood apparently did not achieve fill-up (the replacement of all previously produced fluids with the injection water). Having no detailed information about that water flood makes it impossible to speculate on what effects that original flood may have had on present day operations. Nevertheless, it is likely that it has had some. For instance, if the original source water was incompatible with the connate water some precipitation of scale is likely. This adds to the micro-solids surface processing burden, plugs the formation and well bores, and insulates the surface heating facilities heat transfer surfaces. This is but one example of how this previous water flood may affect today's operation.

4.27 A FOCUS ON RECYCLING

4.28 The term "recycling" is defined simply as the act of returning a process stream effluent to the inlet of the process. This has been a common practice in many oilfield operations throughout time; it is not difficult to find testimonials to the successes of others in process stream recycling.

4.29 It should be pointed out that human nature being what it is; few of us are prone to publicly tout our failures. Recycling, more often than not, is a failure, and the facts support this. The failure may not manifest itself in terms of total process failure, but in term of higher cost economics instead, though the reverse is also often true.

4.30 That is, when recycling appears to solve a process problem, this approach often causes more problems than it cures, costing the operator many more operating dollars than are often attributed to this root cause. And, as stated, the reverse often is the case. In this case, even small recycled streams result in immediate process upsets and treating failures. This leads to eventual downtime, sometimes shutting in the entire operation while process vessels are cleaned of untreatable fluids.

4.31 Since field shut in is the most dramatic and expensive form of all upset conditions in oilfield operations, it is a given in most field operations that this condition is to be avoided at nearly all costs. This "given" all too often results in remedial forms of recycle problem solving, each adding to the operating expense of the field, but each justified on the basis of avoiding the dreaded field shutdown.

4.32 At the existing facility recycling is a major problem. The P&ID's for both the North and South batteries direct the flow of nearly all contaminated interface fluids, contaminated "bottoms", and "bad" oil back into the inlet of the process flow stream. This recycling MUST be minimized, or preferably eliminated at this stage of the waterflood if the more difficult treating conditions of the future (as the flood front reaches more and more of the producing wells. Please find more on this subject under the "Typical Waterflood Operations" section of this report).

4.33 While it may sound trite in the context of this technical report (and perhaps out of place) there are common analogies to the recycling problem in many aspects of our daily life, both in and out of oilfield operations. We all recall the saying, "One bad apple spoils the lot". Translated into the applied science of oilfield operations, we would agree that even a small amount of contaminated fluid often contaminates a large amount of otherwise high quality fluid. It is very likely that this is the case at Existing facility's North and South Central Batteries.

4.34 Let us focus our attention on recycle streams at the North Battery.

4.35 No chemicals are added upstream of the Truck Pit at the North Central Battery (though 20-40 liters/day of DT-67 surfactant is added the twin of this stream in the South Central

Tank Battery adding to the treating problems there, and distinguishing the South Battery from the North). Diluent at this point is added on a 1:4 volume basis. Later, we will extrapolate the combined effects of recycling all of these streams from all sources into both (North and South) Central Batteries.

4.36 Let us look, as an example, at the North Battery Truck Pit and Water Clarification Tank recycle streams individually, expanding to some degree on 1) the <u>cause</u> of their contamination, 2) with <u>form</u> of the contamination, and 3) the <u>effects</u> of recycling this stream is likely to have on the North Central Battery process stream and treating efficiency.

4.37 Truck in Pit Dumps

4.38 Several of the producing wells produce into remote tank batteries. The production from these batteries is trucked into the North Central Battery, and dumped into a "Truck in Pit" (TIP). Fluid is pumped via a centrifugal pump from the TIP to a charge (surge) tank (T-101), and is pumped from there to the inlet of Water Clarification Tank T-300 using a Moyno progressing cavity pump (PM-102 A/B) to minimize emulsification, shearing, and dispersion. Diluent is added to the TIP fluid immediately downstream of the Moyno pump. The Moyno is fitted with a variable frequency driver (VFD for the sake of maintaining a constant level in the charge tank via a level transmitter.

4.39 The influents to the Truck Pit originate in the remote tank batteries. No diluent or treating chemicals are added upstream of this Pit.

4.40 CONTAMINATION CAUSE: This stream is raw produced fluid. It is inherently degassed, and particularly well dispersed if not totally suspended, by virtue of having been pumped with conventional centrifugal/gear pumps to both load and off-load it from each transport truck.

4.41 CONTAMINATION FORM: With no pit cover and gas blanket on this Truck Pit the heavy crude weathers rapidly. In addition, it collects fines carried by local air movements, fresh water from rain/snow, decays in API gravity from the effects of ultra-violet rays from the sun, and begins to oxidize. There is little doubt that asphaltines precipitate as a result of this exposure, aggravating downstream efforts to resolve emulsion conditions by adding micro-particulates to the oil phase.

4.42 CONTAMINATION EFFECTS: These asphaltine particles form nucleation-like sites for water droplets, creating true an inverse emulsion in the oil-continuous phase (an asphaltine particle surrounded by a thin layer of water, all suspended colloidially in the oil phase); a very difficult problem to treat in the most ideal of cases.

4.43 Water Clarification Tank

4.44 Diluent is added to the pit fluid which is pumped either into the inlet of Water Clarification Tank (T-300), and/or through Heat Exchanger (E-300) and then added to the emulsion inlet of the three Pressure Treaters (V-101, V-302, and V-303). The oil/emulsion from the Water Clarification Tank is recycled either to the Heat Exchanger (E-300), or back into the inlet of the Water Clarification Tank, with the Heat Exchanger receiving the bulk of the oil/emulsion, and the remainder recycled on a signal from the Level Transmitter (LT-120) in the Water Clarification Tank. Chemical treating products are added to this stream going to the Heat Exchanger only, which feeds the downstream pressure treaters. These chemicals are Scale Inhibitor (a phosphonate at 25 mg/L), Corrosion Inhibitor, and Demulsifier (at from 170 to 500 mg/L). Each is injected in close proximity to the other.

4.45 CONTAMINATION CAUSE: The direct recycle of the "pad", or interface zone at the oil-emulsion interface in the Water Clarification Tank back into the influent without the opportunity to "treat", even with or without the addition of a chemical demulsifier, is likely to cause repeated upsets and treating problems. In addition, injecting treating chemicals in close proximity to one another can negate the effects of each. This is particularly true with inherently incompatible products like scale inhibitors, demulsifiers, and corrosion inhibitors.

4.46 CONTAMINATION FORM: Recycled Water Clarification Tank oil is throttled back into the influent stream through the trim in a valve. This is the same mechanism used to **mix fluids** (i.e.: fresh water upstream of a desalter), and surely stabilizes any water in oil through the shearing effect on otherwise large and separable water droplets. The chemical incompatibility issue is quite clear.

4.47 CONTAMINATION EFFECTS: The addition of a mechanically stabilized emulsion into the influent of the Water Clarification Tank can and should have a dramatic negative effect on the ability of the Water Clarification Tank to produce a uniform oil quality. It is likely that the Water Clarification Tank oil effluent quality is inversely proportional to the volume-percent of the actual recycled stream.

4.48 Further, the compatibility issue aggravates the very problems each chemical is designed and intended to cure. Not only will these chemicals tend to counteract one another, their Individual effectiveness is severely at risk. Let's see why, taking only the scale inhibitor as an example.

4.49 Phosphonates are crystal modifiers, and as such are excellent scale inhibitors. They are also excellent dispersants, preventing coagulation of particles, whether liquid or solid. In over dosages, phosphonates have demonstrated the ability to make some of the most stable emulsions known to man. Further, few chemical additives, including phosphonates, are totally chemically stable at elevated temperatures. As phosphonates thermally degrade, they revert to simpler forms of the phosphate radical. The simplest of these is orthophosphate, one of the world's most efficient simple dispersants. Dispersants, whether phosphonates, acrylates, or degraded radicals of these or others, have an effect on oil-water emulsions which is diametrically opposed to the principles of attractive surface chemistry, droplet growth, resulting coalescence and subsequent emulsion resolution.

4.50 Similar potential problems exist by virtue of the cause and effect relationship of the other two chemical products introduced in the inlet to the stream going to the Heat Exchanger.

4.51 Pigging Stream

4.52 During pigging operations, the sludge removed during pigging is also added to the Water Clarification Tank inlet, with diluent added.

4.53 CONTAMINATION CAUSE: Plugging in flow lines is common in all oilfield operations, and is typically more severe when heavy asphaltic and paraffinic crudes are produced and cooled in long tubing strings and/or flow lines. Corrosion products add to the plugging problem.

4.54 CONTAMINATION FORM: Deposits of any kind are troublesome to all separation processes. Asphaltines precipitate in micro-crystalline form from asphaltic crude oil due to temperature and pressure changes, exposure to some distillates, and from oxidation. Scale micro-crystals precipitate as incompatible waters are mixed, and/or as the partial pressure of associated fluids is altered as it is rising in the tubing string, and/or from a swing in temperature. These micro-particles, whether asphaltine, paraffinic, or scale crystals, are excellent sites for small water droplet to attach and surround. Once attached, the resulting solid/liquid particle is quite stable, yielding its encapsulated particulate core or water shell only under the most severe of treating scenarios. These particles are commonly extremely small, less than 50 microns, and often less than 10 microns. That means they simply don't have sufficient mass for their true specific gravity to overcome the kinetic energy on their surfaces; and in this event, they remain colloidially suspended in either the oil or water phase, or both phases, or if altered with surfactants, at the interface layer between the oil and water. Dynamics play a large role in the dispersion characteristics of these micro-solids, where quiescence is the key to successfully processing them.

4.55 CONTAMINATION EFFECTS: Small solids are quite difficult to separate from dynamic streams without some form of "brute force" or near total quiescence. The solids in the influent to the treaters represent 4% of the total volume of the inlet streams, even though they have been separated, isolated, heated, treated, and recycled. They aggravate the entire treating scheme, and they accumulate/concentrate, rather than remaining at a manageable level. Managing the produced/precipitated solids in the existing facility is one of the key needs.

4.56 Other Recycle Streams

4.57 In addition to contaminated fluids from pigging operations, recycle streams from the following sources return to the Water Clarification Tank influent in the form of additional recycle streams:

1) Bottoms from the Induced Gas Flotation Unit (T-301).
2) Fluids from unknown sources and of undetermined quality and quantity which are trucked in to two positions on the recycle line.
3) Bottoms from the Treater V-101.
4) Bottoms from Treater V-302.
5) Bottoms from Treater V-303.
6) Liquids from the Knockout "De-sand" Tank T-103.
7) Bottoms from Sand Removal Pit No. 1.
8) Bottoms from Sand Removal Pit No. 2.
9) Bottoms from Sand Removal Pit No. 3.

4.58 CONTAMINATION: As seen above, each stream contributes its unique problem/problems to the process stream. The above are no different, though by now it would be somewhat redundant to reiterate the cause, forms, and effects for these. Suffice it to say that each offender is a problem. In the "Recommendations" section, each is dealt with appropriately, with a recommendation for solutions which fit both the North and the South Central Batteries.

4.59 Varying Chemical Treatment Rates

4.59 Treatment rates with the recommended scale inhibitor (Phosphonate), corrosion inhibitor (RN-209), and demulsifier (FH-235-2) chemicals vary dramatically at both the North and the South Central Batteries. Demulsifier rates fluctuate daily, ranging from highs above 500 ppm down to lows less than 50 ppm. These fluctuations in and of themselves are sure to cause upsets in the process equipment.

4.60 In addition, while less dramatic, 1) scale and corrosion inhibitor injection concentrations vary from under 10 ppm to over 110 ppm, 2) an asphaltine dispersant is or has recently been added to the Water Clarification Tank in an effort to condition the interface in this vessel, 3) a recent recommendation suggests the application of a water clarification chemical to "reduce the tendency of re-dispersion" of the solids (presumed to be clay fines) in the sand removal pits, 4) and approximately 30 liters/day of a surface active agent (DT-67) is added to incoming production from the satellites or satellite wells to the South Battery. This surfactant has the effect of emulsifying the oil in the water continuous phase, thus reducing the effective viscosity of the oil, and the resulting pressure dropping characteristics. This chemical is used to maintain low flow line pressures, which translates to lower bottom hole pressures and more efficient (well pumping) production operations. It inevitably has a significant effect on the process capacity and treating efficiency of the South Battery, but the direct effect is not dramatic enough by itself to identify in the data provided (though the demulsifier usage during the period reported is 33% higher at the North Battery than at the South Battery suggesting that the 30 liters/day of surfactant has the effect of reducing the demulsifier from a period-averaged 88 liters/day at the North Battery to 66 liters/day at the South Battery).

4.61 Stabilizing the injection rates of all needed chemicals so that the rates correlate directly to the actual fluid volumes is tantamount to success. Once stabilized feed concentrations are achieved, meaningful evaluation of various alternate products can achieved, and optimum treatment programs will result.

4.62 Process Fluid Rates Control

4.63 Each process vessel has sufficient intermittent influent flow rates to make realistic evaluations of treatment efficiency, retention time, vessel process efficiency, etc. virtually impossible. Rates should be stabilized wherever possible, and it is possible to do so. The key is to minimize recycle loops and to control each loop at reasonably constant rates.

4.64 This is not so easily accomplished in the trucked in production, but is doable with the proper care for process system design.

4.65 The benefit to stabilizing flows is to bring a consistency of operation to a process which currently has more variables than are conceivably manageable. Consistency will result smoother day-in and day-out production processing operations, minimizing upsets and their associated stress and costs.

4.66 Solids Processing/Treating

4.67 Solids are the largest ingredient in the typical oil-water separation formula. The existing facility is a classic example of this problem, and it must be solved, or at least controlled if the existing process facilities are to have a chance of successful operations over the long term of the water injection enhanced recovery project.

4.68 Solids are difficult to deal with in oilfield production processing. Some are large, heavy, and water wet. These fall to the bottom of flow lines, tanks, and process vessels with little encouragement, and may be routinely "de-sanded" by virtue of sand removal draw-off devices designed for the removal of such solids. Others are light, fluffy, small, and perhaps oil wetted, accumulating in the interface areas of slow moving pipelines, tanks, pits, and process equipment. These may be decanted and processed in several ways. A few of the more common are:

1. Collected continuously, treated and centrifuged and disposed of.
2. Collected intermittently, batch treated, separated and disposed of.
3. Collected, solvent/distillate washed, separated, and disposed of.
4. Collected semi-continuously via timed draw-offs, treated, treated with heat/distillate, separated, and disposed of.
5. Collected and processed through a filter press, returning clear, high quality, solids free fluids to the end of the

Battery process stream (i.e.: oil to sales, water to injection water treatment).

6. Collection, coalescing/mixing and filtration.

4.69 Each of these methods brings with it a degree of cost in terms of capital and operating expense, obviously. It is hardly possible to evaluate the savings from these methods, except to assume the worst case and compare that with one of the above. No effort is made in this study in this direction except to say that effective treatment of produced fines is critical to the long term operation of this field.

4.70 Process Vessel Interface Level Control

4.71 The control of oil-water interface levels in various oilfield process vessels has been a subject of much concern from the time the first barrel of water collected in the first oil-gas separator. Three distinctly different methods exist today, and each has its own merits, and its own place. They are:

1. Electronic interface probes.
2. Displacer type mechanical torque tube devices.
3. Weighted interface floats assemblies.
   A. Same as above with mechanical-to-electronic transducers, converting the mechanical movement to an electrical output used for valve control (i.e.: 4-20 ma, 24 VDC/120 VAC output.

4.72 This report will focus on the first of these since the second and third are widely understood, and rarely misapplied even in "heavy" oil processing.

4.73 The electronic interface devices available today vary not only by manufacturer, but more importantly, by method of function. The simplest is probably the conductance probe; a device that senses the difference in conductivity between water and oil. This can be trick when fresh water with low conductivity is encountered. Another is the capacitance probe, a true workhorse for decades and still widely used. The latest is referred to as a family of "high (or ultra-high) radio frequency" (RF) capacitance devices, touted to be extremely sensitive to interfaces of varying concentrations of oil and water. Experience has shown such devices (i.e.: Drexelbrook, Agar, Invalco) to be quite effective when properly applied … and conversely, ineffective when improperly applied.

4.74 A common practice, started by one of the world's most renowned major oil firms, is to place a RF in a process vessel vertically, through the vertical cross section of the vessel. This presumably allows for the tuning of the device at any elevation within the vessel. Practice has shown that in stable fluids with minimal treating problems this presumption is quite valid. However, in widely fluctuating fluid quality operations such as Existing facility, such installations often provide false indications, upsets, and a sense of knowing what is going on inside process vessels which is simply misleading and untrue. When these same sensitive devices are installed in the horizontal, however, the ability to tune into a BS&W interface concentration is unique and accurate, and the results of such installations prove the effectiveness of this subtle, but important reality.

4.75 Whatever the type(s) of interface device(s) which are applied at Existing facility, the device **<u>must</u>** be calibrated often against known emulsion content. This known content must be obtained from the vessel the respective device is in, and must be taken from the desired interface elevation by means of "sample valves". The sample valves should be located at 15-30 cm proximity across the interface area of each vessel designed to collect and/or process oil-water mixtures. Only in this way is it possible for the operators to maintain control of the processes in their charge.

4.76 Other Chemical Treatment

4.77 As streams are segregated and processed individually (the ultimate and ideal goal at Existing facility), the need for small amounts of specialty chemical products grows. Each individual process should be carefully evaluated every 4-6 months for the optimization of chemical treatment. This evaluation will often result in product replacements/reformulation to improve performance from period to period. It is **absolutely necessary** in the existing facility waterflood because as the flood responds, the fluids characteristics will change dramatically with the response. These changes will result is lessened treatment effectiveness, and justify a careful attention to on-going chemicals evaluation work.

4.78 Insufficient Operations Data

4.79 Information may be the tool needed to manage a complex operation such as Existing facility. It can be the missing link between theory and practice, engineering design and practical operations. Nothing holds more weight or promise than reality.

4.80 Information such as a bi-annual profile of the chemical composition of interface solids from Truck Pits, the Water Clarification Tanks, the Knockout (sand removal) Tanks, the

Treaters, the "Run" Tanks, and the Slop Oil Tanks, would prove quite valuable when an upset occurs. A proactive approach to process management such as a structured information gathering and archiving program could predict and alleviate many of the upsets and difficult treating problems at Existing facility.

4.81 The existing facility is unique because of its past. The existing facility has undergone several attempts at enhanced recovery. The effects of each attempt on today's production operations are unknown except in the broadest of terms. Further, there are many general opinions regarding the methods of processing, treatment, and so on, but there appears to be little hard field or laboratory data supporting these current opinions and beliefs. Daily logs documenting a set of predetermined optimum operating conditions could help troubleshoot during upsets. Baseline water and oil analysis for each well could help determine the effects of the waterflood as the flood front approaches, reaches and moves past each producing well bore.

4.82 Information can be the singular commodity leading to smoother, less costly, more predictable, and more profitable operations in the future.

5.0 TYPICAL WATERFLOOD OPERATIONS - (PERTINENT/RELATED GENERAL INFORMATION)

5.10 A conventional secondary recovery project has been initiated in the Existing facility. This waterflood is in the early stages of injection and will not show significant response until the reservoir approaches "fill-up".

5.11 Typical "short-circuiting" of injection water will occur or already is occurring as water channels through the reservoir from injection wells to adjacent producing wells. This inevitable breakthrough will cause a premature breakthrough of water. This breakthrough will be observed on the surface as increased water production.

5.12 As breakthrough occurs in the early response periods of a waterflood, a valuable and significant opportunity presents itself … one that will not present itself again in the Existing facility. This opportunity comes in the form of single well response to the waterflood. This producer has this opportunity to monitor, study, and quantify the effects of this early waterflood response on the individual producing wells, but this opportunity will soon pass.

5.13 The effects of the connate fluid/injection water reservoir interface passing the well bore of a producer are typically quite dramatic. Studied individually well-by-well, a pattern will begin to form. This pattern, archived, plotted and routinely referenced, is key to a pro-active approach to an understanding and the development of a suitable action plan when the flood reaches its peak.

5.14 Production operations appear difficult today. Upsets are common. Chemical dosages are all over the map. Each effort to bring about some form of stable operations is fraught with frustration. But the flood has not yet responded. When it does respond, operating conditions as they exist today will be remembered as easy by comparison. The reason for this is typified by a description of the flood front, and an explanation of how it will affect each well bore as it approaches, encroaches, and passes each producing well bore. This "general knowledge" is key to an understanding and consensus on the value of programmed daily, weekly, monthly, and bi-annual information gathering at the field level.

5.15 In the typical waterflood the injection water is from a different source than the produced water. Efforts are made before the flood is begun to find a compatible source of water; one that won't react with the native (connate) water in the reservoir. All too often a truly compatible source is unavailable either physically or economically, so a local, lesser compatible source is selected. This appears to be the case in the Existing facility.

5.16 Compatible or not, once the injection water has filled the reservoir sufficiently to begin its migration through the reservoir from the injection well to the producing well, an interface or wall of one-time material (mostly reservoir fines) forms between the connate water and the injection water. Several reasons for this are stated in dozens of foregoing technical papers, but suffice it to say that this interface is made up of small clay platelet, formation silt and sand fines, precipitates from former operations and present incompatibilities, both dead and alive bacteria and biomass, residues from drilling operations, corrosion products, and in Existing facility, asphaltines. In addition, any connate-injection water chemistry incompatibility will be magnified as the fluids are pumped to the surface. The pressure drop from bottom hole to the surface will initiate a change in the carbon dioxide, carbonate, and bicarbonate concentrations resulting in carbonate scale formation as has been previously observed. The same pressure drop phenomenon will result in some degree of asphaltine precipitation, aggravating an already worsening set of treating conditions on the surface.

5.17 However, in a few weeks or months the flood front will completely pass the well bore. The interface and all of its problems will be gone … forever. The once produced connate water will now be virtually 100% injection water. Now, the problems associated with water incompatibility will cease to exist, and they will be replaced with a new set of conditions specific to the water chemistry of the injection water. For instance, if the connate water was high in carbon dioxide, some calcium carbonate scaling and some carbonic acid selective pitting-type corrosion could be predicted. If the injection water were low in carbon dioxide, but high in dissolved sulfates, it would be rather normal to eventually encounter some bacterial action from the desulfovibrio desulfurican strain (commonly referred to as sulfate reducing and/or iron bacteria) resulting in general pitting-type corrosion, iron sulfide corrosion products, and hydrogen sulfide in measurable quantities in the produced oil, water, and gas phases.

5.18 Obviously, each set of problems is vastly different. Each justifies its own specific solutions, and neither is positively affected by the application of a probable solution for the other. Simply stated, each problem is unique. Each demands sufficient attention to quantify it when it exists, and to apply the appropriate remedy accordingly. Only through a dogged commitment to information gathering and field analytical work will long term proactive approach to optimum production processing operations meet with the success desired by the This producer staff.

6.0 RECOMMENDATIONS

6.10 The following problems were offered in Section 4.0 titled "REVIEW OF EXISTING OPERATIONS" under section "Major Problem Areas"

1. PREVIOUS PRODUCTION OPERATIONS

2. RECYCLING

3. VARYING CHEMICAL TREATMENT RATES

4. PROCESS FLUID RATES CONTROL

5. SOLIDS PROCESSING/TREATING

6. PROCESS VESSEL INTERFACE LEVEL CONTROL

7. OTHER CHEMICAL TREATMENT

8. INSUFFICIENT OPERATIONS DATA

9. PROCESS EQUIPMENT DESIGN

6.11 Now that we have reviewed these problems in some depth it is possible to rank order these problems from the most severe to the least significant. By rank ordering the problems we can focus on the areas most likely to result in improved operations and reduced costs. Rank ordered, the above list looks like this:

1. RECYCLING

2. SOLIDS PROCESSING/TREATING

3. PROCESS EQUIPMENT DESIGN

4. WIDELY VARYING OIL TREATMENT RATES

5. PROCESS FLUID RATE CONTROL

6. PROCESS VESSEL INTERFACE LEVEL CONTROL

7. OTHER CHEMICAL TREATMENT

8. INSUFFICIENT OPERATIONS DATA

9. PREVIOUS PRODUCTION OPERATIONS

6.12 The above rank ordered list is a guideline of action priorities. The recommendations that follow are geared to this set of priorities.

6.13 RECYCLING

6.14 Recycling is the single greatest cause of production processing problems in the Existing facility. In order to gain some measure of processing success, continuity, and a degree of "sameness" from day to day, it is an **ABSOLUTE MUST** that recycling be minimized or eliminated.

6.15 Since this producer is not likely to make sweeping and potentially very costly changes in the two Central Batteries, and because so many streams are recycled at both the North and South Batteries, it seems prudent that a list of priorities be established as a foundation for the remedial recommendations which follow. This list should identify the recycle streams in a most-to-least offensive ranking order. I recommend actions on the following list of recycle stream in the priorities listed:

1. THE TREATER WATER
2. THE IGF SPILLOVER
3. THE SAND REMOVAL PIT FLUIDS
4. THE SLOP OIL
5. THE WATER CLARIFICATION TANK INTERFACE
6. THE TREATER SAND REMOVAL FLUID/SOLIDS
7. DATA GATHERING

6.16 While other streams are offensive when recycled, these streams are the greatest offenders in the order listed. The following recommendations address each, in order.

6.17 Treater Water

6.18 This stream was carried to the treater inlets because it is 1) water of emulsion, stable at the crude oil temperature upstream of the treaters and represented by small droplets, typically smaller than 50 microns in diameter, or 2) a stable suspension of water in oil comprised of droplets ranging in size from 50 to 150 microns in diameter. In either event, the addition of heat and a demulsifier allowed this emulsion/suspension to separate. It typically carries a portion of the oil treating demulsifier with it; that portion which was formulated to be more soluble/dispersible in water. This phenomenon makes the water quite chemically active, an activity likely to result in further emulsion stabilization if/when this stream is recycled back to the inlet of the process facility, the Water Clarification Tank, as it is now.

6.19 We recommend that the treater water be cycled to a dedicated Water Clarification tank of superior hydraulic characteristics for pre-IGF separation/conditioning. Several efficient designs are available to this producer. These may also be ranked in order of efficiency. The following is that ranking. We have included the relative hydraulic and separation efficiencies for your reference, based on my own experience in conducting/reviewing hundreds of retention time/separation efficiency field and laboratory tests.

TABLE I

Tanks Efficiency vs. Separation

DESCRIPTION	HYDRAULIC EFFICIENCY*	SEPARATION EFFICIENCY**
Dual Cone, Tangential Inlet, Plug Flow	45-70%	90+%
Amoco Vortex Water Clarification	8-22%	50-85%
Conoco/Joe Stires Dual Cone, Inlet under top cone	25-45%	50-85%
"Magic™" Water Clarification Tank	5-9%	35-70%
Exxon Water Clarification, perforated horizontal spreaders	3-11%	35-50%
Conventional Tank, vertical baffles, torturous path	30-55%	20-35%

**NOTE: Hydraulic Efficiency is the measured relationship between theoretical plug flow (maximum retention time) and actual flow in terms of retention time, as measured adding a tracer chemical. The tracer is typically batched into the influent and analytically measured for rising, peak, and falling concentrations in the effluent, measured against time.*

***NOTE: Separation Efficiency is the analytical relationship between totally quiescent separation and dynamic separation. This is compared for the actual measured retention time of a given process. In oil and water separation, the water phase of an influent sample is analyzed for oil content (water phase decanted from the bulk sample at the determined actual retention time of the vessel), and likewise from a sample taken from the effluent water stream at the actual elapsed retention time after the first sample was taken.*

6.20 It is worth mentioning that excellent retention time characteristics do not necessarily yield high separation efficiencies. While it is not in the scope of this section to digress to explain this fact, suffice it to say that when shearing forces cause improved retention they also result in re-dispersion as separable droplets are reduced in size. From *STOKE'S LAW* we learned that separation time is enhanced by the square of the particle size. This makes particle size, and the converse, shearing, extremely significant in the subject of physical separation.

6.21 Based on the above, I recommend one 750 BBL "HWSB™" Hydraulic Water Clarification Tank for the effective processing of the treater water without the addition of additional heat. This vessel is designed to operate in virtual plug flow, maximizing the retention time. There is no quadrant in the process portion of this design where the actual fluid flow velocity exceeds three feet per minute, making droplet shearing virtually non-existent.

6.22 The water effluent from the new Water Clarification Tank should be routed directly to the IGF for polishing prior to injection, eliminating this presently recycled stream from the existing Water Clarification Tanks (T-200 and T-300). The approximate raw cost of this new tank should be <$30,000.00, plus installation at <$15,000 (Note: all $ is in Canadian dollars).

6.23 IGF Spillover Slops

6.24 The IGF spillover is a form of slop oil. It is typically >80% water with water as the continuous phase. The oil found in this stream is often the very heavy, higher mol-wt crude oil fractions, and may actually be heavier than the water at the temperature of the effluent. It has found its way to the top of the IGF by attachment to the induced gas micro-bubbles, which alter its "effective" specific gravity, rendering it sufficiently light to float on water. However, once the bond between the oil and the gas is broken the oil now either sinks or is suspended in the water phase. The disbonding of droplets from gas happens across transfer pumps, even though they may be the least offensive types (i.e.: progressive cavity type for minimal shearing forces), or from the interaction with any other shearing mechanism.

6.25 This translates to a very difficult treating problem; one recycling will have little positive effect on solving. In addition, chemical treatment programs designed to clarify the water phase in the IGF will have **EXTREMELY** deleterious effects on the slop oil quality. If these "typical" coagulant aid treatment programs can be modified to use no **long chain polymers**, substituting admittedly lesser effective reverse emulsion breakers, the slop oil treating problem will be dramatically simplified. In heavy oil such as that at Existing facility, this may mean the difference between treating the slop oil and hauling it off to disposal.

6.26 All of this supports my strong recommendation against recycling this stream to any other portion of the existing process facilities, particularly back to the Water Clarification Tanks (T-200 and T-300) where it now is routed. Instead, I recommend the acquisition of a dedicated oil heating/settling facility. In addition, I recommend adding diluent at a ratio of at least 1:2 for the oil phase volume only of this stream. This may take one of the following forms:

6.27 1. HEATER TREATER: A vertical heater treater is an ideal candidate for this stream. This stream will have extremely ragged interfaces due to its heavy hydrocarbon fraction nature. Several feet of interface will be normal in the best of treating vessels for this stream, even with an ideal demulsifier (and there is no such thing for this stream because its physical characteristics are ever-changing). This treater should have a minimum of 24 hours of plug flow retention time, and be capable of taking the temperature to at least 120° C. A used/surplus treater should cost <$25,000 plus <$15,000 installation.

6.28 2. HEATED SETTLING TANK: A pair of 300 barrel API 12-F tanks can be heated via indirect steam using internal coils to achieve and hold the 95-98° C needed to process this stream in near-total quiescence. Two tanks are needed so that one can be heated, settled, and separated while the other is collecting the IGF slop.

6.29 A rather generic slop oil treating scheme will have to be developed for the operators to be able to make this process to function. It may involve a wide range demulsifier, wetting agent, or pre-neutralization of residual demulsifier (often high ph. amine based compounds) with an inorganic acid (i.e.: HCl). Your favorite chemical supplier will tailor this batch treatment program for this producer. Expect rates to be an order of magnitude or higher than "normal" treating rates. The important thing here is for the operator to gain an understanding of just what it takes to make this work. If this doesn't happen, a third, then a fourth, fifth, etc. 300 barrel tank will be added as the system fails to process one tank full in time for the need to refill/begin again.

6.30 This system should cost <\$15,000 for the two tanks with coils, <\$15,000 for a low pressure steam generator, and <\$20,000 for installation.

6.31 3. CENTRIFUGING: A high speed (i.e.: Alpha LaValle) may be used to do the work of bulk separation of water/solids from the slop oil. If used, a smaller treater or tank treating facility will still need to be dedicated to the extremely slow process of taking this slop oil to pipeline quality. The centrifuge alone is >\$100,000, making this a difficult first choice option, but this technology has proven itself on the toughest of separation problems and should not be discounted entirely. If applied, the downstream oil treating facility will cost approximately 75% of the above estimates.

6.32 4. FILTER PRESS: A filter press will produce very high quality water while capturing all of the slop oil on the surface of diatomaceous earth. This process deletes any/all potential to reclaim and sell the slop oil, but considering the relative volume of slop oil to water, it often makes economic sense to apply this technology. A filter press will cost approximately $75,000 plus $25,000 installation and $100,000/year utility, chemical, and manpower operating expense. This expensive technology is often used on a batch basis, and is available from several nomad firms who practice sludge/slop remediation on a rental-batch basis, eliminating the capital costs altogether.

6.33 5. RAPID MECHANICAL FILTRATION: Several waste oil filtration systems are available, but **not recommended**. The solids loading in this stream is sure to foreshorten the effective life of any media filter, regardless of the claims of the various manufacturers.

6.34 I recommend the vertical heater treater for this service as my first choice. Everything else is either too labor intensive or too capital intensive to be feasible and/or practical.

6.35 Sand Removal Pit Fluids

6.36 This stream contains a conglomerate of process offenders. Nevertheless, each stream is predominately water. One stream, the Water Clarification Tank (T-200 and T-300) sand removal drain, should be re-routed back to one of the sand removal pits since it is the probable worst case offender in terms of solids collection. The remaining streams are predominately water with lesser amounts of silt/sand/other solids.

6.37 I see no clear reason from the P&IDs that this tank (T-103) should exist (though I am certain there is in fact a very good reason; one that does not present itself in the information provided). This tank appears to be little more than a wide spot in the lines between the vessel drains and the sand removal pits, except for the accumulation of residual oil present in the drain water. If no oil exists, then either the pits have insufficient retention time to settle the solids, or cleaning this 3000 barrel tank is easier/less costly than cleaning the silt and sand collected in the sand removal pits.

6.38 We recommend that this producer look closely at the function of this tank to decide if it is needed for this service.

6.39 If this tank provides needed retention time for solids settling/oil separation, I recommend that an Amoco Vortex (AV) be installed (if one does not now already exist). The AV technology is the least expensive method of increasing solids separation by increasing retention time. Further, I recommend a hard look at the "screen mesh" on the gravity flow effluent piping to the sand removal pits, with a focus on mesh size vs. the actual particle size of the solids collecting in T-103. It is difficult to imagine a screen sufficiently small to contain the settleable solids from these varied sources while maintaining sufficient flow characteristics to allow for the operators to decant only the water to the sand removal pits. This also seems contradictory, since the supposed purpose of the sand removal pits is to collect the sand in the overall system for its removal/disposal. I recommend a closer look at the function and methods of using this tank, looking for ways to improve it such as:

6.40 1. Add a cone bottom (if it is currently flat bottom) with all fluids to the sand removal pits collected from the apex of the cone.

6.41 2. Add 8-12 anti-channel drain boxes for the effective removal of fines from the tank bottom.

6.42 I further recommend that the overflow fluid be continuously automatically collected and be continuously routed directly to the treater tank (T-111 and T-112) for heating to at least 90° C, and the to the inlet of the process selected to process the IGF spillover (above). I recommend adding diluent at a ratio of 1:3 to begin with, and evaluating the effect of diluent vs. separation time. I strongly recommend a demulsifier be selected and dedicated continuously to this comparatively small stream.

<u>6.43 Slop Oil Stream</u>

6.44 The slop oil stream is mostly interface materials, tank "bottoms", and recycled "bad" oil which would not treat in the system normally. As such, it difficult to treat separately, and nearly impossible to treat in a recycle loop. I recommend against recycling all but the "bad" oil back to the inlet of the treaters. The "bad" oil can be recycled back to the inlet of the pressure treaters, normally without creating an upset so long as the recycle rate, when added to the normal influent rate, do not exceed the design processing rate of the treater(s) selected. The HTI treaters appear to function more reliably when fully loaded at the design rate, so I recommend the "bad" oil stream be recycled to the HTI treaters at both the North and South Batteries as occurs now, but with it always routed through the treater tanks (T-111 and T-112) rather than to the treaters directly or to the sand removal pit (I strongly recommend that the by-pass to the sand removal pit be blanked off).

6.45 The remaining slop oil streams should be treated with a "very slow" demulsifier, and treated in a dedicated slop oil treating system such as those suggested above (i.e.: vertical heater treater, heated treating tank, etc.). I recommend routing these fluids ***to the same treating vessel*** used for the IGF spillover, with no diluent added, but retreated with a dedicated demulsifier as previously mentioned. This should be done at very low rates if the selected method is the heater treater, so as not to overload it. The cost of this effort is minimal re-piping.

6.46 If this proves to be less than effective or practical, I recommend a vertical or horizontal treater for dynamic continuous processing, or a heated tank for batch processing. The treaters can be used/surplus. The cost of this system could approach $25,000 for the treater plus $15,000 for piping and installation.

6.48 The Water Clarification Tank (T-200 and T-300) interface is now routed directly back into the inlet of the Water Clarification Tank, or indirectly back to the same point through the heat exchanger.

6.49 I recommend that this interface be *continuously* routed through the heat exchanger *ONLY* with a dedicated, rather fast acting demulsifier added to it as it leaves the Water Clarification tank. At the first opportunity, I recommend installing a spreader-distributor in each of the Water Clarification Tanks to redistribute this hot, treated recycled oil directly into the Water Clarification Tank interface, approximately 0.5-1.0 meter above the fixed (see below) interface level.

6.50 Further, during periods of Water Clarification Tank upsets, I recommend adding diluent **downstream** of the heat exchanger at a rate of 1:4 based on the recycle volume only. If this recycle line from the heat exchanger is not now insulated and heat traced, I recommend this modification to maximize heat input to the process, important year around, but particularly during the colder winter months.

6.51 Treater De-sander Fluids

6.52 These fluids are mostly settleable solids when the vessel de-sanders are properly operated. This is a subtle point, but an important one. I recommend that automatic actuators be installed on the de-sander valves on the appropriate process vessels feeding these pits. Each valve should be automatically actuated on the basis of a time interval which avoids large slugs of fluids, but instead assure a more continuous stream of sand removal fluids to enter the pits. Smoothing out his operation will benefit the entire process train, as well as maximizing the sand removal process efficiency of the existing design.

6.53 These fluids flow from the treaters to the sand removal tank (T-103). As mentioned above, I see no clear reason from the P&IDs that this tank (T-103) should exist since it appears to simply be a wide spot in the lines between the vessel drains and the sand removal pits, except for the accumulation of residual oil present in the drain water. If no oil exists, then either the pits have insufficient retention time to settle the solids, or cleaning this 3000 barrel tank is easier/less costly than cleaning the silt and sand collected in the sand removal pits.

6.54 As recommended above I again recommend that this producer look closely at the function of this tank to decide if it is needed for this service. If this tank provides needed retention time for solids settling/oil separation, I recommend that an Amoco Vortex (AV) be installed (if one does not now already exist). The AV technology is the least expensive method of increasing solids separation by increasing retention time.

6.55 As mentioned above, I recommend a hard look at the "screen mesh" on the gravity flow effluent piping to the sand removal pits, with a focus on mesh size vs. the actual particle size of the solids collecting in T-103. I recommend a closer look at the function and methods of using this tank, looking for ways to improve it such as:

6.56 1. Add a cone bottom (if it is currently flat bottom) with all fluids to the sand removal pits collected from the apex of the cone.

6.57 2. Add 8-12 anti-channel drain boxes for the effective removal of fines from the tank bottom.

6.58 And once again I recommend that the overflow fluid be continuously automatically collected and be continuously routed directly to the treater tank (T-111 and T-112) for heating to at least 90° C, and then to the inlet of the process selected to process the IGF spillover (above) with diluent added at a ratio of 1:3 to begin with, and the addition of a demulsifier dedicated continuously to this comparatively small stream.

6.60 Solids Processing

6.61 The key to solids processing is to prevent the recycling of solids back into any phase of the process treatment plant. This subject was well and thoroughly addressed above. Suffice it to say that I recommend that all solids separated in the sand removal and truck-in pits must be cleaned out of these pits periodically, and disposed of. This cleaning must be scheduled in advance of their collecting to the point that they are in fact picked up and recycled back into the process plant.

6.61 Widely Varying Oil Treatment Rates

6.62 I recommend a degree of what I hope we can all agree is "modern day" application process technology to solve this problem once and for all. I recommend the addition of BS&W monitors on the oil outlet lines form each process vessel, beginning with the Water Clarification Tank (T-200 and T-300), and including the pressure treaters. The function of these monitors is to provide a constant, on-line monitor for treating efficiency, and to feed this monitoring signal via a 4-20 ma signal to the rate controller of the demulsifier chemical pumps now dedicated to treating each influent stream into each oil process vessel. Some chemical pumps are designed to accept a 4-20 ma signal directly, and alter their feed rates accordingly. Where the operator prefers, a transducer can convert this signal using small variable frequency drivers (VFDs) on the chemical pump motors (though this is normally more expensive than simply procuring new pumps from manufacturers such as "Precision Chemical Feeders".

6.63 I further recommend that this same philosophy be applied to the other chemicals added to lower viscosity, and to treat for scale and corrosion, except that for these additions I recommend the dosages be based on the actual measured volume of fluids to be treated. This is a rather simple chore at the existing facility because nearly all fluids are pumped. The addition of small turbine or other 4-20 ma output flow meters will provide the control clink to smooth out the remainder of the chemical treating work. This will eliminate overt-reating and undertreating altogether, and presumably the associated upsets.

6.64 Taking this one step further, a simple PLC (i.e.: GE 90-30) could readily provide a PID loop tuning function based on the incoming 4-20 ma signals, allowing the operators to input some degree of "predictive" or "feed forward" control. The advantage of this sort of control logic is to eventually automatically predict upsets through the feed forward PID feature, and prevent upsets before they get out of control. While I am reluctant to take the existing facility too far beyond its present status, this well proven logic is saving others huge amounts of time and money worldwide.

6.65 Process Fluid Rate Control

6.66 Once metering is installed on the various streams it will become possible to manage the flow of fluids. The word "manage" really means "eliminating large variation in flow rates". As each stream is measured, added at an ever more constant rate to its destination point, large flow fluctuations will cease, and with them, so will the resulting upsets cease. This should be a part of a longer term plan for this producer, and is dependent upon following the foregoing recommendations.

6.67 If we can agree that eliminating, or at least minimizing recycling, is a major key in solving the process problems at Existing facility, then it follows that establishing a constancy of flow in each phase of processing will likewise allow the operations people to better manage the facilities. I again recommend the metering system described above, with a degree of expansion as necessary to maintain knowledge of and control over all fluid flow at both the North and South Batteries.

6.68 Process Vessel Interface Control

6.69 Interfaces are elusive in the real world. Operators cannot see through the shells of process vessels to locate and control interfaces, so they depend on mechanical and/or electrical devices. As mentioned earlier, there are inherent problems with both.

6.70 I recommend all interfaces be physically checked, identified, and recorded at least twice per work-shift, around the clock, seven days a week. I recommend this producer experiment with relocating/reorienting any vertically mounted interface devices to the desired interface elevations, place on the horizontal plane to maximize their sensitivity.

6.71 I recommend that at least one sample be taken from at least the sample cock immediately above each interface device control point once each work-shift, and that this sample be centrifuged to determine the actual oil-water-solids concentrations. This information should also be archived and recorded/plotted to gain an understanding of this condition with any unusual operating conditions.

6.72 Data Gathering/Previous Production Operations

6.73 Nothing can be done about what was done in the past. However, sampling well streams may yield information about previous operations which could help bridge the time between now and the time the flood front passes, finally negating nearly all operating effects of the past.

6.74 For instance, is a given producing well is discovered to be producing large quantities of fine carbon dust from a concentration zone resulting from one of the previous fire floods, this well can either be shut in, or the well fluids treated separately to prevent the contamination of the entire production stream from the fluids of a single well.

6.75 I recommend a cursory sampling of each producer at least once every six months. This sampling should be followed up with a water analysis with a focus on any elements or compounds peculiar to the flood water (i.e.: chlorides, selenium, sulfates, etc.). Simple test kits allow the sample technician or operator to run important field water tests for the likes of pH, total sulfides, and Langlier index measurements for scale/corrosion tendency determinations … all quite valuable in interpreting the changing conditions of each well with the passing of the flood front, and time. The oil gravity should be measured and recorded as well, and should be centrifuged to determine the amount of water, asphaltines, solids, and BS&W. A notation should be included referencing the sample quality of the oil-water interface (i.e.: clean break, ragged, stringy, etc.). This may be the first clue to observing a dramatic change in fluid characteristics.

6.76 Finally, I recommend establishing, maintaining and a monthly review of a data base.

7.0 CONCLUSIONS

Problems at the existing facility are complex and dynamic. A review of these problems has resulted in a rank ordered list of worst offenders and recommended solutions. Recycling is the major offender at Existing facility. Recycling must be minimized to the greatest degree possible. Processing fluids on a single-stream basis presents this producer with the area of greatest optimization opportunity. Dedicated processing is recommended. Facilities must be modified to accommodate dedicated processing on a single stream basis, but modifications are comparatively insignificant when weighed against this producer's investment in existing facilities. More work is needed to identify specific design changes to individual existing processing facilities.

7.0 ACKNOWLEDGEMENTS

8.10 This concludes the work commissioned. It has been a real challenge and a distinct pleasure to review the details of the Existing facility. We would like to take this opportunity to acknowledge the professional input and quality of data from this producer. Because the quality of the information you provided as the basis for this study is unusually high, we believe the quality of my feedback, conclusions and recommendations to this producer is equally enhanced.

8.12 Everyone involved in this study has worked hard to identify problems and find solutions. We would like to take this opportunity to acknowledge and thank this producer's engineering staff, operations professionals, and support service firms for the valuable

input and tireless efforts of each. We believe we are well on the way to understanding the opportunities we have to optimize the process efficiency at the existing facility facilities.

8.13 It is my distinct hope that this producer is more than satisfied with this report, and that this producer will afford me the opportunity to continue to serve as a valuable contributor to this producer's operations in in the future.

This concludes the Study Report

for

This Canadian Production Processing Facility