FLOW ASSURANCE AND MULTIPHASE PUMPING

A Thesis

by

HEMANT G. NIKHAR

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2006

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Stuart L. Scott
Committee Members,	Jerome J. Schubert
	Charles J. Glover
Head of Department,	Stephen A. Holditch

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ABSTRACT

Flow Assurance and Multiphase Pumping.

(December 2006)

Hemant G. Nikhar, B.S., Indian School of Mines, Dhanbad

Chair of Advisory Committee: Dr. Stuart L. Scott

A robust understanding and planning of production enhancement and flow assurance is required as petroleum E&P activities are targeting deepwaters and long distances. Different flow assurance issues and their solutions are put together in this work. The use of multiphase pumps as a flow assurance solution is emphasized. Multiphase pumping aids flow assurance in different ways. However, the problem causing most concern is sand erosion. This work involved a detection-based sand monitoring method.

Our objectives are to investigate the reliability of an acoustic sand detector and analyze the feasibility of gel injection as a method to mitigate sand erosion. Use of a sand detector coupled with twin-screw pumps is studied under varying flow conditions. The feasibility of gel injection to reduce slip and transport produced solids through twin-screw pump is investigated. A unique full-scale laboratory with multiphase pumps was utilized to carry out the experimental tests.

The test results indicate that acoustic sand detection works in a narrow window around the calibration signature. An empirical correlation for predicting the twin-screw pump performance with viscous fluids was developed. It shows good agreement in the practical operational limits – 50% to 100% speed. The results indicate that viscous gel injection should be an effective erosion mitigation approach as it reduces slip, the principle cause of erosive wear. To correlate the performance of viscous fluid injection to hydroabrasive wear, further experimental investigation is needed.

DEDICATION

This work is entirely dedicated to my parents and family for their love, guidance and encouragement.

ACKNOWLEDGEMENTS

I would like to express my sincere gratitude and appreciation to Dr. Stuart L. Scott, chair of the advisory committee, for his valuable guidance and support. I am grateful to Dr. Charles J. Glover and Dr. Jerome Schubert for their guidance, patience and their contribution to the advisory committee.

A word of sincere appreciation goes to Multiphase Research Group for making the Riverside work happen, fixing the piping and instrumentation when needed and running experiments. I would also like to thank the faculty and staff in the Department of Petroleum Engineering for making my graduate studies a wonderful learning experience.

Thanks to Flowserve, Bornemann, Roxar, and BJ for providing their kind donations to the Texas A&M Multiphase Field Laboratory at Riverside campus.

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NOMENCLATURE

A	Constant
a	Coefficient
A_n	Surface area
B	Constant
b	Coefficient
B_o	Oil formation volume factor, reservoir bbl/stb
C	Constant
c	Coefficient
C_{visc}	Viscosity coefficient
D	Constant
d	Coefficient
δ	Clearance between screw tip and casing
d_p	Diameter of pipe, ft
ΔP	Differential pressure, psig
ΔP_f	Frictional pressure drop
D_p	Pipe diameter, in
D_t	Screw tip diameter
ε	Pipe roughness
E	Constant
e	Exponent
F	Constant
f	Friction factor
$f(v_s)$	Sand Noise, 100 nV
G	Constant
$g(v_s)$	Background noise, 100 nV
Gc	Gel concentration, lb/1000gal
g_c	Gravity constant
Gc_{eff}	Effective concentration of gel, lb/1000gal
Gc_i	Gel concentration in injected fluid, lb/1000gal
Gc_w	Gel concentration in water, lb/1000gal
h	Payzone thickness, ft
H	Constant
J	Productivity index, stb/day/psi
k	Permeability of porous media
L	Length of pipeline, ft
l	Length of leak path

μ	Viscosity, cp
μ_e	Effective viscosity of power law fluid
μ_{eff}	Effective viscosity, cp
N	Rotary speed, RPM
N_{Re}	Reynolds number
p	Reservoir pressure, psig
p_i	Pressure downstream of screw thread
p_{i+1}	Pressure upstream of screw thread
p_{wf}	Bottomhole pressure, psig
q	Liquid flow rate, bbl/day
Q_{gel}	Gel flow rate, bbl/day
q_h	Heat flow rate
q_i	Injection flow rate
$Q_{s,i}$	Slip flow across screw thread
q_w	Base flow rate
Q_w	Water flow rate, bbl/day
ρ	Density, lb/cu. ft
r_e	Reservoir radius, ft
r_w	Wellbore radius, ft
s	Skin factor, dimensionless
T_{amb}	Ambient temperature
T_{CL}	Center line temperature
U_n	Overall heat transfer coefficient
v	Velocity of fluid
$\bar{v}$	Average velocity of fluid, ft/min
v_s	Velocity of sand, m/sec

1. INTRODUCTION

The petroleum exploration and production operations are targeting fields in deep and ultra-deep waters throughout many parts of the world. Flow assurance deals with the risks and problems arising from the properties and behavior of produced hydrocarbons, associated fluids and solids. As oil and gas production moves to deeper waters, produced fluids need to be transported through longer tiebacks and taller risers. This trend requires a robust understanding and planning of production enhancement and flow assurance in increasingly demanding conditions.

The well fluids: gas, oil, condensate, water and sand cause problems like hydrate formation, wax, asphaltene, and scale deposition, corrosion and erosion due to sand and other solids. Thermal and hydraulic risks are main issues related to flow assurance. Hydrates, wax, and asphaltene are the concerns with thermal risks and slugging and erosion are the concerns with hydraulic risks. Flow assurance strategies are based on thermal management, pressure management, chemical treatments, and mechanical remediation. Among pressure management techniques comes multiphase boosting and pipeline blowdown (in case of extreme blockage due to hydrates).

A majority of the world's oil and gas are contained in poorly/weakly consolidated reservoirs. Thus, the production strategies should now be shifting from maximum sand free rates to maximum allowable sand rates. In addition, they are driven by technical advances in detection, handling and disposal of sand and by increasing demand for oil and gas.

Multiphase boosting provides an effective solution to drawdown the flowing wellhead pressure and compensate for increased static or frictional flowline inlet pressure and therefore considerably reduce the risk related to the most oilfield developments. For enhanced production and flow assurance, multiphase boosters provide significant cost savings and higher production rates. Multiphase pumping has consistently demonstrated its superiority over the conventional systems under different operating conditions. Multiphase boosters aid in flow assurance by mixing phases, pushing them together and regulating the flow. Multiphase boosting also reduces the cooldown and minimizes slugging. Boosting the untreated produced fluids gives a considerable positive change in temperature, which is not possible with conventional pumping without separation. A higher temperature due to multiphase boosting reduces the need for chemical treatments and contamination is minimized. Among multiphase boosters, the twin-screw multiphase pumps are most popular and widely deployed.

This thesis follows the style of *SPE Production & Facilities.*

With this background, the most robust twin-screw pumps need to be better equipped to handle concentrations of abrasive solids as they rely on very precise clearances for efficient performance. The objectives of this study are to study the reliability of acoustic sand detector, analyze slip flow as a function of different parameters, analyze the feasibility of gel injection process, and predict the performance of twin-screw pump with viscous fluids. The following approach is considered:

- Review of global activities in deepwaters and historical oil prices that are driving the economic viability of previously marginal fields.
- Introduction to flow assurance and discussion of different flow assurance issues, understanding of chemistry and physics involved, mitigation strategies and methods.
- Discussion of multiphase pumping technologies, their suitability to improve the flow assurance and potential huge savings in investments.
- Problems due to solids production and their effects on the performance of twin-screw pumps and overall production system.
- Visual study of solid particles transport in liquid.
- Methods to detect sand in multiphase flow and coupling of sand detector with multiphase pump. Performance and reliability of sand detector.
- Discussion of factors contributing to the efficiency of twin-screw pumps and slip flow analysis.
- Transportation of solids in multiphase flow and through multiphase pumps. Approaches to the problem of solids transport to minimize erosive tendency.
- Investigation of viscous gel injection as an important method to transport the sand particles. Problems and concerns about injecting gels in deepwater pipelines. Effective viscosities achieved on injection of concentrated gel through commercially available tubing sizes.
- Experimental study of twin-screw pump performance with fluids of different viscosities and data collection. Formulation of empirical tool for predicting performance under viscous flow.
- Discussion of future work needed and conclusions about experimental work and flow assurance from integrated production management point of view.

This thesis is divided into nine sections. Section 2 is a literature review of the flow assurance issues and multiphase pumping as a flow assurance strategy. It describes the characteristics of deepwater oilfields, flow assurance issues, subsea process, multiphase pumping and integrated production modeling in general.

Section 3 discusses flow assurance issues in detail. It starts with brief description of flow assurance challenge, and discusses importance of correct fluids sampling and compositional characterization, flow assurance strategies, proactive flow assurance, slugs and their mitigation, solids deposition in brief, screening techniques for solids formed in hydrocarbon streams, management of waxes and hydrates, asphaltene inhibition, describes various chemicals used in production operations, blockages, pigging and plugging while plugging, thermal insulation, heating and operability.

Section 4 discusses multiphase pumping from flow assurance point of view. Conventional and modern production systems and advantages of multiphase pumping are discussed. Possibility of step-out tiebacks with the help of multiphase pumping is discussed. Multiphase pump types, performance, characteristics, costs, operational and location considerations and suitable scenarios for application are discussed.

Section 5 deals with the formation of gas hydrates and scales. It starts with description of gas hydrates as a multitude of field problems. Detection of hydrate nuclei, agglomeration, differential scanning calorimetry, and different means of inhibiting or dissociating hydrates, advantages of LDHI's are discussed. Flow assurance needs for hydrate slurry, NGH transport, cold flow, and different mitigation strategies are also discussed. Description of scales, contributing factors, formation process and mechanism is provided in scales section. Scale formation locations, detection, techniques for prediction from history and current data, remediation and prevention methods are also discussed.

Section 6 details the experimental facility used for solid-liquid flow visualization, sand detector study, twin-screw pump behavior with viscous fluids and under the conditions of gel injection.

Section 7 deals with handling of produced solids in surface production systems. It starts with description of typical deepwater reservoirs with loose consolidation, process, modes and nature of sand production and flow. This section then discusses erosive wear in twin-screw pumps, different approaches to analyze wear and parameters affecting wear. It then discusses sand detection method, calibration and testing of sand detector, performance of detector under varying conditions, solids transport, and slip flow in twin-screw pump. Different approaches to the problem of wear are presented and use of high viscosity gels is emphasized as an effective strategy. The characteristics of gel used for experiment are described, behavior of gels with different viscosities flowing through tubings of different size are analyzed. A method for predicting effective viscosity on injection of gel with particular viscosity is described. An empirical correlation for viscous flow behavior in twin-screw pump is formulated and discussed.

Section 8 discusses an integrated approach to flow assurance. Different strategies and methods for oilfield management, asset management, need for integration of Reservoir, wellbore, subsea, pipeline and process systems for effective flow assurance.

Section 9 describes the summary, conclusions and recommendations of this work.

2. LITERATURE REVIEW

This section is a literature review on the flow assurance issues and multiphase pumping as a flow assurance strategy. Discussion on the characteristics of deepwater oilfields, flow assurance, subsea process, multiphase pumping and integrated production modeling in general set a stage for flow assurance interest.

Petroleum exploration and production operations are targeting fields in deep and ultra-deep waters throughout many parts of the world. Fig. 1 shows the trend in oil prices since 1996. Oil prices have been steadily going up as world's demand is constantly increasing and easy supplies are not in plenty. Increasing oil prices have sent the operators to deeper waters, longer distances and tougher environments. Fig. 2 shows the worldwide interest in scientific drilling in the form of Deep Sea Drilling Program (DSDP), Ocean Drilling Program (ODP), and Integrated Ocean Drilling Program (IODP). This shows that new locations are being searched for new resources to meet the ever increasing demand of energy. The low-hanging fruit in many deep water areas has been picked up[1]. This trend requires a robust understanding and planning of production enhancement and flow assurance in increasingly demanding conditions.

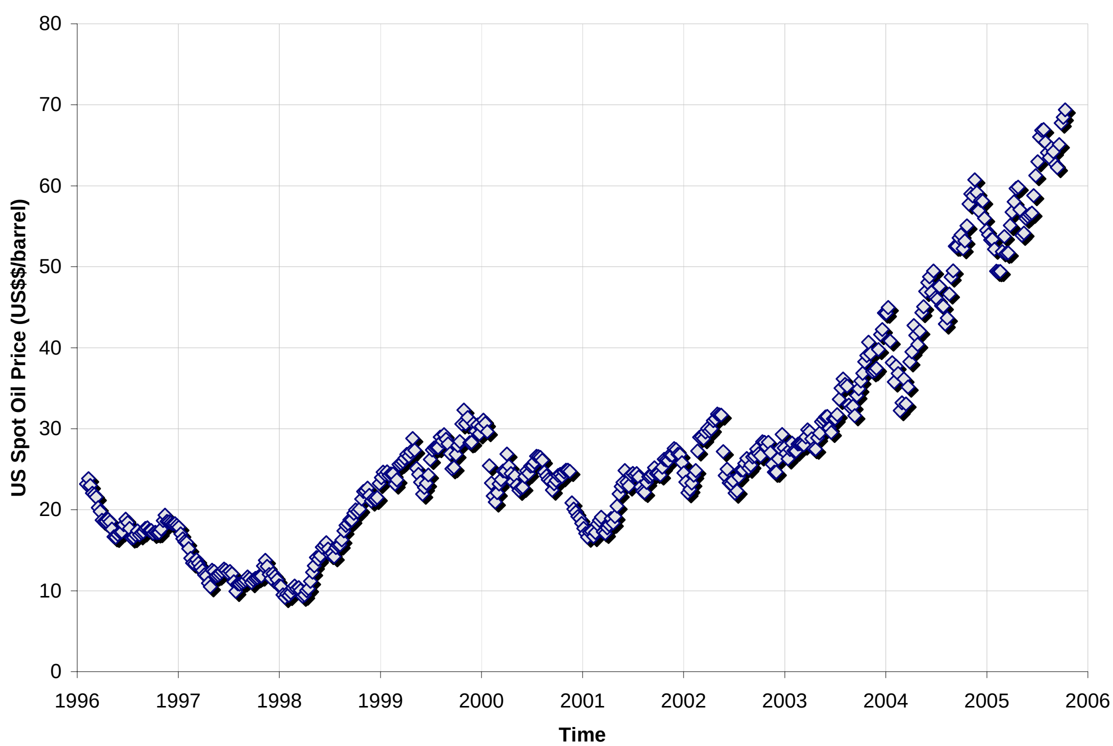


Fig. 1: Historical Oil Prices[2]

The well fluids: gas, crude oil, condensate, water along with sand cause many problems including hydrate formation, wax, paraffin and asphaltene deposition, scale deposition, corrosion and erosion due to sand and other solids. Flow assurance is a multidisciplinary process involving sampling, laboratory analysis, production and facilities engineering working together to assure uninterrupted optimum productivity from an oilfield. Flow assurance predictive modeling is an important foundation for production system selection and design of operational strategies. Multiphase boosting is considered a highly competitive alternative to other boosting alternatives. For enhanced production and flow assurance, multiphase boosters provide significant cost

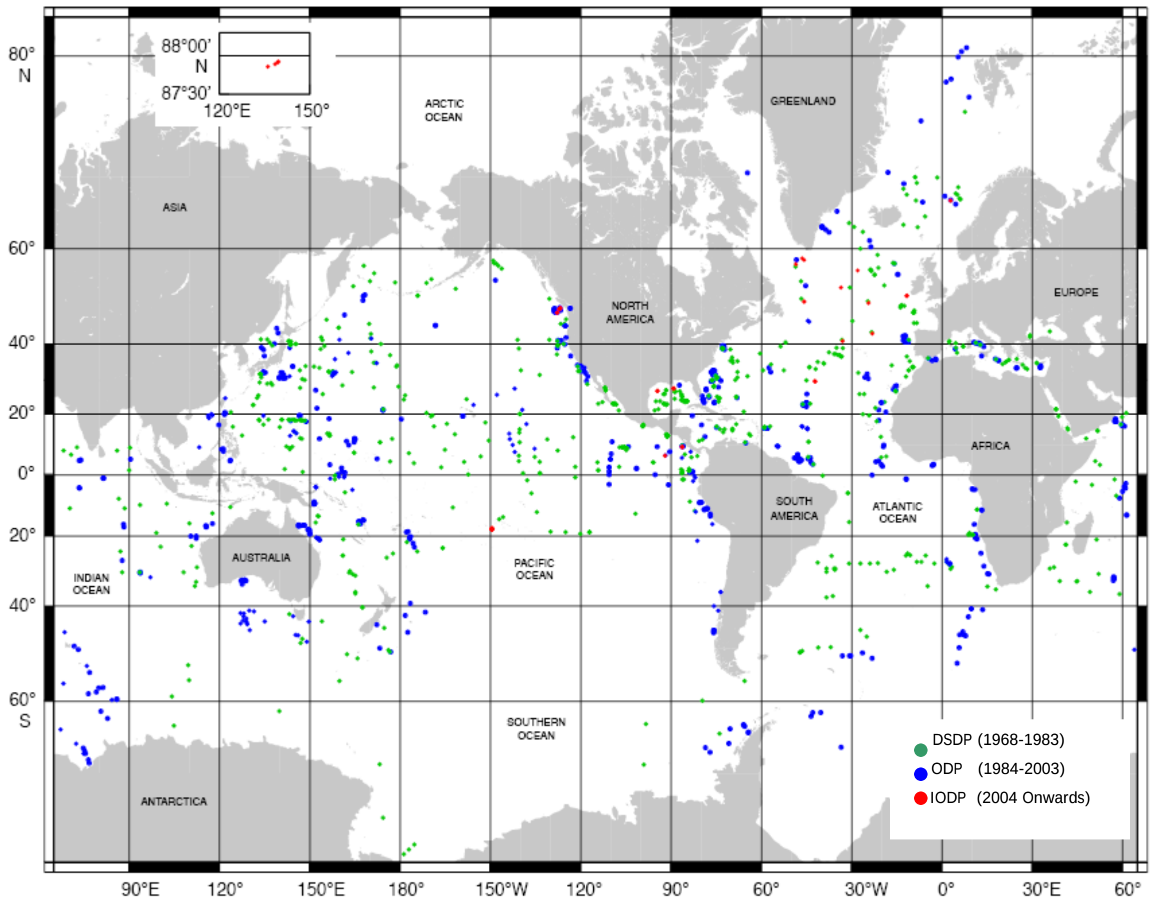


Fig. 2: Scientific Drilling Across World Oceans[3]

savings and production enhancements. The multiphase boosting technology can be applied on either the surface or subsea for multiphase transport, flow assurance, subsea process / raw water injection, simultaneous water and gas injection, wet gas compression, pressure reduction of system without conventional separation to prevent hydrate formation. This can increase the oil production by reducing the flowing wellhead pressure; improve flow assurance by handling untreated well fluid streams or injection streams.

Deepwater Oilfields

Many deepwater oilfield problems are characteristic of the reservoir environment. They tend to be turbidite sandstone formations and while the water depth is large, the depth of formation between seabed and reservoir of interest is very small[4]. As a result, the reservoirs tend to be low-energy having relatively low pressures and temperatures compared to conventional reservoirs at similar TVD. Not only is the pressure for driving the fluids to surface is limited but also the heat needed for avoidance of solids formation is low. Lower pressures invariably call for need to maintain the reservoir pressure by waterflooding or similar means and artificial means such as gas lift and multiphase boosting. On the positive side, these reservoirs have excellent permeability as the degree of consolidation is much less. But this again presents the problem of sand production and sand erosion in the flow assurance equipment of highest interest – multiphase booster.

Fig. 3: Deepwater Basins Worldwide[5]

Fig. 3 shows deepwater basins containing hydrocarbons around the world. It can be seen that most of the development is around the continents and step-out to long distances is still to come. There is a huge potential for long distance tiebacks and flow assurance challenge will be enormous. Fig. 4 shows the progress of water depths for exploration, drilling and production activities. After 1975, the exploration depths have been increasing steadily. During 1990s depths of platforms and subsea activities started setting new records and further advancement is continuing.

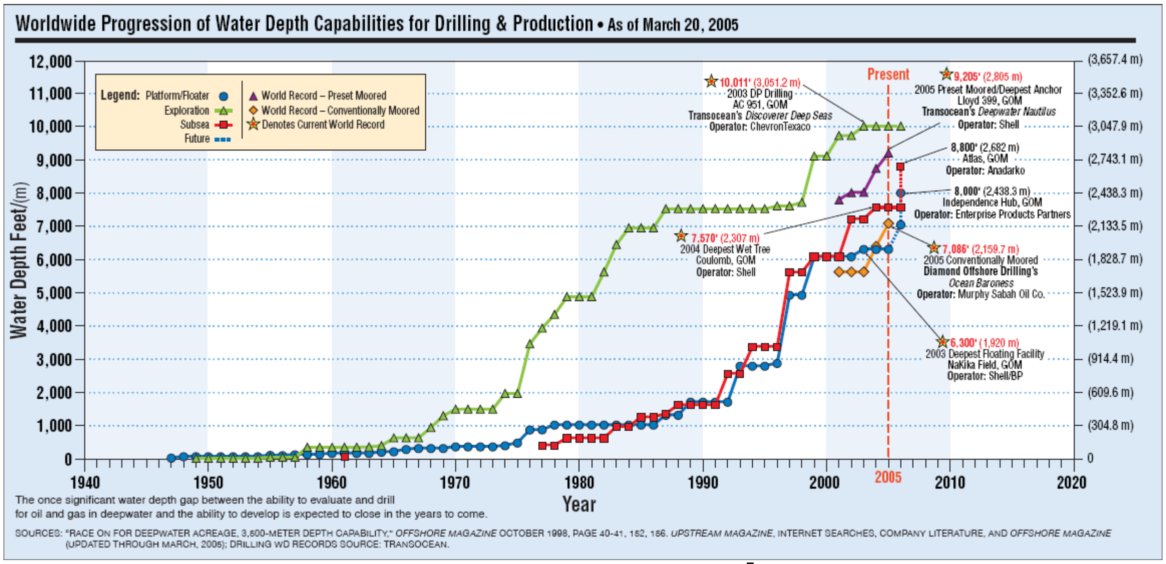


Fig. 4: Water Depth Progress[5]

Fig. 5 shows the number of deepwater developments between 1994 and 2004. Number of new deepwater fields coming up continues to increase year by year.

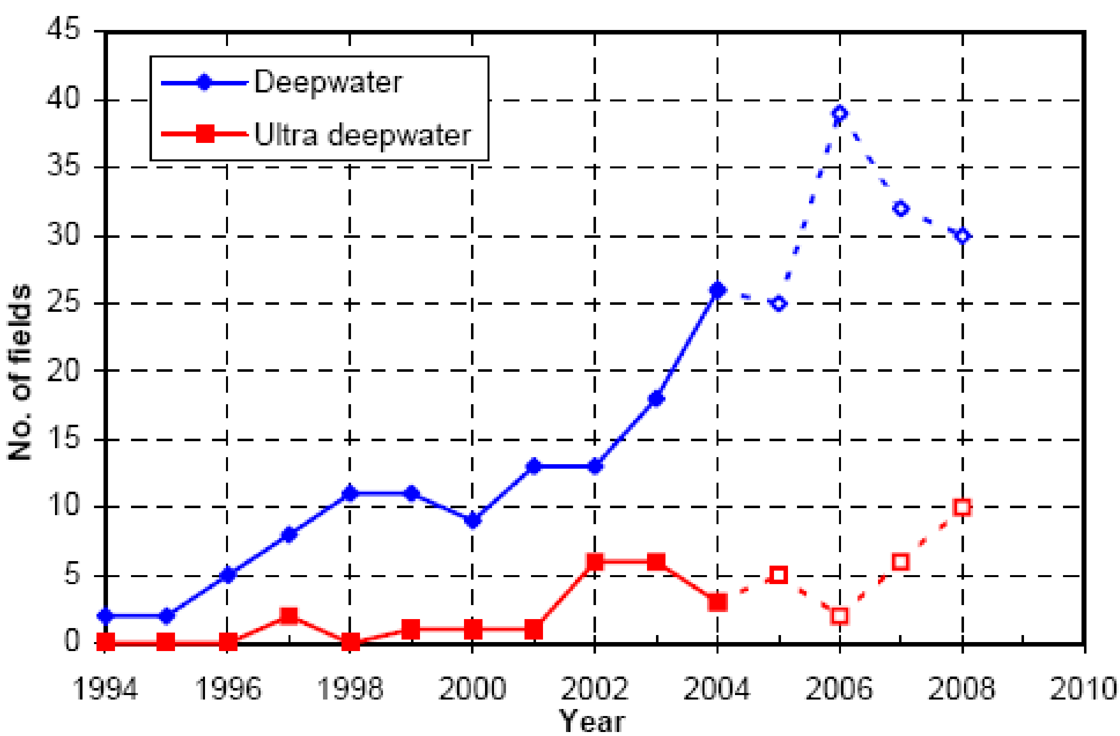


Fig. 5: Number of Deepwater Developments[6]

The first subsea Christmas tree was installed in 1961 and it took industry 37 years to complete 1000 subsea wells. By 2010, additional 1000 subsea wells are expected to flow. Expected subsea capital expenditure will exceed US$ 48 billion[7]. Geographically, the investments will be concentrated in the North Sea, Gulf of Mexico, Brazil, and West Africa.

Flow Assurance

Traditionally, flow assurance means unclogging wells, tieback lines and jumpers, gathering stations and risers of deposits of paraffin, scales or hydrates. The conditions are so diverse and pervasive that there is no unique solution. Sometimes chemical treatment is the answer, other times insulating the flow lines can solve the problem. Sometimes a combination of both will be required. The main issues related to flow assurance are thermal risks and hydraulic risks. Hydrates formation, paraffin deposition, and asphaltene deposition are concerns with thermal risks while slugging and erosion are concerns with hydraulic risks.

The key drivers to system deliverability will be reservoir energy, depth, offset distances from gathering stations, and fluid properties. Flow lines and tubing sizes are optimized looking at erosional velocity constraints and slugging tendency. Reservoir drive mechanism, fluid compositions, field layout will determine the system deliverability. The approaches to keep up with the deliverability of a production system are gas lift, multiphase boosting – downhole and surface, water injection, and separation.

In a dynamic situation, each potential problem exhibits different behavior as a function of temperature and pressure and to some extent, flow rate. Waxes, hydrates and scales exhibit a sort of phase behavior as they appear and agglomerate in flow stream. Without sufficient data, the flow assurance systems are over designed. Inappropriate solutions may create additional concerns such as slugging and associated problems to multiphase flow.

With real time system surveillance, the entire production network can be optimized. In addition to production optimization, flow assurance can be supported using the data to predict the potential bottlenecks and schedule the remedial actions such as changing the rate of LDHI to planning a comprehensive work-over.

Modern proactive approach is feeding real time data into dynamic production models that among other things enable prediction of flow problems in sufficient time to take mitigating action. To shift from reactive to proactive mode, one requires timely and appropriate information. Through systematic data gathering trends affecting flow efficiency can be identified and mitigating prognosis can be developed. Data acquisition for flow assurance benefits the overall asset management. Measurements such as distributed temperature and multiphase flow parameters improve and refine the accuracy of the predictive models.

Extensive studies to analyze the total systems over the life of the field, evaluating fluid characterization and running dynamic flow simulations to determine required paraffin and hydrate management, chemical injection, and liquid slugging management. It covers analysis of the production system from reservoir to export system to optimize the hydrocarbon recovery over the life of the field. The flow assurance strategy should encompass a combined design and management philosophy for all of the following depending upon fluid properties and operating conditions:

- System deliverability,
- Gas hydrates
- Paraffin / asphaltenes
- Sand deposition
- Erosion
- Liquid slugging
- Corrosion
- Scale
- Emulsion
- Foaming

The strategy adopted is applied during detailed system design, developing operating procedures, and during operations to maximize the profitability of the field. Based on the flow-assurance analysis results, a design philosophy and functional specs must be developed for the flowing elements:

- Well completion (tubing sizing, etc)
- Flow lines, risers, sub sea manifolds sizing
- Thermal management (insulation/heating)
- Chemical dosing system
- Pigging strategy

The first step in design of deepwater sub sea facilities is to collect and analyze the reservoir fluids at reservoir conditions. Laboratory analysis provides the quantitative information on fluid composition, chemistry and physical properties. Without fluids information, large safety factors and unwanted process equipment might come into picture.

To prevent and manage hydrate formation, combination of either chemical dosing or thermal management may be applied. The cool-down time can be designed to be sufficient for the operator to take remedial action. Remedial action may include flowline / riser pressure to reduce below hydrate formation region.

Depending on the cloud point temperature and paraffin content, paraffin may deposit on the walls of tubing, flowline and risers; which may totally block the flow depending on deposition rate. Based on the laboratory measurements, multiphase flow and thermal simulations of the production system, the potential severity of the deposition can be evaluated. To prevent and manage the paraffin deposition, combination of chemical dosing, thermal management, and pigging may be applied. A cost/benefit analysis of these solutions should be conducted before final selection of the strategy.

Both hydrodynamically-induced and terrain-induced slugs can form and travel in the surface networks. Transient dynamic analysis of the flowlines and risers must be conducted to evaluate potential severity of the slugging tendency and severity. From the point of view of slugging causing serious ramifications for operations at the receiving facilities, hydrostatic head is a great challenge for ultra deepwater developments. Subsea process with improved subsea water separation and multiphase boosting will eliminate the risk of hydrates formation and hydrostatic heads.

Corrosion inhibition philosophy depends primarily on the produced fluid composition, water chemistry, operating conditions and flow regime. For erosional velocity limits API 14E guidelines are adopted as the base line and also various types of sand and erosion monitors are available for subsea application. Flow assurance continues to be a major concern for deepwater and long subsea tieback distances.

Hydrate Management

As oil and gas developments move into deeper waters, the hydrates become a critical design consideration. Different methods starting with heat retention by means of insulation, providing active heating to keep the system out of hydrate formation region, are adopted. The extent of active heating required for ultra and super deep water developments is such that considerable topside costs are incurred apart from footprint. The trend is therefore away from heat retention or active continuous heating more towards chemicals and intervention.

The intervention heating can be provided by intervention vessel to flowline designed to be able to receive electrical power based on requirement for any small length section at a given time. A hydrate plug can be remedied without footprint.

Chemical way of hydrate management involves low dosage hydrate inhibitors – kinetic and anti-agglomerates. On a volume basis, they cost 3 to 4 times as conventional inhibitors but the dosage rates are so low that costs differ significantly when rates are normalized. A benefit of multiphase pumping is that the stream temperature rises by as it passes through the pump.

Stranded Gas

The gas resource which has been discovered, but remains un-marketable or unusable for either physical or economic reasons is called stranded gas. The associated gas that is produced offshore is increasingly becoming a challenge[8]. Stranded gas transport must be justified with innovative concepts which can be commercialized. Some of the novel processes include liquefied natural gas, compressed natural gas, and electricity generation and distribution. These processes are complex and need considerable investment. Natural gas hydrate technology (NGH) proposes to convert the associated natural gas into solid gas hydrates in a controlled manner. The basis behind this technology is large storage potential of hydrates to encapsulate gas molecules. Dissociation of these hydrates can yield gas up to 180 times their volume. When stored at temperatures below freezing point at atmospheric pressures, these hydrates are stable.

In hydrate slurry process, produced well fluid is separated into oil and gas, gas is further converted into hydrates which are then mixed with chilled crude, creating slurry. This slurry can be stored in tanks at suitable temperature and transported.

Subsea Process

The subsea process is considered to include downhole equipment, separation, pumping, compression, and metering. The subsea systems on a broader perspective cover:

- Pipeline / flowlines heating systems;
- Downhole / subsea separation;
- Subsea chemical distribution;
- Subsea multiphase boosting, single phase boosting, wet gas compression and dry gas compression;
- Control / service buoys / spars;
- Power / communication umbilicals;
- Wireless communication;

- Subsea power generation / distribution / delivery

Since water has density higher than oil, enough separation subsea would enhance the flow assurance via multiphase boosting by reducing the flowline backpressure and hydrostatic head in the vertical sections. Separation of gas subsea enhances the efficiency of boosting. Water separation will always need an injection well or some kind of disposal system for produced water. An example of subsea water separation system is ABB system installed on Troll Pilot in 2001. A typical separation system comprises horizontal three phase gravity based separator, a cyclonic inlet device and a water re-injection system. In case of Troll, the subsea water separation enabled additional production of 15000 bopd due to elimination of bottlenecks which were otherwise present in the system due to need to handle excessive water production.

Although subsea process has positive impact on flow assurance, there are some uncertainties. A water cut of more than 2% could lead to hydrates formation. On the contrary, removal of water from produced well fluid leads to rapid cooldown and potentially deposition of paraffin or asphaltenes. Water separation minimizes the chemical injection requirements. Subsea process helps heating up of the fluids at seabed during start up itself. Lower pressures in flowlines for subsea developments with subsea process have potentially lower risks of hydrates formation.

VASPS

The vertical annular separation and pumping system (VASPS) represents an innovative separation and ESP system. After gas / liquid mixture is passed through a helical section, the liquid is pumped by ESP and gas is allowed to flow on its own[9]. The subsea separation reduces the bottomhole pressure allowing a higher flow rate. Fig. 6 shows main components of a VASPS. VASPS is basically a dummy well close to a producing well. Multiphase fluid produced by well enters tangentially into VASPS. This fluid flows in helical path and centrifugal forces separate the gas and liquid.

The gas “self”-flows and liquid is pumped out with an ESP to the host facility in separate flowlines. This separation close to producer well ensures reduced backpressure and reservoir energy is not wasted in overcoming the gravitational and frictional losses in the multiphase flow.

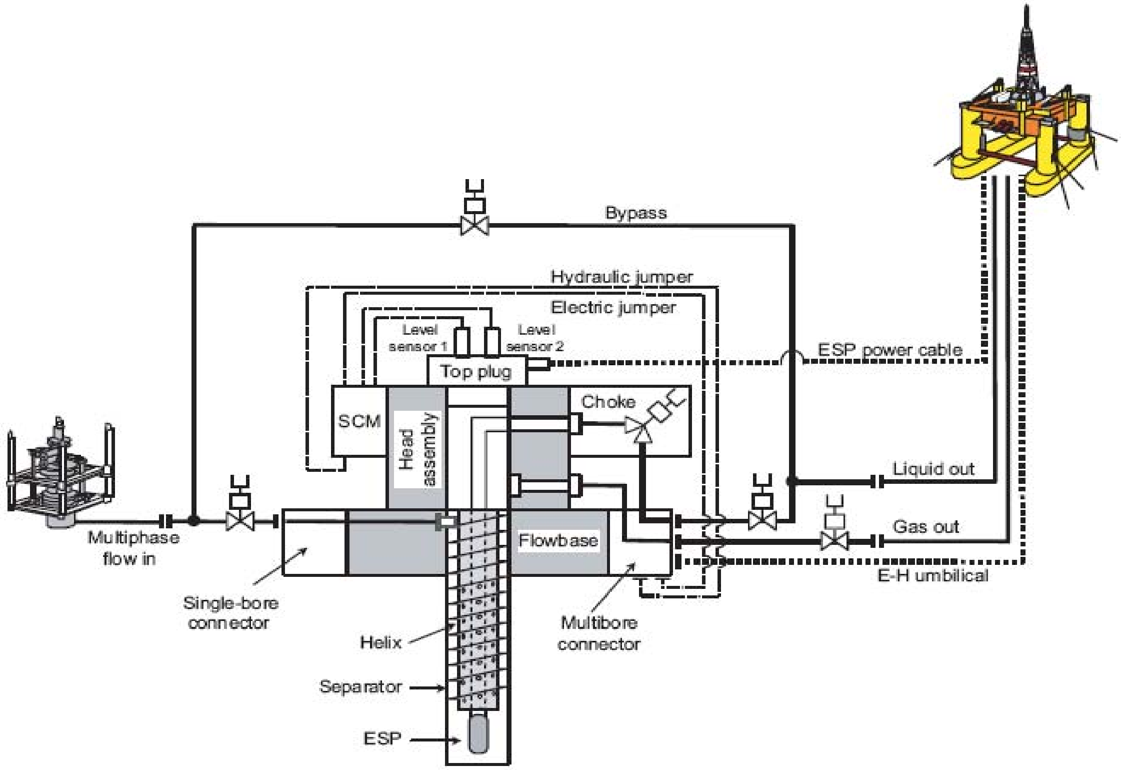


Fig. 6: VASPS Main Components[9]

Multiphase Pumping

Since the very early days of oil and gas production, the transport of untreated well fluids (multiphase) using reservoir energy over a short distance had been in practice. There was no device available to directly pressure boost the stream in case reservoir energy was insufficient. The only feasible approach was separating the liquid and gas phases and transporting them separately. Multiphase pumps have now become a reality.

As opposed to conventional technology, which requires liquid and gas to be separated before pumping and compression can take place, the multiphase pumps generate pressure to the unprocessed stream. Multiphase pumps provide an effective solution to drawdown the flowing wellhead pressure and compensate for increased static or frictional flowline inlet pressure and therefore considerably reduce the reservoir risk related to most oilfield developments.

While the use of long pipelines and flowlines allows for better economics, it imposes higher backpressures on wells and hampers production. Gravitational losses can become significant for higher density fluids in ultra deepwater developments. While these energy losses are significant, it is interesting to note that some form of energy input to transport the fluids will improve the ultimate recovery and reduce wastage of non-renewable natural resources in deepwater. Multiphase pumping is one such energy input.

Maintaining a high backpressure is a production practice that wastes reservoir energy. Energy that could be used to move reservoir fluids to the wellbore and out of the well is instead lost to flow through a choke or long flowline. The multiphase pumps are able to flow any untreated well stream without slugging or surging. They are flow assurance tools of prime importance. There are two main families of multiphase pumps – rotodynamic pumps and positive displacement pumps. Rotodynamic pumps comprise a number of impeller and stator stages on a single shaft that rotates at a high speed. The impellers generate kinetic energy in the enclosed fluid which forms a pressure boost. These pumps are better suited to applications with higher fluid viscosities and gas void fractions. The positive displacement multiphase pumps are generally of twin-screw type, in which a pair of shafts with machined helical profiles are meshed together and rotated together and rotated in opposite directions to form sealed 'locks' of fluid. These locks transfer the fluid-stream longitudinally through the pump, producing a pressure rise against the pump discharge. The working principle of twin-screw pump is like a piston pump with an infinite length of stroke which leads to uninterrupted transport of fluid[10]. The twin-screw pumps operate at lower speeds than rotodynamic pumps, require constant torque drives and can pump higher viscosity fluids. Once installed subsea, access to the equipment for monitoring, adjustments, maintenance or repair becomes a high-tech and huge-cost affair. Therefore, thorough surface testing is essential before marinization.

Reservoir pressure alone is insufficient to provide the flow assurance, so in addition to the normal methods of reservoir pressure maintenance by waterflooding and primary artificial lift by gas lift, ESPs are increasingly being used. In deepwaters and for very long tiebacks, the pressure boost from ESP's may not be sufficient. Here, the multiphase pumps become very important as they enhance the recovery from deepwater fields.

The multiphase pumping technology can allow marginal fields to become economic, and field life and recovery can be extended. The decision about implementing the multiphase pumping is complex[11]. The expected boost in production must be weighed against the cost of the pump, its maintenance and the power requirement.

Subsea multiphase pumping bypasses the technology gap that exists in subsea processing. In addition to the pressure boost, these pumps aid in flow assurance by mixing, pushing and regulating the flow of untreated well fluids[11]. Multiphase pumping has a potential to bring attractive and extra degrees of freedom to the petroleum exploitation schemes, particularly deep sea.

Inbuilt Capability of Twin-Screw Pumps to Handle Slugs

The incoming fluid in a twin-screw pump is diverted to both ends of the screws, and fluid fills up the volumetric chamber between screw flanks. The screw profile axially transports the fluid from the ends to the center of the pump where fluid rejoins and leaves the pump chamber. This feature allows the pump to handle severe liquid slugs[12]. Liquid slugs are split and hit the end of each screw at exactly the same time. Thus any force or thrust caused by liquid slugs occur at the opposite end of each screw at exactly the same time and counters each other. There is a zero net resultant force. Other types of pumps often require thrust bearings and have limitations on the capability to handle slugs.

Suitability of Helico-Axial Pumps for Field Developments

Obtaining reservoir data for new oilfields is often difficult. Practically, such data evolve over the life of the field and can change the demands imposed on the pumps. Helico-axial multiphase pumps have high degree of inherent flexibility as speed can be varied for desired performance, number of pumps installed can be phased in as required, number of stages can be changed to suit changing pressure requirements and internal cartridge with entirely different hydraulic characteristics can be installed if different capacity is needed at some point in the life of the field[13].

Economics

As mankind continues to discover the hydrocarbon reserves in ever deeper waters, or try to make marginal fields economic, field development can go ahead only if a means of reducing the life-of-field costs below currently achievable levels is found.

When compared to other alternatives of the initial complementary development, export systems deploying multiphase pumps are very competitive in terms of CAPEX and OPEX. This technology has ability to eliminate export process system comprising of separators, pumps, compressors, flaring network, safety system for pressure vessels, electrical equipment and gas turbines, etc. Multiphase pumps offer higher operating flexibility and phasing in of the investment for field development than the conventional separator installations, where for example, gas compressor can not be designed for variable inlet conditions such as pressures and flow rates[11]. The modularized subsea multiphase pumps allow easy integration with other production facilities or infrastructure. Retrofitting in existing set-up is also possible. The payback time of installed pump systems is in months rather than years as production is enhanced by several thousand barrels of oil per day.

It is possible to deploy light intervention vessels for interventions of the compact multiphase pumps without the need for large service vessels[14]. Typical weight of the pump, motor and intervention tool is less than 15 tons. A replacement can be done within 24 hours.

System Design with Multiphase Pumps for Flow Assurance

As tieback distances increase and production moves to deepwater, the challenges related to flow assurance escalate significantly. In a development applying subsea process and boosting, the flow assurance risks would be reduced during the normal operation[15]. Multiphase boosting has a positive effect; as it reduces the cooldown and minimizes slugging. Further to this, the subsea separation adds to the hydraulic stability of the fluids flow.

As multiphase pumps are good in handling slugs, it is desirable that field piping, upstream of the pump be modeled using multiphase simulation tools to determine the size and frequency of slugs. Installation of slug catcher downstream of the pump and before any separator is a valid decision. Multiphase pumps are also recommended for transporting well streams from artificially lifted wells to overcome the flow resistance to multiphase stream. Subsea boosting will enable longer tiebacks. Subsea separation could provide an economic alternative for de-bottlenecking existing surface facilities. Subsea gas separation may allow oil and gas to be separated at seabed and transported to different surface facilities allowing better usage of infrastructure[15].

An ongoing and constructive interaction between the field architects and pump designers is a must, as it is vital to understand the complete flow assurance issues, production profile over time and optimize the pump selection and export pipeline configuration accordingly[13].

Higher Ultimate Recovery

Lowering the backpressure gives maximum ultimate recoveries from a reservoir. But this means pressure drops below bubble point pressure early in the life of reservoir and the fluid flow becomes multiphase. No other equipment except multiphase pumps can handle the two phase flow. Thus, the multiphase pumps will be one of the best investments since it will accelerate production, increase ultimate recoveries and will eliminate the footprint of other equipment and facilities (separators, two pipelines, etc.) which would otherwise be needed.

Reduced flaring

Multiphase pumping can, in certain cases of production from more than one source, allow positive choking to achieve stable co-mingled production from several sources, boosting the weaker wells in order to flow with the strong one(s). There may be some cases where the same principle could be applied to co-mingled production from several zones within the same well. It can also enhance the regulatory compliance by reducing flaring. The desired mix of two or more live oils may be governed by multiphase pumping and its associated commercial value in the downstream segment[10]. Mixing different oils while they are being produced or transported is not always feasible due to reasons like source pressure differences. Subsea multiphase pumping brings about the blending of different oils by commingling approach.

Integrated Production Modeling

The primary benefit of integrated modeling is that the artificial and conservative boundary constraints between traditional decoupled models are removed. In conventional developments, this is not much important but as the water depths increase, the direct costs to the facilities of the conservative assumptions have a dramatic effect, for mechanical design and flow assurance performance requirements of flowlines and risers. Integrated production modeling is not necessarily as straightforward as some software developers might suggest. Significant additional effort can be required to set up and run such a model[16].

During the facility concept evaluation and selection phase of most deepwater projects, there is a fundamental decision to be made between wet versus dry trees. Calculating the comparative capital costs is relatively simple, but the real value difference often lies in the projected well intervention costs and predicted frequencies of occurrence. For ultra- and super-deepwater projects, the cost differentials become even more critical to correct concept selection.

Generally a steady state analysis is sufficient. However, when more complex situations are considered, the actual multiphase flow regime may not be stable under all operating conditions and transient analysis may be preferred. Conventional design of production systems took each section of the system and analyzed separately. Each problem would be looked into by an isolated specialist not aware of the big picture. This practice often resulted into conflicts in the design of component systems, poor communication and reactive rather than proactive approach to oilfield operations and reservoir management including the flow assurance issues. Design of whole system from reservoir to downstream process must now be integrated to realize the early production from marginal fields in a competitive marketplace.

3. FLOW ASSURANCE

Introduction

This section carries further the discussion on flow assurance into details. Challenges to flow assurance, importance of fluids sampling and compositional characterization, flow assurance strategies, proactive approach, slugs, solids deposition, and their mitigation are described. Techniques for screening of solids formed out of hydrocarbons, management of waxes, asphaltenes, hydrates and remediation are discussed. Description of pigging, thermal insulation, heating and chemical treatments is given in the discussions.

Flow assurance has been an emerging multi-disciplinary subject addressing the hydrocarbon production from offshore fields. Flow assurance deals with the risks and problems arising from the properties and behavior of the produced hydrocarbons, associated fluids, and solids. The phrase “Garantia de Fluxo” was coined by Petrobras in the early 1990s meaning “Guarantee the Flow”. The field of flow assurance is relatively immature as most of the phenomena in multiphase flow are not well understood yet.

To address to the specific flow assurance problems, there are different flow assurance strategies, including thermal management (insulation, electrical heating and fluid circulation heating), pressure management (boosting, blow down), chemical treatments (various inhibitors, dissolvers, etc), and mechanical remediation techniques (pigging, jetting, cutting, etc.).

Multiphase Flow

Production operations span over reservoir, wells, flowlines, and host facilities. Each element of the system affects performance of the others. Mutual compatibility of all elements is necessary for efficient production operations. Multiphase flow study and behavior prediction is difficult because of changing flow regimes and phase velocity differences. Multiphase flow is transient because of slugging, flow rate changes; blow down, pigging, pumps and compressors, well operations and downstream process operations.

Subsea field development with multiphase transport to the process facility is increasingly being adapted as the preferred concept. For effective flow assurance and operability, the complete system lifecycle including startup, steady state, rate change and shut-in must be considered[1]. An integrated, optimized subsea solution where the benefits of subsea separation, pumping and thermal management are objectively evaluated and implemented, needs a cross-functional approach from project inception to execution.

Flow Assurance Challenge

As oil and gas production moves to deeper waters, the produced fluids need to be transported through longer tiebacks. Deepwater and remote reservoirs means higher pressures, higher temperatures, sand production due to poor consolidation or high drawdown and cooler ambient temperatures inviting hydrates and wax formation problems.

Longer tiebacks are more prone to solids accumulation, scales, and hydrate plugging. These oilfields are thus very high risk yet marginal due to the costs involved and the highly competitive market. Added to this are stricter environmental standards by various governments that prohibit any release of hydrocarbons.

Produced water is a highly significant component of the flow assurance challenge. Complete separation and disposal of water subsea could be the most effective flow assurance strategy. But this may not be the most economic. Thermal insulation and chemical inhibition are currently the

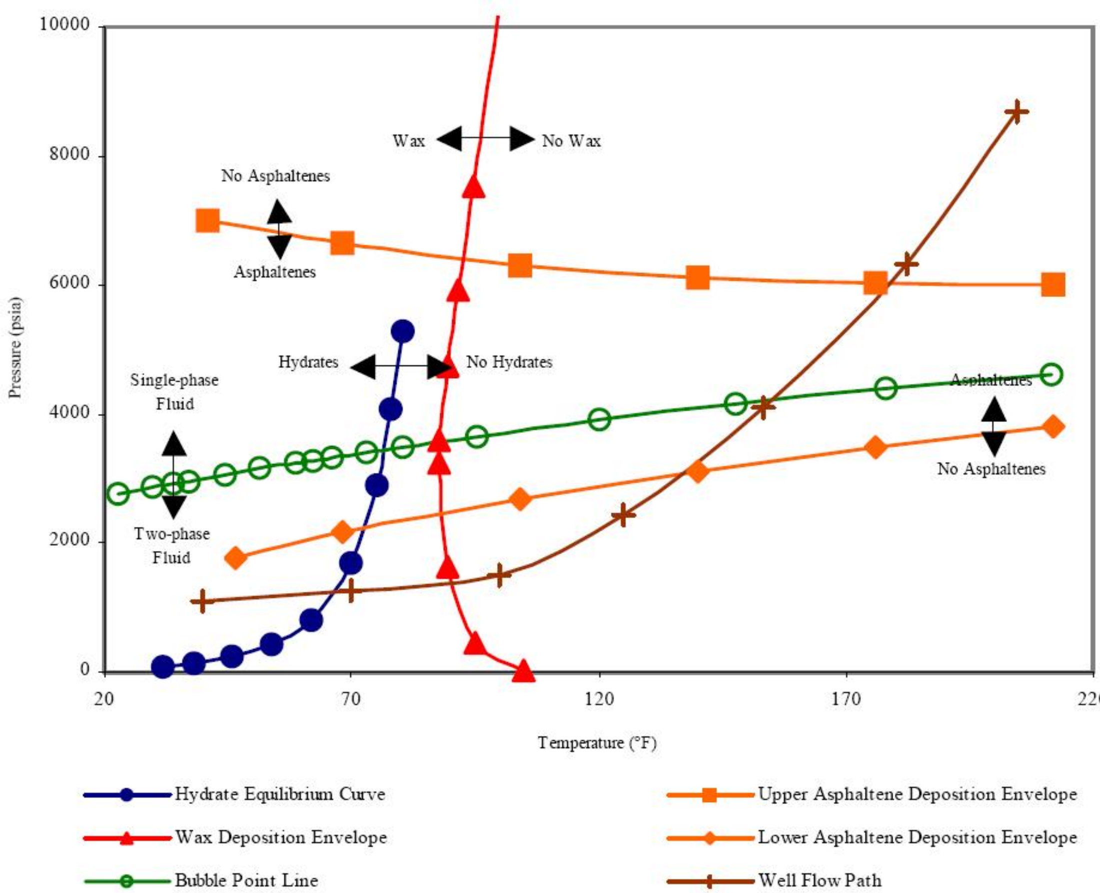


Fig. 7: Asphaltene, Wax and Hydrate Envelopes[17]

most effective yet economic methods. Also, higher the volume of water present in system, the greater will be the dose needed of chemical inhibitors. Toughest deepwater challenges are extremely tall risers, complex subsea systems, and high intervention costs.

Fig. 7 shows the phase envelopes of solids which are the potential flow assurance issues with almost every oilfield. Hydrates and waxes appear in the picture when temperature drops below hydrate equilibrium conditions and wax appearance temperature respectively, which vary with pressure and temperature of the system. It can be observed that asphaltenes can precipitate under wide spectrum of conditions and the well's production path may not have sufficient window of opportunity for production in the absence of a suitable inhibition or flow assurance strategy.

Fluids Sampling

Fluids characterization by thorough testing of real fluid samples under realistic conditions is very crucial. Fluids sampling is the first step in assessing solids formation characteristics. Care while collecting and transporting a sample is essential to prevent irreversible phase behavior since asphaltene precipitation reversibility is uncertain. If the fluids do not truly represent the produced fluids, the conclusions drawn at the end of analysis may not be valid for the system. Sampling of formation water is equally important as the water chemistry has a direct influence on scaling tendency, hydrate formation and corrosion. Availability of a representative water sample for new fields could be a challenge as the wells are initially completed well above the WOC, and the new wells in a new field initially produce with almost no water cut.

A detailed knowledge of sampling tools helps in judging the sampling method so that sample can best represent the reservoir or produced fluids. Drill stem tester (DST), reservoir characterization instrument (RCI), modular dynamic tester (MDT) are some of the sampling tools. The single-phase multi chamber (SPMC) (after Schlumberger) has capability to maintain the sample pressure above reservoir pressure and thereby avoid release of solution gas and precipitation of solids. Obtaining the most representative sample from reservoir and transporting it unaltered to laboratory for analysis is the key to accurate fluid compositional characterization.

Fluid Compositional Characterization

The crude oil may contain a very large number of components. For each component, critical temperature, critical pressure, and acentric factor must be known for predictive PVT analysis of the crude. As it is not practical for thousands of components, it is difficult to fine tune the PVT model in conformance with laboratory PVT analysis.

In the fluid analysis laboratory, the fluid sampler (SPMC) is validated by determining the pressure. The sample is next heated to reservoir temperature and then subjected to continued agitation for a prolonged period to ensure homogenization. A portion of the homogenized sample is subjected to single stage flash to determine GOR, C36+ composition, density, and API gravity. Then the fluid is subjected to gas chromatography. Based on the chromatography results and GOR the live oil composition is calculated. Another portion of the sample is subjected to saturate-aromatic-resin-asphaltene (SARA) analysis. The fraction with boiling point less than 300 ^{0}C is chromatographed for saturates and aromatics content, while the fraction boiling above 300 ^{0}C is analyzed for asphaltene by gravimetric method.

Phase Envelopes

Fig. 8 is a simplified version of fig. 7 for illustration purposes. Fig. 8 illustrates the thermodynamic phase boundaries for potential hydrocarbon solid formation. The production P-T pathway would depend on specific hydrodynamic and thermal characteristics of the production system. Fig. 8 illustrates that the production PT pathway of a system can potentially intersect one or more of the phase envelopes, which means there is a potential for formation of hydrocarbon solids in the system. Crossing the phase envelopes does not necessarily imply that there will be flow assurance problems because formation of the solids does not necessarily mean deposition or blockage.

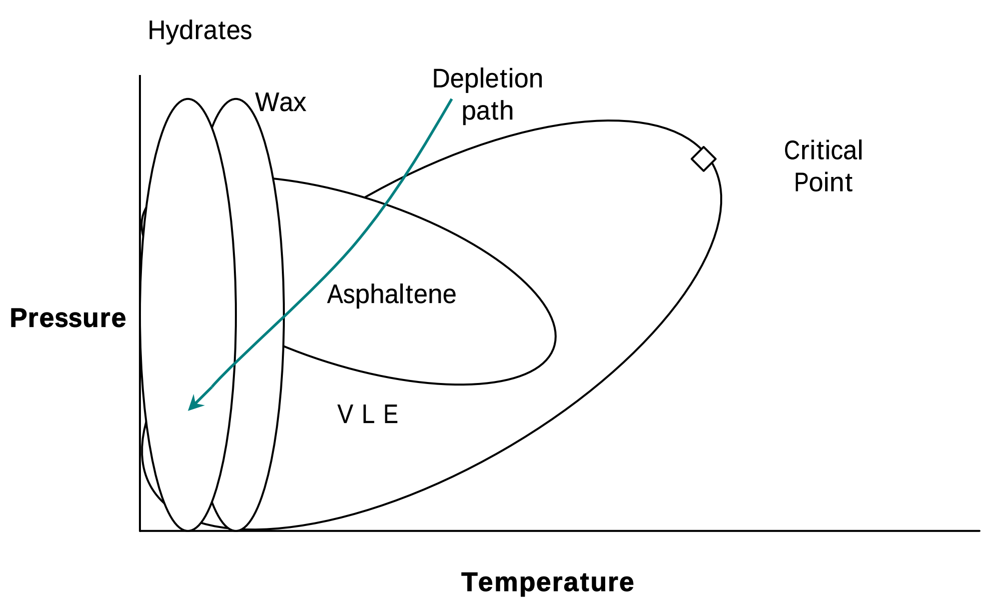


Fig. 8: Schematic Thermodynamic Conditions of Flow Assurance[18]

Flow Assurance Design Strategies

The design for flow assurance can be either robust or adaptable.

Robust Design

The design can take anything unknown and uncertainties. This design is over conservative and typically needs heavy CAPEX. However, the results are not necessarily optimum.

Adaptable Design

This design strategy takes into consideration the changes in reservoir and surface network conditions. The pipelines and umbilicals installed subsea require contingency repair capability. As drilling and workovers become increasingly complicated with increasing water depths, pipelines and umbilicals also become more complicated for deep waters. Their repair capability also needs to be more reliable and accurate.

Proactive Flow Assurance

New technologies are destined to transform the oil industry by enabling remote 3D visualization, 4D seismic, intelligent completions, and smart wells. Downhole pressure and temperature monitoring, sand monitoring with acoustic devices, corrosion probes, and more recently the integrated multi-array subsea sensor capable of measuring metal loss, pressure and temperature, sand and hydrate monitoring with acoustics, solution conductivity and heat transfer characteristics can detect hydrate precipitation, sand production, organic solids formation and deposition, erosion and corrosion. It also helps in determining the real-time temperature profile of the flowline for feeding into process chemistry software to predict the deposit formation[19]. Real-time temperature profile can be obtained by installing optic fiber on the exterior of the flowline and using sensing technology. Fiber optic sensing technology can provide quasi-distributed temperature and pressure measurements.

Integrated real-time flow assurance correlated with modeled simulations helps evolve the optimized intervention strategies and accelerate production, improve expected ultimate recovery, reduce CAPEX, reduce OPEX by reasonable and productive interventions and ultimately make longer tiebacks a reality.

Distributed Temperature Measurement

This technology is based on fiber optics. For the purpose of temperature measurement, the fiber optic carries an intense laser pulse. Fig. 9 shows the scattered light spectrum showing Raman scattering. The light is scattered by molecular and density fluctuations of fiber's glass (Raleigh

Scattering) and by molecular vibrations and rotations of glass molecules (Raman Scattering). The Raleigh scattering is temperature insensitive and the Raman scattering antistoke component is

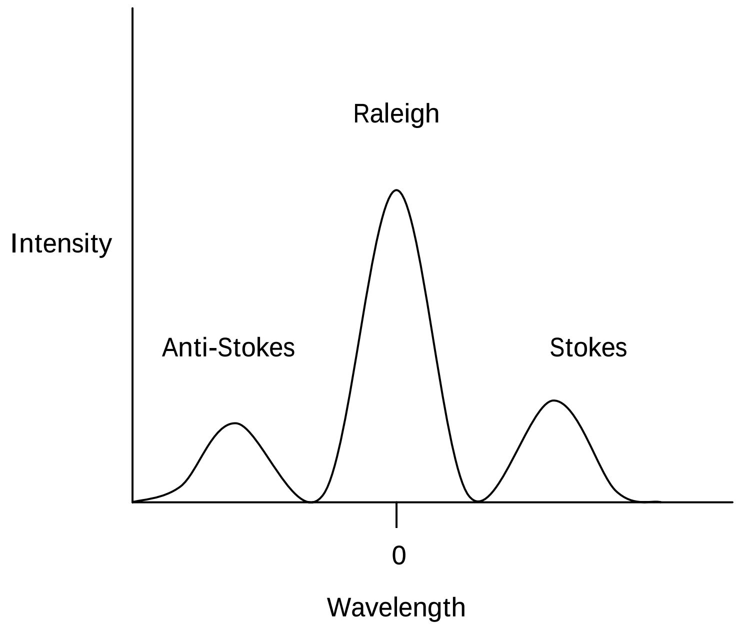


Fig. 9: Scattered Light Spectrum

temperature dependent. Ratio of these quantities is directly proportional to temperature at the location. Location can be determined by optical time-domain reflectometry (OTDR). Thus distributed temperature measurement gives accurate temperatures along the entire length of fiber. Application of this technology has made possible the distributed temperature measurement.

Need for Modeling

Evaluation of the flow assurance issues can help formulate a suitable strategy to mitigate some or all of the problems. Evaluation of potential issues and prediction needs modeling of the entire system from sand face to the host facility and further downstream to process. Modeling offers operators the following advantages:

- Enables safe operation
- Optimizes new and existing systems
- Reduces downtime
- Screening of different options
- Reduces uncertainty

- Describes mathematically what has happened, what is happening and what will happen in a physical system

Table 1 shows a timeline for evolution of different comprehensive predictive tools for flow assurance study and design.

Table 1: Flow Assurance Simulation Tools Evolution

Year	Simulation Tool
1980	SINTEF Multiphase Flow Lab
1980	IFE OLGA Code
1983	SINTEF-IFE
1985	OLGA Compositional
1988	OLGA w/water
1989	OLGA 1.0
1994	PeTra 1
1998	OLGA 2000
1999	PeTra 2
2004	PeTra 3
2006	OLGA 5

Modeling of multiphase production systems needs an integrated approach comprising of the following components:

- Multiphase flow models
- PVT properties
- Hydrate equilibrium
- Wax deposition
- Asphaltene precipitation
- Scale precipitation
- Slug prediction
- Emulsion behavior
- Oil water gas separation
- Sand transport

Flow Assurance Design

At the time of discovery, the oilfield is appraised for commercial viability and to obtain necessary geological, geophysical and engineering information needed for development planning. Design process starts with reservoir fluid analysis and fluid properties modeling. The correlations are then used in thermal-hydraulic modeling of complete production system from sandface to topside, including wellbores, flowlines and risers. The model determines optimum line size and assesses of potential for formation of solids like hydrates, asphaltenes and waxes. After this assessment, the need for thermal insulation is evaluated and chemical inhibitors are assessed for dosing application.

Flow assurance issues must be addressed and incorporated in the design of production system. Characterization of formation fluids is most important step for assessment of flow assurance issues ahead of time. Proper collection and transportation of representative reservoir fluids to laboratories is first step in fluids characterization.

Determination of solid formation boundaries is carried out by asphaltene precipitation tests, wax deposition tests and hydrate formation tests. Result of these tests can be used as input to industry preferred dynamic thermal-hydraulic models like OLGA to investigate and predict system behavior under different scenarios. After adequate investigation, the window of opportunity for operation or “flowing” the system can be determined and operational strategies can be chalked out.

An effort to mitigate and resolve any flow assurance issues by appropriate or optimal design of the system can be devised after the above mentioned stage. From flow assurance point of view, all system downstream of the reservoir is in focus. Thermal management, pressure management, chemical treatment, and remediation options should be incorporated into the system and operational strategies.

Thermal management – hot fluid circulation, direct heating, and insulation can help mitigate wax and hydrate problems. Pressure management – multiphase boosting or depressurization can help in asphaltene or hydrate problems. Chemical management can cover a wide variety of flow assurance problems. Remediation is a reactive technique to solve any severe blockage – coiled tubing intervention, pigging, to name a few.

Slugging

Fluids entering the host process facility are desired to be stable in composition and flow. The process system may get upset or face severe stress if the incoming flow is unstable and fluid composition is drastically varying. As oil and gas production operations are moving to deep waters from shallow waters, the riser lengths have increased from a few hundred feet to over a few thousand feet. After primary depletion, the oil and gas production rates are not stable and water cut is prominently high.

With presence of free gas in liquid (or multiphase) production system, liquids can not be continuously produced. Liquids keep accumulating till the free gas flow is completely blocked and gas builds up enough pressure to "lift" the liquid column through the riser. When this "lift" phenomenon occurs, a large amount of liquid is received at the host process facility. This intermittent bulk of liquid is called slug. Slugs can severely disturb the process or can even force a shutdown. The huge gas bubble following liquid slug has higher pressure than normal pipeline pressure at the receiving end. When this gas enters the system, system can get over pressurized and most of the gas may end up in flare, and is thus wasted adding to the environmental costs.

Length of a liquid slug and size of the gas bubble can be several times the height of riser, depending on flowing GOR and other fluid physical and compositional properties.

Types of Slug

There are three main types of slugs[20].

Hydrodynamic Slugs

The hydrodynamic slugs are formed due to instability of waves at certain gas-liquid flow rates.

Terrain Induced Slugs

They are caused by accumulation of liquid phase and periodic lifting by gas phase in flowline dips. Terrain slugs occur during normal production operations and also after a shutdown.

Operationally Induced Slugs

They are generated by changing the steady state conditions; such as restart, pigging, etc. Slug induced in pigging operation is a challenge for the receiving end of flow line.

Methods to Mitigate Slugs

Subsea Separation

The inputs to the problem of slug are free gas and liquid. If they both coexist in flow and when the riser geometry and pipeline's vertical ups and downs due to uneven seafloor are favorable, slugs can not be avoided, unless very stable flow rates can be maintained outside the slug formation conditions. Subsea separation of gas and liquids can solve the slugging problem.

Topside Choking

By choking the flow at the top of riser, the gas bubble behind the liquid slug will pressurize faster and will push the liquid column more frequently and slower. This will smoothen the slug patterns and the process at the host facility is disturbed to a lesser extent.

Increasing Gas Flow

Liquid accumulation may occur in the riser and pipeline due to insufficient velocity of gas. Gas velocity can be increased by introducing enough additional gas in the stream at the riser base.

Favorable Riser Base Geometry

If the riser geometry can be designed such that there are minimum ups and downs along the seafloor and no depression at the bottom of riser, then the liquid accumulation tendency will reduce and the flow will be smooth overall.

Solids Deposition

The effects of solids formed out of produced fluid hydrocarbon and their potential to disrupt production due to deposition in the production systems are detrimental. The inorganic solids arising from aqueous phase also pose a serious threat to the flow assurance. Fig. 10 shows different locations in a production system where solids can potentially build up either as deposits on inner walls of flowlines or sediments on bottom of vessels and pipelines.

Paraffin Waxes

As oil and gas flowlines move to deeper waters, wax deposition becomes a common occurrence. The cost of remediation or mitigation of wax deposition increases with water depth, therefore avoiding or minimizing the wax deposition becomes a key issue in flow assurance.

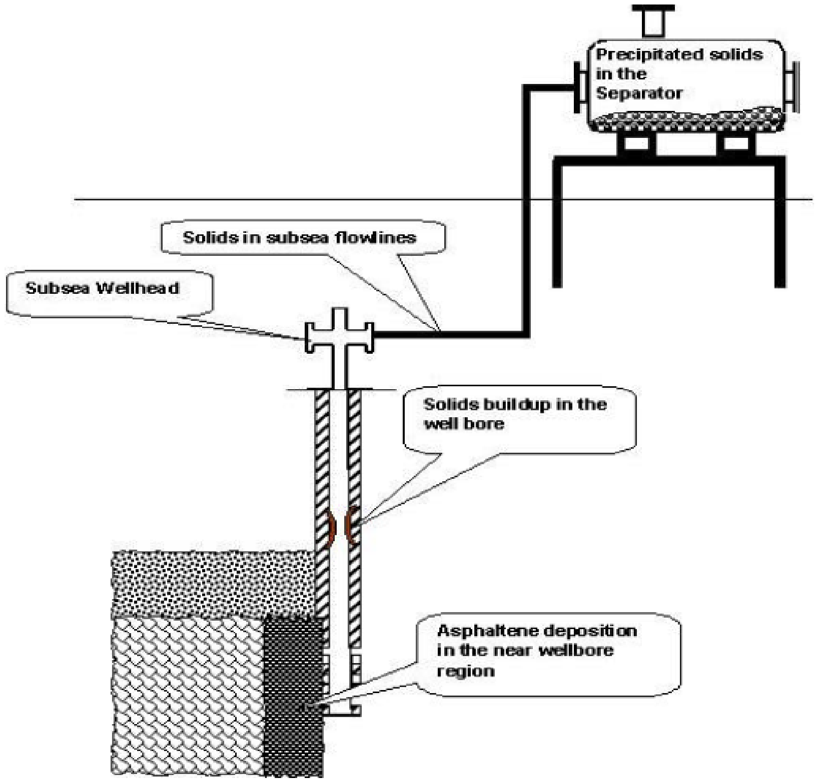


Fig. 10: Solid Buildup Locations in the System[18]

Paraffin wax is a group of straight-chain alkanes that contains more than 15 carbon atoms and has very little branching[21]. One paraffin molecule may have more than 80 carbon atoms. The bigger the molecule size, higher is the melting temperature. Paraffin is deposited in the form of crystalline solids which may collect on the wall of flow line / tubing / pipeline, slowly chocking off the production. In some cases, the paraffin deposits have caused breaking up of the sucker rod pump and in some cases, the paraffin accumulation blocks the formation. Petroleum waxes have been characterized into two categories – macro crystalline (n-alkanes) and microcrystalline (iso-alkanes and cyclo-alkanes). The high molecular weight paraffins present in crude oil are soluble under reservoir conditions.

Waxes are crystalline and are characterized by wax appearance temperature and pour point[22]. The factors affecting wax properties are oil composition, temperature, and pressure, paraffin concentration, nucleating material, shear rate and flow rate. Above wax appearance temperature, wax is soluble in the crude oil.

In all pipelines, fluid cools as it travels downstream due to the loss of thermal energy to the surroundings. When pipeline temperature reaches wax appearance temperature, the wax transports by molecular diffusion. Flow at the center of pipeline is turbulent and the wall is stationery. Precipitation of wax crystals on pipe wall creates a concentration gradient across the cross section. The dissolved wax diffuses towards the wall and builds up into a thick layer over time[23]. The reduced diameter due to wax deposition can still allow the flow of fluids through the pipeline but at a higher pumping cost and less throughput.

The waxy crude fluid dynamics is governed by API gravity, specific heat, viscosity, pour point, and yield stress. Near the pour point region, waxy crudes show non-Newtonian rheology. Under the static conditions, waxy crudes crystallize to form a gel[24]. Partial or complete crystallization of crude oil requires a finite higher start up pressure to initiate flow. Thus prolonged shutdowns can mean higher startup pressures. The pour point depressants incorporate themselves at the edge of growing wax crystal and retard nucleation process eventually forming smaller crystals. The smaller wax crystals have lower gelation tendencies. Chemically, the pour point depressants (PPD) are alkylated naphthenes, alkylated sugar esters, glycidil ester, acrylated copolymers etc. PPDs reduce the pour point, viscosity, and yield stress. Waxy crudes show non-Newtonian behavior below pour point and Newtonian behavior above pour point.

For most reliable wax calculations, measured n-paraffin concentrations instead of estimated concentrations are preferred. Wax appearance temperature (WAT) is very difficult to measure as most experimental methods can detect finite amount of wax. Also calculation of WAT is difficult as it is influenced by the traces of heaviest n-paraffins.

Tang et al.[25] designed a cold disk wax deposition apparatus for measurement of wax deposition rates. This apparatus requires very small amount of crude (115 ml) as compared to conventional loop tests for wax deposition. The tests for determination of wax deposition rates become very simple and fast with this apparatus.

Petrobras R&D developed a versatile wax damage removal method which can safely and efficiently handle wax removal situations[26]. The chemical reaction between two nitrogenous salts in emulsion is exothermic. The quantities of nitrogen and the heat generated promote irreversible fluidization of wax deposits.

Wax control additives (wax crystal modifiers) – typical copolymers are ethylene vinyl acetate (EVA), vinyl acetate olefins, and alkyl esters of styrene maleic anhydrite, alkyl phenols, polyalkylmethacrylates, alpha olefins and polyalkylacrylates[27].

Asphaltenes

The word "asphaltene" was coined by Boussingault in 1837 when he noticed that the distillation residue of some bitumen had asphalt-like properties. Asphaltenes are metallic molecular substances that are found as impurities in crude oil, along with resins, aromatics, and saturates. They are insoluble precipitates of hydrocarbons such as polyaromatics, formed from resins as a result of oxidation.

Little is known about their actual chemical properties, but there are some theories as to how asphaltene molecules are formed and behave. They are presumed to be very large, for example, with molecular weights that can be in the millions. But even this is not certain; as different methods used to derive the weights often yield different results. The chemical structure is, too, difficult to determine and can vary from source to source. Usually, they are composed of oxygen, nitrogen, and sulfur, combined with the metals nickel, vanadium, and/or iron. They are of particular interest to the petroleum industry because of their depositional tendency in flowlines. They continue to be a problem, as their removal is a time-consuming and expensive process.

Normal pressure depletion, acid stimulation, gas lift operations, miscible flooding, etc., are conducive to asphaltene precipitation. Asphaltene precipitation in porous media can cause diffusivity reduction and wettability alteration.

Identification of thermodynamic conditions at which asphaltenes begin to form and their rate of deposition are important in evaluating the flow assurance issues. If asphaltenes are predicted or anticipated, production engineers need to understand the hydrodynamic implications and devise a suitable flow assurance strategy. But their classification depends largely on their behavior in the solvents.

Preliminary Screening for Solids

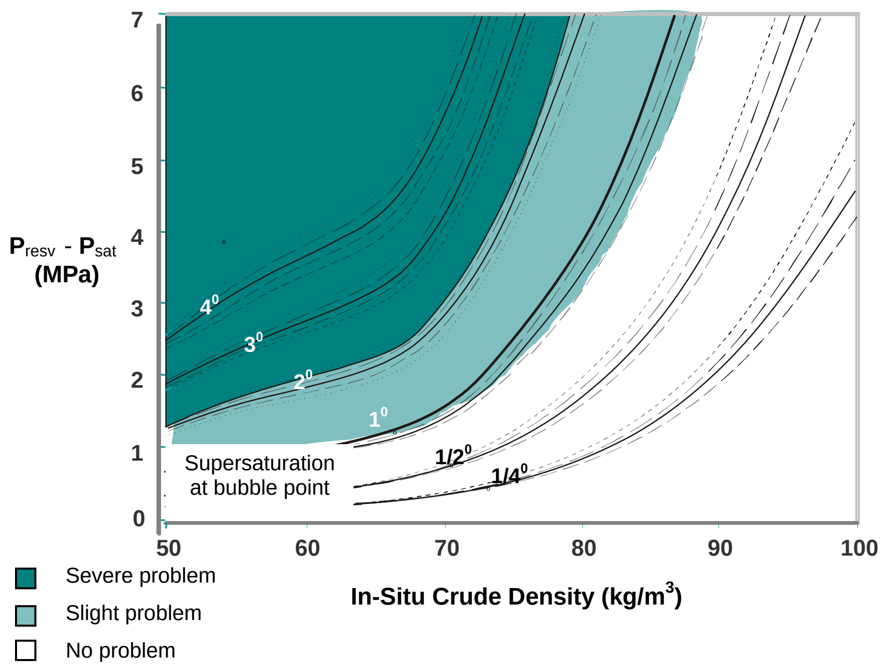


Fig. 11: De Boer Plot

The asphaltenes screening sequence is based on De Boer plot, asphaltenes to resin ratio, colloidal instability index, and asphaltene stability index. Since the reliability of the predictive tools for asphaltene precipitation is not clear, the screening criteria serve the purpose better. Preliminary screening for wax formation includes stock tank oil wax content, cross polar microscopy, wax appearance temperature and preliminary thermodynamic modeling. Fig. 11 shows De Boer Plot. De Boer plot indicates the conditions where asphaltene problem has different degrees of severity. Y-axis shows difference between reservoir pressure and bubble point while X-axis shows the in-situ density of reservoir fluid.

Cross Polar Microscopy for Wax Appearance

In this technique, a drop of homogenized oil sample is taken on a slide at reservoir conditions and kept under microscope to visually observe the wax appearance temperature. Cooling is controlled at very slow rate. The temperature at which first bright spots are observable under microscope is determined as WAT. Wax problem becomes a concern if the wax content is greater than 2 weight % or if the wax appearance temperature is in excess of 120 ^{0}F.

Isobaric Cooling for Wax Appearance

The fluid is charged in a PVT cell and light scattering system is used to continuously record the change in transmittance. The fluid is isothermally flashed and equilibrated at desired pressure. The light transmittance and temperature are recorded continuously. The wax and asphaltene onset behavior is observed to be almost similar at pressures close to reservoir pressure[18]. Running these tests at pressures below reservoir conditions gives more convincing results.

Live and Dead Oil Viscosity Measurements for Wax Appearance

Jamaluddin et al.[18] suggested a method to estimate the oil wax appearance temperature by measuring viscosity at reducing temperature. The reservoir fluid is allowed to achieve thermal and hydraulic equilibrium in an electromagnetic HPHT viscometer. Viscosity is recorded at a series of decreasing temperatures. Fig. 12 shows change in viscosity with temperature. The transition from curvature to straight line on a semi-log scale indicates the WAT.

The WAT is that temperature which changes the rheological behavior of the fluid under decreasing temperature and the results are used to verify CPM results for WAT.

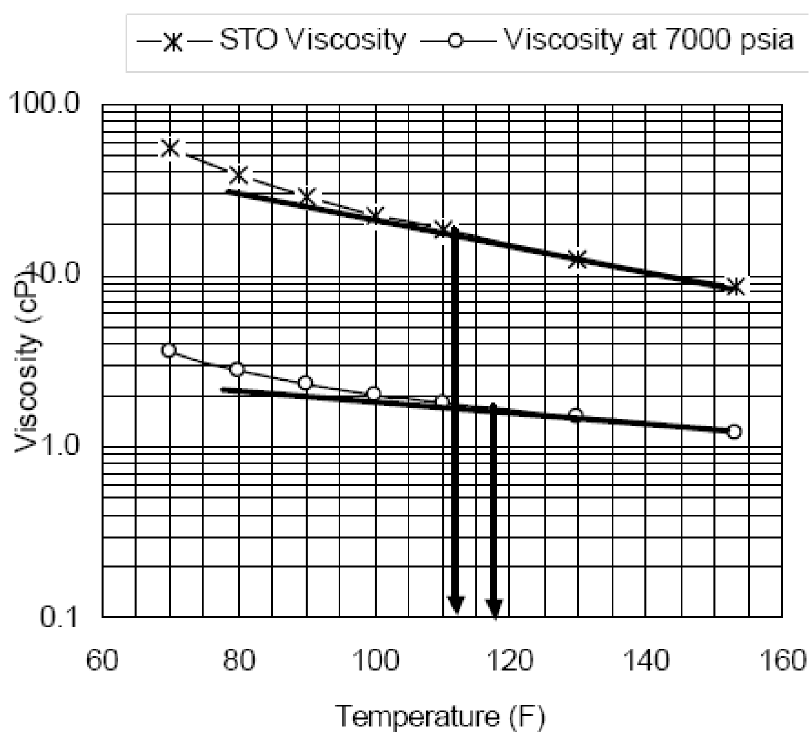


Fig. 12: WAT Measurement Using Viscosity[16]

Experimental Tests for Solid Formation Characterization

Isothermal Depressurization for Asphaltene Precipitation

The isothermal depressurization is carried out using light scattering system, charging a volume of fluid to reservoir conditions in a HPHT PVT cell. Light transmittance scan is used to establish reference baseline. The cell contents are depressurized while scanning. Any change in transmittance characteristic is a reflection of various fluid properties and potential appearance of solids and gas. Also, at the end, rinsing the PVT cell with toluene determines any residual asphaltenes. Contrary to what may seem logical, the asphaltenes have been reported to form even at pressures above the reservoir pressure[18].

Fixed wavelength light scattering gives onset of asphaltene destabilization pressure and variable wavelength light scattering can give more information to understand the asphaltene growth and deposition rate[28].

HPHT Filtration for Bulk Precipitation of Asphaltene

The filtration is maintained through 22 micron filter paper at isobaric conditions close to bubble point pressure by using high pressure helium at downstream side of the filter[29]. After complete displacement of fluid at almost isobaric conditions, the residual asphaltene content is determined. This method gives the amount of asphaltenes greater than particle size of 22 microns. By carrying out this filtration test under different pressures the evidence of change in asphaltene precipitation can be substantiated.

Isobaric Cooling for Hydrate Formation

The fluid at reservoir conditions is transferred into a PVT cell and system pressure is reduced below bubble point to separate the gas phase. Subsequently water is added to the cell and again the system is equilibrated to the desired pressure. Isobaric cooling is started. At onset of hydrate formation, a larger volume of gas enters the hydrate cavity. A substantial decrease in volume of the system is observed during hydrate formation.

A reverse test is carried out to study the hydrate dissociation. There is a difference between hydrate dissociation and formation temperatures due to transient hysterasis. Hydrates are discussed in more details in “Solids Formation and Deposition” section.

Management of Waxes and Hydrates

Hydrates once detected in the system, can be further controlled by thermal, chemical and compositional management. Waxes are also managed by thermal, chemical and mechanical means. Asphaltene removal is mainly achieved by the use of solvents.

Waxy Crude Restart Behavior

Among the flow assurance issues, the gelled oil restart is the oldest one[30]. After a prolonged emergency or planned shutdown, the waxy components of crude oil crystallize and the whole volume of oil inside pipeline becomes congealed. In such a case, to restart the flow, an extra pressure is needed. An accurate knowledge of the restart pressure helps operators control their CAPEX by avoiding the risk of pipeline failure and resulting production deferment. Almost all new and majority of old pipelines are in the areas favorable for crude oil gelation.

The processes that crude oil undergoes during cooling are described as follows: From reservoir temperature where most live oil is liquid, a temperature change occurs where high molecular weight paraffin molecules become unstable and precipitate. This condition corresponds to wax appearance temperature. The oil changes to suspension from liquid. Further cooling causes more wax molecules to precipitate and oil rheology changes from Newtonian to non-Newtonian. Near pour point, the oil starts congealing and for small stresses, the system behaves like a solid. To make it flow it needs stress greater than the critical stress, called yield stress. Uhde and Kopp[30] described the waxy crude cold restart process as:

- Travel of initial pressure wave front down the line
- Yielding of gelled oil
- Breakdown from initial to equilibrium viscosity
- Line clearing

The point at which oil starts gelling is characterized by pour point temperature. At this temperature, wax deposition is enough in oil to begin gelling. Wax gel can form early or after a long time after shutdown depending on fluid chemistry and system thermo-hydraulics. Fig. 13 shows different inhibition and remediation methods for waxes and hydrates.

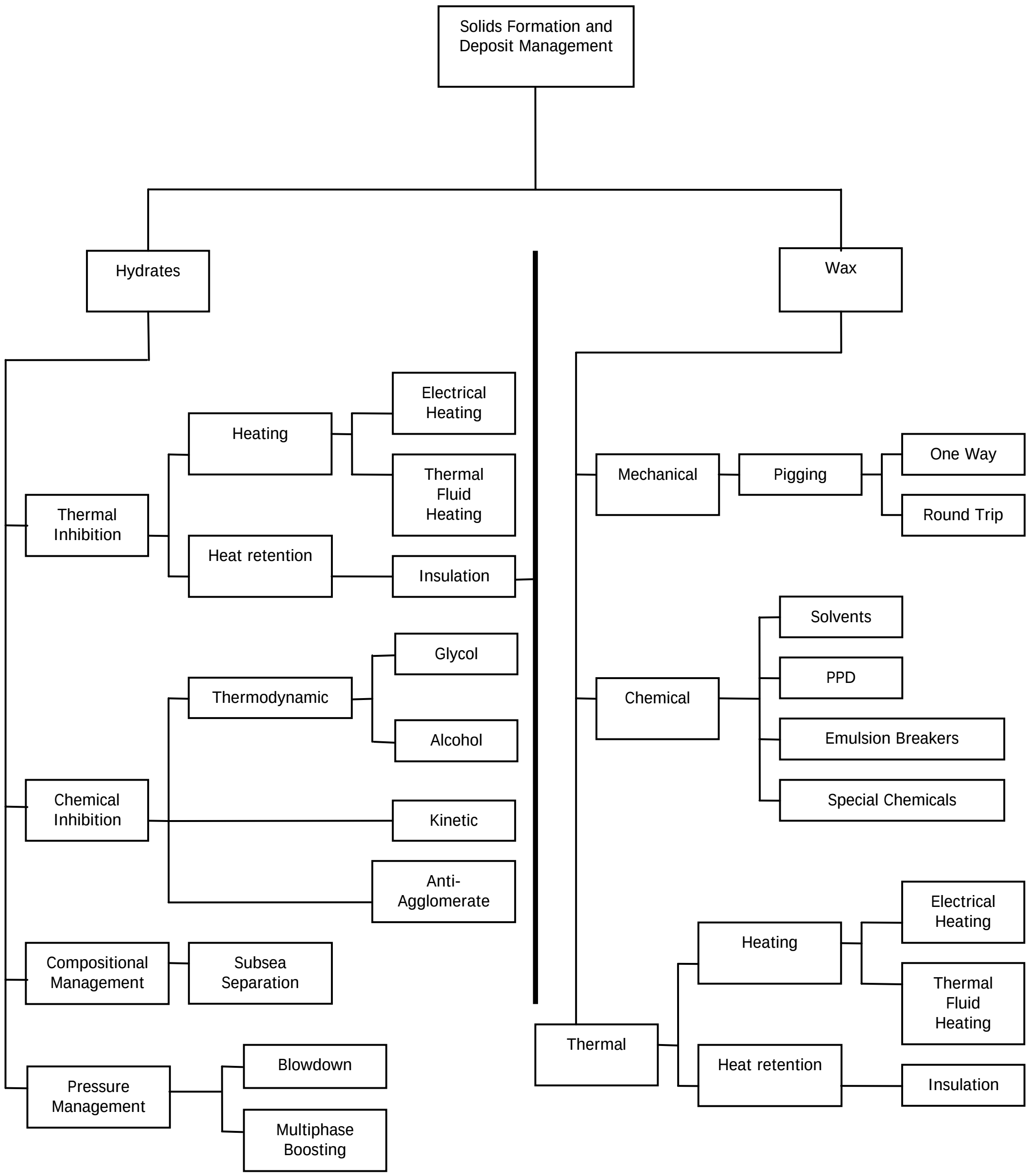


Fig. 13: Management of Hydrates and Waxes

Paraffin Mitigation Methods

The paraffin mitigation methods[21] are discussed below

Mechanical Removal

The typical mechanical removal methods are running scrappers in borehole and pigging in pipelines at some intervention frequency. For deepwaters, frequent intervention is not possible. Pigging is discussed in more details in the blockages and pigging section.

Thermal Methods

The thermal methods include heat retention, active heating and use of suitable exothermic chemical reactions. Thermal insulations, bottomhole heaters, hot oil circulation, steam circulation, and on demand “intervention” heating are appropriate for deepwaters.

Chemical Treatment

Chemical treatment includes the use of solvents like produced condensate, xylene, toluene, benzene, carbon tetrachloride, trichloroethylene, perchloroethylene, carbon disulphide and terpenes. High specific gravity is an important factor that will help solvents penetrate and dissolve the paraffin deposition typically on bottom of the flow-section. Some of the solvents mentioned above are problematic - chlorinated hydrocarbons cause poisoning of downstream process, aromatic solvents have low specific gravities and it is difficult to use them on the well bottoms, they also have low flash points and handling becomes difficult, while carbon disulphide is highly effective but is very highly flammable with toxic fumes.

Use of Dispersants and Detergents

These chemicals cause paraffin molecules to repel each other and metal surfaces. Naturally occurring asphaltenes sometimes can act as dispersant.

Crystal Modifiers

They are polymeric materials which prevent paraffin deposition by disrupting nucleation, cocrystallizing. The crystal modifiers are effective in limited types of crudes. Commercially they are called pour point depressants.

Asphaltene Inhibitor Treatments

The asphaltic crudes are known to occur worldwide. Various flow assurance problems are associated with asphaltene precipitation and deposition[31]. The recent industry experience shows that inhibition rather than removal of asphaltene deposits is more cost effective. The typical return for every dollar invested in inhibition can be in the range from $9 to $33 [31]. The inhibitors peptize the asphaltenes in a manner similar to naturally occurring resins and keep them in solution. Since the inhibitors are synthetic, their composition is further optimized in laboratory to optimize the performance to suit typical crude. Thus, the inhibitors prevent the destabilization and deposition of asphaltenes over a broad range of pressures, temperatures and shear conditions.

Production Chemicals

Oil and gas production comes by flow. So, essentially, all oil and gas production operations are directly or indirectly the flow assurance activities. For ensuring "flow" i.e. production, various chemicals are used in the entire system. The most common objectives of using chemicals are prevention of corrosion, scales, wax deposition, hydrate formation, asphaltene deposition, bacteria control, demulsification, oxygen scavenging, and gas sweetening.

Chemical treatments can be applied at topside, subsea or downhole. Any chemical injection system must be designed to be effective, reliable, forgiving and redundant. Chemical injection in conjunction with system design can maximize the production capacity of the system[17]. Fig. 14 shows the types of chemical treatments for different flow assurance issues in oil and gas industry.

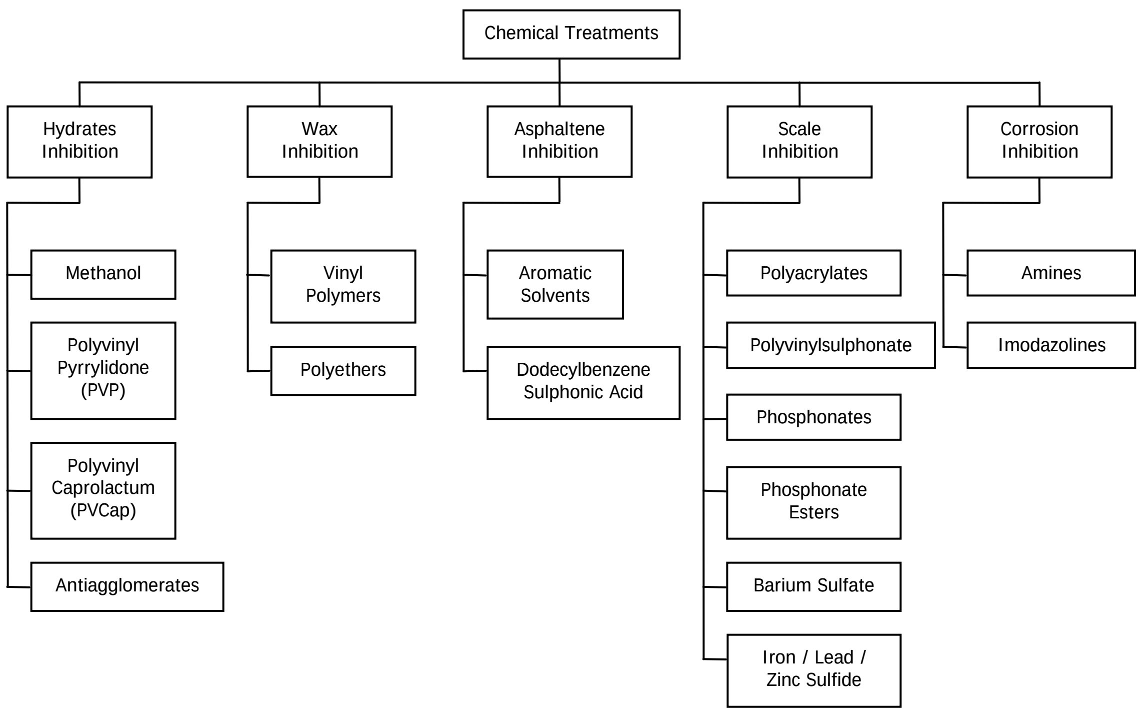


Fig. 14: Various Chemicals Used in Oil and Gas Production Operations

The recommended chemicals, produced fluids, completion fluids, and hydraulic fluids should be screened for mutual compatibility[17]. No unforeseen solids, emulsions, foams, etc should be encountered when chemicals enter the system. The chemicals also should not change the calorific value of the hydrocarbons and should not cause any harm to the environment when discharged overboard through produced water.

Blockages and Pigging

Early detection of pipeline blockages is the best strategy for more effective pigging[32]. Early knowledge of location and severity of pipeline blockage enables the operator to take more informed decision on pigging operation strategy. This is possible by determining the number of flow constrictions that exist.

In locating the blockages the principle used is pressure transient initiated by shortly altering the mass influx at the inlet. The transient propagates in pipeline and is partially reflected back at blockage. The reflection propagates back to the inlet upstream and results in pressure variation. The monitoring of these variations yields information useful for analyzing the blockage location and severity.

Modern methods for blockage detection are gamma ray absorption scanning of pipeline and distributed pressure / temperature monitoring. Gamma ray absorption pipe scanner can accurately identify the location and severity of blockage due to solids formation and deposition but it does not give continuous information. Radioactive source usage keeps this technology on a shelf of not so popular ones.

Fiber-optic (distributed measurement) pressure and temperature data can identify the blockage location and severity based on pressure drop monitoring. It can give continuous real time information and based on which, the chemical inhibition strategy can be optimized. The most demanding requirement of this technology is that, fiber-optic cable must have an interface with flowing stream inside the flowline. Construction of this capability in a pipeline becomes a specialized job.

Paraffin and produced solids are handled with pigging. Pigs include poly, scrapper, foam, gel, etc. used solo or in combination with other types. If pigging is frequently required in long subsea pipelines, then subsea pig launchers may be needed. Depending on the frequency of pigging operation, launcher with multiple pigs held ready may be required to avoid frequent ROV trips for loading and launching the pigs. Pig travel velocity can be increased when it has crossed the constrictions.

Pigging is a mature technology. With new smart pigs, it is possible to internally “log” a pipeline for sites of solids deposits, wall thickness, corrosion, flow rates, and temperature data. This information helps in talking the corrective actions.

On the down side, pigs sometimes can get stuck due to heavy deposits, odd constrictions, and other mechanical reasons. Retrieval of a stuck pig may even require a major intervention or shutting down of a pipeline. Pigging of large diameter and long distance gas lines is easier compared to pigging of similar line carrying heavy crude, as later have more probability of getting the pig stuck. Pigging operation also causes gigantic slugs and arrival of slug at host facility or terminal can even throw everything out of control if adequate capacity for slug handling is not available or designed. Pigging also needs pipelines to be strong structurally. Subsea pig launching is relatively a new technology.

Plugging While Pigging

Aidan[23] suggested the mechanism of pipeline plugging while pigging-wax is scrapped off as pig travels, scrapped wax accumulates downstream of the pig, wax accumulation gets harder as oil is squeezed out, finally when the accumulation of wax grows enough in mass that friction exceeds the force available due to pressure upstream, the pipeline gets plugged.

To avoid such an accumulation ahead of the pig, there should be something which will keep the scrapped wax mass continuously flowing and clearing from the path of pig. This is possible if a suitable port is built into pig which will allow desired fluid flow to carry away the scrapped wax. Size of this port should be optimum as too small size will have insufficient flow to carry away the scrapped wax and too large size will divert all flow through the port and pig may completely stop moving[23]. Bypass flow through the port should be sufficiently greater than rate of wax removal ahead of pig.

Importance of Transient Behavior

No insulation is perfect. Whatever the amount of CAPEX for installing the best possible pipeline thermal insulation system, all pipelines are going to cool down in the event of unexpected prolonged shut downs. The transient behavior of the system becomes important as water depths increases.

Thermal Insulation

The revenue loss, risk from hydrates formation, paraffin accumulation, and adverse fluid viscosity effects due to low temperatures can be minimized with effectively insulated flowlines. The heat retention characteristics are quantified by the heat transfer coefficient U_n [33]. Radial heat flow is give by the following equation

$$q_h = U_n A_n \left(T_{CL} - T_{amb} \right) \tag{1}$$

where, q_h is heat flow rate, U_n is overall heat transfer coefficient, A_n is surface area, T_{CL} is centerline temperature, and T_{amb} is ambient temperature. The desirable U_n values are in the range 0.1 – 1.0 Btu/hr-ft^2-^{O}F [33].

Insulation Materials

The oil and gas industry uses polypropylene, polyethylene and polyurethane as insulating material for pipelines. Table 2 shows the thermal conductivities of different insulation materials.

Table 2: Thermal Conductivities of Insulation Materials

Insulation Material	**Thermal Conductivity (Btu/hr-ft^2-^{O}F)**
Polyethylene	0.20
Polypropylene	0.13
Polyurethane	0.07

These materials are used in different combinations and configurations to insulate the pipelines resulting in composite thermal conductivities ranging from 0.07 Btu/hr-ft^2-^{O}F to 0.13 Btu/hr-ft^2-^{O}F.

The insulation material is further broadly classified into two types – dry insulation and wet insulation. Dry insulations need a protective covering which will prevent the ingress of water when system is submerged for subsea applications. Wet insulations need no barrier to prevent water ingress or have no effect or degradation even when water enters and stays in the material matrix. The examples of dry insulation are mineral wool, fiberglass, extruded polystyrene, polyurethane foam, etc. The examples of wet insulation are polypropylene, polyurethane, syntactic polyurethane, syntactic polypropylene, etc.

General Requirements for Insulation Selection

Flow assurance analysis is necessary prior to the selection and configuration of pipeline insulation. This may include:

- Flash analysis for hydrate formation temperature.
- Thermal-hydraulic analysis along the entire length and route of pipeline.
- Heat transfer analysis for determination of type and thickness of insulation along the pipeline.

- Transient heat transfer analysis and development of cool down curves to assess the risk of blockage due to potential hydrate formation or wax-gelling.

Pipe-in-Pipe is a flowline concentrically positioned inside a protective jacket pipe and annulus filled with polymeric foam of low density, particulate insulation or vacuum. They are simple and economic to fabricate and strong enough for unlimited depths. Pipe-in-pipe insulations are suitable for pipelines producing from HPHT formations in deepwaters. The outer pipe is generally called carrier pipe and it can house multiple lines apart from production flowline such as control lines, chemical inhibitor lines, and power cables. Insulating all the lines together is more economic than insulating each line individually. Dulang field, Malaysia, Seahorse and Tarwhine fields, Australia, and Mobile Bay flowline system are examples of pipe-in-pipe applications.

Non-Jacketed Insulation Systems do not have protective outer pipe. The insulation coated on the main flowline should be strong enough to withstand the hydrostatic head and other forces due to water currents, subsea installation process, etc.

Syntactic Insulation coating has an elastomer, polyurethane, or polypropylene matrix with hollow microspheres distributed. The concentration of microspheres in the matrix and their strength can be designed to suit the application requirements. Typically, syntactic foams are used for high pressure applications.

As insulation foams have tendency to “creep” excessively at high flowline temperatures, they can be combined with syntactic coatings to form multilayer insulation with alternating layers of syntactic and foam material.

The elastomeric coatings for flowlines could be promising as they are strong at depths up to 3000 ft and stable at temperatures up to 300 ^{0}F.

The insulation in wellbore is also one concept to raise the wellhead temperature[34]. The possibilities are multilayer thin film insulation coating and low thermal conductivity completion fluid. When gas temperature used for gas lift in insulated wells is high enough, heat loss can be minimized and wells can flow above WAT beyond wellhead.

Heating

Flowlines without active heating will eventually cool down during a shutdown. The vertical temperature distribution of sea water (Fig. 15) explains the reason for rapid cool down of pipelines. The heating systems should allow the fluid temperature inside the pipeline to stay above WAT during normal flow and should also be able to heat the fluid reasonably fast after a prolonged shutdown planed or unplanned.

Operators prefer to have least trouble restarting the flow after a shutdown. Call-out electric heating similar to Nakika field in Gulf of Mexico is one example[35].

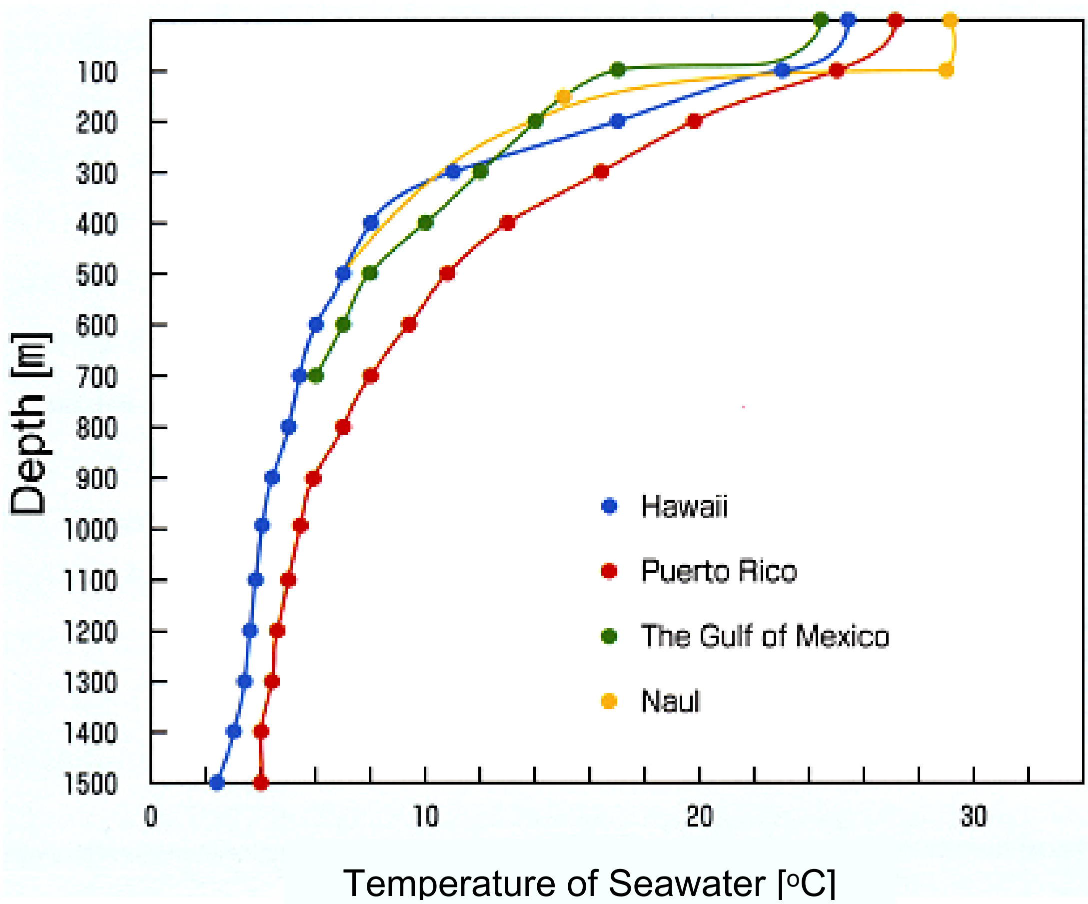


Fig. 15: Seawater Temperature Gradients[36]

Heated bundles are of two types[37] - electric heating and heating by thermal fluid circulation. Electric heating needs a large amount of power, subsea electric connectivity, and footprint for power generation. However, there are several success stories of thermal fluid circulation heating.

To investigate the effect of change in heat loss characteristics of a system, a simulation study was carried out. The parameters of production system and reservoir fluid are shown in table 3.

Table 3: Production System and Reservoir Fluid

Reservoir pressure	5000 psi
Reservoir temperature	200 ^{0}F
GOR	350
Oil API	20
Water cut	0%
Well depth	10000 ft
Tubing ID	4.8"
Flowline	8", 10 miles
All risers	8", 360 ft
Surface temperature	60 ^{0}F
Liquid PI	2 stb/d/psi

Fig. 16 shows a flow diagram of simulated flow loop.

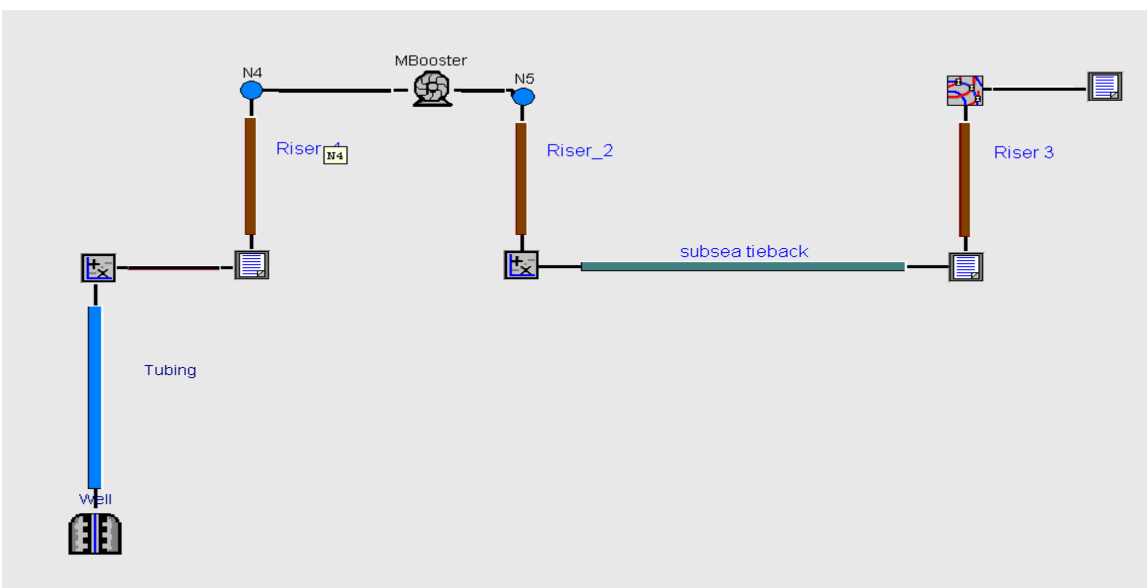


Fig. 16: Flow Model Schematic

The seabed temperature is 200 ^{0}F. Using a twin-screw pump with nominal capacity of 2000 m^3/h, simulations run show that the burial of tieback will prevent heat loss. This can improve deliverability by about 1000 stbo/day if the pressure at host facility is around 250 psig.

Fig. 17 shows that the deliverability of a well can be improved if the flowline going to host facility is thermally insulated. Better insulation means better retention of pipeline heat and hence better flow assurance leading to a higher deliverability.

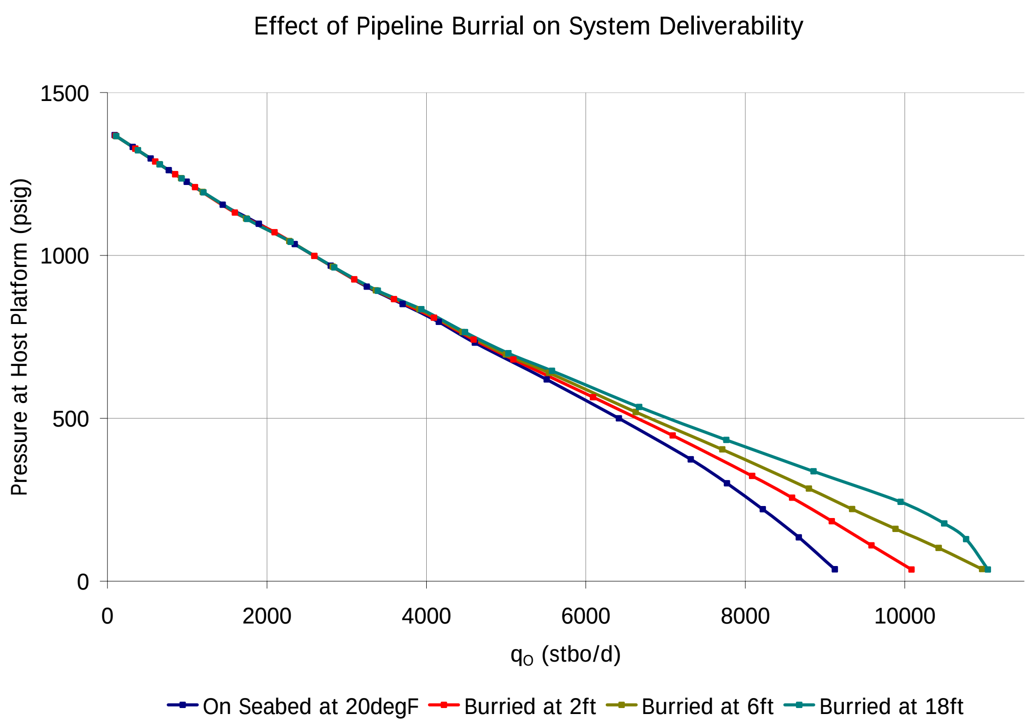


Fig. 17: Deliverability Affected by Cooling Effect of Pipeline

Pipeline Configurations for Heating

Pipeline with Insulation Coating

In this insulation configuration, the pipeline is coated with thermal insulation material. This option can not keep the oil flow above WAT for long even if the upstream feed is actively heated.

Insulated Pipe-in-Pipe

In this configuration, the annulus between two pipes is filled with an insulation material. The insulated pipe-in-pipe can keep the temperature of the system temperature satisfactorily within acceptable range but again for prolonged shutdowns, the system will not stay above WAT for long. This calls for active heating.

Pipeline Bundle with Hot Fluid Flow in the Annulus

This configuration has thermal fluid in the annulus between two pipelines. Thermal fluid is heated with external heat and circulated through the annulus. Circulation has two alternatives – co-

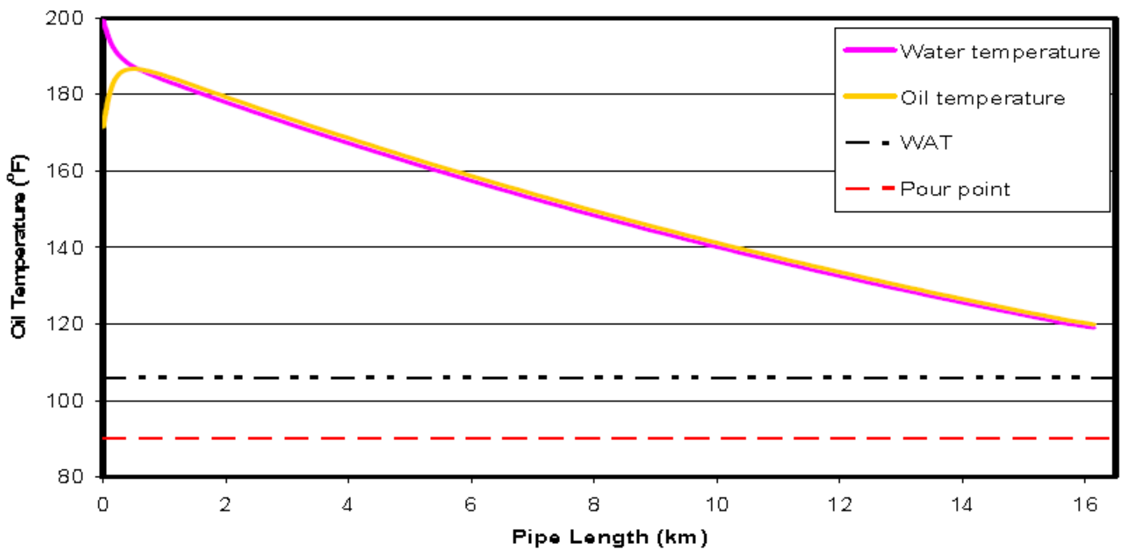


Fig. 18: Co-Current Flow of Heating Fluid[37]

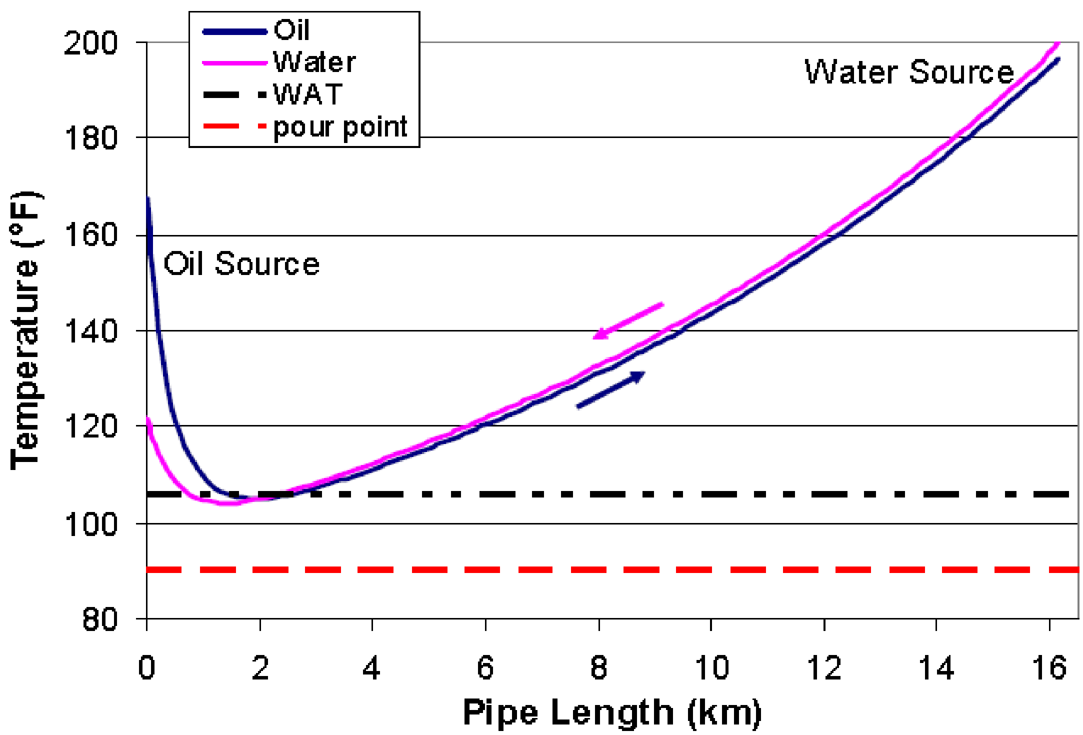


Fig. 19: Counter-Current Flow of Heating Fluid[37]

current flow and counter-current flow. Fig. 18 and fig. 19 illustrate the performance of co-current and counter-current hot-fluid flow bundles. In the illustrated case, the co-current flow of heating fluid (generally water) performs better than counter-current flow in keeping the whole system above WAT[37].

Overall performance of thermal fluid heating in the annulus depends upon various factors like pipeline length specific heat content of the fluid, specific heat content of fluid being transported and ambient temperature.

Pipeline Bundle with Annulus filled with Glycol and two or more circulation lines inside for thermal fluid circulation and cold fluid return is one type of configuration. This configuration has no benefit over the concentric pipeline bundle and the construction cost is higher.

At the locations where flowline route has substantial highs and lows to trap gas, the release of all the gas even with complete blowdown is not possible. In such cases, the hydrate problem becomes tough to resolve without direct heating options. Direct impedance heating can save up to 30% in investments as compared to PIP[38].

Subsea Processing

The main drivers behind subsea processing is reducing or eliminating the need for surface structures, reducing personnel exposure to the HSE hazards, increasing flow rates and maintaining them for longer period with higher expected ultimate recovery.

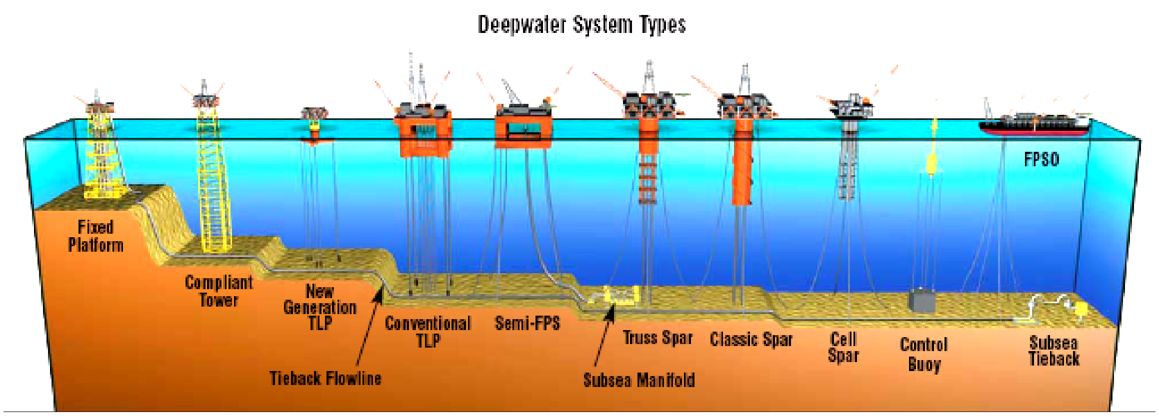


Fig. 20: Offshore Systems[5]

Fig. 20 shows the different types of systems for offshore oil and gas production activities. With increasing water depth, the need to minimize structural costs arises. This concern is taken care of by structures like TLP, FPS, SPAR, FPSO and subsea technology.

Downstream flow assurance problems are minimized if the crude is processed close to wellhead. Subsea processing equipment should be simple, reliable, and capable to continue working with minimum intervention. Adoption of this technology for field applications has been slow. Although multiphase pump systems are simpler than subsea separation, they can not pump wet gas (98 – 100 % GVF) for long time. Subsea separation overcomes these problems. Separation of water significantly reduces the power consumption. By separating gas from water, hydrate formation problem can also be mitigated. Apart from being costly, subsea separation is not considered reliable.

Subsea separation, if reliable and successful, will give the following benefits:

- Reduced backpressure on the well
- Improved boosting efficiency by separating gas and liquid
- Reduced multiphase flow losses
- Reduced accumulation of sand in pipeline
- Reduced slugging problems at host facility.

In mitigating the hydrate formation problem, a three phase subsea separator can be more effective than a two phase separator[39]. Typically, separators on the surface or subsea are prone to sand accumulation, paraffin buildup, emulsification of liquids, and foaming. The performance of separator is further wellfluid specific. Certain components in separators like level sensors and controllers are high risk items as they can fail most frequently.

Operability

The method to operate and coordinate with flow assurance requirements is known as operability. Design and operation of production systems must consider the entire system from reservoir to export, all possible modes of operation: startup, normal production, shutdown and restart, non routine operations like well testing, pigging, etc. over the entire life of development. The operability design may include the following steps:

- Developing the preliminary operating strategies / philosophies
- Determination of process equipment, pumps, and storage tank
- Developing the operating envelopes for given system design (maximum to minimum temperatures, pressures, rates, etc)
- Consideration of non-routine operations
- Chemical dosing strategies – rates and durations

Flow Assurance – Operability and Risk

The investigation of different issues regarding pipeline sizing, routing and layout is possible with steady state tools. But the operability analysis like slugging, start-up, shutdown, ramp-up, choke down, pigging and blowdown needs to be investigated using dynamic tools. Operability analysis helps:

- Minimize CAPEX and improve the flow assurance
- Remove unnecessary conservatism and minimize uncertainty with
    - Reservoir and production profiles
    - System performance and deliverability
    - Fluid composition and properties.
    - Solids formation and blockage potential.
- Optimize the solution.

Drag Reducers

They are long chain, ultra high molecular weight polymeric compounds. The typical molecular weights are 1 to 10 million. When pipeline flow is turbulent, the cross section is divided into three regions – laminar sublayer, buffer region, and turbulent core. Laminar layer tends to be stationary while turbulent core is moving fastest. Because of a wide difference in velocities, the buffer region experience turbulent eddies. This activity "draws down" the hydraulic energy of the stream and upstream end gets additional back pressure.

With concentrations of order of a few ppm, drag reducers suppress turbulent eddies in buffer region and hydraulic energy is better utilized in moving fluid instead of overcoming "random drag". The use of drag reducers can reduce frictional pressure drop by up to 70%. Difference in frictional pressure drop with and without the use of drag reducer is known as drag reduction.

A marginal development does not mean marginal engineering; the level of efforts needed is much greater in early stages of engineering!

4. MULTIPHASE PUMPING

This section discusses the conventional and modern production systems, multiphase pumping technology and it's superiority over single phase pumping, types of multiphase pumps, performance characteristics, costs, operational and location considerations, suitable cases for application and potential improvement in flow assurance.

Modern Production Engineering

The productivity index (PI) of a well is defined as flow rate delivered at sand-face per unit drawdown and is denoted as J.

$$J = \frac{q}{(p - p_{wf})} \tag{2}$$

where, q is flow rate, p is reservoir pressure and p_{wf} is bottomhole pressure.

And also,

$$J = \frac{kh}{141.2 B_o \mu \left[\ln\left(\frac{r_e}{r_w}\right) + s \right]} \tag{3}$$

where, k is permeability of formation, h is payzone thickness, μ is viscosity of oil, r_e is reservoir radius, r_w is wellbore radius and s is the skin factor.

To improve the production under given conditions, petroleum engineers have only limited variables with which they can play. The options are well bottomhole pressure reduction, wellbore skin reduction, stimulation, and in some rare cases reduction of oil viscosity in situ by miscible flooding, microbial treatment, or some thermal recovery method. It is not practical to increase the drawdown by increasing reservoir pressure although water flooding or gas injection is implemented for reservoir pressure maintenance. The bottomhole pressure reduction is possible with reduction of backpressure by subsurface artificial lift or surface pressure boosting by adding energy to the stream. Fig. 21 shows the effect of backpressure on the flow rate of a well.

For deep waters and long offsets, the challenge is to engineer a system that can reliably deliver fluids from deep waters over long offset distances to the host process facilities. For this reason, "delivery" rather than traditional "production" is more appropriate term. The current record for maximum tieback lengths for gas developments is 120 km and for oil/gas developments is 65 km[1]. Depleting onshore reserves and economics is bound to force E&P business to move further deep and further long. A recent review shows that over the next few years, more than 250 new offshore developments, 80% in shallow waters for small developments and 20% in

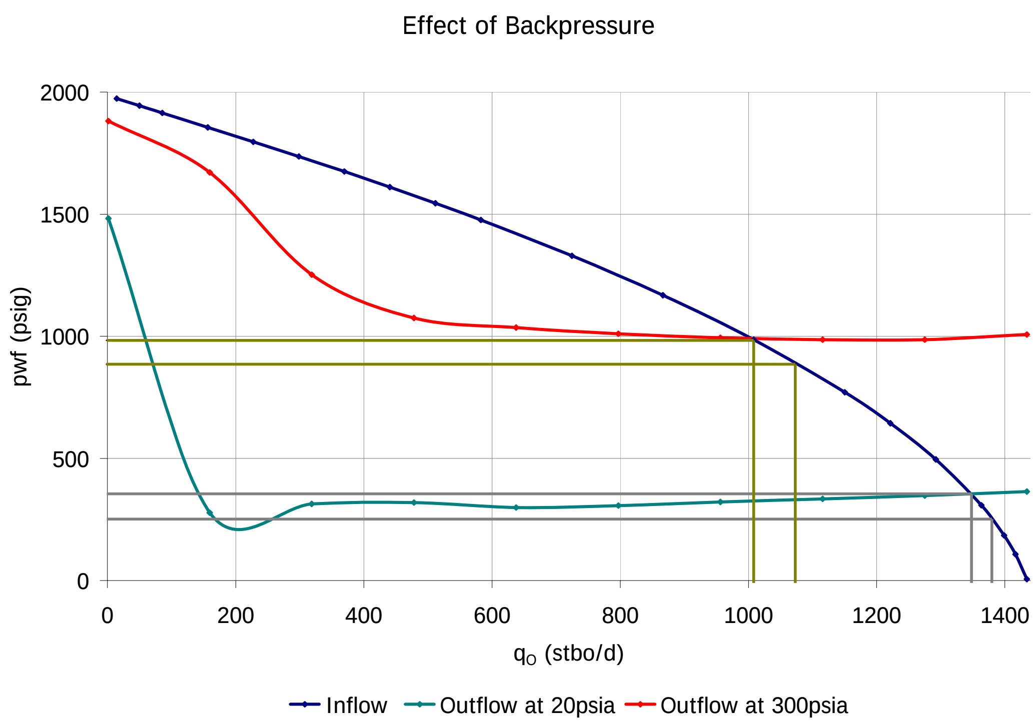


Fig. 21: Well Performance at Different Backpressures

deep and ultra-deep waters for large fields[40] are coming up. The application of subsea compression and separation in shallow water fields is increasing and this requires incorporation of the subsea boosting capacity in the network to tieback production to existing platforms. The platforms continue to supply energy for subsea process and boosting.

For successful development of long distance delivery systems (LDDS), the industry needs successful design and operation of subsea multiphase production system. There is a need to evaluate entire system from the reservoir to export[1]. The system designers need to consider reservoir characteristics, production profiles, produced fluid properties and behavior, design of system components and operating strategies.

The conventional boosting technologies can tolerate only trace amounts of gas in liquid. Multiphase boosting is the most popular modern technology which is helping develop oilfields throughout the world without conventional large investments for facilities upstream to main stabilization unit. With multiphase boosting, it has been possible to add energy to the untreated wellstream and reduce the well bottomhole pressure to improve delivery.

Artificial Lift

If the bottomhole pressure in a well is sufficient to push the liquid to surface and produce at a commercially viable rate, the well is "self flowing". In cases where additional energy needs to be added to the column to make the well produce the well is said to be on "artificial lift". Artificial lifts are of several different types – mechanical lift, for example ESP and hydrodynamic lift for example gas lift. ESP lifts liquid up the column by mechanical pumping, whereas in the gas-lift, gas is injected into the liquid column in well to reduce the mixture density and "lift" up.

Properly applying the artificial lift is a cross functional process that relies on understanding hydraulic, mechanical and electrical basics. Decision-making will depend on the experience and technology. Even when oil prices are low, installing artificial lift or switching to a different lift system can increase oil output and economic return. Therefore, it is important to minimize the well interventions and deferred production, reduce installation costs and operating expenses, and decrease failure frequencies. Relative performance is one key measure for artificial-lift systems. Higher efficiency or lesser failures does not make any system better. The systems that will give maximum NPV can be called the best ones. The lift methods should be monitored continuously to optimize the well performance. The monitoring systems that provide real-time data to help operators make decisions are essential. These systems use surface and downhole measurements to determine if problems exist. In high-cost areas, the use of these data in reducing or eliminating the failures justifies monitoring system investments. Once there is confidence in this approach, the industry will move towards closed-looped automation and will use computers to make real-time operational decisions.

Multiphase Pumping

The mid eighties and nineties saw the first multiphase pumps as a means to boost the untreated well streams. It was followed by successful trials around the world. Of all the subsea process technologies, multiphase boosting is comparatively most mature. Potentially, the multiphase boosting reduces the number of wells required for field development[15]. Typically, the reservoir pressure in a field development applying subsea process will be very low as compared to the conventional subsea development (wet trees + surface process).

Today, several pump manufacturers offer their multiphase pumping equipment in increasingly demanding and competitive oil industry. Multiphase pumping is a proven technology that has consistently demonstrated its importance under different operating conditions. The increasing use of this new technology prompts the need to understand the interaction between the reservoir, well, and the surface networks involving multiphase pumps. The reservoir, well and surface network conditions change continuously throughout the life of the oilfield. Start-ups and conditions like unplanned shutdowns may change the working conditions for a multiphase pump. The pumps need to be designed for widest anticipated operating conditions and capacities within economic limits.

Till a few years back, majority of the surface tests for multiphase pumps involved testing only with water or oil. But now the time has arrived when everyone have realized the importance of testing these engineering marvels underwater and under the multiphase flow regimes involving gas volume fractions.

As the name suggests, multiphase pumps boost the fluids containing more than one phase. It means they are capable of handling and boosting the fluids without going for liquid gas separation thereby saving on footprint and CAPEX. Petrobras have reported a reduction in onboard equipment, decreased energy demand, reduced gas flaring, and a lower operating noise level by switching over to multiphase pumping in Campos basin[41].

Subsea boosting has a significant impact later in the field life to maintain the flowing pressure and produce at the plateau for a longer period of time[15]. Subsea boosting may eliminate the need for gas lift and other artificial lift when reservoir has depleted of energy. But many operators still hesitate to be the first users of subsea technology before the benefits are fully understood. One of the main concerns for operators is the uncertainty related to the operating expenditures and intervention costs for unforeseen events. Intervention and repairs could be expensive and long waiting times for the intervention vessels and resources are significant risk contributors. Contrary to this hesitation, several oil companies have mentioned this technology as mature and reliable from their experience[15].

Conventional Production System

When the wellfluid reaches surface, it is directed to a manifold. The reservoir fluid consists of oil, gas, water, and sediment solid particles. Conventionally, the untreated fluid is not transported to long distances. The oil, gas, water, and solids are separated and then pipelined or stored for bulk transport. Fig. 22 shows a typical conventional production system.

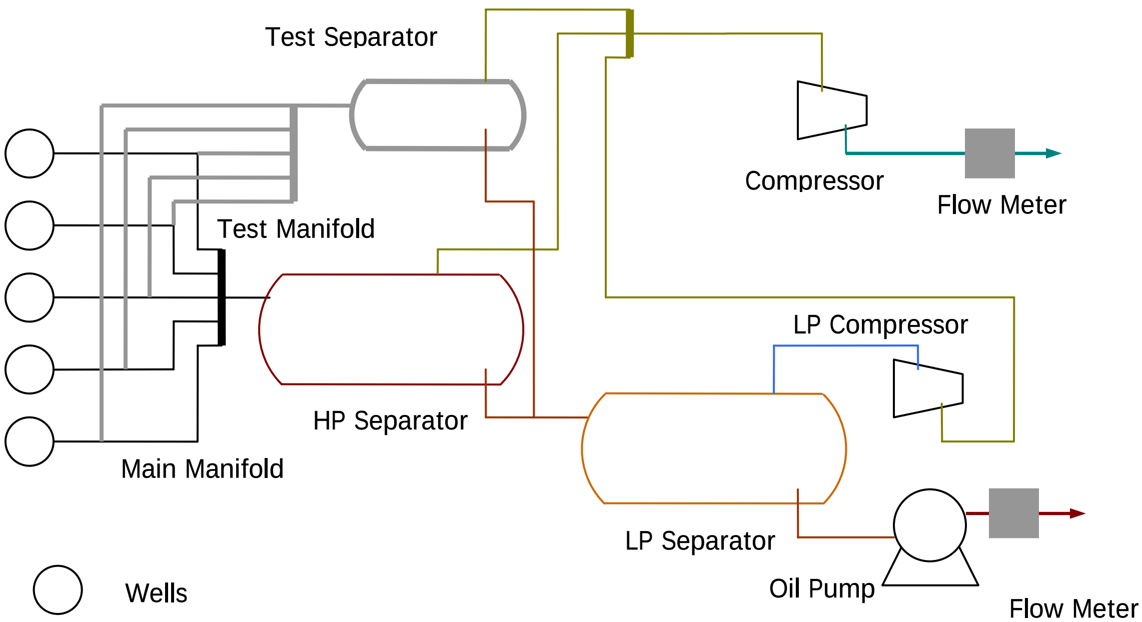


Fig. 22: Conventional Production System

Modern Artificial Lift

Traditionally, the artificial lift has been referred to as downhole pumping and gas lift. Today,

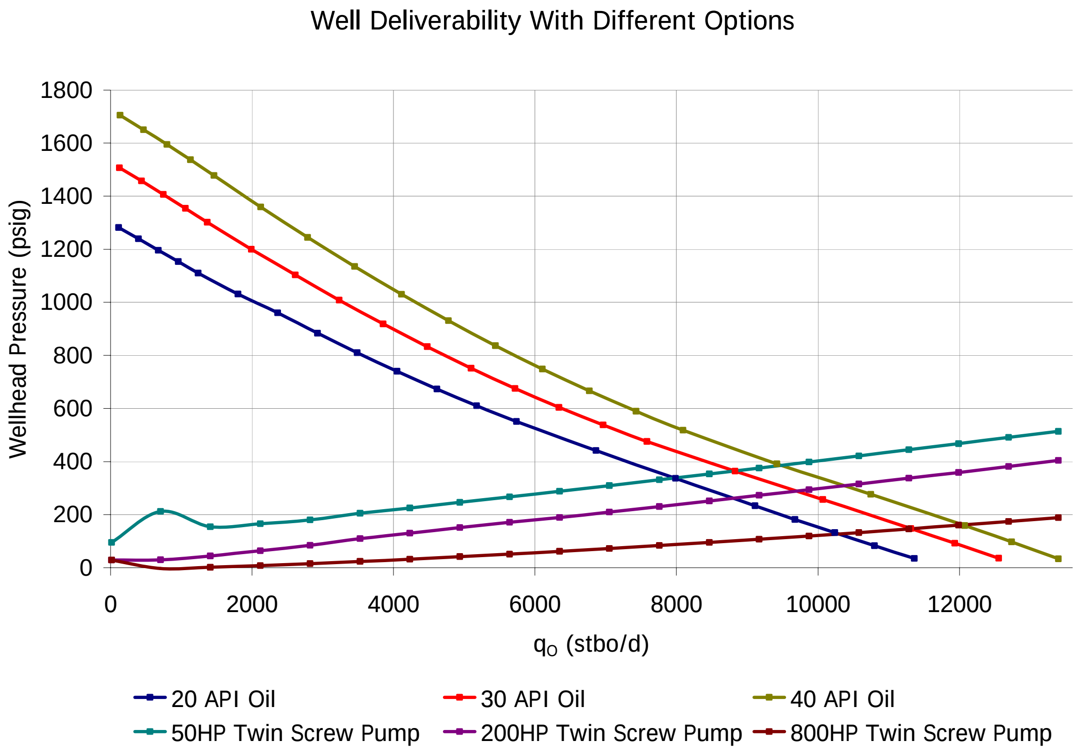


Fig. 23: Deliverability with Different Pump Power

artificial lift is not limited to wellbore, but also includes all methods applied to lift or boost the produced fluids to destination[42].

Deepwater and ultra deepwater developments have forced a broader definition of artificial lift. A combination of downhole pumping or gas lift with surface multiphase pumps constitutes modern artificial “lift” to transport the wellfluids. Wet gas compression with multiphase “compressors” also classify under the modern artificial lift.

Fig. 23 shows an example of improved well deliverability with bigger size and capacity of multiphase booster pump.

Multiphase Production System

The multiphase production systems represent a significant departure from the conventional operations. When the need for an offshore structure and other process facilities is eliminated by switching over to multiphase pumping, the savings realized are very attractive and highly significant. Fig. 24 shows a reduced footprint when compared to fig. 22, due to the use of multiphase pump and elimination of conventional separation system.

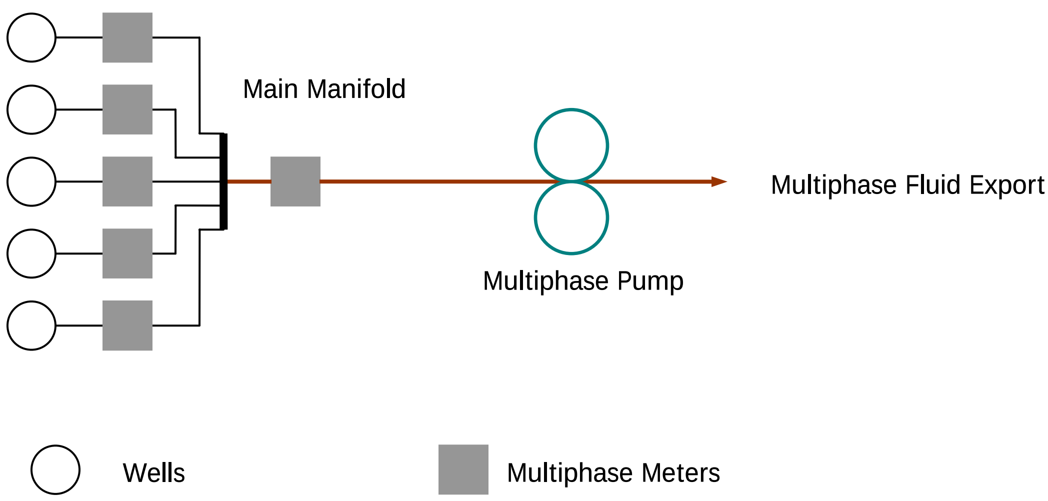


Fig. 24: Drastically Reduced Footprint and by Application of Multiphase Pumping

There is an increasing interest in subsea multiphase boosting, as more and more deep sea resources continue to be discovered and become economic as technology is advancing and oil prices going up. Fig. 25 shows the reserve sizes for different types of deepwater development systems. The subsea wellheads eliminate the need for dry facilities and structures. But they alone

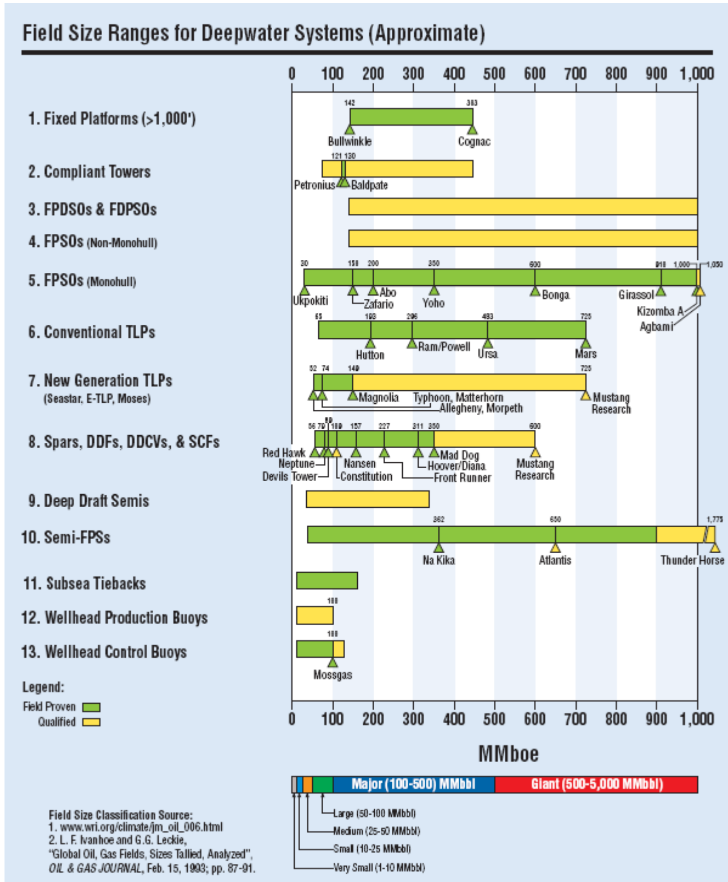


Fig. 25: Deepwater Systems and Reserve Size[5]

are not sufficient to lower the abandonment pressure on wells largely because of long tiebacks. High back pressure on wells wastes the reservoir energy and impacts the ultimate recovery in a negative way[43]. Subsea multiphase pumping helps reduce the back pressure and bring the production from otherwise abandoned wells to substantial profits.

The most commercialized form of subsea process technology is multiphase boosting[44]. Multiphase boosting can be used in conjunction with other subsea process systems. Any separation which is not complete gives some gas in the liquid flow or liquid in gas flow. Such condition can easily arise in subsea process and hence multiphase boosting / wet gas compression turns out to be the best options for onward journey of oil and gas to host facility.

By boosting the produced fluids, there is a considerable positive change in temperature. This reduces the need for methanol, glycol or other flow assurance chemicals[15]. As a consequence, there is a reduced need for chemical recovery from treated fluids downstream and process is more environment-friendly at effluent discharge point. Fig. 26 shows the rise in temperature of fluid flow through riverside twin-screw pump at speeds ranging from 700 RPM to 1700 RPM.

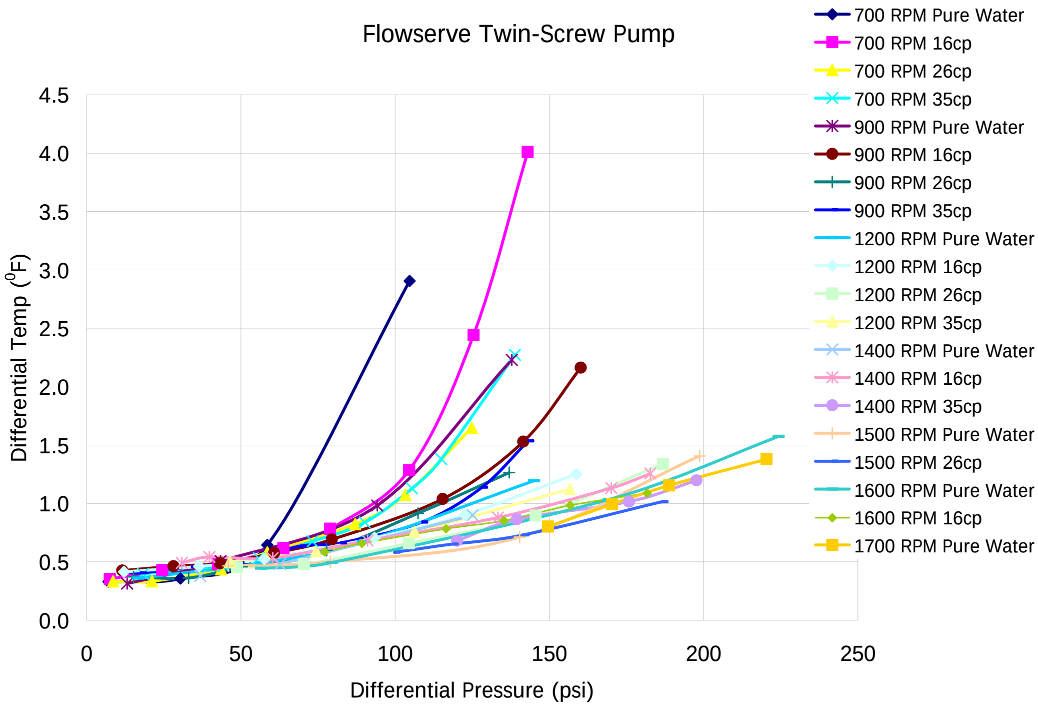


Fig. 26: Change in Temperature of Stream by Boosting with Twin-Screw Multiphase Pump

Tieback Distance

To investigate the application of twin-screw pump for high GOR production, a simulation study was carried out. The main parameters of production system and properties of the reservoir fluid are shown in table 4.

Table 4: Parameters of Production System and Reservoir Fluid

Reservoir pressure	3500 psi
Reservoir temperature	300 ^{0}F
GOR	20000
Water cut	0%
Well depth	5000 ft
Tubing ID	4.8”
Flowline ID	6.0”
Surface temperature	60 ^{0}F
Liquid PI	2 stb/d/psi

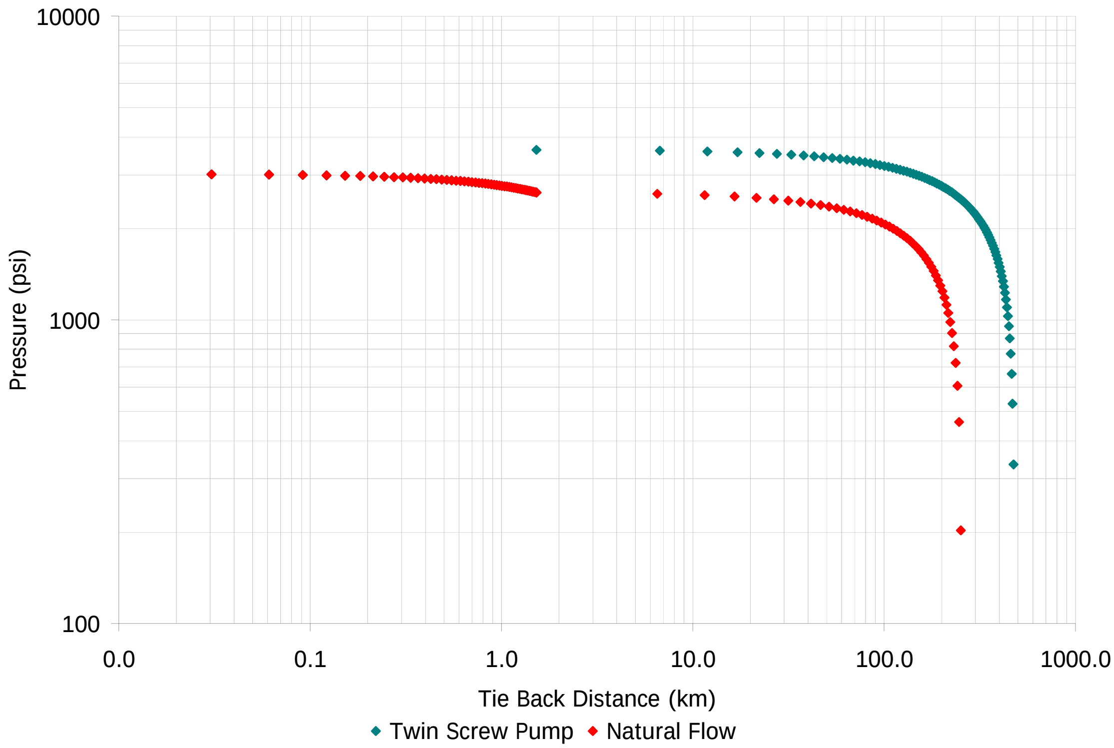


Fig. 27: Tieback Distance for High GOR Stream Boosting Using Twin-Screw Pump

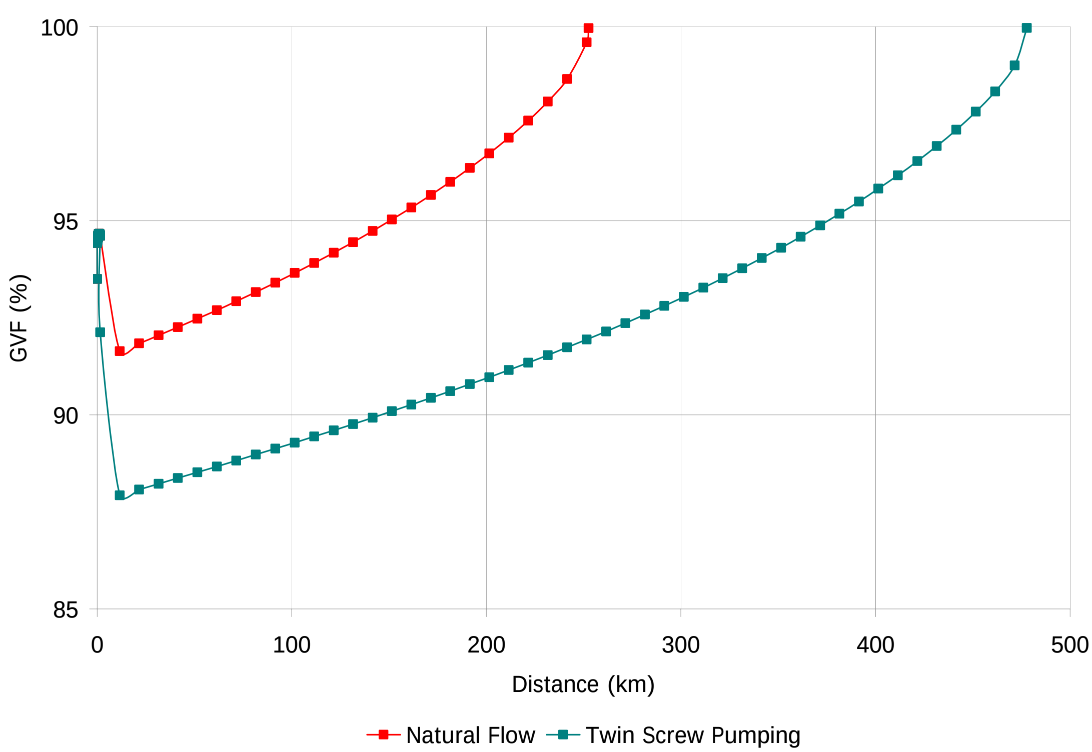


Fig. 28: GVF Variation with Distance under Different Scenarios

Using a twin-screw pump with nominal capacity of 700 m^3/h, the simulations run for 900 bbl/day liquid rate show that twin-screw pump can increase the tieback distance by about 200 km for the host facility to operate at 200psi. In this case if some conventional pumping technology is used, the pump will lose priming several times during operation and will need several interventions and restarts. This case, being a high GOR case, was not investigated for gas lift and combinations with other lift options. Fig. 27 shows the results of using a twin-screw pump as compared to natural flow and illustrates that tie-back distances can be increased if twin-screw multiphase pump is used.

In this study, the GVF at pump suction was found to be 88%. Fig. 28 shows the trend of GVF along the pipeline with and without twin-screw pumping. Fig. 29 shows the actual record of tieback distances in oil industry.

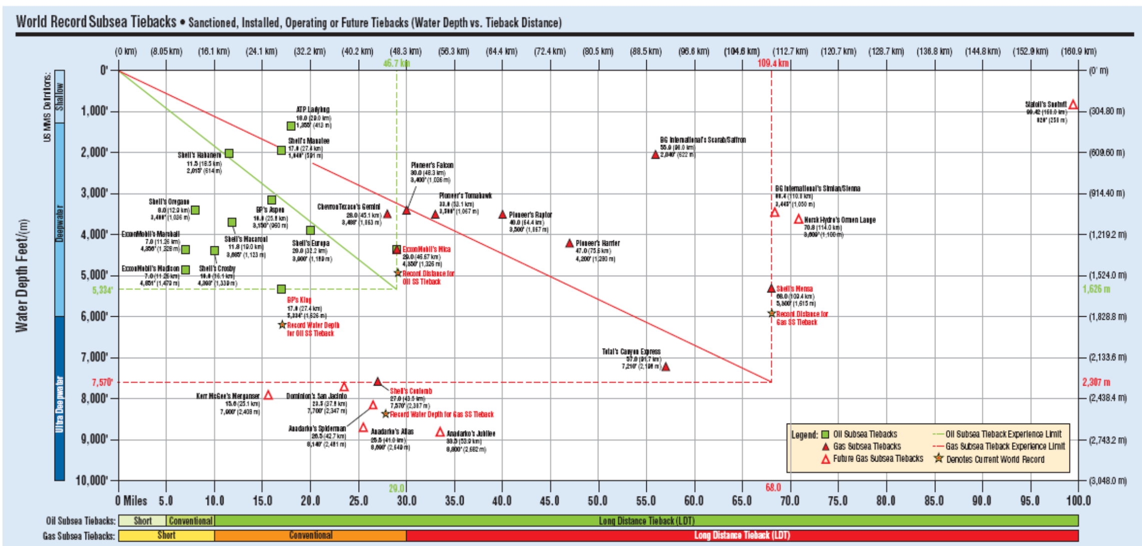


Fig. 29: Subsea Tieback Distances in Record[5]

Multiphase Pump Types

Several multiphase pumping technologies have developed over the last few decades as a result of the quest for transporting unprocessed wellfluids over long distances. The broad categories are positive displacement and rotodynamic. Fig. 30 shows that use of multiphase pumps is going up, whereas fig. 31 shows that twin-screw multiphase pumps are gaining popularity.

Among the rotodynamic and positive displacement technologies, the Helico-Axial rotodynamic pumps have the capacities to pump much larger volumes of fluids than positive displacement type pumps. Fig. 32 shows different types of multiphase pumping technologies.

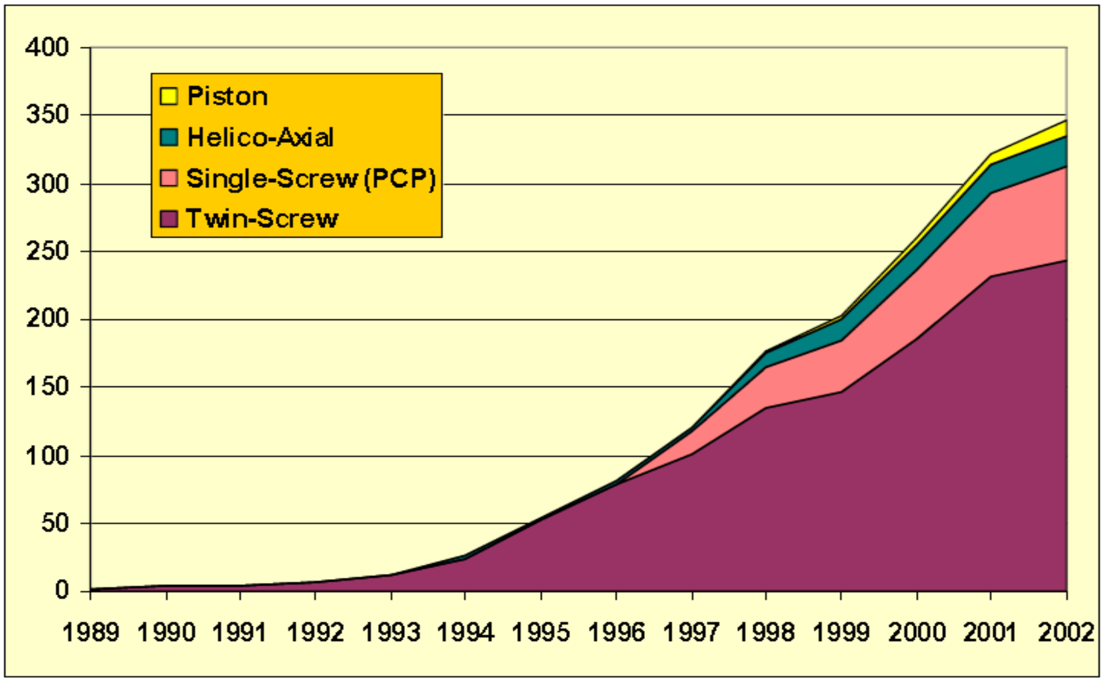


Fig. 30: Worldwide Multiphase Pumps Installations by 2002[45]

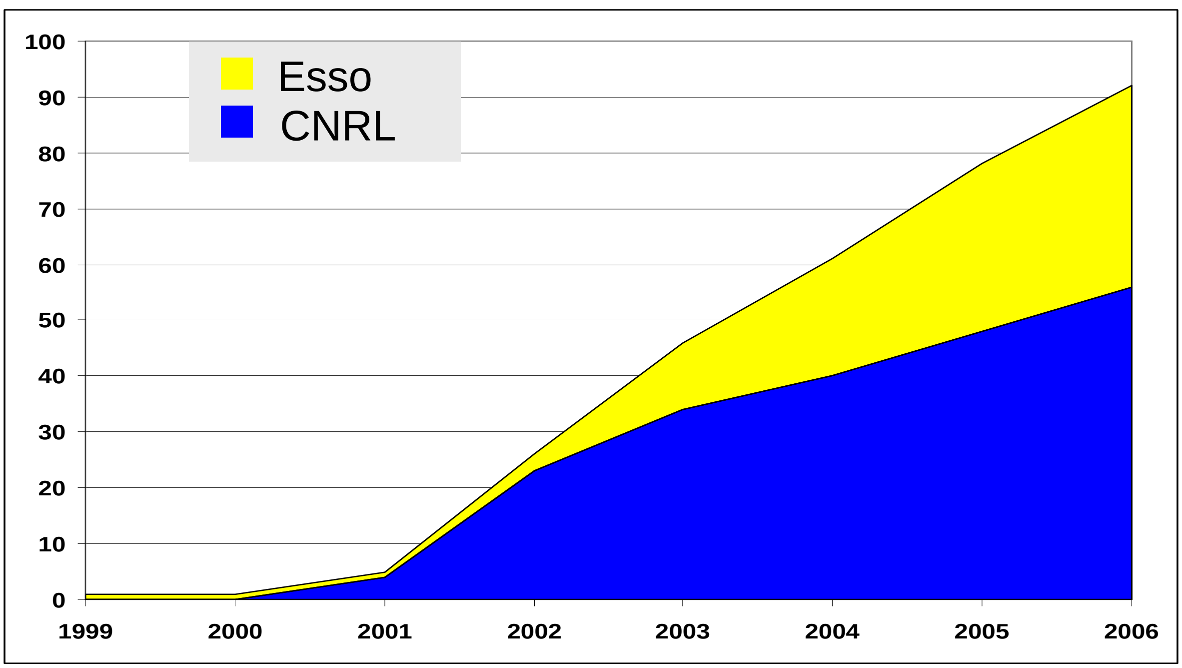


Fig. 31: Twin-Screw Pump Installations in Canadian Oil Sands[46]

Positive Displacement Pumps

Positive-displacement pumps operate by forcing a fixed volume of fluid from the inlet pressure section of the pump into the discharge zone of the pump. These pumps generally tend to be larger than equal-capacity dynamic pumps. As long as the seal between displacing impeller and stationary case is maintained, these pumps can "compress" the gas along with pumped liquid.

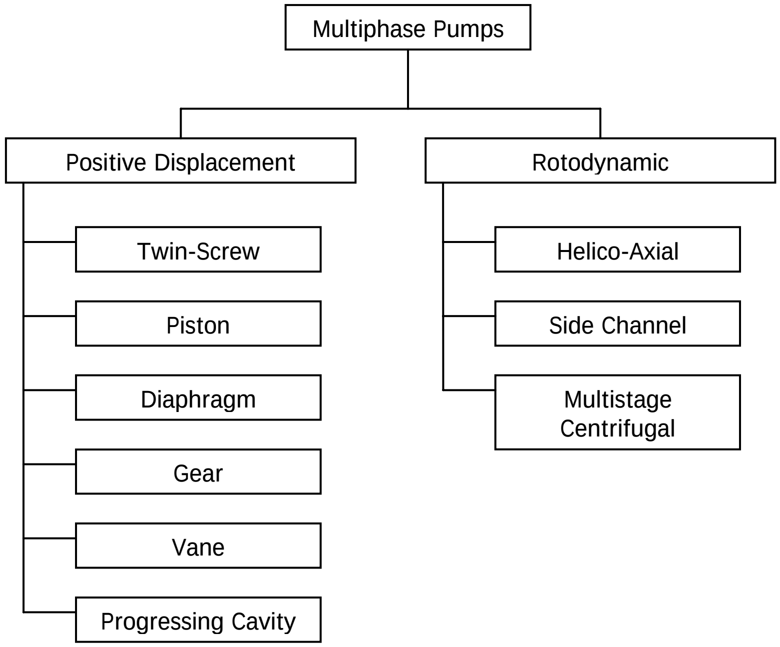


Fig. 32: Types of Multiphase Pumps

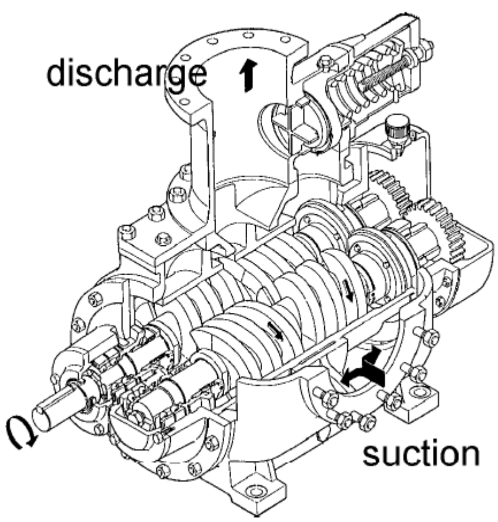


Fig. 33: Twin-Screw Pump[47]

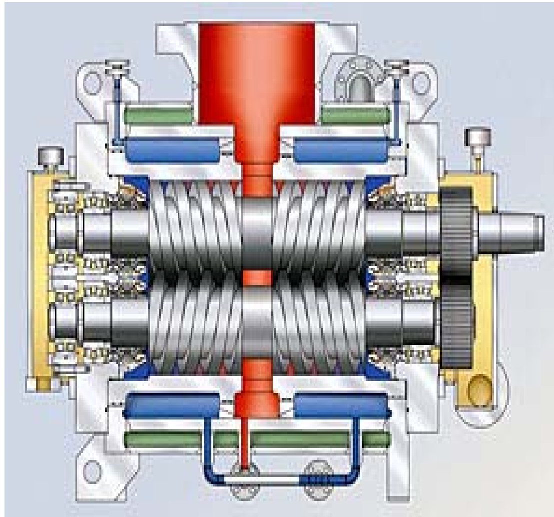


Fig. 34: Twin-Screw Pump Top View[48]

Twin-Screw Pump

The incoming fluid in a twin-screw pump is diverted to both ends of the screws and fluid fills up the volumetric chamber between screw flanks. The screw profile axially transports the fluid from ends to the center of pump where fluid rejoins and leaves the pump chamber.

Because of the precise timing gears, there is no contact between pairs of screws or between screws and surrounding housing. This allows the pump to handle a variety of abrasives. The typical twin-screw pump module consists of an electrical motor, pump, cooling system, oil refilling and instrumentation. The system design is based on proven equipment and components are selected based on high reliability. Figures 33, 34, and 35 show the inside construction of twin-screw multiphase pumps. The mechanical seals designed to prevent scaling and sand flow, to restrict axial displacement and to prevent damage to static seals.

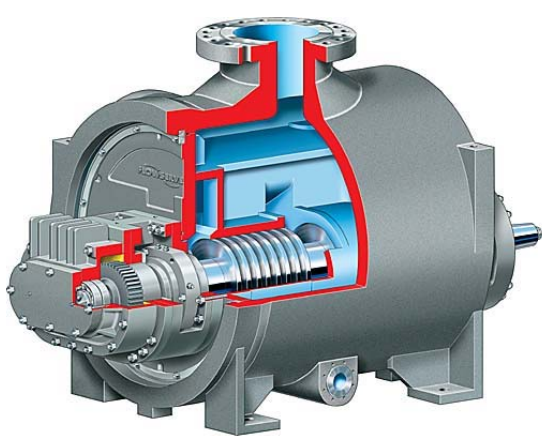


Fig. 35: Twin-Screw Pump Cut View[49]

Fig. 36 shows the photographs of twin-screw multiphase pumps installed at Texas A&M Riverside campus. This is a LSJIS model Flowserve twin-screw pump with 10105 bbl/day throughput and pressure boost up to 500 psig.

Fig. 36: Flowserve LSJIS Twin-Screw Pump at Texas A&M University Riverside Campus

Progressing Cavity Pump

A progressing cavity pump (PCP) moves fluid by means of a cavity, which progresses along the body of the pump. As the cavity moves, fluid is sucked in to fill the cavity, further rotation of the pump causes the fluid to flow and be delivered from the pump. The concept was invented by French designer René Moineau. They were developed during 1980s for oilfield application.

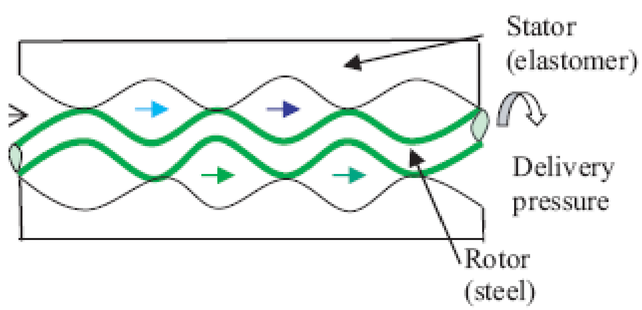


Fig. 37: PCP Principle[50]

The rotor of the pump is a steel helix which is coated with a smooth hard material, normally chromium. The rotor fits inside a pump body (the stator) which normally is elastomer lined steel tube. The stator has a helical cavity. The rotor turns inside the helical stator in such a way that one point along the helix is at the edge of the cavity, and the opposite point is at its center. Rotation of the rotor inside the stator causes the cavity to progress along the pump thus inducing fluid flow. It tolerates very low inlet pressures[50]. PCP working principle is shown in fig. 37.

While progressing cavity pumps offer a long life and reliable service, abrasive fluids significantly shorten the life of the stator. A unique feature of the progressing cavity pump is the design of its stator. Common designs are the "Equal-walled" stator and the "Unequal-walled" stator. The latter, being unequal in wall-thickness allows for larger sized-solids to pass through because of its ability to compress under pressure. The interface between rotor and stator is lubricated by the fluid being pumped, however if the pump is allowed to 'run dry', rapid deterioration of the stator results. The term "run dry" is loosely related to the pump's self-priming capabilities. This means the pump is able to run dry for a given period of time while it draws in the pumped medium.

The progressing cavity pumps were specifically designed for crude oil lifting and gas well dewatering. The rotary action of the PCP outperforms the reciprocating pumps, its operating efficiency surpasses conventional electric submersible pumps and it is ideal for dewatering gaseous formations because it is never affected by gas lock. High production rates and abrasives content call for frequent replacement of the wearable stator.

An all-metal PCP has been developed and testing is underway since early 2005 [50]. This design eliminates elastomeric stator. The stator is hydroformed and metals are so chosen that they can withstand temperatures more than 200 ^{0}C. During thermal expansions and contractions, the clearance between stator and rotor should not change significantly and this is achieved by choosing the same metal for both.

Piston Pumps

The piston pumps are double acting reciprocating pumps. The system includes two check valves on both suction and discharge sides. The principle of operation is very simple.

Overall efficiency is good compared to other multiphase boosting technologies. They can handle high GVFs for extended period with high pressure boost. Their versatility makes them suitable for single or multiple wells application. Fig.38 shows a RamPump.

The RamPump™ by Weatherford is a duplex piston pump that operates using a hydraulic power system. The benefits of this type of system are most apparent to applications needing lower operating pressures of wells to maintain or even improve production but do not have the space to install separators, flash tanks, compressors, liquid pumps and vapor recovery units to drawdown the surface pressure. This pump alone can be used to lower the wellhead pressure by creating a low pressure zone between the well and the high backpressure node such as upstream end of a long flowline or downstream separator thus minimizing equipment requirements. Further system modularity ensures relocation of the unit. A number of RamPumps are in operation in the Gulf of Mexico.

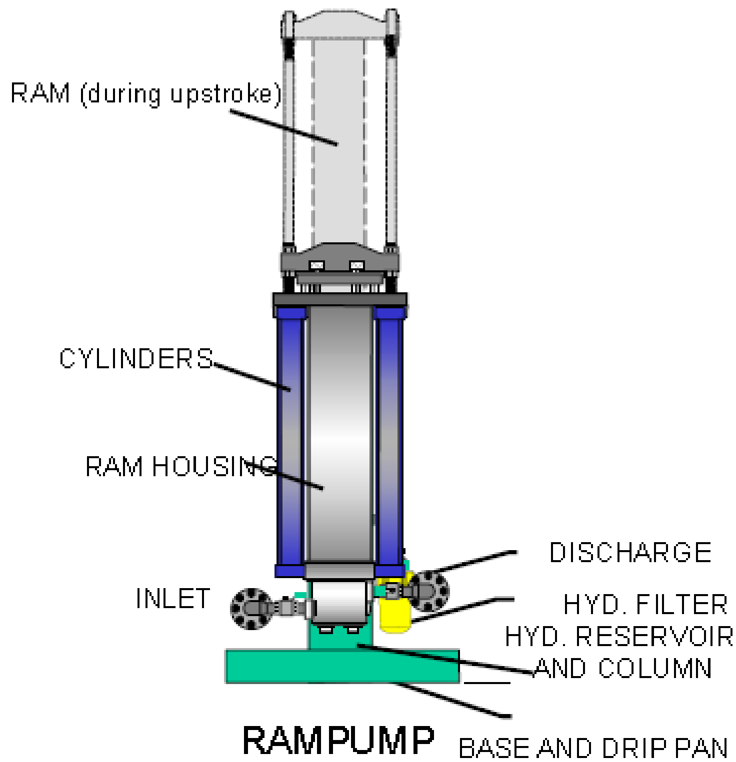


Fig. 38: RamPump[51]

The Mass Transfer Pump by National Oilwell first installed in Canada in 1998 is the first type of piston pump applied for multiphase boosting. A number of mass transfer pumps are in operation in Canada.

Diaphragm Pumps

A diaphragm pump is a positive displacement pump that uses a combination of the reciprocating action of a rubber or Teflon diaphragm and suitable non-return check valves to pump a fluid. Sometimes this type of pump is also called membrane pump or peristaltic pump. There are two main types of diaphragm pump. In the first type, the diaphragm is sealed with one side in the fluid to be pumped, and the other in air or hydraulic fluid. The diaphragm is flexed, causing the volume of the pump chamber to increase and decrease. A pair of non-return check valves prevents reverse flow of the fluid.

The second type of diaphragm pump has one or more unsealed diaphragms with the fluid to be pumped on both sides. The diaphragm(s) again are flexed, causing the volume to change. When the volume of a chamber of either type is increased (the diaphragm moving up), the pressure decreases, and the fluid is drawn into the chamber. When the chamber pressure later increases from decreased volume (the diaphragm moving down), the fluid previously drawn in is forced out. Finally, the diaphragm moving up once again draws fluid into the chamber, completing the cycle. This action is similar to that of the cylinder in an internal combustion engine.

Rotodynamic Pumps

The dynamic pumps work on the principle that kinetic energy is transferred to the fluid. These pumps are based on bladed impellers which rotate within the fluid to impart a tangential acceleration to the fluid and a consequent increase in the energy of the fluid. The purpose of the pump is to convert this energy into pressure energy of the fluid.

Helico-Axial Pump

The helico-axial pump was developed by Poseidon Group and is now manufactured by Framo and Sulzer. The fluid flows horizontally through a series of pump stages consisting of helical impellers and stationary diffuser.

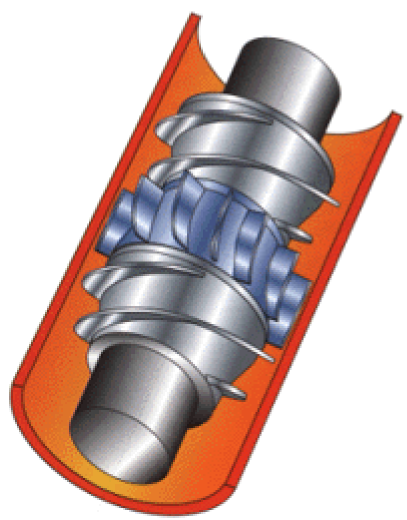


Fig. 39: Hydraulic Design of Helico-Axial Pump[52]

The number of stages depends on the required head. The number of stages is limited by the dynamic behavior of the rotating assembly. The special shape of the impeller limits accelerations and also low-pressure zones. The initial shape was invented in the late seventies by Souriau and Arnaudeau[15]. This shape was improved later several times. It avoids the phase separation and facilitates the gas carry over, providing good performance in multiphase flow. This feature enables stable operation, independent of conditions such as transients and slugging. The specially designed (Fig. 39) axial flow stages prime the main production pump and push the gas-liquid flow stream into the stages. Gas volume is reduced through the Poseidon system by compression.

Multistage Centrifugal Pump

Downhole ESP's manufactured by Baker-Centrilift and Schlumberger-REDA are widely in use. Multi-stage centrifugal pumps are adaptable to many different environments because they are available in a variety of configurations. Recently, the ESP's have been developed to work with harsh conditions like abrasive solid content and gas presence and highly corrosive fluids and environment.

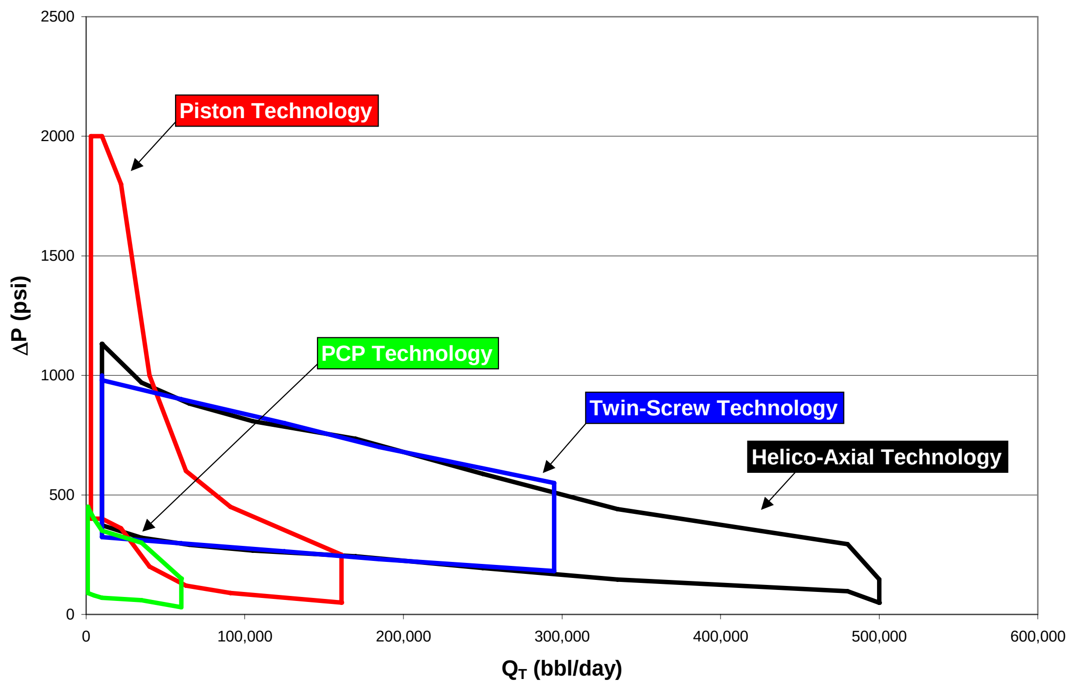


Fig. 40: Operating Envelopes for Multiphase Pumping[44]

Multiphase Pump Performance

The multiphase pumping technologies are compared in the following figure (fig. 40) based on operating envelope provided by manufacturers.

Performance Characteristics

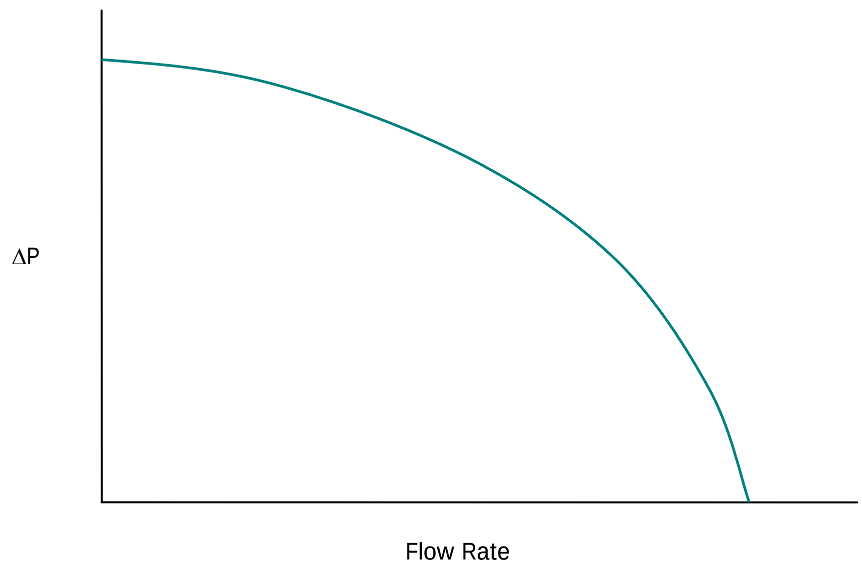


Fig. 41: Centrifugal Pump Behavior

One outstanding capability of dynamic pumps is that they can operate safely even with discharge valve closed. The pressure does not exceed a definite limit called shut off pressure. Fig. 41 shows the performance behavior of centrifugal pumps. Fig. 42 shows the performance of twin-screw multiphase pumps.

On the contrary, positive displacement pumps can generate extraordinarily high discharge pressures. If the discharge line is closed, the fluid will try to escape from the weakest point on equipment or piping. The discharge pressure can stabilize at a limiting value if clearance is enough to allow large slip flow. The change in flow rates against differential is fairly flat unlike dynamic pumps. Dynamic pumps are highly sensitive to change in differential pressure.

Positive displacement pumps need no priming and in turn can operate on high GVFs. Centrifugal pumps with single stage commercially available may develop only 100 psi pressure boost whereas pressures up to 500 psi can be expected from the most common positive displacement pumps. Piston pumps can develop pressures easily above 10000 psi.

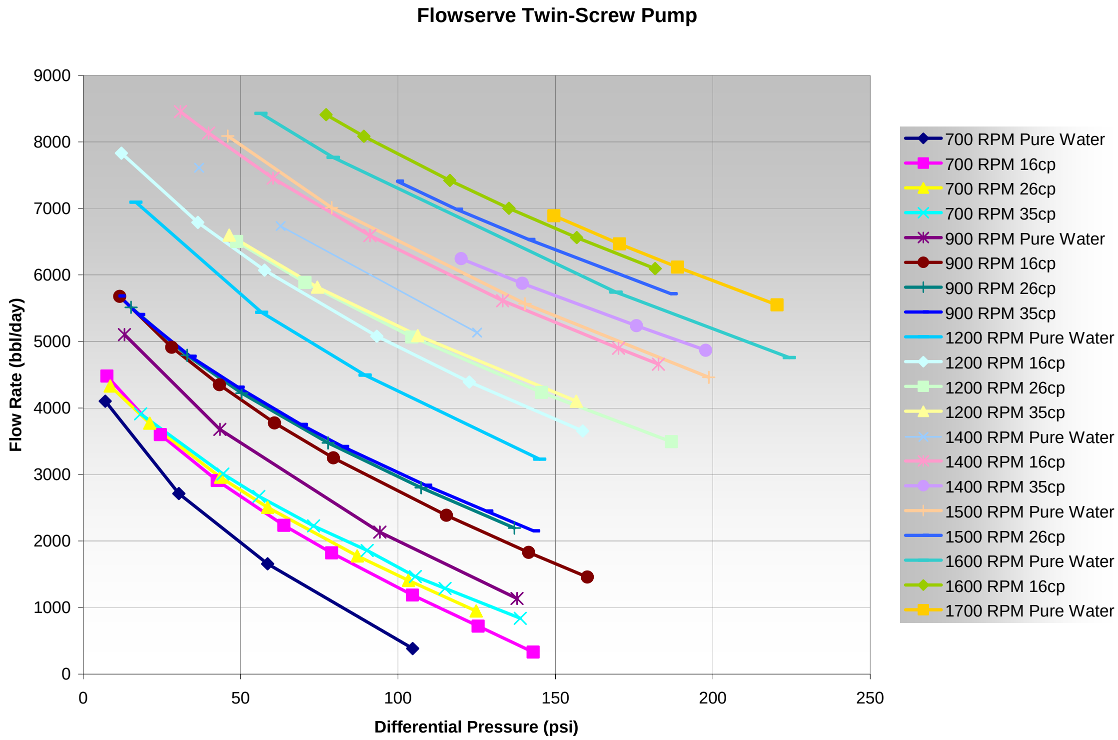


Fig. 42: Twin-Screw Pump Performance

Cost

Higher precision needed in clearances and small tolerances make the positive displacement pumps significantly costlier than dynamic pumps. Piston pumps have a very complicated mechanical design as compared to the centrifugal pumps. Gear pumps are simplest in construction. Owing to close clearances, abrasives present in fluids can significantly damage the positive displacement pumps.

Operational Considerations

The place where multiphase pumps are in the highest demand is subsea and deep sea. The most severe operational concerns are sand erosion, seal failure, high temperatures, presence of hydrates in fluid stream and long term performance under water. The screw wear resulting from sand erosion represents the primary cause of pump downtime[53].

Apart from these concerns, the power supply reliability for the pumps is a major concern. There is a substantial loss of power when power is transmitted over long distances. A subsea step-up using subsea transformer is not desirable for majority of operators. Instead they prefer to rely on high quality umbilical made to perform well under deepwater environments. The equipment must be tested on surface by physically simulating the marine deepwater wet conditions to study the performance and reliability. Once marinized, the intervention to solve even the most trivial problem that hampers the operation of these pumps would cost huge amounts of money. The operating efficiency of the pump is less because of the voltage losses in the power umbilical and in the pump motor.

Multiphase Boosting System Location Considerations

The performance of modern production system based on multiphase boosting system is very sensitive to the location of pump. Theoretically, multiphase boosters can be located anywhere from the wellhead, up to the riser base, on the host platform or shore pumping station[10].

If the system is located close to wellhead, the backpressure on the flowline will be higher than those close to the riser base or further on the host platform. Further, this leads to longer power umbilicals.

On one hand, higher backpressures mean lower volumetric flow rates leading to fewer losses associated with acceleration and friction. The higher backpressures lead to higher mixture densities, and higher gravitational losses in vertical flow sections. The optimum location of the multiphase booster will depend upon parameters like fluid properties, fluid velocities, pipe diameter, roughness, inclination, gas liquid ratio, etc.

Along a horizontal and little horizontally-inclined flowline, the best location for a pump will be close to the wellhead. The high pressure on the downstream of the pump will lead to higher suction pressures, less gas volume fraction and consequent less requirement of power. For inclined flowlines, the best location of the pump could be close to riser base. The higher gas volume fraction reduces the gravitational losses but adds to the frictional losses. Higher volumetric flow rates will need more booster power. This location will save CAPEX on power umbilical. For a given booster capacity, it should be located as close to the wellhead as possible to allow maximum liquid flow under minimum volumetric flow rate.

Typical Cases Where Multiphase Boosting is Suitable

The following common cases[14] are most suitable for multiphase boosting:

Medium to Long Tiebacks

The multiphase boosting was originally conceptualized to enable tieback of remote marginal fields to the existing host facilities; overcoming frictional and static losses. The increased fluid velocities stabilize the flow regime and prevent severe slugging.

Medium to Low GOR

A GOR below 1000 scf/bbl is very favorable for multiphase boosting. Anything above 1000 scf/stb will need wet gas compression.

Limited Energy Reservoirs and Deep Waters

In deepwater and in cases where reservoir drive is weak, the high static backpressure on the flowline hampers higher rates of production and multiphase boosting becomes necessary. By adding the necessary energy to the stream the backpressure on wellhead and thereby reservoir can be reduced. This will improve the production rates and recovery.

Some of the recent field applications of multiphase boosting are Draugen, North Sea, Lufeng, South China Sea, Topacio, Zafiro, and Ceiba, West Africa. Multiphase pumps installed as retrofit later in the life of a field helps improve the economics. Devon Canada saved $84000 in OPEX when they switched over to twin-screw pump for reducing backpressure in the line to take the system outside hydrate formation region[54].

Some concerns about subsea multiphase pumping are large power requirements for large pumps, sophisticated and expensive umbilicals for longer tieback distances, wet gas compression capability, intervention costs, and erosion due to abrasive solids.

5. SOLIDS FORMATION AND DEPOSITION

This section deals with the formation of gas hydrates and scales. It starts with the description of gas hydrates and continues with detection of hydrate nuclei, agglomeration, differential scanning calorimetry, different means of inhibiting or dissociating hydrates, and advantages of LDHI's. The flow assurance needs for hydrate slurry, NGH transport, cold flow, and different mitigation strategies have been discussed. In the section for oilfield scales, the description of scales, contributing factors, formation process and mechanism is provided. Also, the scale formation locations, detection, techniques for prediction from history and current data, remediation and prevention methods are discussed.

Gas Hydrates

The existence of gas hydrates was recognized by Davy nearly 200 years ago. Sir Humphrey Davy observed the hydrates experimentally in 1810. It took another 100 years for oil industry to recognize the hydrates as a major issue in flow assurance. Most of the research has been done over past 50 years. The gas hydrates are non-stochiometric clatherates of water and gas. These crystals contain 85% or more water on a molecular basis[55].

The hydrate crystals form because the gas molecules dissolved in water support an open ordered crystalline system at a temperature higher than freezing point of pure water. Gas molecules occupy the empty spaces. Larger molecules (up to butane) create more order and more stable hydrates[56].

Gas hydrates form at low temperatures (below 2 ^{0}C) and high pressures. The subsea pressure and temperature especially under deepwater scenarios and under permafrost are conducive for hydrates to form or exist with stability. As water is abundantly available on the earth, only availability of gas molecules under right conditions is needed for existence or formation of hydrates.

The common types of hydrate structures are sI, sII, and sH. These structures differ in the number and size of cages, and in their unit cells. Type of guest molecule determines the type of hydrate crystal structure. Methane and ethane form sI structures, butane forms sII structures and larger guest molecules form sH type hydrate structures. sI and sII have cubic structure whereas sH has hexagonal structure. More hydrate structures possibly exist in nature, but the oil and gas industry is mainly concerned with sI, sII and sH types as they are most common. Table 5 describes the structural properties of sI, sII and sH type gas hydrates. sI structure occurs in two sizes, small cage and large cage. Small cage is made of 12 pentagons and large cage structure is made of 12 pentagons as well as 2 hexagons. The sI structure contains 46 water molecules.

Table 5: Structural Properties of Gas Hydrates[57]

Property	sI	sII	sH
Lattice Type	Primitive Cubic	Face-Centered Cubic	Hexagonal
Number of water molecules per unit cell	46	136	34
Ratio of number of small to large cavities	0.33	2	5
Average cavity radius (nm) [number of cavities per unit cell (cavity type)]	0.395 [2 (5^{12})] (S) 0.433 [6 ($5^{12}6^{2}$)] (L)	0.391 [16 (5^{12})] (S) 0.473 [8 ($5^{12}6^{4}$)] (L)	0.391 [3 (5^{12})] (S) 0.406 [2 ($4^{3}5^{6}6^{3}$)] (S) 0.571 [1 ($5^{12}6^{8}$) (L)

sII structure also has two sizes, small cage and large cage. Small cage is made of 12 pentagons and large cage structure is made of 12 pentagons as well as 4 hexagons. sII structure contains 136 water molecules. sH structure has three cage sizes, two small cage sizes and one large cage size. The first small cage is made of 12 pentagons, second small cage size is made of 3 squares, 6 pentagons, and 3 hexagons. The large cage structure is made of 12 pentagons and 8 hexagons. The sH structure contains 34 water molecules.

The kinetics of formation and dissociation of hydrates with time is the most challenging concern for the interest of oil and gas industry. Hydrate nucleation is the process of appearance of hydrate crystals, their growth and progression to critical size for stable continued growth. Nucleation begins with very small number of constituent molecules, typically ranging from ten to a thousand. Hydrate nucleation is not heat or mass transfer limited, but growth of nuclei is limited by both processes. When small aggregates of hydrate crystals exceed the critical size, they start growing[58]. Experimental detection of onset of nucleation is difficult. Compared to thermodynamic investigations for hydrates, the kinetic studies are yet to be fully understood. Growth of the nuclei depends on interfacial area, pressure, temperature and supercooling. Induction period is the time elapsed between crystallization onset and formation of critical sized stable nuclei.

The purpose of almost all offshore platforms right from the initial time is making conditions favorable for flow assurance. The primary functions of offshore platforms like separation, compression, pumping and dehydration lead to hydrate prevention. The cost of preventing hydrate formation by pipeline insulation or thermodynamic inhibitors can be a significant economic factor while considering the marginal developments.

Devon, Canada for their Ferrier Field installed a twin-screw pump to reduce the pressure below 200 psig at 5 ^{0}C. The result was that the field continued production round the year which was otherwise frozen up for 210 days every year. The payback period of the pump was much less than estimated one year[54]. Devon saved more than $84000 a year in OPEX.

Field Problems

Under deepwater conditions, the hydrates formed in manifolds and flowlines are difficult to dissociate and remove as reducing the production system pressure is difficult. Some method to remove pipeline liquids and gas by pumping could be helpful[59]. This method can best match with multiphase pumping.

As one remediation measure to mitigate hydrate blockage in pipeline, depressurization can take days of flow interruption. It is not always practical to apply heat to the exact location of the plug. In such a case, line depressurization at both ends is needed. For long multiphase pipelines under deepwater environment, thermal insulation alone can not assure heat retention for continued fluid flow. Methanol dosed in gas phase comes into contact with the water phase and dissolves providing necessary inhibition. A significant amount of methanol is finally lost in the gas phase downstream[60].

Some deepwater locations have another unique problem. Gas seepage on ocean floor and associated hydrate mounds is a common occurrence. Routing of pipelines around such structures lead to dissociation of hydrates and further destabilization of pipeline foundation which can lead to complicated structural failures and subsequently hampering the flow assurance. Jolliet TLP in the Gulf of Mexico had such concerns for its foundations and pipelines.

Extreme conditions encountered while drilling in deepwater could be favorable for formation of hydrates. If hydrate crystals occur in drilling fluids, there can be drastic changes in mud rheological properties causing plugging and damage to drilling equipment[61]. The plot (fig. 43) shows vulnerability of deepwater drilling fluids to hydrate problem. In drilling operations the stopped circulation can trigger formation of hydrates and conditions can be stable if proper inhibition or remediation strategies are not adapted to.

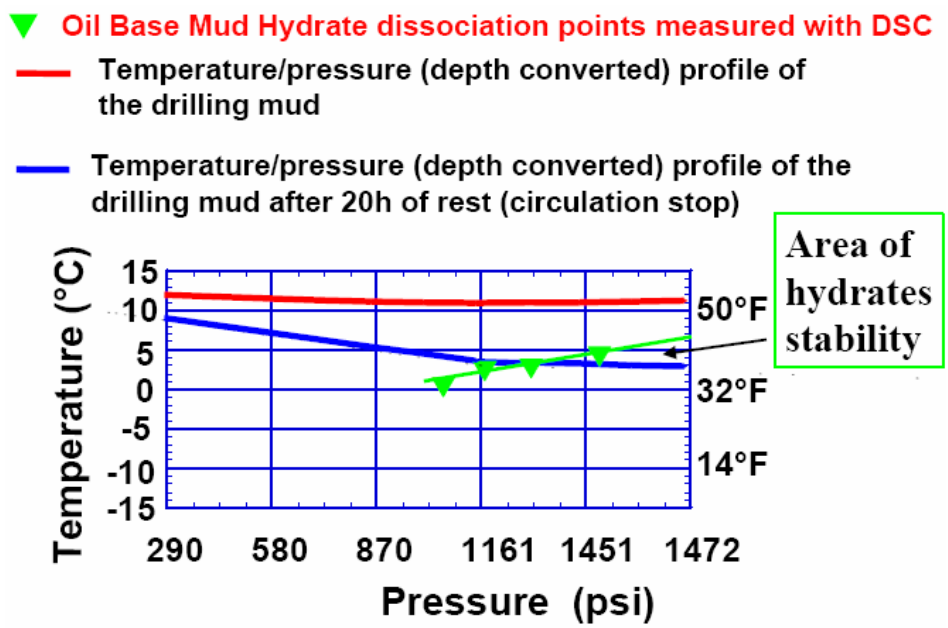


Fig. 43: Vulnerability of Drilling Mud System to Hydrate Formation[61]

Hydrates can also accumulate in the inlet separators and eventually interfere with the level control instrumentation and upset process[62].

Hydrate Layer as Source-Cum-Cap Rock

This is a unique situation that helps maintain the hydrocarbon production from a formation. The in-situ gas hydrates on the top of Mesokhaya gas reservoir in Siberia act as cap rock and also helps replenish the depleting reservoir by dissociation of hydrates. Permafrost and deepwater are probable locations for more such reserves. There is a need to study the phenomena of such process to arrive at a predictive capability. Predictive capability of dissociation of naturally occurring hydrate layer will enable simulation studies which will help in engineering and planning the production facilities and networks.

Hydrate Nuclei Detection by Ultrasonics

Velocity, amplitude, frequency spectrum and phase shift are the acoustic quantities which can be used as an indication of hydrate crystallization[63]. Frequency spectrum and amplitude are stable for pressure changes and sensitive to appearance of hydrate crystals. Ultrasonic detection could detect the presence of minute hydrate crystals and nuclei while there is no sign of hydrate formation from system pressure. Thus, the onset of hydrate formation will be possible to detect and suitable actions for assuring flow can be taken in advance.

Agglomeration

When the hydrate nuclei comes in contact with each other and joins to form larger particles, the process is named agglomeration. Once the critical size of nuclei is achieved and they are in contact with each other in numbers, the rate of hydrate formation is very fast or even catastrophic which can totally block the pipelines.

At the gas and water interface, there is maximum possible interaction between both molecules and hence hydrate formation is easy. As interfacial area is increased by stirring or using suitable additives, hydrate nucleation can be accelerated.

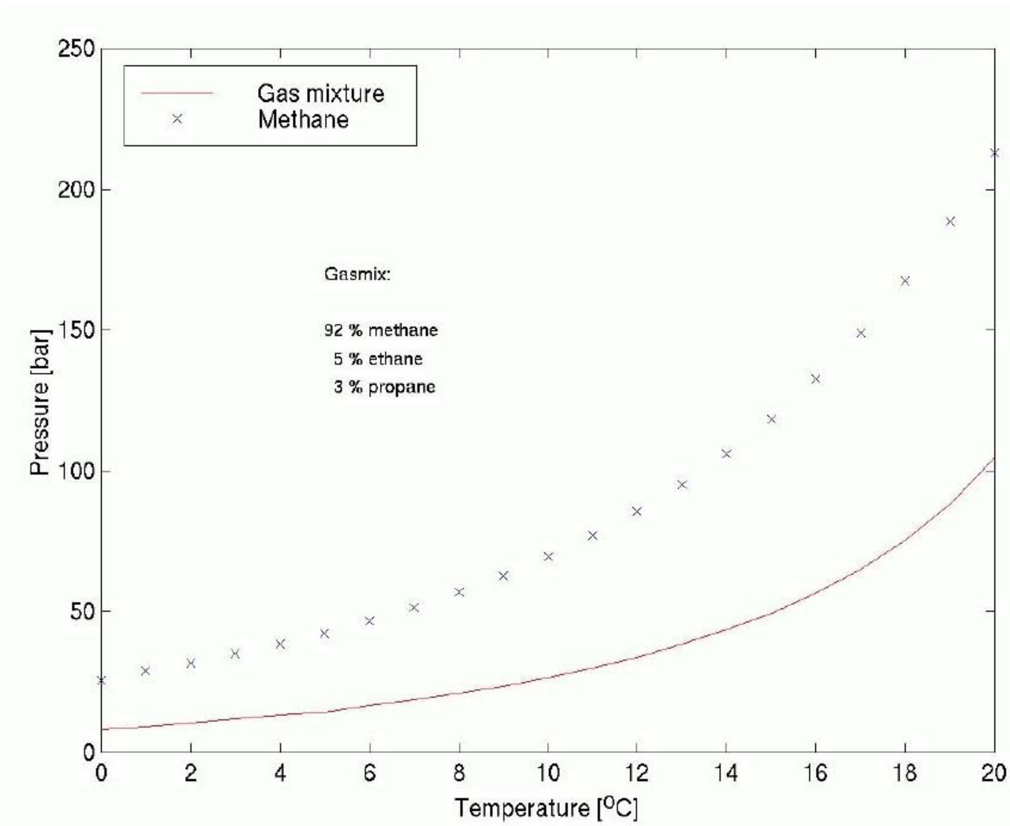


Fig. 44: Hydrate Equilibrium Curves[8]

The conditions favoring hydrate formation are function of composition of gas and water phases, temperature and pressure. A typical hydrate equilibrium curve is shown in fig. 44. Left side of the curve indicates conditions favorable for hydrate formation. Hydrate locus shows temperatures along the X-axis and pressures along the Y-axis. At bubble point, the slope of curve changes sharply and below bubble point, curve shows presence of water, hydrocarbon liquid, hydrate crystals and vapor. Above bubble point the curve shows no vapor phase. Hydrates form at the interface between hydrocarbon phases, and free water phase[55].

Methane, ethane, propane, butane, nitrogen, carbon dioxide, and hydrogen sulfide are the most common reservoir gases that form hydrates. N-butane to oil industry is known as the heaviest hydrate forming alkane[64]. Two distinct types of hydrates - dispersed (particle size < 1 mm) and granular (particle size > 1 mm) were observed by Fadnes et al.[65] at low and high water cuts respectively.

Differential Scanning Calorimetry

The usual method to determine the thermodynamic conditions of the formation of hydrates in drilling mud formulations is to use PVT cell with visual observation and pressure and temperature measurements. This technique requires complex instrumentation and often does not permit to work with a whole formulation (especially in the presence of solids). Moreover, PVT cells do not give a quantitative evaluation of the kinetic properties of hydrate formation.

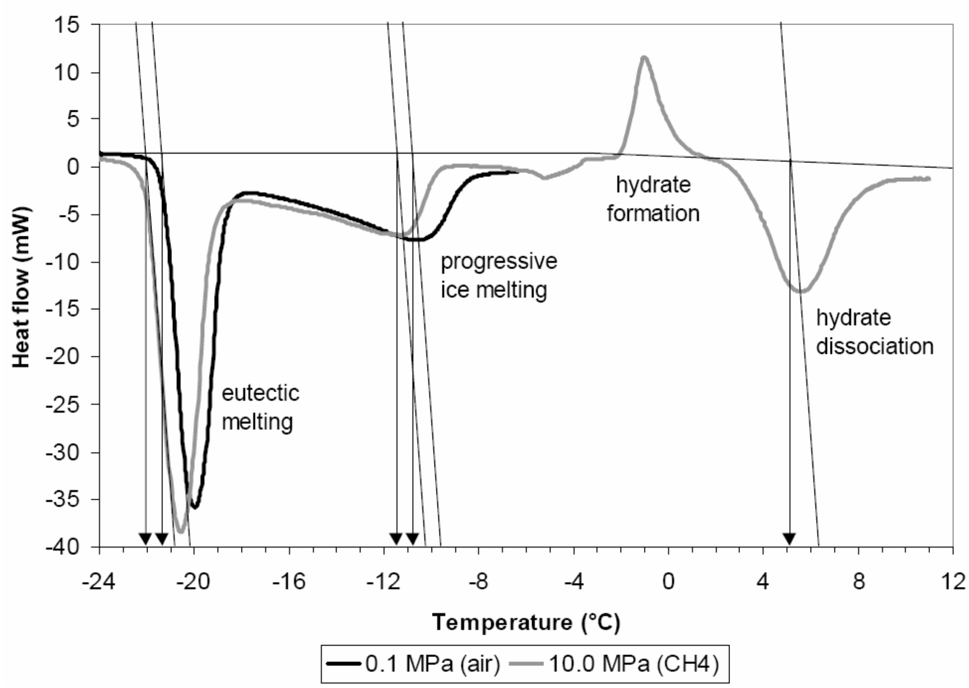


Fig. 45: Detection of Phase Transition Using Heat Flow as a Function of Time, Temperature and Pressure[61]

The Differential Scanning Calorimetry (DSC) to determine the thermodynamic equilibrium properties and kinetics of hydrate formation in mud formulations, particularly in the presence of large amounts of mineral is easier and less time consuming as compared to the PVT technique. This technique allows the measurement of heat transfers as a function of time, temperature and pressure and thus detects phase transitions. It requires smaller sample volumes. DSC records the heat flow as a function of temperature. The endothermic peaks (negative on heat transfer scale) indicate phase changes and the corresponding temperatures[61]. Exothermic peaks indicate formation of hydrates. Fig. 45 illustrates behavior of heat flow with temperature for air and methane at 0.1 MPa and 10 MPa pressures respectively.

Remediation methods for tackling the problem of hydrates in oilfield are also well known but the drive to continuous flow of hydrocarbons calls for prevention rather than cure of hydrate blockage problems.

Means of Inhibiting / Dissociating Hydrates

The following are methods for inhibiting or remediation of the hydrates in oil and gas industry:

1. Removing one of the components.
2. Heating the system to exceed hydrate formation temperature.
   Electrical heating, thermal insulation, and hot stabilized oil circulation are preferred methods.
3. Depressurizing the system below hydrate formation pressure.
4. Dosing the system with external chemical inhibitors which can be thermodynamic or kinetic. Methanol, glycol injection and unconventional inhibitors are the examples.
5. Maintaining high flow velocities by appropriately sizing the pipelines.
6. Coiled tubing cleanout. Most critical part is access to location with coiled tubing although many service companies provide this service currently[35].

Thermodynamic Inhibition

The thermodynamic inhibitor is a third active component added to a two component system (gas and water). It changes the energy of intermolecular interaction and changes thermodynamic equilibrium. It works by lowering the hydrate formation temperature at the cost of a high concentration of inhibitor per unit mass of water present in the system. Thermodynamic inhibition moves the system away from thermodynamic stability of hydrate formation.

Water phase from natural gas can be removed by absorption (glycol), adsorption (desiccant), or condensation (glycol/methanol injection). Absorption and adsorption involves mass transfer of the water molecules into liquid solvent or a crystalline structure and condensation involves cooling of gas stream and subsequent injection of inhibitor (thermodynamic).

The distances over which gas was being transported began to increase in 1930s and following World War II the natural gas process industry grew rapidly. Dry desiccant (silica gel and activated alumina) were popular in the beginning. 1950s saw the first installation of glycol dehydration in Texas[66]. It remains the most popular gas dehydration process to meet most of the pipeline specifications. As glycol accumulates in pipelines, it degrades and becomes acidic. This may trigger the problem of corrosion.

The deliquescing desiccants offer many advantages such as no volatile organic compound emissions and aromatic hydrocarbon emissions, no ground contamination, no fire hazard, low CAPEX, and OPEX. To meet the pipeline specifications and hydrate control, desiccants are an inexpensive method. Desiccant dehydration is well suited for remote, unmanned locations[67]. As desiccant drying equipment is simpler, as compared to glycol, membrane filters and regenerative absorption, it comes cheaper. The operating costs are influenced by temperature, pressure and water vapor removal requirement. Desiccant do not react with hydrogen sulfide, thus it can effectively dehydrate the sour gas.

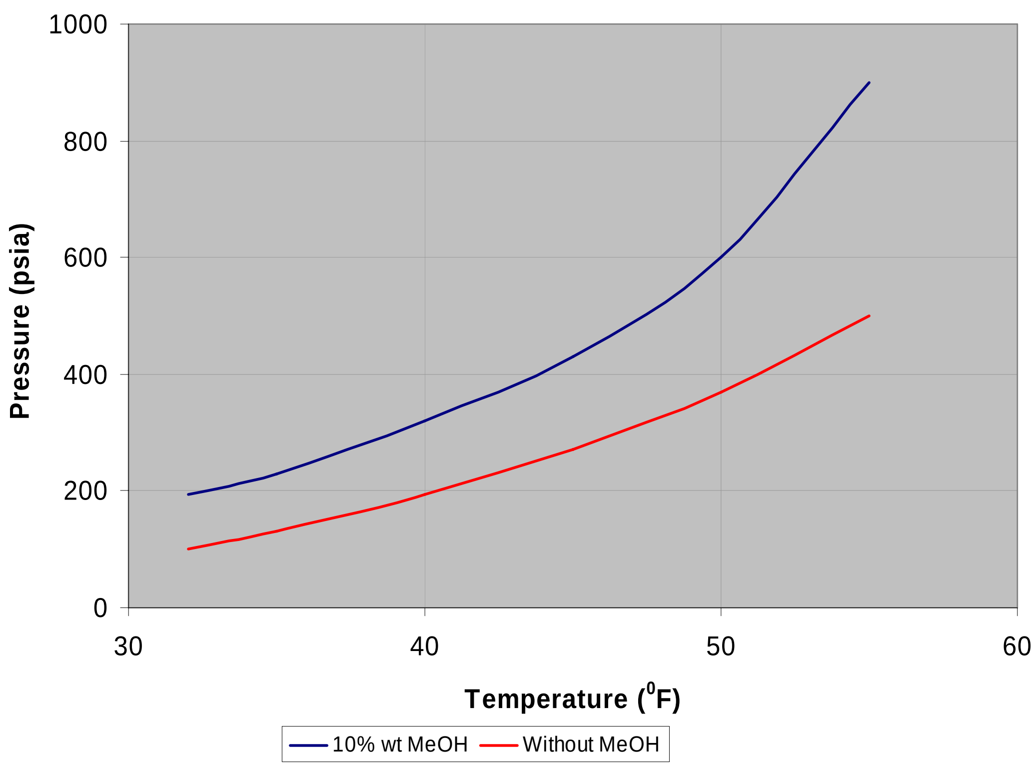


Fig. 46: Shifting of Hydrate Equilibrium by Addition of Methanol[58]

Sub-cooling can be stated as the hydrate formation curve shift to the left when system is treated with an inhibitor. Sub-cooling is the difference between temperatures at which hydrates dissociate and the actual fluid temperature. In other words, degree of sub-cooling means the temperature difference by which hydrate dissociation point rolls back after treating the system with an inhibitor .Degree of sub-cooling needed determines the hydrate inhibitor type. Fig. 46 illustrates the shifting of hydrate equilibrium by addition of methanol to gas and water system. With addition of methanol, the equilibrium shifts to the left giving more margin to the production operations from flow assurance point of view.

Once the type of inhibitor to be used is established, field trials in alternate pipeline systems should be carried out. For trials, the main production lines should be avoided before the type and dose validation for produced fluid to assure recovery of the system in case of hydrate formation during trial. Also, all the variables for hydrate formation such as pressure, temperature, and stream composition should be monitored. Initial dosing should always be higher than determined in laboratories as this would positively ensure inhibition of hydrates. Once inhibition is guaranteed from trials, the dosing can be optimized.

Surfactants and Hydrate Formation

Surfactants can significantly alter the surface or interfacial free energies even at low concentrations. Some surfactants are suitable as kinetic inhibitors in the flowing pipelines while others could be suitable for storage of hydrates for solid state transportation or preservation.

Kinetic Inhibition

Kinetic inhibitors do not lower the hydrate formation temperature. They work by changing diffusive-sorptional exchange at gas – inhibitor – water interface. Primarily they get adsorbed on the surface of both hydrate microcrystals and water droplets. They decrease the growth of nuclei to critical size, prevent coagulation, sedimentation, and prevent large plugs in flow paths.

The kinetic inhibition allows the hydrate system to exist in thermodynamic stability region, but the small nuclei are kept from agglomerating to larger masses. However, the kinetic inhibitors known are effective for sub-cooling up to 10 ^{0}C. Probably, the KIs effective for higher degree of sub-cooling are yet to be discovered[68]. Oil industry is focused on a third type of hydrate inhibitors called anti-agglomerates.

Thermodynamic inhibitors are added at 10-60 wt%, whereas kinetic inhibitors and anti-agglomerates are added at less than 1 wt%. Looking at the concentration needs in case of anti –

agglomerates and kinetic inhibitors, even if they are costly chemicals as compared to methanol or glycol, their choice for hydrate inhibition can be significantly small when total volume, storage needs, and transportation costs are compared[68]. The KI VIMA-VCap developed by Exxon was used at a rate of 0.5 gal/day in West Pembina field for oil flowline hydrate inhibition, against the previous use of 260 gallons of methanol, twice a week[62]. Fig. 47 shows the comparison between quantities of methanol, glycol (monoethylene) and anti-agglomerate (VIMA-VCap) needed to achieve similar sub-cooling.

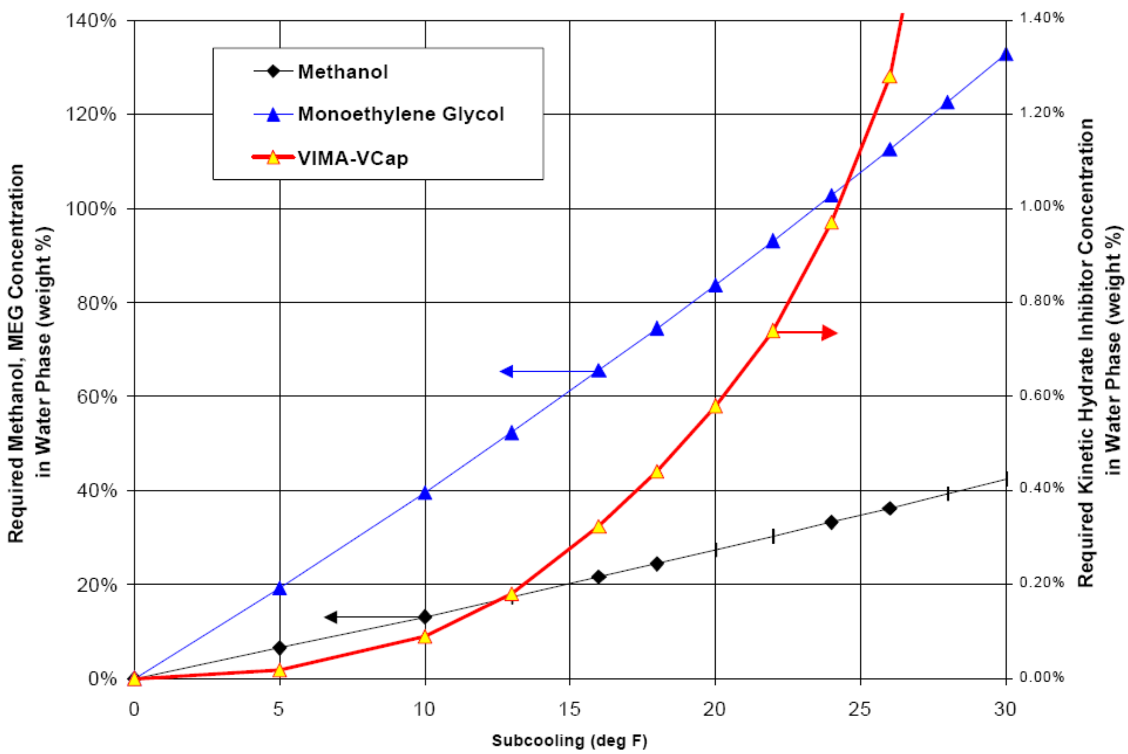


Fig. 47: Comparison of Inhibitor Quantities Needed to Achieve Sub-Cooling[62]

Potential advantages of AAs and KIs over thermodynamic inhibitors include smaller umbilicals, smaller pumps, smaller storage, and less frequent transportation for supply.

During the prolonged shutdowns, the degree of sub-cooling may seem beyond the inhibition capacity of some kinetic inhibitors. At the same time, hydrate nucleation is greatly reduced because of lack of turbulence. At the startup, methanol should be pumped and then switch over to KI injection during normal production. Anti-agglomerates are much less dependent on degree of sub-cooling. Injection of anti-agglomerates may be more effective even in case of prolonged shutdowns as they prevent agglomeration of hydrate nuclei. But AAs are known to be working only in conjunction with presence of a liquid hydrocarbon phase[68]. The AAs must have the ability to produce low viscosity hydrate slurry. AAs do not depend on chemisorption as in case of KI. One mechanism whereby AAs control hydrate crystals from agglomerating is emulsification of water phase in oil phase. If emulsion phase change occurs or oil phase passes through cloud point, the AA may not be as effective. In case of significant water cut increase, water phase may become continuous and AA may be ineffective. KIs can not handle higher degree of sub-cooling and AAs can not handle excessive water cuts.

Development of kinetic hydrate inhibitors is inspired by the kinetic ice inhibitors as ice and gas hydrates have similarities in composition. Poly-N-Vinyl pyrrolidone (PVP) has been knows as ice inhibitor and antifreeze proteins found in fish have inspired KI research in E&P companies[68]. In early 1993, Shell identified PVP, its polybutyl derivative, agrimer P-904 as a KI.

Unlike scale inhibitors, KIs are not able to check the growth of larger hydrate crystals[56]. This may be because of the fact that hydrates are able to grow over the entire surface instead of just certain growth site.

Advantages of LDHI's

Following are the advantages[69] of low dosage hydrate inhibitors (LDHIs):

- Lower chemical costs on total stock
- Lower transportation costs
- Lower manpower requirement as less total stock needs to be handled
- No contamination of topside and downstream facilities with undesirable alcohol
    - MeOH adversely affects the separation process as it makes the aqueous phase lighter and density difference between oil and water phases diminishing.
    - Also it adversely affects the quality of disposed produced water making it environmentally unsafe.
    - MeOH or glycol concentration in the vicinity of high salinity water can accelerate scale precipitation.
    - On the refining side, high concentration of MeOH adversely affects the efficiency of wastewater biotreaters.
- Less pump maintenance is needed as smaller pumps and much smaller dosing rates are required
- Intervention-less shut-ins as LDHIs shows good performance even during lengthy shutdowns.
- Accelerated production

    - As LDHIs allow higher water production rates, restarts and planned shutdowns are simpler to manage.
- Delay in water-cut related curtailment
    - Wells do not need to be shut down because of hydrate or other problems arising out of high water cuts.
- Improved operational flexibility
    - As LDHIs are compatible with other chemicals, changing for unexpected conditions is easier.
- Increased ultimate recovery
    - As wells keep flowing continuously, the problem of liquid load-up in gas wells is minimized and it helps a well to produce more as compared to the wells having frequent trouble.

Chemistry of KHI's – typical KHI's are polyvinylpyrrolidone (PVP), hydroxycellulose (HEC), polyvinylcaprolactam (PVCap) [27]. PVP can provide less amount of sub-cooling (10 ^{0}F) for short period of time (20 minutes) while PVCap can provide a higher sub-cooling (18 ^{0}F) for more than a month.

While studying the effect of inhibitors on hydrates, the following parameters[70] are of interest:

- Induction time to the onset of hydrate crystal formation.
- Induction time to the onset temperature of hydrate formation.
- Initial growth rate of hydrate crystals.
- Extent and time to agglomeration.
- Total gas consumption for conversion into hydrates.

Determination of Induction Time

The most important technique in the study of hydrate behavior is determination of induction time. Direct determination of induction time is difficult as it is a stochastic parameter for large number of hydrate crystals. Cingotti et al.[71] developed a concept of determining the hydrate crystal particle size distribution in suspension by turbidity measurement. The turbidity sensor they used is a UV-visible analyzer that measures the attenuation of polychromatic beam in the wavelength range of 230-750 nm. The identical elements in sensor act as light source and collimator. Light scattering in the path is measured.

This method quickly determines the efficiency of kinetic inhibitors both quantitatively and qualitatively. Induction time is the period between the moments the system enters hydrate region and the hydrate crystals start forming. Induction time determines the efficiency of inhibitor. Fig. 48 illustrates the ease with which different additives can be evaluated for their effectiveness as hydrate inhibitors. Comparison shows that an additive showing behavior similar to additive C can be an efficient hydrate inhibitor.

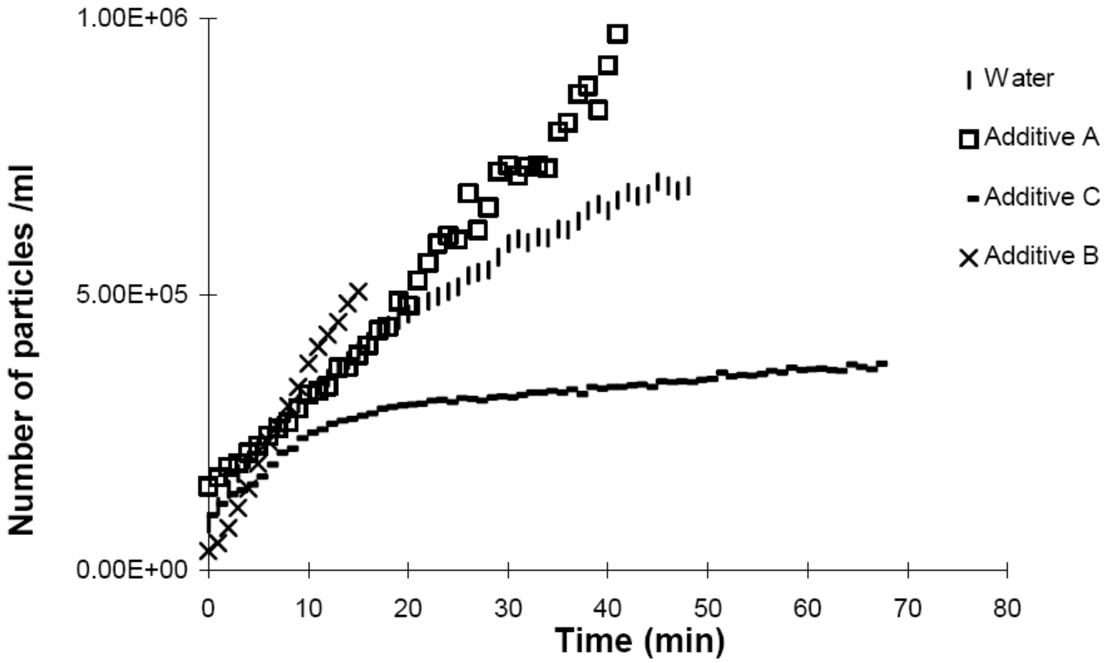


Fig. 48: Effect of Inhibitors on Number of Hydrate Particles Formed with Time[71]

Desirable Properties of Chemical Additives

For any application in oil and gas industry, the following properties are desirable for all types of chemical additives:

- Chemical additives must be compatible with other additives.
- Solubility must be examined over all possible temperature range.
- Viscosity should not be a limiting factor in pumping.
- Environment standards must be met or exceeded.
- Concentration requirements for effective inhibition should be as low as possible.

Flow Assurance Needs

To make hydrate slurries flow in the pipelines, water film should be prevented from forming on the pipe inner wall. Water film can lead to growth of nuclei and blocking of the entire cross section. Emulfip 102b, a flow assurance chemical can stabilize the hydrate (water) - oil emulsion and prevent agglomeration of crystals[8]. The anti-agglomerates are a better alternative to the traditional methanol injection.

For qualification of hydrate control strategy for flow assurance, the following aspects of hydrates need to be considered[65]:

- Composition, density, heat capacity, heat of dissociation, thermal conductivity and viscosity
- Equilibrium
- Kinetics
- Inhibition
- Blockage potential

The laboratory characterization of hydrates includes study of thermodynamic equilibrium conditions, amount of sub-cooling required, degree of hydrate formation and change in rheology. The evaluation of inhibitors is focused on their ability to prevent agglomeration of hydrate nuclei and minimize rheology alteration. Addition of inhibitors increases the environmental concerns downstream. Methanol has been known to cause total hydrocarbon content of produced water effluent to exceed allowable limits in the Gulf of Mexico.

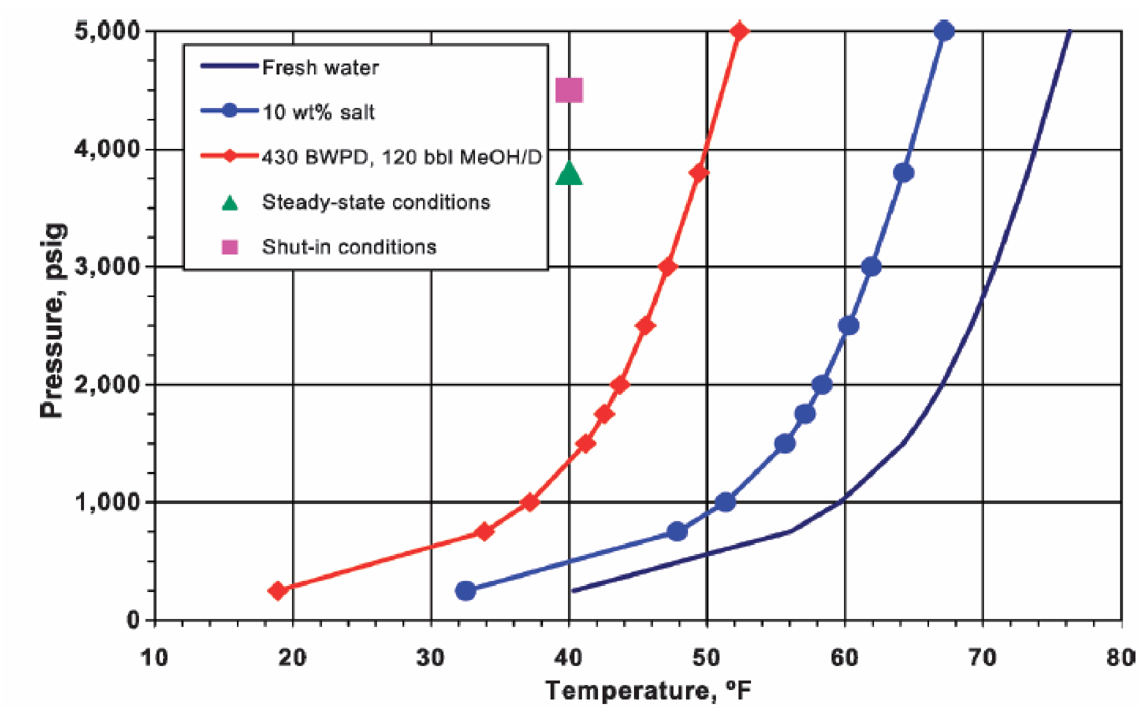


Fig. 49: Shifting of Hydrate Equilibrium by Presence of Electrolyte and MeOH[72]

The dissolved salts in produced water help inhibit hydrate formation to some extent[64]. Where water salinity is not enough to inhibit hydrate formation, the flow of hydrates as slurry in pipeline using kinetic inhibitors is attractive for high water cut systems. Tohidi et al.[64] has shown that electrolytes present in system shift the hydrate equilibrium curve to the left. Fig. 49 shows that addition of salt to water in water-hydrocarbon system shifts the hydrate equilibrium to the left.

The unconventional inhibitors are effective at much less concentrations as compared to typical methanol and glycol injection requirements[65]. In oil industry, it is often difficult to introduce any new technology or any new chemical. Consequences of failure are so severe that the operators remain very conservative in adapting anything new for the first time.

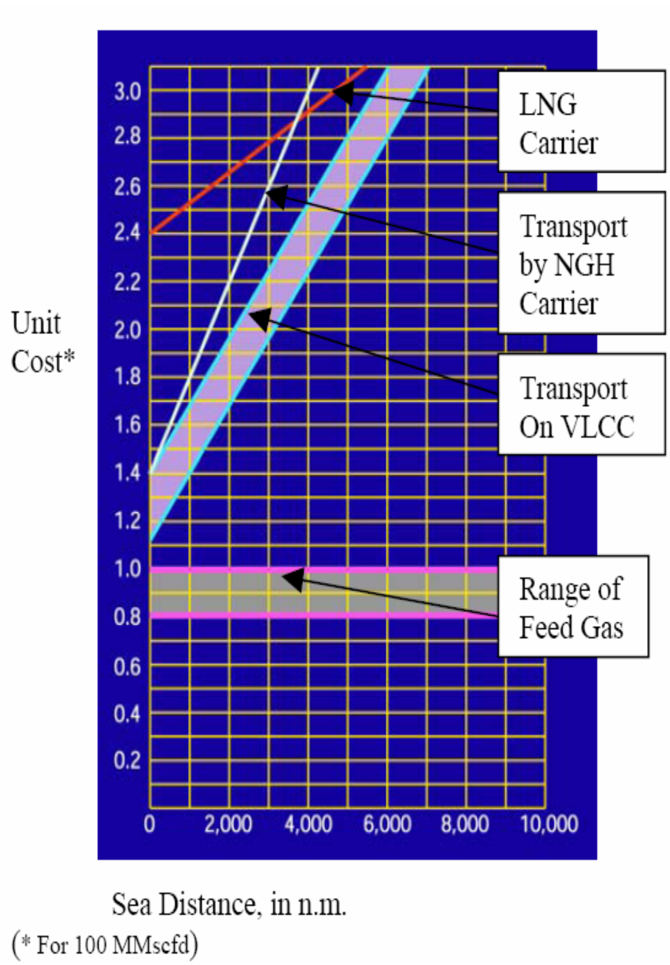


Fig. 50: Options for Transport of NGH[73]

Emulsion Flow in Arctic Environment

In environments with subzero ambient temperatures, like in Alaska, the concept of oil-in-brine transportation in pipelines could be successful[74]. Brine will not freeze even at the freezing point of water. Oil in water emulsions flow more readily than water in oil emulsions. This is why some wells which produce emulsions usually flow oil in water emulsions as it can more easily flow in the porous media.

NGH Transport

Natural gas hydrates (NGH) in the meta-stable range of pressures / temperatures allow handling at atmospheric pressures at subzero temperatures (23 ^{0}F). Close to 5000 trillion cubic ft natural gas is stranded worldwide[73]. This is mainly because pipelines are impractical. Hydrate transport systems are Eastern Canada, Venezuela, Trinidad, Egypt and Indonesia. In many cases, the oil production costs are very high because of need to re-inject associated produced gas. NGH systems are safer than LNG, GTL, or CNG transport systems and have lower CAPEX and OPEX. NGH can also be adapted to store the gas being flared. A comparison of NGH carried on carrier, VLCC and LNG carrier is shown in fig. 50.

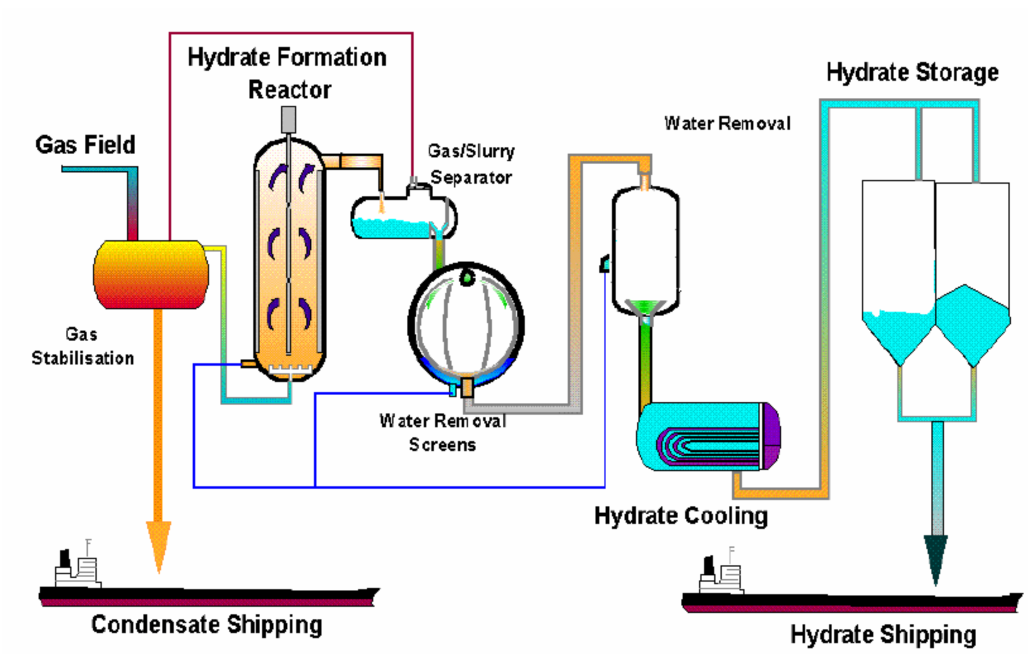


Fig. 51: Conversion of Natural Gas to NGH[75]

The schematic process for natural gas to NGH conversion and transport is illustrated by Mark et al. [75]. The produced gas from wells comes to stabilization facility where most of the condensate is separated and gas is diverted to hydrate formation reactor. After hydrate slurry is formed, it goes to a slurry / gas separator. Hydrate slurry along with free water goes to water removal screens and further cooling. After cooling, hydrates are stored temporarily before loading into ship for onward transport. Condensate is separately transported. Fig. 51 shows this process.

However, Mackagon and Holditch[76] concluded that specific energy of gas hydrates is lower than LNG, GTL. In fig. 52, the steep lines (grey and red dotted) show energy concentration of natural gas hydrates and methane hydrates respectively. The rest of four curves show energy concentration of free (non-hydrated) gas. Thus, hydrates are less concentrated in energy when compared to free gas products (LNG, GTL). Further, preparation of hydrates and re-gasification takes 12-16% energy of the transported gas. This makes NGH transport over long distances unattractive. Short distance transport in slurry form is however feasible.

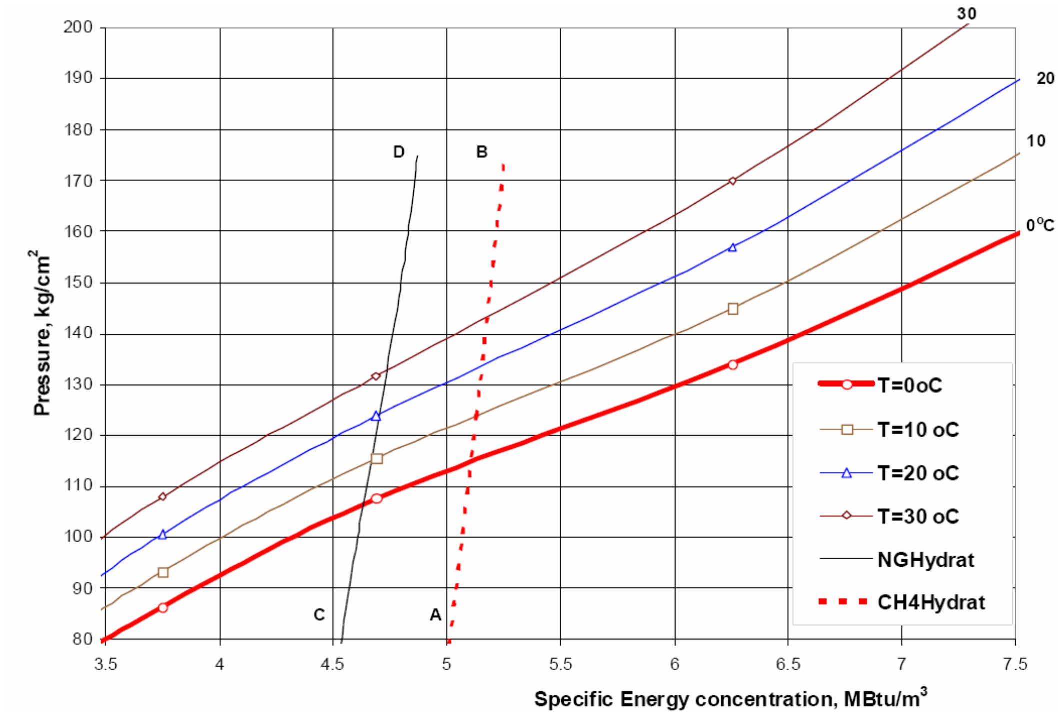


Fig. 52: Energy Concentration in Hydrates and Free Gas[76]

Cold Flow Technology for Hydrates

This technique allows hydrates to form but not agglomerate and flow in pipeline without insulation. The key factor is stability of hydrate slurry. LDHI and AAs help produce hydrate micro crystals but prevent from agglomerating. The cold hydrate slurry behaves linear for solids concentration up to 40%. Beyond 40% solids (hydrates) viscosity increases sharply and behavior is non-linear. Fig. 53 shows trend of hydrate slurry viscosity with varying hydrate concentration by weight. Experience of mining industry also conforms to this trend. For long flowlines, the cold oil viscosity is high and can reduce the production rate but multiphase pumps can effectively overcome this issue.

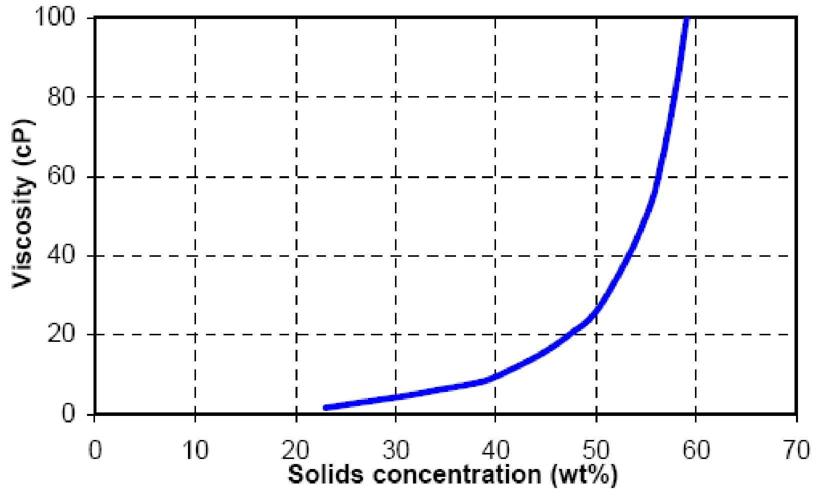


Fig. 53: Cold Slurry Flow[6]

Hydrate Mitigation Strategies

Chemical Inhibition

Thermodynamic and kinetic inhibitors are used as chemical inhibitants. In systems with constant potential of hydrates formation, the inhibitors are used on a continuous basis. Systems where hydrates do not form when system is running are treated with chemical inhibitors if any prolonged shutdown occurs. Sometimes, the wells are bullheaded with MEG to prevent hydrate formation in borehole. A sophisticated chemical inhibition strategy can be based on real-time water cuts, gas, oil compositions, pressure and temperature along the system.

Heating

Electrical heating can be useful especially after prolonged shutdown. Heating can maintain the temperature of stagnant fluid trapped in pipeline outside the hydrate formation region. Electrical heating is more reliable than other methods. But the CAPEX for system installation in deepwater and long tiebacks can be gigantic.

Hot Fluid Circulation

Hot fluid circulation serves as warm-up for pipelines after shutdown and before startup for hydrate free flow. The time needed to achieve the warm up will depend on length, depth and volume of the pipeline.

Thermal Insulation

Thermal insulations are discussed in more detail in "Flow Assurance". Thermal insulations keep the pipeline temperature outside the hydrate formation region, when in normal operation. The biggest disadvantage with thermal insulation material is that it traps the moisture and trapped moisture corrodes the outer wall of the pipeline, as in case of BP's North Slope Alaskan pipeline recently.

System Depressurization

System depressurization removes the system out of the hydrate formation region by disturbing the equilibrium necessary for hydrate occurrence. Depressurization can be looked at as a last resort when neither chemical nor thermal strategies seem to be effective in case of prolonged and severe shutdown.

Scales

Scales are inorganic crystalline deposits that cake perforations, casing, production tubing, valves, chokes and flowlines. Oilfield scales are deposited from oilfield brines when there is a disturbance in the thermodynamic and chemical equilibrium that may result in certain degree of super saturation. The disturbance in thermodynamic and chemical equilibrium can be a change in pressure, temperature, pH and ionic composition[77]. Certain areas like North Sea and Canada consider scale as one of the top issues for flow assurance[78].

Scales form from solution by first forming a chance assembly of growth units. If radius of the assembly is greater than the critical radius, it grows to a macroscopic size[56]. The rate of scale crystal formation depends on driving forces. A wide variety of solids formed this way can hamper the recovery of hydrocarbons.

Formation Waters

Water found on this planet is rich in dissolved minerals as a result of mineral diagenesis, marine and fresh water life byproducts, and water evaporation[78]. Typically, increase in temperature increases the solubility of water for mineral ions, but it is not necessary that all ions will conform to the general trend. Calcium carbonate shows higher solubilities between 25 ^{0}C and 100 ^{0}C than around 200 ^{0}C.

Presence of CO_2 and H_2S further complicates the carbonates solubility behavior. This is due to the acidic nature of water with dissolved CO_2 or H_2S. Upon pressure reduction, these gases release out of the solution and solubility is reduced causing deposition of scale.

Scale Formation Process

Scale deposition means equilibrium of dissolved salts with solid salt. Dissolution of scaled salt is influenced by pressure, temperature, surface area, pH, movement of fluid, and solubility product. Scale formation starts with homogeneous nucleation - formation of unstable cluster of atoms[78]. Local disturbances in equilibrium forms atom clusters into seed crystals which grow further by absorbing more ions. Surface free energy of crystals decreases with increasing radius after critical size is achieved. Larger crystals are more conducive for stable crystal growth whereas small crystal seeds may re-dissolve back. Heterogeneities along flow path such as small dents or projections within flowline and locations of rough surface initiate crystal growth. High turbulence also catalyzes scale formation and deposition.

Principle Mechanisms of Formation of Scales

There are three principle mechanisms[77] of formation of scales:

1. Reduction in pressure or increase in temperature of brine, leading to a reduction in the solubility of salt. This mechanism mostly leads to formation of carbonate scales, such as calcium carbonate.

   $Ca(HCO_3)_2 = CaCO_3 + CO_2 + H_2O$

2. Mixing of water rich in barium, calcium, strontium cations with sulfate rich seawater leading to sulfate scales precipitation.

   $Ba^{2+} / Sr^{2+} / Ca^{2+} + SO_4^{2-} = BaSO_4 / SrSO_4 / CaSO_4$

3. Brine evaporation in HPHT wells. Typically in gas wells with very low water cut leads to evaporation of brine in stream and deposition of salt crystals as scale.

In the life of every oilfield, the physical environments conducive for scale deposition vary as water cuts and water qualities vary. The phases in the life of oilfield are typically – natural depletion, pressure maintenance by water flooding, artificial lift, EOR, and abandonment.

During natural depletion, calcium carbonate scale is predominant. As the system pressure falls, the point where gas is released out of the fluid moves further upstream – starting from surface system, to wellhead to well and reservoir. The chemical treatment point also needs to move upstream with the life of field[77].

Normally, in case of water injection, before injection water breakthrough, only carbonate and sulfide scale is predominant. As injection water breaks through, barium sulfate scales form at 5-

15% commingling. With time, water cut increases and it becomes possible to re-inject the produced water with some seawater and again there is formation of scale due to difference in chemistries. But when produced water re-injection exceeds 60% of injection fluid, the scale formation tendency declines.

Scale Formation Locations

The main scale formation locations are:

- Around the injection well where injected fluid comes into contact with reservoir brine.
- Locations of injected and produced fluid convergence paths.
- Multilateral wells where brines from different layers enter and commingle.
- Manifolds where different wells inflow produced waters of different chemistries.
- Locations of major pressure reductions such as chokes.

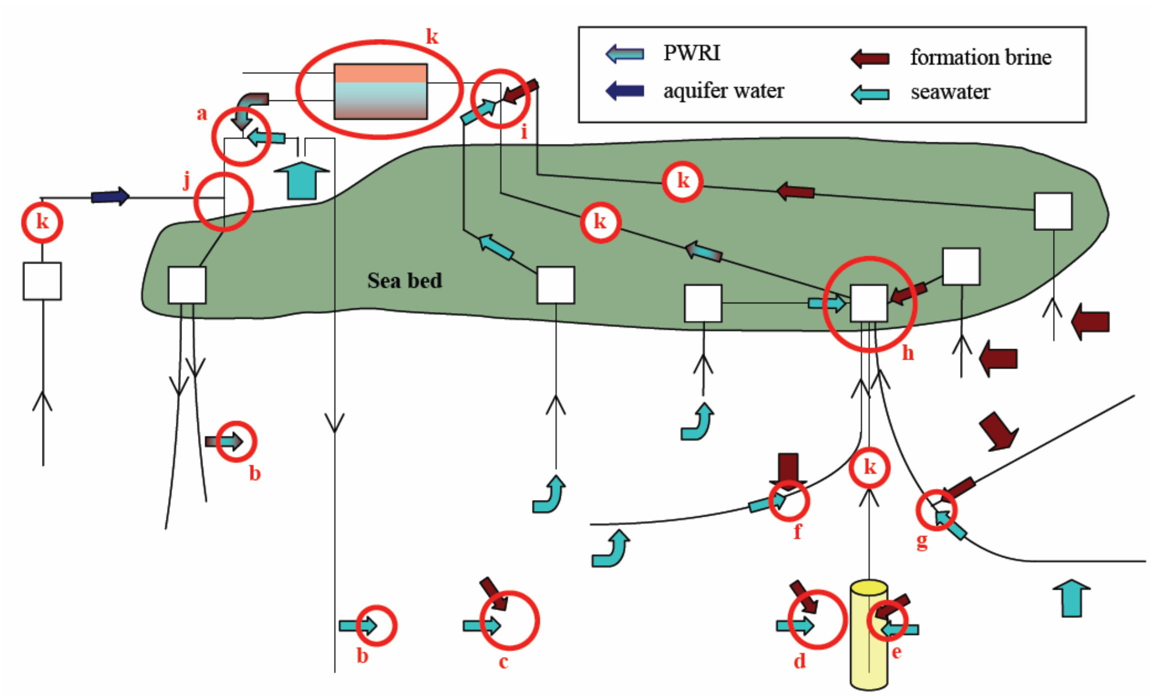


Fig. 54: Scale Deposition Locations[77]

Fig. 54 shows the locations of scale deposition. The potential locations where scales can form are shown by letters a to k. Each letter has a meaning in this figure as described below:

a	point of mixing of seawater and produced water to supplement injection
b	around injection well on reservoir face
c, d, e, f	inside the formation where injected and formation water chemistries differ
g	junction of a multilateral well

h subsea manifold
i surface facilities
j water production from aquifer for water-injection process
k separators

Types of Inorganic Scales

The types of inorganic scales are:

- Carbonates
  - They are a result of pressure reduction
  - They are pH and temperature dependent
- Sulfates
  - They are a result of mixing of waters
  - Higher solubility in cold water
- Sulfides
  - Corrosion
  - H_2S
- Oxides
  - Corrosion
  - Silica
- Hydroxides
  - Corrosion
  - Also result due to stimulation treatments
- Naturally occurring radioactive materials
- Naphthanates
  - High Naphthenic acid content
  - Calcium or divalent cation source

Detection of Scale

Early warning of scaling conditions would be valuable to operators. Intelligent wells will soon have design to detect change in produced water chemistry. Downhole electrochemical sensors capable to detect pH and chloride ion concentration change, along with temperature, pressure and multiphase flow measurement is included in BP Amoco's integrated scale management system. This will detect potential carbonate buildup and drive strategies for chemical treatments.

Prominent change in scale forming ions such as barium or sulfate coinciding with increased water cut and reduced oil production can indicate injection water breakthrough and conditions suitable for scale formation.

NODAL analysis can indicate tubing scale if the well suddenly indicates tubing constraints[78]. Identification of increasing reservoir constraints on production also implies scale in formation matrix.

Prediction Techniques

Geo-chemical models based on thermodynamics and geochemical databases can predict phase equilibrium[78]. The inputs required include pressure, temperature, elemental concentration of dissolved minerals, and gas composition. Highly developed geo-chemical models can predict the future scaling tendencies. For new developments where no prior information on scale formation is available, the geo-chemical models prove to be of immense utility as scale problems for future can be studied and mitigation strategies can be incorporated into engineering at design stage of the development. The following techniques are useful for assessing the potential for formation of scale and prediction of future behavior based on chemical, thermal and fluid flow data:

- Bottle tests
- Thermodynamic geochemical modeling
- Software
    - Commercial
        - Scalechem (OLI, USA)
        - Multiscale (Petrotech, Norway)
        - Geochemists Workbench (Bekthe)
    - In house by E&P
        - SPAM (BP)
        - SASP (Saudi Aramco)
- Near IR spectroscopy
- Pressurized fluid imaging
- Capillary tube blocking

Fig. 55 outlines a workflow for scale prediction and further risk assessment towards selection of prevention / remediation strategy. Initial chemical analysis is based on fluid samples from reservoir, wellhead or separator. The chemical analysis measures pH, cation concentration, anion concentration, H_2S content, organic acid content, carbonate, sulfate and other dissolved solids content. With this information and scale prediction software, the super-saturation and mass of precipitation of different types of scale under the pressure and temperature condition prevailing within the production system. Based on super-saturation and precipitation mass predicted, the risk of scale deposition at various locations is assessed. Based on risk assessed, the need for inhibition is ascertained. The monitoring of fluids chemistry has to be a continuous process for the proactive management of scales problem.

The reservoir simulation models may be used to investigate the water flow profiles during production and treatment (scale squeeze) to evaluate treatment performance[77]. This can be used to investigate scaling tendency of well fluid as it reaches the vulnerable part. The detailed scale control program at the project development stage –

- Investigation of reservoir model to study impact of scale deposition in wells.
- Lab analysis of produced water samples, injection water samples, available potential inhibitors to identify the best one.
- Assessment of required quantity and dosage rate of inhibitors.
- Economics

The knowledge of flow paths within reservoir matrix, well completions, scale prediction, inhibitor selection, treatment monitoring and analysis needs a cross functional multidisciplinary effort for effective reservoir management.

The main scale control techniques are injection water source selection, chemical inhibition, remediation, and flow conformance[77].

Scale Removal

Scale removal can be as costly as $2.5M per well excluding the deferred revenue due to deferred production[78]. Dissolution of carbonate scales is simple but dissolution of acid-insoluble scales is complex. Barium, strontium and calcium sulfate scales are insoluble in acid[79]. Dissolution of metal sulfate requires separation of the scaling metal ion.

All completion hardware, formation matrix and topside hardware should be safe from any type of potential damage as a result of scale removal technique. Strength of scale deposit and texture drive the choice of scale removal technique[78]. The following tables (tables 6, 7, and 8) summarize the scale removal techniques.

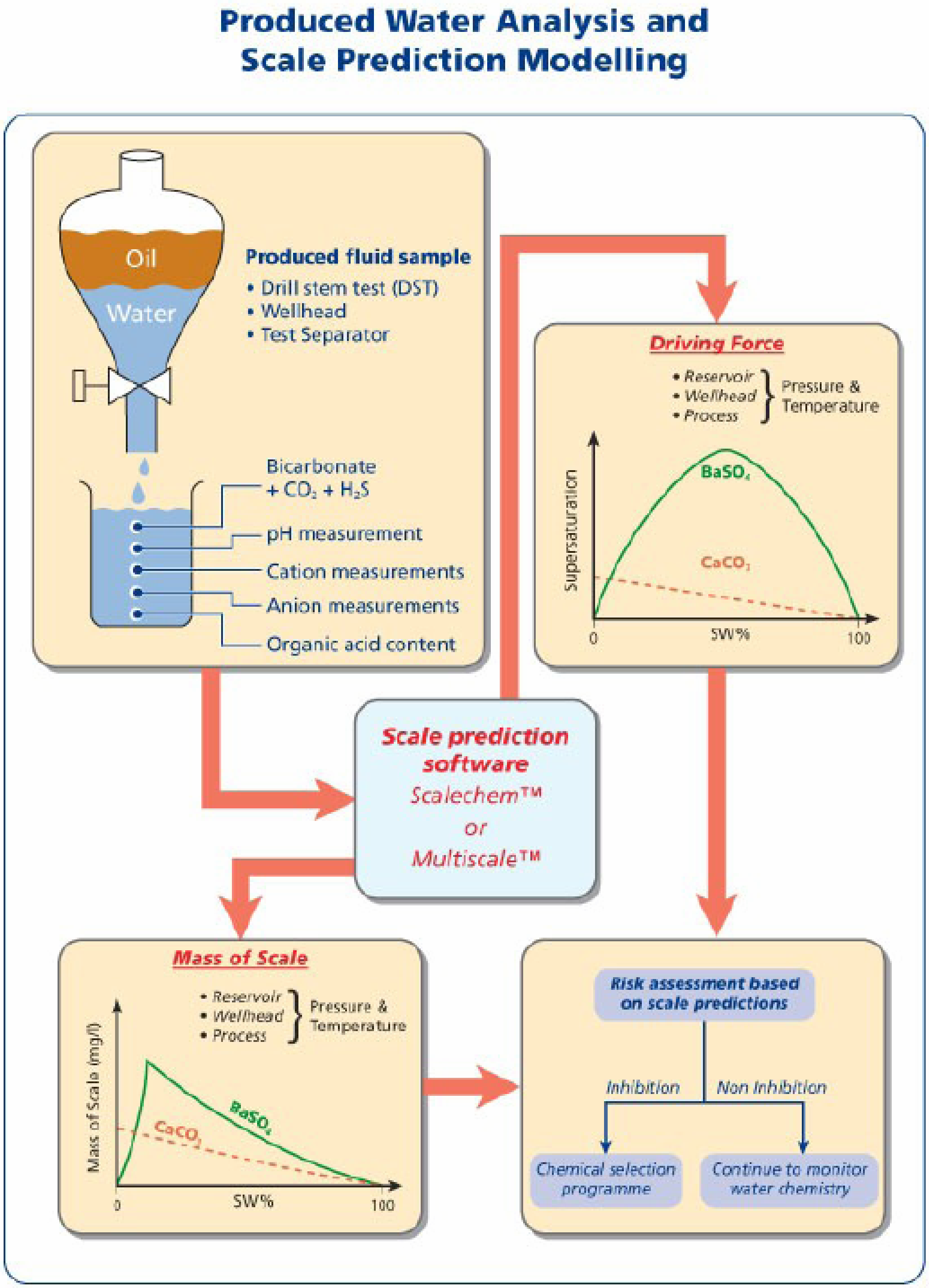


Fig. 55: Scale Prediction Workflow[77]

Scale treatment takes place in two chemical stages – dissociation of scale ions by scale dissolver and chemical reaction between components in scale dissolver and dissolved scale. As low solubility scales take long time to dissolve, their removal is essentially a soak process. The scale

Table 6: Mechanical Scale Removal Methods

Mechanical Removal				
Method	**Description**	**Hard Bridge**	**Advantages**	**Disadvantages**
Positive Displacement Fluid-Motor and Mill	'Moineau' motor and mill.	Can clean.	Small cuttings make cleaning easy.	Not suitable with high temperatures and/or scale dissolvers as stator elastomer fails.
Impact Hammer	Percussion hammer powered by fluid power. Impacts shatter scale deposits.	Can clean.	Simple and robust	Large cutting size. Cleaning of cuttings can be problematic.

removal chemicals are needed to be in scaled intervals for sufficient time. The scale removal chemicals can be placed by coiled tubing or bullheaded.

Table 7: Jet Blasting Scale Removal Methods

Jet Blasting					
Method	**Description**	**Hard Bridge**	**Tubular**	**Advantages**	**Disadvantages**
Scale Blasting	Nozzle head rotated by two nozzles offset from tool axis. Viscous brake controls speed.		Can clean.	Complete wellbore coverage.	
Bridge Blasting	Radial jets follow 'Moineau' motor and mill.	Can clean.	Can clean		High temperature is a limitation.

Coating of oil on scale deposit prohibits optimum reaction between scale dissolver chemical and scale deposit. To remove oil film and alter the wettability of scale to water wet, pre-flush ahead of scale dissolver can help in optimal cleaning of oil. Such pre-flush can consist of 5 – 10% mutual solvent with surfactant.

Scale Prevention

Scale prevention by chemical inhibition is better than mechanical cure just as in the case of medical practice. Methods can be simple as dilution and highly advanced as cost-effective threshold inhibitors. Dilution is employed in high salinity wells. Dilution method continuously supplies fresh water in the wellbore to reduce the saturation of scale forming ingredients. A small

Table 8: Chemical Methods

Chemical Cleaning				
Method	**Description**	**Tubular**	**Advantages**	**Disadvantages**
Fixed Wash Tool	Tool with many large diameter nozzles. Used with chemical dissolvers.	Can clean.	Simple and robust	Fluid power is lost to circulating friction.
Spinning Jetting Tool	Rotational torque provided by nozzles offset from main axis. Used with chemical dissolvers.	Can clean	Simple and complete wellbore coverage	No speed control and inefficient jet action at high rotary speeds.
Indexed Jetting Tool	Used with coiled tubing unit. Pressure cycling rotates nozzle head by 90^0. Nozzle head houses multiple small diameter nozzles. Used with chemical dissolvers.	Can clean		Needs coiled tubing unit and multiple runs for better cleaning.
Turbine Powered Jetting	Fluid turbine rotates nozzle head with two nozzles.	Can clean	Complete wellbore coverage	Abrasives can not be passed through turbine due to potential damage.

diameter (<1.5”) string is needed to supply the fresh water at the depth of dilution.

Common scale inhibitors “chelate” or tie up the reactants in soluble form at the cost of consuming scale ions in stichiometric ratios[78]. Chelating inhibitors can control scale precipitation only for limited level of oversaturation. Because of high volumetric requirements, the cost-effectiveness and efficiency is not always attractive.

Threshold scale inhibitors (kinetic inhibitors) chemically interact with scale crystal nucleation sites and inhibit the crystal growth. Kinetic inhibition is a well known technique for scale prevention[68]. Scale inhibitors work by blocking the growth sites on the surface of chance assembly. The assemblies which are kept from growing to critical radius fall apart and scale is effectively inhibited. The required concentration of threshold inhibitors can be 1000 times less as compared to chelating inhibitors. Thus economically, they are much more attractive and more efficient.

The scale inhibitors when made to adsorb in the formation matrix or precipitating in pore spaces can work wonders in preventing scales over a period long enough to match a couple of years, if treatment is properly designed and executed[78]. This can maintain the well’s productivity by keeping formation (scale) damage and tubular blocking to the minimum.

6. EXPERIMENTAL SETUP

This section details the experimental facility used for solid-liquid flow visualization, sand detector study, twin-screw pump behavior with viscous fluid and under the conditions of viscous gel injection.

The experiments were carried out at Texas A&M University Petroleum Engineering laboratory and Riverside Campus field lab. Sand and water flow visualization experiments were carried out using the flow loop which is shown in fig. 56. The laboratory scale multiphase flow facility includes a hopper, a centrifugal pump, liquid and gas mass flow meters, transparent sections, and 2” piping. The hopper also works as a recirculation tank.

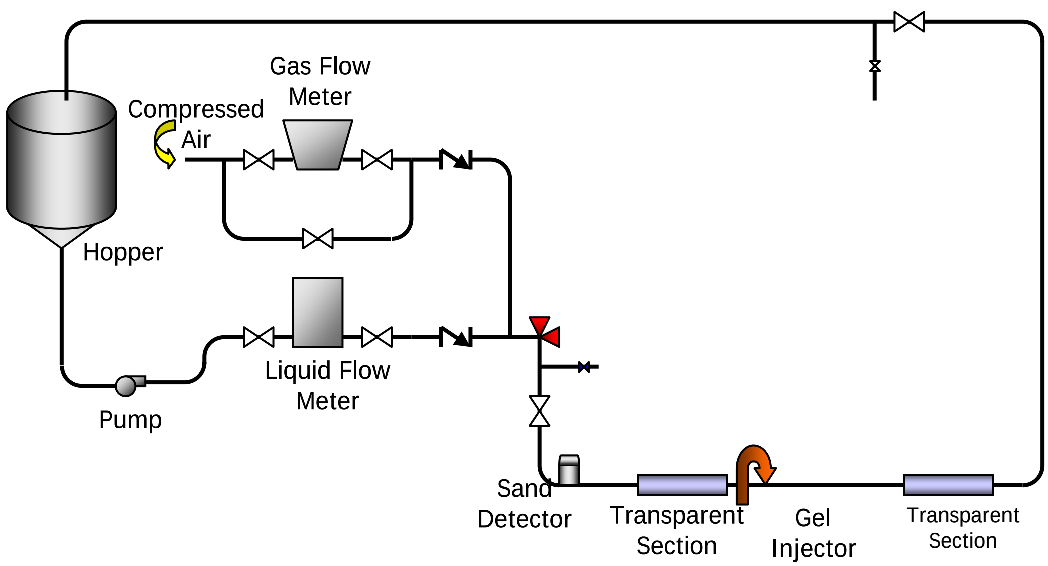


Fig. 56: Visualization Loop Flow Diagram

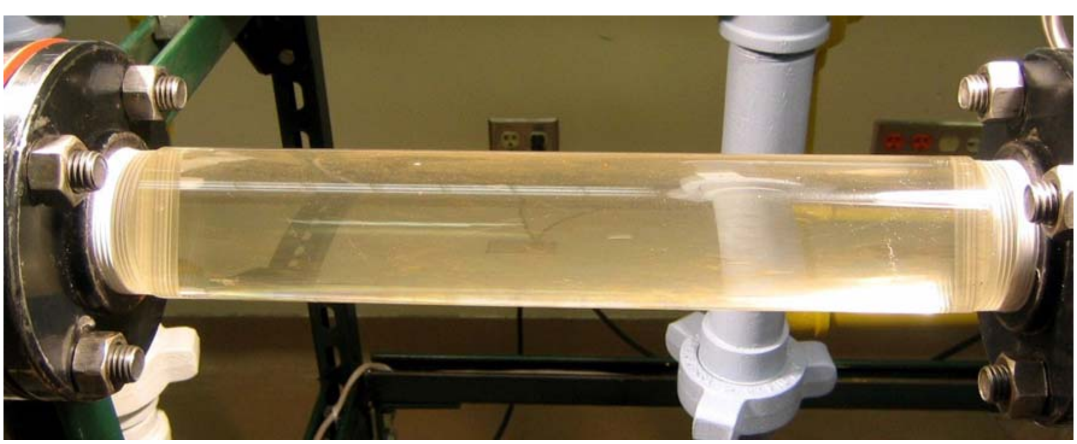


Fig. 57: Transparent Section

Fig. 57 shows the transparent section of the flow loop for visually studying the solid-liquid flow. Figures 58 and 59 shows the visualization setup and a screen showing the magnified image of sand particles flowing with water flow.

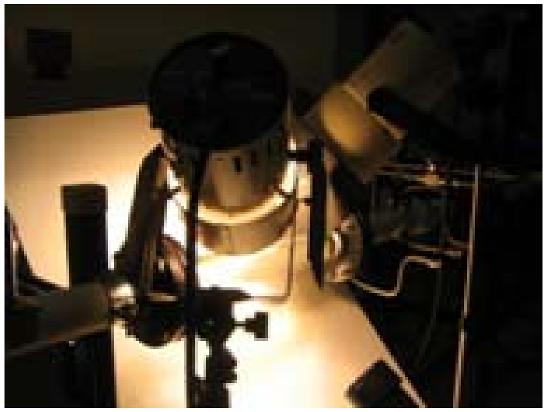


Fig. 58: Visualization Setup

Fig. 59: Image of Sand Particles Flowing in Water

The field scale multiphase flow facility includes two full size twin-screw pumps, 6” and 4” suction piping, 3” discharge piping, centrifugal feed pumps, liquid storage and recirculation tanks. Schematic flow diagram for the setup is shown in fig. 60.

Data Acquisition is real time and is incorporated into LabView 7.0 interface on a PC. The service software for sand detector can be separately run for calibration and other options. The speed control systems for twin-screw pumps work independently and can be operated in local and remote modes.

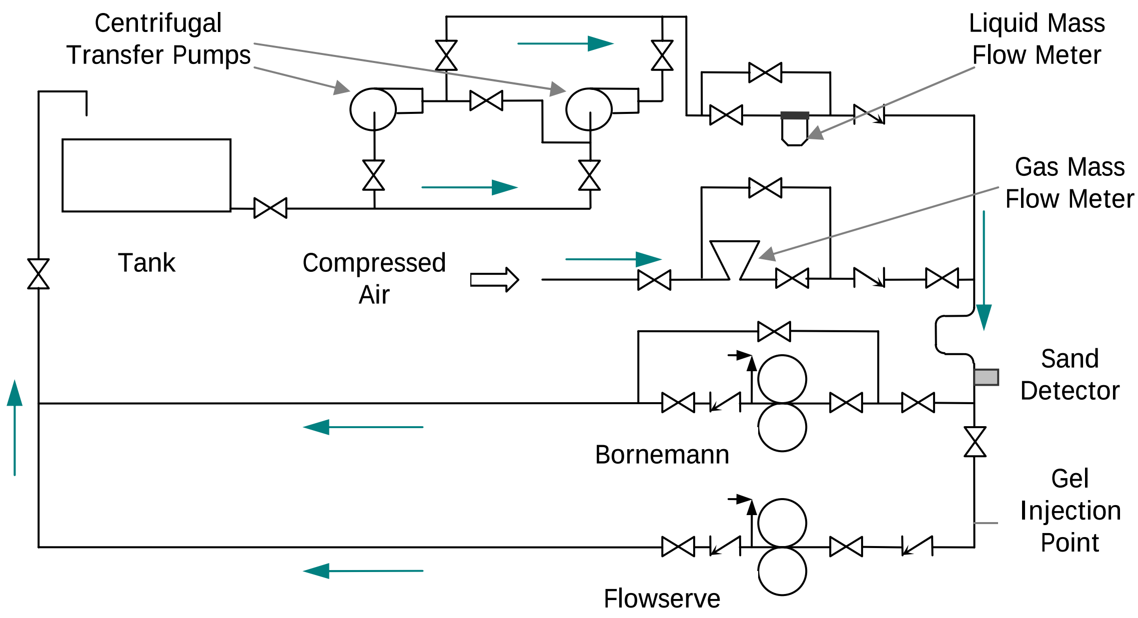


Fig. 60: Riverside Facility Flow Diagram

Description of Riverside Facility

Liquid Storage Tanks

There are two open tanks of capacity 40 barrels each. One tank is connected to the flow loop while other tank is used to store a reserve quantity of water. Fig. 61 shows the liquid tanks.

Fig. 61: Tanks and Feed Pumps

Compressed Air Source

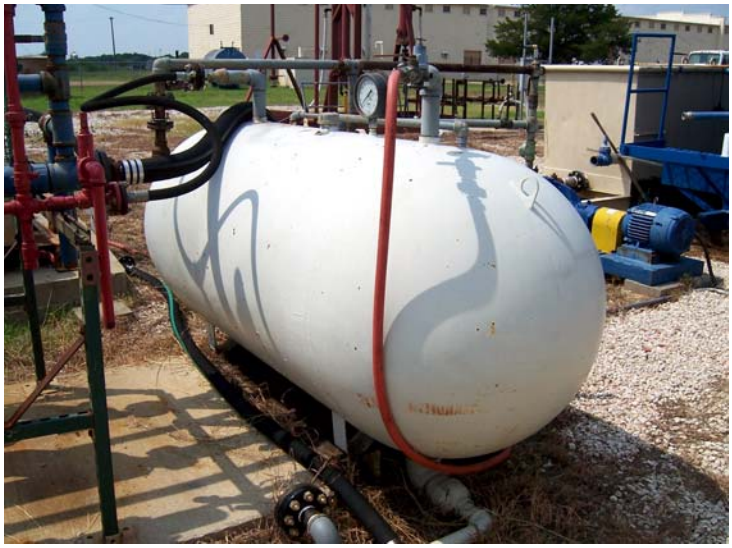


Fig. 62: Pressure Vessel for Compressed Air Storage

A 49 HP air compressor capable to deliver a pressure of 110 psig is hooked up with the air storage tank in which compressed air is stored up to 90 psig and supplied to the flow loop as needed. Air storage tank is a 420gallon pressure vessel (fig. 62).

Fig. 63: Centrifugal Feed Pumps

Centrifugal Pumps

The centrifugal feed pumps (fig. 63) are so networked that they can be run in parallel or in series. They provide a boost to the liquid from storage tank to the suction of twin-screw multiphase pumps through measurement skid and 4" suction piping with acoustic sand detector. The pump specifications are 15 HP, 230/460 V, 37/18.5 A, 60 Hz. Configuration to operate in both series and parallel gives flexibility to control the suction conditions of the twin-screw pumps. For high speed requirements, flow at the suction needed is on a higher side and feed pumps can be operated in parallel. For low differential pressure needs across twin-screw pumps, the pressure at suction needed is on a higher side and feed pumps can be operated in series.

Flow Measurements

The metering skid consists of oil, water and gas legs (fig. 64). Only water and gas legs were used for this experimental study. Gas volume fraction (GVF) is controlled by adjusting the flow rate of air or liquid or both by manually throttling the valves. This gives a wide range of suction conditions. Phases are metered individually and then mixed at the end of metering skid. Sand is monitored in main suction piping. Liquid coriolis meter is a 3" Micromotion Elite Series mass flow sensor; model CMF300M420NU while gas coriolis meter is a 1" Micromotion Elite Series mass flow sensor, model CFM100M329NU.

Fig. 64: Gas (Red Line), Water (Blue Line) and Oil (Green Line) Coriolis Meters

Fluids Used

- Water

- Guar gel 29.77 lb/1000gal, 43.07 lb/1000gal and 53.09 lb/1000gal concentrations
- Sand: Silica sand 20/40

Acoustic Sand Detector

The Roxar acoustic sand detector (fig. 65) is a non intrusive passive sensor with calculation and interface unit (CIU). It is clamped externally on the piping after a 90^0 bend. The CIU (fig. 66) converts the noise generated by particle impact to a measure of the quantity of particles flowing in the pipe. The specifications of sand detector are as following:

- Fluenta SAM 400 TC
- Smallest particle detectable 50 μm
- Pipe dimensions => 2”
- Power consumption max 0.6 W
- Supply voltage 11-18 V
- Pipe surface temperature -60 ^{0}C to +115 ^{0}C
- Ambient temperature -40 ^{0}C to +80 ^{0}C
- Dimensions Φ80 X 100
- Weight 3 kg
- Ingress protection IP 67
- Material Stainless steel
- Max cable length 1500 m

Fig. 65: Acoustic Sand Detector

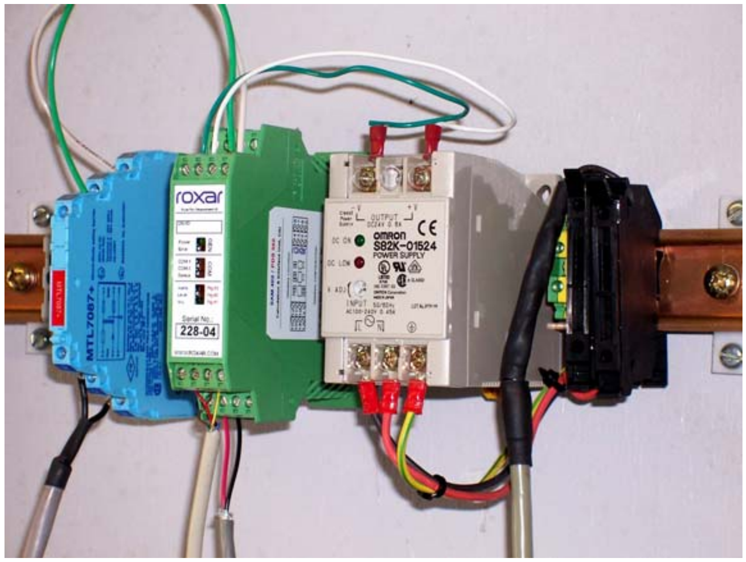


Fig. 66: Calculation and Interface Unit for Sand Detector

Method of Sand Injection

The sand is easily introduced into the flow loop by injecting through tank outlet using a 1" diameter PVC pipe that reaches the tank outlet on bottom (fig. 67). This pipe has one T attached on the bottom. One end of T is free and other end is connected to a small piece of pipe to ensure that it enters the 4" outlet and ensures sand flow exactly towards the suction of centrifugal pumps without falling down in tank or flowing to any other direction. A paper cone is used as a "funnel" for sand particles.

Fig. 67: Pipe for Sand Injection through Tank Outlet (Left) and Paper Cone for Pouring Sand into the Pipe (Right)

Temperature, Pressure and Differential Pressure Measurements

For the temperature measurement, direct immersion type Weed 201 RTDs are installed on suction and discharge of both twin-screw pumps. The data acquisition system receives pressure and differential pressure data from transmitters (fig. 68).

Fig. 68: Pressure Transmitter on Suction of Flowserve Twin-Screw Pump

Twin-Screw Pumps

The main components of facility are the twin-screw pumps.

Flowserve Twin-Screw Pump

This is LSJIS model (Fig. 69) with a maximum throughput of 10105 bbl/day. It boosts pressure up to 500 psig and has no internal recirculation system. It is driven and speed controlled by Voith Turbo torque converter. Torque converter is driven by an electric motor which has an ABB variable frequency drive (VFD) for precise speed control. Flowserve twin-screw pump can be run at a top speed of 1800 RPM.

Fig. 69: Flowserve Twin-Screw Pump

Voith Turbo Torque Converter

The Flowserve twin-screw pump speed is controlled by Voith Turbo torque converter (fig. 70). Texas A&M University, Petroleum Engineering Dept. riverside facility is the first place in world to test and use a torque converter for speed control of twin-screw pump. Torque converter is a

Fig. 70: Voith Turbo Torque Converter

hydrodynamic gear unit that can vary the speed and the torque between input and output shafts. The mechanical energy of the motor is converted into hydraulic energy through the pump wheel.

In the turbine wheel, the same hydraulic energy is converted back into mechanical energy and transmitted to the output shaft. The adjustable guide vanes regulate the mass flow.

Fig. 71: Speed Control Hardware

Fig. 71 shows the complete speed control hardware i.e. electric motor, torque converter, and gearbox for Flowserve twin-screw pump.

Fig. 72: Remote Panel for Speed Control

Fig. 72 shows the LCD screen of speed control remote panel for Flowserve twin-screw pump. Fig. 73 shows the ABB VFD for speed control of Flowserve twin-screw pump electrical motor.

Fig. 73: ABB VFD for Electrical Motor

Bornemann Twin-Screw Pump

The Bornemann twin-screw pump, model MW-6.5zk-37, is a 10000 bbl/day pump that boosts the pressure up to 250 psig and has an internal recirculation system. It is driven by a 50 HP electrical motor and controlled by a Kimo MM3 Frequency Inverter, MotoMaster 37 FEP 37 kW, 3AC 380-460 V, 73 A. Fig. 74 shows the Bornemann twin-screw pump.

Fig. 74: Bornemann Twin-Screw Pump

Data Acquisition

Data acquisition is real time and is provided by National Instruments data acquisition board for Windows based PC along with LabView 7.0

Discharge Piping

The twin-screw pumps feed to 3” discharge piping which loops back to the liquid tank. To simulate different field conditions, pressure can be built up to 500 psi by throttling a valve towards the end of 3” discharge piping (fig. 75). Finally, all fluid in the loop flows back to the tanks.

Fig. 75: Valve used to Buildup High Pressure on Discharge Side

7. SOLIDS PRODUCTION AND MANAGEMENT

This section deals with handling of the produced solids in surface production systems. It begins with the description of typical deepwater reservoirs with loose consolidation, process, modes and nature of sand production and flow. Erosive wear in twin-screw pumps, different approaches to analyze wear and parameters affecting wear are discussed. Sand detection method, calibration, testing and performance of sand detector under varying conditions are discussed. Slip flow in the clearances of twin-screw pumps, approaches to solving the problem of wear are studied and use of high viscosity gel is emphasized as an effective method. An empirical model for predicting viscous fluid flow across twin-screw pump is developed and prediction of effective viscosity across pump based on speed, flow rate and differential pressure is discussed. Also, prediction of effective viscosity in a pipeline flow based on viscosity of injected fluid and injection rate is discussed.

At some stage in the life of a well, solids are produced[80]. They originate from reservoir rock, drilling activity, and from installed hardware. Identifying the type and source of solids is critical to determine the mitigating action. Mud filter cake and solids from completion fluids may be produced early in the life of well. But early detection of sand production indicates possible compromise of completion integrity or reservoir consolidation.

Historically, sand control techniques such as expandable screens, gravel packs, frac packs, etc have been used. In cases where this is not possible, the conservative approach is to step down the production. All this leads to a reduction in revenue.

Fig. 76: Sand Detector

Complete separation of solids is not a realistic approach due to operational limitations. Further, subsea process for desanding operation has its own limitations due to sand disposal problem. It is, therefore, necessary to flow oil and gas with sand content. Emphasis on maximum production rates within operational safety and economy have led to the development of the acoustic sand detector (fig. 76). Sand management strategies are now evolving. Maximum sand free rate objectives are superseded by maximum acceptable sand rates. This shift in philosophy is driven by technical advances in detection, handling and disposal of sand, and also by ever increasing demand for oil and gas.

Deepwater Reservoirs

Geologically young formations are poorly consolidated because of neutral or no cementation and they often lead to sand production[81]. The deepwater reservoirs are generally geologically different[59]. They are typically, large area, thick sand deposits with minimal aquifer support and not over-pressured. They are not associated with salt domes and hence their temperature is lower. They may contain silt fines and are poorly consolidated. Such formations may produce large amounts of sand into the production system and can potentially damage the system components.

One option to protect the system is using gravel packs. The gravel packs have a tendency to choke themselves and stop producing. Hence, the wells completed in typical deepwater reservoirs need to have sand detection devices installed on flowlines so that in the event of high sand production, these wells can be shut down, or choked to produce at low rates. Surface monitoring and early detection of sand production is vital in providing mitigating actions downstream. Early detection can prevent incidents due to erosion and improve production.

Maximum sand free production rates offer several benefits. As reservoir depletes, the nature and composition of produced fluid keeps on changing and maximum sand free rate also varies. Sand production if not monitored, can lead to tubular, piping or surface equipment and networks failure leading to loss of containment.

Deepwater wells being typically high production wells are very sensitive to any concern which forces shutdown or intervention. Sand production is one such top concern for deepwater high production wells, as sand production can cause damage to equipment, deferred or lost production and environmental hazard due to potential loss of containment[80].

Sand Production

About 70% of the world's oil and gas are contained in poorly/weakly consolidated reservoirs[82]. And about 37% of the producing formations are sandstones[83].

Sand production is a common problem in wells, especially when the reservoir is poorly consolidated. This process comprises of loss of mechanical integrity of rocks surrounding wellbore, separation of sand particles from rock mass due to hydrodynamic forces, and transportation of sand to wellbore and downstream. Sand grains from formation are able to mobilize once the retaining forces weaken. Fig. 77 shows the sand particles flowing with liquid.

Fig. 77: Sand Particles Flowing with Liquid

When the stress acting on rock around the wellbore wall exceeds rock strength, shear failure takes place leading to breaking of the bonds between neighboring sand grains[84]. Drag forces exerted on sand grains cause them to part loose and flow into the well and downstream. Drag forces are related to the product of fluid velocity and viscosity. Cement bonds, intergranular friction, gravity and capillary forces oppose the movement of grains[81].

Fluid flow erodes the rock, and with sufficient velocity, carries sand grains into the wellbore and to the production systems. Sand production is known to show up with water breakthrough[84]. The formation rock strength properties are known to vary during the life of well[85].

Sand management encompasses the technologies for handling and well completion for production from weakly consolidated formations[85]. The technologies include completion methods to optimize production rates with sand content, downhole and surface equipment for handling, monitoring, workover and disposal of produced sand.

The ability to reliably predict sand production conditions, quantity, and nature of periodicity helps in decision for downhole sand control completion and sand production management. The CAPEX for downhole sand control could run into millions of dollars but still eventually resulting into high skin factor and reduced productivity.

The operators are aware of the dangers of solids produced from reservoir formation. Solids production is episodic and can cause extreme damage almost instantaneously. The consequences of this phenomenon are erosion of chokes, erosion of flowlines, equipment, and filling up of separators. All put together gives us a reduced deliverability. Reliable measurement of sand content in flow streams is thus very important to take mitigating actions ahead of time. The sand content in produced fluids is a challenge to the E&P business.

Modes of Sand Production

There are three[81] modes of sand production from the reservoirs:

Transient

In transient sand production, the sand concentration typically declines with steady production conditions after a perforation, acid stimulation or propped frac flow back job.

Steady State

This is continuous sand production at steady average concentration. A part of the produced sand keeps on accumulating in wellbore and may eventually block the perforated interval. This stage can come sooner or later depending on the sand lifting capacity of the well fluid.

Catastrophic

This is a sudden large production of sand “slug” due to major failure of formation cement or sand control completion.

Nature of Sand Flow

The sand concentration in production flowlines in an oilfield is not of the order of concrete slurry. The concentration of sand particles is substantially lower as compared to “slurry” concentration. Thus, the liquid carrying sand particles is not able to keep the particles in homogeneous suspension all the time. There is a concentration gradient across the pipeline cross section. If the turbulence is insufficient to keep the fast settling sand particles in suspension, the particles travel with discontinuous jumps or roll along a sliding bed along the pipeline bottom. The sand particles

Fig. 78: Sand Mass Accumulation

flow shows periodic patterns. Their concentration is not uniform when they are flowing with liquids. This is similar to “sand flow”-dune movement in deserts. The particles are lifted from one location, and shifted to another location. Fig. 78 shows the accumulation of sand particles in the periodic process of solid liquid flow. In this process they settle and more particles accumulate at

Fig. 79: Shifting of Accumulated Mass to Next Location Downstream

a new place. When the size of accumulation is large enough to restrict the fluid flow, fluid once again starts transporting the particles and as soon as the size of accumulation diminishes, the fluid stream is strong enough to completely wash out the accumulation. This process keeps on repeating in pipelines. The size of accumulation is large for large concentration of sand and small for small concentrations. The photographs (figures 78 and 79) show this phenomenon.

Sand detector test with 0.09 g/sec average concentration was tried to study this phenomenon. Sand detector output confirmed it by showing periodic picks and drops in signal amplitude and

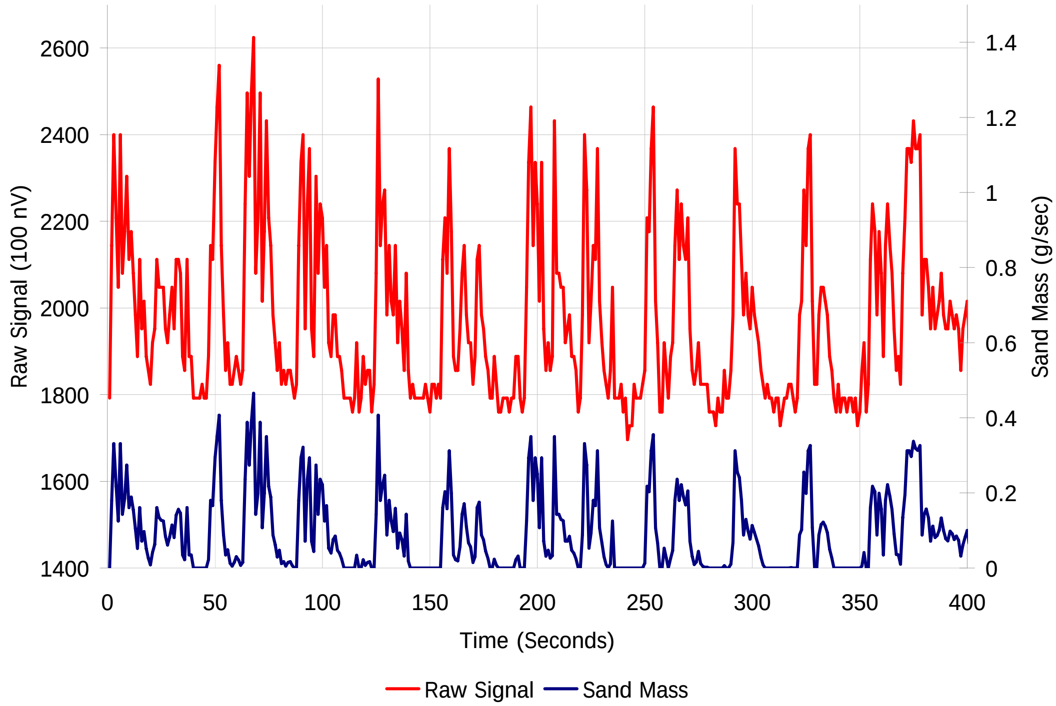


Fig. 80: Periodic Flow of Sand

detected sand mass (fig. 80). In all cases, the output signal (sand mass) is a function of raw signal. Thus filtering “false” sand noise or any “false” particles noise is a key to rely on the acoustic sand detection devices.

Management of Solids Production

It is important to estimate the potential that a well can produce sand, the quantity and rate of sand production. For surface facilities design from safety and efficiency point of view, the “if”, “when” and “how fast” for sand production are very critical. Once it is known that the formation has a potential to produce sand, the sand management needs to be implemented through historic data analysis and provision for future monitoring with data acquisition.

Once the sand particles part from the formation, it is also important that sand is efficiently transported out of the wellbore. Sand accumulation in wellbore can seriously hamper the normal production operation and intervention to de-sand the well may be needed. To ensure the successful transport of sand particles, the produced fluids must have enough energy and viscosity to keep sand particles from settling down.

Complete sand separation is the most conservative approach for sand management. However, due to practical limitations in solids separation techniques, the best separation process may not be the most economic. It is, therefore, necessary to allow the oil and gas production with sand content. To keep the losses due to erosion under control, it is necessary to focus on the use of sand monitoring technology. When the produced sand concentration needs to be managed through controlled production rates, monitoring of sand concentration can monitor the effectiveness of the rate control being implemented for sand control.

The primary goal of sand monitoring is to have a control over erosion rate of production system. The erosion rates depend on density and velocity of fluid, sand particle size distribution, geometry of flow path, sand release rate from the formation and hardness of the metal hardware handling the fluid flow[82].

Wear In Twin-Screw Pumps

As twin-screw multiphase pumps rely on the tight clearances for efficiency, loosing tightness of clearances can have catastrophic effects on performance. A suitable configuration of sealing clearances is very important to avoid losing the boosting efficiency of twin-screw pumps. Table 9 shows the circumferential clearances in different models of twin-screw pumps. Ensuring that the dimensions of clearances stay unaffected for life of the pump is very important.

Table 9: Circumferential Clearances

Twin-Screw Pump		Circumferential Clearance (mm)
Flowserve	MPP-380	0.3048 - 0.3810
Flowserve	MPP-275	0.3048 - 0.3810
Flowserve	LSJIS	0.3048 - 0.3810
Bornemann	MW6.5zk37	0.1016 - 0.3048
Livgidromash	A9 2VV 16/25	0.1016 - 0.2032

The only means to completely avoid the wear of screws will be complete separation of produced solids from produced liquid and gas. Before choosing a multiphase pump, the potential for abrasive wear must be determined.

Approaches to Analyze Screw Wear

There can be three approaches to analyze the wear in screws:

Field Tests

With field tests, the real wear on screws can be evaluated. This approach is expensive and time consuming. However, the wear characteristics will be valid only for the model tested. It will, therefore, be necessary to carry out all tests on all different pump models in subject.

Tribometers

The tribometer is a device which allows simulation of the wear process with a relatively simple process and lower costs. It is possible to simulate the conditions and clearances matching those in twin-screw pumps. But this will never represent the true geometry of screws and casing. Results obtained can be a general representation of wear process but they will not represent the true phenomena in the real pumps.

Modeling with Computational Fluid Dynamics

Computational fluid dynamics (CFD) is a sophisticated design and analysis technique. CFD has the power to simulate multiphase flow, with heat, mass and solids transfer, and chemical reactions. Using CFD gives an insight into the phenomena, predictive capability, and saves time. All "what if" scenarios can be tested before final physical model is manufactured. As simulation is fast, it is possible to improve the design before anything is sent to market or test a product like twin-screw pump before it is purchased and installed.

To study the erosive process using CFD, it is necessary to have the dimensional profiles of screws and casing. This data is highly proprietary and pump manufacturers are reluctant to publish the complete dimensions and profiles of the twin-screw pump internals as the technology is still very new and very highly competitive.

Parameters Affecting Wear

Velocity of flow in the clearances is the main parameter. The tip wear is caused by velocities composed of axial and circumferential components (fig. 81). The casing wear is mainly due to axial velocity. The wear losses are proportional to particle concentration and mean particle diameter[86]. For particle sizes smaller than clearances, the wear pattern is jet wear but with particle sizes approaching the size of clearances, sliding wear is predominant and wear losses jump by a factor of 10. Also, the wear losses increase proportionally with meshing ratio. Meshing ratio is a fraction of the total time period during which a surface element of screw geometry is meshing with its counterpart. Table 10 shows the meshing ratios for different components in a twin-screw pump.

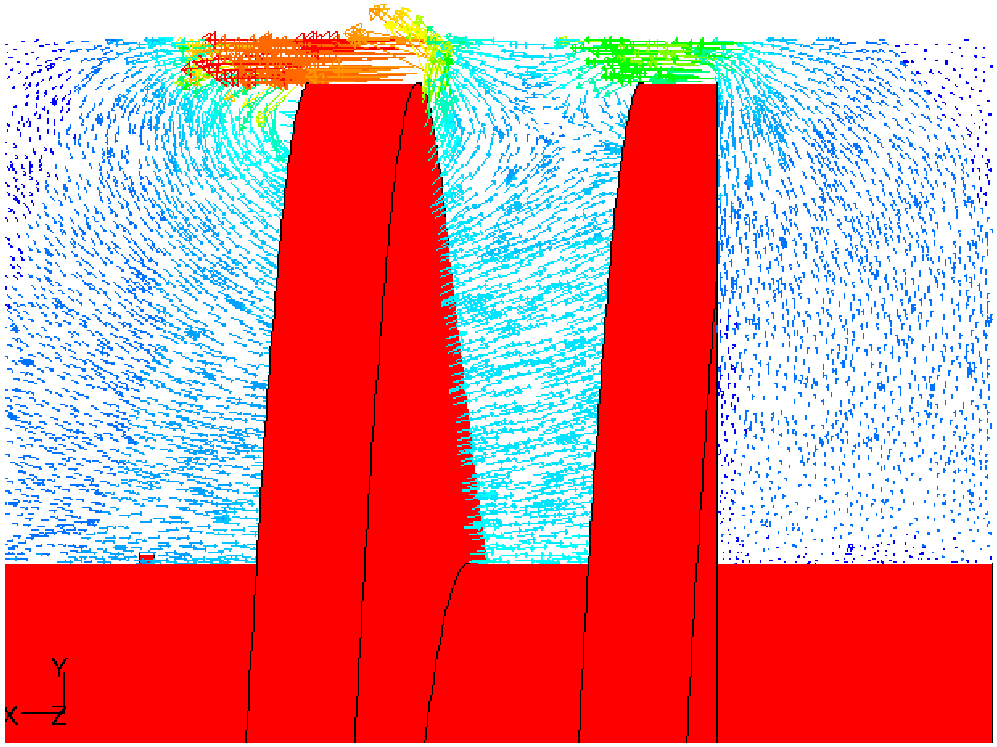


Fig. 81: Velocity Vectors at Screw Tip[87]

Table 10: Typical Meshing Ratios for Twin-Screw Pump[86]

Element	**Meshing Ratio**
Housing	0.50
Screw Top	0.80
Screw Bottom	0.03
Screw Flank	0.12

The following picture of screw from a twin-screw pump (fig. 82) shows wear prominently on the edges of screw threads. The location and pattern of wear confirms the phenomenon illustrated in fig. 81. The velocity of backflow or slip is highest in the circumferential gap. Also, the velocity of relative motion between screw and the fluid being "displaced" is maximum on the periphery of the screws. The screw-edge facing downstream of the flow is thus the weakest section. As any erosive action starts with the most vulnerable section first, the screw edge facing downstream is most vulnerable for wear. Hence, the screw edges erode faster as compared to any other area on the screw. Backflow or slip is thus a major contributor to the erosive wear on the screws. It is, therefore, important to study the slip flow in twin-screw pumps. Many authors have worked on investigation of slip flow. One recent work on slip is by Prang[88]. For laminar flow, the slip across a

Fig. 82: Screw Erosion on Edge

thread of screw due to the pressure differential can be given by

$$Q_{s,i} = \frac{(p_{i+1} - p_i)4\pi D_t \delta^3}{12\mu l} \tag{4}$$

where, p_i and p_{i+1} are pressures on the i^{th} and $i+1^{th}$ sides of the screw thread, D_t is screw tip diameter, δ is clearance between screw tip and casing, l is length of the leak path and μ is absolute viscosity of the fluid. Laminar flow is assumed here as the screw gaps should be tight and slip flow is desired to be small. Fig. 83 illustrates the screw and clearance dimensions.

The investigation of slip flow across a screw thread is discussed in the solids transport section. The hardness ratio between solid particle and wearing metal surface is an important parameter for hydro abrasive wear. Vetter et al.[84] found that the rate of wear jumps to higher values when the hardness ratio is close to one (fig. 84). For sand erosion mitigation, the hardness of screws should exceed 1200, as hardness of silica sand is 1100 (Vickers). Screws and casing with very hard, reliably adhering coating having sufficient thickness will ensure minimum wear while in operation. Strong material bonding will ensure resistance to bending and shearing stresses due to particle friction. Tough matrix will prevent brittle rupture and sufficient thickness (up to 1 mm) will help minimize the local indentation due to ploughing action of particles on screw / casing surfaces. Thus selection of hard coatings should be carefully taken into account to avoid the possible flaking and should ensure long lasting bonding in abrasive service under multiphase environment.

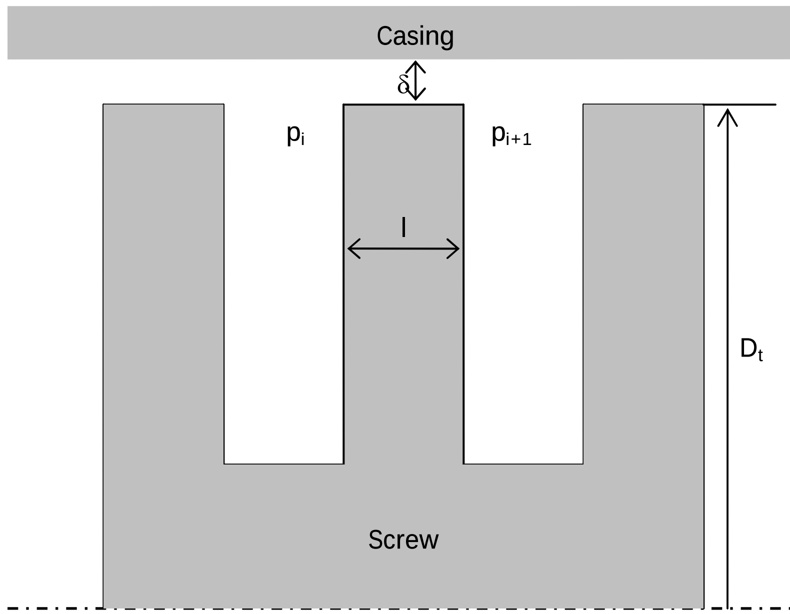


Fig. 83: Screw and Circumferential Clearance

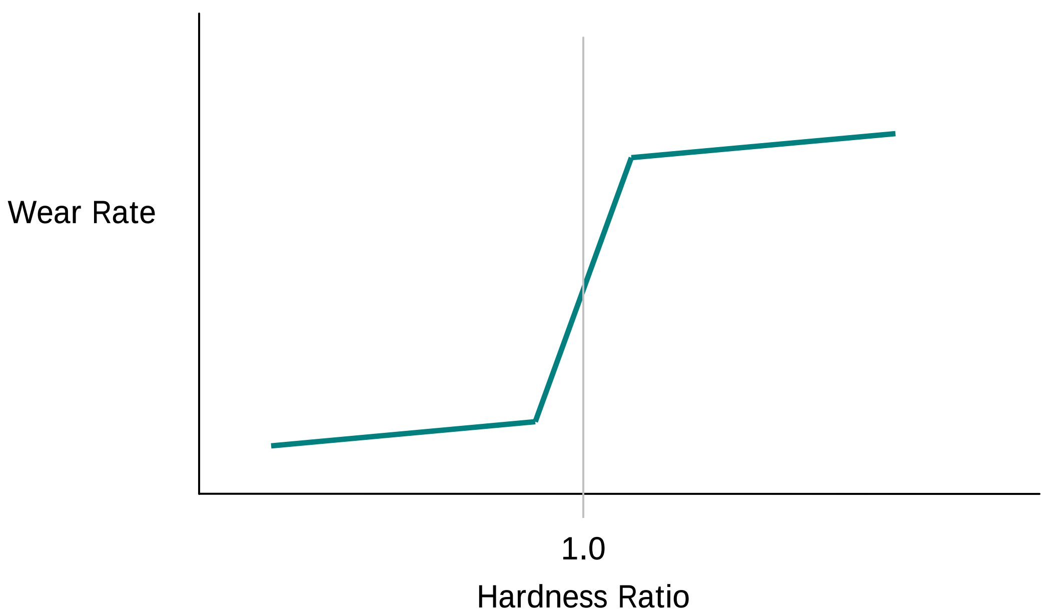


Fig. 84: Effect of Hardness Ratio[84]

If the hard coating on screw surface is brittle it can develop fractures. The fractured hard coating can wear off due to erosive action of back-flow[89]. Due to inadequate bonding between hard coating and substrate metal surfaces, the loosened particles of hard coating can get carried away to other locations and initiate wear more strongly than produced sand within twin-screw pump or other downstream components of the production system.

Sand Detection

The ability to accurately watch the sand concentration in the produced fluids and production systems will enable operators to optimize the production within safe limits for mechanical integrity of well completions, pipelines and downstream process. With accurate data of sand production, better correlations for erosion will also be possible. Two types of acoustic sand detectors – intrusive and non-intrusive are available. Intrusive sand detectors penetrate the flowline. Their installation or replacement needs shutting down the flow.

Fig. 85: Acoustic Sand Detector at Riverside

Non-intrusive type detectors are able to detect smaller concentrations of sand as compared to intrusive types. The acoustic sand detector is ideal for production optimization for maximum sand free flow or with maximum acceptable sand concentration, assurance on integrity of downhole sand control, early detection of sand production even in small quantities, and monitoring the sand concentration. Fig. 85 shows the acoustic sand detector installed at Texas A&M Riverside experimental facility.

Acoustic sand detectors allow early detection while maximizing the production rates. If the flow conditions remain similar to those during calibration, the sand concentration in fluid stream can be accurately determined. Since these conditions change over the life of reservoir, there is a need to calibrate the detector several times.

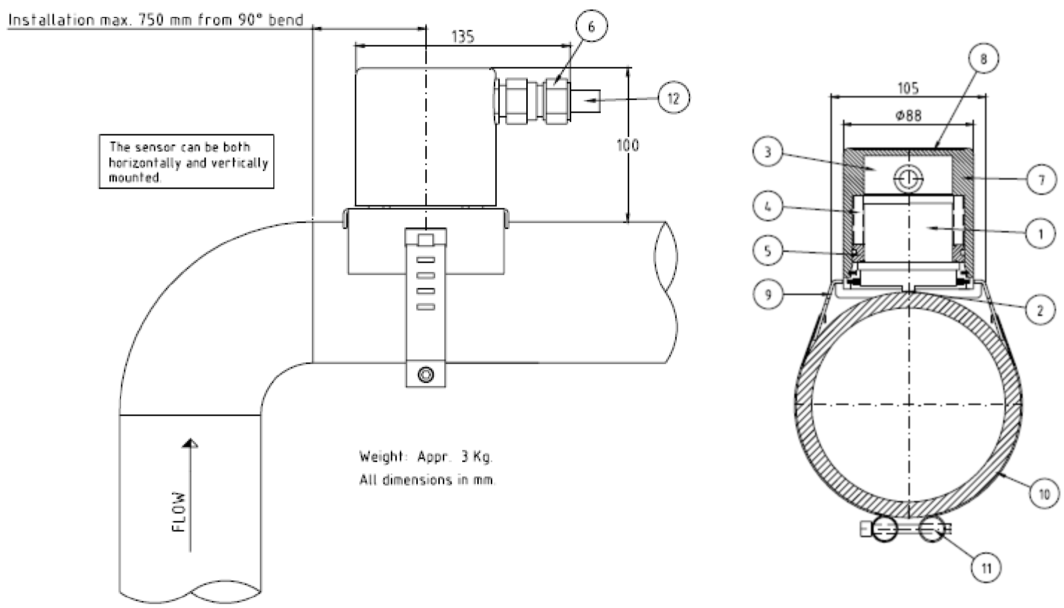
Low viscosity fluids, high gas rates, small flowline diameters, high velocity and large sand particles favor good sand detection with acoustic devices. High viscosity fluids, slugging, large diameter pipelines and small velocities, hydrate formation; wax deposition, small particle sizes and variable background noise hinder sand detection. Changing GORs, water cuts, temperature and velocity all affect detector accuracy. To detect the sand particles, they must impact the pipe wall at certain minimum velocity. Low fluid velocity results in creeping flow of sand on the bottom of flowline and it does not necessarily cause any measurable impact. As every flow has some noise, the acoustic sand detector always gives a non-zero output. In presence of sand particles, this output is distinctly more than the background noise. Thus the increase in signal above background noise is measured to characterize sand concentration.

Acoustic sand detectors perform best at locations where acoustic activity is ample within the pipeline. The most ideal location will be downstream of an elbow bend, and away from other sources of noise such as chokes, valves and equipment with high vibrations and noise levels. Preferably, the detector should be installed after a 90^0 bend downstream of the wellhead. Before calibration, the exact location of detector relative to bend is not critical.

To determine the sand concentration in flowlines, two parameters are needed – increase in acoustic signal and mixture velocity. The increase in signal by impact of sand particle with pipe wall depends on fluid velocity and viscosity. Assuming that the average size and angularity of sand grains, and the fluid properties are steady, the increase in signal can give a measure of sand concentration.

The chance that a sand particle will hit the pipe wall depends on the ratio of inertial to viscous forces exerted on the particle. The output from the device indicates kinetic energy of impacting particles. Coupled with velocity measurement, it gives the rate of sand production and sand concentration. Ideal location for acoustic sand detector would be away from sources of flow and other background noises. Lack of understanding on data interpretation from sand detectors can be useless and can incur huge losses. Overreacting on certain alarm may result in unnecessary deferment of production and under-reacting on reservoir sand release may eventually lead to well interventions.

Fig. 86 shows the components of acoustic sand detector. The acoustic sensor is housed inside an enclosure on a waveguide which can be fastened with strap and screw. The sensor tip is fastened tight in continuous physical contact with the pipeline. A spring inside the sensor housing keeps the sensor in tight contact. All gaps are water tight and air tight so that the device can be explosion safe. The power supply and signal output cable passes through a cable gland. The contact between pipeline and tip of the acoustic sensor should be free from any material like paint or grease. To avoid corrosion on the contact, a special corrosion inhibiting silicone gel is applied. This is recommended if the pipe surface is not corrosion resistant where paint, rust, salt is removed. In case of materials which are corrosion resistant, this may not be a necessity. Installation of detector must be completely tight as loose contact will introduce errors in measurement.



1 Sensor	7 Detector Housing
2 Waveguide	8 Label
3 Junction Box	9 Clamp / Detector
4 Spring	10 Mounting Straps
5 Seal Ring	11 Clamp Fastening Arrangement
6 Cable Gland	12 Cable

Fig. 86: Roxar Sand Detector Components[90]

Sand Detector Calibration

Background Noise

Acoustic signal output from detector comprises of background noise and sand noise. Background noise needs to be separated to reveal the sand noise. As every flow produces some noise, the acoustic detector always gives a non-zero output at no flow conditions. The background noise curve is defined[90] by equation (5):

$$g(v_s) = Av_s^3 + Bv_s^2 + Cv_s + D \tag{5}$$

The background noise curve (fig. 87) is calibrated by specifying signal values at different flow rates and then fitting a curve.

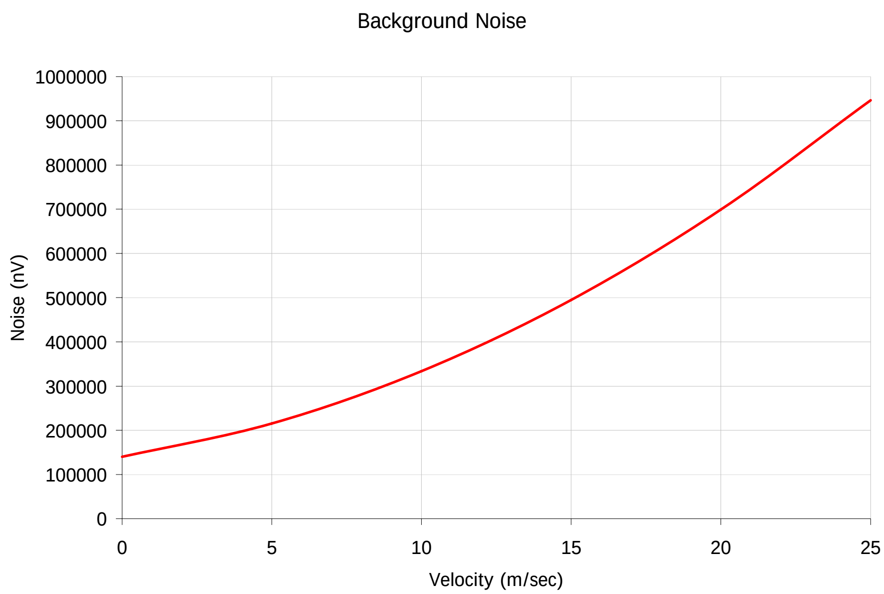


Fig. 87: Background Noise Calibration

Sand Noise

Sand noise calibration specifies the sand noise at different sand concentrations. The sand noise curve is calibrated by specifying output signal values at different flow rates when sand is flowing at the rate of 1 g/sec in stream. It is given[90] by eq. (9).

$$f(v_s) = Ev_s^3 + Fv_s^2 + Gv_s + H \tag{9}$$

Fig. 88: Pneumatic Pump for Controlled Sand Injection

A controlled sand injection at 1 g/sec in the base flow having velocity greater than 1 m/sec was carried out using a pneumatic pump and a positive displacement mechanism (fig. 88). After calibration, the acoustic sand detector should not be moved from the location of installation. Moving the detector to a different location will invalidate the calibration and recalibration will be required. Fig. 89 shows the sand noise calibration curve.

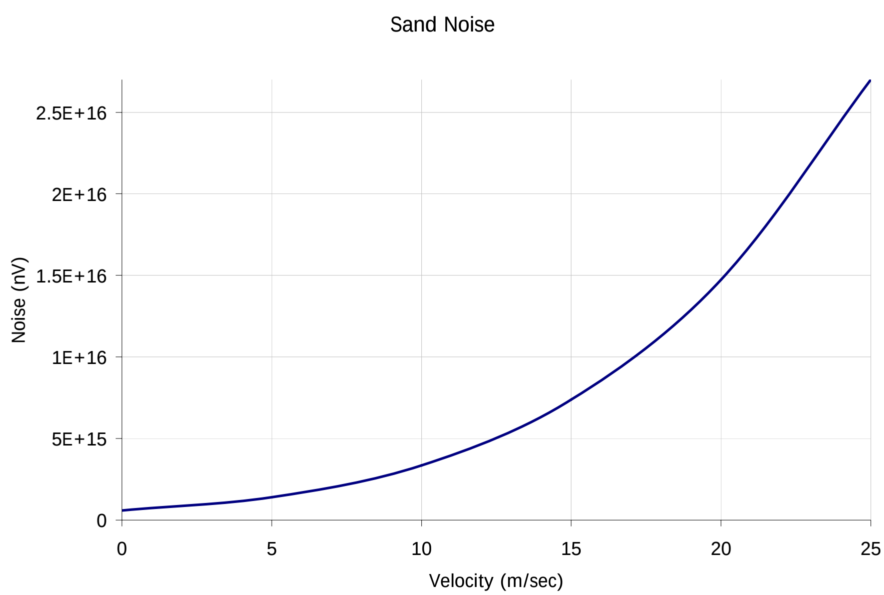


Fig. 89: Sand Noise Calibration

Sand Detector Testing

For testing the sensitivity of detector after calibration, we tested sand detector in two different

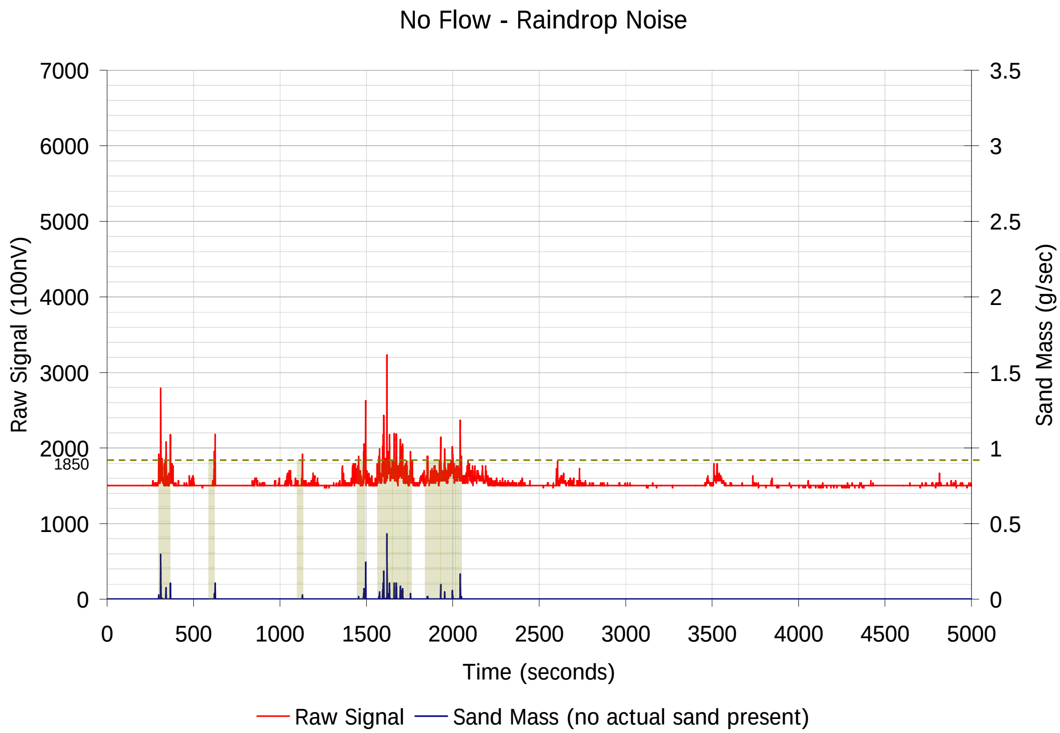


Fig. 90: Noise Picked up from Rain Drops

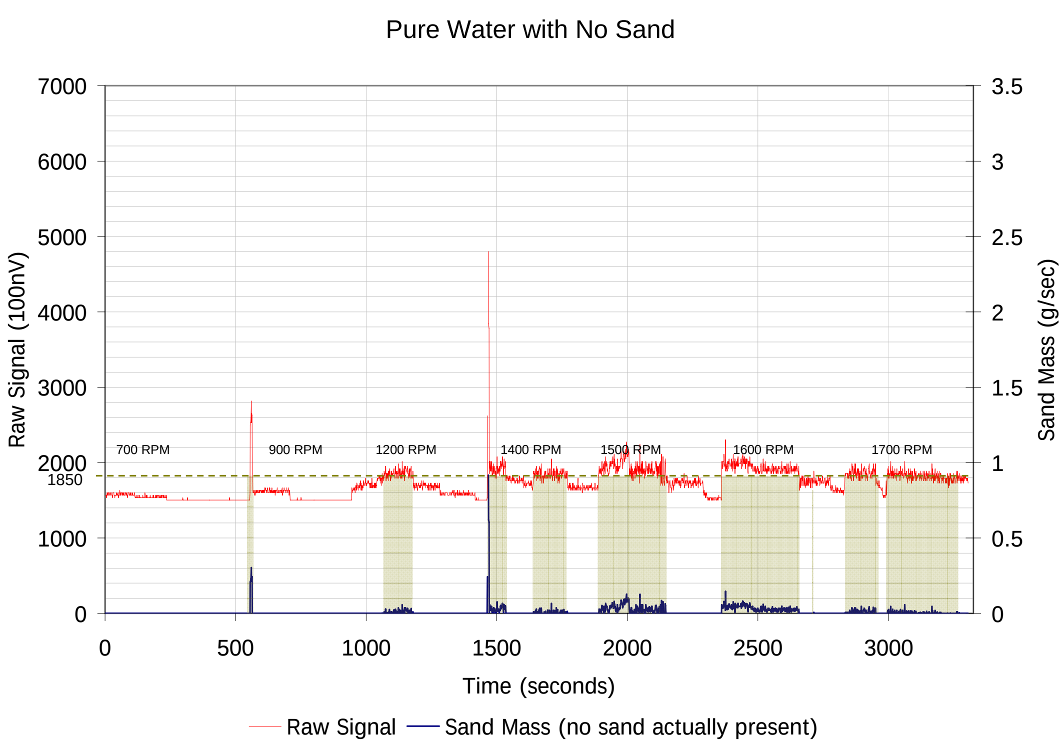


Fig. 91: False Sand Noise Picked up from High Velocities

ways. During the first sensitivity test, the detector was powered on and data acquisition was in progress without any flow in the pipe and it was raining. The rain drops impacting on pipe-wall from outside caused noise. The noise levels recorded are shown in fig. 90.

The second test was without any sand concentration in liquid flow. A wide range of velocities was achieved by changing the speed and controlling the differential pressures across the twin-screw-pump. The detector turned out to be very sensitive. For flow without sand, raw signal levels were proportionate with fluid velocities. The data recorded is plotted as shown in fig. 91. The steps in noise signal amplitude shows changing differential pressure or step change in flow rates and thereby velocities.

The introduction of gas in liquid flow introduces additional noise. The sand detector picks up noise due to free gas and interprets it as sand concentration. The raw signal picked up goes on increasing as the gas volume fraction of the flow increases. This increase continues till the total flow (gas + liquid) goes on increasing. When the total flow rate starts stabilizing, the raw signal again begins dropping. This is possibly due to less turbulence created as liquid volume fraction goes on decreasing. The flow loop and setup is limited by a maximum possible air flow rate due to compressor capacity. To increase gas volume fraction beyond a certain limit, the liquid flow

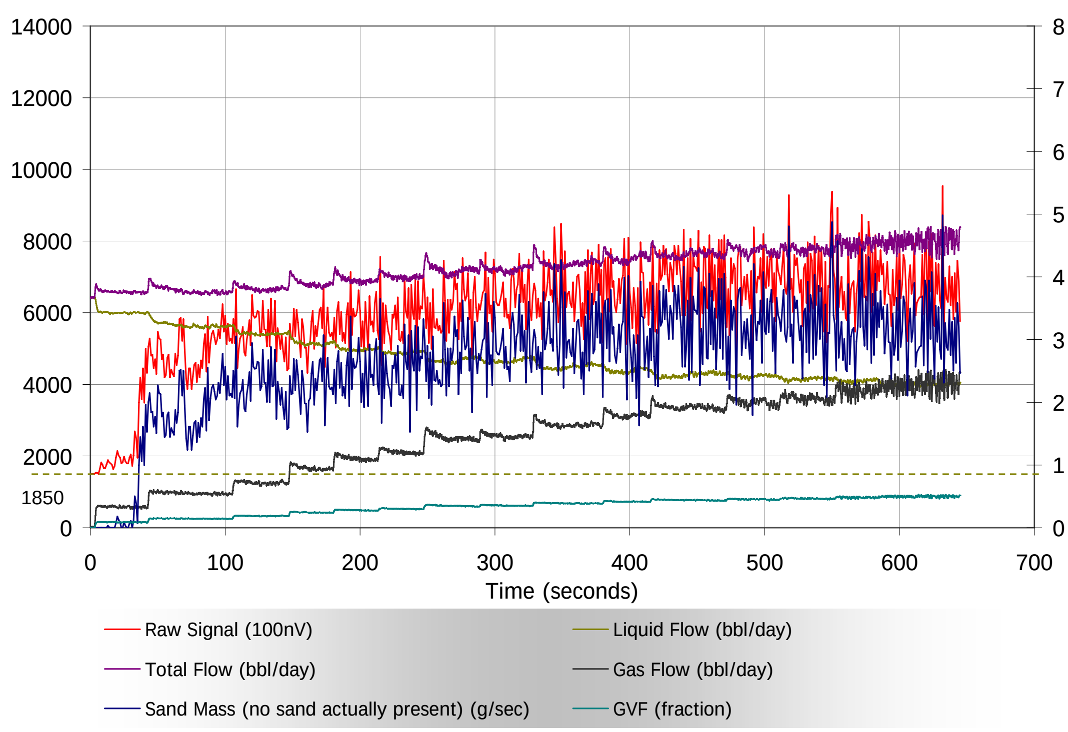


Fig. 92: Sand Detector Response at 1000 RPM

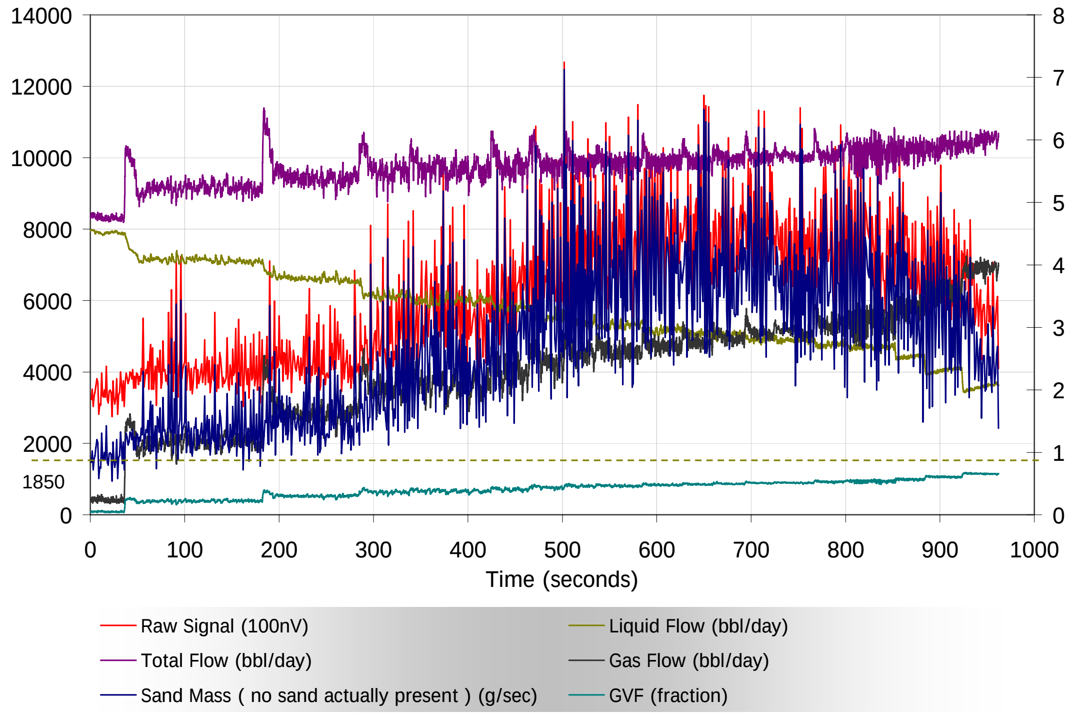


Fig. 93: Sand Detector Response at 1600 RPM

rate needs to be controlled by throttling a valve on the liquid leg of metering. The maximum possible (at Riverside flow loop) total flow rate at 1000 RPM speed is about 8000 bbl/day and in case of 1600 RPM; it is about 10000 bbl/day. In both the cases, (figures 92 and 93) it was observed that the raw signal levels exceeded the sand noise detection threshold (185000 nV) at calibrated signature as soon as the gas phase enters the flow and the sand detector is not accurate in detecting the sand concentration.

Fig. 94 shows that there is no predictable correlation between gas volume fraction and detected “false” sand at different flow rates (implied by different pump speeds).

After establishing that sand detector is calibrated and sensitivity is confirmed, sand particles were introduced in the flow. Sand was introduced in the flow loop using a 1” PVC pipe with an open T on the bottom end (fig. 67). The bottom end was exactly placed inside the 4” outlet of the 40 barrel yellow tank which connects to the centrifugal charging pump suction. This ensured no loss of any quantity of sand on the tank bottom due to settling, which can not be avoided otherwise.

100 g, 200 g, 300 g and 640 g of sand were introduced in the pure water flow and sand detector measured the quantities as 104 g, 202 g, 291 g and 638 g in the output (fig. 95). It was

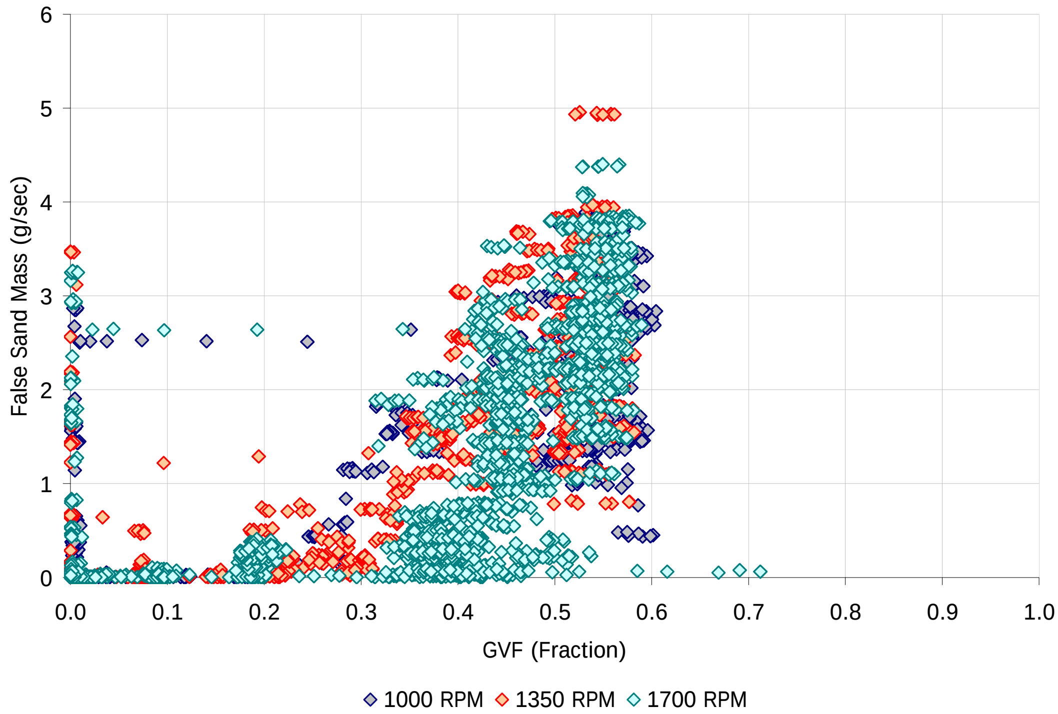


Fig. 94: Unpredictable Behavior

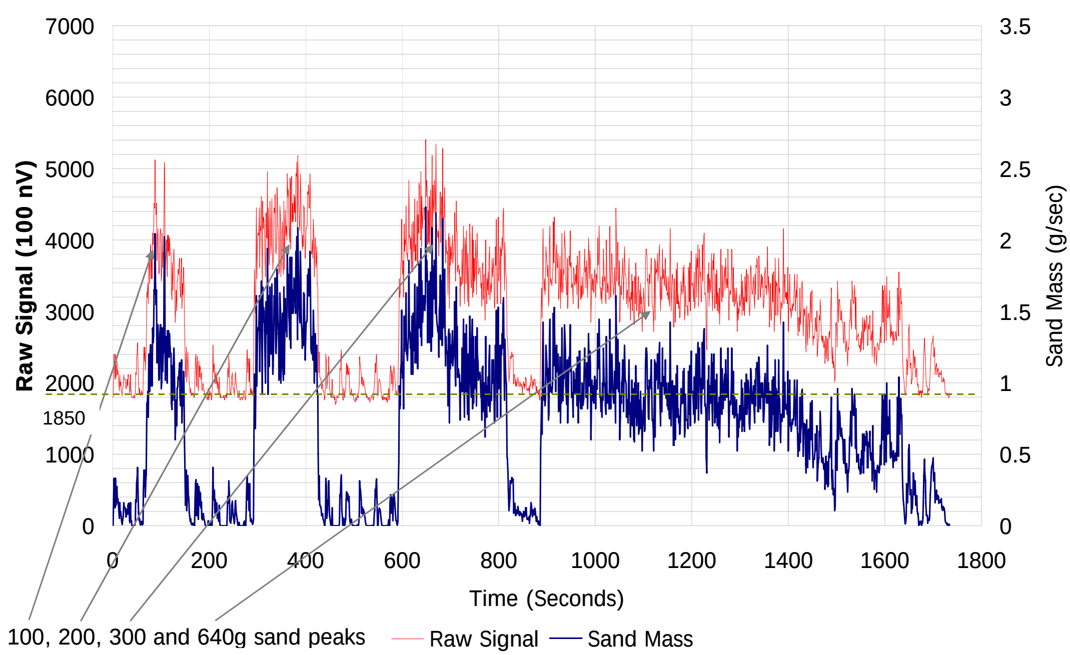


Fig. 95: Sand Detection in Pure Water

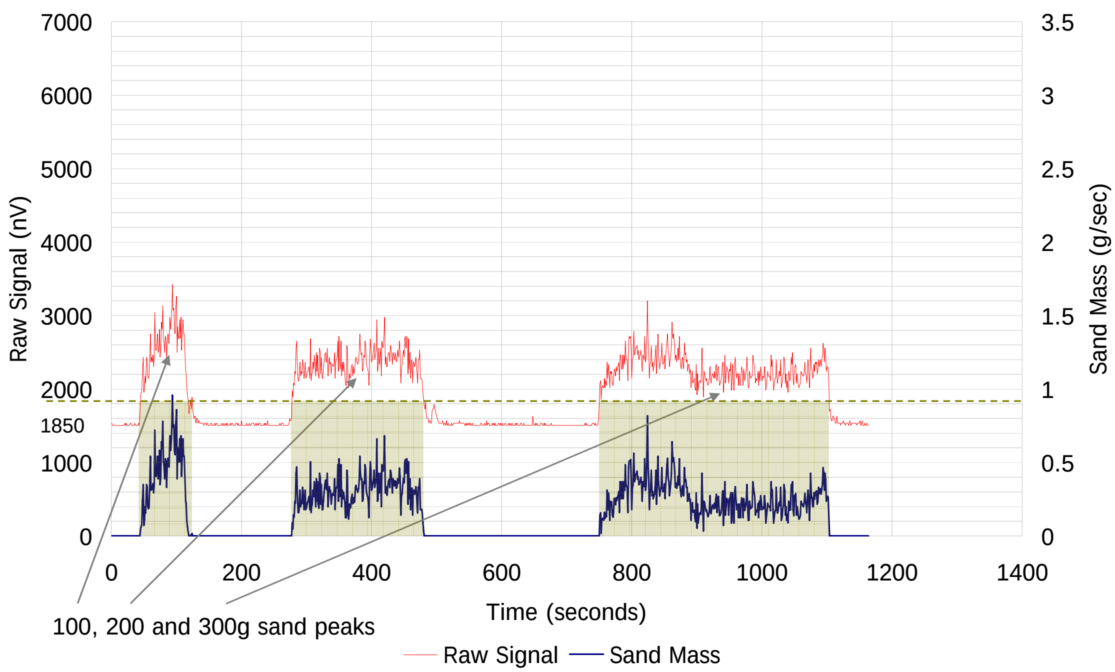


Fig. 96: Sand Detection in 2 cp Gel

observed that with introduction of viscosity in base fluids, the response of sand detector for similar quantity of injected sand was different. In 2 cp liquid flow, 100 g, 200 g and 300 g of injected sand was measured as 32 g, 62 g and 92 g respectively (fig. 96); whereas, in 3 cp liquid flow 200 g, 400 g, 500 g and 600 g of injected sand quantities were measured as 23 g, 61 g, 90 g and 107 g (fig. 97). It is observed that with increasing viscosity, the amplitude of raw signal and estimated sand mass goes on decreasing.

With introduction of gas volume fraction in the stream, there is more acoustic noise and the detector becomes more sensitive and shows certain "false" sand quantity in the absence of sand particles. When actual sand is encountered, the amplitude of output signal is higher than in case of pure water under calibration conditions. In the presence of 50% GVF at 10000 bbl/day total flow rate, 100 g, 200 g, 300 g, and 600 g of injected sand quantities were interpreted as 317 g, 640 g, 735 g, and 1499 g respectively (fig. 98).

Fig. 99 shows the effect of viscosity and presence of GVF on detection of sand mass against injected sand mass in the flow-loop.

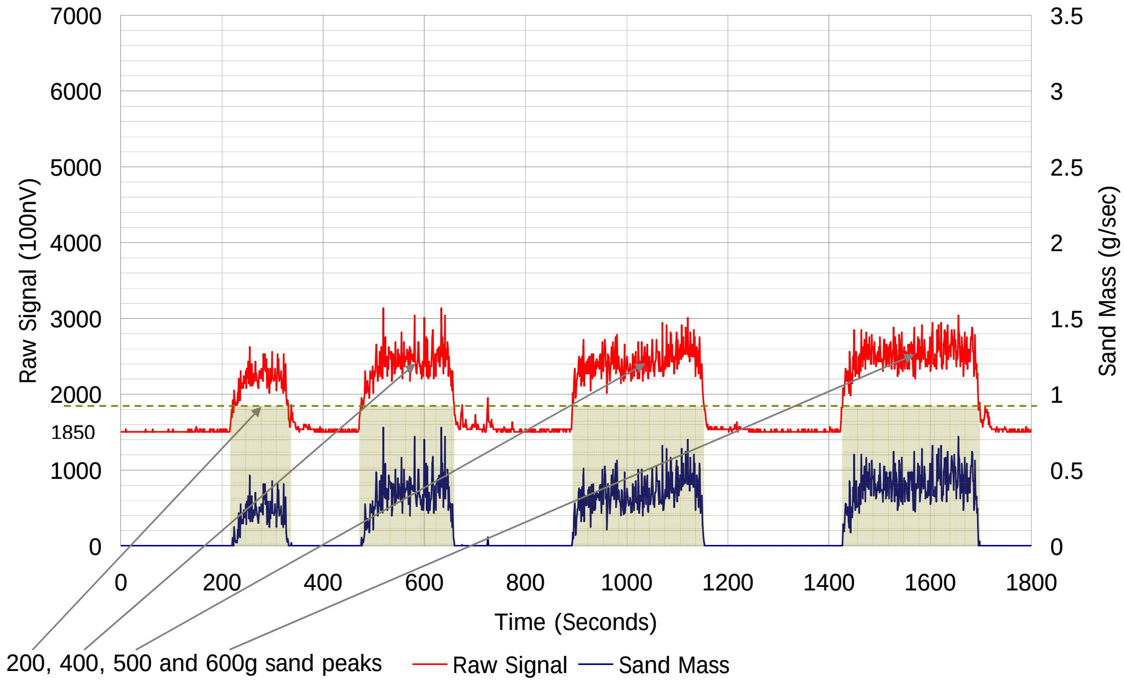


Fig. 97: Sand Detection in 3 cp Gel

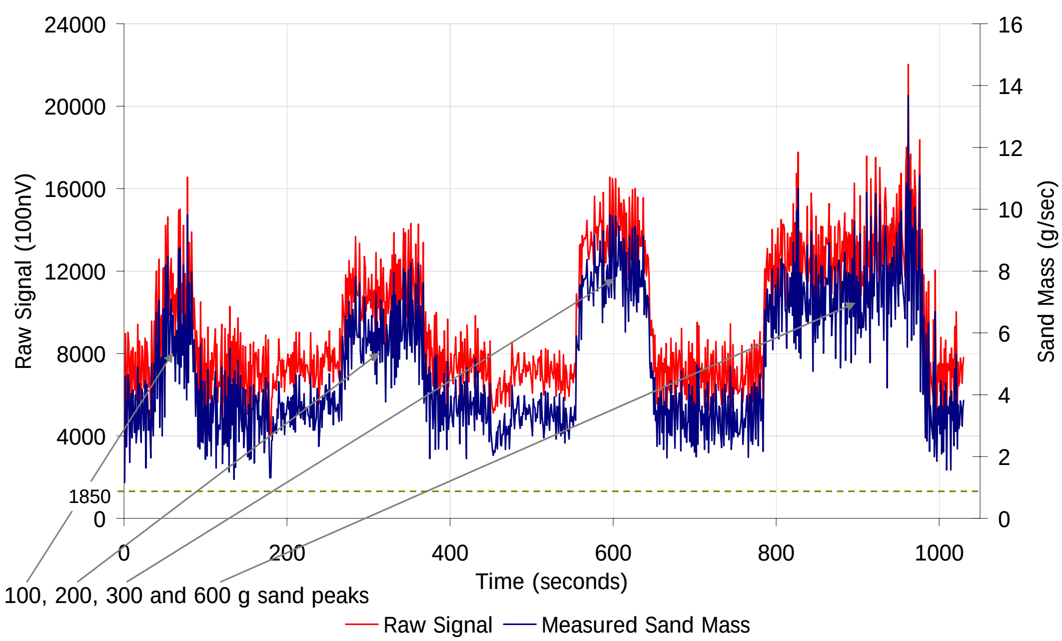


Fig. 98: Sand Detection with 50% GVF and 10000 bbl/day Flow Rate

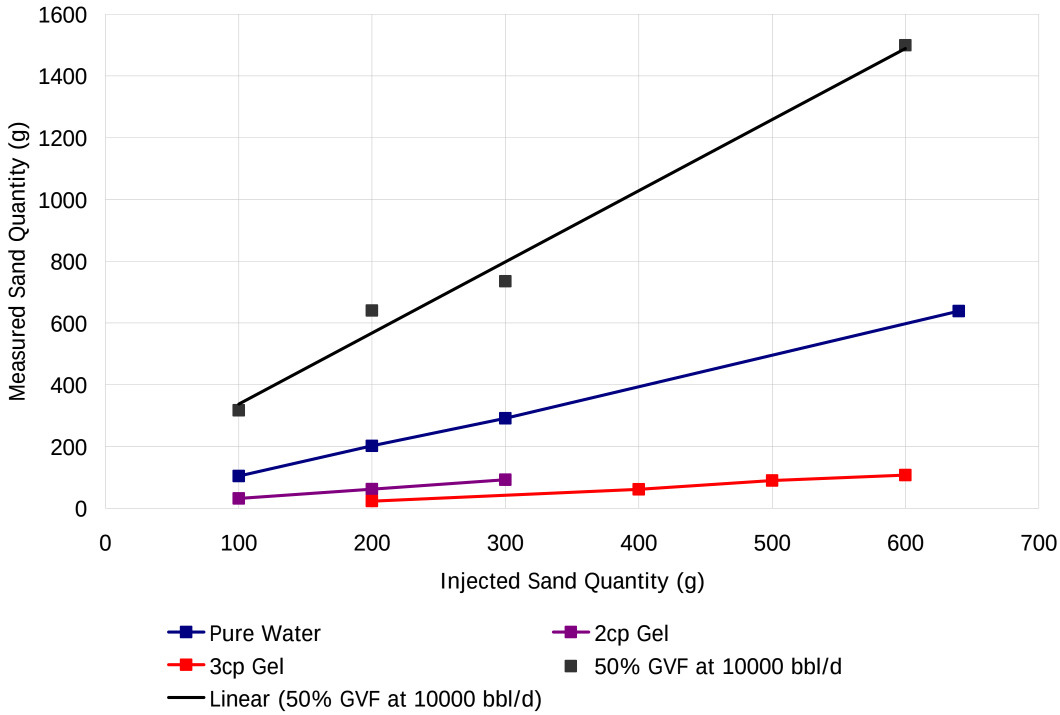


Fig. 99: Effect of Viscosity on Sand Detection

From all above sand detection tests, the estimated sand mass quantities were plotted against corresponding raw signal values. The plot shows a straight line (fig. 100). This plot shows that the straight line crosses X-axis at 185000 nV. This signal value matches with the threshold raw signal value marked in all other sand detection plots. The slope of this line will vary with calibration. With a calibration under different conditions, a general correlation valid for the current calibration of sand detector can be written as

$$\text{Sand Mass} = 0.0006 \text{ X Raw Signal} - 1.1383 \quad (7)$$

where, the sand mass is in g/sec and raw signal is in 100 nV

The detection of solids like sand particles with acoustic devices is reliable only when the actual flow conditions are close to the flow conditions at the time of calibration.

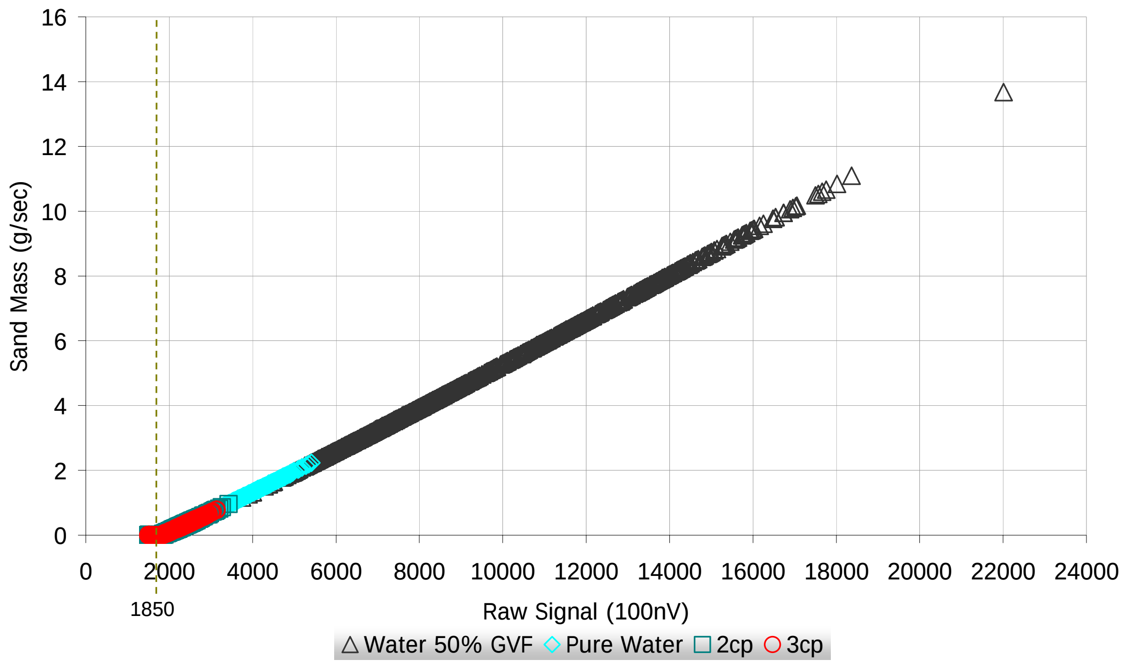


Fig. 100: Estimated Sand Mass against Raw Signal

Solids Transport

Various types of gels are used as fracturing fluids for hydraulic fracturing to stimulate the formation. The viscous gels used posses certain special properties which enable them to suspend and efficiently transport proppants with minimum friction losses at minimum cost.

Linear gels transport proppants allowing settlement of proppants or with perfect suspension in case of cross-linked gels. Viscosity imparts transportation capability to the fluid. Other desirable properties of fracturing fluids are thinning on adequate residence time and resistance to thermal thinning. One modern characteristic of fracturing fluids is extremely easy pump-ability even at high viscosities.

Keeping the above type of fluid in mind, one option for transporting the produced sand through twin-screw multiphase pumps would be incorporation of gel injection capability upstream of the pump. This would allow suspension of sand particles on detection with sand detector, and enveloping the particles in gel bulk before passing through pump chamber to reduce friction and metal loss.

Analysis of Slip Flow

Using the equation for slip across a screw thread by Prang et al.[88], on screws with different clearances and leak path lengths, we investigated the effect of viscous gel in controlling the slip flow.

The slip flow was calculated for water and a 50 cp liquid with different differential pressures for clearances ranging from 0.008” to 0.02”, across screw threads having 15” and 7.25” diameters respectively. By increasing the viscosity, the slip flow can be considerably controlled. For similar conditions, the slip flow can increase by up to more than 10 times if clearance is increased by up to 3 times. Fig 101 and 102 shows that slip flow is drastically reduced if a high viscosity fluid is sealing the clearances.

By increasing the width of screw thread (leak path length), the slip flow can be effectively reduced at high differential pressures (fig. 103).

Fig. 104 shows the slip rate behavior at different differential pressures with increasing viscosity.

Figures 105 and 106 show the effect of clearance size on slip flow at different differential pressures and viscosities.

Fig. 107 shows the effect of screw diameter on slip flow at different clearance sizes with a 10 cp liquid sealing the clearances.

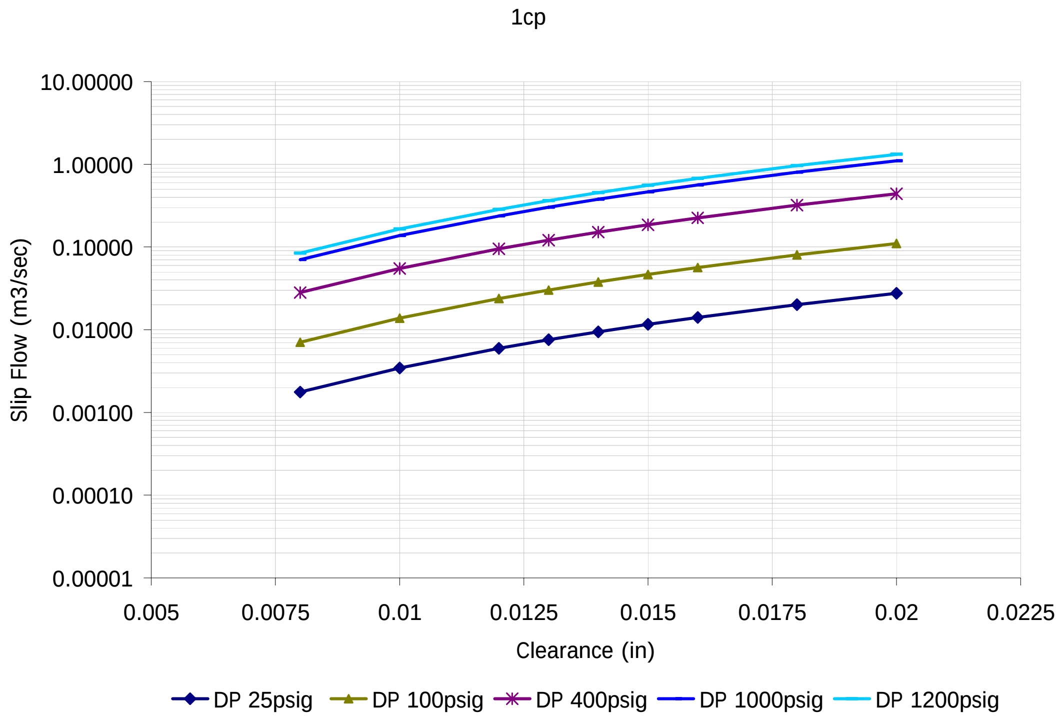


Fig. 101: Slip Flow across 15” Diameter Screw with Pure Water

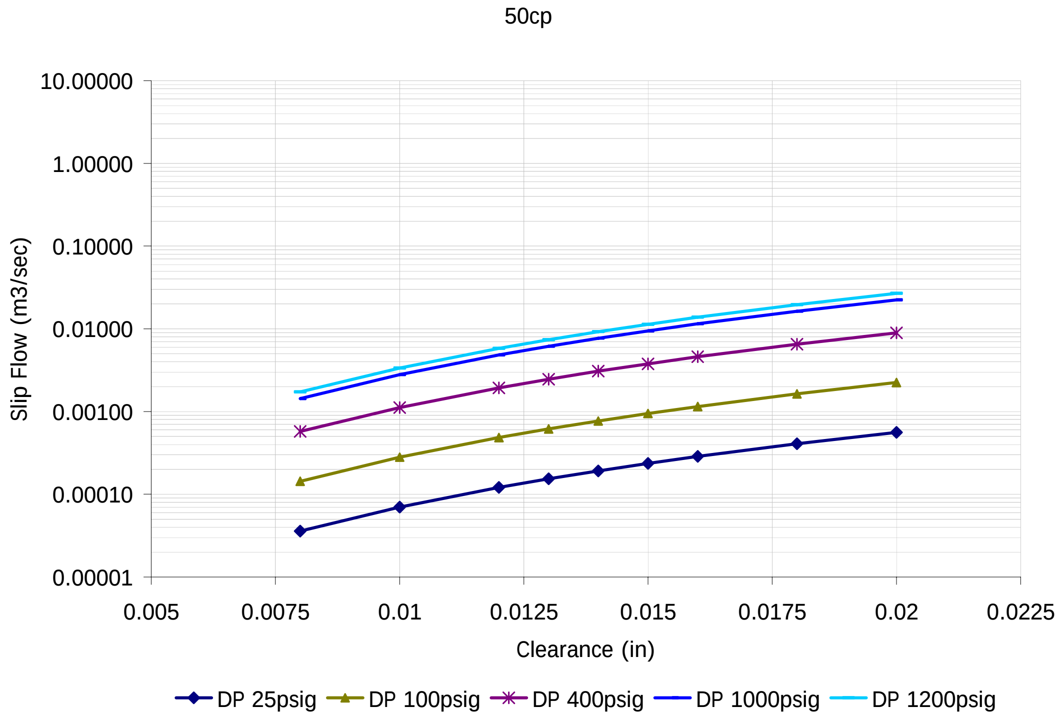


Fig. 102: Slip Flow across 7.25” Diameter Screw with 50 cp Fluid

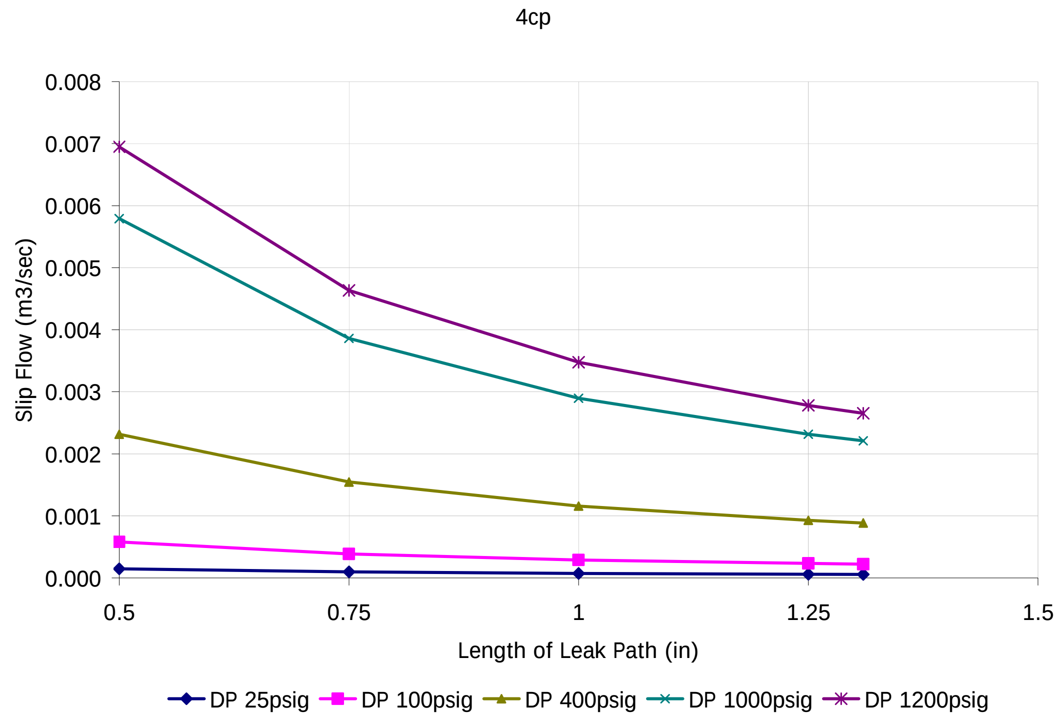


Fig. 103: Effect of Leak Path Length on Slip Flow across 15” Diameter Screw and 0.04” Clearance with 4 cp Fluid

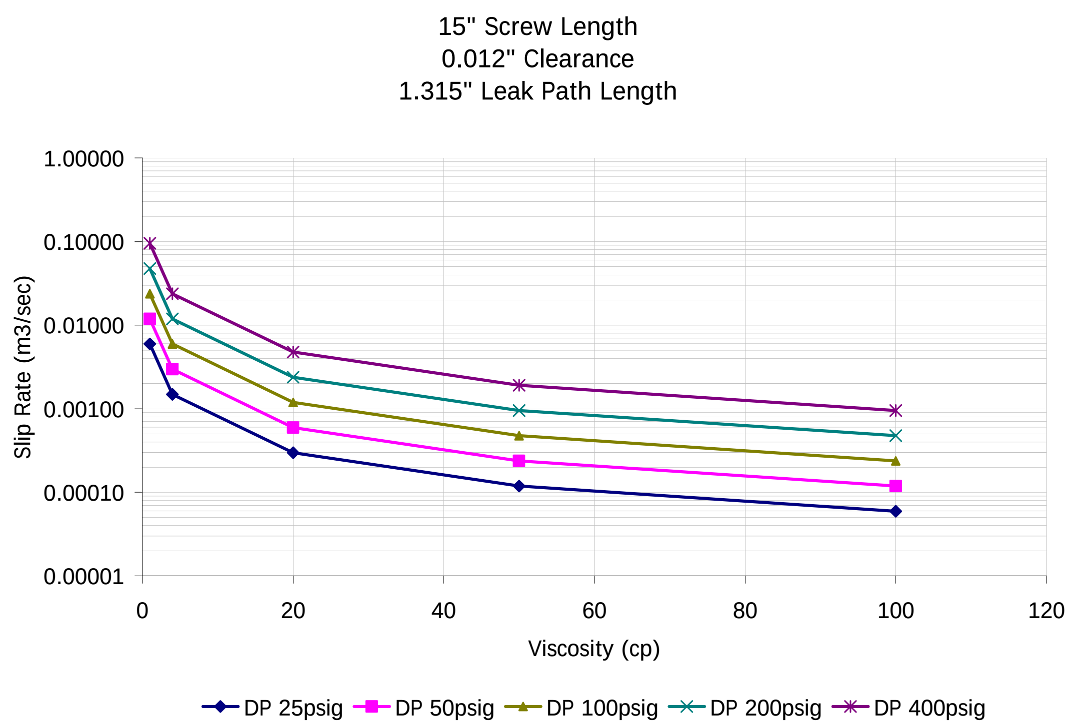


Fig. 104: Effect of Differential Pressure on Slip

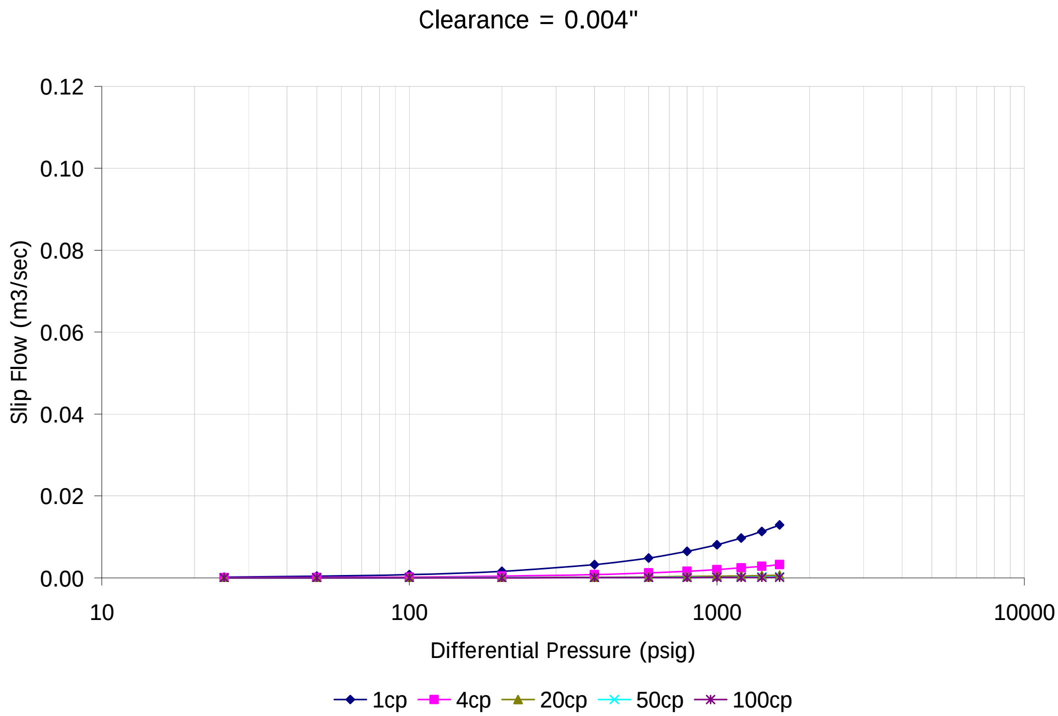


Fig. 105: Slip Flow across 5.24” Screw and 0.004” Clearance

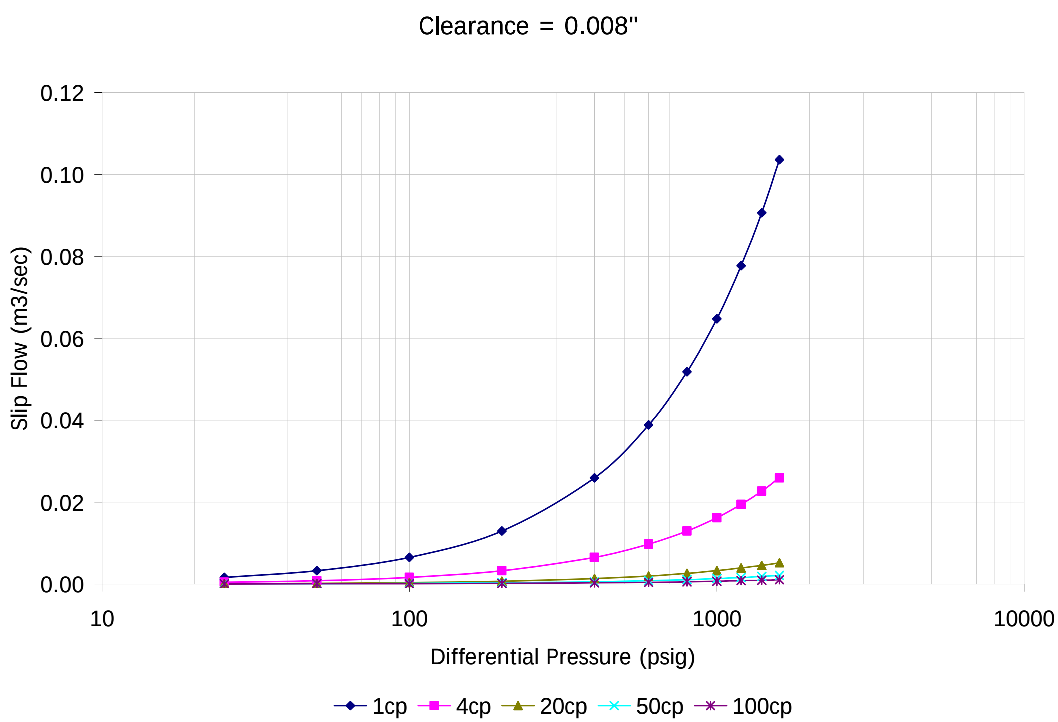


Fig. 106: Slip Flow across 5.24” Screw and 0.008” Clearance

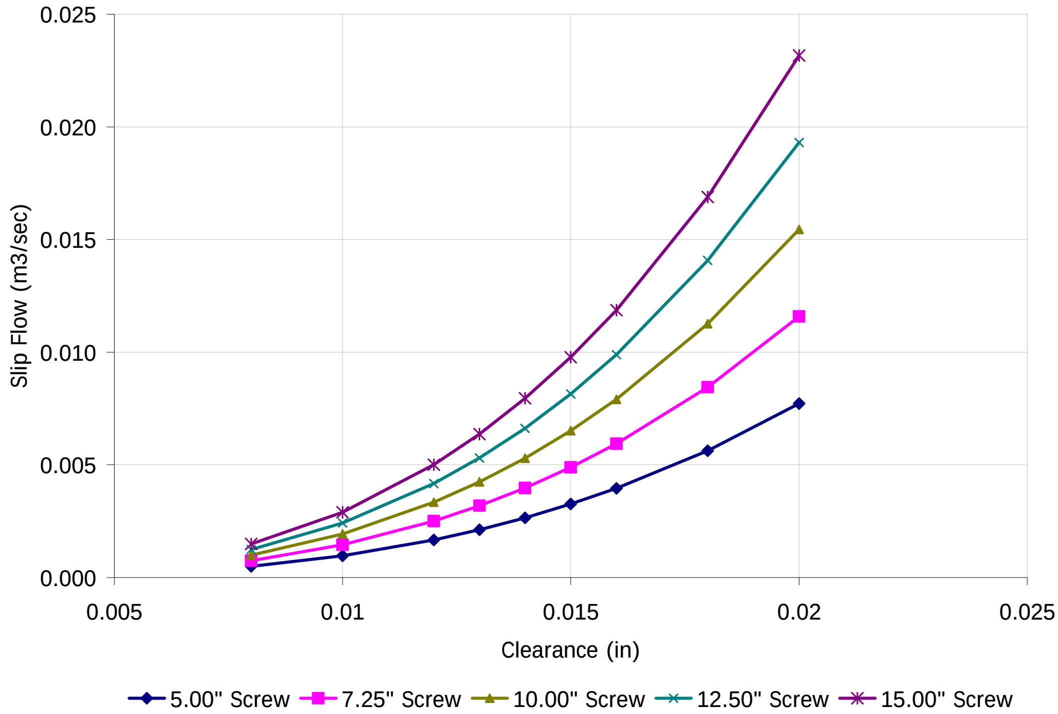


Fig. 107: Slip Flow across Screw Threads of Different Diameters with a 10 cp Fluid at 200 psig Differential Pressure

Approach to the Problem of Erosion

There can be different possible approaches to tackle the problem of produced sand concentration passing through twin-screw pumps. Complete separation is not the most economic operation. Sand concentration has to pass through the pumps in such scenario. It is, therefore, necessary to devise some method which will take care of efficient transport without causing any metal loss in the screws and casing.

Reduction of pump speed, diversion of high concentration “sand slug” to a mixing section so that sand particles are evenly mixed and suspended, and injection of high viscosity fluid to envelope sand particles on detection of sand concentration are a few possible solutions. We will focus on gel injection towards mitigating the problem of solids transport without causing damage to the metal of screws. Figures 108 and 109 depict the concept of gel injection system on detecting the sand concentration.

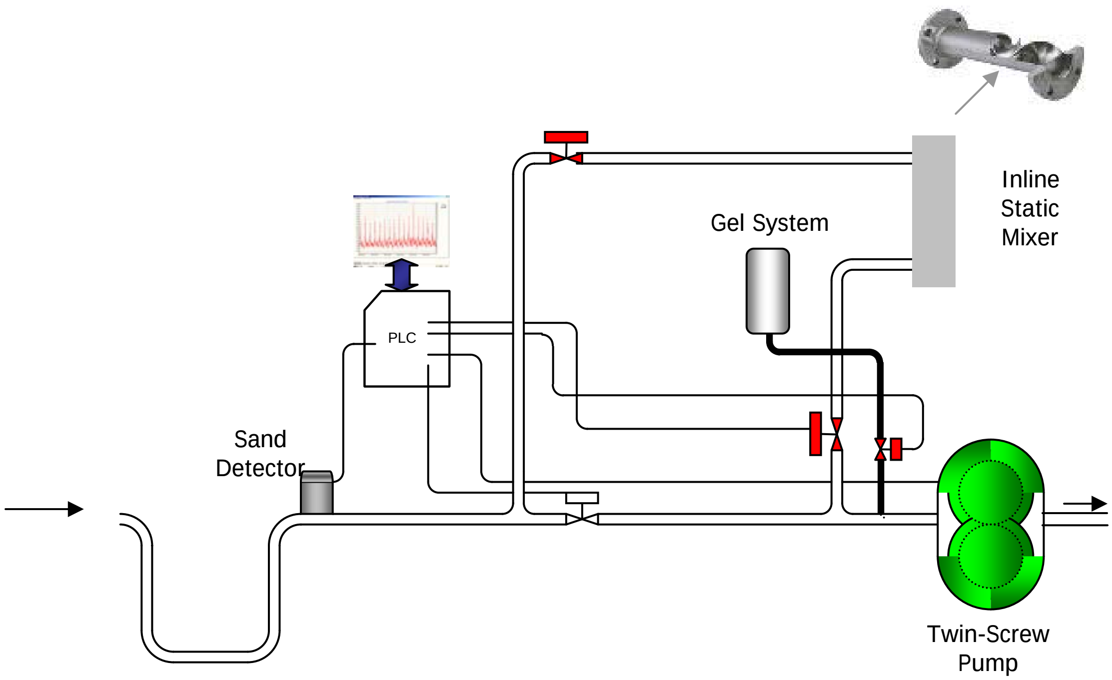


Fig. 108: Schematic Showing Sand Detection, Mixing and Gel Injection

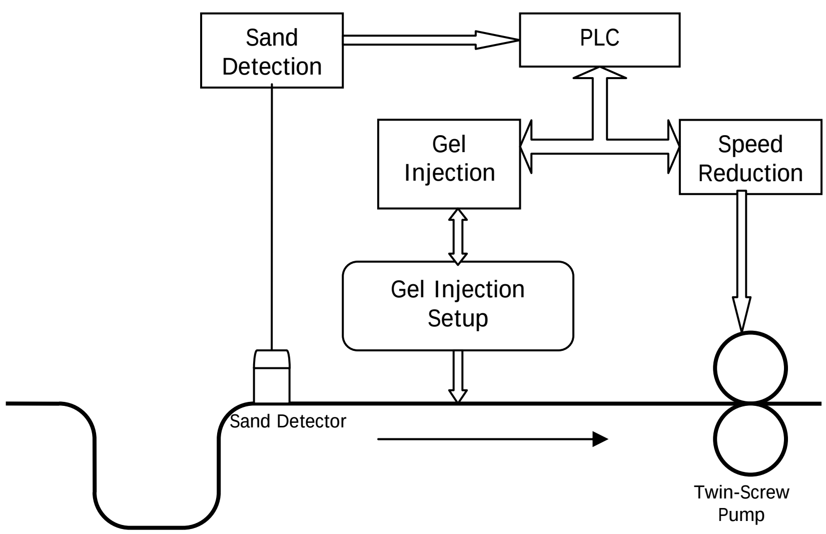


Fig. 109: Gel Injection Concept

In the event of very high sand concentration, it will still be necessary to divert the flow to a sand disposal system. Gel injection will need continuously pressurized injection system. In real oilfield, this system can be a gel storage tank, mixer, dosing pump with precise controls and metering system to keep track of the quantity being injected. Further, it will be necessary to have a special kind of gel which will be stable for long periods of time. Gels which would be easily pumpable with commercially available oilfield dosing equipment and tubing sizes to current and future water depths are the need of time.

Gel Injection

The gel Injection setup at riverside facility is extremely simple (fig. 110). A small pressure vessel (25 gallon) can be filled with a gel of required viscosity and then pressurized to 115 psig with external compressed air to inject gel in flow loop. There is no flow meter on the outlet. A known volume of gel is filled up and while injecting at a fixed valve opening, the time to empty is recorded to determine injection flow rate.

Fig. 110: Gel Injection Setup

Gel Characterization

The gel used for experiments is a guar gum gel concentrate compatible with water. The gel concentrate liquid quickly viscosifies when it comes in contact with water. Adding gel concentrate at steady and slow rates in water tank while stirrer is running is very important to achieve a clump-free uniform gel. Apart from stirring, mixing is achieved by continuously re-circulating the liquid mix with a pump. The gel viscosity is determined with a Fann 35 viscometer.

Apparent viscosity = dial reading at 600 RPM / 2 (8)

The change in viscosity with the concentration shows a non-linear trend as shown in the following plot (fig. 111). The curve fit to the points of experimentally measured viscosities can be expressed as

$$\mu = 0.00001047Gc^3 + 0.00499532Gc^2 + 0.34572653Gc + 1 \quad (9)$$

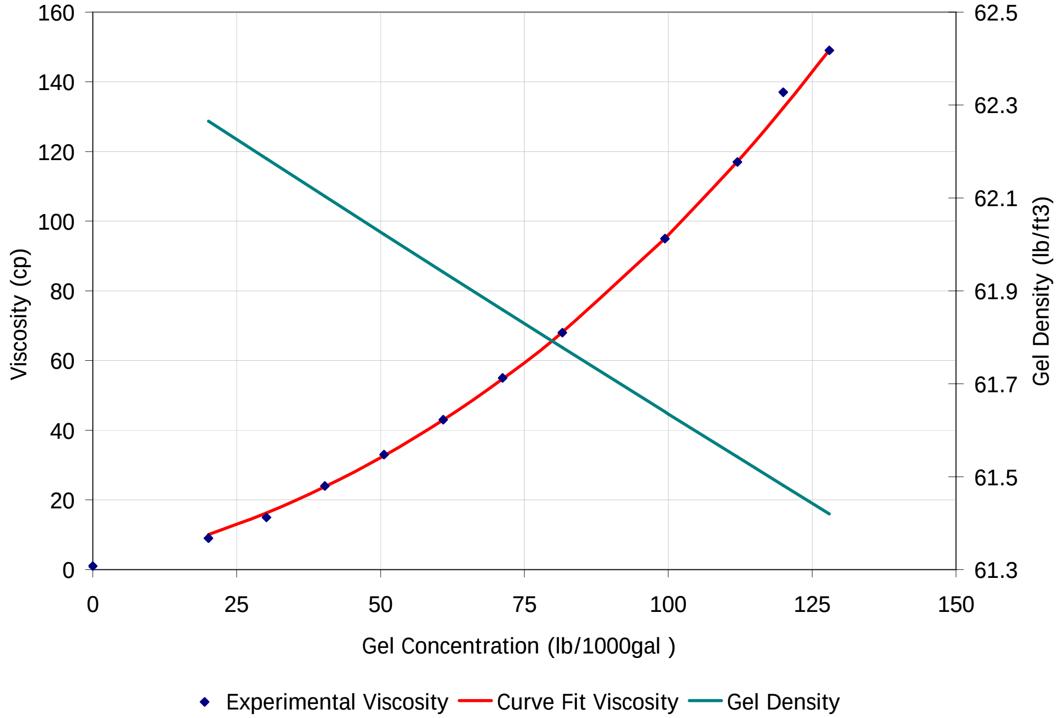


Fig. 111: Gel Characteristics

where μ is apparent viscosity in cp and Gc is gel concentration in lb/1000gal. If Gc_i is gel concentration in injection gel and Gc_w is gel concentration in base flow, the effective concentration upon injection and mixing can be given by

$$Gc_{eff} = \frac{Gc_i q_i + Gc_w q_w}{q_i + q_w} \quad (10)$$

Substituting G_{eff} in the empirical equation for μ, the effective viscosity can be determined.

$$\mu_{eff} = 0.00001047\, Gc_{eff}^{\ 3} + 0.00499532\, Gc_{eff}^{\ 2} + 0.34572653\, Gc_{eff} + 1 \quad (11)$$

Using the above relationship, it is possible to determine the viscosity resulting in a pipeline flow due to injection of high viscosity gel. Figures 112, 113 and 114 illustrate the effect of varying the injection rate of concentrated gels (60, 80, 100, 110, 120 and 130 lb/1000gal) on effective viscosity of the base flow. For small base flow rates, the effect of concentrated gel injection on effective viscosity is significant if gel injection rates are high (>300 bbl/day). At the high base flow rates, the effective viscosity trend flattens and different strengths of gel concentrate have little effect on final effective viscosity. The gel used for experiments showed the following characteristics (table 11) when tested with Fann 35 viscometer.

Table 11: Viscometer Readings for Gels

Gel Strength (lb/1000gal)	Dial Readings		
	100 RPM	300 RPM	600 RPM
29.77	13	23	32
43.07	27	42	55
53.09	40	58	74

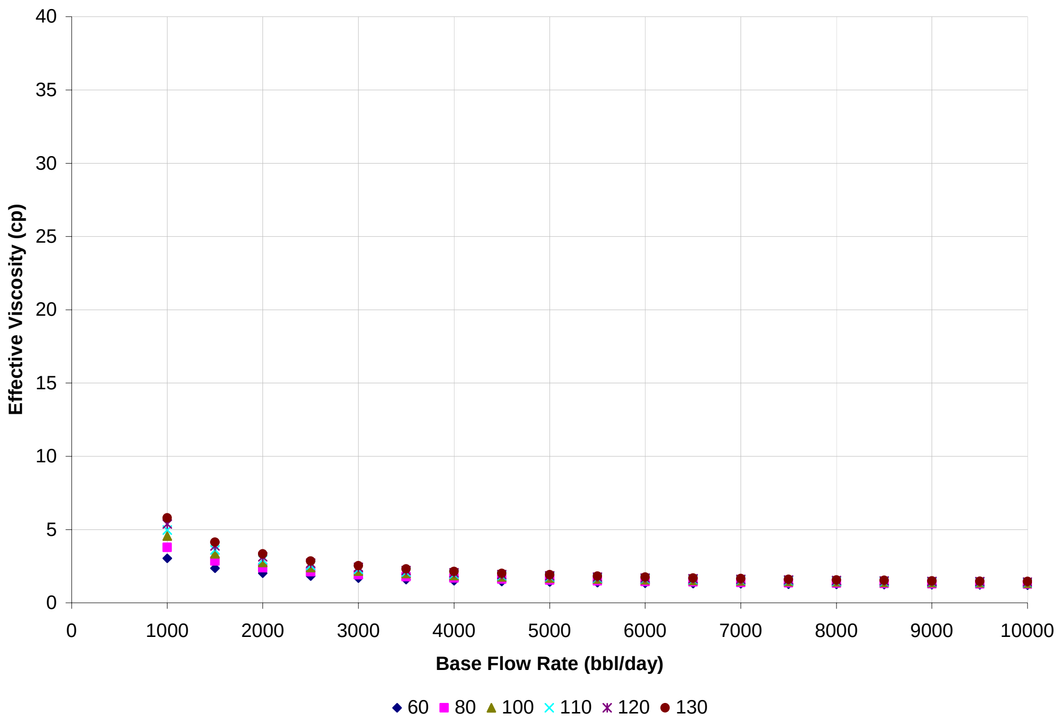


Fig. 112: Effective Viscosity in Main Flow Line with Gel Injection Rate of 100 bbl/day

Applying the factors to determine effective viscosity, we find that the effective viscosities (table 12) at different rates of shear are different and hence the gel is not showing Newtonian behavior.

Table 12: Effective Viscosities at Different Rotary Speeds

Gel Strength (lb/1000gal)	Effective Viscosity (cp)		
	100 RPM	300 RPM	600 RPM
29.77	39	23	16
43.07	81	42	27.5
53.09	120	58	37

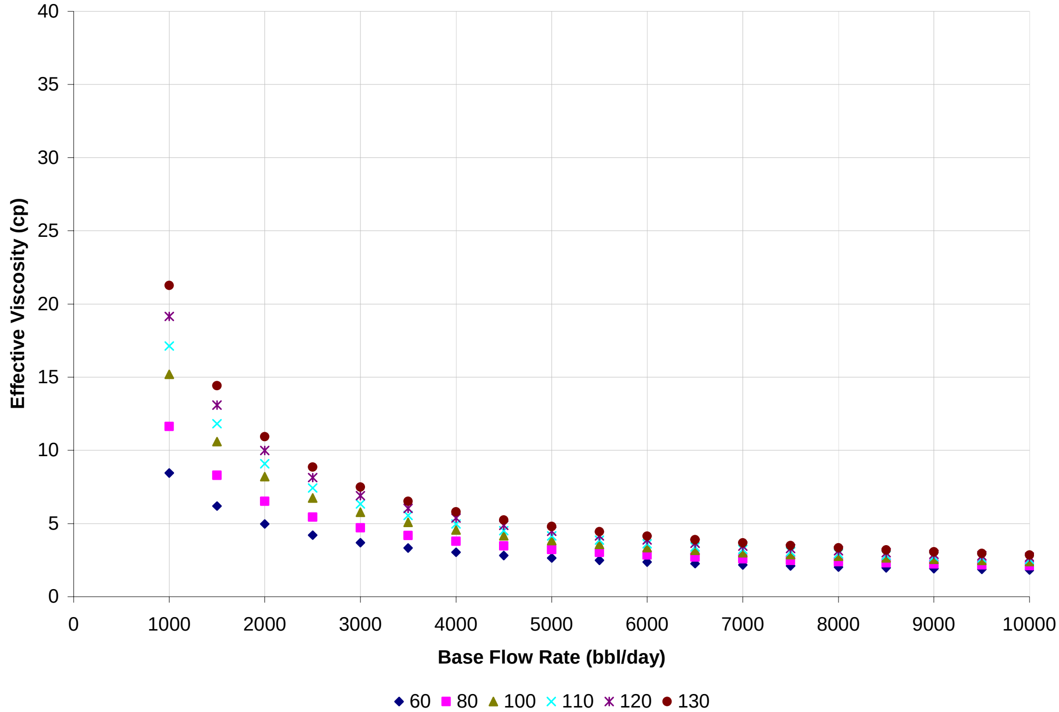


Fig. 113: Effective Viscosity in Main Flow Line with Gel Injection Rate of 400 bbl/day

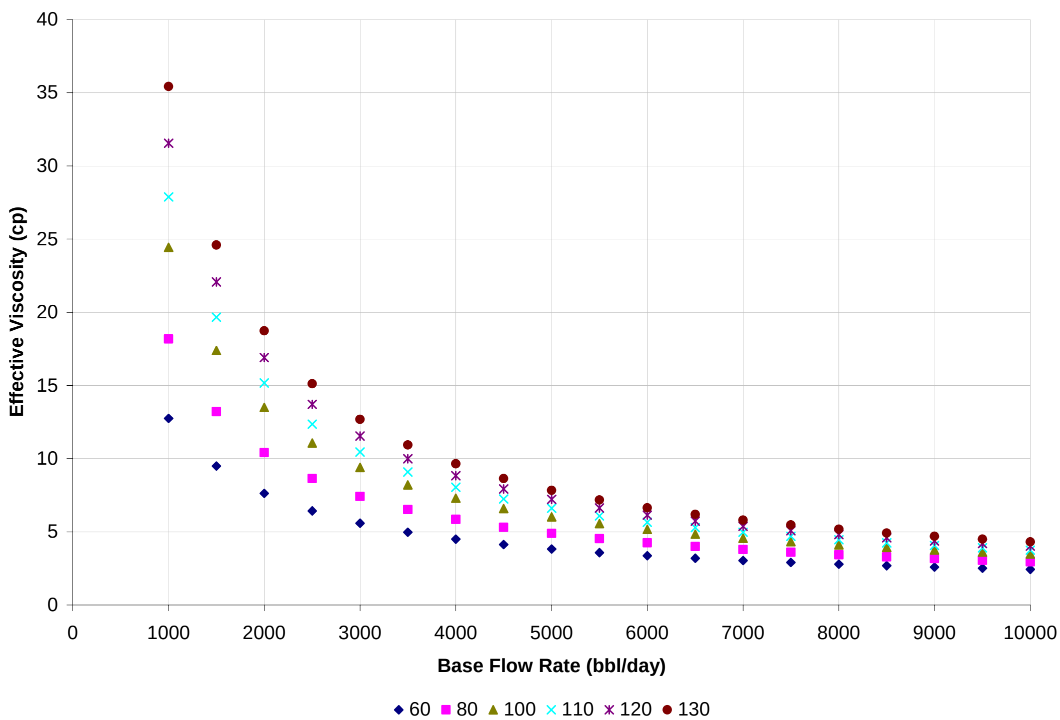


Fig. 114: Effective Viscosity in Main Flow Line with Gel Injection Rate of 700 bbl/day

The gel characteristics are calculated in table 13.

Table 13: Pseudo-Plastic Parameters of Gels

Gel Strength (lb/1000gal)	**Flow Behavior Index (n)**	**Consistency Index (K) (dyne-s^n/cm^2)**
29.77	0.4764	6.01
43.07	0.3891	18.93
53.09	0.3515	33.04

The flow behavior indices show that the gel is a pseudo-plastic power law fluid.

Power-Law Fluid Flow

The power law does not assume a linear relationship between shear stress and shear rate. The lower the value of n, the more shear thinning fluid is. The effective viscosity of power law fluid is given by

$$\mu_e = 100K\left(\frac{1.6\bar{v}}{D_p}\right)^{n-1}\left(\frac{3n+1}{4n}\right)^n \qquad (12)$$

Figures 115 and 116 shows the change in effective viscosities for 2500 psig frictional pressure overcome in 500 ft and 5000 ft tubings, respectively.

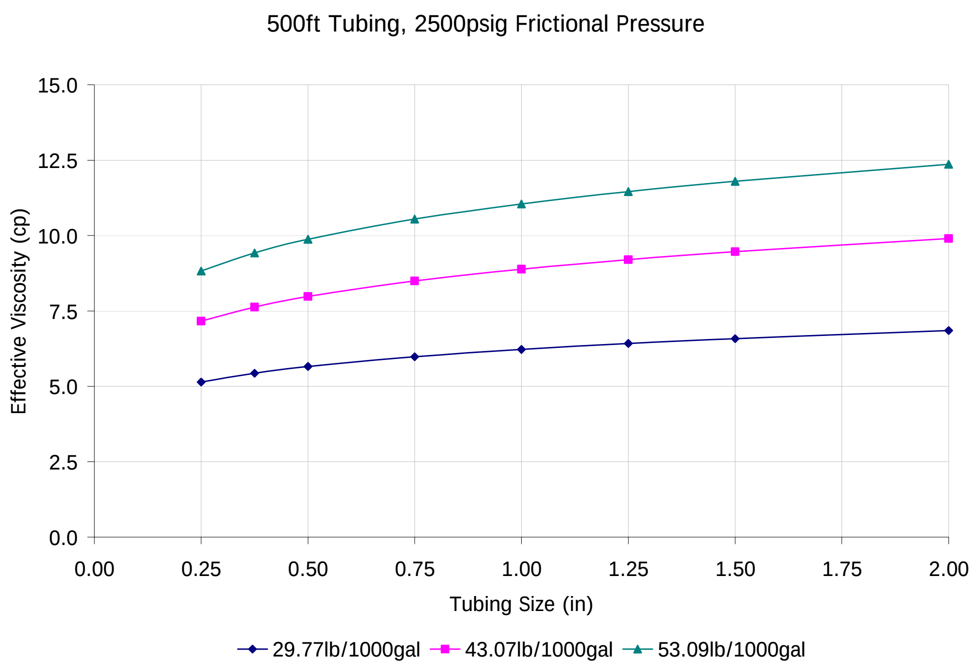


Fig. 115: Effective Viscosities in 500 ft Long Tubing with 2500 psig Frictional Pressure Drop (Pseudo-Plastic Fluid)

The Reynolds number for power-law fluid is given by

$$N_{Re} = \frac{15.467 D_p \rho \bar{v}}{\mu_e} \tag{13}$$

where ρ is in pounds per gallon, D_p in inches and v in ft/min. The critical Reynolds number for power law fluids where flow becomes turbulent from laminar is 2100. If the Reynolds number is higher than critical, the flow is turbulent and below critical value, it is laminar. For laminar flow,

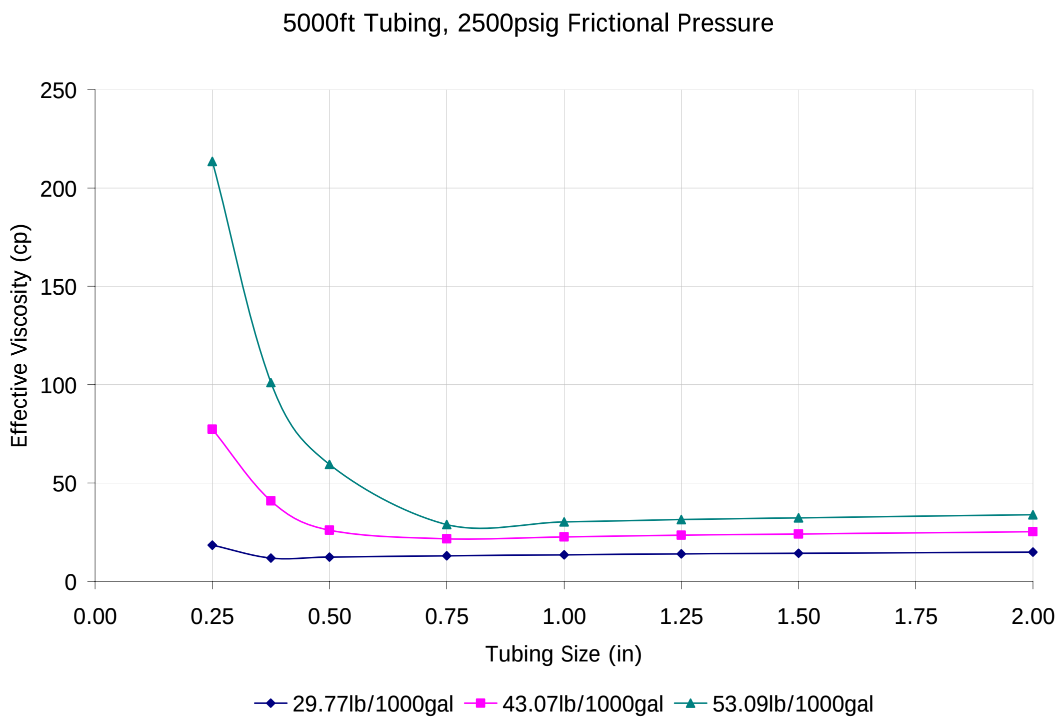


Fig. 116: Effective Viscosities in 5000 ft long Tubing with 2500 psig Frictional Pressure Drop (Pseudo-Plastic Fluid)

the friction factor is given by

$$f_p = \frac{16}{N_{Re}} \tag{14}$$

For turbulent flow, the friction factor is given by

$$f_p = \frac{\text{Log}n + 3.93}{50 N_{Re}^{\left(\frac{1.75 - \text{Log}n}{7}\right)}} \tag{15}$$

Each different viscosity of a power law fluid will have a unique value of n and K. So, the complete characterization of a power law fluid is a tedious and complex process.

For laminar flow, the frictional pressure drop is given by

$$\Delta P_f = \frac{f_p \bar{v} \rho L}{92916 D_p} \tag{16}$$

The frictional pressure drop for a power law fluid is given by

$$\Delta P_f = \frac{f L v^2 \rho}{25.8 D_p} \tag{17}$$

Given the complex and tedious nature of analysis of power law fluid due to changing nature of flow behavior index for different strength of gel, the analysis for frictional pressure drop is carried out only for the experimental samples as n and K values need to be determined experimentally for each concentration (strength) of gel.

Figures 117 and 118 show a comparison between possible gel injection rates with different sizes of 500ft long tubing as a function of viscosity, at 25 psig and 2500 psig pressure drops.

Fig. 119 shows that beyond 0.75" tubing size, for a frictional pressure drop around 2500 psig, the flow rates do not differ much for a tubing length of 5000 ft, typically of deepwater depth.

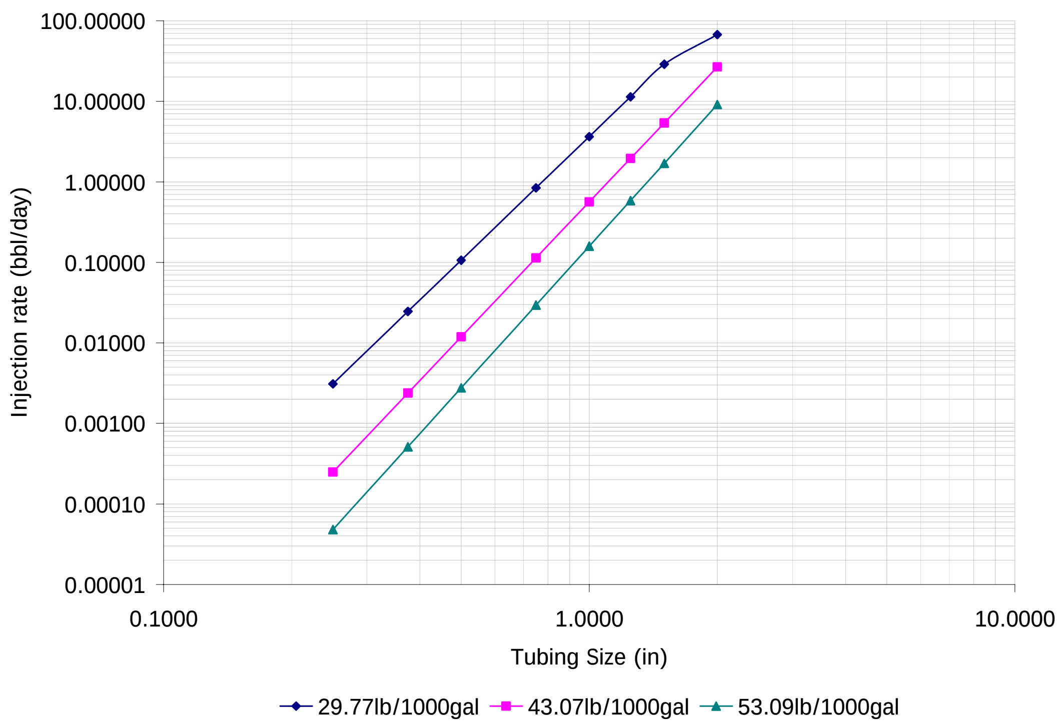


Fig. 117: Flow Rate at 25 psig Pressure Drop through 500 ft Long Tubing as a Function of Viscosity (Pseudo-Plastic Fluid)

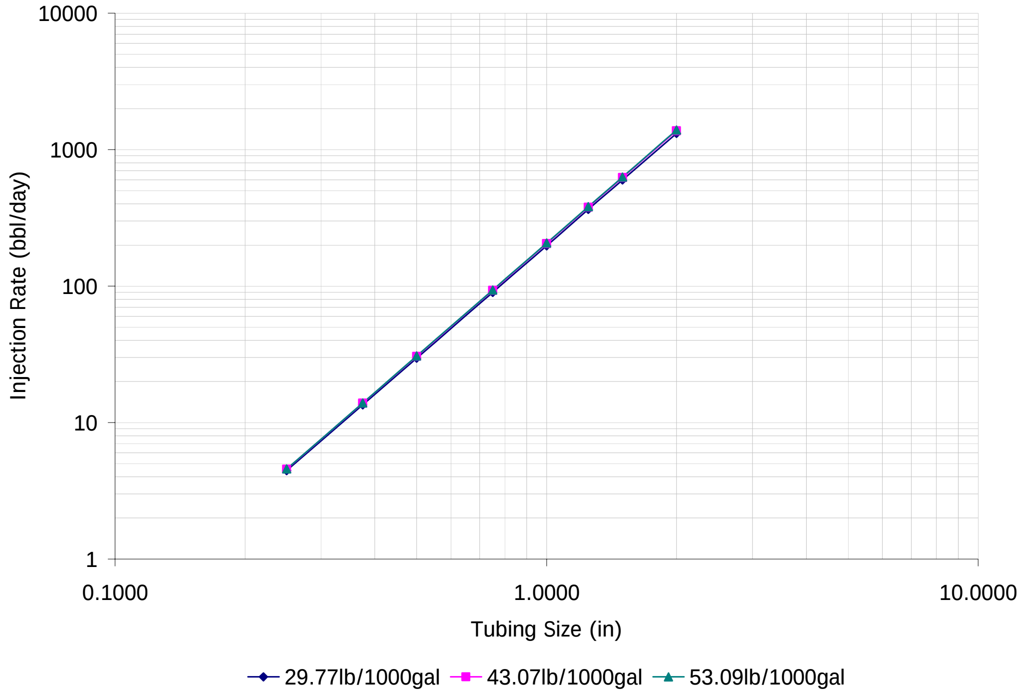


Fig. 118: Flow Rate at 2500 psig Pressure Drop through 500 ft Long Tubing as a Function of Viscosity (Pseudo-Plastic Fluid)

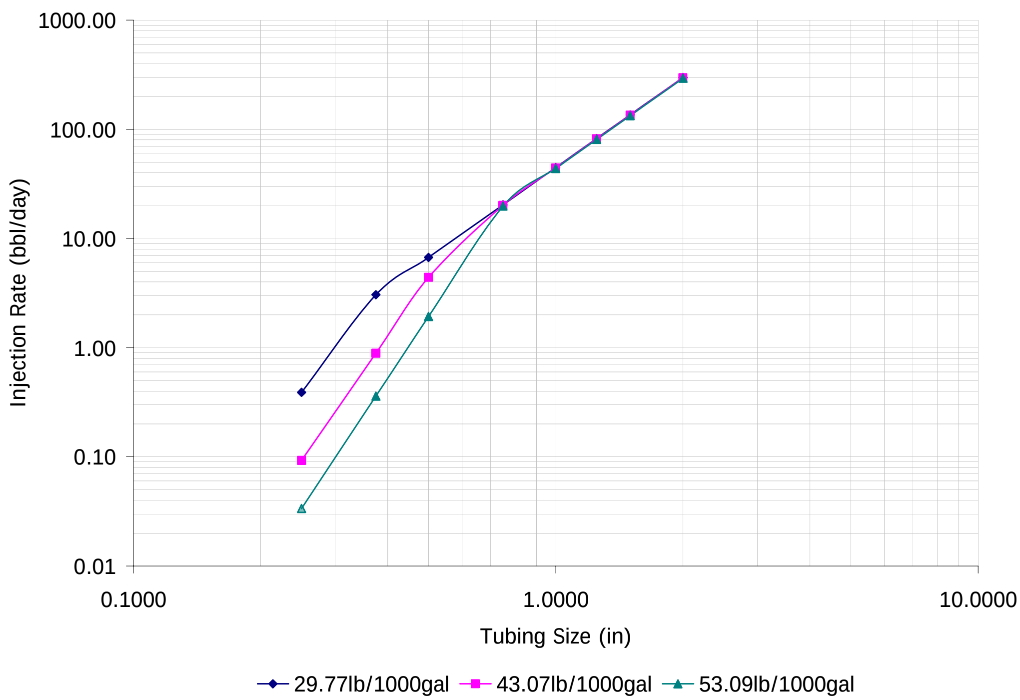


Fig. 119: Flow Rate at 2500 psig Pressure Drop through 5000 ft Long Tubing as a Function of Viscosity (Pseudo-Plastic Fluid)

Figures 120, 121, and 122 show a comparison between pipeline viscosities on injecting the three samples of gels, used for the experiments, through 0.75”, 1”, and 1.25” tubings with 2000 psig frictional pressure drop.

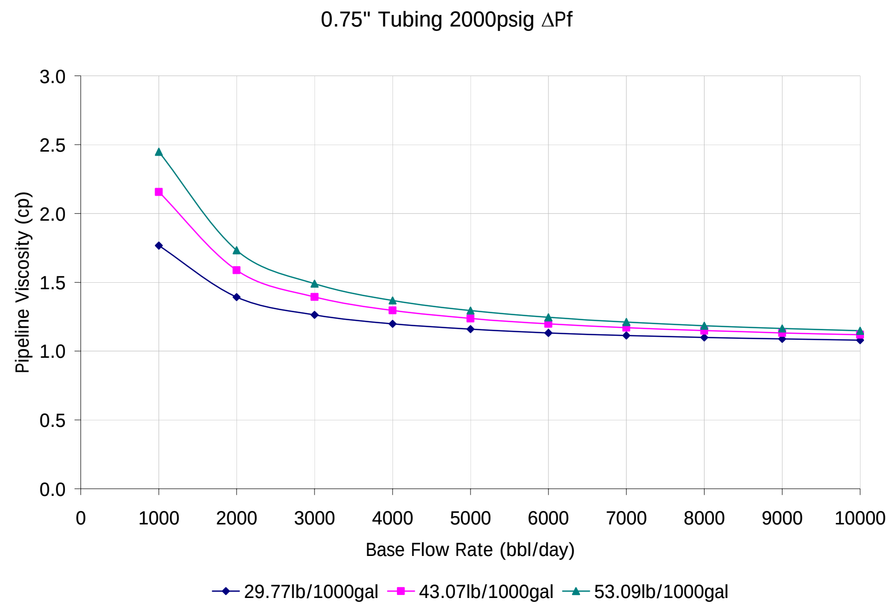


Fig. 120: Effective Viscosity with Gel Injection through 500 ft Long 0.75” Tubing (Pseudo-Plastic Fluid)

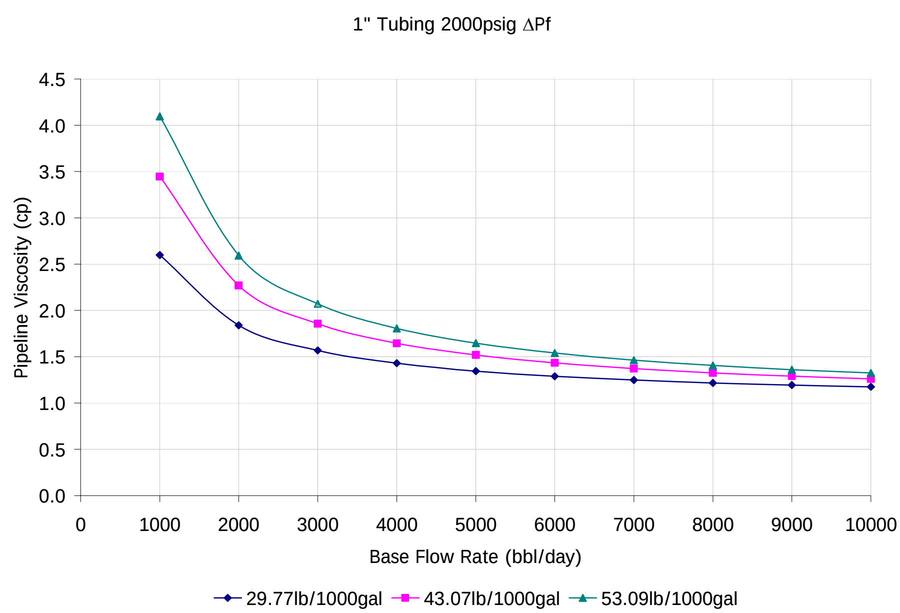


Fig. 121: Effective Viscosity with Gel Injection through 500 ft Long 1” Tubing (Pseudo-Plastic Fluid)

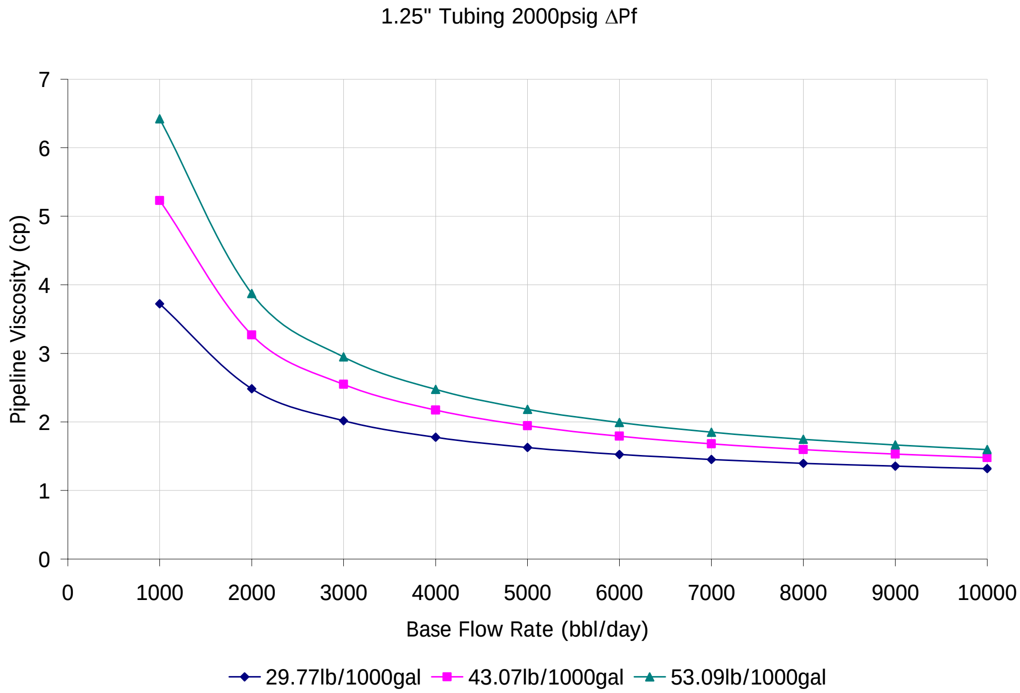


Fig. 122: Effective Viscosity with Gel Injection through 500 ft Long 1.25” Tubing (Pseudo-Plastic Fluid)

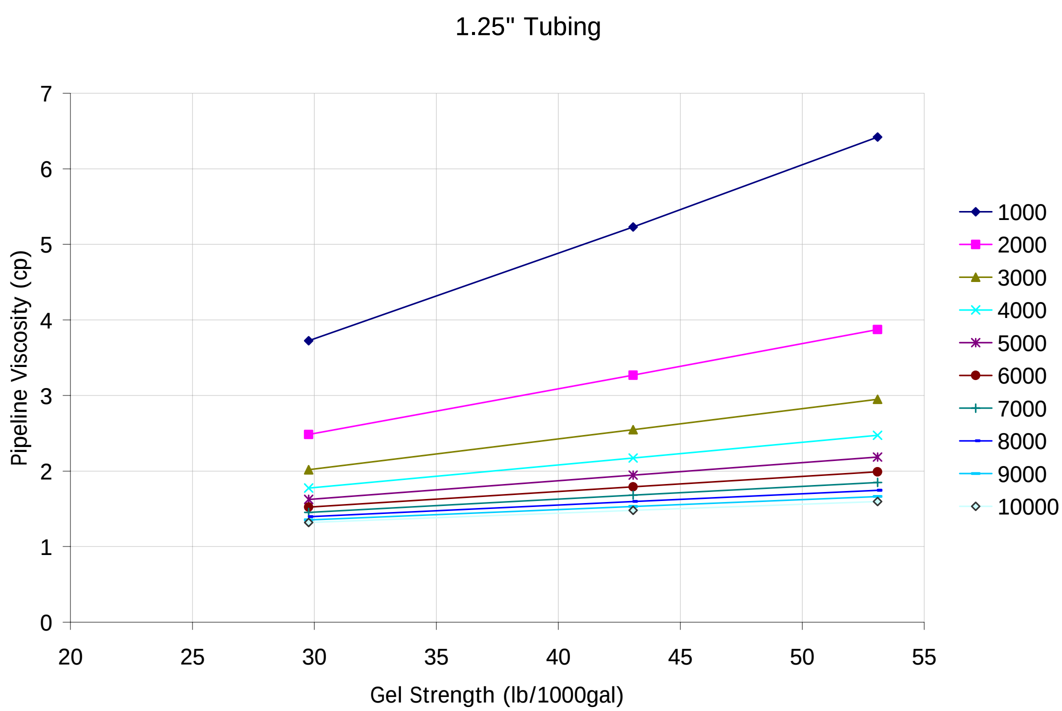


Fig. 123: Viscosities Achieved with Injection through 500 ft Long 1.25” Tubing at 2000 psig Frictional Pressure Drop (Pseudo-Plastic Fluid)

Figures 123, 124, and 125 demonstrate that with an increase in frictional resistance, the maximum pipeline viscosity by injecting concentrated gel goes on decreasing beyond a certain gel strength. This is prominently explained by fig. 125.

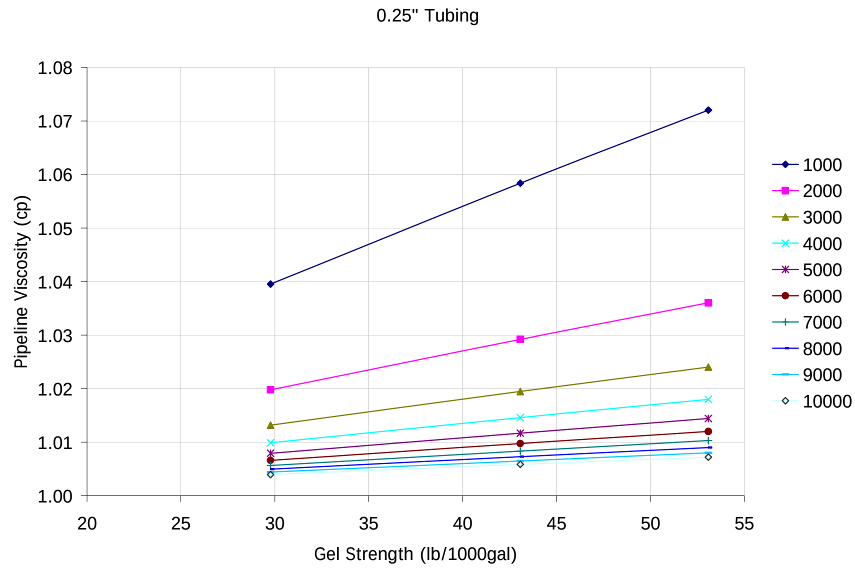


Fig. 124: Viscosities Achieved with Injection through 500 ft Long 0.25" Tubing at 2000 psig Frictional Pressure Drop (Pseudo-Plastic Fluid)

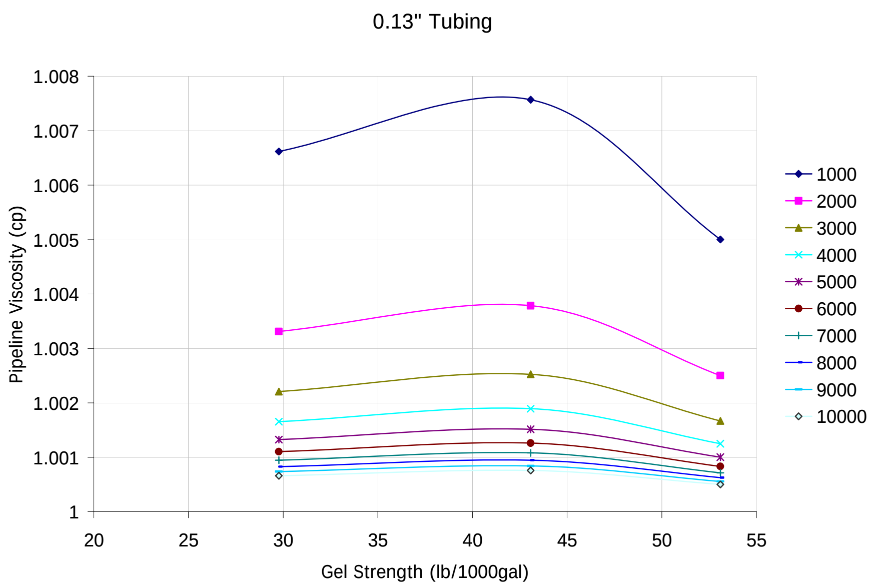


Fig. 125: Viscosities Achieved with Injection through 500 ft Long 0.13" Tubing at 2000 psig Frictional Pressure Drop (Pseudo-Plastic Fluid)

Newtonian Fluid Flow

Injection of viscous gels through injection umbilicals into the flowlines will involve high frictional pressure drops. It is essential to investigate the flow rates and pressure drops for gels with piping diameters to arrive at practical range of operational possibilities. Determination of frictional pressure losses will involve evaluation of the type of flow – laminar or turbulent. Laminar flow has Reynolds number less than 2000 and turbulent flow has Reynolds number greater than 4000. The flow regime having Reynolds number between 2000 and 4000 is transition flow. The Reynolds number is defined as

$$N_{Re} = \frac{\rho v d_p}{\mu} \tag{18}$$

where, N_{Re} is Reynolds number, ρ is liquid density, v is velocity of flow, d_p is pipe diameter, and μ is viscosity of liquid.

The Jain equation for friction factor is known to be accurate for a wide range of Reynolds number from less than 2000 to 10^8. The equation is

$$\frac{1}{\sqrt{f}} = 1.14 - 2\mathrm{Log}\left(\frac{\varepsilon}{d_p} + \frac{21.25}{N_{Re}^{0.9}}\right) \tag{19}$$

where, f is friction factor and ε is pipe roughness. This equation is valid for laminar, transition and turbulent flow. The frictional pressure drop is expressed as

$$\Delta P_f = \frac{fLv^2\rho}{2g_c d} \tag{20}$$

where, ΔP_f is frictional pressure drop and g_c is acceleration due to gravity.

Using the equations for Reynolds number, friction factor and frictional pressure drop in an iterative process, it is possible to arrive at a stable solution for pressure drop or flow rate.

Figures 126 and 127 show a comparison of gel injection rates possible with different sizes of 10 ft long tubing as a function of viscosity, at 25 psig and 75 psig frictional pressure drops.

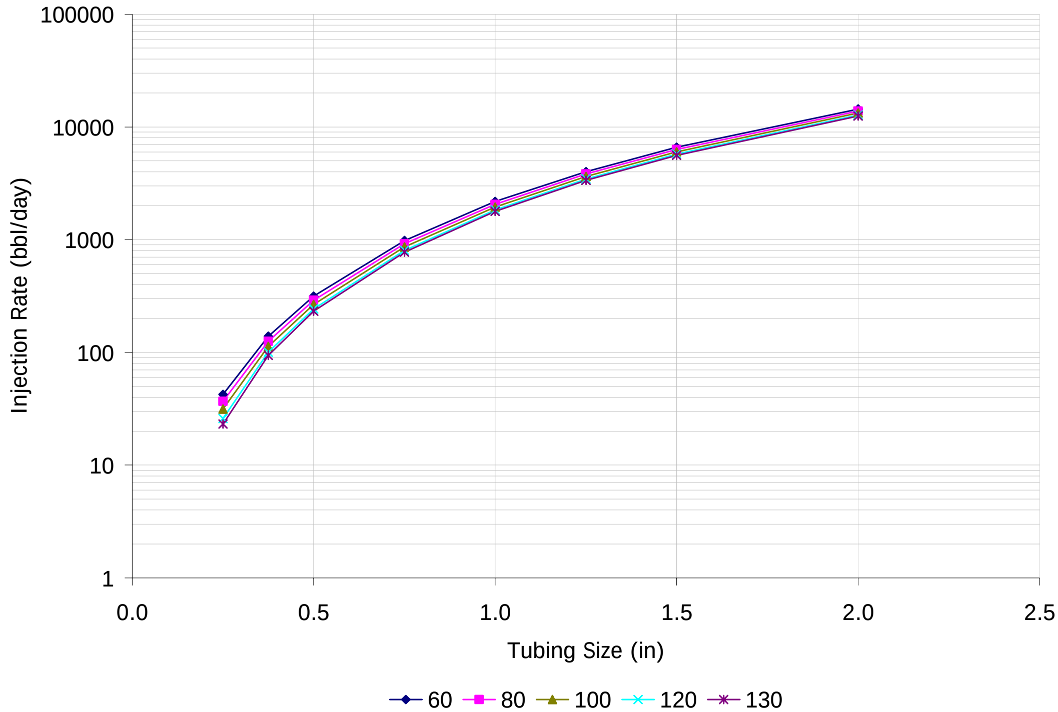


Fig. 126: Flow Rate at 25 psig Pressure Drop through 10 ft Long Tubing as a Function of Viscosity

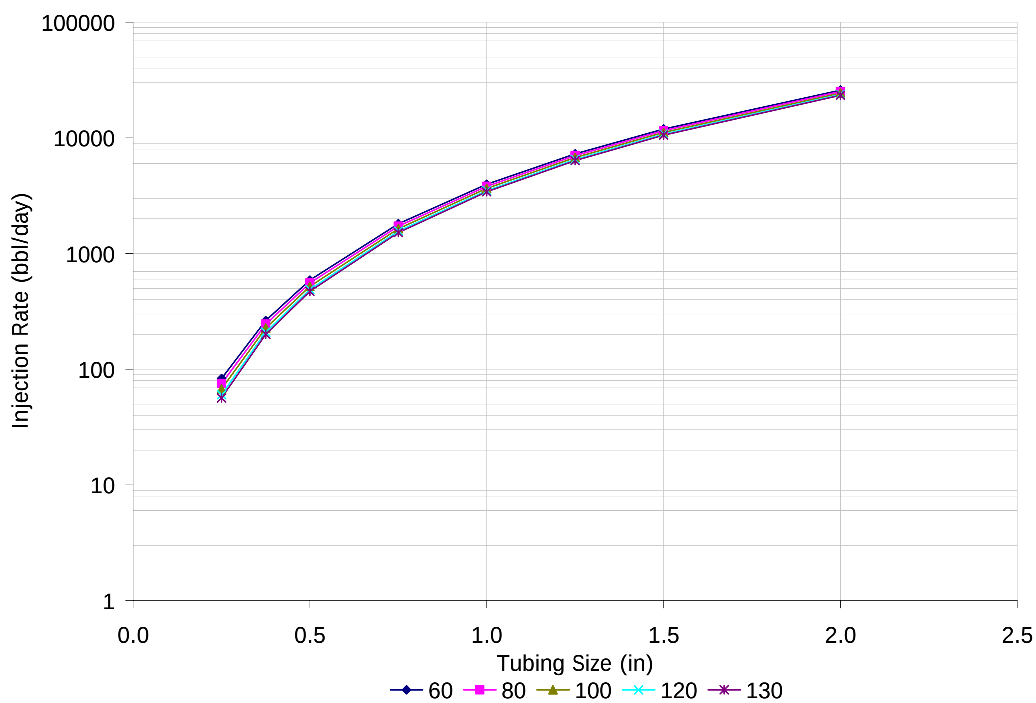


Fig. 127: Flow Rate at 75 psig Pressure Drop through 10 ft Long Tubing as a Function of Viscosity

Figures 128 and 129 show a comparison of gel injection rates possible with different sizes of 500 ft long tubings as a function of viscosity, at 25 psig and 2500 psig frictional pressure drops respectively.

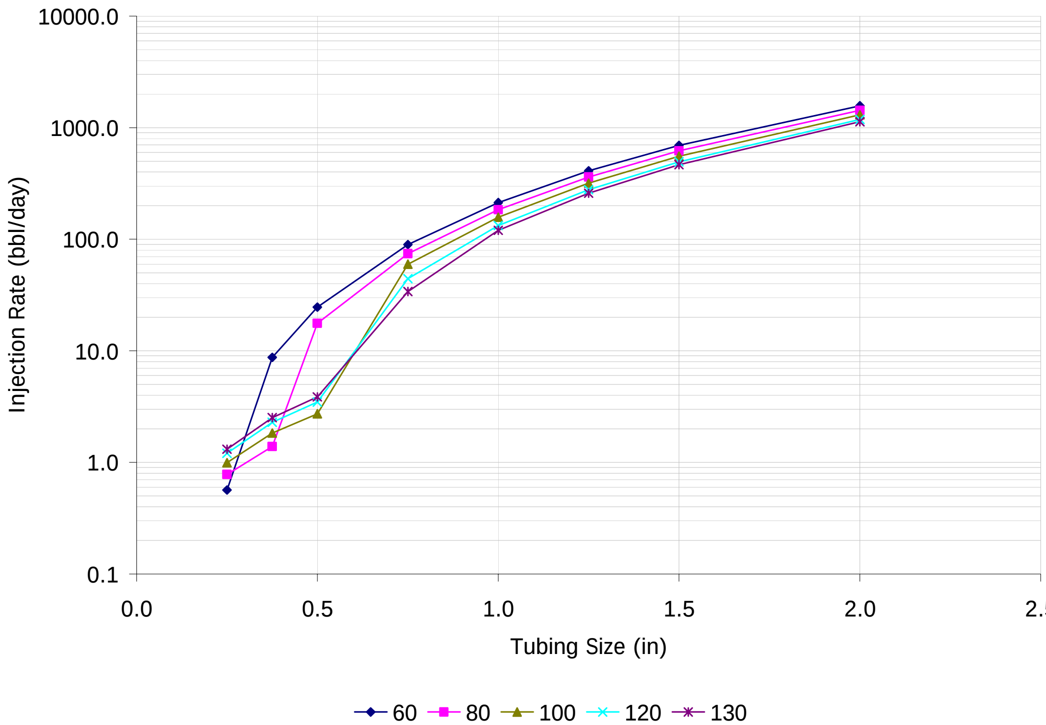


Fig. 128: Flow Rate at 25 psig Pressure Drop through 500 ft Long Tubing as a Function of Viscosity

Figures 126, 127, 128, and 129 show that for real application of gel injection for controlling the slip flow across clearances in twin-screw pumps installed in moderately deep waters, the frictional pressure drop needed to be overcome will be in the range of a few thousand psig if commercially available tubing sizes are used.

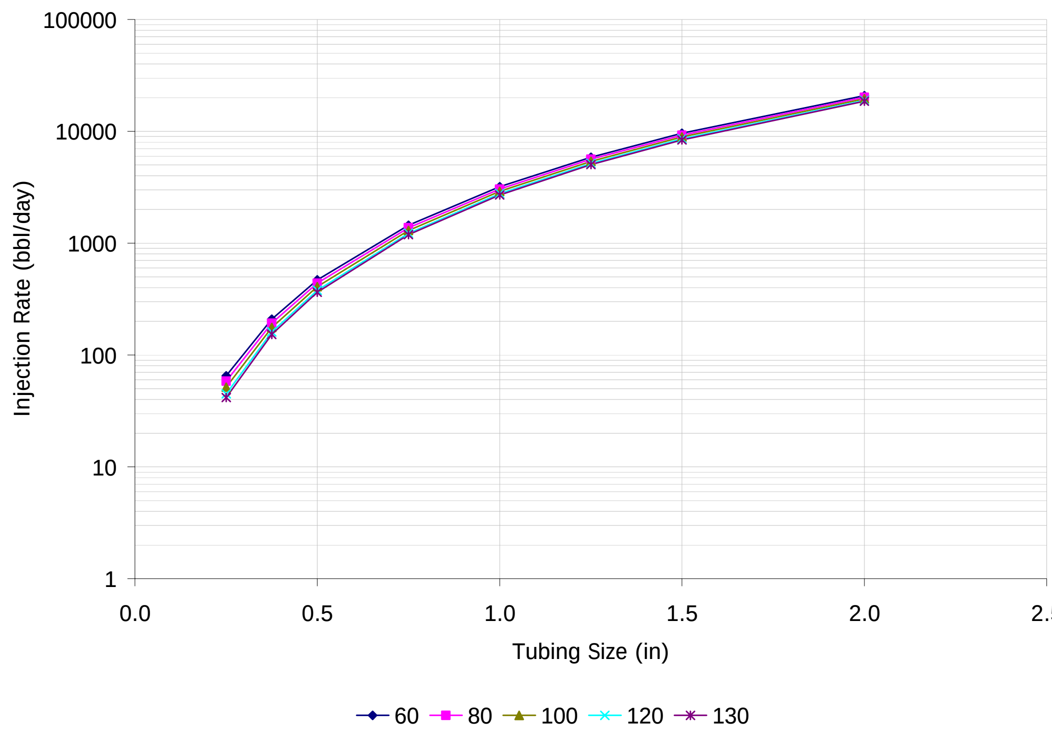


Fig. 129: Flow Rate at 2500 psig Pressure Drop through 500 ft Long Tubing as a Function of Viscosity

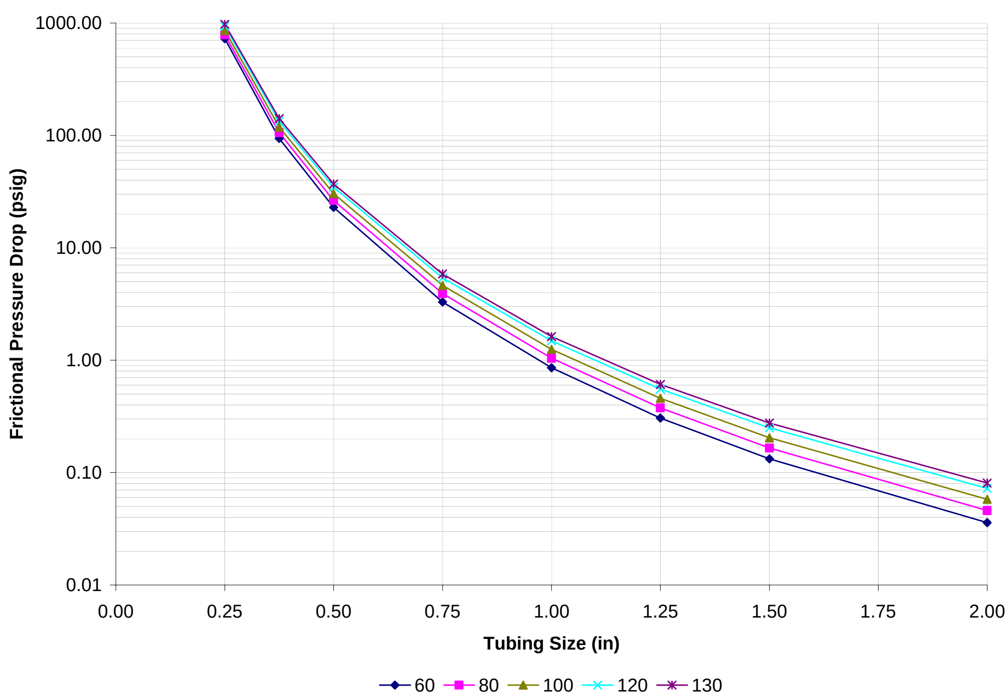


Fig. 130: Frictional Pressure Drop at 300 bbl/day Injection Rate through 10 ft Long Tubing as a Function of Viscosity

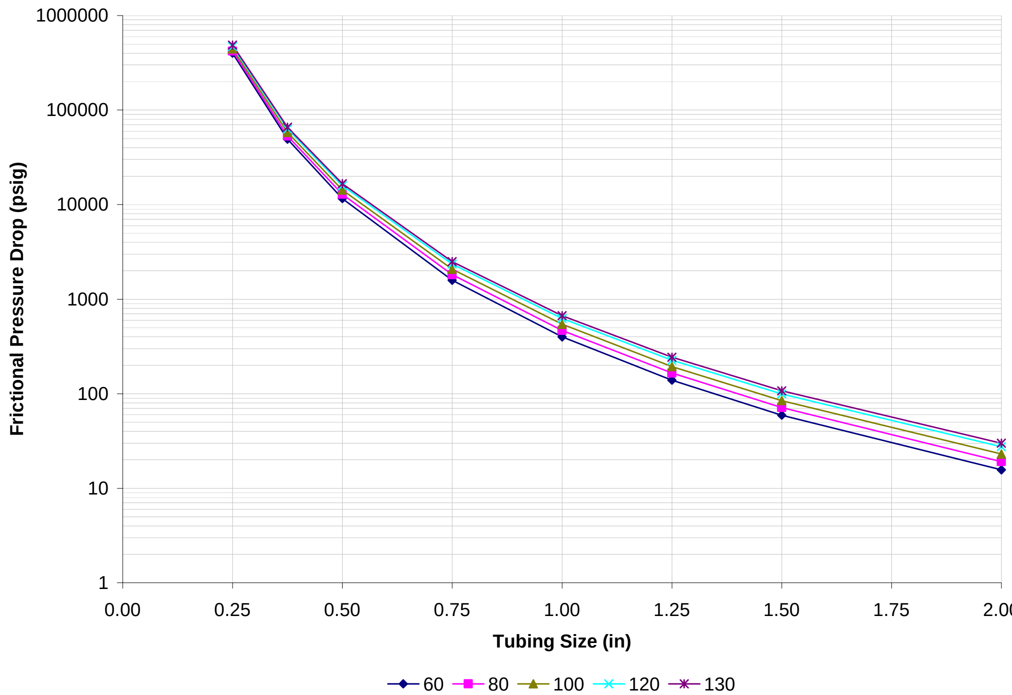


Fig. 131: Frictional Pressure Drop at 600 bbl/day Injection Rate through 1500 ft Long Tubing as a Function of Viscosity

The above plots (figures 130 and 131) indicate that for deep water depths, smaller tubings provide very high frictional pressure drops and hence small injection rates. For typically 500 ft water depths, tubing sizes of 0.75", 1" and 1.25" were found to be most suitable for using with injection equipment which can overcome frictional pressure drops up to 2000 psig. In all analysis, a pipe roughness of 0.0006 ft was assumed before starting the iterations. In some cases (for tubing size up to 0.5"), iterative process gives friction factor higher than 1, which seems unrealistic.

Effective Viscosity Determination Using Field Data

Using the above analysis, and gel concentration-viscosity relation, it is possible to estimate the effective viscosity in a pipeline when other data is available. Perfect mixing is assumed in all analysis.

Figures 132 and 133 show a comparison between effective viscosities achieved in pipeline flow with injection of viscous gels with different strengths through 500 ft long tubings of 0.75" and 1" diameters respectively at a frictional pressure drop of 2000 psig.

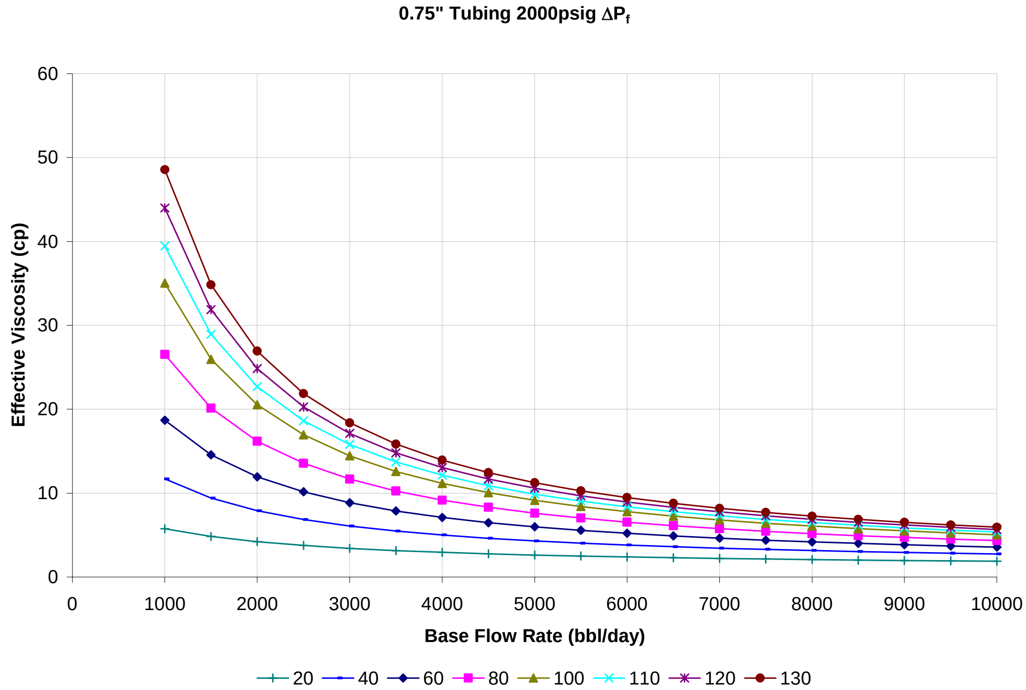


Fig. 132: Effective Viscosity with Gel Injection through 500 ft Long 0.75” Tubing with 2000 psig Frictional Pressure Drop

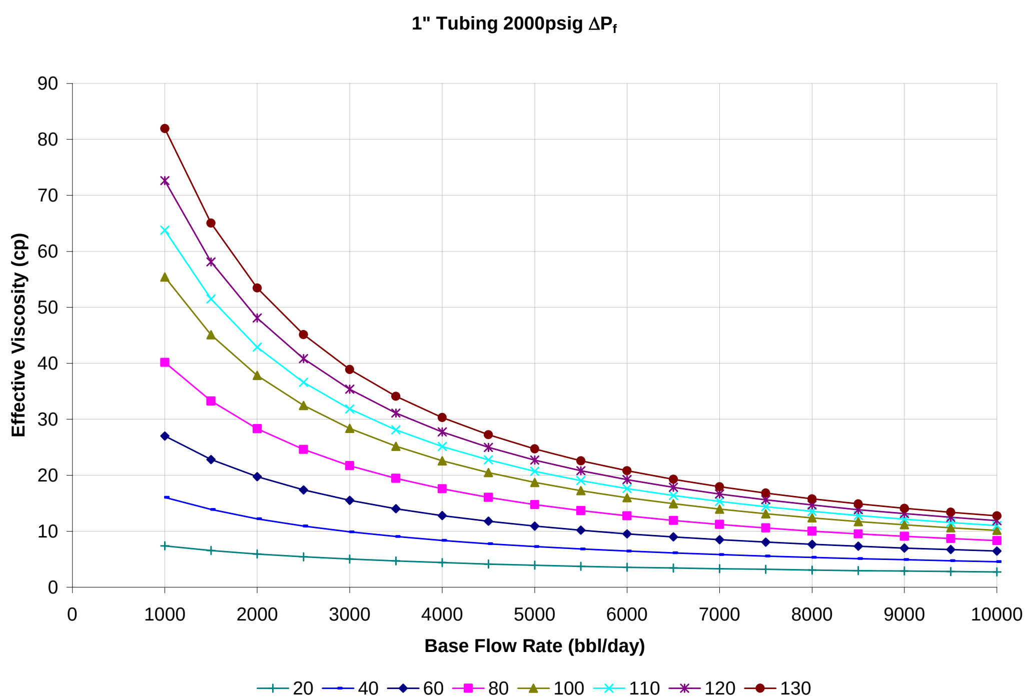


Fig. 133: Effective Viscosity with Gel Injection through 500 ft Long 1” Tubing with 2000 psig Frictional Pressure Drop

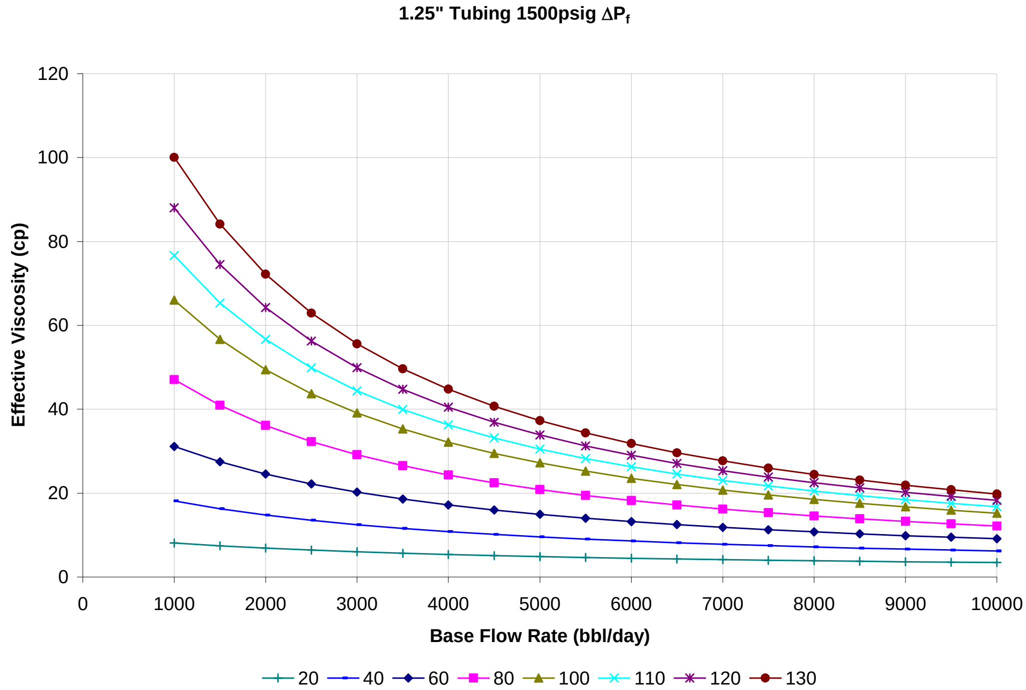


Fig. 134: Effective Viscosity with Gel Injection through 500 ft Long 1.25" Tubing with 1500 psig Frictional Pressure Drop

Fig. 134 shows that for umbilicals with larger diameters the frictional pressure drop needed to be overcome is less and hence injection rate is higher which gives higher effective viscosity.

Fig. 135 shows a comparison of maximum gel injection rate which can be achieved by gels of different strengths under different combinations of tubing sizes and frictional drops.

Figures 136 and 137 compare the effective viscosities in pipeline after gel injection under different combinations of tubing sizes and frictional pressure drops into 6000 bbl/day and 10000 bbl/day base flow rates respectively.

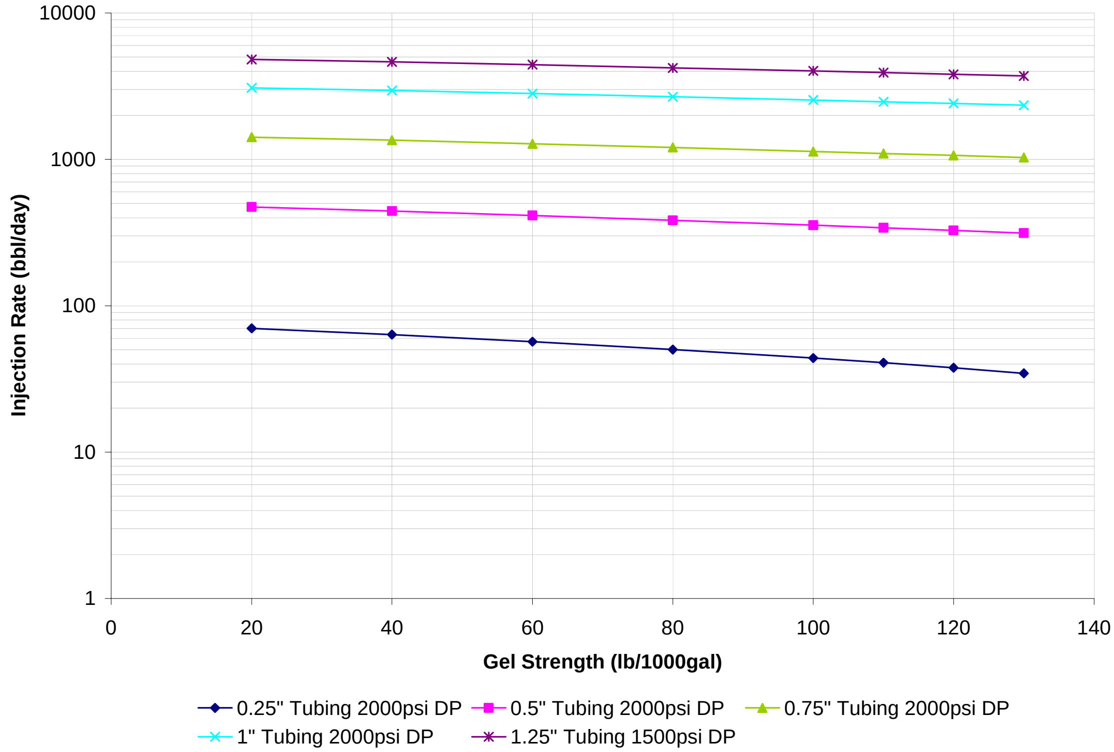


Fig. 135: Injection Rates Possible with Different Gel Strengths and Tubing Sizes

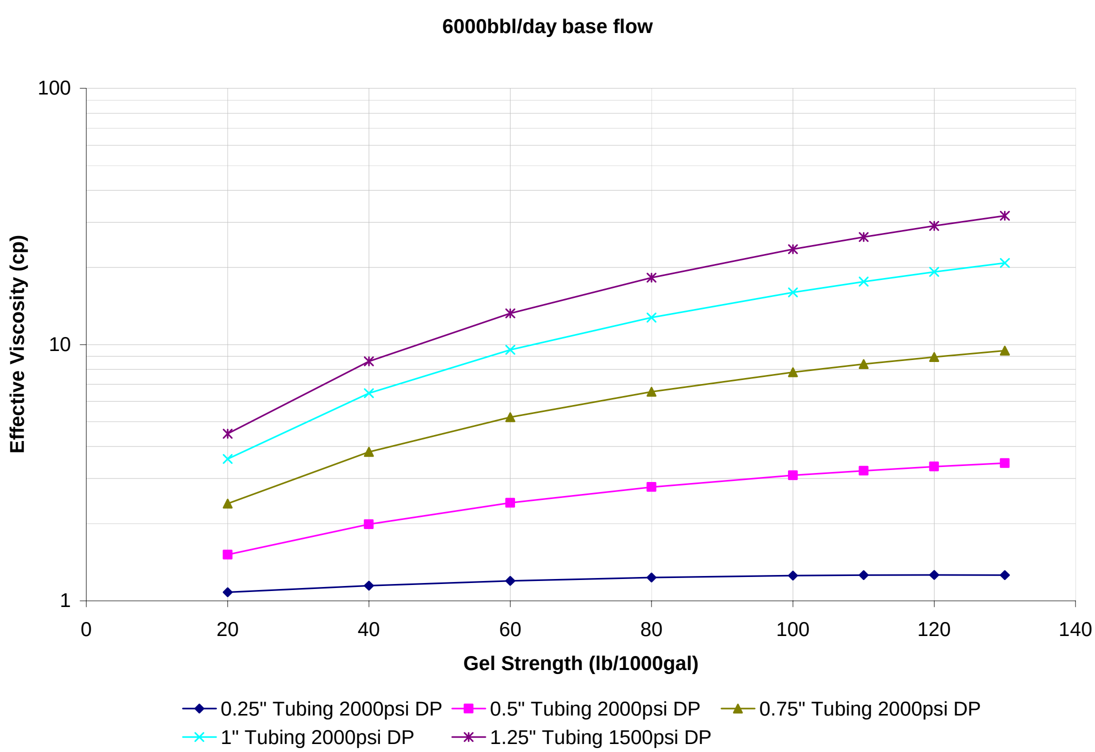


Fig. 136: Viscosities Achievable at 6000 bbl/day Base Flow Rate and 500 ft Tubing Length

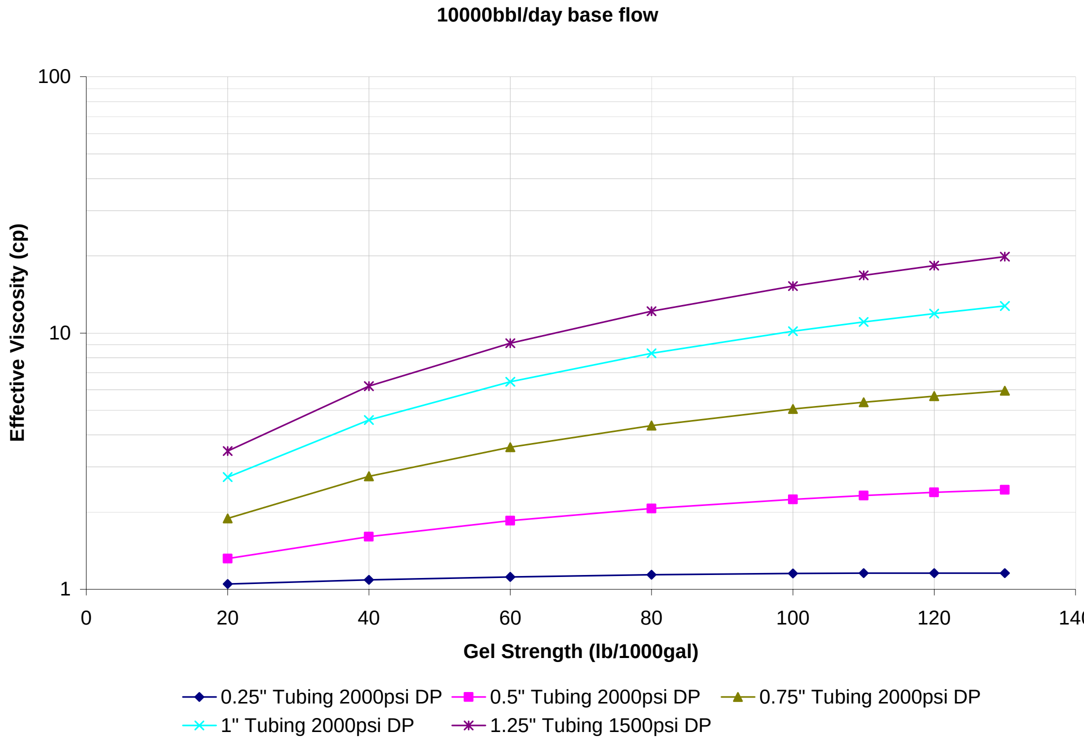


Fig. 137: Viscosities Achievable at 10000 bbl/day Base Flow Rate and 500 ft Tubing Length

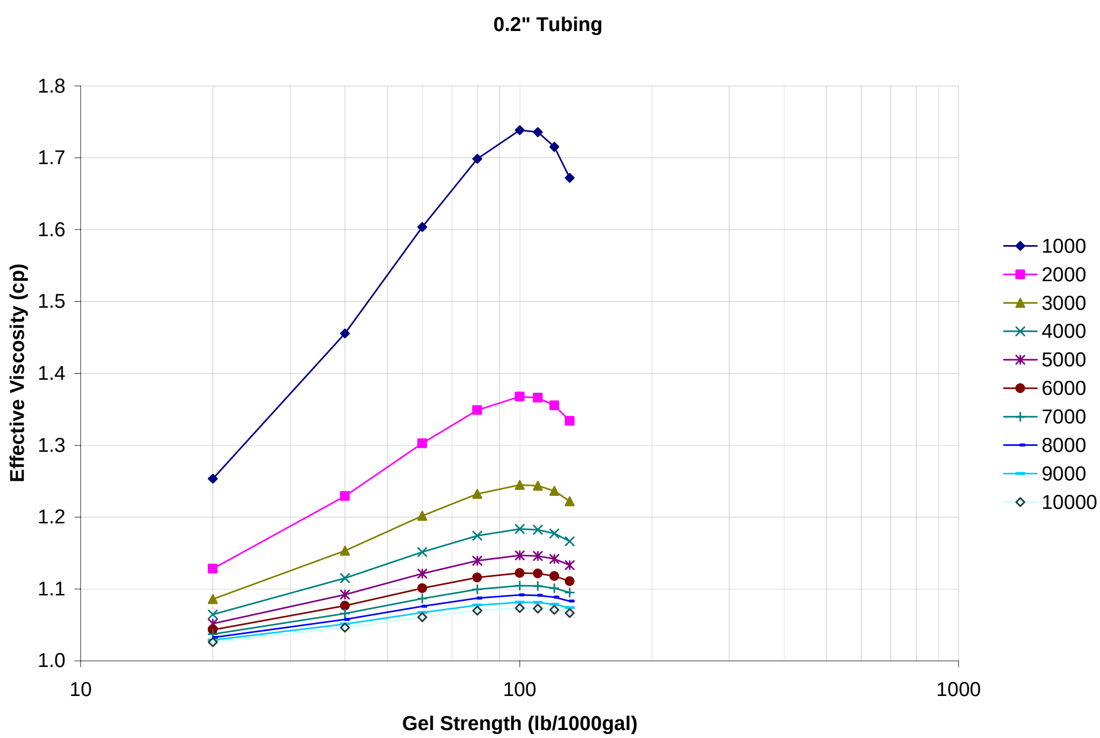


Fig. 138: Viscosities Achieved with Injection through 500 ft Long 0.2” Tubing

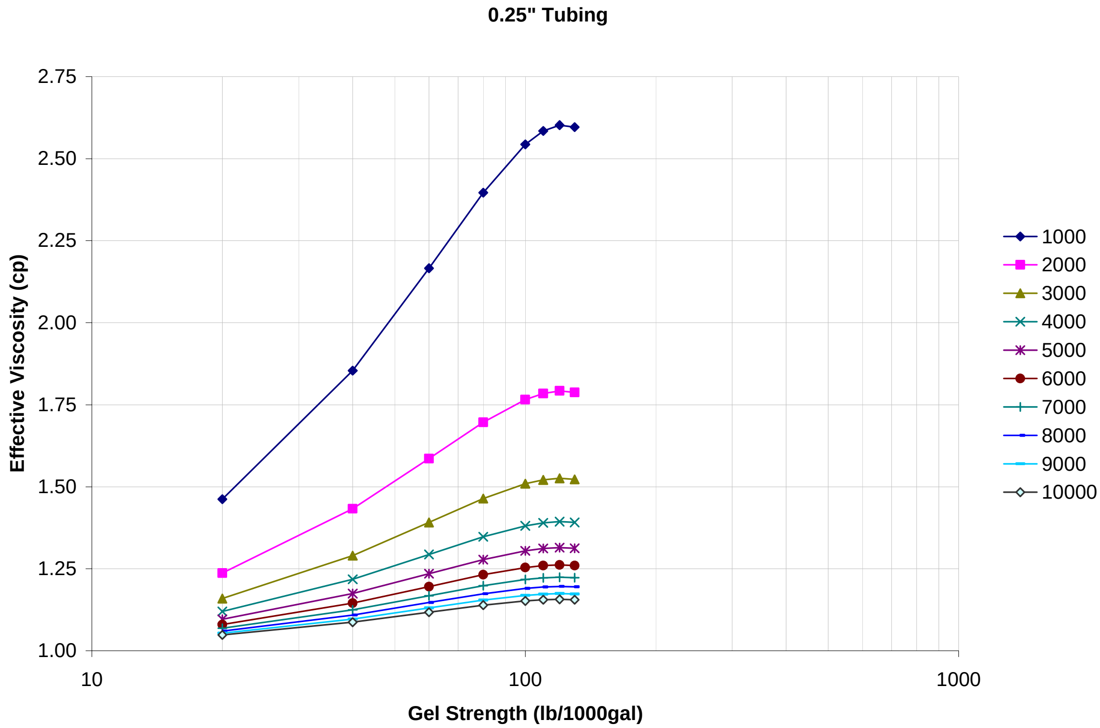


Fig. 139: Viscosities Achieved with Injection through 500 ft Long 0.25” Tubing

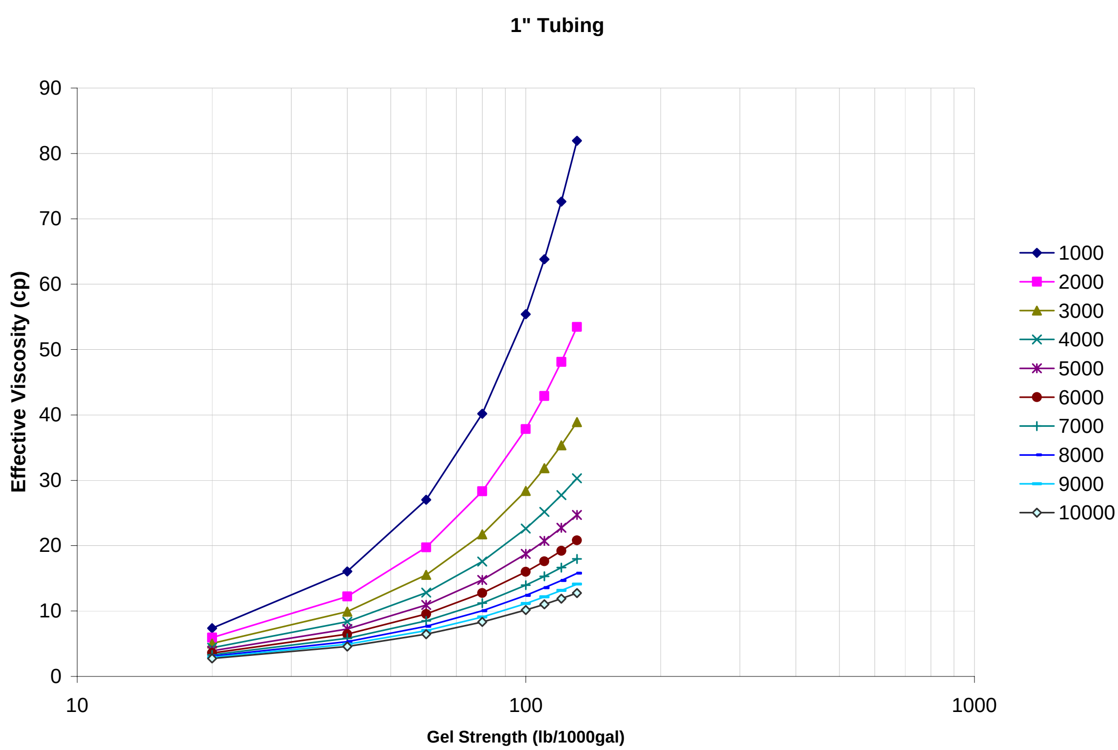


Fig. 140: Viscosities Achieved with Injection through 500 ft Long 1” Tubing

The above plots (figures 138, 139, and 140) indicate that there is a maximum effective viscosity achievable when a tubing size is used for gel injection. This maximum does not occur at maximum gel strength, and varies for tubing sizes and lengths. For a tubing size of 0.2”, this maximum is achieved when injected gel has 100 lb/1000bbl concentration, for 0.25” tubing, it is 120 lb/1000gal and for 1” tubing, it will occur beyond the range of viscosities used in experiments. The gel strength at which maximum effective viscosity is achievable in a pipeline flow can be called as the optimum gel strength for that setup. Using gel strengths higher than optimum will result in higher frictional losses and effective concentration in pipeline upon injection will be less than with optimum gel strength hence reducing effective viscosities. Thus it is highly recommended that analysis for optimum gel strength be carried out before designing a gel injection system.

Gel Injection Tests Upstream Twin-Screw Pump

Experimental tests focused on gel injection were carried out and effects of gel injection on effective viscosity at different flow rates across pump chamber were studied. The first tests were with locked rotor with 16 cp, 26 cp and 35 cp gels (fig. 141). Next, a 100 cp gel was injected at different rates and at different base flow rates. The results obtained suggest that the effective viscosity across pump chamber could be estimated if data is available.

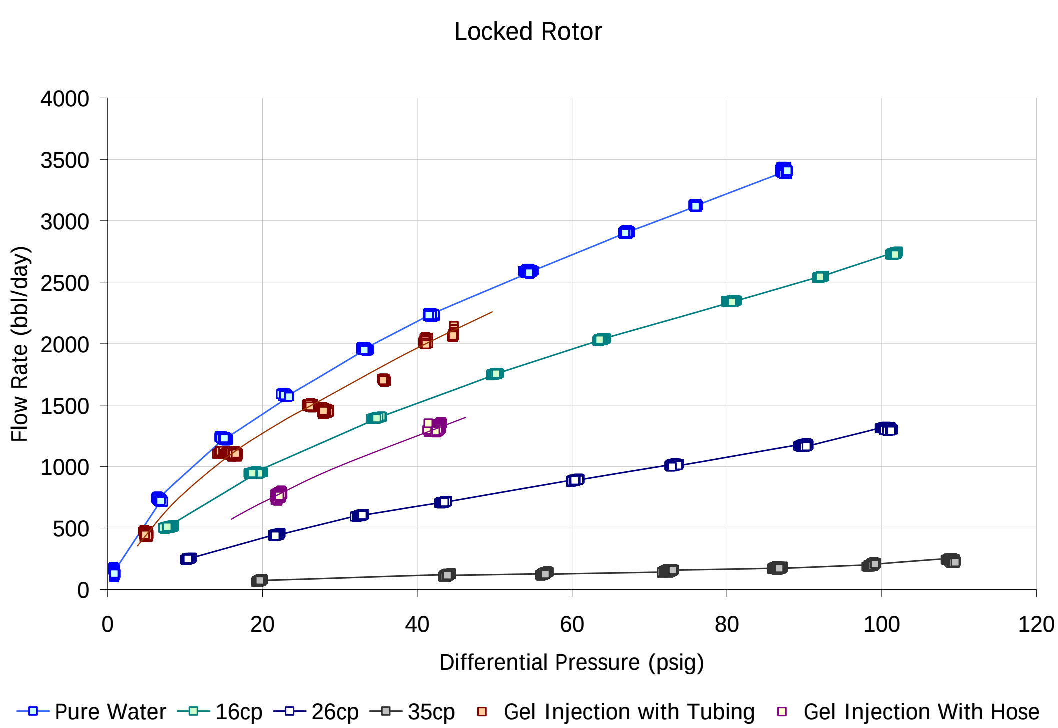


Fig. 141: Gel Injection with Locked Rotor Flow

The plot shows that with higher rate of gel injection, it is possible to increase the viscosity across the pump chamber and it can be estimated using differential pressure and total flow rate. The effective viscosity however, will depend on how quickly and effectively the injected gel disperses and mixes with the base fluid. The choice of gel to be used for the purpose is itself a topic of in depth research as fluid composition and properties produced in the oilfields vary across the world. Certain type of viscous gel will be readily miscible with one type of produced fluid to increase viscosity momentarily for transporting the detected sand particles but not for other formation fluids produced from another field.

To study the behavior of running pump with viscous fluids, same viscosities of gel were used. At the 1200 RPM speed, 100 cp gel was injected at different flow rates and results were plotted on the same background plot (fig. 142). This plot confirms the concept mentioned above. Gel injection tests at 1400 RPM supported this concept and the viscosities could be roughly "read" to be lying in between pure water and other tested viscosities (fig. 143).

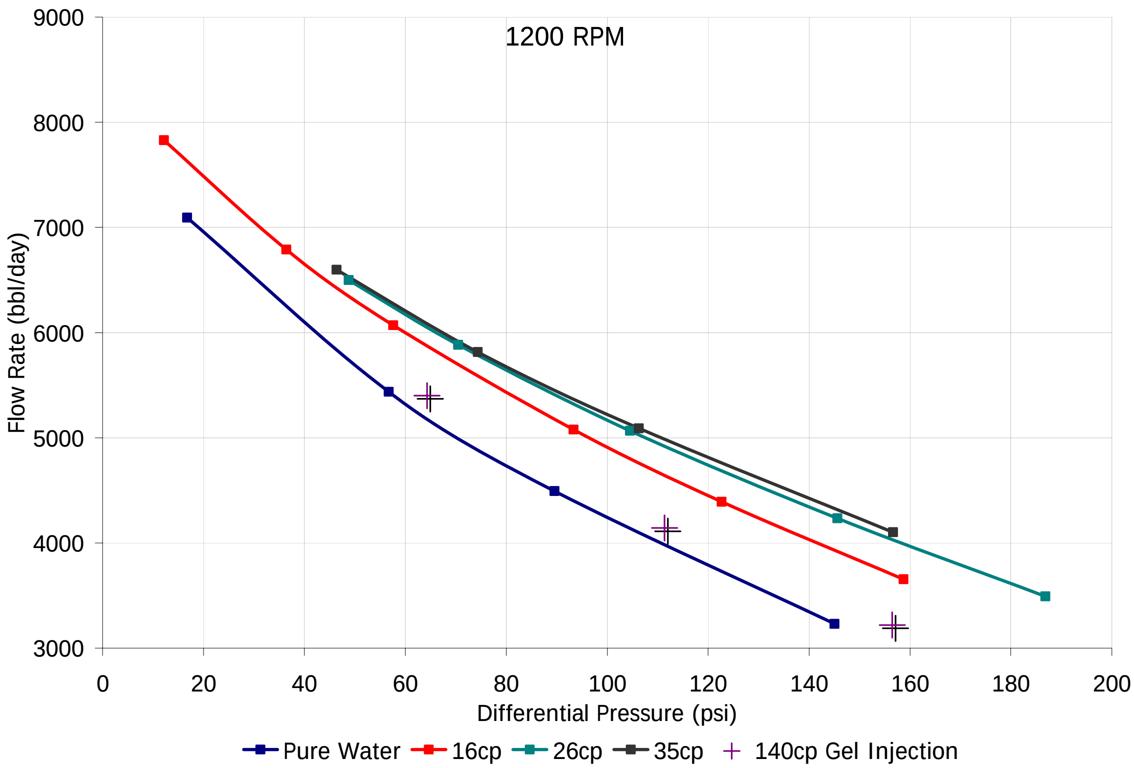


Fig. 142: Gel Injection in Loop at Pump Speed 1200 RPM

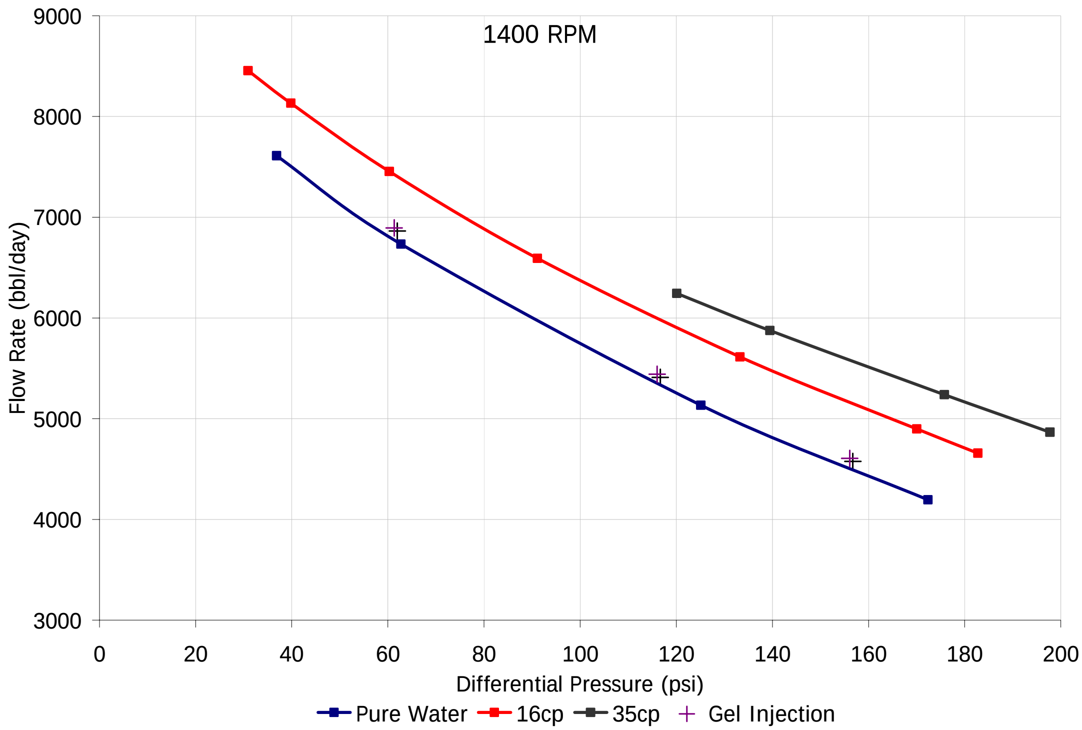


Fig. 143: Gel Injection in Loop at Pump Speed 1400 RPM

Prediction of Viscous Flow through Twin-Screw Pump

Using data from different speed and viscosity tests on Flowserve twin-screw multiphase pumps, a correlation for predicting the flow rates at a given differential pressure and a give fluid viscosity was developed. The flow of viscous fluid across twin-screw pumps is obtained by multiplying the pure water flow by a coefficient called viscosity coefficient.

$$Q_{gel} = Q_w C_{visc} \tag{21}$$

The pure water flow is a function of differential pressure and pump rotary speed.

$$\begin{aligned}
&Q_w = a\Delta P^{2.99} + b\Delta P^2 + c\Delta P + d \\
&a = -1.556X10^{-9} N^2 + 5.3556X10^{-6} N - 0.0047 \\
&b = 2.2488X10^{-7} N^2 - 9.7637X10^{-4} N + 1.0761 \\
&c = 2.0917X10^{-5} N^2 - 0.0129N - 70.5219 \\
&d = -1.5206X10^{-3} N^2 + 10.1643N - 2046.9066
\end{aligned} \tag{22}$$

The viscosity coefficient is a function of viscosity, differential pressure and pump speed. The viscosity coefficient is empirically expressed as

$$C_{visc} = \mu^{[0.0085\Delta P\left(0.011X16^{e}+0.0011\Delta P-0.00016\Delta P^{1.285}+6X10^{-11}\Delta P^{2\mu^{0.19}}+0.0001\Delta P^{-0.26}\right)+\frac{\mu^{1.16}}{9000}]} \tag{23}$$

$$e = -5X10^{-7}N^{2} + 5X10^{-4}N + 1.3245 \tag{24}$$

The correlation shows a good match with the experimental measurements (figures 144, 145, and 146). The slight mismatch at higher viscosities for higher speeds is possibly because of difficulty faced by centrifugal charging pumps in handling viscous fluids sometimes entrapped with air bubbles. The entrapment of air bubbles in high viscosity gel takes more time to completely separate than the possible residence time in 40 barrel tank at high flow rates. The key limitation of the test loop is that fluid flows back to the tank which supplies fluid to loop. This gives very little residence time in case of air entrapment. Due to entrapped air, the flow measured using mass flow meter includes air bubble component and may significantly differ from the case in which there would be no entrapment of air bubbles.

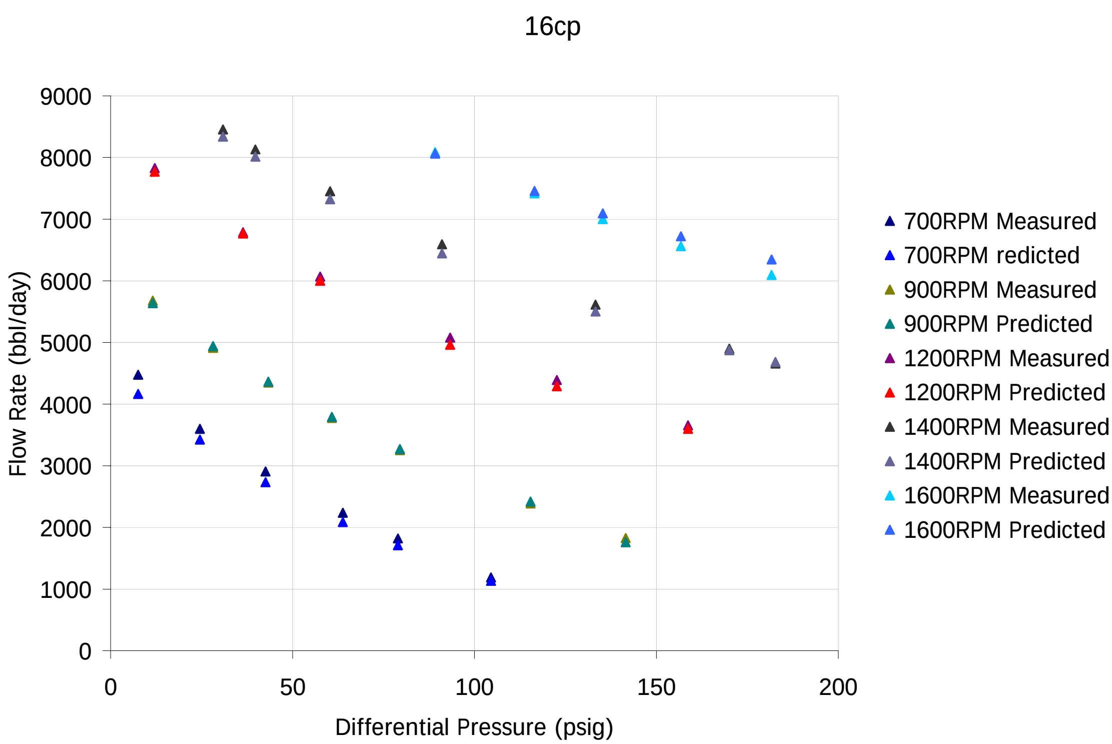


Fig. 144: Twin-Screw Pump Performance for 16 cp Gel

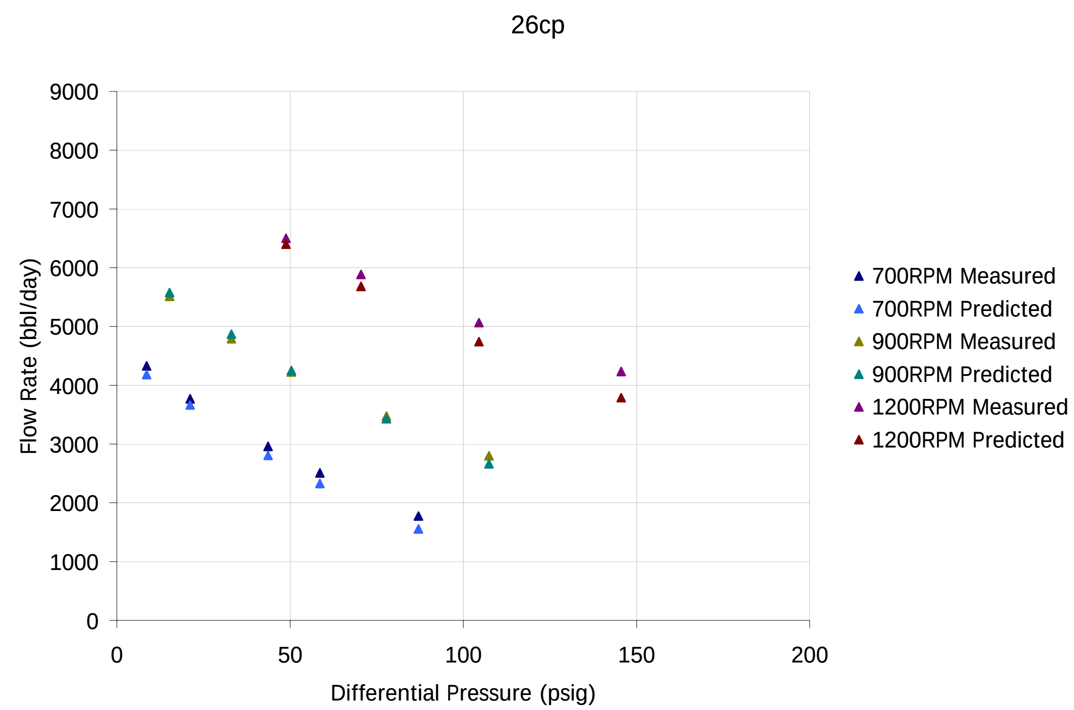


Fig. 145: Twin-Screw Pump Performance for 26 cp Gel

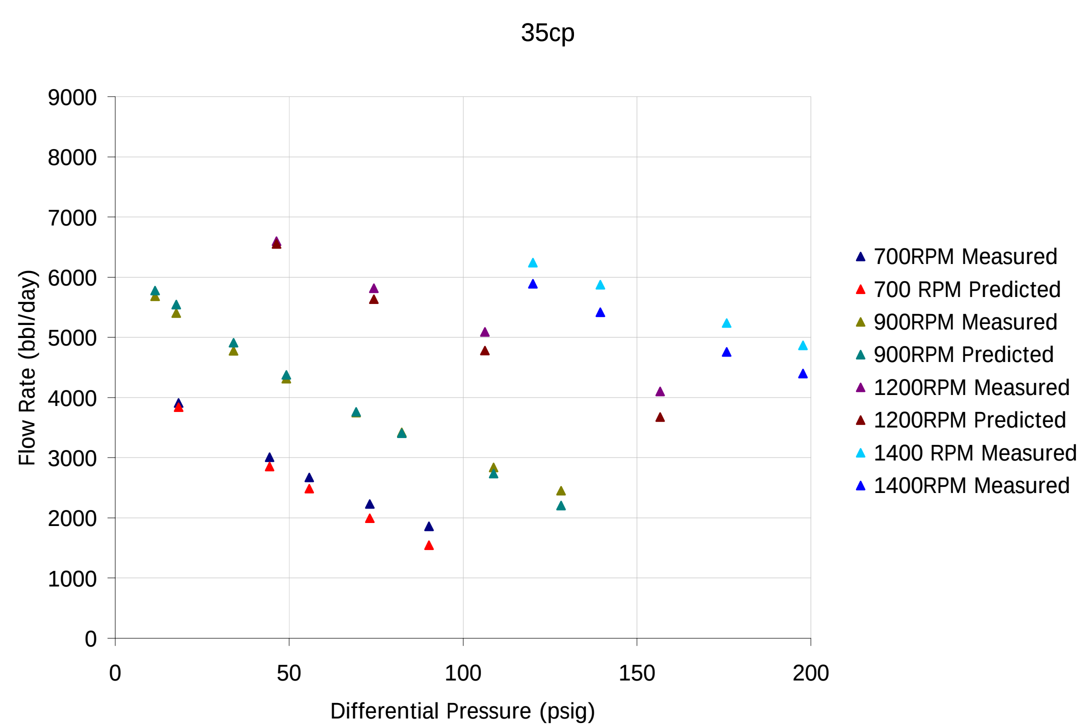


Fig. 146: Twin-Screw Pump Performance for 35 cp Gel

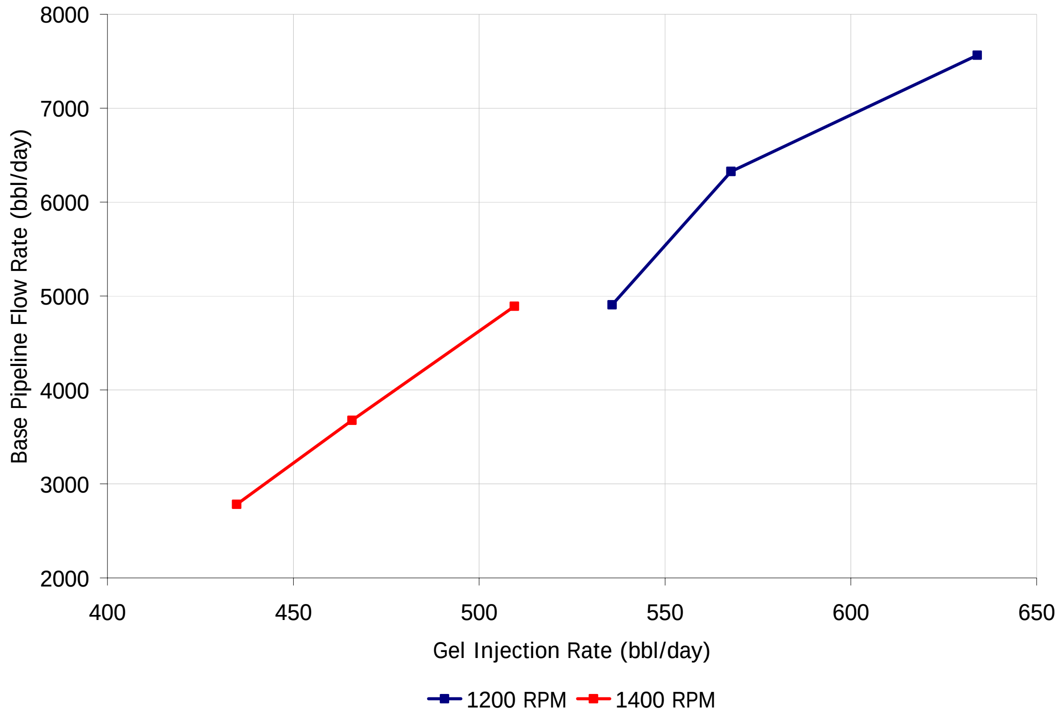
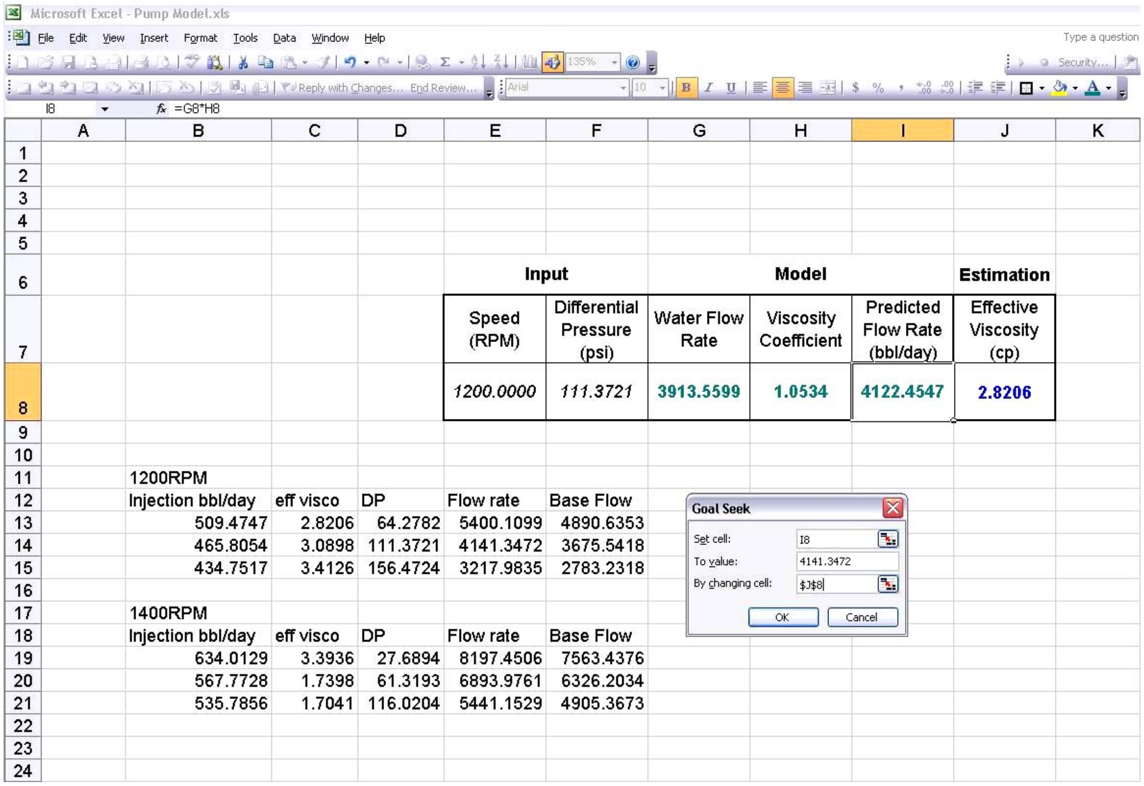


Fig. 147: Gel Injection with Pressurized Air

100 cp gel was injected against backpressure at three different base flow rates on the suction side of twin-screw pump at two speeds. The trend shows higher injection rates at higher base flow rates because of lower back pressures experienced at the injection point (fig. 147).

Using the correlation and some known data, i.e. differential pressure, flow rate and speed, it is possible to estimate the viscosity of fluid across pump chamber. This is made easy by the use of solver tool in MS Excel (figures 148 and 149).



Input		Model			Estimation
Speed (RPM)	Differential Pressure (psi)	Water Flow Rate	Viscosity Coefficient	Predicted Flow Rate (bbl/day)	Effective Viscosity (cp)
1200.0000	111.3721	3913.5599	1.0534	4122.4547	2.8206

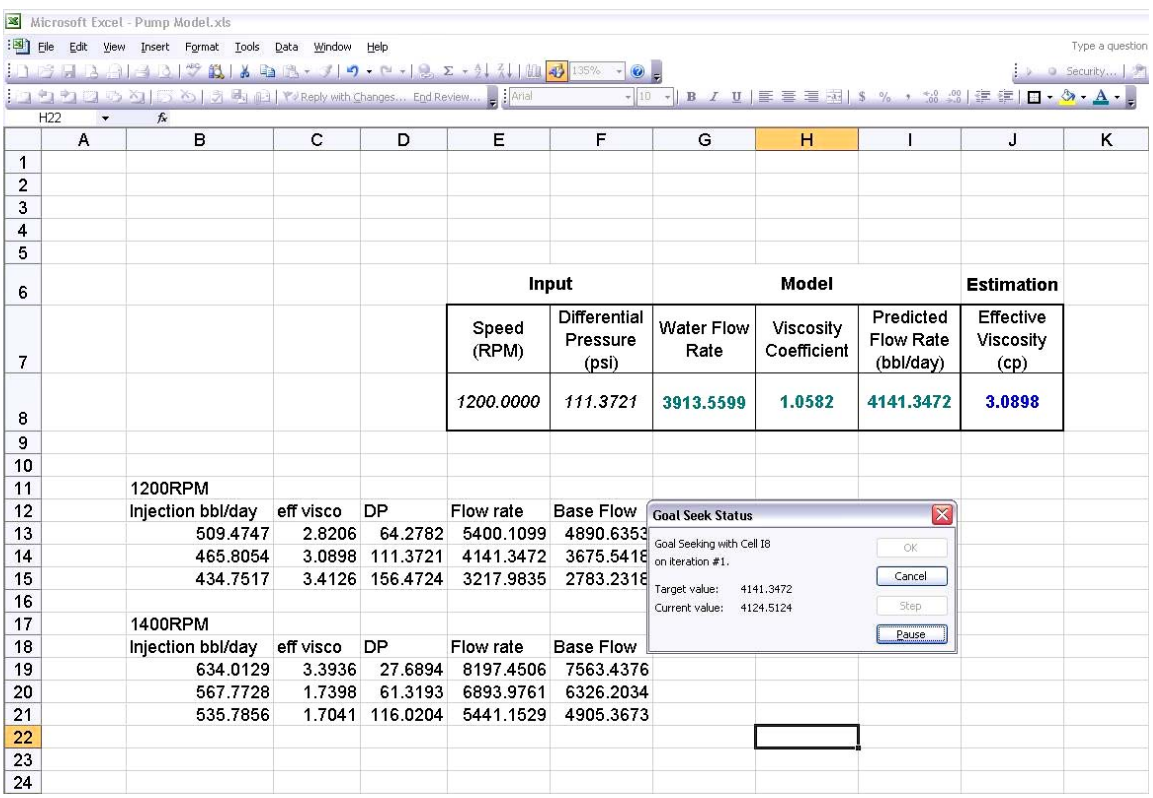
1200RPM

Injection bbl/day	eff visco	DP	Flow rate	Base Flow
509.4747	2.8206	64.2782	5400.1099	4890.6353
465.8054	3.0898	111.3721	4141.3472	3675.5418
434.7517	3.4126	156.4724	3217.9835	2783.2318

1400RPM

Injection bbl/day	eff visco	DP	Flow rate	Base Flow
634.0129	3.3936	27.6894	8197.4506	7563.4376
567.7728	1.7398	61.3193	6893.9761	6326.2034
535.7856	1.7041	116.0204	5441.1529	4905.3673

Fig. 148: Using Solver to Estimate Effective Viscosity



Input		Model			Estimation
Speed (RPM)	Differential Pressure (psi)	Water Flow Rate	Viscosity Coefficient	Predicted Flow Rate (bbl/day)	Effective Viscosity (cp)
1200.0000	111.3721	3913.5599	1.0582	4141.3472	3.0898

1200RPM

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1400RPM

Injection bbl/day	eff visco	DP	Flow rate	Base Flow
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567.7728	1.7398	61.3193	6893.9761	6326.2034
535.7856	1.7041	116.0204	5441.1529	4905.3673

Fig. 149: Viscosity Calculation in Progress

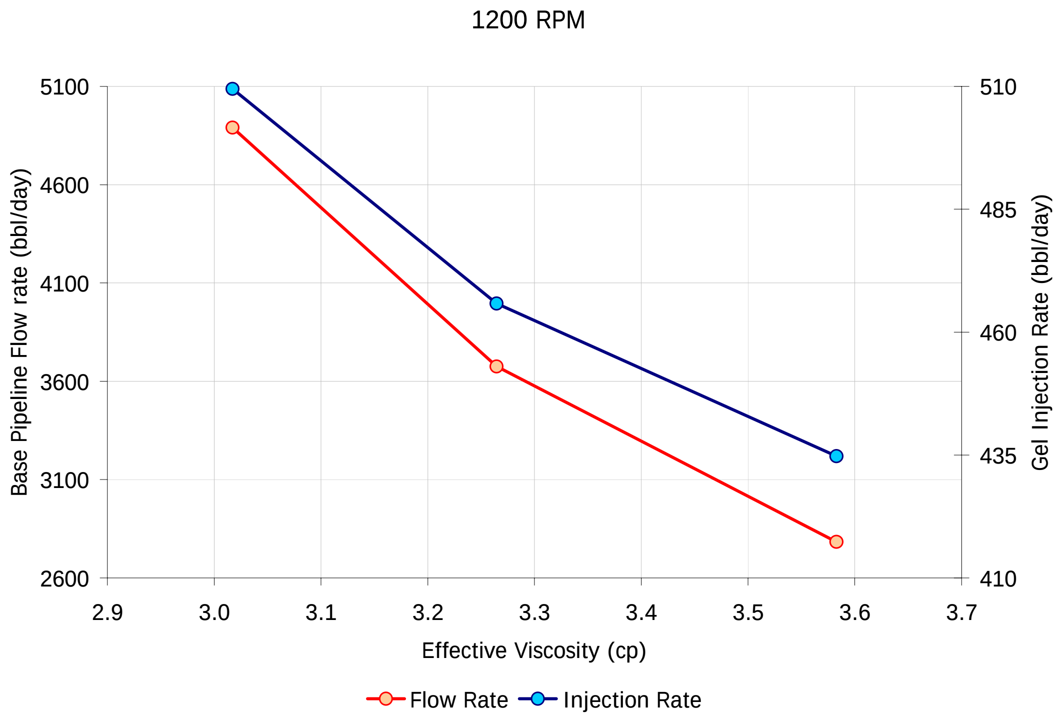

Fig. 150: Dispersion Dominated Mixing

We observe two different behaviors at two speeds by gel injection tests. The first test at 1200 RPM shows that the viscosity is reducing with increasing base flow rate (fig. 150). The second test at 1400 RPM shows that viscosity is increasing with increasing flow rate (fig. 151). This suggests that there are possibly two mechanisms of gel mixing in base fluid (water in this case). One is dispersion without active participation of churning in the mixing process and second is active churning process resulting in proper mixing. Thus 1200 RPM viscosity change is influenced by dispersion. There is better dispersion due to more residence time at lower flow rates. At 1400 RPM, the viscosity change is influenced by active churning. There is better mixing due to better churning at higher flow velocities.

Thus, mere injection of viscous gels will not be sufficient in increasing the viscosity across twin-screw pump or any other equipment. Along with injection, proper mixing and in-situ blending must also be ensured to achieve the full utilization of concentrated gel.

With fluids having high viscosities passing across the pump clearances, it is possible that fluid gets heated excessively due to viscous drag due to shearing of leaking liquid. This temperature rise can reduce the viscosity and hence special gels with thermally stable viscosity characteristics will be required to effectively mitigate slip flow at high differential pressures and thus avoid or reduce erosion of screw edges due to sand particles.

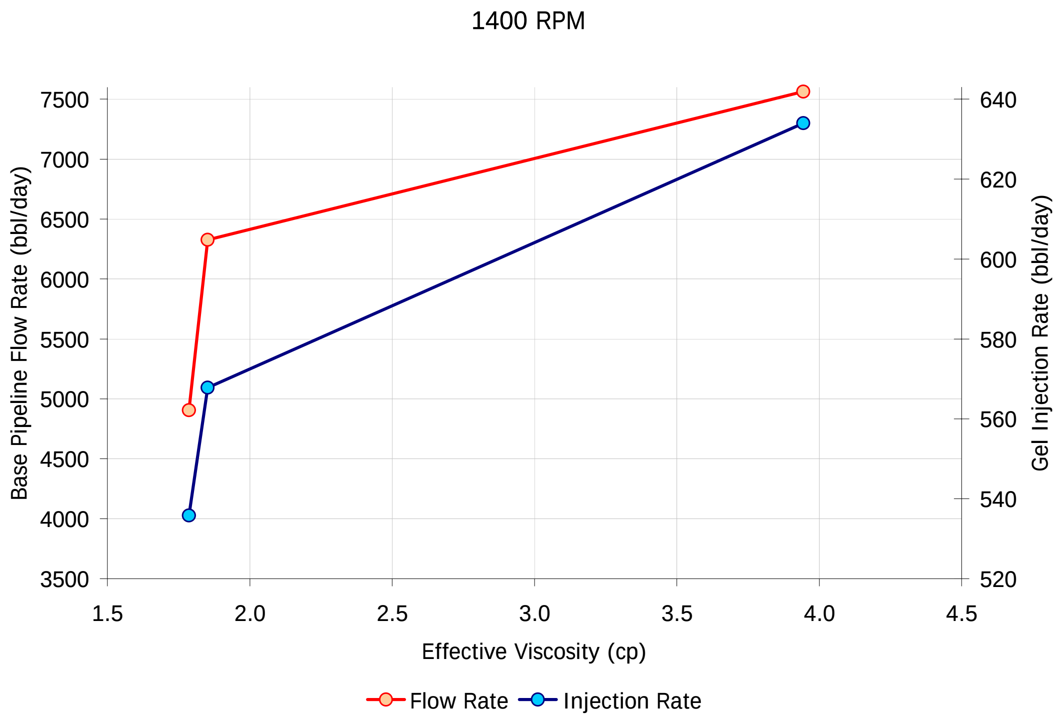

Fig. 151: Churning Dominated Mixing

The sand erosion will be a function of differential pressure across the twin-screw pump clearances when sand particles are passing. The more viscous the gel enveloping and carrying sand particles, the higher will be differential pressure for same flow rate as compared with a fluid of less viscosity. To estimate the effective viscosities needed across pump chamber at a given speed and given flow rate to increase the differential pressure (and thereby cushion the abrasive particles, the correlation described by eq. (21) is used and the following observation is made (fig. 152).

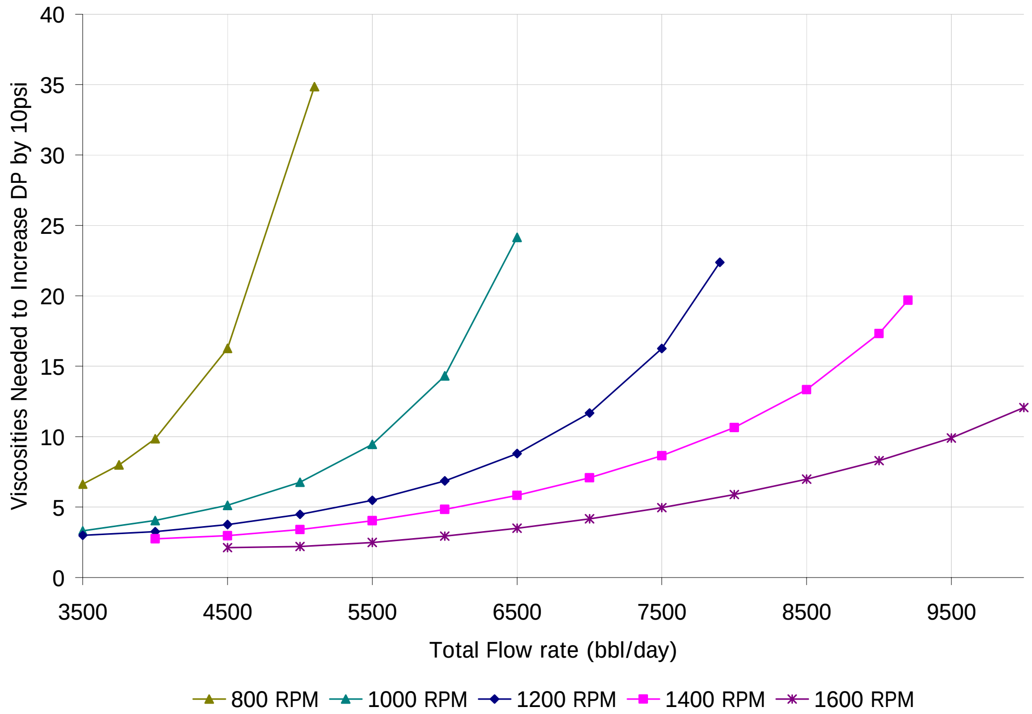

Fig. 152: Effective Viscosity Needed across the Pump Chamber to Increase DP by 10 psi above Pure Water Flow

At lower speeds, the viscosities needed for same change in differential pressure are higher than at higher speeds. The relationship between effective viscosity, differential pressures, and erosion rates needs to be determined and that is a recommended future work in this direction.

8. INTEGRATED APPROACH TO FLOW ASSURANCE

This section discusses the integrated approach to flow assurance. Different strategies and the methods for oilfield management, and asset management, are discussed along with the need for integration of reservoir, wellbore, subsea, pipeline and process systems for effective flow assurance.

Introduction

The historical accounting principles keep emphasizing that the lowest cost business will make highest profits and will become most successful. In the race to become the most profitable company, the E&P companies have been cutting costs, focusing on economies of scale, and consolidating through acquisitions, mergers and buyouts[91]. Tough competition among companies keeps the profits low and consumers are benefited. Companies without debt become most successful. The examples of debt-free companies are Cisco Systems, Dell, and Microsoft. All these companies work on the principle of maintaining minimum possible inventories. Capital, like land is not important these days for wealth creation. On the same lines, large E&P companies tend to work as investment bankers. E&P companies bring together other teams to develop new prospects, build facilities, organize transportation by pipelining or tankers, refine crude and distribute the product to end users. On development or while developing, a significant portion of production share is sold off to the competitors to recover investment and reduce risk. This also limits the opportunity to dominate. Currently, the world is rich with abundant supply of fossil fuels and other chemical products sourced from petroleum refiners, because of successful gas and oil exploration, production, transport and refining technologies. Other contributors to the success are skilled personnel and easy capital.

Gas and oil industry is subject to major business cycle changes driven mainly through price fluctuations. In E&P industry over the last 22 years, it is estimated that unit costs have declined by two thirds and 80% of the improvement is due to continuously developing technology[92].

Management in Oil and Gas

Before 1980s, the reservoir management was based on scarce production data, rudimentary tools and modular workflow. 1980s witnessed increasing interest in the use of SCADA systems, although initially limited to the process plants for monitoring the process. 1990s saw a boom in information technology. SCADA and DCS expanded from process monitoring to entire field surveillance. Multiphase meters on wells or clusters, and shifting of rudimentary simulators on workstations to more sophisticated and comprehensive simulators on petroleum engineer's laptops or desktops made it easy to better analyze and optimize every well, cluster, node, network and improvements still continue.

Several new technologies brought “real-time” reservoir management into reality. To name a few of them – 4D seismic, intelligent wells, multiphase metering, multiphase pumping, improved, powerful and industry preferred dynamic simulation tools, etc.

Internet is driving technology and commerce to grow at a geometric rate. Evolution of internet had a profound impact on the manner in which data is being transmitted and processed. With the advent of cheaper digital technologies, faster and quality data communication and storage, the number of computational tools available to a petroleum engineer continues to grow[93]. E&P companies are exploiting the benefits of highly “connected” fields for optimal operation of their assets.

Wellbores are a link between reservoir and topside facilities. Production system includes and is characterized by reservoir, geology, petrophysics and fluid properties; wells; flow control devices; flowlines; flow assurance solutions such as multiphase boosting, thermal management, chemical management, and separation and stabilization facilities both subsea and topside.

The flow assurance system becomes less effective with limited continuous information. Over-design is often a result of scarce information. Dynamic simulation for wellbore and pipeline flow has been a domain of flow assurance and pipeline experts. Traditionally, a decoupled approach for subsea modeling has been adapted. Separate evaluation of wellbore or flowline thermal-hydraulic behavior and communication to another design group for evaluation of topside facilities and formulation of operational procedures is the decoupled approach.

Constraints and Recent Advances

Unique constraints with deep sea developments stress the detailed dynamic analysis for optimal design of topside or host facilities. Since different mathematical codes and convergence procedures simulate different elements of a production system, instability arises when arriving at converging solutions. Definition of boundary conditions is very critical in such cases. Multiphase flow is highly complex and largely unpredictable over entire range of conditions. This leads to inconsistent correlations and leads to unstable or non-converging solutions[94]. Extensive localization of software tools and engineering efforts to wellbores, flowlines and topside facilities without complete communication among each other has limited the realization of whole system modeling capability. Compatibility problems often arise when tools from different sources are coupled together.

If computational time were not a limiting factor, the simultaneous solution of equations for reservoir and production facilities could be a possible approach. In this approach, the production network can be solved first and the solution is used as boundary conditions for reservoir model, to test if convergence occurs. In case of non-convergence, a new flow rate and conditions are assumed and model is iterated again[94]. In this implicit method, convergence can be very slow or may never be achieved. Explicit alternative to this is setting convergence conditions at bottomhole and then finding the solutions for network and reservoir. Explicit method will not be very accurate but will save the computational time.

Recent advances in software tools, computer speed, and communication now enable the development of a complete dynamic model[95].

Optimization for Oilfield Management

In mathematics, optimization is the discipline which is concerned with finding the maxima and minima of functions, possibly subject to constraints. In engineering, optimization is the best outcome that is achieved for a specified objective function honoring the system constraints. In oilfield, the objective function can represent production rate, cumulative ultimate recovery or more logically, the NPV. Constraints can be surface network, subsea environment, wellbore or reservoir limitations or the external delivery pressure and throughput.

The short-term optimization of field management focuses on finding the optimum operational conditions such as choke settings, wellwise allocation of lift-gas and dosed chemicals, for maximum possible production rates while honoring the system constraints[94].

Medium-term optimization includes planning of startups and shutdowns to handle effect of transients.

Long-term optimization looks at achieving maximum EUR and considers necessary de-bottlenecking in the system to accommodate changing fluid composition and changing rates. Different analyses are needed at different stages in the life of a field. Early life and design stages are very critical as very little is known. Late life stages are also important as flow conditions are unstable.

There is a trade-off between production capacity and the cost of production to derive maximum recovery. Once the network configuration is optimized, it can be used to forecast the production. In forecast models, traditionally, the simultaneous interaction of reservoir, wellbore and surface networks were not adequately considered. But in modern times, simultaneous interaction of different software tools has become very important.

Asset Management

E&P assets pass through different phases in their life. Typical phases are acquisition, exploration, development and abandonment. During these phases, importance of all the skills in achieving optimal productivity is not the same. Certain skills are more important than others at different times. Mistakes are less forgiving in highly competitive markets. Doing things right the first time becomes focus while evaluating each phase. Multidisciplinary cross-functional teams work in synergism for better ways to run E&P business and manage assets.

Web Based Asset Management

.Net is a Microsoft Web Services strategy to connect information, people, systems, and devices through software. .Net technology provides ability to quickly build, deploy, manage and use connected, security enhanced solutions. Systems integrate more rapidly, and realize the information exchange anytime, anywhere, on any device[96]. .Net is revolutionizing the way applications are interacting with each another – by providing a universal data format that lets the data be easily transformed or adopted. Communication is possible across platforms and operating systems, regardless of the programming languages in which the applications are written. For developers, it is possible to choose between developing each and every piece of application or absorbing the applications and modules created by others.

Web based asset management is made possible by .Net. Information travels from wellsite to secure database and application servers. Web servers provide interconnectivity between wellsite and corporate intranet. Web servers, are primarily interface for petroleum experts within the organization and are capable of providing information to multiple users simultaneously. They capture and process the user's request and send the requested information to user on their browser. Application servers house and run all applications for analysis of data. Database servers continuously receive and dispatch data. .Net enables quick retrieval and processing of large amount of oilfield data from any access point on the world-wide-web.

Need to Integrate

Reservoir, wellbore, subsea, pipeline and process systems must be combined to simultaneously work for better analytical results as these systems physically work together. Fixed pressure, temperature, flow rate boundary is less realistic at any interface. Stand-alone reservoir simulation tools can work best for fixed boundary conditions, standalone wellbore and pipeline dynamic simulators work best for fixed sand face and downstream boundary conditions, and standalone process simulators work best taking downstream process as fixed domain. For the best and realistic results in analysis, simulation and prediction, all software tools must work simultaneously together and exchange data working towards common convergence.

A large field often has multiple reservoirs which may or may not be directly communicating with each other. But if they produce to the same host facility through same flowlines, they are indirectly influencing each other. The boundary conditions for production could be identical. If they are on pressure maintenance through waterflooding fed by the same water injection facility, then injection boundary conditions are also identical. This scenario necessitates ability to simulate different reservoirs as coupled systems while retaining their individual models.

The coupled dynamic models can be used for investigation of different scenarios including start-up, shutdown, blow down, flaring, ramp-up, process upsets, reservoir upsets, wellbore changes in case of intelligent wells, etc. Specifically, this will be of great utility for facilities design as the slug catcher size can be optimized. Effects of pipeline induced offsets can be studied both upstream (wellbore and reservoir) and downstream (process facility) in case of hydrate, wax blockages or rupture.

Modern Production Management Systems

Online monitoring and surveillance tool for production system (wellbore, flowlines and host process system). It provides a real-time picture of conditions even in the absence of any instrumentation. With real-time production management model, it is possible to predict desired scenarios based on current snapshot. If the model is made to run offline (without real-time data input), system planning and strategic studies can be done. Predictive calculations can determine cool-down times for shutdown conditions. Based on cooldown time and fluid properties, formation of solids in pipeline is predictable.

Production management system enables faster and accurate decision making, and formulating a proactive operating philosophy. This makes asset management more economic and efficient.

9. SUMMARY AND CONCLUSIONS

This section details the summary, conclusions and recommendations from this study.

Multiphase Pumping

- Conventional production systems for deepwater and longer tiebacks are not adequate to attain maximum production potential of an oilfield.
- Multiphase pumping is a form of energy input to untreated stream of produced fluids, which can overcome the losses due to backpressure and gravity, thus improving the ultimate recovery, especially in remote operating environments. However, in case of tubing limited wells, multiphase boosting will not necessarily have an impact on recovery levels.
- Multiphase boosting is highly competitive in terms of CAPEX and OPEX over conventional production systems. Use of multiphase boosting can drastically reduce the footprint for operations. Use of subsea multiphase boosters allow long tieback distances and reduce the number of process platforms and main the host platform can still be stationed in shallow waters thus cutting on costs.
- In case of conventional production system, where one phase line (gas or liquid) fails and repair or replacement is not economically viable, multiphase boosting can commingle the phases and produce to the host facility through single line after required modifications at both the ends.
- Slip flow is one of the major causes of erosion at the edges of screws.
- Viscous gel injection in Twin-screw pumps can very effectively reduce the slip flow even under high speeds.

Flow Assurance

- All flowlines eventually cool down in the absence of active heating or heat retention methods leading to thermal risks of flow assurance.
- Estimation of conditions favorable for formation of hydrates, wax, corrosion, erosion, pressure drops are very important. These conditions can be either or more among temperature, pressure, fluid composition and fluid properties. Water depth or riser height and tieback distance are also very important parameters which can affect the flow assurance issues.
- Use of low dosage inhibitors for hydrates considerably reduces the logistics and contamination of crude and produced water, offering huge reduction in OPEX over the life of the system.

- Presence of free gas phase in stream leads to hydraulic risks for flow assurance.
- Subsea separation can add to the hydraulic stability of the flow.
- Flow assurance design and monitoring is still evolving with development of new technologies for fluid sampling, analysis, data acquisition and modeling tools.
- Multiphase pumps aid in flow assurance by mixing, pushing and regulating the flow of untreated fluids.
- Twin-screw pumps have inbuilt capacity to handle slugs. With multiphase boosting, the higher velocities of untreated multiphase fluid stabilize the flow regime and prevent severe slugging.
- Multiphase pumps can be effectively used for mitigating thermal risks of flow assurance as they reduce cooldown. Hence, hydrates and wax deposition problem can be mitigated to some extent. Complete mitigation will also need insulation and chemical inhibition in addition to multiphase boosting.
- A marginal development does not mean marginal engineering; the level of efforts needed is much greater in the early stages of engineering.

Sand Detection

- Sand detector was coupled for the first time with a twin-screw multiphase pump on a flow loop.
- Continuous monitoring of solids production can reduce the risk of severe erosion in production systems. Correct interpretation of acoustic data from sand and background noises is very important for correct decisions in oilfield.
- Acoustic sand detectors in combination with other cross functional data are a proactive system to ensure safe optimization of production levels.
- Acoustic sand detectors need certain minimum flow velocity for sand particles to impact and produce noise. Below the minimum velocities, the sand concentration interpreted is inaccurate.
- Acoustic sand detector gives non zero output even in case of zero sand concentration due to background noises. Filtering of such noises is vital for reliability of acoustic devices.
- With increasing fluid viscosity, the noise picked up for a given sand concentration flowing per unit time goes on diminishing.
- With introduction of gas volume fraction in fluid, the noise levels detected go up in an unpredictable manner.
- Calibration of sand detector is valid only for the flow conditions at the time of calibration. If there is any change in flow conditions for example, change in GOR or change in oil

viscosity, the sand detector does not give accurate results for mass. Recalibration several times is necessary to get the reliable results on measurement.

- When noise picked up crosses certain threshold, sand mass is interpreted. This can be true even in absence of real sand if the noise produced by factors such as high gas velocities exceeds this threshold.

Viscous Gels Injection and Twin-screw Pump Performance

- Similar to proppants transport by gels in hydraulic fracturing, the high concentration of produced sand can be "transported" efficiently through twin-screw pumps to avoid excessive wear and tear.
- The effective viscosity on mixing injected gel with a pipeline flow depends on the effective concentration of gel concentrate in a predictable manner. Thus, higher effective viscosities can be achieved by higher gel injection rates.
- When gel injection viscosity is increased, the effective viscosity after injection has a limiting value after which, the effective viscosity will decrease further due to less flow as a result of higher friction factor and more laminar flow regime.
- Upon injection, mixing or dispersion of gel with pipeline flow takes time. The time taken is more for higher difference in viscosity. Mixing gel with very high viscosities will be difficult or incomplete without some means of mixing in the pipeline.
- The most suitable tubing size for injecting gels were found to be in the range of 0.75" to 1.25" for depths up to 500 ft if gels 20 lb/1000gal to 130 lb/1000gal were used with a pressure of 2000 psi. For smaller tubing sizes, deepwaters and long distances are not feasible as frictional pressure drop exceeds 10000 psi in most cases and procuring/installing and operating an injection equipment to overcome this large pressure drop may not be justifiable.
- For tubing sizes larger than 1.25" (in case of 500 ft water depth and 2000 psi injection equipment) the rate of injection will be very high and a need will arise to make and store large volumes of gel ready for use.
- In gel injection for abrasion mitigation purpose, the stability of gel viscosity is very important as all gel will not be used instantly. Gel will be injected upon detection of sand concentration and stopped when (sand) concentration drops to negligible. This will need very accurate coordination between sand detection and gel injection.
- Since gel injection tubing and vessel will be always pressurized to high pressures, the quality of valves closing and opening for stopping and starting gel injection will have to very reliable.

- Gels when used for subsea application to mitigate sand erosion must be stable in viscosity even at varying temperatures, as they will be injected from topside at ambient temperature, through umbilical passing into deepwater with a vertical seawater thermal gradient, and again entering a hot stream on injection when sand detection will trigger injection to envelope sand particles.
- All gels used for this purpose will need to be readily miscible with fluids flowing in pipeline to assure effective boost in viscosity on time.
- All types of inhibitors – for mitigating hydrates, wax, corrosion and solids erosion must be very effective at small concentrations yet must be very easily pumpable through small diameter tubings without any need for sophisticated injection equipment.
- An empirical correlation for predicting performance of Flowserve twin-screw pump at riverside is developed. Using this correlation, it is possible to estimate viscosity across the pump screw at a given rotary speed and differential pressure. The model works well between the operating limits of the pump, i.e. 50% to 100% speed and was tested for viscosities between 1 cp and 35 cp.
- Reduction of slip flow across the screw threads in twin-screw pumps can effectively reduce the erosion at screw thread edges and this can be achieved by injection of viscous gel. Gel injection, thus will have twofold purpose – arresting the slip and efficiently transporting the sand particles without letting them settle.

Recommendations

- The testing of twin-screw pump with varying sand concentrations and subsequent study of locked rotor performance to observe the effect on clearances.
- Similar test with fluid having viscosity greater than water, to asses the range of viscosities needed which can substantially reduce erosion rate.
- Visual study of wear patterns on screws and casing to correlate the effect of viscosity, rotary speed, sand concentration, and sand particle size and particle size distribution.
- Economic analysis to investigate CAPEX and OPEX with and without sand mitigation measures for the typical entire subsea production system to arrive at a decision whether to implement any erosion mitigation method.

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