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by

JAMALUDIN BIN TAKEI

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TITLE PAGE

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ABSTRACT

Chinguetti a deepwater oil field development offshore Mauritania is experiencing a rapid decline in its production that resulted to severe flow instability or slugging in flowlines and risers of its subsea oil production system. Slugging initiates oscillations and puts field operator in a demanding situation to manage and control flow instability.

It is crucial to have a model to describe flow instability issues in live field conditions. Apparently, there is no applicable model to represent flow instability in deepwater operations. Current available data that represents flow instability in flowlines and risers in live field conditions has not been published in any literature. The available data is mostly from laboratory controlled conditions or laboratory scale ideal condition. Model using laboratory conditions has limited capability that cannot be used to assess severity of slugging.

A study was undertaken in which integrated production system of the Chinguetti wells, flowlines and risers were developed using the OLGA transient multiphase flow simulator. Field validation was performed by tuning the models to match field pressures and phase flowrates and instability in the systems. The impact of various changes in operating conditions on the flow instability was examined by simulating the models that included changes in well routings, gas lift injection rates and location of injection points, riser and wellhead choke openings. The severity of flow instabilities for the different operating conditions was categorized by the degree of fluctuations in liquid arrival rates and the characteristics of its liquid slugs, length and frequency.

Results from field implementation of the recommended changes in operating conditions indicated improvement in flow stability and oil recovery. From the study, a methodology has been developed to assess the severity of slugging and strategies to mitigate flow stability and productivity in the flowlines and risers of Chinguetti oil production system.

ABSTRAK

Lapangan minyak laut dalam Chinguetti yang berada di luar pantai Mauritania mengalami penurunan dalam pengeluaran minyaknya sehingga menyebabkan ketidakstabilan aliran atau ketidakseimbangan dalam saluran pengaliran dan aliran-saluran dalam sistem pengeluaran minyak dasar lautnya. Ketidakseimbangan ini memberi kesan yang amat sangat kepada pengendali lapangan untuk mengurus dan menangani ketidakstabilan aliran ini.

Dalam operasi lapangan sebenar, satu modul amat diperlukan untuk menerangkan perkara berhubung dengan ketidakstabilan aliran. Namun tidak terdapat satu modul yang dapat menerangkan ketidakstabilan aliran ini dalam operasi laut dalam. Data-data terkini yang berhubung dengan ketidakstabilan aliran belum ada disiarkan dalam mana mana penerbitan. Data-data yang ada kebanyakannya dari keadaan makmal terkawal atau keadaan makmal terkawal yang sempurna. Modul yang berasaskan keadaan makmal terkawal mempunyai keupayaan yang terbatas dan tidak boleh digunakan untuk menilai tahap ketidakstabilan aliran.

Satu kajian telah dilakukan terhadap sistem integrasi pengeluaran minyak Chinguetti ke atas telaga, aliran pengeluaran dan aliran-saluran dengan menggunakan simulator OLGA pelbagai aliran. Pemeriksaan lapangan dilakukan dengan menghalusi modul supaya dapat mengimbangi tekanan dan aliran pengeluaran dan juga ketidakstabilan aliran di dalam sistem. Kesan daripada perubahan keadaan operasi ke atas aliran telaga, daya angkat gas, lokasi tembusan, aliran-saluran dan kadar pembukaan injap telaga dapat diperiksa melalui simulasi modul. Tahap ketidakstabilan kadar aliran dalam pelbagai keadaan operasi dapat dikategorikan menurut darjah aliran yang mendatang dan karekter serta panjang dan frekuensi aliran ketidakseimbangan, Hasil daripada perlaksanaan yang dilakukan di lapangan ke atas perbagai keadaan operasi, telah memberi kesan yang baik terhadap keseimbangan aliran dan penghasilan minyak.

Dari kajian ini, satu kaedah telah dihasilkan untuk mengenal-pasti tahap ketidakseimbangan aliran dan strategi untuk mengawal keseimbangan aliran di dalam dalam saluran pengaliran dan aliran-saluran sistem Chinguetti. Hasil daripada perlaksanaan yang dilakukan di lapangan ke atas perbagai keadaan operasi, telah memberi kesan yang baik terhadap keseimbangan aliran dan penghasilan minyak. Dari kajian ini, satu kaedah telah dihasilkan untuk mengenal-pasti tahap ketidakseimbangan aliran dan strategi untuk mengawal keseimbangan aliran di dalam dalam saluran pengaliran dan aliran-saluran sistem Chinguetti.

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NOMENCLATURE

Roman	**Description**
U	Velocity, m/s
P_P	Pressure of separator at separator conditions, Pa
ρ_L	Density of liquid, kg/m^3
g	gravitational constant, m/s^2
L	Pipe length, m
U_{GS}	Velocity of superficial gas
ρ_{GO}	Density of gas at standard conditions
ρ_L	Density of liquid, kg/m^3
L	pipe length, m
U_{GSO}	Velocity of gas at standard conditions
P_{sep}	Pressure of separator at separator conditions, Pa
p_o	Pressure of separator at standard conditions
l	Pipe length, m
P	Pipe
h	Height of riser, m
g	Gravitational constant, m/s^2

Subscripts

LS	Superficial liquid
GS	Superficial gas

Greek

α	Gas void fraction in the pipeline
Φ	Liquid hold-up in the riser
α'	Void fraction of gas bubble entering the riser (approx. 0.5)

ABBREVIATIONS

API	American Petroleum Institute
bara	bar at atmosphere
BOPD	barrels of oil per day
BHP	Bottom Hole Pressure
BHRG	group of engineering companies
BOD	Basis of Design
BP	British Petroleum
CAR	Central African Republic
CV	valve coefficient
DC	Drilling Centers
FGOR	Formation Gas Oil Ratio
FL1	Flowline 1/Riser 1
FL2	Flowline 2/Riser 2
FPSO	Floating Production Storage and Offloading
FTHP	Flowing Tubing Head Pressure
FTHT	Flowing Tubing Head Temperature
GDP	Gross Domestic Product
GLR	Gas Liquid Ratio
GOG	Gulf of Guinea
GOM	Gulf of Mexico
GOR	Gas Oil Ratio
ID	Internal Diameter
IEA	International Energy Agency
IMF	International Monetary Fund
IMS	Information Management System
IPR	Inflow Performance Relationship

m	meter
m/s	meter per second
m^3/h	cubic meter per hour
MDML	Measured Depth Mud Line (MD with christmas tree as a reference point)
MM BOP/D	million barrels oil per day
MMS	Minerals Management Services, U.S. Department of Interior, USA
MMSCFD	million standard cubic feet per day
MPFM	Multiphase Flow Meter
MRBL	Multiphase Riser Base Lift
NEOTEC	commercial simulation company
NPV	Net Present Value
OCS	Outer Continental Shelf
OLGA	transient multiphase simulator
OPEC	Organization of the Petroleum Exporting Countries
OREDA	Offshore Reliability Data
OWEM	OPEC's World Energy Model
P&ID	Process and Instrumentation Diagram
pa	pascal
PCMPL	PC Mauritania I Pty Ltd
PeTra	transient multiphase simulator
Petrobras	National Oil Company of Brazil
PI	Productivity Index
PIPEFLO	transient multiphase simulator
PIPEPHASE	transient multiphase simulator
PIPESIM	transient multiphase simulator
PLAC	transient multiphase simulator
PROCAP	Deepwater and Ultra-deepwater Advanced Development and Technological Innovation Program of Petrobras
psig	pressure per square inch gauge
PVT	Pressure Volume Temperature
PVTSim	transient multiphase simulator

RBGL	Riser Base Gas Lift
ROV	Remote Operated Vehicle
sc	standard conditions at 60 °F and 1 atmosphere
scf/stb	standard cubic feet/stock tank barrel
SINTEF	research institute in Norway
sm^3/h	standard cubic meter per hour
stb/d	stock tank barrel per day
stb/d/psi	stock tank barrel per day per pound per square inch
STP	Standard Temperature and Pressure at 15°C and 1 atmosphere
TACITE	transient multiphase simulator
TGLR	Total Gas Liquid Ratio
THP	Tubing Head Pressure
TVD	True Vertical Depth
TVDML	True Vertical Depth Mud Line (TVD with christmas tree as a reference point)
UK	United Kingdom
U-value	heat transfer coefficient
VLCC	Very Large Crude Carrier
WAT	Wax Appearance Temperature
WC	water cut
WellFlo	well flow model

CHAPTER 1

INTRODUCTION

CHAPTER 1

INTRODUCTION

1.1 Background

1.1.1 World Energy Outlook

Current global trends in energy supply and consumption are patently unsustainable – environmentally, economically and socially. It is not an overstatement to claim that the future of human prosperity depends on how successfully we engage in the two central energy challenges facing us today: securing the supply of reliable and affordable energy; and effecting a rapid transformation to a low-carbon, efficient and environmentally benign system of energy supply (IEA, 2008).

Oil is the world's vital source of energy and will remain so for many years to come, even under the most optimistic of assumptions about the pace of development and deployment of alternative energy. As illustrated in Table 1-1, with world economic growth assumed at an average of 3.5% per annum (p.a), energy demand grows by an average of 1.7% p.a. in the reference case, amounting to a rise of more than 50% from 2006 to 2030. Fossils fuels will continue to provide most of the world's energy needs, with a share consistently over 85%. Oil has been in the leading position with its current share of 37%, falling slightly to 33% by 2030. Gas is expected to grow at fast rates, while coal retains its importance in the energy mix (OPEC, 2008).

Table 1-1: World Supply of Primary Energy in the Reference Case, (OPEC 2008)

	Levels				Growth	Fuel shares			
	Metric ton oil equivalent (mtoe)				% p.a.	%			
	2006	2010	2020	2030	2006-2030	2006	2010	2020	2030
Oil	4,031	4,257	4,830	5,360	1.2	37.3	36.3	34.6	32.7
Coal	2,989	3,298	3,993	4,655	1.9	27.6	28.1	28.6	28.4
Gas	2,400	2,637	3,239	3,993	2.1	22.2	22.5	23.2	24.4
Nuclear	731	762	864	1,022	1.4	6.8	6.5	6.2	6.2
Hydro	251	278	350	427	2.2	2.3	2.4	2.5	2.6
Biomass	349	408	537	674	2.8	3.2	3.5	3.8	4.1
Other Renewable	61	81	150	258	6.2	0.6	0.7	1.1	1.6
Total	10,813	11,720	13,964	16,389	1.7	100	100	100	100

But the source of oil to meet the rising demand, the cost of producing it and the prices that consumers need to pay for it are extremely uncertain, perhaps more than ever. As shown in Figure 1-1, the surge in prices in recent years culminating in the price spike of 2008, coupled with much greater short-term price volatility, have highlighted just how sensitive prices are to short-term market imbalances.

	Yearly Basket Price
1996	20.29
1997	18.68
1998	12.28
1999	17.48
2000	27.6
2001	23.12
2002	24.36
2003	28.1
2004	36.05
2005	50.64
2006	61.08
2007	69.08
2008	94.45
2009	50.19

Figure 1-1: OPEC Yearly Average Basket Price, (OPEC, 2009)

Upstream investment has been rising rapidly in nominal terms, but much of the increase is due to surging costs and the need to combat rising decline rates especially in higher-cost provinces outside OPEC (IEA, 2008). Today, most capital goes to exploring for and developing high-cost reserves partly because of limitations on oil companies access to the cheapest resources, dwindling resources in most parts of the world and accelerating decline rates everywhere.

In summary, the future world energy outlook will be very different. With all the uncertainties, we can be certain that the energy world will look a lot different in 2030 than it does today. The world energy system will be transformed, but not necessarily in the way we would like to see. While market imbalances could temporarily cause prices to fall back, it is becoming increasingly apparent that the era of cheap oil is over. It is within the power of all governments, of producing and consuming countries alike, acting alone or together, to steer the world towards a cleaner, cleverer and more competitive energy system.

1.1.2 World Oil at a Glance

Today, the reliance on oil is a significant factor in determining the direction of many countries in this world. This dependence has driven some nations to secure energy resources, behaving and reverting to ugly colonialist-like behavior towards meeting that objective, for instance the 2003 invasion of Iraq, from 20th March 2003 to 1st May, 2003 (Nazery, 2006). The world proven crude oil reserves are estimated at slightly more than 1.2 trillion barrels, of which OPEC Member Countries hold approximately 78% as shown in Figure 1-2 and Figure 1-3.

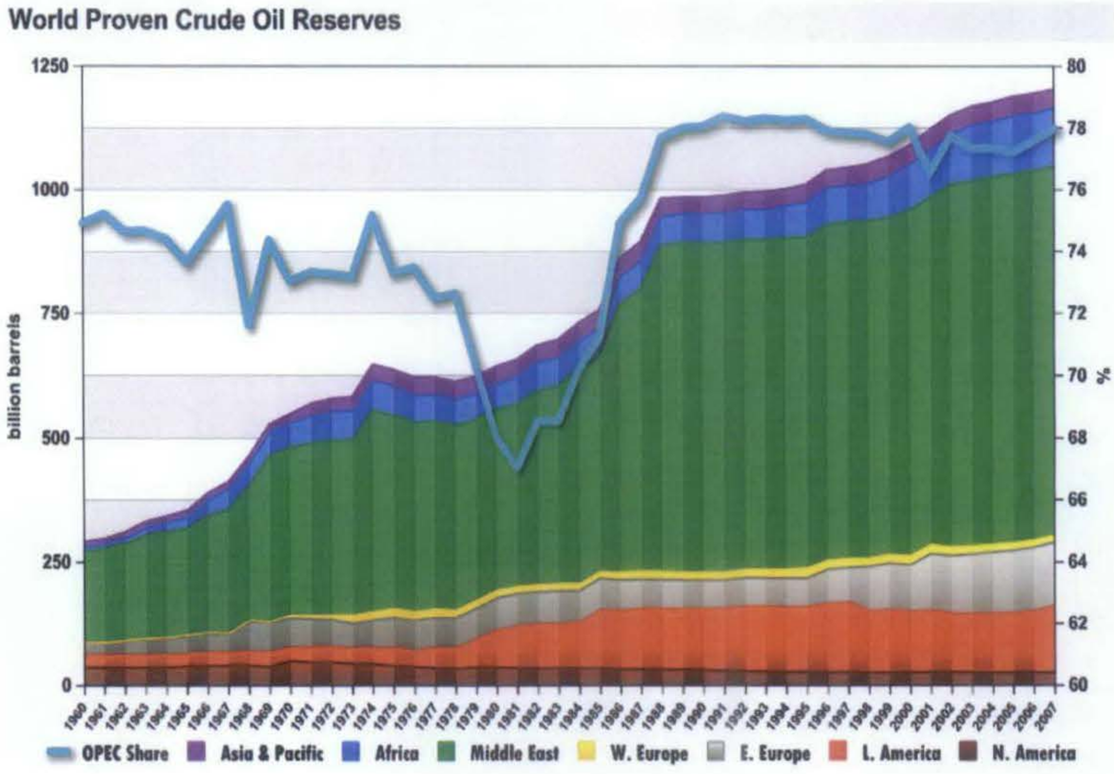


Figure 1-2: World Proven Crude Oil Reserves, (OPEC, 2007)

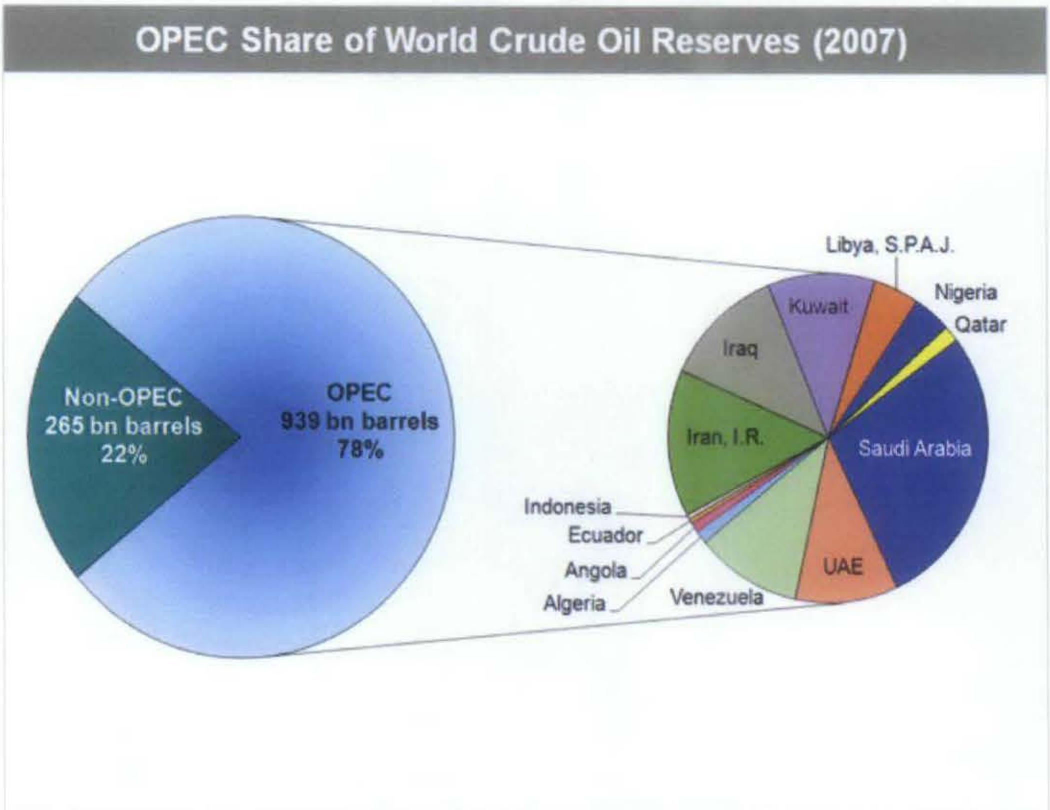


Figure 1-3: World Crude Oil Reserves, (OPEC, 2007)

According to current estimates, more than three-quarters of the world's oil reserves are located in OPEC countries. The bulk of OPEC oil reserves are located in the Middle East, with Saudi Arabia, Iran and Iraq contributing 55% to the OPEC total. OPEC countries have made significant contributions to their reserves in recent years by adopting best practices in the industry. As a result, OPEC proven reserves currently stand well above 900 billion barrels.

As of 2007, the world oil production stands at 71,482.3 million barrels per day (MM BOP/D) of which OPEC is producing 32,077.1 m b/d or 44.9% of the total world oil market, as shown in Figure 1-4. Oil is a limited resource, so it eventually runs out although it takes many years to come. At the rate of production in 2007, OPEC's oil reserves are sufficient to last for more than 80 years, while non-OPEC oil producers' reserves might last less than 20 years.

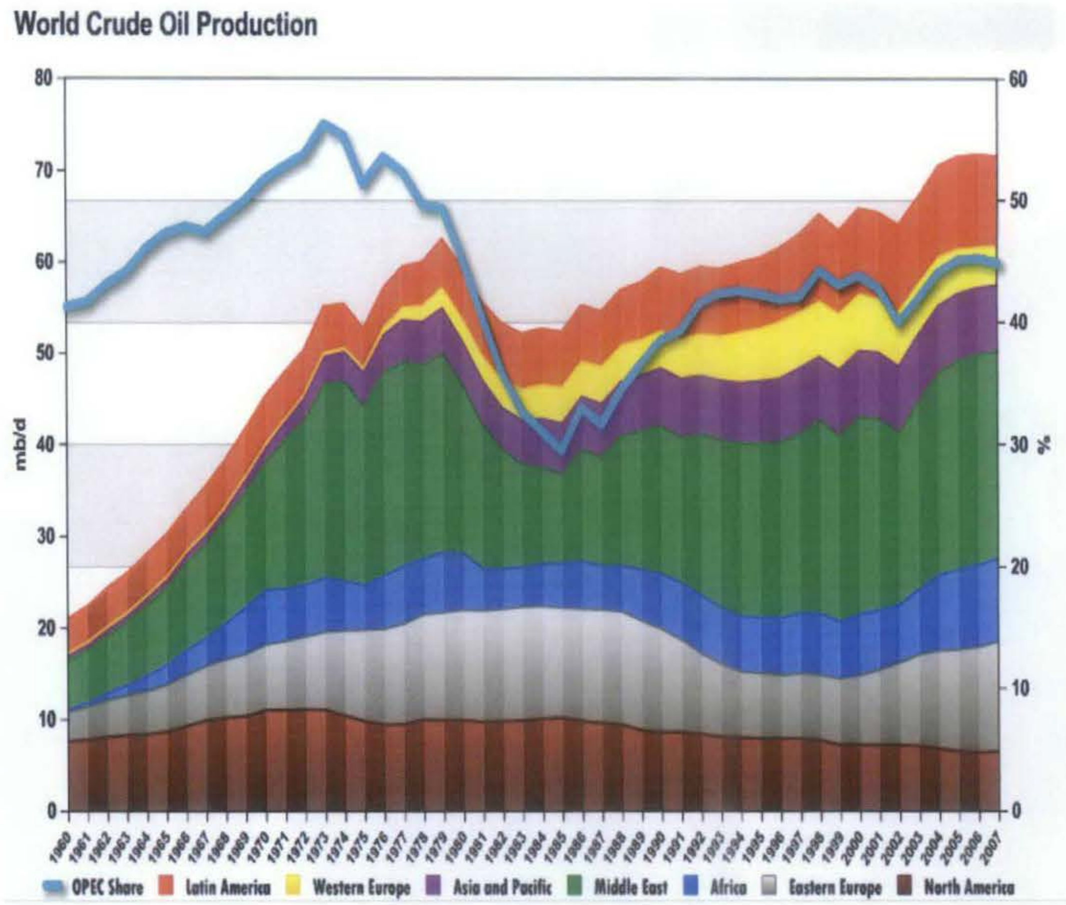


Figure 1-4: World Crude Oil Production 2007, (OPEC, 2007)

On the hand, the current world oil consumption or demand as of 2006 was at 84.7 m b/d. As world economic growth continues, crude oil demand will also rise to 96.1 m b/d in 2015, 102.2 m b/d by 2020 and 113,3 m b/d by 2030, according to OPEC's "World Oil Outlook 2008" (OPEC, 2008).

As the world's demand for hydrocarbon energy grows, the question of the adequacy of energy supply has been put in sharp focus. With all price reaching all-time high levels and showing no sign of relenting, the world seems to be going on a continuous mode in its search for new sources of oil to quench its insatiable thirst for energy. The race is on to ease skepticism and allays worries over the sufficiency of supply, and to bolster output to meet ever-rising global demand.

1.1.3 Market Overview of Deepwater

As energy is fundamental to the economic security and strategic interest of many countries, greater focus is trained on diversifying its sources of supply. Although renewable energy sources such as solar, wind and waves are increasingly playing an important role, their practical application, commercial value and reliability still have a lot to be desired. In the foreseeable future, much of the world will continue to rely on fossil fuel to meet much of its energy demands, (Nazery, 2006).

Many experts believe that easily tapped resources of energy are already nearing full exploitation (Douglas and Westwood, 2008). This renders it necessary for new sources of energy to be identified and developed, leading to more challenging and expensive exploration of new frontiers. With declining production from near-shore sources and shallow ocean waters, oil majors have aligned their attention to oil resources in waters of greater depths.

Since oil exploration shifted offshore close to a half century ago, the pursuit has been carried out in deeper and deeper waters. Amongst industry players, deepwater connotes areas too deep to accommodate conventional freestanding steel platforms.

As forecasted by Infield (2008), an independent market survey company, the value of the global deepwater market will be USD 115 billion over the period of 2008 to 2012, an increase of 80% on the proceeding years. Regionally, capital expenditure will be focused on Latin America, Africa and the US Gulf of Mexico. The Atlantic deepwater developments will account for over 80% of all global deepwater expenditure over the next five years. In Asia, activity increase will see the expenditure raise to USD 0.9 billion over the period 2003 – 2007 to USD 12.7 billion for 2008 – 2012, a 14 fold increase. Australasia and Europe will also see activity increases; USD 3.4 billion and USD 4.9 billion respectively.

In the analysis by John Westwood (2007), between 2006 and 2010, the expenditure in the deepwater sector is projected to expand at a compound annual growth rate of 7.3%, with particularly strong growth coming from the Asia and Latin America regions. The 'Golden Triangle' of deepwater, namely the Gulf of Guinea (GOG), Africa; Gulf of Mexico

(GOM) and Brazilian waters, will still account for 85% of global deepwater expenditure over the forecast period estimated at USD 20 billion by 2010. Nevertheless, the rapid emergence of Asia as a significant deepwater region should not be overlooked.

Technically, there have been great advances in production methods with deeper wells, longer flowlines and larger facilities. Even though it continues, this remains an area fraught with risks and considerable costs. Over the past five years, a broad analysis of deepwater projects brought either on-stream or imminently due on-stream shows that a majority have higher costs than their original estimates.

While many have come in on 'budget', in reality this is usually against revised budgets. The impact of cost overruns in this area can be huge than can run to over USD 500 million. Not only have budgets been pushed, but timescales also had to be much lax for those developing technically challenging deepwater fields (Douglas and Westwood, 2008).

The change in the energy market has demanded that the worldwide oil industry produces more and more hydrocarbons. This increase demand has "stretched" every single area of the industry whilst at the same time presented ever more challenging projects to extract hydrocarbons. Hence, the shift to deepwater production has grown dramatically to accommodate those demand and energy changes. Deepwater projects continue to provide the engine of growth for offshore oil and gas activity. With commodity prices increasing, and the debate over future reserves intensifying, the significance of deepwater, and the potential to harness large fields has become more evident.

1.1.4 Frontiers Expanded From Shallow Continental Shelf to Deepwater

Moving offshore in the 20th century is another milestone in making a new paradigms and a jumpstart for the oil industry. The first oil well structures to be built in open waters were in the Gulf of Mexico (GOM). They were in water depths of up to 100 m and constructed of a piled jacket formation, in which a framed template has piles driven through it to pin the structure to the sea bed. To this, a support frame was added as working parts of the rig such as decks and modules to house the accommodation and process facilities. These structures were then the fore-runners for the massive platforms that now stand in very deepwater and in many locations around the world. Bullwinkle of SHELL is the first deepwater facility in the GOM at 423 m water depth, and thereby the era of deepwater begins.

In the North Sea, the massive Groningen land gas discovered in Netherlands have led geologists estimated the same rock formations might be found beneath the southern North Sea basin in UK waters. They were right and gas was discovered of the English Coast in the 1960s. Clues around the coast of Greenland gave geologists the idea that there may be oil and gas around Scottish waters. It wasn't until 1969 oil was finally struck in North Sea and new fields have been discovered since then. The subsequent development of the North Sea is one of the greatest investment projects in the world.

After GOM and North Sea, Petrobras, the national oil company of Brazil, is under fortunate circumstances as compared to the GOM and North Sea. In 1974, it began exploring with modest success in the Campos Basin where the era of deepwater began. The Enchova is the first conventional fixed-based installation of Garoupa Field at 124 m water depth. After that, in burst of productivity and originality, they discovered Bonita, Pirauna, Marimba, Albacora and Barracauda. The oil is produced from subsea wells and evacuated through the floating production system.

From time to time the 'elephant hunt', discoveries whose size would warrant spending hundreds of millions of dollars in development expenditures, continues. As a result, it has initiated scores of other enterprises that contributed technology and technique to tapping hydrocarbons in the deepwater – drillers, mud companies, cementing, services, fabricators, geo-service and seismic companies, maritime services and more, not to mention the emergence of other oil companies. This has brought the industry grown globally expanding the quest of oil to the ultimate frontiers, the deep and ultra-deepwater as shown in Figure 1-5.

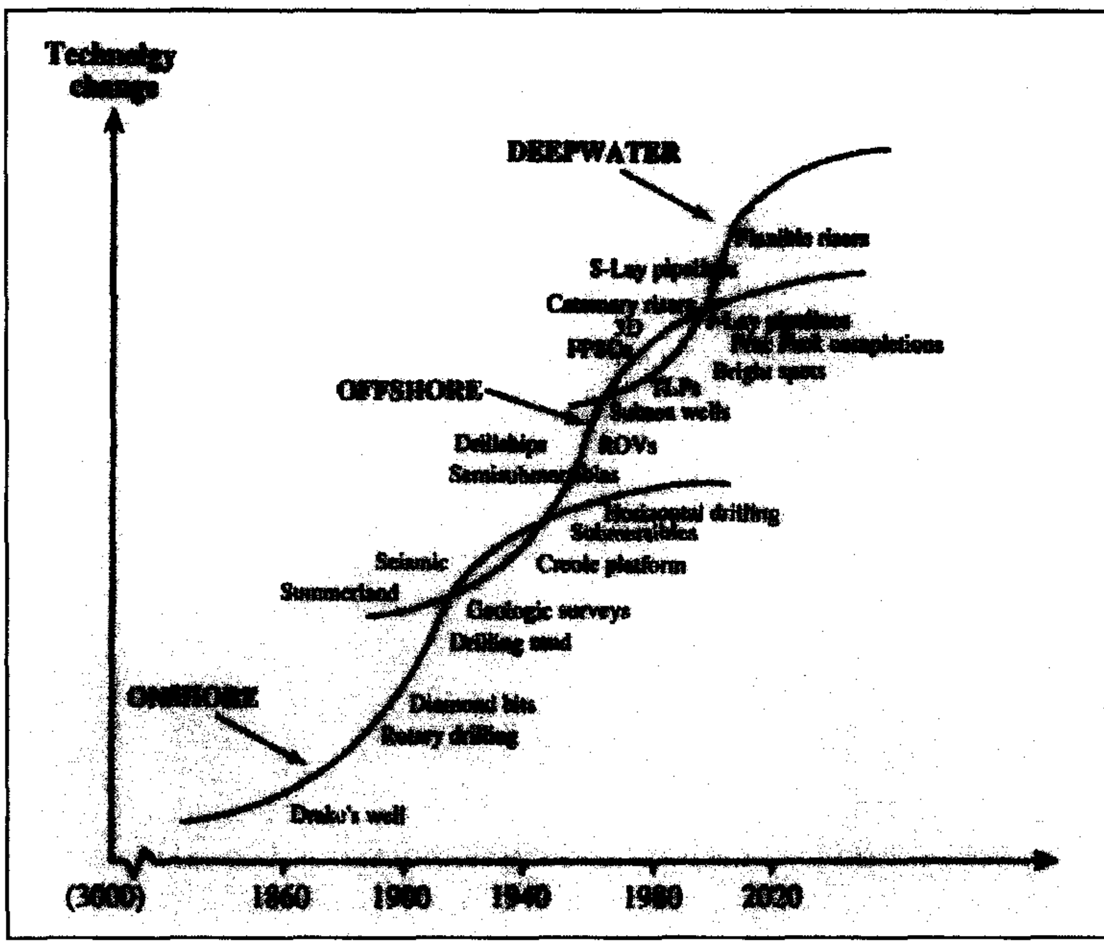


Figure 1-5: Deepwater Evolution of Oil and Gas Exploration, (William et.al, 2003)

In the late 1990's, more and more discoveries were made in ultra-deepwaters. Hugh find in key areas set-off a new momentum that simulated major Research and Development (R&D) investments. With breakthroughs that secured the success of gigantic deepwater projects, many oil producers have demonstrated their capacities to continue pushing to the limits of possibility.

1.1.5 The Definition of Shallow and Deepwater

By definition, a variety of criteria can be used to define deepwater. The threshold separating shallow and deepwater can range from 200 – 457 m. Industry standards categorize deepwater area as one with water depth between 200 and 1,000 m, while ultra-deep area features depth beyond 1,000 m.

As defined by Minerals Management Services (MMS) of US Department of Interior, deepwater is defined as water depths greater than or equal to 305 meter. Similarly, for ultra- deep is defined as water depths greater than or equal to 1,524 m (MMS, 2000).

1.1.6 The Global Regions and Players of Deepwater

Today, most of the deepwater operations are located in the 'Golden Triangle', namely in North America – the Gulf of Mexico (GOM), Africa – the Gulf of Guinea (GOG) and South America – the Brazilian Campos Basin.

1.1.6.1 Gulf of Mexico (GOM), North America

The Gulf of Mexico Outer Continental Shelf is divided into three sectors – the western, central and eastern planning areas as in Figure 1-6.

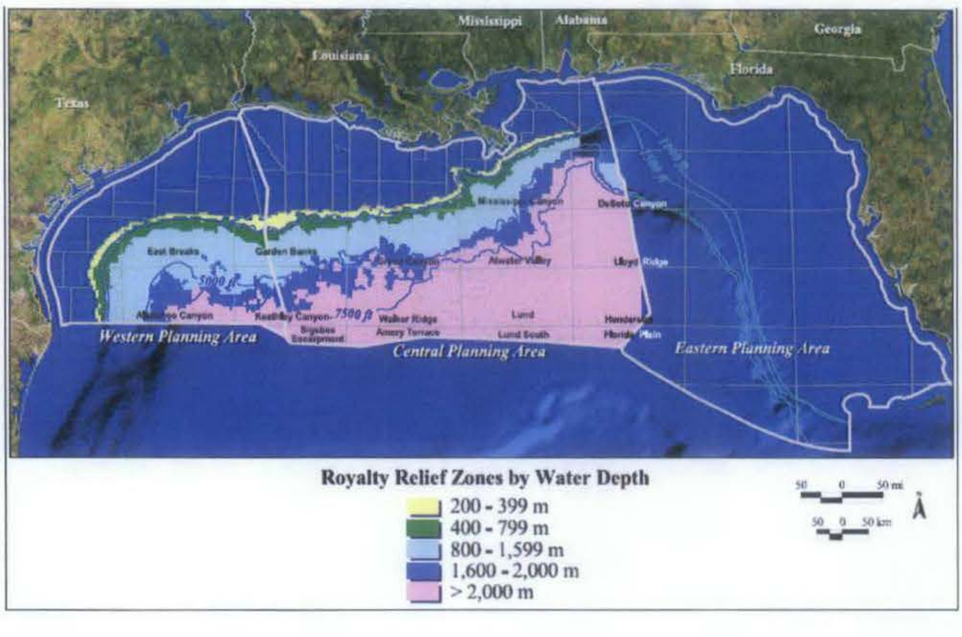


Figure 1-6: GOM Deepwater Areas by Depth, (MMS, 2008)

In GOM, deepwater has continued to be a very important part of the total GOM production, providing approximately 70% of the oil and 36% of the gas in the region. At the end of 2008, there were 141 producing projects in the deepwater Gulf, up from 130 ends of 2007 (MMS, 2008). The 20 highest producing blocks in the Gulf continue to be located in deepwater. Despite the challenges of deepwater, there was a shift over time and the number of deepwater discoveries continues at a steady pace as shown in Figure 1-7.

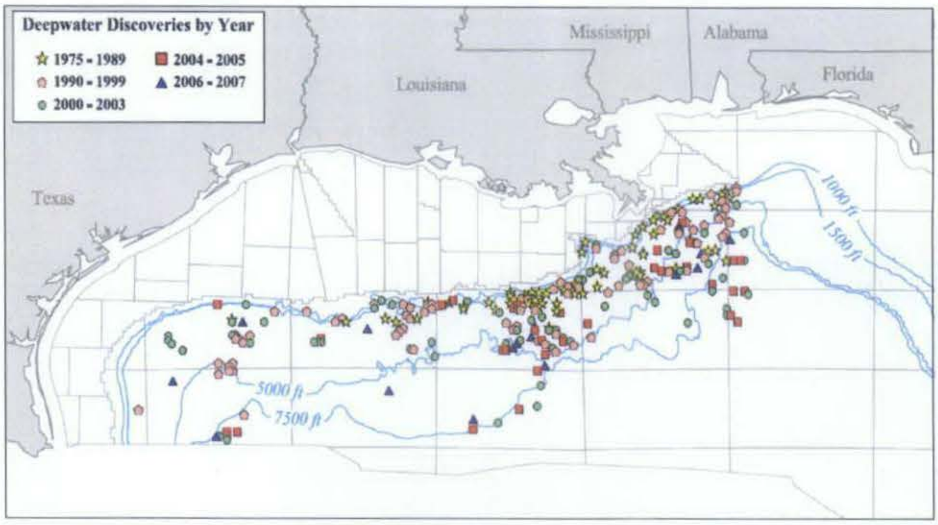


Figure 1-7: Deepwater Discoveries in GOM, (MMS, 2008)

The historic trends of oil production in the GOM are illustrated in Figure 1-8. Shallow water-oil production rose rapidly in the 1960's, peaked in 1971, and has undergone cycles of increase and decline since then. Since 1997, the shallow-water GOM oil production has steadily declined and, at the end of 2006, was at its lowest level since 1965. From 1995 through 2003, deepwater oil production experienced a dramatic increase similar to what seen in the shallow water during the 1960's. Starting in 2003, deepwater production leveled off. In 2006, deepwater oil production accounted for over 72% of total GOM oil production.

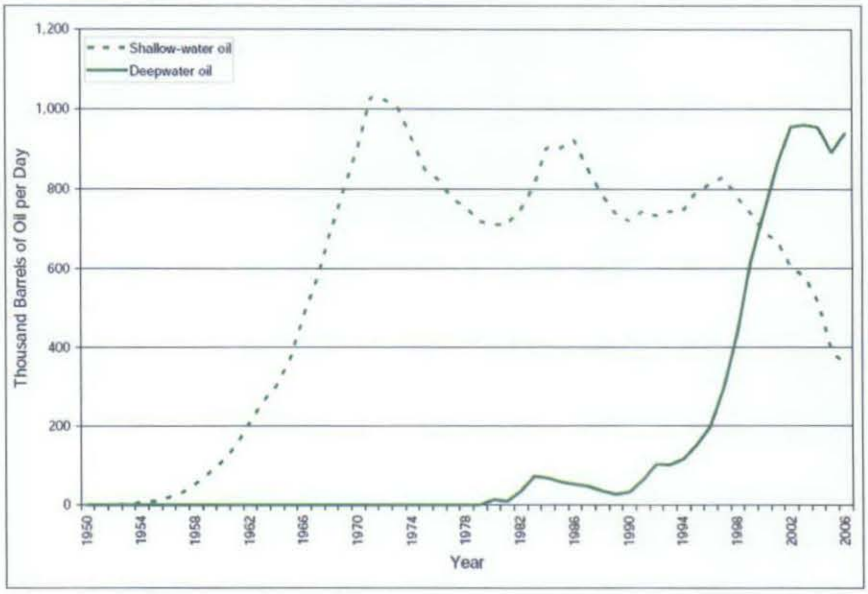


Figure 1-8: Comparison of Average Annual Shallow, Deepwater Production, (MMS 2008)

In the GOM, Shell has been the leader in deepwater exploration and production for the last 30 years, the milestones are shown if Figure 1-9. Likewise ExxonMobil and BP have also contributed significantly in the development and production of oil and gas in the GOM, and ensure that GOM will remain one of the world's premier oil and gas basins.

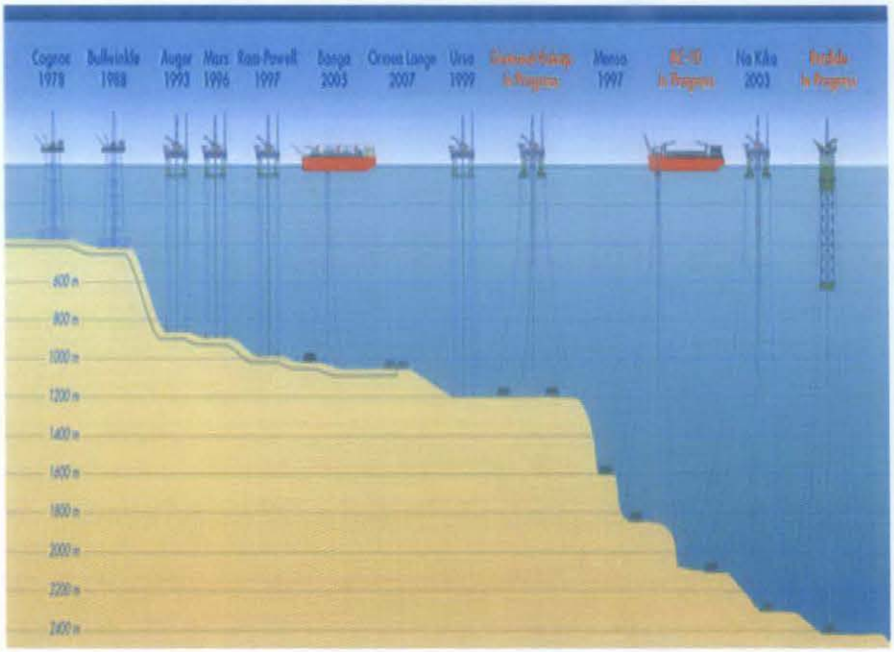


Figure 1-9: Shell Deepwater Milestones, (Shell, 2008)

1.1.6.2 Gulf of Guinea (GOG), West Africa

The Gulf of Guinea (GOG) has a market share of about 300 million consumers. As shown in Figure 1-10, it encompasses a large number of countries from West and Central Africa: Angola, Benin, Cameroon, Central African Republic (CAR), Cote d'Ivoire, the Democratic Republic of Congo (DRC), Equatorial Guinea, Gabon, The Gambia, Ghana, Guinea, Guinea-Bissau, Liberia, Nigeria, Republic of Congo, Sao Tome and Principe, Senegal, Sierra Leone and Togo. These countries enjoy a wide geological, geographical and cultural diversity. Overall the GOG generates a gross domestic product (GDP) of USD 112 billion, exports of about USD 45.5 billion and imports of about USD 31.63 billion (Damain, 2005).

Figure 1-10: Gulf of Guinea

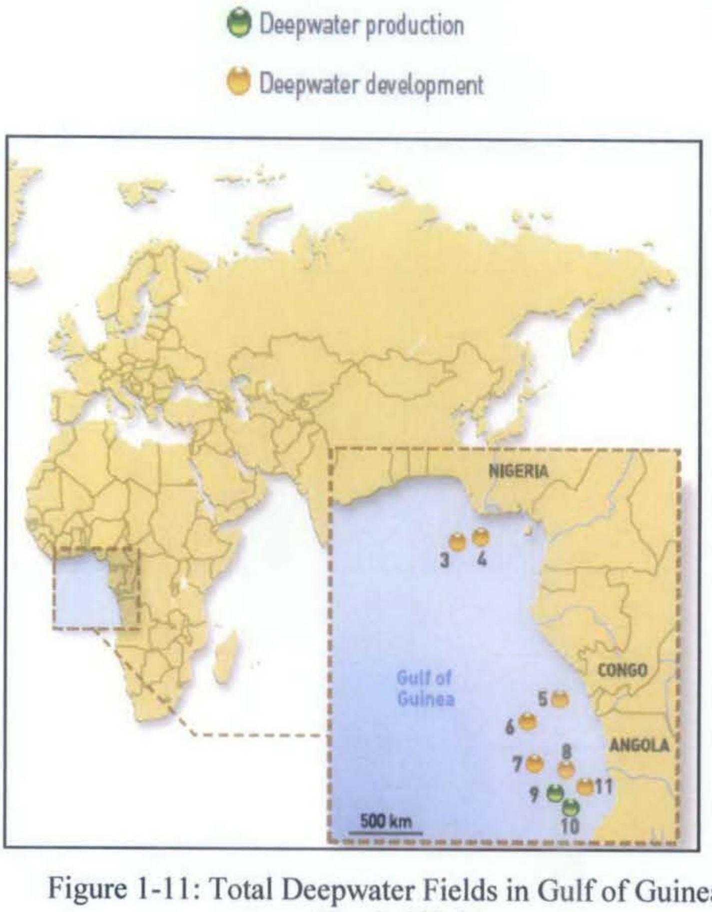


Figure 1-11: Total Deepwater Fields in Gulf of Guinea, (Total, 2006)

In the GOG, Total is the largest oil producer. Total has made or is involved in 28 deep offshore discoveries in Angola – Girassol, Dalia, Rosa, Jasmin etc and 3 in Congo. Total's deepwater production and development in GOG is shown in Figure 1-11.

1.1.6.3 Campos Basin Brazil, South America

The Campos Basin as shown in Figure 1-12 is located off the coast of Brazil is considered the biggest oil reserve in the Brazilian Continental Platform. It measures some 100,000 square kilometers and ranges from the state of Espirito Santo, near the city of Vitoria, to the Arraial do Cabo, off the northern coast of the state of Rio de Janeiro. This basin accounts for nearly 84% of Brazil's oil production.

Exploration was kicked-off in the Campos Basin in late 1976 which gave rise to the Garoupa field, located at a depth of 100 meters. Meanwhile, commercial production began in 1977 at Enchova field with an output of 10,000 barrels of oil/day (bop/d), the oil is then produced to a semi-submersible platform moored at a water depth of 124 m. This was the beginning of a successful history that led Petrobras to become a world leader company in petroleum exploration and production in deep (300- 1500 m) and ultra deep (>1500 m) waters.

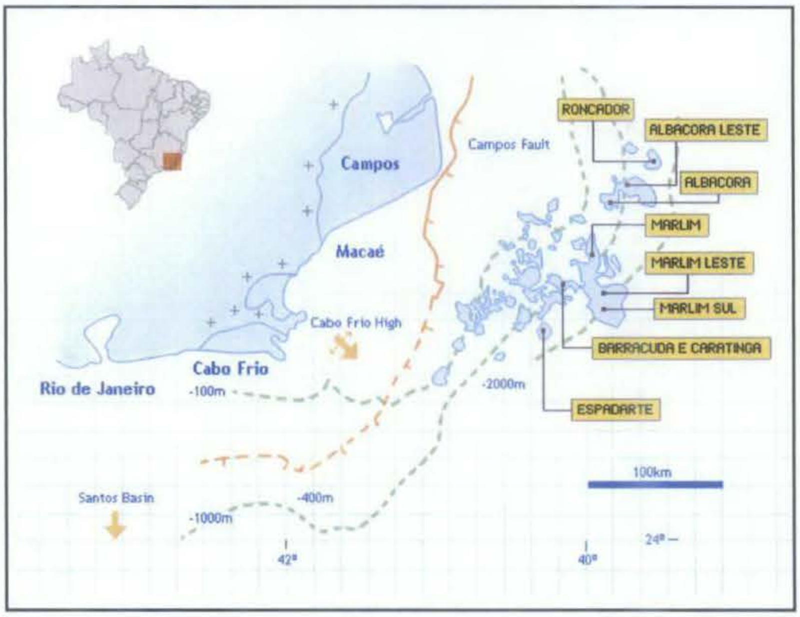


Figure 1-12: Campos Basin, Brazil

Petrobras is the national oil company of Brazil and a world leader in deepwater petroleum exploration and production. Petrobras in that area is top ranking worldwide in both the exploration and production development segments. Deep and ultra-deep water giant fields started to be discovered in early 1984 as shown in Figure 1-13. There was a succession of large discoveries from Albacora, Marlim, Albacora Leste, Marlim Sul, Barracuda, Caratinga, Roncador, Jubarte, Cachalote, and the recent discovery of gigantic accumulation of oil and gas off the southeast coastline of Brazil named Tupi. Today more than 55 oil fields have been discovered in the basin, between 50 and 140 km off the Brazilian coast under water depths ranging from 80 to 2,400 m.

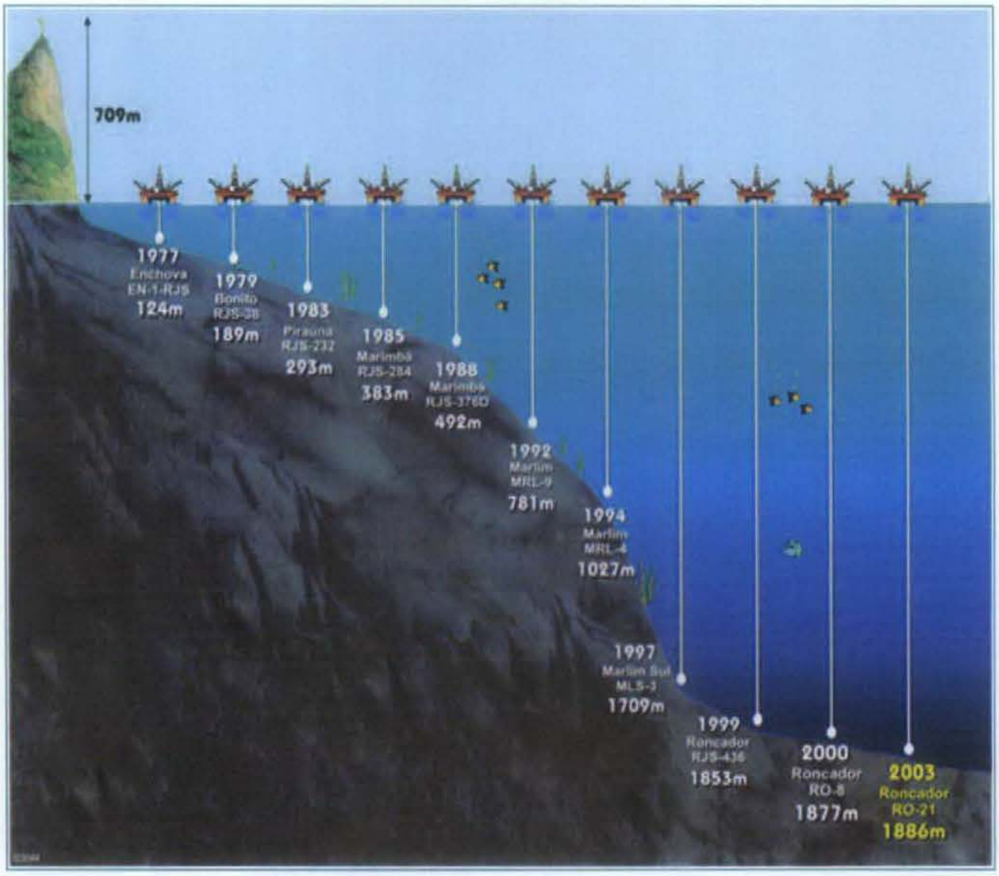


Figure 1-13: Brazil Deepwater Development in
Campos Basin, (Petrobras, 2007)

With the challenges of producing oil in increasingly deeper waters, Petrobras has developed a strategic program called PROCAP – Deepwater and Ultra-deepwater Advanced Development and Technological Innovation Program. PROCAP is a technological achievements that help the company produce petroleum in deep water (over 400 meters).

1.1.7 The Operating Challenges in Subsea Condition of Deepwater

Today, the exploration and production of hydrocarbons have moved from the traditional shallow continental shelf to offshore deepwater. The change in the energy market has demanded that the worldwide oil industry produces more and more hydrocarbons. This increased demand has "stretched" every single area of the industry whilst at the same time presented ever more challenging projects to extract hydrocarbons. Despite the extreme challenges, however, due to its commercial attractiveness, the search for oil in deep and ultra deepwater continues against the unprecedented increase in demand of oil.

There is an enormous difference operating in shallow and deepwater especially in the subsea condition. Operating challenges relate to all areas of operations including but not limited to, seismic acquisition, drilling and completion operations, production operations, logistics and technical support. At deeper water depth of more than 300 m, these deep water zones are subject to extreme conditions of pressure and temperature, and shrouded in total darkness making impossible for any human intervention. In a mile deep, water squeezes everything at more than one ton/sq in. Imagine such an immense pressure at the sea bed, for this reason pressure is a major factor in designs of pipeline and subsea equipment.

Anywhere in the world, at below 600 m the sea ocean temperature is below 4°C. This low temperature especially in deepwater gas wells can cause water vapor and natural gas to form ice-like crystals hydrates, waxes, asphalthene, solid depositions etc in the pipelines, flowlines and risers which may significantly impede flow. In order to surface the oil to the topsides processing facility, the critical aspects of flow assurance have to be cautiously implemented right from design to operational phase.

Apart from the extreme pressures and low temperatures at the seabed, the marine ecosystems are a bit unusual. Colonies of worms and mussels often thrive around naturally occurring oil and gas seeps. Over thousands of years their remains have formed rock-hard deposits that must be avoided to prevent damage to equipment on the ocean floor. In some places of the seabed, the ocean floor is very soft and any unsupported equipment will sink out of reach. Elsewhere, underwater hills and valleys pose the threat of sediment and rock slides that can damage subsea wells.

Obviously working in open deepwater, sea current and waves cannot be avoided. Currents can complicate the installation and operation of offshore equipment. Storms can generate waves taller than a seven-story building and wave crests moving at 20 knots. The unique challenges operating in subsea condition of the deepwater, some of which are shown in Figure 1-14.

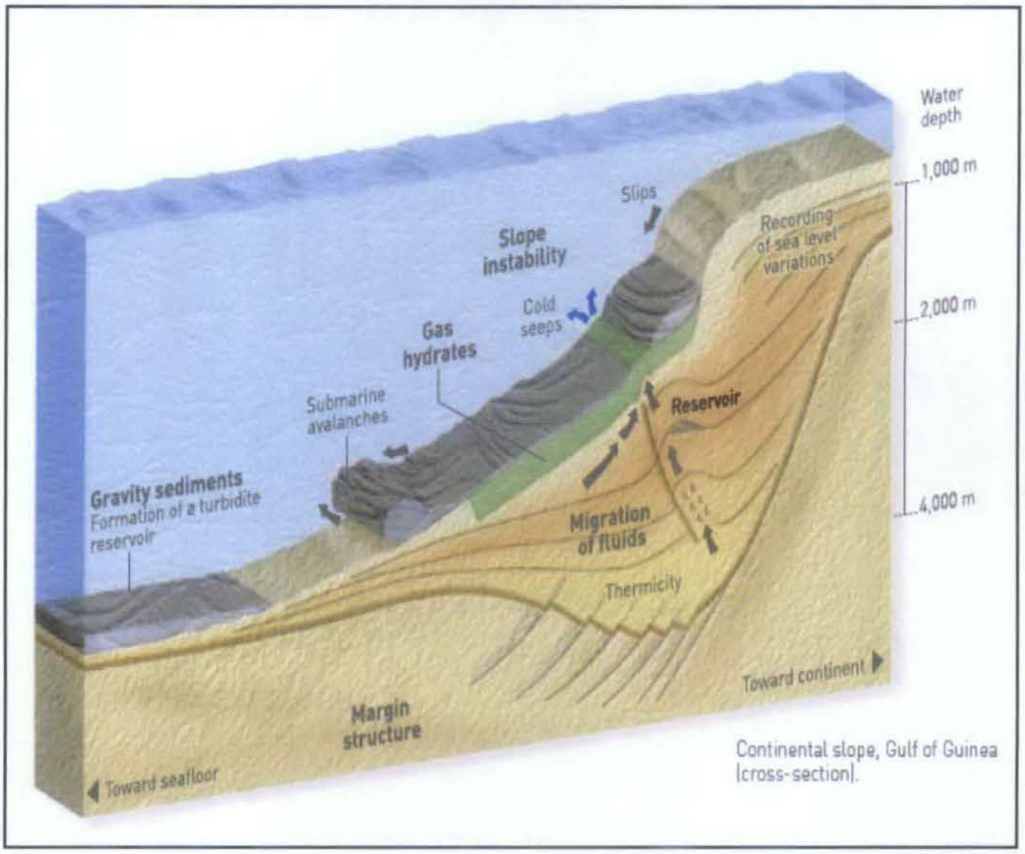


Figure 1-14: Operating Challenges in Deepwater, (Total, 2006)

Much of the deepwater exploration prospects now lie in sub-salt environment, with salt canopies ranging from 2,000 to 6,000 m thick, and have target depth ranges from 7,000 to 11,000 m true vertical depth. The vast salt zones inhibit deeper seismic resolution and present great challenges in exploration, appraisal and development operations. The requirement to be able to understand the geology associated with the massive salt, and more importantly the quality of imaging below the salt, is one of the paramount challenges facing operators, as shown in Figure 1-15.

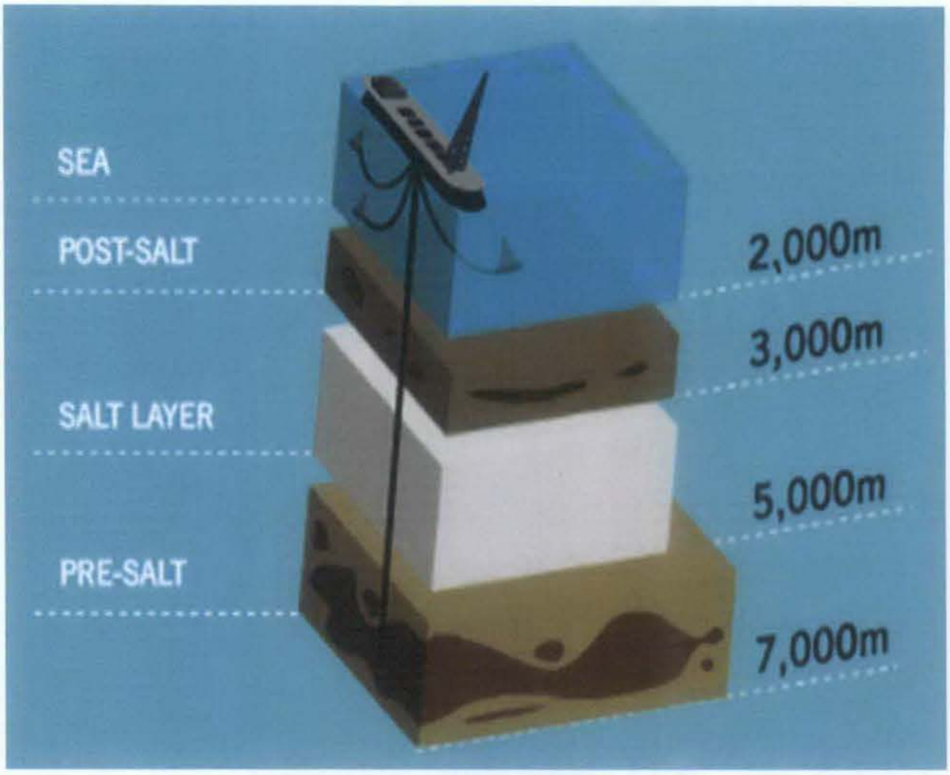


Figure 1-15: Hydrocarbon at Pre-Salt Pole, (Petrobras, 2007)

The potential impacts and major environmental concerns with subsea operations are similar to those observed with existing surface technologies. The primary difference between surface and deep sea technologies is the restricted ability to detect and respond to releases at or near the seabed. Additionally, the major potential impacts and environmental effects could be different in deepwater because the potentially affected biological communities are not as well characterized in terms of species composition, ecological significance, and the rates of community recovery from physical or chemical interventions. Other potential environmental hazards associated with the operation of subsea processing systems include exposure to large thermal gradients, induced electromagnetic fields and low-level noise. Under the extreme subsea condition and hostile environment, there is no possibility of any human intervention at deepwater depths. All subsea works will be performed through remote operated vehicle (ROV) from the surface, equipment capable to perform installation, surveillance and maintenance works.

1.1.7.1 The Subsea System

The subsea system is typically made up of six components mainly wells, subsea trees, manifold and sleds, flowlines, electric and hydraulic umbilicals, and subsea and surface controls. In addition, these components are connected by jumpers and flying leads. The typical subsea system is as illustrated in Figure 1-16.

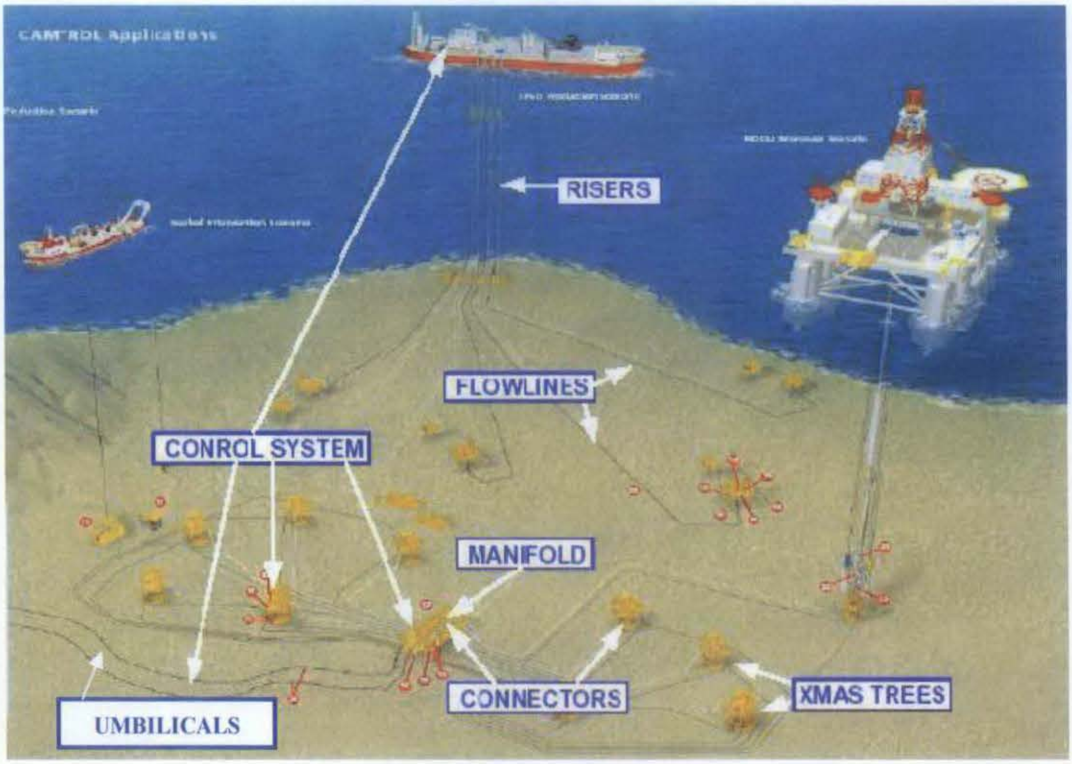


Figure 1-16: Subsea System, (MMS, 2000)

Well as shown in Figure 1-17, is where the hydrocarbon fluids coming from the reservoir in terms of oil and gas at natural flow. The designs and specifications of all subsea components – trees, manifolds, umbilical and so on are a function of the characteristics of the wells.

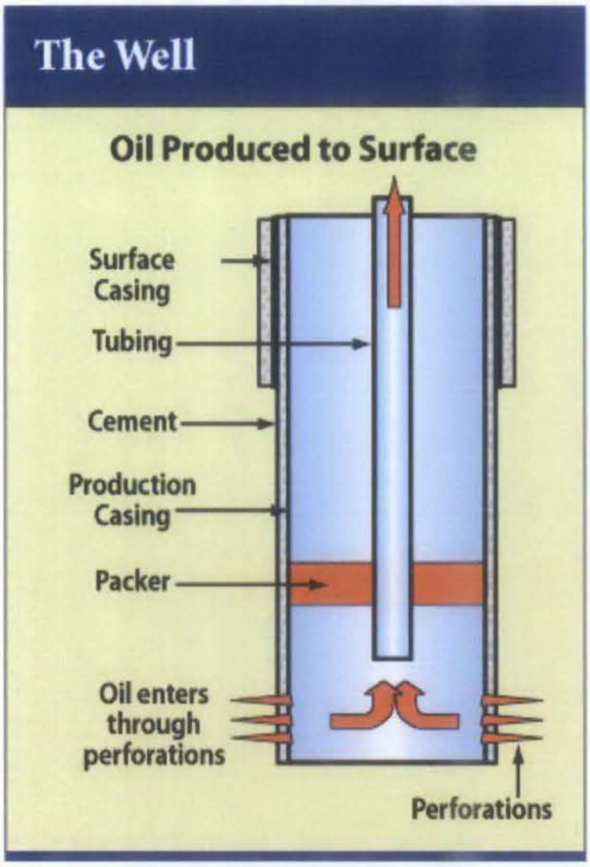


Figure 1-17: The Well

Subsea trees sit on top of the well at the seabed. Although they have little visual similarity to the original onshore Christmas trees, they provide essentially the same functions. They furnish the flow paths and primary containment for the oil and gas production and the valves needed for both operation and safety. Subsea trees normally have the external handles and fixtures to enable ROVs to physically turn valves and activate other control functions during normal operations.

A manifold is quite simple in concept. It provides the node between the individual flowlines from the wells and the flowline to the host platform. A sled is a termination structure for a flowline or gathering line on the one side and a connection to a subsea well or manifold on the other. Pipeline and flowline are conduits to transport fluids from one location to another.

Pipeline and flowline are distinguished where pipeline are piping, risers and appurtenances installed for the purpose of transporting oil, gas, sulfur and produced water between two separate facilities. Flowline is piping installed within the confines of the platform or manifold for the purpose of commingling, for example subsea manifold or routing into the processing equipment.

An umbilical as shown in Figure 1-18, is a bundled arrangement of tubing, piping and or electrical conductors in an armored sheath from the host facility to the subsea production system. An umbilical is used to transmit the control fluid and or electrical current necessary to control the functions of the subsea production and safety equipment (tree, valves, manifold etc).

Figure 1-18: The Umbilical

Dedicated tubes in an umbilical are used to monitor pressures and inject fluids – chemicals such as methanol, from the host facility to critical areas within the subsea production equipment. Electrical conductors transmit power to operate subsea electronic devices.

A jumper is a prefabricated section of steel pipe specially configured to make a specific connection or it is a length of flexible composite line. A flying led is a sort of subsea extension cords that are “flown” by Remotely Operated Vehicle (ROV) and plugged into waiting receptacles.

The ability to monitor and control wells and manifold functions from the host facility is critical to overall subsea system performance. Trees and manifolds have control pods, modules that contain electro-hydraulic controls, logic software and communication signals. Collaborating with a surface vessel, an ROV can fly in, disconnect the pod from its support structure, and pull the pod to the surface. This is more or less a subsea version of changing a card in a computer.

1.2 Problem Statement

Chinguetti a deepwater oil field development offshore Mauritania is experiencing a rapid decline in its production that resulted to severe flow instability or slugging in flowlines and risers of its subsea oil production system. With less energy for the fluids to overcome the system hydrostatic head, hence slugging phenomenon exists. Slugging is further complicated by the changes in reservoir behavior as an effect of depletion.

Slugging initiates oscillations and puts field operator in a demanding situation to manage and control flow instability. Given the dimension and magnitude of this phenomenon, one cannot underestimate its presence. If it continues to prolong, it will leads to unwarranted process upsets, excessive strain on equipment especially compressor, disproportionate flaring and unable to maximize oil recovery from the reservoir. Consequently, they can potentially have a significant negative impact on the net present value of a system and the economics associated with deepwater production. Therefore, it is crucial to have a model to describe flow instability issues in live field conditions. However, there is no applicable model to represent flow instability in deepwater operations.

Current available data that represents flow instability in flowlines and risers in live field conditions has not been published in any literature. The available data is mostly from laboratory controlled conditions or laboratory scale ideal condition. Model using laboratory conditions has limited capability that cannot be used to assess severity of slugging and flow instability.

In order to obtain a more representative model, hence it is critical to validate the model with a real field data. A representative model will then investigate potential operating strategies to improve the stability and productivity of the oil production system.

1.3 Objectives

Important advancement in technologies have resulted in a number of innovative methodologies, solutions and applications which proved to be able to successfully assist deepwater upstream players in their quest for operational performance excellence. Motivated by this factor, a case study has been performed in Chinguetti field that will bring valuable lessons and inputs from a stability study of a deepwater oil field development.

The main objectives of the study are:

- To develop engineering simulation models using OLGA flow assurance simulation tool
- To benchmark and validate the simulation models against measured data from the field
- To assess severity of slugging and flow instability in the subsea oil production systems based on the developed model
- To examine strategies to mitigate or improve flow stability and productivity in the flowlines and risers

In this study, a steady state and transient analysis simulations for the flowlines and risers were conducted utilizing the latest version of OLGA version 5.3 and PVTSim version 17.0.0. , to determine potential solutions to minimize severe slugging and improves production from the Chinguetti wells.

1.4 Scope of Work

The approach of this study is essentially that of a literature review from past works done by researchers' and an engineering analysis of a real life field case study. The review of industry's literatures provides a better understanding of the problem faced in the Chinguetti operations and the methods to improve the flow instability. The use of a case study approach is to emphasize the similarity of the problems with other deepwater development systems and to assess the applicability of available mitigation solutions for the situations in Chinguetti.

Additionally, the use of a case study approach was not just to focus on the concepts and ideas of mitigation strategies but also to identify the guiding principles of flow instability and proven mitigation strategies.

In this study, the scope of work is confined to the three main areas i.e. the production tubing, the field flowlines and the flexible risers of the subsea oil production system. To define further, production tubing is a tubular used in a wellbore through which production fluids (mixture of oil, gas and water in formation fluid that flows to the surface of an oil well from a reservoir). Production tubing is run into the drilled well after the casing is run and cemented in place. Along with other components that constitute the production string, it provides a continuous bore from the production zone to the wellhead through which oil and gas can be produced.

Meanwhile flowlines are conduits to transport fluids from one location to another. Flowlines are piping installed within the confines of the manifold for the purpose of commingling, for example, subsea manifold or routing into the processing equipment. Typical dimensions can range from 3 to 12 inches OD (outer diameter), and can be as large as 36 inches OD.

The risers or sometimes called production risers are that portion of the flowline that resides between the host facility and the seabed adjacent to a host. Risers can be flexible or rigid and they can be contained within the area of the fixed platform or floating facility, run on the sea-floor, as well as partially in the water column. Length is defined by the water depth and riser configuration, which can be vertical or variety wave forms. Facility dimensions range from 3 to 12 inches in OD.

In summary, chapter 1 provides an overview of the world's energy and oil outlook where oil remains the vital source of energy for many years to come despite the emergence of other renewable sources. It also reveals that with declining production from near shore sources and shallow waters, the industry oil majors have shifted their course of attention in waters of greater depth. The difference of shallow and deepwater is defined in this chapter and also highlights the operating challenges in deepwater. The problem statement outlines the related issues and how they are going to be addressed in meeting the objectives and within the scope of this study.

In chapter 2, it reviews the available industry literatures of past researchers and industry's experience and to show practical applications of known principles. This chapter will outline the production flow regimes, slugging phenomena, slugging impacts, slugging prediction and methods, current commercial modeling tools to analyze flow instability, and finally some of the elimination techniques to mitigate the problem.

In chapter 3, it begins with the introduction of transient multiphase simulator OLGA, the theory and application of OLGA algorithm relevant to this study. It reveals the methodology or approach taken in the model construction. In this chapter, field validation against actual conditions of the field was highlighted. It also discusses the simulations of models against various operating conditions and its impact to flow instability in flowlines and risers of the oil production system.

In chapter 4, it highlights the results and discussion of the developed models. It elaborates the details of the simulated cases in relation to the severity of slugging and various strategies to mitigate or improve flow stability and productivity in the flowlines and risers. The preferred option that has significant impact to the instability of flow is also being discussed.

In chapter 5, it presents the conclusion and recommendation for future works.

CHAPTER 2
LITERATURE REVIEW

CHAPTER 2

LITERATURE REVIEW

2.1 Introduction

As the quest for energy advances into deeper waters, new issues and greater challenges emerge on many fronts. Flow instability in deepwater flowlines and risers of a subsea oil development is amongst one of them. Flow instability as a consequence of slugging in flowlines and risers can be a vexing problem. The understanding and predicting of flowline-riser system operability will help to improve the production and safety for operators affected by this occurrence.

This chapter will outline the production flow regimes, slugging phenomena, slugging impacts, slugging prediction and methods, current commercial modeling tools to analyze flow instability, and finally some of the elimination techniques to mitigate the problem. This chapter will also review available industry literatures of past researchers and industry's experience and to show practical applications of known principles.

2.2 Production Flow Regimes

Understanding the basic principles of flow in a pipe is a starting point for a scientific treatment of gas-liquid flows. Gas-liquid flows in a pipe are often referred as multiphase flow. Multiphase flow is characterized by the existence of interfaces between phases and discontinuities of associated properties. Single-phase flow can be classified according to the external geometry of the flow channel as well as the 'character' of the flow i.e. laminar – following streamlines, or turbulent – exhibiting fluctuations and chaotic motions.

Laminar flow, sometimes known as streamline flow, occurs when a fluid flows in parallel layers, with no disruption between the layers. In fluid dynamics, laminar flow is a flow regime characterized by high momentum diffusion, low momentum convection, pressure and velocity independent from time. It is the opposite of turbulent flow. In nonscientific terms laminar flow is "smooth," while turbulent flow is "rough."

In contrast, multiphase flow is classified according to the internal phase distributions or "flow patterns" or "regimes". For a two-phase mixture of a gas or vapor and a liquid flowing together in a channel, different internal flow geometries or structures can occur depending on the size or orientation of the flow channel, the magnitudes of the gas and liquid flow parameters, the relative magnitudes of these flow parameters, and on the fluid properties of the two phases.

A wide variety of multiphase flow patterns has been observed and identified in the literature. Rouhani and Sohel (1983) cited a survey which suggested 84 different flow-patterns definitions, and partly to a variety of names given basically the same geometric flow patterns. The rate of exchange of mass, momentum and energy between gas and liquid phases as well as between any multiphase mixture and the external boundaries depends on these flow geometries and interfacial area. Therefore, it is dependent on flow pattern. For instance, the relationships for pressure drop and heat transfer are likely to be different for a dispersed flow consisting of bubbles in a liquid than for a separated flow consisting of a liquid film on a channel wall with a central gas core. This leads to the use of flow-pattern dependent models for mass, momentum and energy transfer, together with appropriate flow-pattern transition criteria.

Facing the difficulty to predict the nature of multiphase flow, researchers have sought realistic approaches to resolve the problem. Over the last fifty years, various visualization experiments have been performed mainly with convenient fluids air and water. Meanwhile researchers have identified that the flows observed can usually be classified or categorized into one kind or another in terms of flow patterns or flow regimes.

Hewitt (1999) provides discussion on flow and states that it can be categorized into three types i.e. dispersed, separated and intermittent flows. Dispersed flows include all flow regimes where one phase is uniformly distributed as roughly spherical elements throughout another continuous phase that includes bubbly flow. Bubbly flow is described as small bubbles dispersed through a liquid continuous phase or drop flow where small droplets of liquid are carried along in vapor stream.

Separated flows are those where the phases are not thoroughly mixed that includes stratified flow in horizontal pipes where the liquid flows at the base of the pipe with the gas stream flowing above. In addition, it also includes annular flow where the liquid flows around the periphery of the pipe as a thin film with a gas core flowing internally. Intermittent flows are those where the places are not distributed uniformly along the pipe, for example slug flow or plug flow.

On the other hand, Watson (1999) presents various flow patterns that exist in vertical two-phase flows as shown in Figure 2-18 that illustrates bubble, slug, churn, annular and wispy-annular flows. A bubbly flow is where small bubbles of gas distributed throughout the continuous liquid phase and it occurs at lower gas-liquid ratios (which in oil and gas production is water-in-oil dispersion). The slugs, occasionally known as plug and churn flow regimes occur at intermediate gas-oil ratios. At higher gas-liquid ratios, the fluids are transported in the annular flow regime. The wispy-annular flow regime occurs when the flow rates of both liquid and gas are at high flow rates.

Comparatively, Watson (1999) is describing flow patterns in a vertical manner where as Hewitt (1999) provides discussion on horizontal pipes. Hence, the occurrences of flow patterns in vertical and horizontal pipe flow, both combinations are closely relevant that reflects the flowlines and risers of Chinguetti, horizontal-vertical configuration.

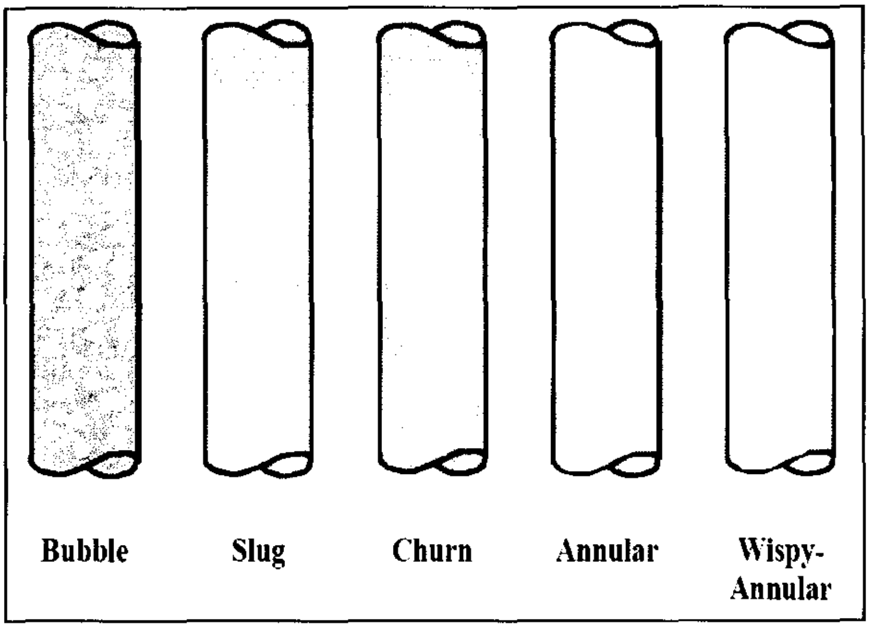


Figure 2-19: Flow Patterns in Vertical Two-Phase Flows (Watson, 1999)

When gas and liquid flow in a pipe over a certain ranges of flowrates, a flow pattern develops whereby a long bubbles filling almost the pipe cross section and successfully followed by liquid. The long bubbles are commonly referred to as Taylor bubbles or Dumitrescu bubbles and the gas-liquid pattern is usually called slug flow Pinto et al., (2000).

A useful approach for the modeling of multiphase flows is being presented by the identification and classification of flows into flow patterns especially when the pressure drop and phase hold-ups differ significantly from one pattern to another. Having knowledge of the flow pattern and the appropriate relationships specific to the flow pattern, it provides some advantage to the prediction of multiphase flow Pickering et al., (2001).

From the flow pattern for upwards concurrent flow as illustrated by Hewitt and Roberts (1969) in Figure 2-20, researchers first sought to define two-dimensional flow pattern maps in order to predict flow patterns. The procedure was then to locate a system on the map and apply the appropriate correlations for the prevailing pattern.

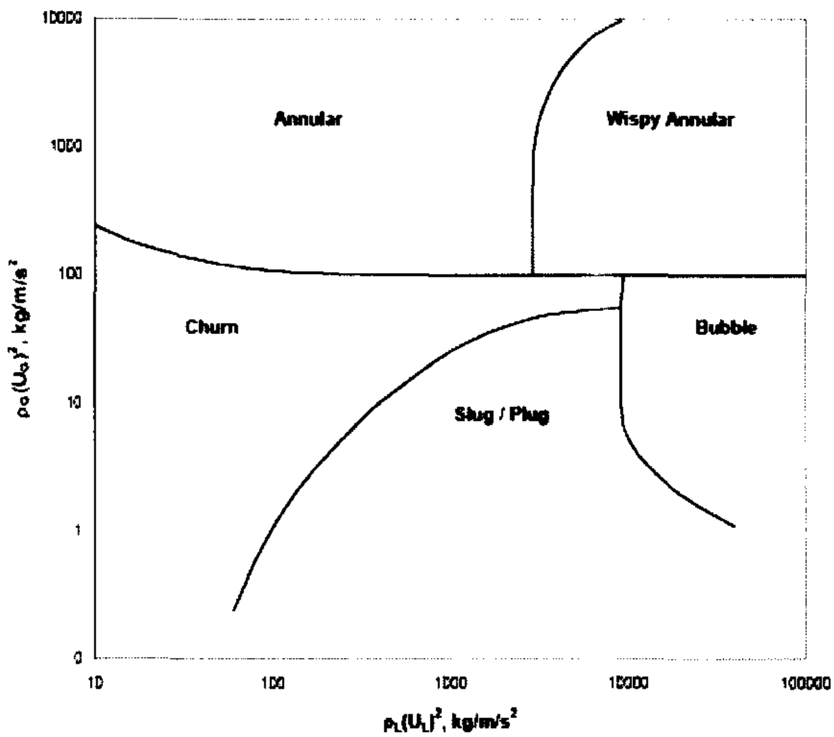


Figure 2-20: Vertical Upwards Flow Map (Hewitt & Roberts 1969)

From the map, on the y-axis it plots the momentum flux of the gas and the x-axis the corresponding liquid parameter. However, this approach is useful and relevant and has limited applicability. The fundamental problem is that the transition from one flow regime to

another cannot be reduced to just two-dimensional flow pattern. Even through the application of dimensional analysis, it is not possible to group parameters into just two groups. Motivated by this limitation, researchers of late have attempted to predict transitions from one regime to another by mechanistic means. For example, the transition from a bubble to slug flow has traditionally being explained through competing effects of bubble break-up and coalescence using arguments based on surface tension and turbulence forces, proposed earlier by Levich (1962) and more recently developed by Taitel et al., (1980).

Ultimately through the application of tested mechanistic relationships for transitions between flow patterns, it is hoped that it will be possible to consistently predict the boundaries between flow patterns in a multi-dimensional parameter space. Besides that it will also precisely predict the characteristics of multiphase flows. However, in general there is no accepted mechanistic basis for predicting flow regimes using mechanistic approach. As an example for the formation of slug, many people have thought a necessary condition on the development of regions of high bubble concentration (void waves) within the preceding bubble flow. Therefore, before a 'grand-unified theory' is available and generally accepted, a great deal of effort is required to proof this concept Pickering et al., (2001).

Given the existence of any pattern, it is possible to model the two-phase flow field and to select a proper set of flow-pattern dependent equations to predict the important process design parameters. However, the central task is to predict which flow-pattern will exist under any set of operating conditions as well as to predict the value of characteristic fluid and flow parameters at which the transition from one flow-pattern to another will take place. Therefore, in order to accomplish a reliable design of gas-liquid systems such as pipelines, flowlines and risers, a prior knowledge of the flow-pattern is required.

2.3 Slugging Phenomena

When liquid and gas are flowing together in a pipeline, the liquid can form slugs that are divided by gas pockets. In other words, the slugs are characterized by an unsteady, alternating flow of liquid slugs and gas pockets Kjetil, H et al., (2004). The typical behavior of slug in an enclosed line is shown in Figure 2-21. The formation of liquid slugs can be caused by a variety of mechanisms: hydrodynamic effects (surface waves), terrain effects (dip in pipe layout), operationally induced events such as pigging, start-up and blowdown, and flow rate or pressure changes.

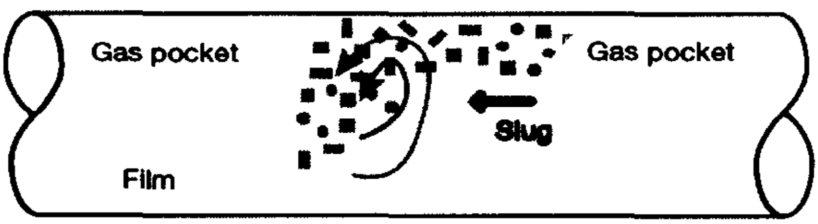


Figure 2-21: Typical Behaviour of Slug

The severity of slugging depends on types of slugging. There are three types of slugging that can be identified in industry's literatures, i.e. hydrodynamic slugs, operationally induced surges and terrain induced slugs as defined by Tang and Danielson (2006).
Hydrodynamic slugs - in horizontal and near horizontal pipes, are formed by waves growing on the liquid surface for a height sufficient to completely fill the pipe. In vertical pipes the hydrodynamic slugs are associated with Taylor bubbles. The hydrodynamic slugging is difficult to prevent since it occurs over a wide range of flow conditions.

Furthermore, several hydrodynamic slugs can gather together due to terrain effects, creating larger slugs. Initially, hydrodynamic slugs are relatively short, however, the slugs can gather together to form longer slugs. The hydrodynamic slugs can form during "steady-state" conditions (Burke and Kashou, 1995). It is useful to predict the slug volume, velocity, and frequency of slugs in order to assess the slugging characteristics.

Operationally induced slugs - are slugging generated by changing the flow conditions from one steady state to another, such as restart, flow rate ramp-up or pigging operations. The generated liquid surge can upset the system. Generally, these slugging conditions occur as a result of the "transient" operations (Burke and Kashou, 1995).

Terrain induced slugs - also called severe slugging is caused by accumulation and periodic purging of liquid in flowline dips at low flow rates, and can in principle only occur if there is a downward flow. Terrain slugs can be hundred meters long. The terrain slugging can also occur during "steady-state" conditions (Burke and Kashou, 1995).

Slugging also can occur in such systems where a flowline segment with a downward inclination or undulating horizontal flowline is connected to a vertical riser (Jansen and Shoham, 1994). This slugging condition is classified as "severe slugging". In general, severe slugging in the flowline and riser systems is a result of the unsteady alternating flow of liquid slugs and gas and can be characterized by periodical change of pressure, gas and liquid flow. The typical unstable periodic cycle is illustrated in Figure 2-21.

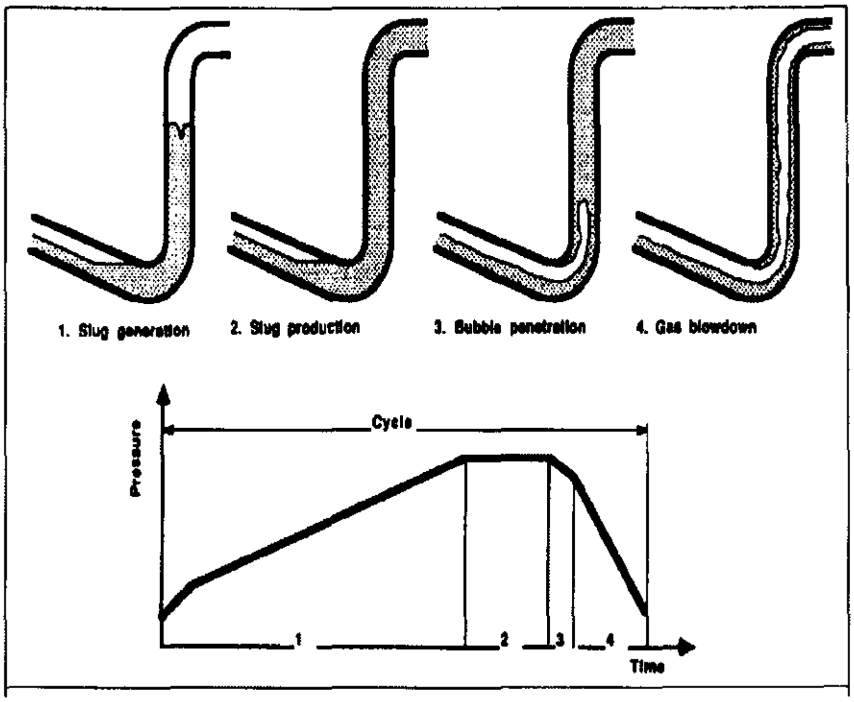


Figure 2-22: Description of Severe Slugging (Schmidt et al., 1980)

The first step, slug generation, corresponds to an increase of the pressure in the bottom of the riser. The liquid level does not reach the top of the riser. During this period, the liquid is no longer supported by the gas and begins to fall. As the pressure increases, the gas accumulates in the pipeline, so the riser is supplied by liquid and eventually gas at a lower rate, Schmidt et al., (1980).

In the second period, the liquid level is again built up by liquid entering from the bottom of the pipeline. For downward flow, a liquid slug is formed at the bottom, so the rise in the liquid level results from liquid flowing alone in the riser. For horizontal flow, the fallback phenomenon does occur, and the rise in liquid level may result from a poor gaseous mixture flowing in the riser Schmidt et al., (1980).

During the second step, slug production, the liquid level reaches the riser outlet, and the liquid slug eventually formed at the bottom of the pipeline is produced until the gas again supplies the riser. This step does not exist for horizontal pipes Schmidt et al., (1980).

In the third step, bubble penetration, gas is again supplied to the riser, so the hydrostatic pressure decreases. As a result, the gas flow rate increases Schmidt et al., (1980).

The fourth step corresponds to "gas blowdown". When the gas produced at the riser bottom reaches the top, the pressure is minimal and the liquid is no longer gas-lifted. The liquid level falls and a new cycle begins Schmidt et al., (1980).

During the life span of a pipeline-riser pipe system, both hydrodynamic and terrain slugs can also be present and further impact the stability of the system. Large flow rates initiated by severe slugs can cause major problems for topside equipment like separator vessels and compressors.

2.4 Slugging Impacts

Slugging initiates oscillations and puts excessive demand for field operator to manage and control the flow instability. Given the dimension and magnitude of this phenomenon, one cannot underestimate its presence and left unchecked. The main impact of slugging is production deferment caused by the following as indicated by Kovalev et al., (2004):

- unwarranted process upsets and platform trips as a result of liquid and gas surges
- inefficient utilization of the separation system specifically first stage separator, since part of its volume is needed for slug catching
- excessive strain on equipment especially compressor, unsteady operation of heat exchangers etc due to process instabilities which decrease separator efficiency
- slow well bean-up to avoid formation of large slugs
- top-side choking to restrict the liquid production

If it continues to prolong, it will leads to disproportionate flaring and unable to maximise oil recovery from the reservoir. Consequently, they can potentially have a significant negative impact on the net present value of a system.

2.5 Slugging Prediction and Methods

Yocum (1973) was the first researcher to report the symptoms of severe slugging phenomena. Due to this effect, he observed that the flow capacity of a production system could be reduced to 50% because of the back-pressure caused by severe slugging. He then proposed a prediction model based on the available hydrodynamic slugging models.

Schmidt et al., (1980) developed a hydrodynamic model to predict the dynamic slug characteristics of severe slugging. The model assumed constant inlet liquid and gas mass flow rates, constant separator pressure, and liquid slugs free of entrained bubbles, and required empirical correlations for the liquid hold-up in the pipeline and the liquid fall back in the riser. However, no verification of the model was presented. Despite that the authors provided three separate severe slugging transition criteria:

- Stratified – non stratified flow transition – they postulate that the flow in the pipeline segment before the riser has to be stratified for severe slugging to occur
- The stability of the flow in the riser i.e. if the pressure drop in the riser decreases as the gas flow rate is increased for a given liquid flow rate, then the flow is said to be unstable and susceptible to severe slugging
- The criterion in assigning the boundary between severe slugging and transition to severe slugging is a direct solution of their hydrodynamic model for the lowest gas flow rate corresponding to a liquid flow rate that will produce riser generated slugs shorter than the riser length.

Needham et al., (2007) has developed a hydraulic theory to describe the occurrence and structure of slugging in a confined two-layer gas-liquid flow generated by prescribed, constant, upstream volumetric flow rates in each layer. For uniform flow a linearized theory is established, after which a bifurcation theory was used to study the fully non-linear periodic traveling wave structure. The study verified that under given circumstances two-parameter family of such traveling wave solution exists. However, Needham et al. (2007), observed some unresolved issues remain:

- First, can a weak non-linear theory provide some insight into the amplification, steepening and lengthening of the waves created by a small disturbance when the Froude number is close to the critical value for instability?
- Second, is there any way of analytically investigating the interaction of a small disturbance with a liquid slug? It is this interaction that appears from the numerical solutions to damp out the disturbances as they propagate through the solution.
- Third, what are the dynamics of the flow in a pipe of finite length, as opposed to a periodic domain?
- Finally, can this analysis be extended to the more realistic situation of flow in a circular pipe and compared with existing experimental data (hydraulic flow of a

gas over a liquid inside a closed rectangular channel)? All these issues are currently under investigation.

Froude number can be described as a dimensionless number comparing inertia and gravitational forces. It may be used to quantify the resistance of an object moving through water, and compare objects of different sizes based on speed/length ratio.

2.5.1 Slug Flow Correlations

Several empirical and mechanistic models have also been developed by past researchers. Most researchers have spent considerable efforts developing correlations from laboratory and field data for prediction of slug length, slug frequency, slug velocity, and slug volume. The majority of these correlations is for steady-state hydrodynamic slugging and was developed for horizontal or near-horizontal pipe. A good number of the available correlations are for hydrodynamic slugging, the most common being Brill (1981), Scott (1987), Gregory (1969), and Norris (1982) correlations. One common limitation of these correlations deals with the handling of slug-length distribution. Various techniques, such as log-normal distribution and inverse Gaussian distributions, have been used to describe slug distribution. However, not even one technique appears to be generally practical for applications.

The Brill (1981) correlation is based on Prudhoe Bay data. This slug length correlation is independent of any pipeline pressure-loss or hold-up calculation and can be used as a stand-alone slug length analysis tool. However, the results are limited to one particular condition and subject to many uncertainties.

The Scott et al., (1989) correlation is a modification to Brill's, still based mainly on Prudhoe Bay data. The results do not differ a great deal in diameter range that is of interesting to the industries.

Fewer correlations are also available for predicting terrain-induced slugging. The most common terrain-induced slugging are the Potts (1987) method and the Fuchs (1989) method used to predict severe slugging in risers.

Schmidt et al., (1985) developed a hydrodynamic model to predict the dynamic slug characteristics of severe slugging. The model assumed constant inlet liquid and gas mass flow rates, constant separator pressure, and liquid slugs free of entrained bubbles. He also considered the empirical correlations for the liquid holdup in the pipeline and the liquid fall back in the riser.

New slug tracking models are being developed and employed in transient simulators such as Bendiksen (1991) and Straume (1992) models. Both are hybrid of Lagrangian-Eulerian scheme where a Lagrangian front tracking scheme is superimposed on a standard Eulerian model. Each slug tail and front is described with Lagrangian coordinates giving the position of the tail and the front as a function of time. This approach is currently used in many commercially available transient multiphase simulators such as OLGA.

In fluid dynamics and finite-deformation plasticity the Lagrangian specification of the flow field is a way of looking at fluid motion where the observer follows an individual fluid parcel as it moves through space and time. Plotting the position of an individual parcel through time gives the pathline of the parcel. This can be visualized as sitting in a boat and drifting down a river.

The Eulerian specification of the flow field is a way of looking at fluid motion that focuses on specific locations in the space through which the fluid flows. This can be visualized by sitting on the bank of a river and watching the water pass the fixed location.

2.5.2 Flow Instability Criterion

Bøe (1981) proposed a criterion based on the forces that are acting on a liquid slug. The Bøe criterion is a simple mathematical expression which gives the necessary conditions for the occurrence of severe slugging. This criterion is given by the following equations:

$$U_{LS} \geq \frac{P_P}{\rho_L g \alpha L} U_{GS} \qquad (1)$$

Where:

U Velocity, m/s

$_{LS}$ Superficial liquid

P_P Pressure of separator at separator conditions, Pa

ρ_L Density of liquid, kg/m^3

g Gravitational constant, m/s^2

α Gas void fraction in the pipeline

L Pipe length, m

U_{GS} Velocity of superficial gas

Or

$$U_{GS} \geq \frac{\rho_{GO}}{\rho_L g \alpha L} U_{GSO} \quad \text{.......... (2)}$$

GS Superficial gas

ρ_{GO} Density of gas at standard conditions

ρ_L Density of liquid, kg/m^3

g gravitational constant, m/s^2

α Gas void fraction in the pipeline

L pipe length, m

U_{GSO} Velocity of gas at standard conditions

This criterion is based on the forces that act on a liquid slug blocking the entrance into the riser, namely, the gas pressure that builds in the pipeline and the hydrostatic head of the liquid in the riser. When this expression is satisfied, the severe slugging is assumed to occur.

The above equation is valid only when no elimination methods are applied. Pots et al., (1985) carried out a detail investigation of severe slugging that included small-scale tests, field tests and hydrodynamic modeling. They proposed a similar criterion to Bøe, to predict the severe slugging region. They claimed that the stratified flow in the pipeline was not necessarily a pre-condition for severe slugging occurrence. Instead, the separation of the phases and the momentum carried out by the liquid were claimed to be the key factors.

Taitel (1986) provided a theoretical explanation for the success of choking to stabilize the flow. Taitel investigated the conditions for stable riser flow. A simple force balance on the gas phase and liquid column was applied, where the system is stable when the expansion force from the gas increases slower than the hydrostatic force of the liquid column in the riser.

The stability criterion is given as below:

$$\frac{P_{sep}}{p_o} > \frac{\Phi([\alpha/\alpha']l_p - h)}{P_O/(\rho_L g)} \quad \text{.......} (3)$$

Where:

P_{sep}	Pressure of separator at separator conditions, Pa
p_o	Pressure of separator at standard conditions
Φ	Liquid hold-up in the riser
α	Gas void fraction in the pipeline
α'	Void fraction of gas bubble entering the riser (approx. 0.5)
l	Pipe length, m
$_p$	Pipe
h	Height of riser, m
g	Gravitational constant, m/s^2

Taitel's stability and Bøe's criteria were proposed by Taitel (1986) to be used together to predict the severe slugging region. Taitel claimed Bøe criterion alone over predicted the severe slugging region based on Scmidt's experimental data (Schmidt, 1976).

2.6 Slugging Experimental Works

Tin (1991) and Tin and Sarshar (1993) presented their experimental and modeling study for "S" shaped risers. From the experimental results, it indicated that the trapped gas in the downward inclined section before the last upward inclined section of the riser had significantly impact on the severe slugging behavior. The acquired data are considered to be reliable for "S" shaped risers and have been used by other researchers such as Kashou (1996) in a simulator verification study.

Corteville (1995) conducted an experiment on severe slugging in a "U" shaped flowline that resembles a transport line between two platforms. The facility consisted of a 3 in inner diameter pipe composed of a 50 ft long downcomer, a 492 ft long horizontal flexible pipe and 50 ft long riser. At very low flow rates, the severe slugging phenomenon is claimed to be very similar to that observed in pipeline-riser systems.

From the modeling and experimental of "S" shaped risers, it can be derived that the extent and variation of severe slugging in the downward section was not analyzed. There was no report of slug lengths greater than the riser height indicating that severity of the slugging is less than that in a pipeline-riser system. Consequently, this observation cannot be generalized for "U" shaped systems since the topography of the line might present downward inclinations right before the riser, hence implying the possibility of the larger terrain slugs that could lead to severe slugging in this configuration.

Montgomery and Yeung (2000) conducted an experimental study on severe slugging using a 2 in inner diameter; 225 ft long "S" shaped pipeline-riser system. From the study, it was concluded that at the largest liquid volumes there were no liquid accumulation in the pipeline; hence the possibility of severe slugging was quite remote.

Experiments conducted by Vierkandt (1988) showed slugging even above the line predicted by Taitels's criterion. This observation led Taitel et al., (1990) to refine the definition of severe slugging to different types namely 'cyclic with fallback', 'cyclic without fallback' and 'unstable oscillations'.

2.7 Slugging Modeling Works

The main objectives of modeling flows of production fluids in wells, pipelines and risers are to predict the:

- Pressure drop
- Phase distributions
- Potential for unsteady phase delivery (commonly referred to as slugging)
- Thermal characteristics of a system

In this discussion, it will focus on past researchers work on the modeling of multiphase flow and reviews the approaches that have been applied to date. As is well known, true predictions of fluid flow are only available for single-phase laminar flows and very low Reynolds number flows in simplified geometries. When the Reynolds number increases to values typical of real applications, true predictions are no longer available and the only practical way forward is through empiricism i.e. the application of observation and experiment, and not theory, in determining something.

To describe Reynolds number Re, in fluid mechanics Re is a dimensionless number that gives a measure of the ratio of inertial forces ($V\varrho$) to viscous forces (μ / L) and consequently quantifies the relative importance of these two types of forces for given flow conditions. Reynolds numbers frequently arise when performing dimensional analysis of fluid dynamics problems, and as such can be used to determine dynamic similitude between different experimental cases. They are also used to characterize different flow regimes, such as laminar or turbulent flow: laminar flow occurs at low Reynolds numbers, where viscous forces are dominant, and is characterized by smooth, constant fluid motion, while turbulent flow occurs at high Reynolds numbers and is dominated by inertial forces, which tend to produce random eddies, vortices and other flow instabilities. Reynolds numbers can be greatly varied depending on the temperature of fluids, viscosity, and also the elevation at which the experiment is conducted.

It's amazing that multiphase flows with deformable interfaces can be in unlimited number of configurations. It presents a difficult problem which only exists in ideal scenarios, for example laminar flow over an isolated spherical particle, bubble or droplet that produces analytical solutions to conservation equations Einstein, (1906), Einstein (1911) and Taylor, (1932). A simple model for multiphase flow is the one-dimensional homogenous flow model which assumes that the phases are thoroughly mixed and travel at identical velocities However, the model's applicability is very limited and its accuracy in predicting real multiphase flows is usually poor Hewitt (1999).

Zuber and Findlay (1965), and Chexxal and Lellouche (1986) presented a similar in formulation to one-dimensional separated flow (drift-flux) model. In this case, the restriction of identical phase velocities is removed, that is necessary to provide an additional empirical relationship to relate the local void fraction against separate phase flow rates.

In one-dimensional two-fluid model, separate conservation equations for mass, momentum and energy are proposed for the gas liquid phases, thus providing a total of six coupled partial differential equations that describe the multiphase flow. However due to its increasing complexity, it requires additional empirical relationships to close the model mainly correlations are required to quantify the interfacial exchange of mass, momentum and energy and the wall shear stresses for the respective phases.

The methods that possibly offer the best chance of predicting multiphase flows accurately are the phenomenological models. These models rely on the identification of flow patterns and the use of separate modified models for each regime. For example in slug flow, the traditional Eulerian solution of a two-fluid model specifies a stationery shape and size over which the partial differential equations are discretized. However, it presents certain difficulties associated with the unphysical dispersion of continuities (i.e. the noses and tails of slugs).

The advance in Computational Fluid Dynamics (CFD) and their extension to multiphase flow offers a long-term solution to multi-dimensional multiphase flows. It has been established how the fundamental equations of fluid mechanics can be averaged and discretized in three-dimensions for multiphase flows and have produced successful engineering problems. However, the ultimate accuracy depends intrinsically on the empirical relationships that are provided to close the model. Furthermore, for the specific problem of multiphase flows in risers which have large Length to Diameter (L/D) ratios, it is difficult to see how the application of CFD could produce practical engineering solutions.

Fabre et al., (1987) proposed a model based on method of characteristics to simulate the transient flow in the riser under the conditions of continuous gas infiltration into the riser. The transient model is a Lagrangian drift-flux model. No friction and mass transfer between phases are allowed and isothermal flow conditions and ideal gas assumptions are made. Sarica and Shoham (1991) adapted the model and modified it for the discontinuities of the two-phase and single-phase interface in the riser.

2.8 Current Commercial Modeling Tools

Based on the various methods applied by past researchers for the solution of multiphase flows in risers, it is appropriate to consider the state-of-art in commercially available simulation software. The current commercial methods for modeling multiphase oil and gas production systems are subdivide into steady-state and the transient codes. Referring to the steady-state codes, the three main software vendors are Pipesim from Baker Jardine, Petroleum Experts with Prosper Gap and SimSci with Pipephase. The steady-state codes are predominantly based on the traditional empirical methods developed over the years.

As shown in Table 2-2, some of the common oil industry flow correlations for vertical flow in wells and risers are as listed Pickering et al., (2001).

Table 2-2: Popular Oil Industry Flow Correlations

Name	Published	Comments
Ansari	-	Developed as part of the Tulsa University Fluid Flow Projects (TUFFP). A comprehensive mechanistic model designed primarily for well flows
Aziz, Govier & Forgasi	1972	A semi-empirical method designed and tested for gas-condensate flows in wells
Dun & Ros	1963	Developed for vertical flow of gas and liquid mixtures in wells and based on extensive experimental work using air and oil simulants
Gray	1974	Developed by SHELL for modeling vertical flows of gas-condensate mixtures in tubes up to 3.5"
Hagedorn & Brown	1965	Developed using data gathered from a 1500 ft experimental well but restricted to tubing diameters of less than 1.5"
OLGA-s	1983	Mechanistic model developed using data collected in the 8 inch SINTEF flow loop which includes a 50m riser
Orkiszewski	1967	Developed for flows in vertical and deviated wells

From Table 2-1, it can be revealed that only OLGA's correlation can claim to have been developed for flows of larger diameter. The other correlations have been developed for flows in wells which usually have internal diameters of less than 5 inches. Moreover, the correlations are largely empirical and based on interpolation of two-dimensional flow regime maps.

While these traditional correlations remain popular for steady-state studies in oil and gas production systems, however they are being progressively displaced by the more advanced mechanistic or phenomenological models that are embodied in the transient multiphase flow codes. For example, the three main commercially available codes are

OLGA of Scandpower, PROFES of AEA Technology (formerly known as PLAC) and TACITE of IFP. Both OLGA and PROFES are based on complex one-drift flux formulation. These codes are generally superior to the traditional steady-state methods and have been extensively validated against experimental measurements. However, in common with all other available techniques a great deal of additional effort is required, particularly in the case of large diameter deepwater risers.

Philbin and Black (1991) and Hall and Butcher (1993) presented the use of PROFES, a general purpose transient multiphase flow simulator. PROFES is a two-fluid model originated from TRAC, a dynamic nuclear reactor core. PROFES numerically solves a system of equations consisting of continuity and momentum conservation equations for each phase and one mixture energy conservation equation.

TACITE a compositional general purpose transient multiphase flow simulator can simulate the severe slugging and the effects of gas lifting and riser base pressure control. TACITE is a drift flux simulator with the capability of component tracking. This might be very important for deepwater developments because of large pressure and temperature differences between the riser base and platform.

Henriot et al., (1999) have showed that TACITE a compositional general purpose transient multiphase flow simulator can simulate the severe slugging and the effects of different elimination techniques including gas lifting and riser base pressure control. TACITE is a drift flux simulator with the capability of component tracking. Based on TACITE runs, the authors claimed that the fluid properties or the characterization of the fluids might have an impact on the severity and cycle times of the severe slugging. This might be very important for deepwater developments because of large pressure and temperature differences between the riser base and platform.

OLGA, however, is different from others. OLGA is the only multiphase flow simulation tool with its implicit two-fluid solution model and new slug tracking model. OLGA is a mechanistic model developed using data collected in the 8 inch SINTEF flow loop which includes a 50 m riser.

Bendiksen et al., (1991) presented OLGA as one of the most widely used general purpose transient multiphase simulators. OLGA is two-fluid model that numerically solves a system of equations consisting of separate continuity equations for gas, liquid bulk and liquid droplets, two momentum equations for the liquid film, and gas and liquid droplets, and one energy conservation equation.

Kashou (1996) verified that OLGA could simulate severe slugging in "S" shaped or catenary risers by comparing simulation results with the data taken at BHRG facilities (one of the producing installation in North Sea).

Xu (1997) presented the capabilities of OLGA in predicting different multiphase flows including severe slugging.

Song and Kouba (2000) have used OLGA to simulate the severe slugging for water depths up to 5,000 m for both conventional and "S" shaped risers. They have concluded that severe slugging is extremely likely to occur especially at the later stage of the field life when flow rates become too low. It is pointed out that increasing water cuts for a constant GOR can enhance the severe slugging due to its higher density. They have also emphasized that gas and liquid velocities will be higher than erosion velocities.

Mehrdad et al., (2004) has revealed that OLGA has made significant progress to address slugging in multiphase flows. Capitalizing the advancement in system control and automation, a dynamic OLGA 2000 multiphase simulation tools model of Tiller loop has been developed and verified against test data. The model has captured the physical mechanisms of the slugs generated in the Tiller loop, where important phenomena such as inverse response of the top pressure and asymmetric step response of the bottom pressure have been reported. Hence, it appears that a cascade-control strategy with feedback from the bottom pressure and flow rate at the top of the riser is best capable of suppressing the slugs.

2.9 Slugging Elimination Techniques

Yocum (1973) was the first to report symptoms of severe slugging phenomena. He has identified several severe slugging elimination techniques that the industry still considers until today. These are the reduction of the line diameter, the splitting of the flow into dual or multiple streams, the gas injection into the riser, the use of mixing devices at the riser base, choking and back pressure. He observed that the flow capacity of an installation could be reduced to 50% due to back pressure fluctuations caused by severe slugging. He also claimed that choking would also cause severe reductions in the flow capacity.

However, contrary to Yocum's claim, Schmidt (1977) and Schmidt et al., (1985) noted that the severe slugging in a pipeline-riser system could be mitigated by choking at the riser top, causing little or no changes in flow rates and pipeline pressure. Schmidt also observed that elimination of severe slugging could be achieved by gas injection. Nevertheless it is not economically viable due to the cost of compressor to pressurize the gas for injection and other associated piping to the base of the riser.

Pots et al., (1985) investigated the use of gas injection as an elimination method of severe slugging. It came to a conclusion that the severity of the cycle was considerably lower for riser injection of about 50% inlet gas flow. Even with 300% injection, the severe slugging cannot be completely removed or disappear.

Farghaly (1987) presented field examples showing that choking can eliminate severe slugging. Severe slugging occurred at low liquid and gas rates in undulating near horizontal pipelines of various diameters, length and riser heights. Severe slugging caused several problems and instability to the field. In some cases, as pointed out by Yocum, the average production rate was reduced to less than 50% of its desired capacity.

Jansen (1990) investigated different elimination techniques such as back-pressure increase, choking, gas lifting, choking and gas lifting combination. For the elimination techniques, he proposed the stability and the quasi-equilibrium models. By experiment, he has made the following observations:

- Very high back-pressures were required to eliminate the severe slugging
- Careful choking was needed to stabilize the flow with minimal back-pressure increase
- Large amounts of injected gas were needed to stabilize the flow with gas-lifting method

- Choking and gas-lifting combination were the best elimination method reducing the degree of choking and the amount of injected gas needed to stabilize the flow.

Jansen and Shoham (1994) have proposed a more optimum method for the elimination or minimization riser flow instabilities. An experimental study has been conducted to predict the behavior of different methods of elimination of riser instabilities. It was found that a combination of gas lift and choking is an efficient elimination method, reducing both the required degree of choking and the amount of injected gas required to stabilize the flow in the riser. The proposed method is less sensitive to choke setting and injected gas volume, as compared to elimination by either choking or gas lift alone. Additional advantage is the capability of a smooth and controlled start-up of the system. The stability criteria for choking and gas lifting were developed by modifying the original Taitel et al. model (Taitel, 1990).

Hill (1989) and Hill (1990) described the riser-base gas injection tests to eliminate severe slugging, and the gas injection was shown to reduce the extent of the severe slugging. The condition for eliminating severe slugging was to bring the flow pattern in the riser to annular flow thus preventing liquid accumulation at the riser base. Therefore, large amounts of injection gas were needed to completely stabilize the flow.

Kaasa (1990) proposed a second riser connecting the pipeline to the platform to eliminate severe slugging. There is a tendency for downward sloping pipeline acts like a slug catcher since the prevailing flow pattern is mostly stratified flow at low flow rates. The second riser is placed at such a point on the pipeline that all of the gas is diverted to it. The original riser then transports all the liquid. However, this method has two disadvantages:

- First, the original riser will be almost full of liquid imposing a considerable back pressure to the system. As a result it will significantly reduce the production capacity.
- Second, a second riser may not be economically viable.

McGuinness and Cooke (1993) presented a field case where severe slugging problem was observed when a new satellite field was brought on stream due to increased pipeline volume available for the gas to expand and compress. The severe slugging resulted in higher back-pressure and reduced the production capacity of the system. The solution to the problem was the separation of the fluids at a satellite platform and transporting the liquid and gas in separate flowlines to the main platform. A minimum back-pressure was accomplished by utilization of a surge vessel at atmospheric pressure for liquid stream rather than a low-pressure separator.

Barbuto (1995) proposed a different approach to eliminate severe slugging. The pipeline and riser were connected to each other to transmit the pipeline gas to riser at a predetermined position. This position is said to be at ⅓ of the total riser height from the riser base. Different control schemes on the bypass lines are discussed. The main theme is to keep the pipeline pressure under control. However, for this method of elimination, Barbuto did not substantiate any explanation nor justification i.e. no field trials, experimental data and theoretical proof.

Hollenberg et al., (1995) proposed a topside flow control system to eliminate severe slugging. The principle of the system is to keep the mixture flow rate constant throughout the operation with a control valve. Nevertheless, they realized that it was not possible to implement the control valve because of difficulties in measuring the two-phase mixture velocity, which is the parameter of interest for the control. The problem was resolved by replacing the control valve with a small control separator allowing separation of phases and measurements of flow rates. The laboratory tests were conducted using an experimental facility a 2-in. internal diameter (ID), 328 ft long pipeline and 54 ft high riser. Even though the control system was shown to work for all the cases investigated, the riser back-pressures were tripled representing a tremendous back-pressure applied to the upstream.

Wyllie and Brackenridge (1994) proposed a retrofit solution to reduce severe slugging effects. The solution requires a small diameter pipe insert into the riser, thereby creating an annulus that can be used for gas injection. This might be considered a good retrofit solution when there is no provision for severe slugging on the existing riser. Theoretically, in contrast, it is a restriction to the flow that might pose problems for operations such as pigging.

Song and Kouba (2000) have proposed a subsea separation of gas and liquid as a method of severe slugging elimination. After separation, gas and liquid are transported to a separator at the platform. A liquid pump is used to overcome the hydrostatic head, thus preventing the capacity reduction due to back-pressure.

Almeida and Goncalves (1999) proposed the use of a venturi valve at the riser base inlet to eliminate severe slugging. The venture device accelerates the fluids in the flowline near riser base. The absence of stratified flow in this region prevents the liquid accumulation at the riser base and consequently lessens the presence of severe slugging. The method has been verified using a small test facility, where the proposed method was compared to choking for severe slugging elimination.

A new technique has been proposed by Sarica and Tengesdal (2000), a novel technique to lessen or eliminate severe slugging in the pipeline-riser systems applicable to all water depths. The idea is to transfer the pipeline gas (in-situ gas) to the riser at a point above the riser-base. The transfer process will reduce both the hydrostatic head in the riser and the pressure in the pipeline consequently lessening or eliminating the severe slugging. This technique can be considered as self-gas lifting i.e. no gas injection required. An existing severe slugging model based on one-dimensional drift flux formulation, has been modified to simulate the new severe slugging elimination method.

Hassanein and Fairhurst (1998) presented the challenges in mechanical and hydraulic aspects of the riser design for deepwater developments. They pointed out that flow rate variations would be larger due to bigger hydrodynamic slugs expected owing to larger flowline diameters. Moreover the longer flowlines combined with the risers may increase the possibility of severe slugging. The larger system volume can lead to more severe surges during transient operations, and expected to create very large flow rate variations. A solution to this was Riser Base Gas Lift (RBGL) along with foaming as viable techniques for elimination.

Johan et al., (1997) pointed out that RBGL may cause additional problems due to Joule-Thompson cooling of the injected gas. Gas acts like a heat sink and lowers the temperature of the fluids making flow conditions more susceptible for the wax and hydrate problems. Therefore, operators would need to heat the gas before injecting or use chemicals to prevent the formation of paraffin and hydrates.

Alternatively, the authors proposed a technique called Multiphase Riser-Base Lift (MRBL) for deepwater developments. MRBL is based on the idea of diverting the nearby multiphase flow stream to the pipeline-riser system experiencing severe slugging. This will help alleviate the severe slugging problem without exposing the system to other potential problems.

In summary, the following is a brief discussion of the applicability of the existing elimination techniques for deepwater systems:

Back pressure Increase

This is not a viable option even in shallow water due to reduce in production when back-pressures are imposed. The reduction in production capacity is expected to worsen for deepwater production systems.

Choking

Even though this technique is proven to reduce or eliminate severe slugging, however choking is to be implemented at smallest amount back-pressure in order to evade production curtailment. It has been reported in the literature that only one field application is proven to be successful (Fargalhy, 1987). For deepwater systems, the back-pressure could be more important due to potential production loses.

Flow Rate Control

The principle of this method is to keep the mixture flow rate constant throughout the operation with control valve (Hollenberg et al., 1995). Experimental studies showed that back-pressure was tripled when the stable flow was achieved. For deepwater, this system will essentially have the problems of significant reduction in production capacity due to increased riser base pressure and the longer travel times of information to the top side causing delays in the response of the control system.

Gas-Lift and Choking Combination

This is a suggested viable method by Jansen et al. (1990) but no field application was reported for current pipeline-riser systems. It might lessen some of the cooling and excessive frictional loss problems by requiring less gas injection. It requires injection gas and the necessary gas lift installation.

Riser Base Gas Lift (RBGL)

RBGL is one of the most used methods for the current applications. In deepwater, increased frictional pressure loss and Joule-Thompson cooling are potential problems resulting from high injection gas flow rates. The other shortcomings are the necessity of injection gas and gas injection system. The use of RBGL has been proven to work in subsea developments not only for flow stabilization but for production enhancement and flowline depressurization as well at water depths ranging from 1000 – 2000 m. Case studies have been implement at working sites of different parameters mostly uphill and downhill flowlines, Jayawardena et al., (2007).

Multiphase Riser Base Lift (MRBL)

MRBL requires nearby high capacity multiphase lines that some part of their production could be diverted to a pipeline-riser system to either eliminate severe slugging or during start-up after prolong shutdown. It is anticipated as a better alternative to RBGL since the lift fluids will not cause cooling, and no injection gas and related equipment required. MRBL requires the availability and usability of other multiphase lines, therefore it is a system specific solution and possible for limited cases.

Riser Base Pressure Control with a Surface Control Valve

This technique was successfully applied in a Dunbar 16" pipeline-riser system, Courbot, (1996). In principle, this technique is very similar to choking. The field data indicated significant overall system pressure increase. It may pose potential production reduction problem for deepwater productions.

Small Diameter Pipe Insertion

It is a retrofit gas lift method and may not be suitable since it is an intrusive solution which may have an effect on pigging activity. Additionally, it poses concerns on gas lifting requirements.

Subsea Separation

This is a viable solution that does not impose back-pressure on the system. However it requires two separate flowlines and a liquid pump to pump the liquids to the surface.

Foaming

This method requires foaming agents and a way to form the foam as mentioned by Hassanein and Fairhurst (1998). However, there are no further details on this method.

Venturi Device

This method requires careful selection of proper throat diameter of the venture device to ensure that the flow is moved outside the severe slugging envelope. Additional pressure losses through the device and its intrusive nature may render it unsuitable for certain production systems, Almeida and Goncalves, (1999).

Although there have been numerous severe-slugging elimination techniques as reported by Sarica and Tengesdal (2000), nevertheless different techniques can be suitable to some but not to others, depending on types of problems and production systems.

3.0 The Accuracy of the Established Methods

Having discussed the slugging phenomena and the current state of the commercially available modeling tools and the techniques to eliminate slugging, what remains is the possible accuracy of the established methods. It is perhaps little known in the industry that nearly all information on multiphase flow in vertical pipes is for diameter less than 2 inches (50 mm). In single-phase flows, there is a rational basis for extrapolating from small diameter pipes to larger diameter pipes on the basis of Reynolds number and pipe roughness. However, for multiphase flows, extrapolation from small to large diameters is not at all secure.

The tendency in more recent work has been to use phenomenological models. Here, the flow pattern or flow regime is identified by one means or another and models developed which deal with specific flow pattern (bubble flow, slug flow, annular flow etc). Alternatively, phenomenological interpretations of flow regime can be hypothesized, an example of this approach being that of Taitel et al., (1980). The difficulty with this approach is that the suggested transition mechanisms may not be correct, or if they are correct for smaller diameter tubes, they cannot be applied to larger diameter tubes.

3.1 Conclusion

From the assessment of multiphase flow in deepwater flowlines-riser systems, a number of important conclusions are evident. As flow instability is tantamount to slugging, the understanding on the basic principles of flow in a pipe is a starting point for a scientific treatment of gas-liquid flows. This effort is of paramount importance when we are operating in a deepwater environment.

From the established design methods, it is clear that these have developed into complex tools able to qualitatively predict rich and varied physical phenomena such as severe slugging. However, while it is accepted that to a great extent these methods do predict the data, their general accuracy is doubtful especially given the large variations in hydrocarbon fluids and development scenarios.

For multiphase flows in risers, it is known that the vast majority of experimental data have been collected in vertical air-water systems with pipes less than 2 inches in diameter. Current design practices for larger diameters (such as those proposed for deepwater flowlines-risers) rely on the extrapolation of the methods developed from the data gathered in the small diameter tests. The reliability of this extrapolation is extremely doubtful and it is highly likely that the characteristics of multiphase flows are markedly different in larger diameters

Based on the assessment of the current commercial modeling tools, it is clear that only OLGA's correlation can claim to have been developed for flows of larger diameter. OLGA is the most widely used general purpose transient multiphase simulators and the only multiphase flow simulation tool with its implicit two-fluid solution model and new slug tracking model, that numerically solves a system of equations consisting of separate continuity equations for gas, liquid bulk and liquid droplets, two momentum equations for the liquid film, and gas and liquid droplets, and one energy conservation equation.

In a multi-dimensional multiphase flows, it should be stressed that there is no generally accepted mechanistic basis for predicting flow regimes. Thus it is correct to say that a great deal aeffort is required before a generally accepted 'grand-unified theory' is available. The application of such theory particularly in deepwater environment seems to visage more challenges. The deeper the water, the conditions that impede flow are so diverse and pervasive, hence there is no "one size-fits-all" solution

Even though there are numerous elimination techniques, as outlined in the assessment, however different techniques can be suitable to some but not to others, depending on types of problems and production systems.

Motivated by the above conclusions, this study on flow instability in deepwater flowlines and risers is an effort to address and enhance those specific issues that are of interests and could add value to the industry specifically in mitigating severe slugging of multiphase flows in any deepwater development.

CHAPTER 3

METHODOLOGY

CHAPTER 3

METHODOLOGY

3.1 Introduction

This chapter begins by introducing the transient multiphase flow simulator, OLGA used in this study. It elaborates OLGA's development information and provides the basis and understanding in developing the simulation model of this study. OLGA has a slug tracking option which is able to initiate and track individual slugs. Using the model, sensitivity simulations were performed to investigate several different operating conditions in which flow instabilities mitigation strategies could be developed. From the simulation results, one can obtain the slugging statistics such as slug length distribution. The simulation model will then be validated to match the field data with the aim to closely imitate the conditions of the field.

3.1.1 The Dynamic Two-Fluid Model OLGA: Theory and Application

The development of the one dimensional dynamic two-phase flow model OLGA started in 1980 at Insitutt for Energiteknikk (IFE) as a project for Norwegian state oil company, Statoil. The purpose of the development was meant to simulate slow transients in two-phase hydrocarbon transport pipelines, such as terrain induced slugging, as well as shut-in and start-up of pipelines Rygg and Ellul, (1991).

In 1983, a group of oil companies' further developed the flow model in a joint IFE/SINTEF project called "The SINTEF/IFE Two-Phase Flow Project". In this project the emphasis has been placed on experimental validation of the model. In addition several new applications, such as gathering pipeline network, compressors, heat exchangers, and plugging of pipelines have been included. These extensions are important for understanding the effects of slugging on the downstream facilities and to investigate the mitigation measures. The model has been applied to a variety of different situations including on-line offshore pipeline simulators (Ek et al., 1990), well kill planning (Rygg and Gilhuus, 1990) and pipeline shut-in and start-up (Ellul et al., 1990).

Apart from what has been discussed in the previous section on OLGA's suitability as the main tool for this study, the extended two-fluid OLGA model has specified three mass conservation equations; one for the gas phase, one for the liquid film at the wall, and one for the liquid droplets. As the droplet field moves with approximately the same velocity as the gas, one combined momentum of equation is used for the gas phase and the liquid droplet field, in addition to the momentum equation for the liquid film at the wall. Therefore, the selection of OLGA is certainly right because OLGA is the only multiphase flow simulation tool with its implicit two-fluid solution model and slug tracking model.

A pressure equation is introduced by combining the three mass conservation equations and expanding with respect to pressure, temperature and composition. Solving the pressure equation and the momentum equations simultaneously make it possible to use a step wise time integration procedure. The energy in the pipeline system is modelled by a mixture energy equation assuming the gas and liquid temperature are equal at a certain point in time and space. The heat transfer through the pipe walls is computed based on the flow conditions and the heat transfer to the surroundings (Rygg and Ellul, 1991).

All fluid properties have to be tabulated as tables in temperature and pressure calculated by a suitable PVT-package. The two-phase flow model needs information about densities, compressibilities, viscosities, surface tension, heat capacities, enthalpies and thermal conductivities for both gas and liquid phases. The interfacial mass transfer is calculated from the equilibrium gas mass fraction given from the PVT calculations.

The key to the modelling of two-phase flow is the determination of flow regimes and transition between the flow regimes. The flow regime description in OLGA includes distributed and separated flow. The former is split into bubble and slug flow, the latter stratified and annular mist flow. The flow regimes are treated as an integral part of the two-fluid system and transitions between the flow regimes are determined according to a minimum slip concept (Rygg and Ellul, 1991).

The conservation equations are discretized using a finite difference formulation with a staggered mesh where temperatures, pressures, densities, etc are defined at cell mid-points and velocities and fluxes are defined at cell boundaries. An upwind or donor cell technique is applied for the mass and energy equations. The implicit scheme applied allows for large time steps only limited by mass transport criteria (Rygg and Ellul, 1991).

To conclude, details of the OLGA three mass conservation equations; one for the gas phase, liquid film at the wall and liquid droplets are as illustrated in Appendix A Ryagg and Ellul, 1991.

3.1.2 Screening of Slugging Mechanisms

During normal production, slugging can be caused by several mechanisms and removal of liquid due to interruption of lift gas injection rate. The severity of slugging depends on generally three types of slugging:

1. Operationally-induced slugging – generated by changing the flow conditions from one steady state to another, such as restart from shutdown, flowrates ramp-up or when line pigging is in operations
2. Hydrodynamic slugging - a feature of the slug flow regime where slugs are continuously formed due to instability of waves at certain gas-liquid flow rates
3. Terrain induced slugs – also called as severe slugs caused by accumulation and periodic purging of liquid in flowline dips at low flow rates

Moreover, if the oil production system is dependent on the gas-lifting mode, the disturbance of the lift gas injection rate i.e. inadequate gas lift rate or without gas lift at all, will also contribute to the flowlines and risers surging as well.

In this study, the slug tracking option in OLGA was used to model the slugging. Several simulation runs were made to identify the cause of the slugging. Slugging can be generated by three mechanisms:

1. Level slug - this applies after shutdown of a pipeline. During the shutdown period, the liquid moves to the dips along the pipeline, forming liquid pockets. Upon restart operation, the liquid pockets are treated as slugs and the movements of each individual pocket can be tracked.
2. Hydrodynamic Slug – this applies to slugs that are generated when the slug flow regime is predicted.
3. Terrain Slug – slugs may also be formed due to blockage at locations where the pipe inclination changes from downward to upward direction. OLGA assumes some liquid at the dips and check if the liquid will form a blockage. A slug is generated if a blockage is formed.

Slugs are tracked in the same manner regardless of the initiating mechanism. The positions of slug front and tail for each individual slug, as well as the liquid holdup in the slug and the liquid holdup between the slugs are tracked during the simulation. When the front position of a slug front moves into the tail of the slug ahead of it, the two slugs are merged. When the tail moves faster than the front, the slug length decreases and the slug may eventually disappear.

In summary, the screening simulation showed that hydrodynamic and terrain slugging is the slug generation mechanism at the current production condition. Therefore, slug tracking is then required to consider the interactions between slugs and the effects of hydrodynamic and terrain slugging.

3.2 Methodology

The transient multiphase flow simulator OLGA was used as the simulation tool for this study. OLGA has a slug tracking option which is able to initiate and track individual slugs. A work by Burke and Kashou (1995) demonstrates the capability of OLGA slug tracking model in tracking hydrodynamic slugs and predicting slug lengths and slug volumes in the form of liquid holdup in slug and void fractions ahead of the front and behind the tail.

Figure 3-23, illustrates how the study was structured according to its work flow and functionality. The typical work flow in the model building begins with the understanding of the fluid and reservoir properties from basis of design. The basis of design identifies the 'design intent' of the facilities and details the necessary requirements in meeting the design intent.

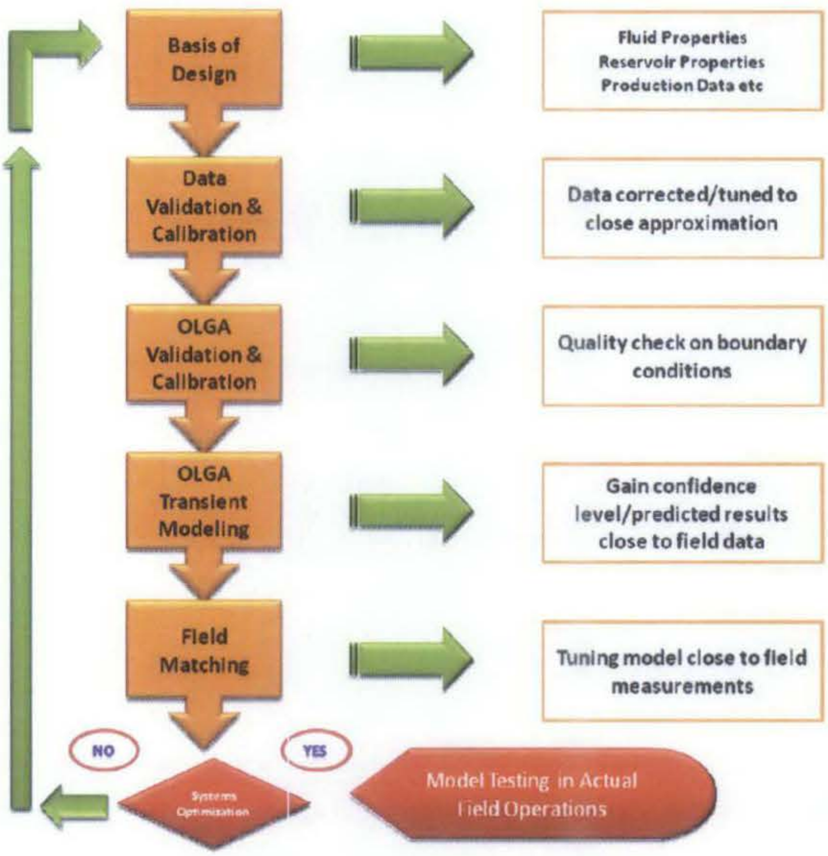


Figure 3-23: Work Flow and Functionality

During the initial phase of the work both modeling and data acquisition activities were carried out in parallel. The data validation and calibration phase describes the process whereby the field data is corrected and tuned to closely imitate the conditions in the field. At the same time, the OLGA system validation and calibration will perform quality checks on the boundary conditions entailing flowlines and risers, well profile and dimensions, gas injection points, thermal conditions and chokes for wellhead and risers.

In the field matching phase, the tuning of the model was performed so as to match the pressures and flowrates. The tuning method was used whereby the flowlines and risers diameters were adjusted to match the pressure drops. The aim of tuning is to ensure that the model predictions are generally in good agreement with the field measurements.

Simulations were then performed to examine the impact of various changes in operating conditions on the flow instability and system productivity. These included changes in well routings, gas lift injection rates and location of injection points, riser and wellhead choke openings. The degree of fluctuations in liquid arrival rates and the characteristics of liquid slugs (length and frequency) were used to categorize the severity of flow instabilities for the different operating conditions. The results observed from the simulations will then determined the proposed solutions to mitigate the flow instabilities in the flowlines and risers system.

3.2.1 Field Overview

The Chinguetti oil field from Mauritania operations which is operating in a deepwater has been used as a case study to illustrate the model development approach or methodology. The model has been built according to Chinguetti field schematic and subsea layout as illustrated in Figure 3-24 and Figure 3-25. The field process overview is as illustrated in Figure 3-26.

Chinguetti is a deepwater oilfield development located 80 km west of the coastline offshore Mauritania approximately 90 km from the capital, Nouakchott. The field with a water depth of 800 m was discovered in 2001 and the first oil production was in February 2006, see Figure 3-24. The reservoir is roughly circular in plan view with a diameter of 5 km and the structure is a faulted domal anticline developed over an underlying salt diaper. The faulting of the field has produced compartmentalization and perched fluid contacts across the structure. The oil from the well stream has gravities in the range 25-30° API. The excess gas is being injected at Banda gas field which is approximately 17 km away from Chinguetti.

The field is developed using subsea wells, manifolds, flexible flowlines, umbilicals and risers tied back to a permanently moored Floating Production Storage Offloading (FPSO) with a maximum storage capacity of 1.67 million barrels of oil in approximately 695 meter depth.

Production from the field is tied back to the FPSO through a 10-inch piggable flowline and riser loop and a 6-inch gas lift flowline. The 9 production wells are distributed at the

3 production manifolds and each well can be routed either to the left or right line of the loop. The looped production flowline allows the system to be dead-oil-displaced after a shutdown, which will remove water and prevent hydrate blockages The field is equipped with gas lift valve system and 5 water injection wells arranged in a daisy-chain configuration to improve oil production and ultimate recovery from the reservoir.

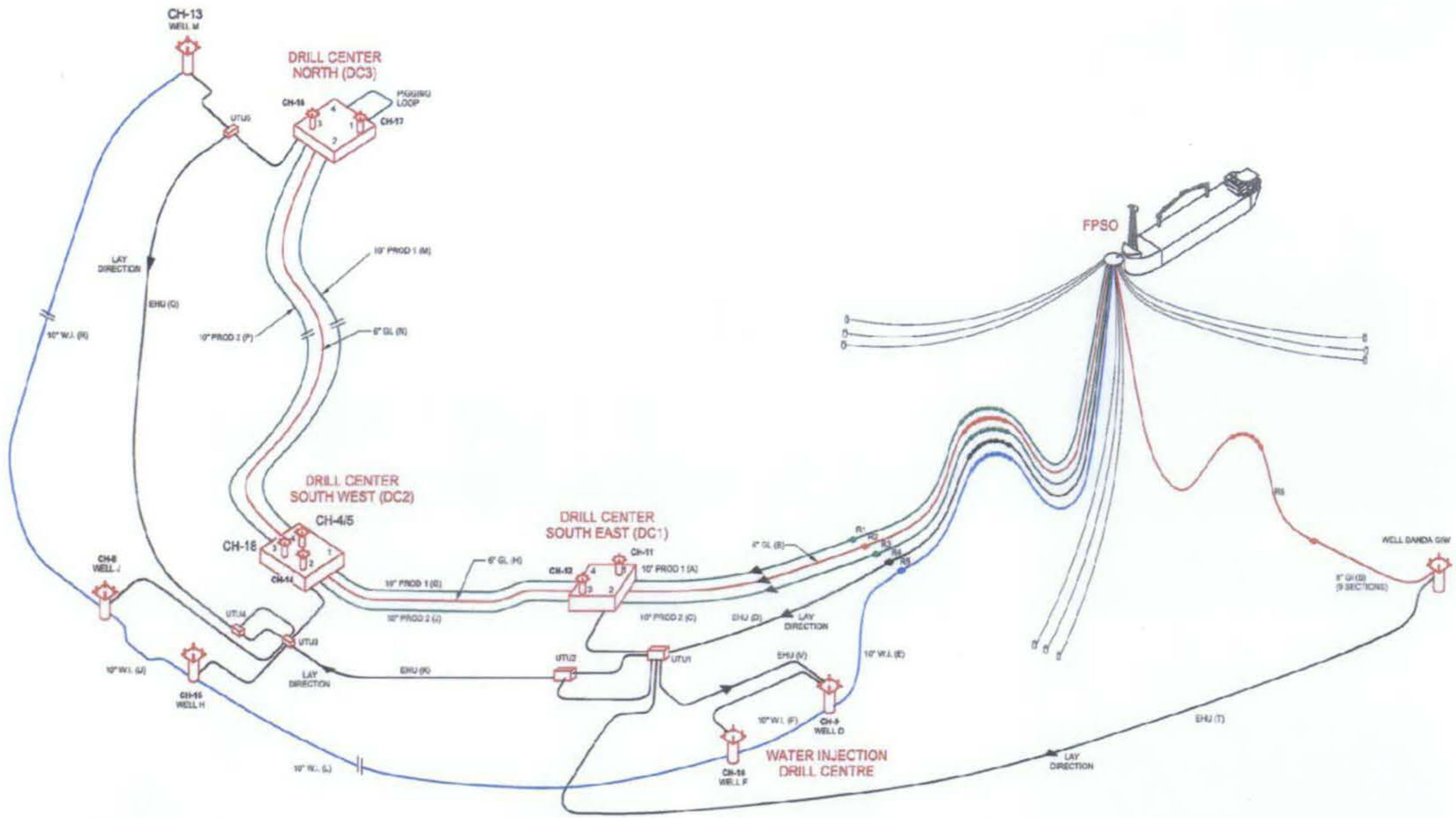


Figure 3-24: Chinguetti Field Overview

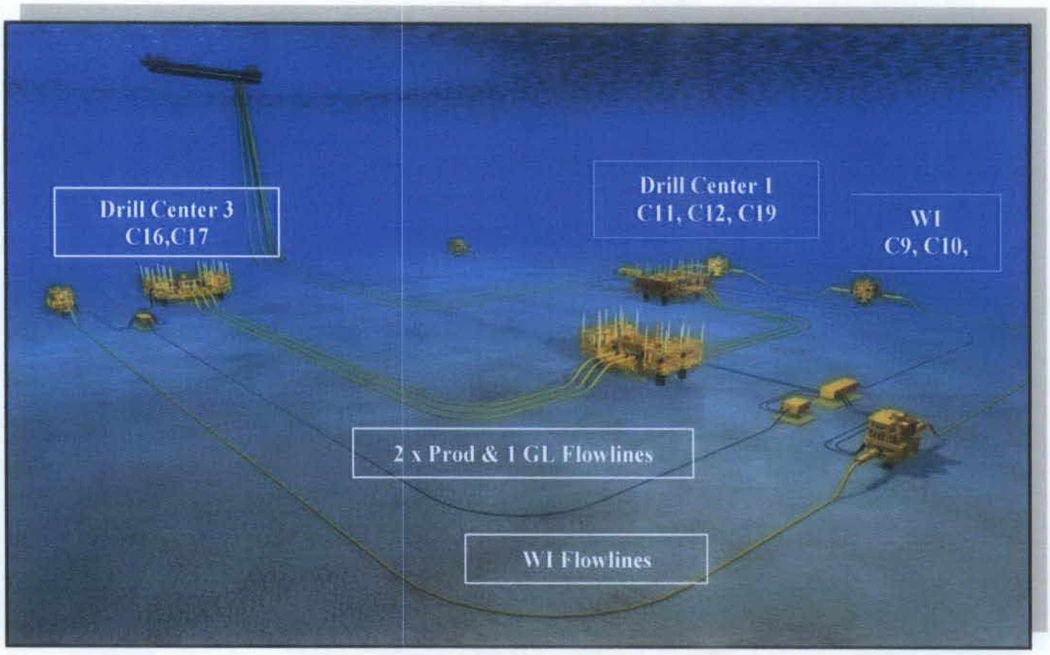


Figure 3-25: Subsea Assembly and Well Location at Drill Centers

Legend:
WI – Water Injection
C – Denotes Chinguetti Well Numbering
GL – Gas Lift

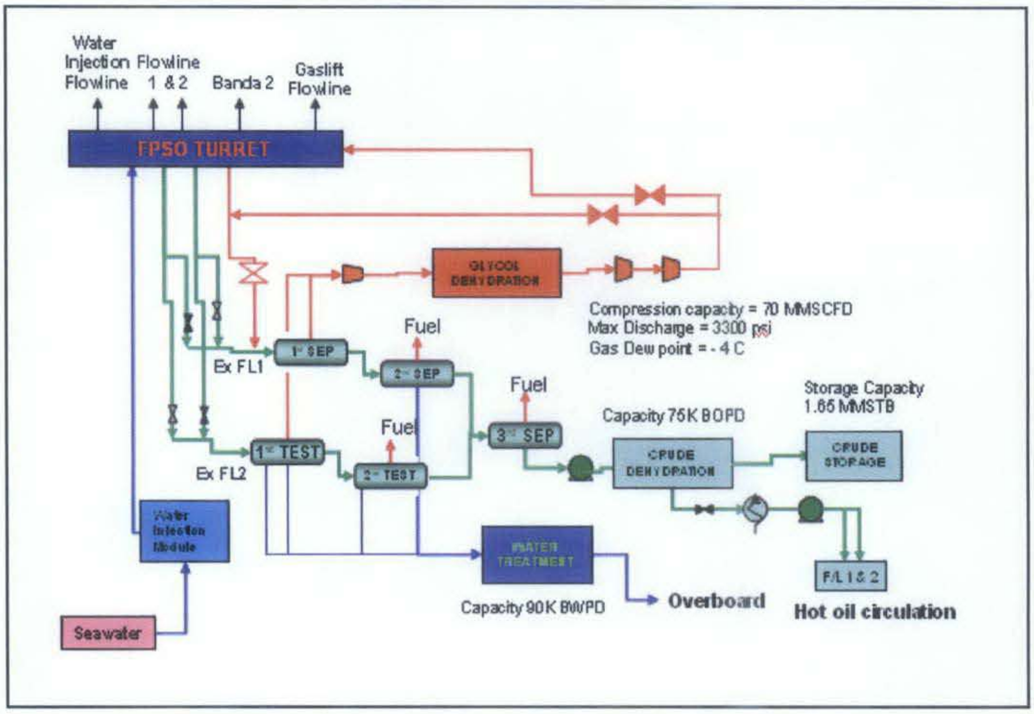


Figure 3-26: FPSO Process Overview

3.2.2 Process Overview

The incoming well streams from the Chinguetti field arrive on the bow turret and led via two topsides choke valves into the process topside modules for fluid separation. The production separation system consists of a three-stage separation system with an electrostatic dehydrator and an electric desalter. The oil separation train consists of 1st stage separator, 1st stage test separator, 1st stage inlet heaters, inlet heater, 2nd stage separator, test inlet header, 2nd stage test separator, interstage heater, 3rd stage separator/degasser, electrostatic dehydrator, electrostatic desalter, coalescer water recycle pump, electrostatic coalescer produced water pumps, crude oil transfer pumps and crude coolers.

The gas compression system is designed to compress 70 mmscfd of gas to 3,300 psia. The gas compression is based on three by thirty three percent capacity (3 by 33% compression capacity meaning to say each compressor has a capacity of 33%, 3 stage reciprocating compressors each rated for 23.5 mmscfd, and a common dehydration system. The compressed gas is then used for gas lifting purposes, enhancing oil flow to surface facilities. For reservoir pressure maintenance and to enhance oil recovery, water injection system is deployed in the field. The water injection capacity is at 100,000 bwpd and will be utilizing used cooling water from the turbo generator condensers. The water injection consists of two by one hundred percent (2 by 100%) water injection booster pumps, water injection coarse filter, deaerator, two by one hundred percent (2 by 100%) water injection pumps, and water injection chemical injection package, stripping gas scrubber and water injection sampling point.

The produced formation water, prior bring discharged to sea, it undergo the produced water system that consists of 1st stage hydrocyclone, produced water degasser, 2nd stage hydrocyclone, 3rd stage separator/degasser, produced water transfer pumps and produced water coolers.

3.2.3 Basis of Design

The important input parameters that are used as the basis of assumptions in this study are as follow:

3.2.3.1 Flowlines and risers

The profile of the flexible flowlines and the lazy 'S' shape riser were obtained from the basis of design. The profile of Flowline 1 (FL1) and Flowline 2 (FL2) were almost identical, hence a single geometry has been considered. The thermal properties of the flowlines with regards to wall specifications, water temperature profiles etc were also obtained from the basis of design. The thermal properties of the flexible flowline and riser wall layers were used to determine the heat transfer between the production fluids and the surroundings. The values were obtained from the design phase specifications data. The model started downstream of the wellhead manifold at DC 3 and terminated upstream of the separator at the FPSO. The bathymetry of the flowlines and risers is shown in Figure 3-27.

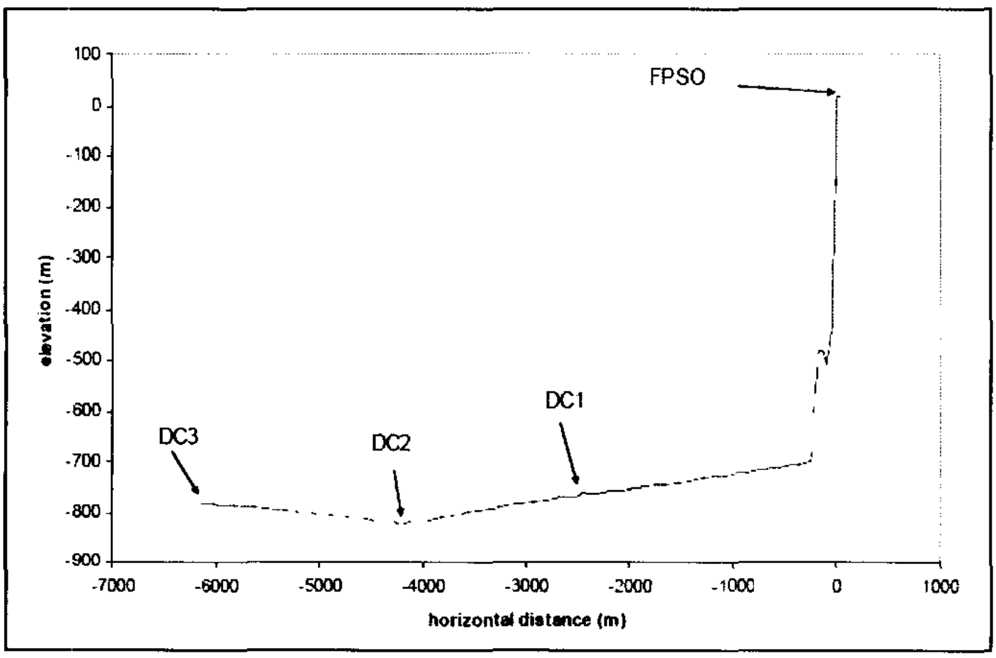


Figure 3-27: Pipeline Bathymetry of Flowline and Riser

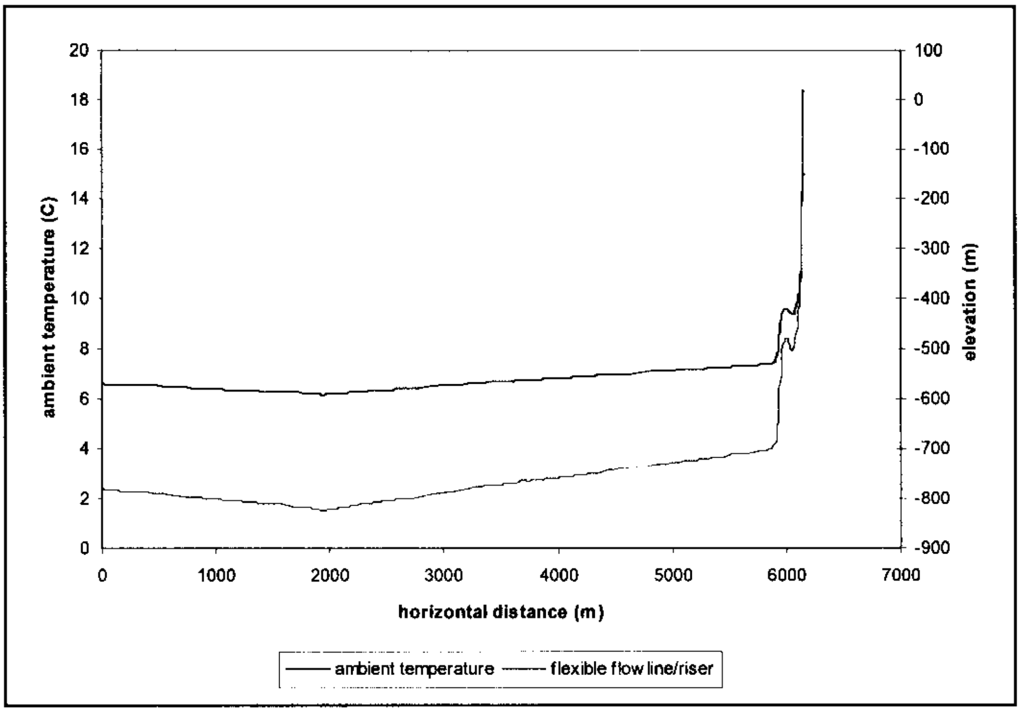


Figure 3-28: Ambient Temperature of Flowline and Riser

3.2.3.2 Boundary conditions

Ambient temperatures - the ambient temperatures used in the study are plotted in Figure 3-28 with a minimum seabed temperature of 6.6°C and an air temperature at the FPSO of 15°C. The water current velocity and the wind velocity were assumed to be 0.3 m/s and 5m/s, respectively.

Outlet boundary – due to insufficient data, the production and test separators have not been included in the FL1 and FL2 models. Hence, the operating pressures of the separators have been applied as the outlet pressure. In this study, a constant outlet pressure of 11 bars has been used for both flowlines.

3.2.3.3 Production rates

Two sets of production data were used in this study i.e. March 2006 production data and April 09 production data reason being March 2006 was the highest production rates and April 09 being the lowest production rates. Thus these rates will provide the range in order to check the model

Considering March 2006 was the highest production rate by virtue the field has just started to produce oil in February 2006 i.e. the first oil production from the field. Hence the data acquired in March was considered an appropriate data. The initial field production was at 75,000 bop/d.

Considering April 2009 was the lowest production rate by virtue the reservoir production has declined rapidly. At the time of this study, the field oil production was at 17,000 bop/d.

3.2.3.4 Fluids

The Pressure Volume Temperature (PVT) for the various well fluids was based on the design phase data. The composition for each well has been tuned to the respective Gas to Oil Ratio (GOR) and water cuts. However, a single equivalent fluid composition based on mass weighting of the fluids from the different wells was used in the flowline. However, this assumption is expected to not significantly impact the properties that are derived from the mixture fluids.

3.2.3.5 Thermal conditions

An overall heat transfer coefficient (U-value) of 7 $W/m^2/K$ was used for modeling of the heat transfer in the wells. The formation temperature followed a constant and a linear geothermal gradient from the reservoir temperature to 8°C at seabed.

3.2.3.6 Gas lift injection

The gas lift points of injection are being determined by the data taken from the Wellflo model. The gas lift gas injection temperature was set to 10°C. However at the point of injection, the lift gas injection temperature was expected to equilibrate to the geothermal temperature or the flowing temperature of the well.

3.2.3.7 Inflow Performance Relationship (IPR) basis

The well Inflow Performance Relationship (IPR) data used in this study is determined by the Wellflo model. However, some modifications have been made on the data that relate to:

- Well Productivity Index (PI)
- Water cut reduction from the reference values
- Formation Gas Oil Ratio (FGOR)

Inflow Performance Relationship (IPR) is defined as the functional relationship between the production rate and the bottom hole flowing pressure. IPR describes the behavior of the well's flowing pressure and production rate, which is an important tool in understanding the reservoir/well behavior and quantifying the production rate. The IPR is often required for designing well completion, optimizing well production, nodal analysis calculations, and designing artificial lift.

Productivity Index (PI) is the relationship between total production of liquid from the reservoir (oil and water) against the drawdown pressure i.e. the shut-in pressure less the flowing bottom hole pressure

Formation Gas Oil Ratio (FGOR) is the proportional amount of gas to oil liquid occurring in production from formation i.e. reservoir usually expressed as cubic feet per barrel
Water Cut refers to amount of water that has migrated to the oil column in the reservoir usually expressed in percentage of water

3.2.3.8 Wellhead and Riser Chokes

Wellhead chokes were modeled as a simple valve with a default discharge coefficient of 0.8. Riser chokes were present upstream of the production separator along Flowline 1 (FL1) and upstream of the test separator along Flowline 2 (FL2) and they are assumed to have a linear valve coefficient (CV) against opening relationship.

The primary source of the data collection is from the process parameters of the oil production system through an integrated real time-control information system called

Information Management System or IMS. The IMS is based on Information Manager (IM) that is seamlessly integrated with the Process Portal aspect and connectivity servers. The real time field data from the respective “sensing nodes” will be transmitted dynamically via a local network processed and stored the data in the IMS server database. Finally the IMS server will then provide the client tools for data presentation and export.

Due to the nature of deepwater operations specifically referring to the water depths, the reliability of subsea instrument system is of very high, in the range of 98.5 to 99.5%, as established in the Offshore Reliability Data database (OREDA, 2002). It should be noted that the system is entirely engineered with high precision equipment and technology that requires without or minimal maintenance intervention. In the event of any instrument or equipment failure, the system redundancy enables switching to the stand by unit thus allowing the system to function without interruption. Thus in this study if or where data is not available, an estimation or assumption based on past historical values or best industry practices are to be used as source of data inputs in the model building.

3.2.4 The Simulation Model

Figure 3-29 and Figure 3-30 illustrates the final model built of both flowlines and risers. The model started downstream of the wellhead manifold at DC 3 and terminated upstream of the separator at the FPSO.

Figure 3-29 illustrates the final model built for Flowline 1 (FL1) and Figure 3-30 for Flowline 2 (FL2), an integrated well and flowline models. For FL1, the model consists of the Drilling Center 1 (DC) with wells C11 and C19, DC 2 comprises wells C18 and C20 and DC 3 comprises well C16. For FL2, the model consists of the DC 2 with well C4-5 and DC 1 with well C12. Using these models, sensitivity simulations will then be performed to investigate several operating conditions in which flow instabilities and production performance could be improved.

The model will addressed some of the challenges faced in incorporating the field data in the tuning and model validation exercise. It will assists in resolving some of the modeling challenges and in demarking the performance of the model as a tool that could be used to examine the strategies to mitigate the flow instabilities in the flowlines and risers.

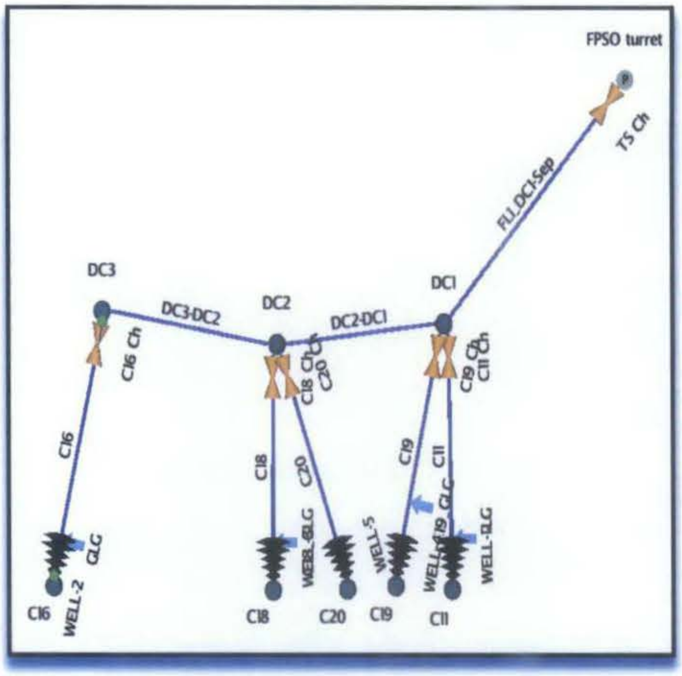


Figure 3-29: Flowline1 Schematic Simulation Model

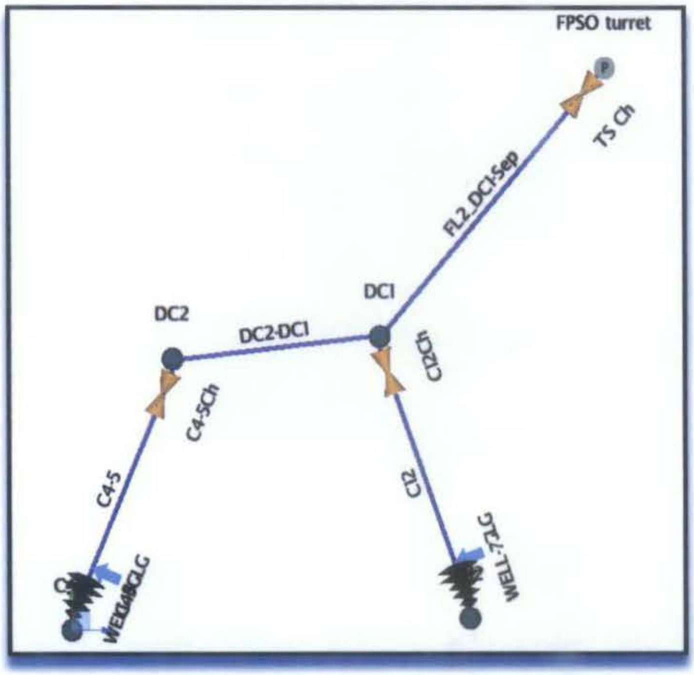


Figure 3-30: Flowline2 Schematic Simulation Model

3.2.4.1 Field Validation

Field validation was performed by tuning the model to match pressures and flowrates obtained from the well test results. The purpose of field validation is to certify the model in a way closely imitates the conditions in the field, such that the predicted results were close to the field measurements as possible.

3.2.4.2 Sensitivity Analysis

The simulation models developed for the flowlines and risers were used to investigate the flow instabilities and measures to minimize the severe slugging in the wells, flowlines and risers. Sensitivity cases have been outlined to investigate the impact of several operating modes on the flow instability and productivity in the wells, flowlines and risers.

The sensitivity cases outlined in this study include changes in the well routings, the gas lift rate and point of injection, and in the riser choke and wellhead choke openings. Few sensitivity cases i.e. by removing flow restrictions in the flowlines, setting choke on automated control have also been investigated.

For the purpose of determining the flow stability in the sensitivity analysis, the flow instability was quantified using a dimensionless number, the Stability Index as defined below:

$$\text{Stability Index} = \frac{(\text{Max liquid flow} - \text{Minimum liquid flow})}{\text{Average liquid flow}}$$

The Stability Index derived from this study has considered the difference of the highest and lowest liquid flow rates in the flowlines and risers against the average liquid flow. This assumption has been made possible and used to determine the stability indices to compare the relative flow instabilities for different flow rates and conditions.

In this study, a higher stability index denotes the system is highly unstable and a lower stability index denotes the system is reasonably stable. It has been assumed that even though the flow becomes more unstable at higher stability indices, however there is no single value at which the stability index could be capped. Nevertheless, one would tend to operate with as small as possible stability index.

Since the stability indices were formulated from this study, the following criteria's were used to qualitatively evaluate the system's flow instability in terms of total liquid flows. For comparison purposes, the system stability has been assumed to response to the different operating conditions distinguished by the stability index:

1 < stability index < 2 = system is stable (denotes as "high")
2 < stability index < 3 = system is moderately unstable (denotes as "medium")
3 > stability index = system is highly unstable (denotes as "low")

In terms of the slugs' characteristics, similar approach has been adopted based on the stability indices of liquid flow rates in the flowline and riser system. For slugs arriving at the FPSO, the following criteria were used to qualitatively evaluate the characteristics of the slugs in FL1 and FL2 and risers distinguished by the slug's frequency. The lowest slug frequencies and slug length have been determined within the range of 80 and 125 respectively based on the simulated modeling results. In this study, the frequency of slug occurrence for an hour and the average slug length that reflect their characteristics are defined as below:

Slug frequency < 80/hr = denotes systems with low frequency slugs
Slug frequency > 80/hr = denotes systems with high frequency slugs
Average slug length < 125 = denotes systems with multiple short slugs
Average slug length > 125 = denotes systems with multiple long slugs

This is to note that in general, a system operating with relatively multiple short slugs and low frequency was the least preferred since it can cause serious flow instabilities.

CHAPTER 4

RESULTS AND DISCUSSION

CHAPTER 4

RESULTS AND DISCUSSIONS

4.1 Introduction

This chapter highlights the results and discussion in understanding the cause of flow instability in flowlines and risers of a deepwater oil producing field. It will elaborate the details of the field validation and the sensitivity simulations for the stability analysis of and the mitigating solutions to manage the flow instability. In this study, Chinguetti field has been chosen as the 'live field laboratory' where all the pertinent data and information originate from this field.

The developed models were used to examine the flow instabilities in the wells, flowlines and risers. The development of the integrated model used two sets of production rates i.e. one in March 2006 and the other in April 2009. As explained in Chapter 3 under the basis of study, these two rates were meant as a comparison when the field was producing at its peak and when it was at its lowest oil production. . Thus the rates will provide the range in order to check the simulated model performance.

4.2 Field Validation

As a first step, the developed models for Chinguetti field were then validated for field matching. The aim of the field validation was to tune the models in a way that made the models closely imitates the condition in the field. The direct flow rate measurements for each individual well were available and were used to define the total flow rates in each flowline. The field matching results for the March 2006 data is as tabulated in Table 4-3.

As shown in the table, the differential errors between the OLGA's prediction and measured pressure drops along the flowlines and risers section were fairly low, except for 13th and 28th March production rates data. This observation suggested that the model predictions were fairly consistent with the field conditions. Furthermore, no tuning was done on the models.

Table 4-3: March 2006 Riser Flow Matching – No Tuning

Date	Flowline	Oil Rate (Sm^3/h)	Gas Rate (Sm^3/h)	Water Rate (m^3/h)	Separator Pressure (barg)	Measured DC1 Pressure (barg)	OLGA DC1 Pressure (barg)	Differential Pressure Error (%)
08/03/06	FL1	284.5	50321	0	11	52.5	51.3	-3%
13/03/06	FL1	221.3	36593	0	11	47.2	41.0	-17%
28/03/06	FL1	152.7	53751	18	11	49.7	41.1	-22%
08/03/06	FL2	207.8	18146	0	11	42.8	40.3	-8%
13/03/06	FL2	179.8	16550	0	11	36.6	37.7	4%
28/03/06	FL2	239.4	38376	0	11	42.9	43.2	1%

From the field validation, these results also suggested that flows were not affected due to sand accumulations and/or wax formation. The March 2006 production rates were relatively high to prevent any sand accumulation or blockages and fluid temperatures were also relatively high enough to prevent any wax formations. However, uncertainties in the field data had proved it very hard to reach a satisfactory result in the validation process.

Using the April 2009 production data, it has been assumed that the Chinguetti flowlines and risers could now (at the point of this study) have experienced flow restrictions from sand depositions and wax formation due to the continuing low production from the wells. The flowlines and risers could have been subjected to solids deposition due to low production from the wells. If there were localized blockages from sand and/or wax, hot spots for these accumulations would be at the base of the riser and/or along the sag bend of the riser.

However, there had not been any attempt to model these localized restrictions. Instead, it was decided to use only a simplistic tuning method on pipe roughness and flow area to match the pressure drops from the April 2009 production rates data. The tuning was applied uniformly throughout the flowlines and risers from DC1 to FPSO. The April 2009 well routings are as shown in Table 4-4.

Table 4-4: April 2009 Well Routings

Combination	Flowline 1 wells	Flowline 2 wells
Combination 1	12, 16,17,18,19,20	11,4-5
Combination 2	11,16,17,19,20,4-5	12,18
Default	11,16,17,18,19,20	12,4-5

The matching of pressures using the April 2009 production rates data resulted with a roughness factor of 1 mm in both flowlines, and 16.5% and 15.5% reductions in flow area for FL1 and FL2 respectively. Due to the uncertainties in the current state of the flowlines and risers, it was decided to use a simplistic tuning approach which gave a good match in the flowlines and risers pressure drops for the phase flow rates. However, it is important to note that a uniform diameter reduction was a coarse tuning approach and the validity of this single operating point tuning would be limited if there were localized solids deposits causing the difference in the pressure drops predictions. The results presented also indicated that the validity range of the tuning was relatively low with respect to the variation in GOR. The GOR indicates volume fraction gas and liquid. With mainly liquid present, it is low chance of getting severe slugging because the system will be stiff. However, although severe slugging does not occur with high volume fraction, fluctuations in holdup and/or hydrodynamic slugging may still be a problem Boe, (1981).

A summary of these comparisons is shown in Table 4-5 and Table 4-6, where errors in the OLGA predictions for the different combinations of well routings and flow rates ranged from 0% to 36%, for both FL1 and FL2. The high errors in the prediction are due to different well combinations whereby in a dynamic field conditions each well has its own behavior, characteristics and performance. For example the effect of fluid composition, the possibility of severe slugging is highly related to the gas-liquid ratio (GLR) and to the pressure P. The high errors are also being contributed by the geometric effects that can influenced severe slugging due to flowline geometry, riser height and shape, and wells with different watercut. Therefore, for the accuracy of modeling this range of accuracy is considered acceptable.

Table 4-5: April 2009 Flowline 1 Riser Flow

Date	Time (avg) (h)	Label	Stream From Wells	DC1 Pressure Measurement Location (Downstream Choke)	Oil Flow Rate (m^3/h)	Gas Flow Rate (Sm^3/h)	Water Flow Rate (Sm^3/h)	Upstream Topside Choke Pressure (barg)	Separator Pressure (barg)	DC1 Flowline Pressure	OLGA Non-Tuned DC1 Pressure (barg)	OLGA Tuned(1) DC1 Pressure (barg)	Pressure Drop Error (%)
010409	00-08	Default	11,19,20 18,16,17	C19	63.0	17941	31.1	12.8	9.2	39.0	30.7	35.4	-14
010409	17-20	Comb 1	19,12,20 18,16,17	C19	67.8	21899	55.6	15.8	9.3	42.2	36.5	45.4	12
020409	06-07	Default	11,19,20 18,16,17	C19	60.7	17651	40.1	13.5	9.2	39.8	32.6	38.0	-7
020409	16-18	Comb 2	11,19,204--5,16,17	C19	71.1	30570	47.6	16.0	9.3	39.0	35.5	47.2	36
030409	00-24	Default	11,19,20 18,16,17	C19	63.4	17826	42.2	13.1	9.3	39.2	32.6	38.6	-3
040409	00-24	Default	11,19,20 18,16,17	C19	64.0	17805	40.9	13.2	9.4	39.3	32.6	38.5	-3
050409	00-24	Default	11,19,20 18,16,17	C19	63.7	17659	40.6	13.3	9.5	39.1	33.0	38.4	-3

Remarks:

(1) The single operating point tuning was determined from the total well rates as measured from the well tests. The tuning parameters used were roughness 1 mm, and inner diameter reduced by 16.5% and 15.5% for FL1 and FL2 respectively

OLGA inlet temperatures were set to 55°C at DC1 and this also gave a good match in outlet temperatures

Table 4-6: April 2009 Flowline 2 Riser Flow

Date	Time (avg) (h)	Label	Stream From Wells	DC1 Pressure Measurement Location (Downstream Choke)	Oil Flow Rate (m^3/h)	Gas Flow Rate (Sm^3/h)	Water Flow Rate (Sm^3/h)	Upstream Topside Choke Pressure (barg)	Separator Pressure (barg)	DC1 Flowline Pressure	OLGA Non-Tuned DC1 Pressure (barg)	OLGA Tuned[(1)] DC1 Pressure (barg)	Pressure Drop Error (%)
010409	15-17	Comb 1	12, 4-5	C11	31.9	24395	38.4	12.3	9.5	32.8	25.2	30.56	-11
010409	05-07	Default	11,4-5	C12	43.9	28894	55.1	12.9	9.3	36.0	29.1	36.9	4
020409	15-17	Comb 2	12,18	C12	29.6	15301	50.2	10.4	9.0	38.7	26.0	29.5	-33
020409	03-07	Default	11,4-5	C12	44.1	28888	56.1	12.7	9.3	35.6	28.9	37.0	6
030409	00-24	Default	11,4-5	C12	43.8	28637	53.8	12.8	9.3	35.8	28.9	36.5	3
040409	00-24	Default	11,4-5	C12	42.4	28415	53.7	12.9	9.4	35.9	29.0	36.1	1
050409	00-24	Default	11,4-5	C12	42.7	28320	53.8	12.9	9.5	35.9	28.7	36.2	1

Remarks:

(1) The single operating point tuning was determined from the total well rates as measured from the well tests. The tuning parameters used were roughness 1 mm, and inner diameter reduced by 16.5% and 15.5% for FL1 and FL2 respectively

OLGA inlet temperatures were set to 55°C at DC1 and this also gave a good match in outlet temperatures

Base Case Model

This is to emphasize that April 2009 oil production scenario was selected as the base case data for the model validation and stability analysis. Based on the well combinations, the following wells were routed to the respective flowlines i.e. Flowline 1 (FL1) and Flowline 2 (FL2):

- FL1 – wells C16, C20, C18, C11 and C19
- FL2 – wells C4-5 and C12

However, wells C14 and C17 was reported idling and were not included in the model development due to little or no production data. The wells from FL1 were routed to the production separator whereas wells from FL2 were routed to test separator. For FL1, the production scenario as compared to the prediction results by OLGA is being summarized in the following tables:

- Table 4-7 indicates summary of topside wells and flowline models
- Table 4-8 indicates summary of well pressure-temperature
- Table 4-9 indicates summary of the well details

Table 4-7: FL1 Well and Flowline Model – Topside Summary

	Oil Rate (m^3/h)	Gas Rate (Sm^3/h)	Water Rate (m^3/h)	Upstream Choke Pressure (barg)	Separator Pressure (barg)	Separator Temperature
Measured	63.7	17659	40.6	13.3	9.5	42.9
OLGA	62.3	20718	42.8	13.3	9.5	39.5
Error (%)	-1	17	2	1	1	-2

From the above table, the errors in the OLGA predictions for the different flow rates ranged from 0% to 17% for FL1. All wells in FL1 used a linear type Inflow Performance Relationship (IPR) or Productivity Index (PI). It is to be noted that the choke openings for these wells were set to match the measured Flow Tubing Head Pressures (FTHPs).

As shown in Table 4-7, the total liquid phase predicted by OLGA reasonably matched the measured phase rates at FPSO. However, as shown in Table 4-9 it was noted that the predicted oil rates for wells C11 and C20 were much higher than what were measured by the Multiphase Flow Meter (MPFM). The mismatch in the readings is due to wells C11 and C20 experiencing high percentage of water cuts measured at 78.9% and 28.5% respectively. In addition the lift gas for well C20 has registered an uncertain value of 0 (zero) rate indicating that the well was probably not gas-lifted, hence less oil is able to be surfaced up against the tubing hydrostatic head. Producing wells need sufficient reservoir pressure in order to produce liquid in the upward section. On the other hand, the potential cause for no gas lift for well C20 is probably due to the gas lift valve itself having mechanical failure or not functioning as it is.

In order to match the measured topside water cut, the reference water cuts for each well was reduced by the same percentage and these water cuts were used in the following sensitivity studies on flow stability. As shown in Table 4.9, slugging was predicted for wells C11, C16, C18 and C19 and well C20 was predicted to be in the bubbly flow regime. The specifications as per Table 4-9 were used in the following sensitivity simulations for the stability analysis for FL1.

Table 4-8: FL1 Wells and Flowline Model - Well Pressure-Temperature Summary

Well	Measured Downstream Choke Pressure (barg)	OLGA Downstream Choke Pressure (barg)	Measured FTHP (barg)	OLGA FTHP (1) (barg)	Measured FTHT (°C)	OLGA FTHT (°C)
C11	39.9	39.5	49.3	49.3	63.9	62.9
C16	42.3	42.3	44.9	44.9	12.1	30.5
C18	42.2	42.5	50.0	50.0	44.8	50.4
C19	39.1	39.5	82.1	82.1	56.5	51.0
C20	42.0	42.5	58.1	58.1	59.7	62.1

Remarks:

1) Choke openings were controlled such as to match measured FTHPs
2) The single point operating point tuning has been used for the flowline between DC1 and FPSO, i.e. roughness 1 mm, 16.5% diameter reduction, i.e. ID of 212.1 mm

However as tabulated in Table 4-9, there is a big deference of gas rate measured by MPFM against rate measured by OLGA due to the effect of fluid composition, the gas-oil ratio (GOR) from the reservoir. GOR is defined as the volume of gas produced at standard pressure and temperature (STP) 15°C and 1 atmosphere per volume of oil produced. When the pressure is increased gas is dissolved into the oil. With each well having different water cuts and reservoir pressures, the ratio of GOR/P (Gas Oil Ratio over Pressure) indicates volume fraction of gas and liquid with varying fluid properties. Hence, the possibility of severe slugging is highly related to the gas-oil ratio and to the pressure P. Thus wells C11, C16, C18 and C19 are in a slugging flow regime as predicted by OLGA and it reasonably match the measured well test results. In the reservoir, the oil is either saturated or under-saturated. If it is saturated, the oil is at its bubble point and a small drop in pressure or a small increase in temperature will give formation of bubbles. This might be the case for well C20 which is in a bubble flow regime.

Table 4-9: FL1 Wells and Flowline Model - Well Details Summary

Well	FGOR (scf/stb)	Gas Lift Rate (mmscfd)	OLGA Watercut (%)	Reservoir Pressure (barg)	Reservoir Temperature (°F)	Productivity Index (PI) (stb/d/psi)	Oil Rate MPFM (m^3/h)	Oil Rate OLGA (m^3/h)	Gas Rate MPFM (Sm^3/h)	Gas Rate OLGA (Sm^3/h)	Water Rate MPFM (m^3/h)	Water Rate OLGA (m^3/h)	Bottom Hole Pressure (BHP) OLGA (barg)	Flow Regime OLGA
C11	705	3.4	78.9	219.6	167	3.84	4.8	7.4	4383	3917	20.8	26.2	132.1	slugging
C16	800	2.0	1.9	101.0	152	4.00	5.5	5.3	1563	2453	0.2	0.3	88.1	slugging
C18	262	5.2	13.3	152.7	169	4.46	11.4[(2)]	20.8	1438[(2)]	5945	5.9[(2)]	3.5	100.0	slugging
C19	650	2.5	33.3	192.0	160	9.95	11.2	13.3	4469	3880	7.7	6.3	173.5	slugging
C20	881	0.0	28.5	176.2	166	15.91	11.0	17.8	1413	2174	5.9	6.7	161.5	bubble

Remarks:

[(2)] Denotes values from 3rd April 09 measurements for well C18

Similarly for FL2, the comparison of the prediction results by OLGA is being summarized in the following tables:

- Table 4-10 indicates summary of topside wells and flowline models
- Table 4-11 indicates summary of well pressure-temperature
- Table 4-12 indicates summary of the well details

Table 4-10: FL2 Wells and Flowline Model - Topside Summary

	Oil Rate (m^3/h)	Gas Rate (Sm^3/h)	Water Rate (m^3/h)	Upstream Choke Pressure (barg)	Separator Pressure (barg)	Separator Temperature
Measured	42.7	28319.5	53.8	12.9	9.5	45.3
OLGA®	42.7	28342.1	53.1	12.9	9.5	47.4

As shown in Table 4-10, the total liquid phase rates predicted by OLGA reasonably match the measured phase rates at FPSO.

Table 4-11: FL2 Wells and Flowline Model - Well Pressure-Temperature Summary

Well	Measured Downstream Choke Pressure (barg)	OLGA Downstream Choke Pressure (barg)	Measured FTHP (barg)	OLGA FTHP (1) (barg)	Measured FTHT (°C)	OLGA FTHT (°C)
C12	35.7	35.8	39.7	39.6	67.4	68.2
C4-5	38.3	38.9	48	47.7	58.7	58.5

Remarks:
The single point operating point tuning has been used for the flowline between DC1 and separator, i.e. roughness 1 mm, 15.5% diameter reduction, i.e. ID of 214.6 mm.

It was observed that a satisfactory match in both flow rates and pressures could be achieved by using a Vogel type Inflow Performance Relationship (IPR) for well C4-5 and a linear IPR for well C12.

In reservoir engineering for well characterization uses among other tools, the inflow curves also known as IPR curves (Inflow Performance Relationships). The inflow curve of a well is equivalent to the output curve but is measured at bottom hole conditions. Both curves are individuals for each well and vary with the productive life of the well. The output curves are obtained from the measurements at surface conditions of the flow and pressure. Linear IPR or straight-line inflow performance relationship is meant normally for single phase flow whereas Vogel IPR is a curve meant for multiphase flow. Different IPR correlations exist today and Vogel is amongst the most commonly used model in the petroleum industry (Vogel, 1968).

With the well configuration as tabulated in Table 4-12, well C4-5 was predicted to be in the slugging regime whilst C12 was predicted to be in a bubbly flow regime. It was observed that Multiphase Flow meter (MPFM) readings for C12 and C4-5 wells in the "default" routing configuration were not available. Hence, a cross- checked against the total flow rates at the FPSO was performed and the choke settings for these wells were configured to match the measured flow tubing head pressures. This approach gave reasonable estimates on the phase flow rates from each well. Similarly, in order to get a closer match in the measured water cuts at topside, the reference water cuts from each well was reduced by the same percentage With the configuration as described, well C4-5 was predicted to be in the slugging regime whilst well C12 was predicted to be in bubbly flow regime

Table 4-12: FL2 Wells and Flowline Model - Well Details Summary

Well	FGOR (scf/stb)	Gas Lift Rate (mmscfd)	OLGA Watercut (%)	Reservoir Pressure (barg)	Reservoir Temperature (°F)	Productivity Index (PI) (stb/d/psi)	Absolute Open Flow (oil & water Vogel) (stb/d)	Maximum Rate Oil OLGA Vogel (stb/d)	Oil OLGA (m^3/h)	Gas Rate OLGA (Sm^3/h)	Water Rate OLGA (m^3/h)	Bottom Hole Pressure (BHP) OLGA (barg)	Flow Regime OLGA
C12	1416	3.3	58.0	163.1	175	13.862	-	-	27.9	8499	35.5	118.9	bubble
C4-5	6387	2.4	53.6	141.0	163	-	8224.2	7597.8	17.1	16227	18.1	88	slugging

During the course of analyzing the production rates from each well, it was discovered that the MPFM readings for well C18 (production rates data 3rd April 2009) have significant discrepancies between the predicted and the measured well rates, as shown in Table 4-9. For this particular well the gas lift rate at 5.2 mmscfd was higher as compared to the other wells. This indicated that the IPR and/or the gas lift rate used in the matching exercise were unrealistic for this well. It was also noted that the reference value for the gas lift rate from the field measurements used in the modeling was significantly larger than what was anticipated from the measured gas rate. The measured gas rate was substantially lower indicating that the well was probably not gas-lifted. These uncertainties in the field measurements have made it difficult to ensure accurate assumptions in the modeling basis. Hence, it was decided that the IPR value and the gas lift rate used in Table 4-9 were used for C18 in the subsequent sensitivity simulations for the stability analysis.

Additionally, it was also observed that the MPFM oil rate readings from each individual well did not add up to what was measured at the topsides. Thus, these uncertainties supported the decision to use the IPR and the gas lift rates from Table 4-9 and Table 4-12 as the base case assumptions for the subsequent sensitivity studies.

4.3 Sensitivity Simulations

The next step towards determining and understanding the flow instability in Chinguetti production system is to perform sensitivity simulations on the models that have been developed at this juncture. Sensitivity cases have been outlined to examine the impact of several different operating modes on the flow instability and productivity in the wells, flowlines and risers. The sensitivity cases include changes in the well routings, in the gas lift rate and point of injection, and in the riser choke and wellhead openings. A case in which the modeled flow restrictions in the Chinguetti flowlines were removed was also examined. In addition, the impact of FPSO riser chokes set on automated control on flow instabilities was also examined.

4.3.1 Base Case Routing

In the above mentioned section 'Base Case Model', the April 2009 production scenario was selected as the base case scenario for the flow instability sensitivity study. Based on the well combinations, the following wells were routed to the respective flowlines i.e. Flowline 1 (FL1) and Flowline 2 (FL2):

- FL1 – wells C16, C20, C18, C11 and C19
- FL2 – wells C4-5 and C12

Wells C14 and C17 were reported idling and were not included in the model development due to little or no production data. The wells from FL1 were routed to the production separator whereas wells from FL2 were routed to test separator.

4.3.2 Simulation Observation

From the sensitivity runs, the amplitudes of predicted pressure oscillation were comparable with measured values indicating that the model was in good agreement with the field results. The variation of predicted and measured pressures at the FPSO Turret for FL1 and FL2 are as shown in Figure 4-31 and Figure 4-32.

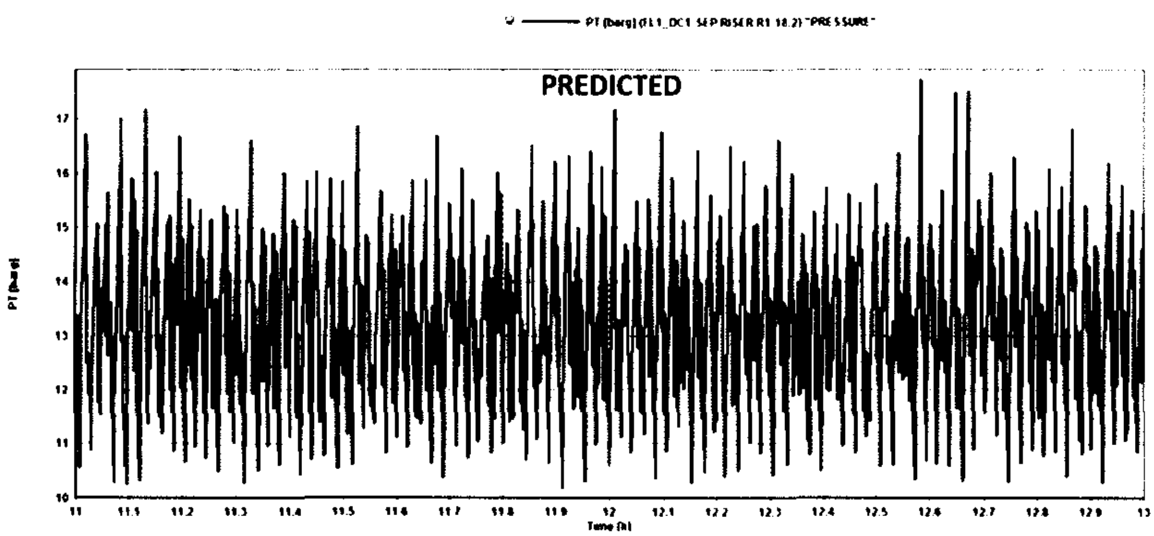


Figure 4-31: Variation of Predicted Pressures
At the FPSO Turret for FL1 and FL2

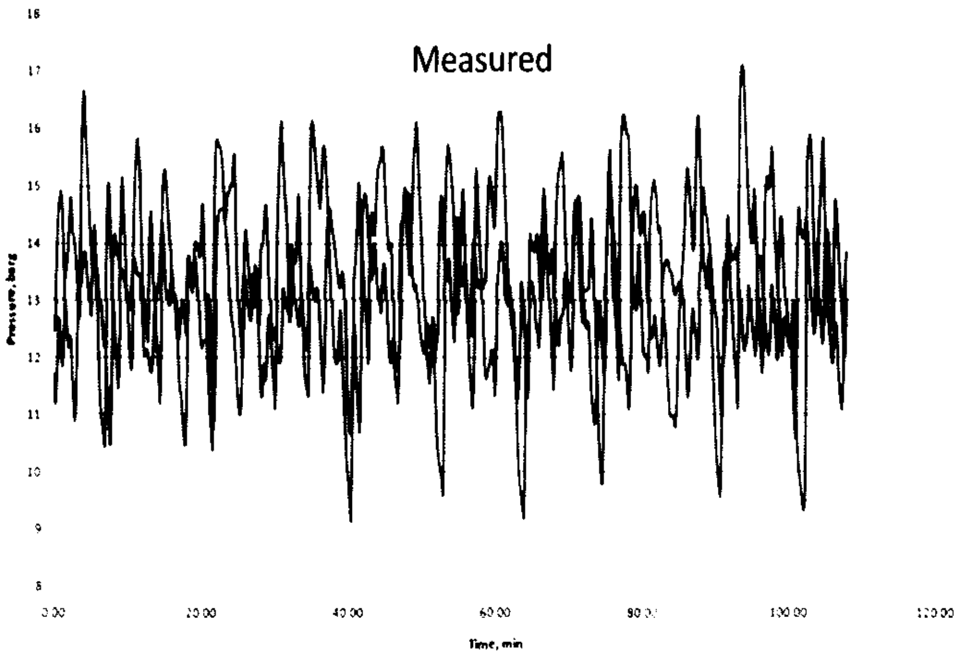
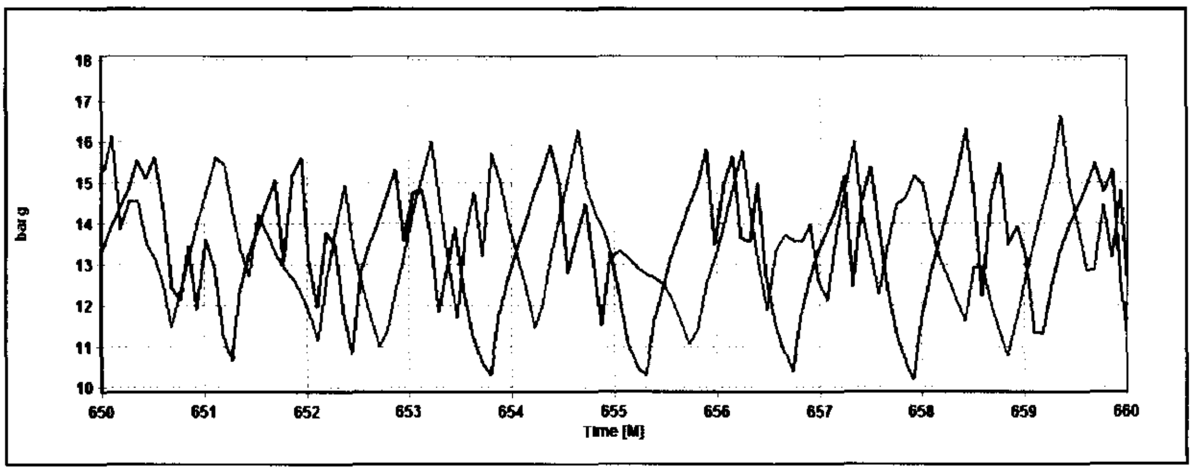


Figure 4-32: Variation of Measured Pressures
At the FPSO Turret for FL1 and FL2

M denotes time in minutes (min) with time interval of 10 minutes



— Flowline 1 (FL1)

— Flowline 2 (FL2)

M denotes time in minutes (min)

Figure 4-33: Variation of Predicted Pressures at the FPSO Turret for FL1 and FL2

Using the April 2009 as the base case production scenario, the stability indices and the characteristics of the slugs are as shown in Table 4-13 and Table 4-14.

Table 4-13: Stability Index – Base Case Routing

	Average Oil Flow (m^3/hr)	Average Liquid Flow (m^3/hr)	Maximum Liquid Flow (m^3/hr)	Minimum Liquid Flow (m^3/hr)	Stability Index
FL1	62	107	386	4	3.5
FL2	42	98	392	7	3.9

Table 4-14: Slugging Characteristics – Base Case Routing

	Slug Frequency length (L)/hr) (Average Length)	Maximum Slug Length @ Top of Riser (m)	Average Slug Length @ Top of Riser (m)
FL1	77	342	130
FL2	84	347	136

As shown in Table 4-13, the stability indices for the April 2009 production rates were relatively high. These indicate that the entire production systems were highly unstable. On April 2009, the total liquid production from both FL1 and FL2 was 205 m^3/hr. The total oil production was averaged at 104 m^3/hr.

An average slug length of 130 m was predicted in both FL1 and FL2 with a frequency of 80 slugs per hour as shown in Table 4-14. This slugging behavior was categorized as 'system with multiple long slugs and at a low frequency", meaning to say that the slugging behavior was severely high.

From the above stability indices shown in Table 4-13, it demonstrates that the production system is experiencing severe slugging with multiple long slugs and at a low frequency. A way of increasing the flow stability would be to increase the total liquid production from the wells. However, this approach was not possible due to the limitation of the wells.
The model is further simulated to perform sensitivity analysis on flow instability through different well routing alternatives. Using April 2009 production scenario as the base case,

several different well routing combinations were examined of the following wells combinations:

1. Set 1 - producer well high and low Productivity Index (PI)
2. Set 2 - producer well with high and low Total Gas Liquid Ratio (TGLR)
3. Set 3 - producer well high and low Tubing Head Pressure (THP)
4. Set 4 – balancing Total Gas Liquid Ratio (TGLR) or matching TGLR
5. Set 5 – producer well with low and high water cut
6. Set 6 – all producing wells in flowing in Flowline 1 (FL1)

The above well combinations are either routed to Flowline 1 (FL1) or Flowline 2 (FL2). The wellhead chokes openings and gas-lift rates settings were kept as per April 2009 conditions. The different well routing alternatives are as tabulated in Table 4-15.

Table 4-15: Routing Alternatives Sensitivity

	Configuration	FL1	FL2
1	Base Case - April 2009	C16, C20, C18, C11, C19	C4-5, C12
2	Set 1 - High/Low PI	C20, C4-5, C12	C16, C18, C11, C19
3	Set 2 - High/Low TGLR	C20, C11, C19, C12	C16, C18, C4-5
4	Set 3 - High/Low THP	C16, C18, C4-5, C12	C20, C11, C19
5	Set 4 – Balancing TGLR	C16, C18, C19, C12	C20, C4-5, C11
6	Set 5 – Low/High Water Cut	C16, C20, C18, C19	C11, C4-5, C12
7	Set 6 – All in FL1	C16, C20, C18, C4-5, C11, C19, C12	

Remarks:

Wells C14 and C17 were assumed shut-in (non-producing).

Based on the different well routing alternatives, the stability indices for Flowline 1 (FL1) and Flowline 2 (FL2) are as tabulated in Table 4-16 and Table 4-17 respectively. Table 4-18 provides the total liquid flows into FPSO from both FL1 and FL2.

Table 4-16: FL1 Stability Index Comparison

Routing Options	Average Oil Flow (m^3/hr)	Average Liquid Flow (m^3/hr)	Maximum Liquid Flow (m^3/hr)	Minimum Liquid Flow (m^3/hr)	Stability Index	Stability Group
April 2009	62	107	386	4	3.5	Low
Set 1	55	108	186	3	1.6	High
Set 2	58	132	174	1	1.3	High
Set 3	54	104	206	3	1.9	High
Set 4	62	108	227	5	2.1	Med
Set 5	66	77	142	0	1.8	High
Set 6	59	128	217	29	1.5	High

Table 4-17: FL2 Stability Index Comparison

Routing Options	Average Oil Flow (m^3/hr)	Average Liquid Flow (m^3/hr)	Maximum Liquid Flow (m^3/hr)	Minimum Liquid Flow (m^3/hr)	Stability Index	Stability Group
April 2009	42	98	392	7	3.9	Low
Set 1	47	86	175	4	2.0	Med
Set 2	44	70	180	4	2.5	Med
Set 3	40	86	155	0	1.9	High
Set 4	42	95	320	7	3.3	Low
Set 5	46	122	204	34	1.4	High
Set 6	-	-	-	-	-	-

Table 4-18: Total Liquid Flows FL1 and FL2 to FPSO

Routing Options	Total FL1 and FL2 Average Oil Flow (m^3/hr)	Total FL1 and FL2 Average Liquid Flow (m^3/hr)
April 2009	104	205
Set 1	102	194
Set 2	102	202
Set 3	94	190
Set 4	104	203
Set 5	112	199
Set 6	59	128

4.4.1.1 Conclusion

From the alternative well routing sensitivity analysis, the results indicated the stability index varied with well routing. The stability indices were generally low in Set 2 and Set 5 indicating that the flows were more stable in Set 2 and Set 5. This was demonstrated in Table 4-16 in Set 2 of FL1 and Table 4-17 in Set 5 of FL2. Set 2 isolated the high PI wells from the low PI wells, whilst Set 5 segregated the low and high water cuts wells in the two flowlines.

Referring to Table 4-16 and Table 4-17, there was no significant impact on the system productivity and flow instability in Set 1, Set 2, Set 3 and Set 5 of FL1 and Set 3 and Set 5 of FL2. The variances in the average oil flow are quite marginal in both FL1 and FL2 and this denotes that the flow is reasonably stable.

From the well routings alternatives, the impact on the total liquid flows of FL1 and FL2 to FPSO as tabulated in Table 4-18 was insignificant. This suggested that the high productivity wells were competing with the low productivity wells. However, Set 5 routing option indicated an increase in oil production. The total oil production in Set 5 was 8% higher than in the base case April 2009 well routings.

Although flow instabilities were much lower in Set 3 and Set 6, these were not at the expense of the reductions in the total liquid flows. The oil production has reduced from 104 m^3/hr, per

April 2009 production rates, to 94 m^3/hr and 59 m^3/hr in Set 3 and Set 6 respectively as illustrated in Table 4-18.

Routing all wells to FL1 indicates an improved to flow stability. However, the net liquid production from the wells had dramatically reduced to 59 m^3/hr. As shown in Table 4-16 and 4-18 respectively, it can be concluded that routing all wells into FL1 was not a recommended option due to the significant reduction in oil production. Furthermore this option could induce a much bigger back pressure to the wells and reducing the flows from some of the weaker wells.

4.4.2 Slugging Characteristics

In the sensitivity runs, the following criteria were used to qualitatively evaluate the characteristics of the slugs in FL1 and FL2:

Slug Frequency < 80/hr – denotes system with low frequency slugs
Slug Frequency > 80/hr – denotes system with high frequency slugs
Average Slug Length < 125 - denotes systems with multiple short slugs
Average Slug Length > 125 – denotes systems with multiple long slugs

Similar to the derivation of stability index as mentioned in section 4.4.1, the origin of slugging characteristics can also be considered as a new finding. From the simulations done, 80 frequencies of slugs/hr have been considered as the reverence value whilst 125 for the average slug length. A system operating with relative multiple short slugs and of high frequency was generally most favored and it denotes the system is reasonably stable. Alternatively, a system with relatively multiple short slugs and low frequency was the least preferred since it can cause serious flow instabilities.

The characteristics of the slugs arriving at the FPSO for FL1 and FL2 were captured and tabulated in Table 4- 19 and 4-20.

Table 4-19: FL1 Slugging Characteristic Comparison

Routing Options	Slug Frequency length/hr (l/hr) (Average Length)	Maximum Slug Length @Top of Riser (m)	Average Slug Length @Top of Riser (m)	Slugging Group
April 2009	77	342	130	Low Frequency, Long Slugs
Set 1	120	343	123	High Frequency, Long Slugs
Set 2	103	422	173	High Frequency, Long Slugs
Set 3	120	247	120	High Frequency, Long Slugs
Set 4	52	471	198	Low Frequency, Long Slugs
Set 5	119	276	95	High Frequency, Short Slugs
Set 6	112	355	149	High Frequency, Long Slugs

Table 4-20: FL2 Slugging Characteristic Comparison

Routing Options	Slug Frequency length/hr (l/hr) (Average Length)	Maximum Slug Length @Top of Riser (m)	Average Slug Length @Top of Riser (m)	Slugging Group
April 2009	84	347	136	High Frequency, Long Slugs
Set 1	81	281	103	High Frequency, Short Slugs
Set 2	88	268	101	High Frequency, Short Slugs
Set 3	97	339	93	High Frequency, Short Slugs
Set 4	138	303	94	High Frequency, Short Slugs
Set 5	84	382	167	High Frequency, Long Slugs
Set 6	-	-	-	-

4.4.2.1 Conclusion

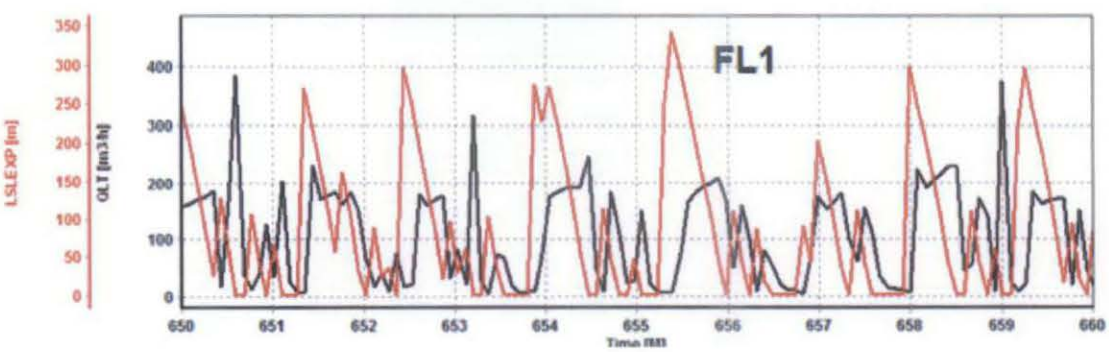
As shown in Table 4-19 and Table 4-20, the results of the slugging characteristics analysis indicated that the slugging frequencies for the different routing options ranged from 50 lengths per hr (l/hr) to 140 l/hr. The average lengths of the slugs ranged from 90 m to 200 m and the maximum length of the slugs ranged from 250 m to 480 m.

The routing options of Set 1, Set 2, Set 3, Set 5 and Set 6 were in general produced high frequency slugs. This was evident in FL1 and FL2. The high frequency slugs were generally more stable than low frequency with the exception of routing option Set 4 of FL1 as shown in Table 4-19. The flow stability in these routings alternatives was generally more established that produced high frequency short slugs. This observation substantiated the conclusions drawn for the flow stability based on the stability indices.

Systems with low slugging frequencies and with long slugs such as in FL1 of routing option Set 4 and FL1 base case April 2009 was less stable as shown in Table 4-19. This conclusion also substantiated the conclusions drawn based on the stability indices.

4.4.3 Slug Length and Liquid Volume

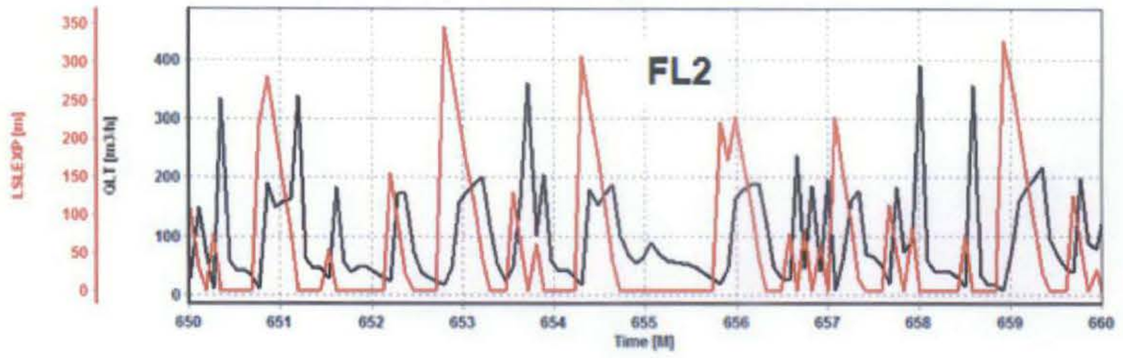
In this study, the slug tracking option in OLGA was used to model the slugging. Several simulations runs were made to identify the length of the slugs as well as the total liquid flow. From the simulations done, the maximum lengths of the slugs generated for the different routing alternatives generally ranged between 30 to 65% of the total riser height as illustrated in Figure 4-35 and Figure 4-36 respectively. The maximum volume of slugs could range up to 24 m^3. Consequently, the separator surge volumes must be able to accommodate the slug volumes in order to stabilize the impact of the slugging, and to cushion the flow instabilities from propagating towards the downstream process facilities.



— LSLEXP denotes Liquid Slug Length measured in meter (m)

— QLT denotes Liquid Volume in cubic meter/hour (m3/hr)

Figure 4-35: Slug Length and Liquid Volume of FL1



— LSLEXP denotes Liquid Slug Length measured in meter (m)

— QLT denotes Liquid Volume in cubic meter/hour (m3/hr)

Figure 4-36: Slug Length and Liquid Volume of FL2

The trend plots of oil, water and gas flowrates arriving at the FPSO, lengths of slugs, hold-up fractions of the slugs and pressures at the turret and top of riser are as illustrated in Figure 4-37 till Figure 4-61 respectively.

4.4.4 Routing Alternatives Ranking

From the sensitivity cases done with different sets of well configuration i.e. based on the stability indices and slugging characteristics results, the most preferred option in order to achieve flow stability is Set 5. The routing option Set 5 consists of combination of low and high water cuts wells C16, C20, C18 and C19 routed to FL1 and wells C11, C4-5 and C12 routed to FL2.

In conclusion, due to the limitations of the wells the potential increase in oil production from the changes in well routings as predicted by OLGA is in the range of 8%.

Table 4-21 illustrates the most preferred and least preferred options according to the routing alternatives ranking.

Table 4-21: Routing Alternatives Ranking

	Configuration	FL1	FL2
Most Preferred	Set 5 – Low/High Water Cut	C16, C20, C18, C19	C11, C4-5, C12
	Set 2 - High/Low TGLR	C20, C11, C19, C12	C16, C18, C4-5
	Set 1 - High/Low PI	C20, C4-5, C12	C16, C18, C11, C19
	Base 5th April 2009	C16, C20, C18, C11, C19	C4-5, C12
	Set 4 – Balancing TGLR	C16, C18, C19, C12	C20, C4-5, C11
	Set 3 - High/Low THP	C16, C18, C4-5, C12	C20, C11, C19
Least Preferred	Set 6 – All in FL1	C16, C20, C18, C4-5, C11, C19, C12	-

Remarks:

Wells C14 and C17 were assumed shut-in (non-producing)

4.4.5 Field Implementation

From Table 4-21, the most preferred option in order to achieve flow stability was Set 5. Set 5 well routing combination was implemented in the field subsequent to the recommendation made by the study. Routing of all wells to FL1 i.e. the least preferred option Set 6, was also implemented but the results showed a significant reduction in total production. FL1 showed positive results in terms of flow stability and production improvement after 2 weeks of implementing Set 5 as shown in Table 4-22. The net oil production from the two flowlines was found to increase gradually from 9,400 to 10,600 barrels of oil per day.

The topsides choke of FL1 and FL2 were set at the original settings of 42% and 37%, respectively. FL2 however had not showed positive improvement. Slugging condition had remained over a period of time with only two wells were produced into FL2, i.e., C4-5 and C12.

Table 4-22: Set 5 Field Implementation Results

Date	FL1			FL2			Watercut (%)	Gross oil (Bbls/d)	Net oil (Bbls/d)
July 2009	Oil (Bbls/d)	Water (Bbls/d)	Gas (mmscfd)	Oil (Bbls/d)	Water (Bbls/d)	Gas (mmscfd)			
7/7	6550	3261	11.35	2970	6500	13.35	48.48	20631	9420
8/7	6750	3351	12.35	2870	6553	13.38	48.51	22632	9660
9/7	6850	3471	13.56	2880	6579	14.55	59.04	23612	9890
10/7	7550	4361	14.15	3860	8570	14.81	59.38	24612	10100
11/7	7350	3781	14.35	3770	8600	14.38	58.48	25360	10252
12/7	7540	4561	14.25	3890	9500	15.55	58.51	25631	10350
13/7	7113	4261	14.52	4331	9831	16.81	59.04	25536	10512
14/7	7153	4271	14.51	4351	9845	15.55	59.38	25360	10528
15/7	7263	4291	14.53	4341	9851	16.81	58.48	25631	10538
16/7	7163	4391	14.50	4247	9841	13.35	58.48	25360	10528
17/7	7269	4103	14.10	4351	10037	14.38	58.51	25631	10635
18/7	7586	3801	13.75	4368	10156	15.55	59.04	25632	10584
19/7	6890	3788	13.92	4254	10194	16.81	59.38	25612	10502
20/7	7430	3750	14.15	4440	10232	16.35	58.89	25568	10609

It was observed that the low pressure well C17, that was idled prior to initiating field implementation due to problems with the flow instability, had also started to flow with a net rate of 700 BOPD. However its being a concern that water production would start to increase by the improvement in flow stability. From this exercise, the net oil production from the flowlines had stabilized in the range of 10,500 and 10,600 barrels of oil/day. The actual increase in total production was approximately 12% which was more than what was initially predicted by OLGA models at 8%.

4.5 Conclusion

The developed models underwent field validation by tuning the models to match pressure and flow rates from the well tests results. The purpose of the field validation is to closely imitate the conditions in the field. It was observed that OLGA predictions of the pressure drops along the flowlines and risers compared reasonably well with the measured data from the March 2006 well test results as shown in Table 4-3. This observation suggested that the model predictions were fairly consistent with the field conditions.

Further field matching was done on April 2009 production data which required tuning on its roughness and flow area. The tuning resulted with a roughness factor of 1 mm in both flowlines, and 16.5% and 15.5% reductions in flow area for FL1 and FL2. The errors in the predictions of pressures for the different well combinations of well routings and flow rates ranged from 0% to 36%. The high errors are due to each well has its own behavior, characteristics and performance. The high errors are also being contributed by the geometric effects that can influenced severe slugging due to flowline geometry, riser height and shape, and wells with different watercut in a live field conditions. Therefore, for the accuracy of modeling this range of accuracy is considered acceptable.

The production scenario from April 2009 data was selected as the base case model for the model validation and stability analysis. For FL1, all wells used a linear Inflow Performance Relationship (IPR) or Productivity Index (PI). For FL2, well C4-5 used Vogel type IPR and C12 used a linear type IPR which gave a satisfactory match in the phase flow rates as shown in Table 4-7. Although some predicted well rates did not match up measured rates from Multiphase Flow Meter (MPFM), the total phase rates predicted at separators reasonably matched the measured phase flow rates at FPSO as tabulated in Table 4-10.

Some uncertainties were observed in the gas lift and water cuts. Moreover, it was observed that the MPFM oil rate readings from each individual well did not sum up to what was actually measured at FPSO. Therefore, assumptions were made to use the well specifications that provided a good match in the phase flow rates measured at FPSO.

The results of the slugging characteristics analysis indicated that the slugging frequencies and average lengths of the slugs varied with different well routing options as tabulated in Table 4-19 and Table 4-20.

The stability index used to compare the relative flow instabilities for the different flow rates and conditions revealed that the entire production systems were highly unstable. The stability indices were generally low in Set 2 and Set 5 indicating that the flows were more stable in Set

2 and Set 5. This was demonstrated in Table 4-16 in Set 2 of FL1 and Table 4-17 in Set 5 of FL2. Set 5 well routing combination was then implemented in the field for about two weeks period. As shown in Table 4-22, the net oil production from the two flowlines was found to increase gradually from 9,400 to 10,600 barrels of oil per day. The net oil production from the flowlines had stabilized in the range of 10,500 and 10,600 barrels of oil/day which was approximately 12% more than what was initially predicted by the OLGA model at 8%.

Routing all wells to FL1 indicates an improved to flow stability. However, it was not a recommended option due to the significant reduction in oil production. Furthermore this option could induce a much bigger back pressure to the wells and reducing the flows from some of the weaker wells.

As a conclusion, this study has met its objectives in entirety whereby the results from field implementation have indicated improvement in flow stability in flowlines and risers as well as able to maximize oil recovery from the reservoir.

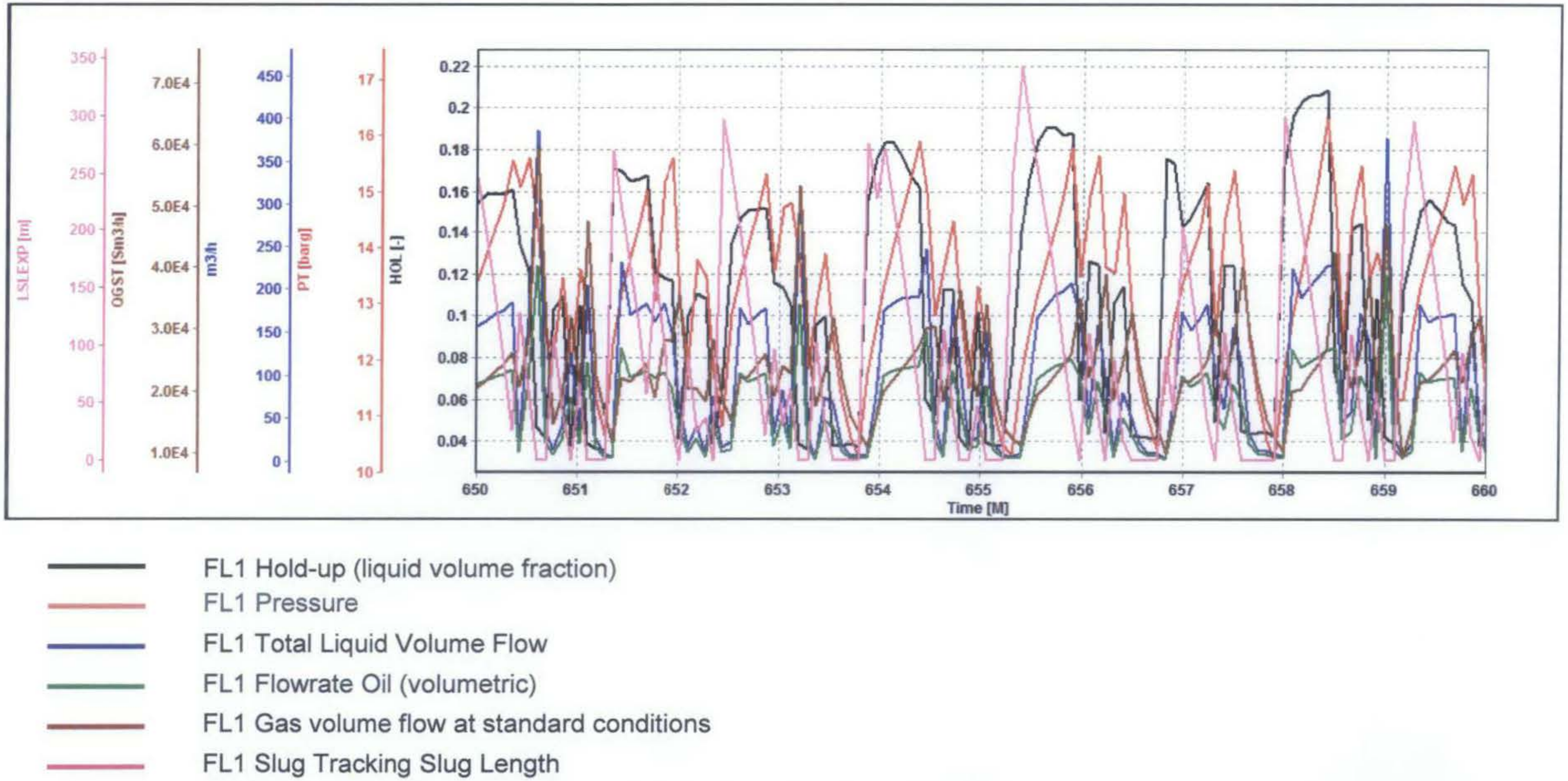
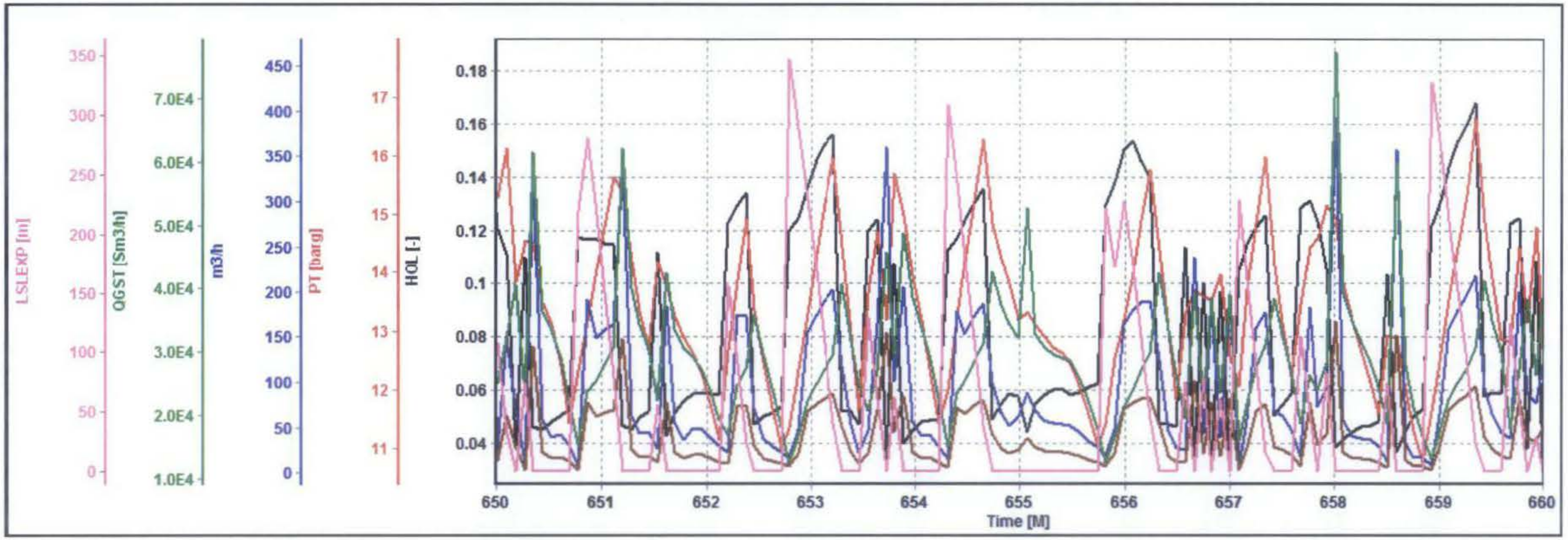


Figure 4-37: Flow Instability FL 1 April 2009



FL2 Hold-up (liquid volume fraction)
FL2 Pressure
FL2 Total Liquid Volume Flow
FL2 Flowrate Oil (volumetric)
FL2 Gas volume flow at standard conditions
FL2 Slug Tracking Slug Length

Figure 4-38: Flow Instability FL 2 April 2009

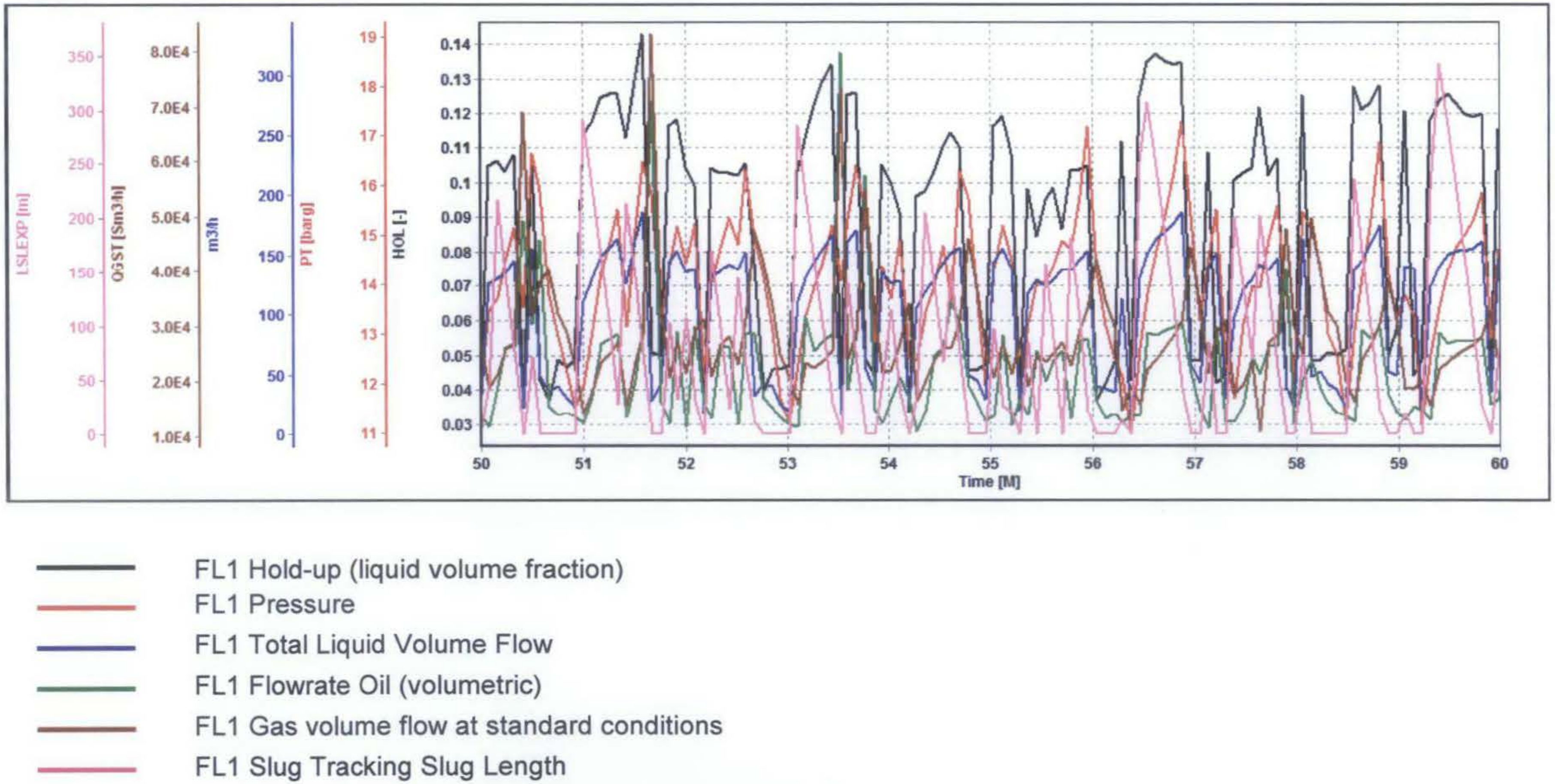
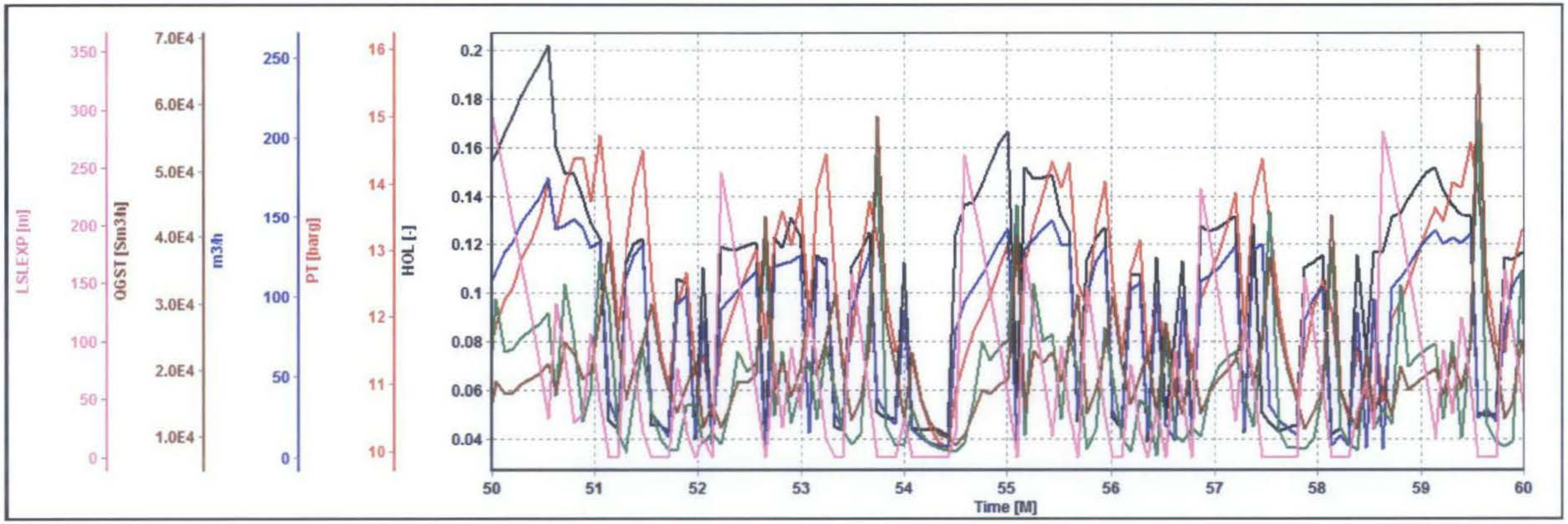
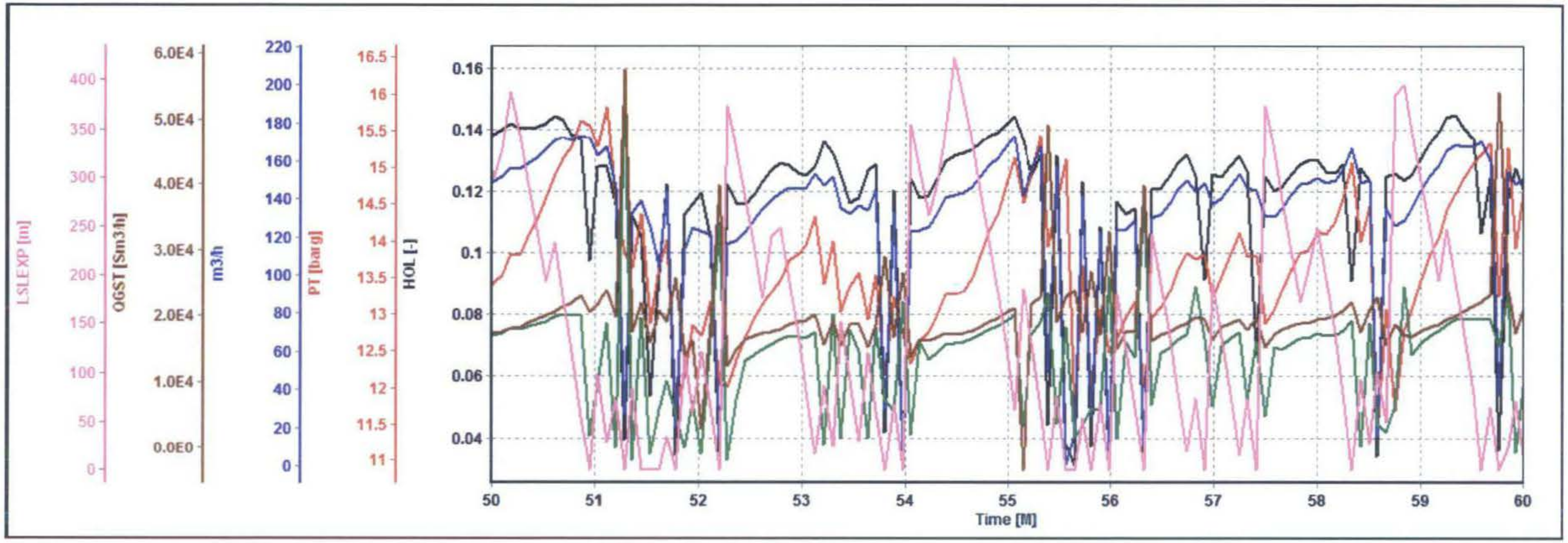


Figure 4-39: FL 1 Routing Alternative Set 1 – High/Low PI



FL2 Hold-up (liquid volume fraction)
FL2 Pressure
FL2 Total Liquid Volume Flow
FL2 Flowrate Oil (volumetric)
FL2 Gas volume flow at standard conditions
FL2 Slug Tracking Slug Length

Figure 4-40: FL 2 Routing Alternative Set 1 – High/Low PI



FL1 Hold-up (liquid volume fraction)

FL1 Pressure

FL1 Total Liquid Volume Flow

FL1 Flowrate Oil (volumetric)

FL1 Gas volume flow at standard conditions

FL1 Slug Tracking Slug Length

Figure 4-41: FL 1 Routing Alternative Set 2 – High/Low TGLR

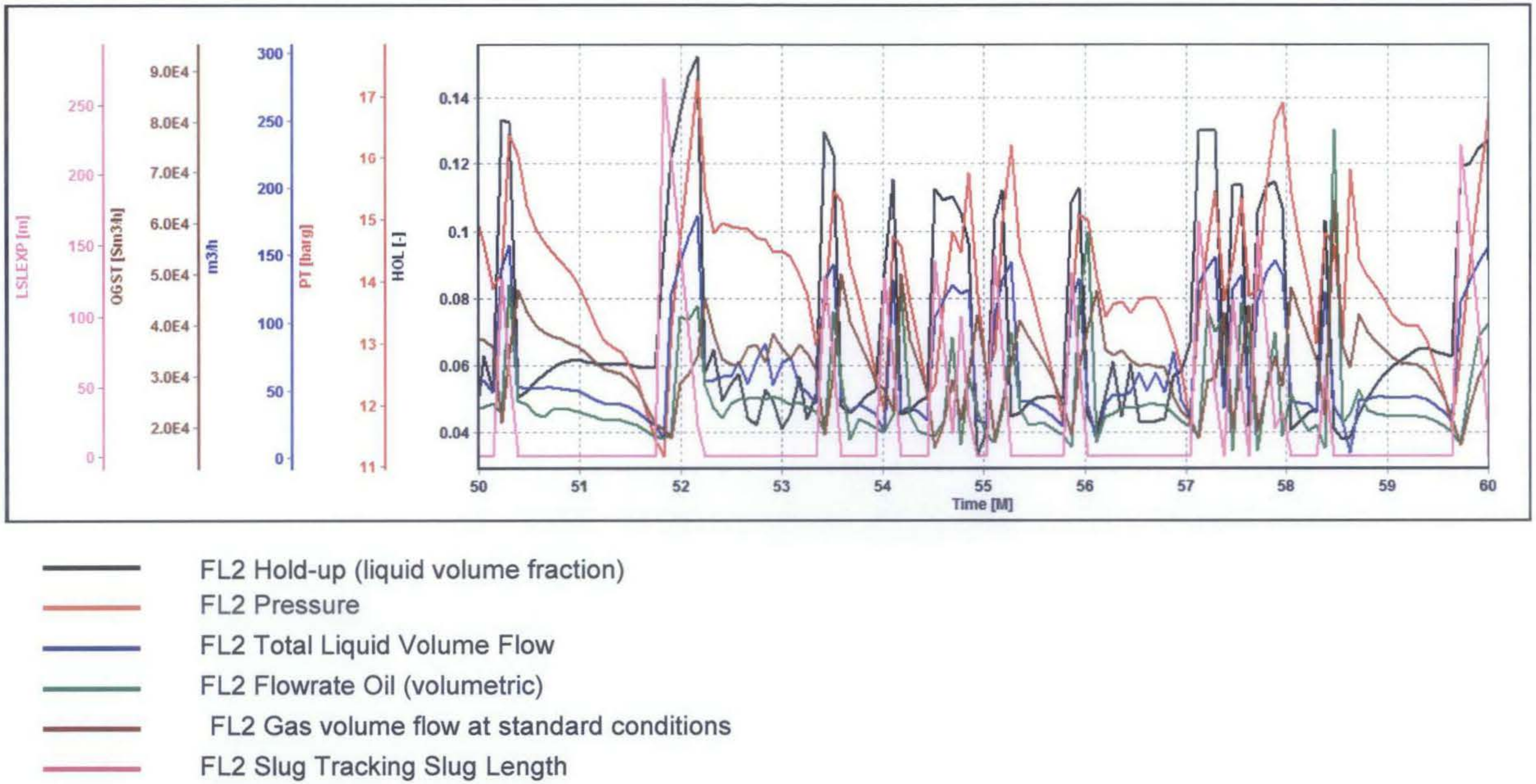
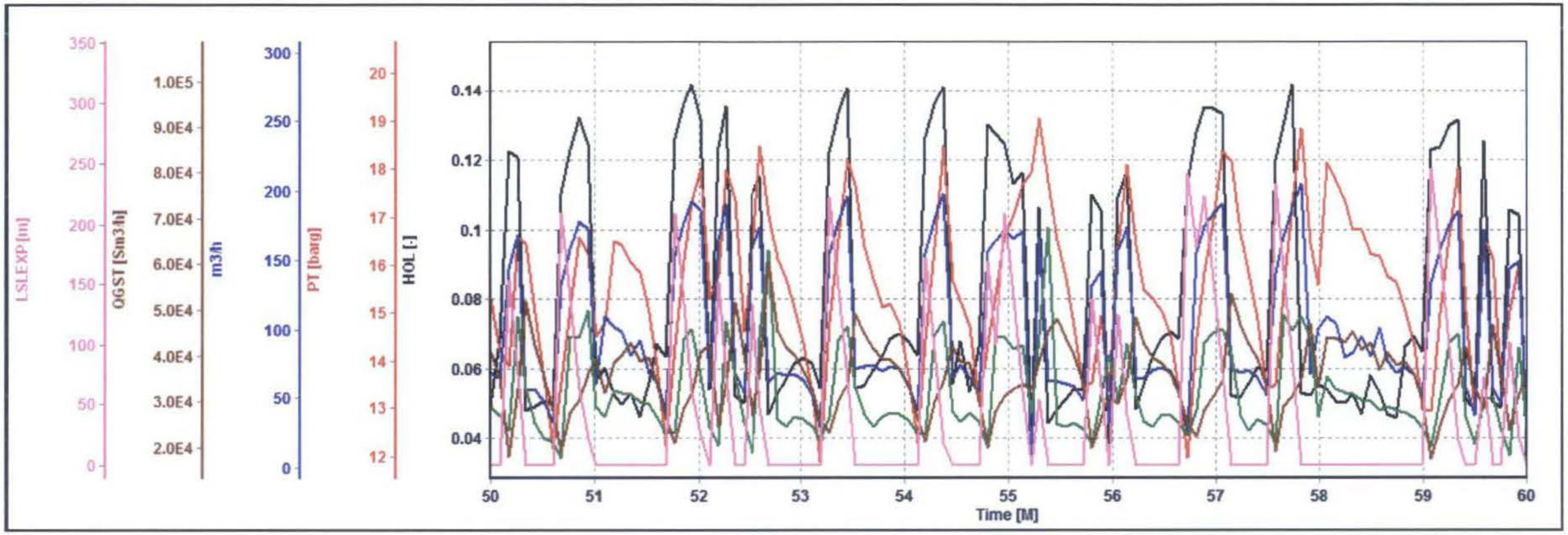


Figure 4-42: FL 2 Routing Alternative Set 2 – High/Low TGLR



FL1 Hold-up (liquid volume fraction)
FL1 Pressure
FL1 Total Liquid Volume Flow
FL1 Flowrate Oil (volumetric)
FL1 Gas volume flow at standard conditions
FL1 Slug Tracking Slug Length

Figure 4-43: FL 1 Routing Alternative Set 3 – High/Low THP

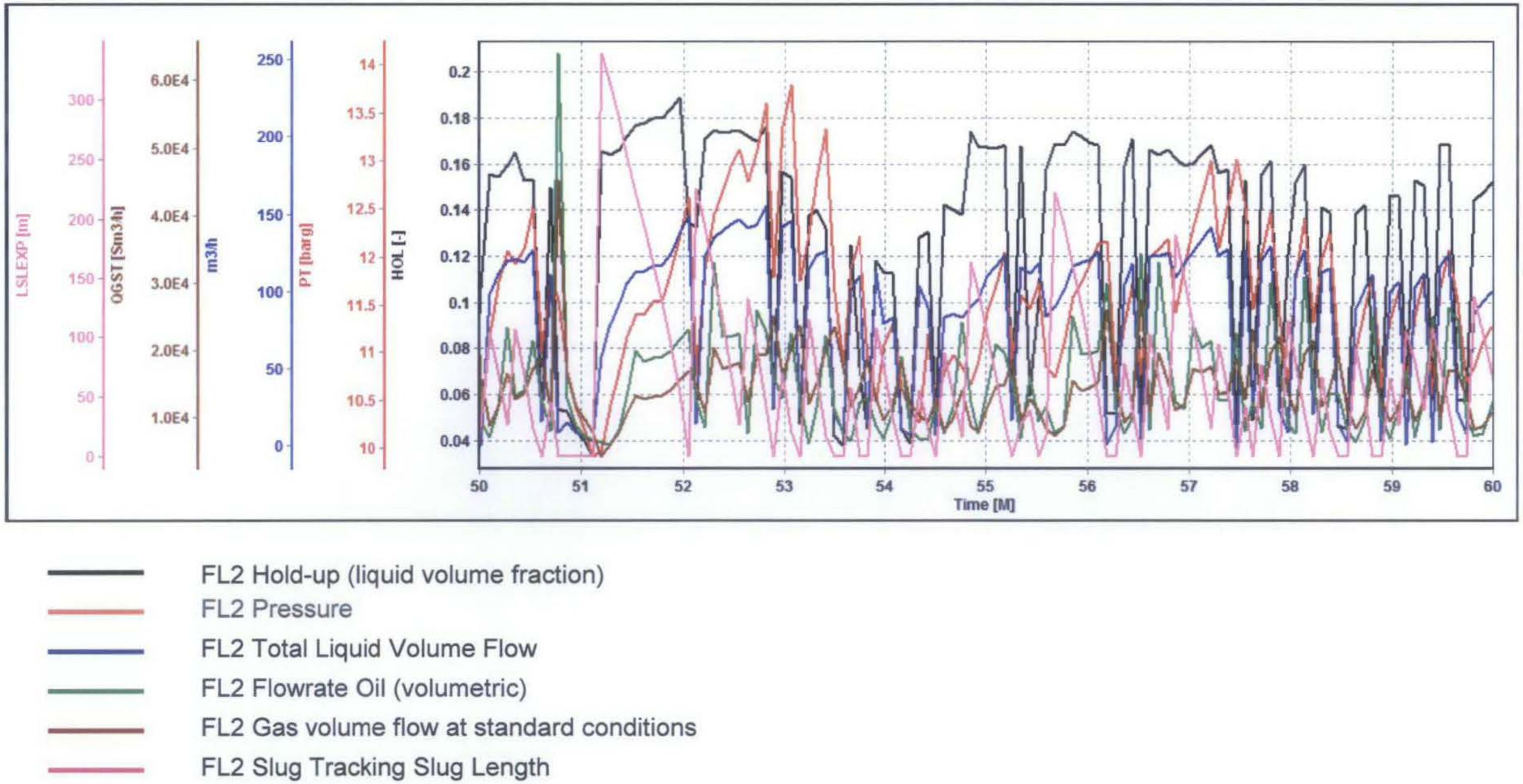


Figure 4-44: FL 2 Routing Alternative Set 3 – High/Low THP

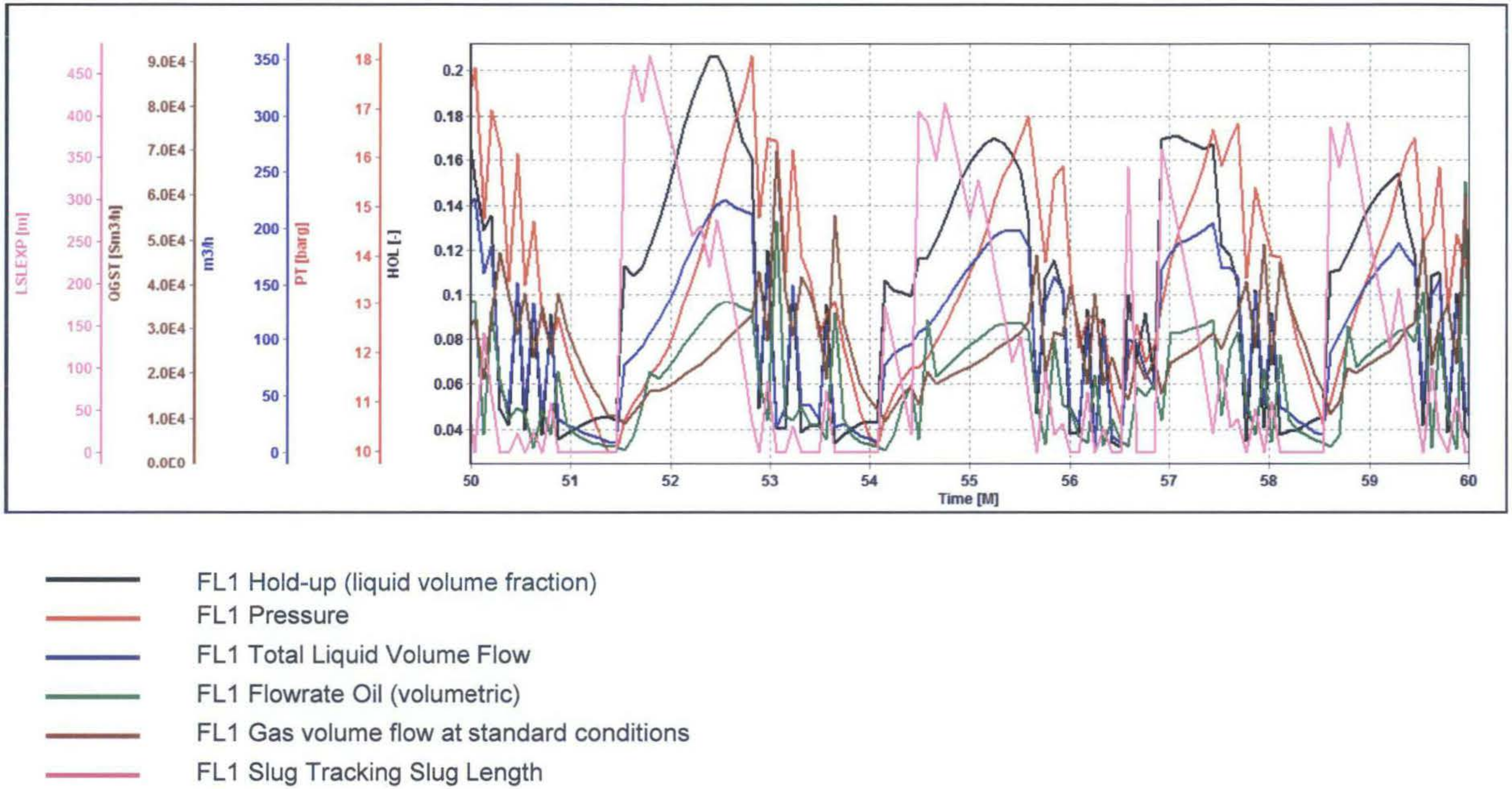


Figure 4-45: FL 1 Routing Alternative Set 4 – Balancing TGLR

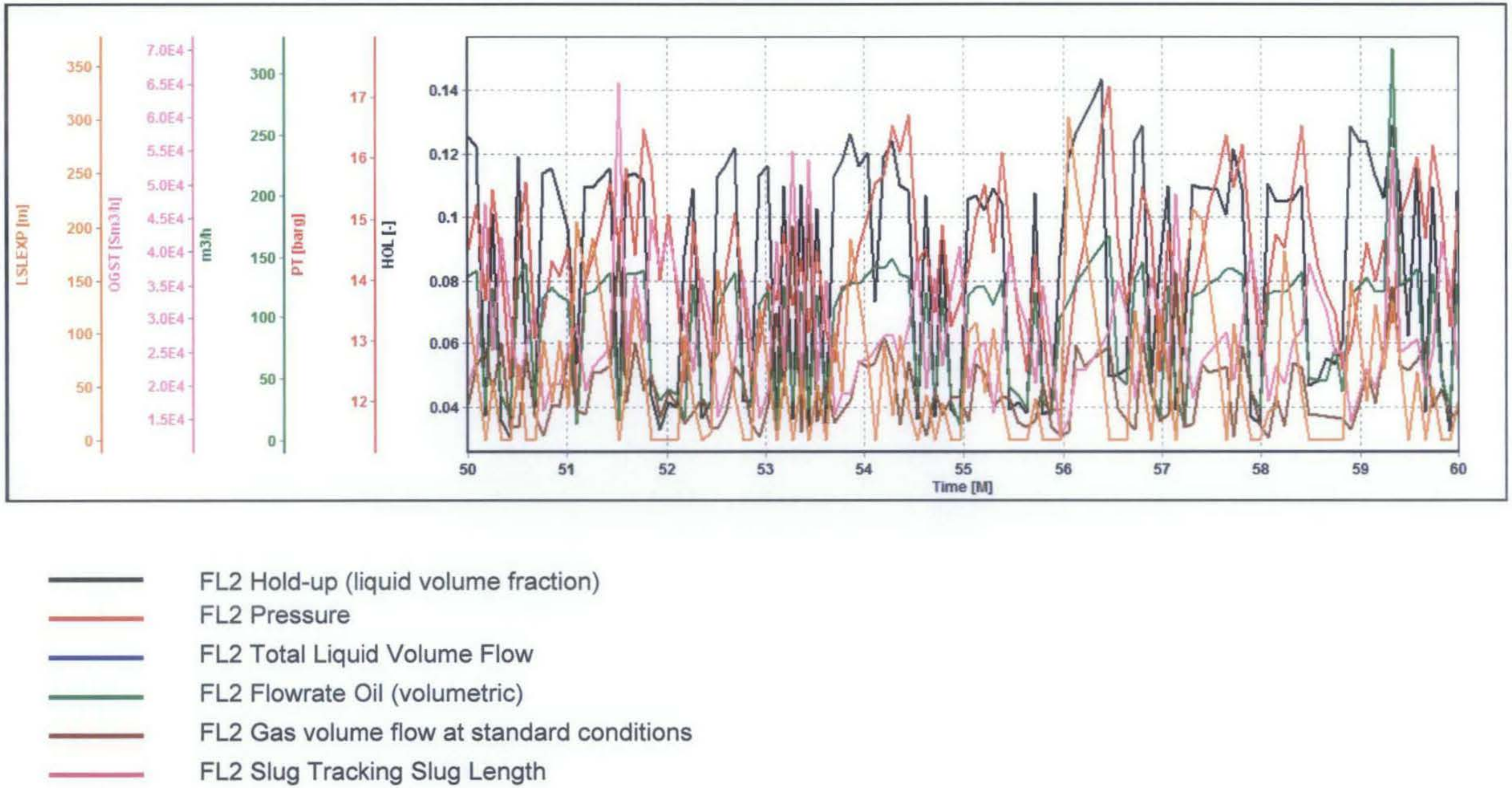


Figure 4-46: FL 2 Routing Alternative Set 4 – Balancing TGLR

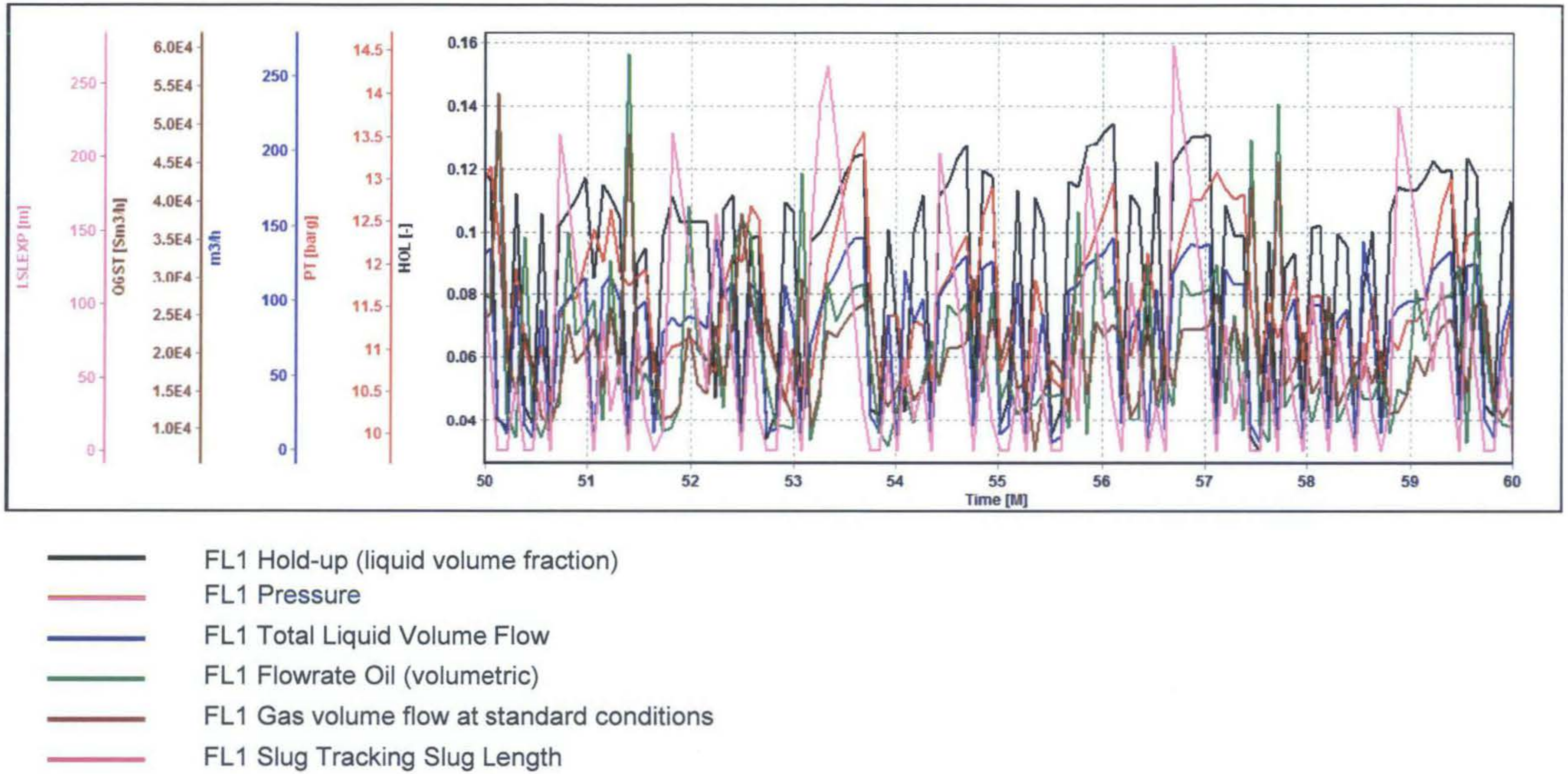
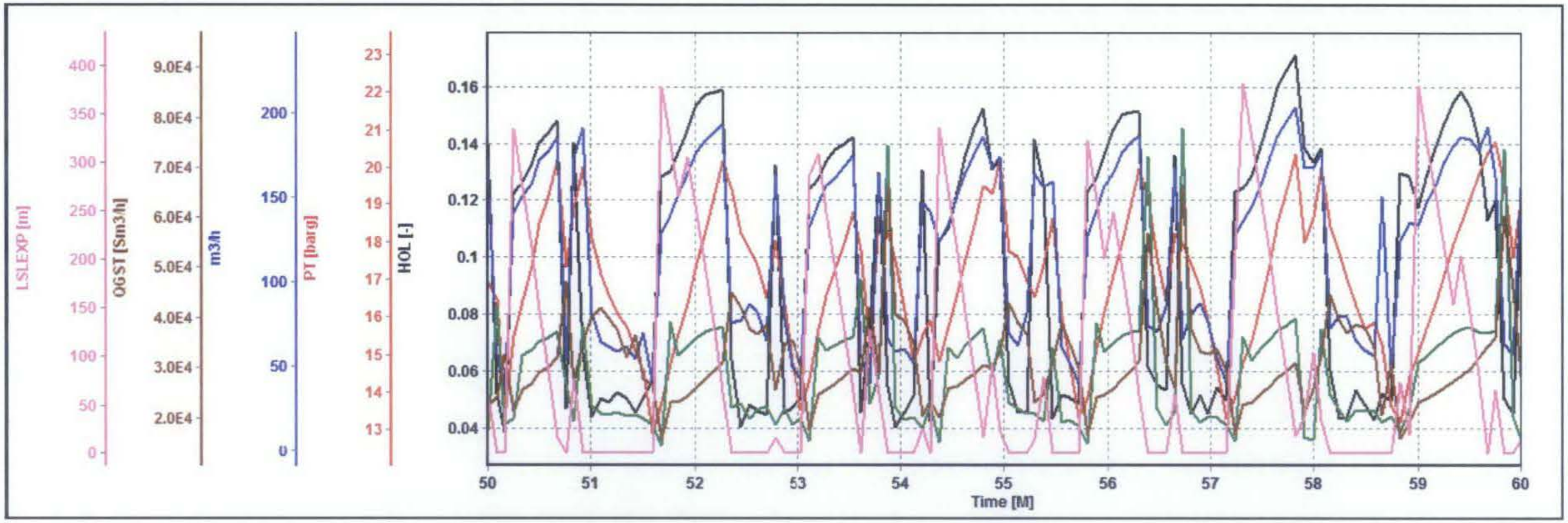


Figure 4-47: FL 1 Routing Alternative Set 5 – Low/High Water Cut



FL2 Hold-up (liquid volume fraction)
FL2 Pressure
FL2 Total Liquid Volume Flow
FL2 Flowrate Oil (volumetric)
FL2 Gas volume flow at standard conditions
FL2 Slug Tracking Slug Length

Figure 4-48: FL 2 Routing Alternative Set 5 – Low/High Water Cut

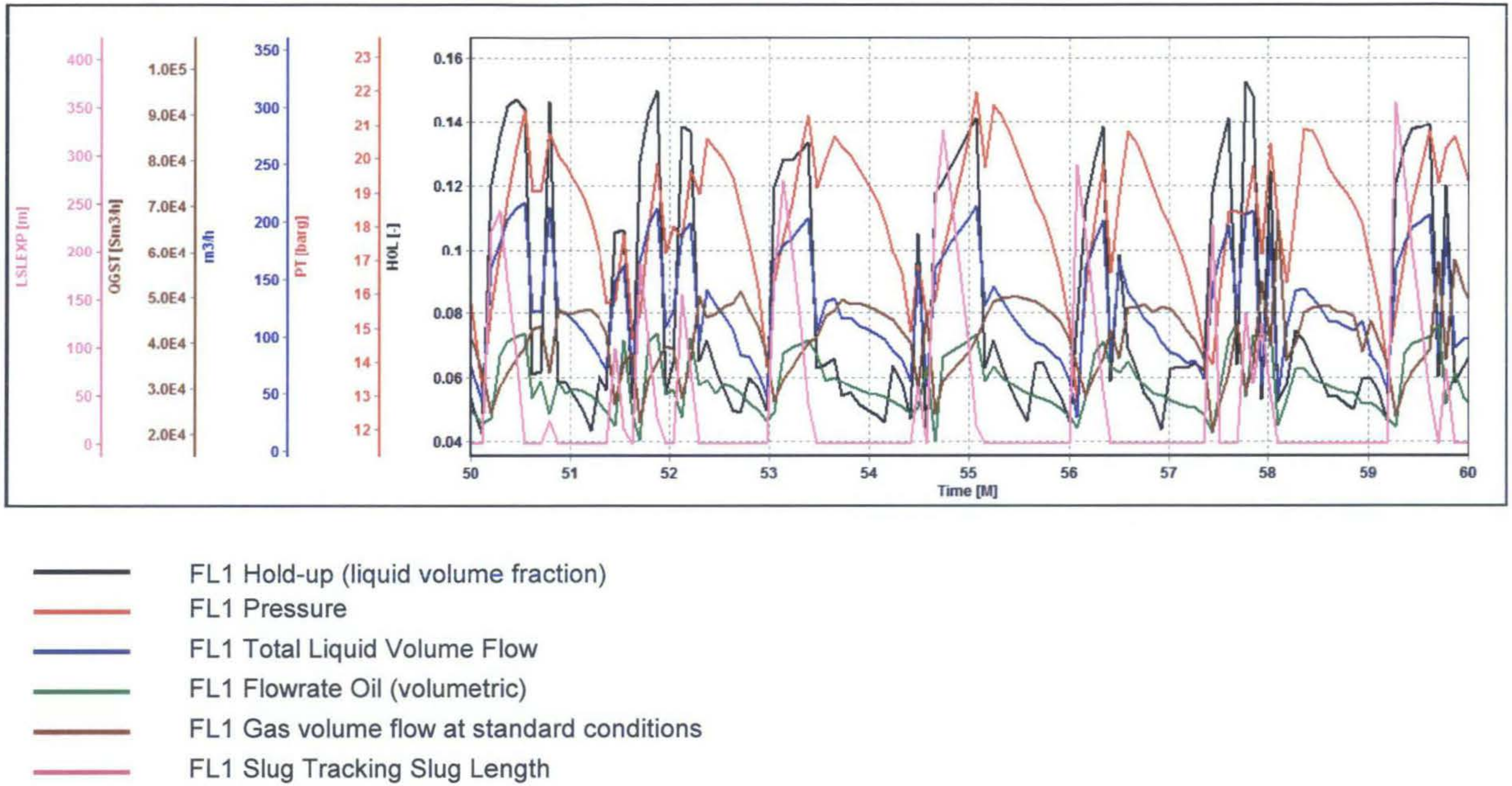
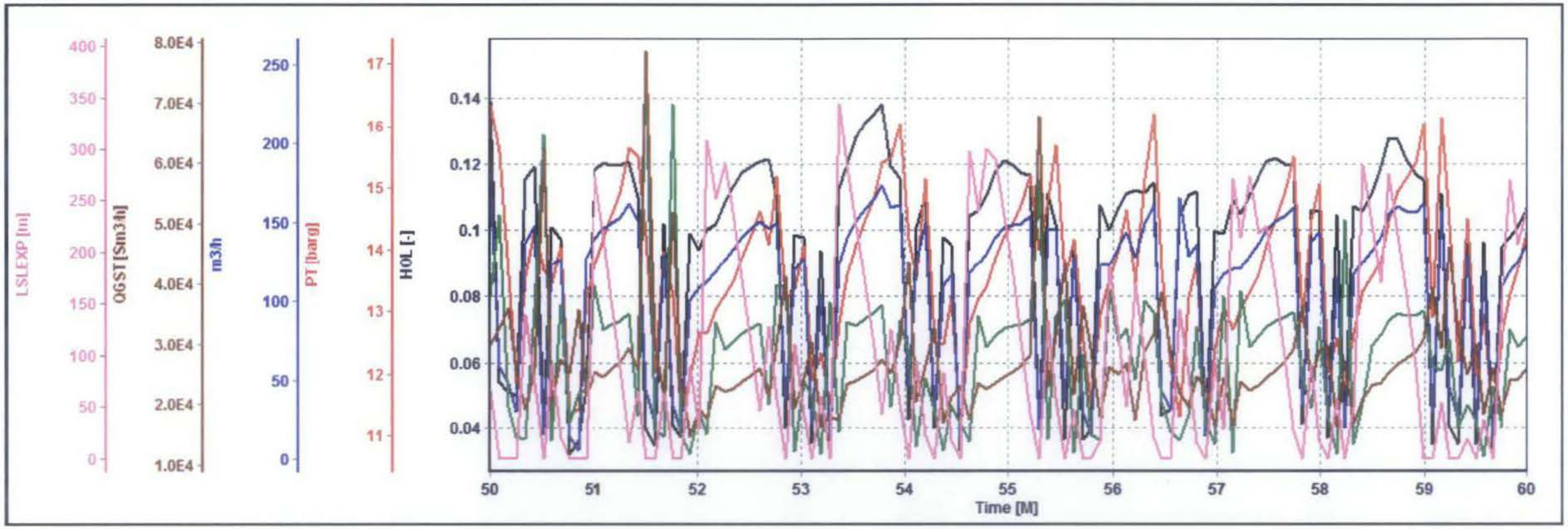
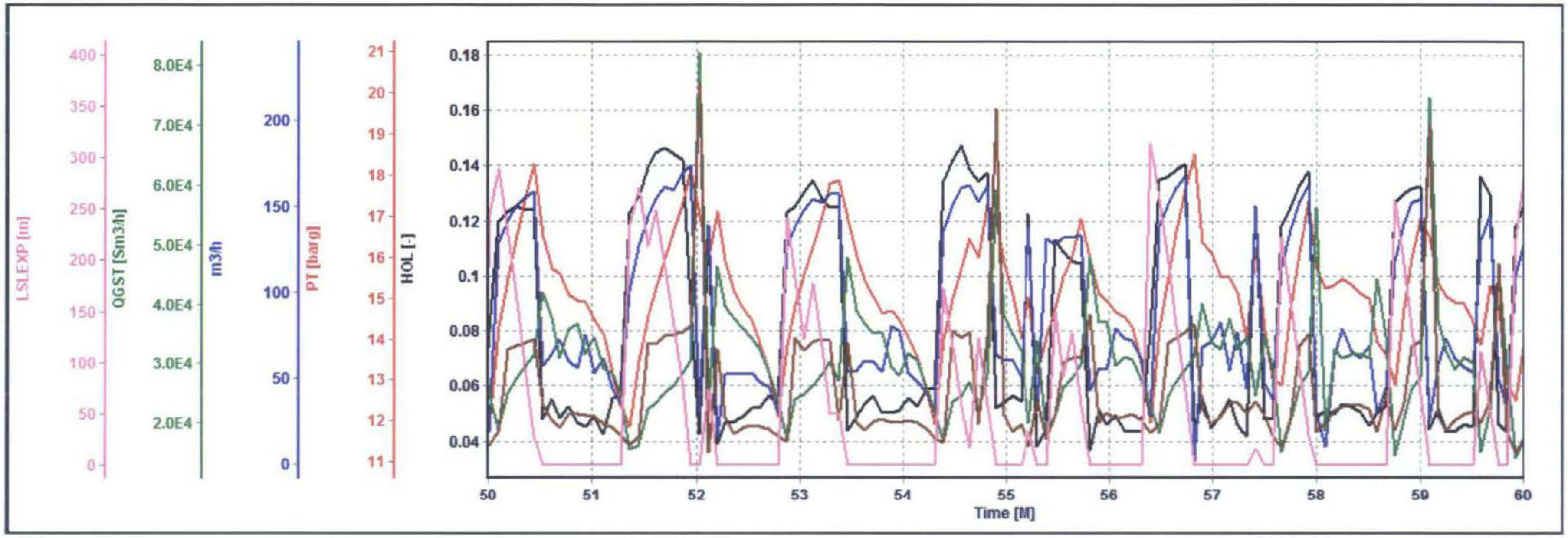


Figure 4-49: FL 1 Routing Alternative Set 6 – All in FL1



FL1 Hold-up (liquid volume fraction)
FL1 Pressure
FL1 Total Liquid Volume Flow
FL1 Flowrate Oil (volumetric)
FL1 Gas volume flow at standard conditions
FL1 Slug Tracking Slug Length

Figure 4-50: Sensitivity FL 1 April 2009 – Increase Gas Lift Rate



FL2 Hold-up (liquid volume fraction)

FL2 Pressure

FL2 Total Liquid Volume Flow

FL2 Flowrate Oil (volumetric)

FL2 Gas volume flow at standard conditions

FL2 Slug Tracking Slug Length

Figure 4-51: Sensitivity FL 2 April 2009 – Increase Gas Lift Rate

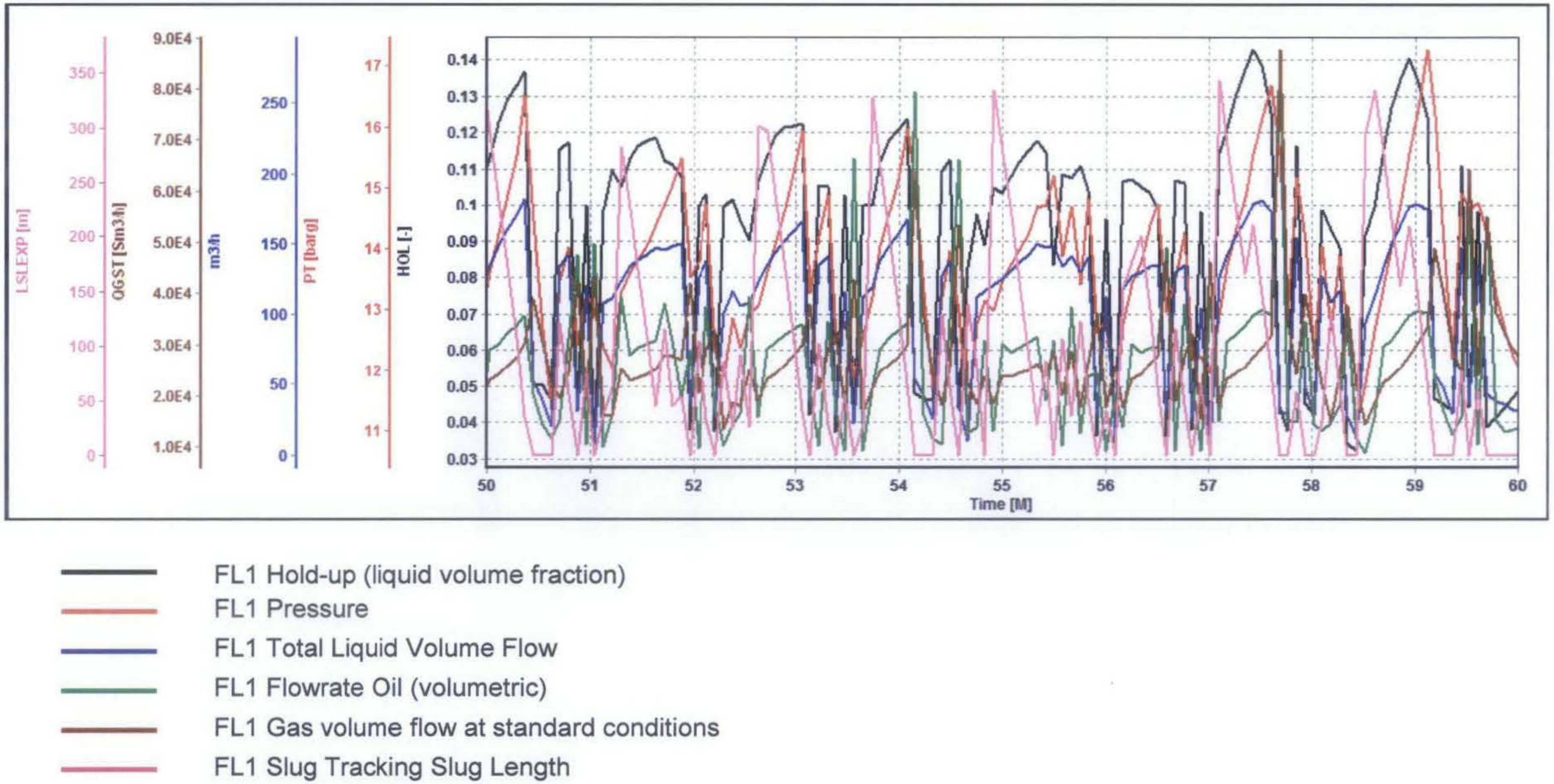
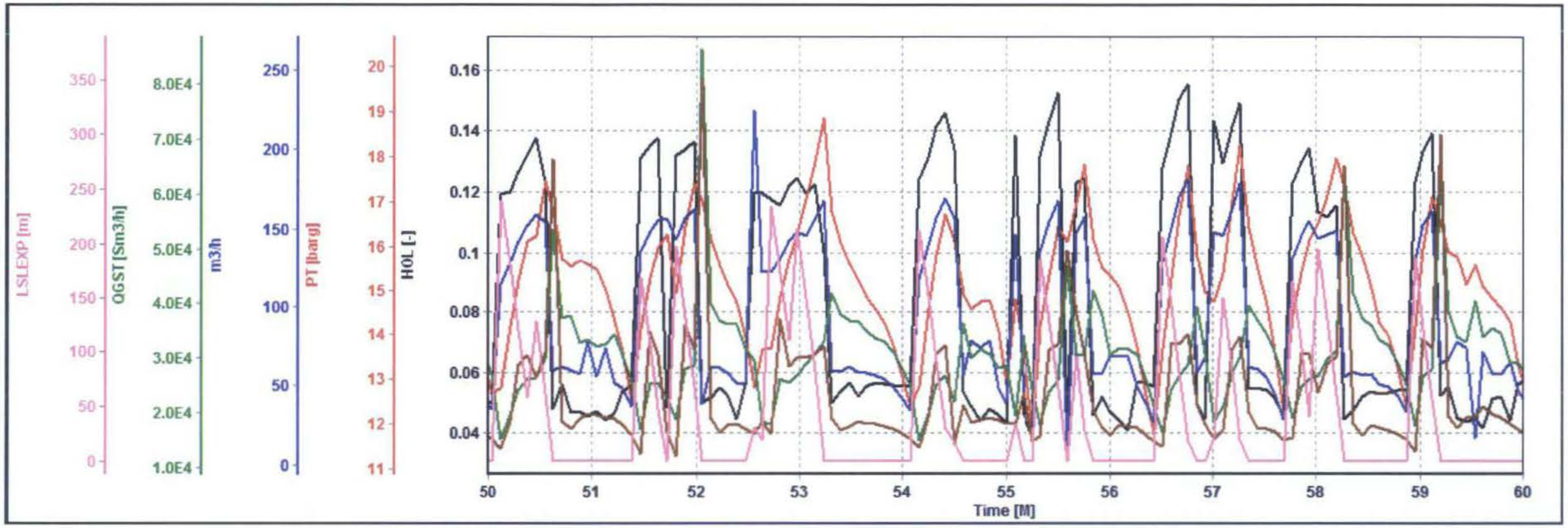
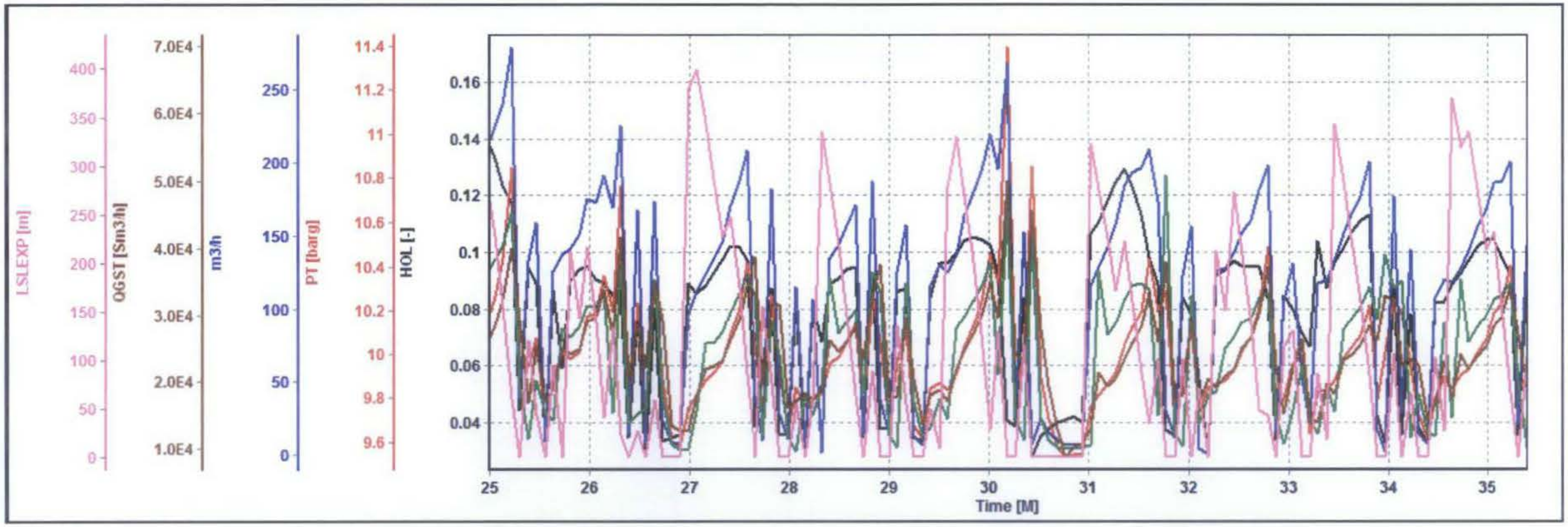


Figure 4-52: Sensitivity FL 1 April 2009 - Injection Gas at Wellhead



FL2 Hold-up (liquid volume fraction)
FL2 Pressure
FL2 Total Liquid Volume Flow
FL2 Flowrate Oil (volumetric)
FL2 Gas volume flow at standard conditions
FL2 Slug Tracking Slug Length

Figure 4-53: Sensitivity FL 2 April 2009 - Injection Gas at Wellhead



FL1 Hold-up (liquid volume fraction)
FL1 Pressure
FL1 Total Liquid Volume Flow
FL1 Flowrate Oil (volumetric)
FL1 Gas volume flow at standard conditions
FL1 Slug Tracking Slug Length

Figure 4-54: Sensitivity FL 1 April 2009 – Riser Choke Full Open

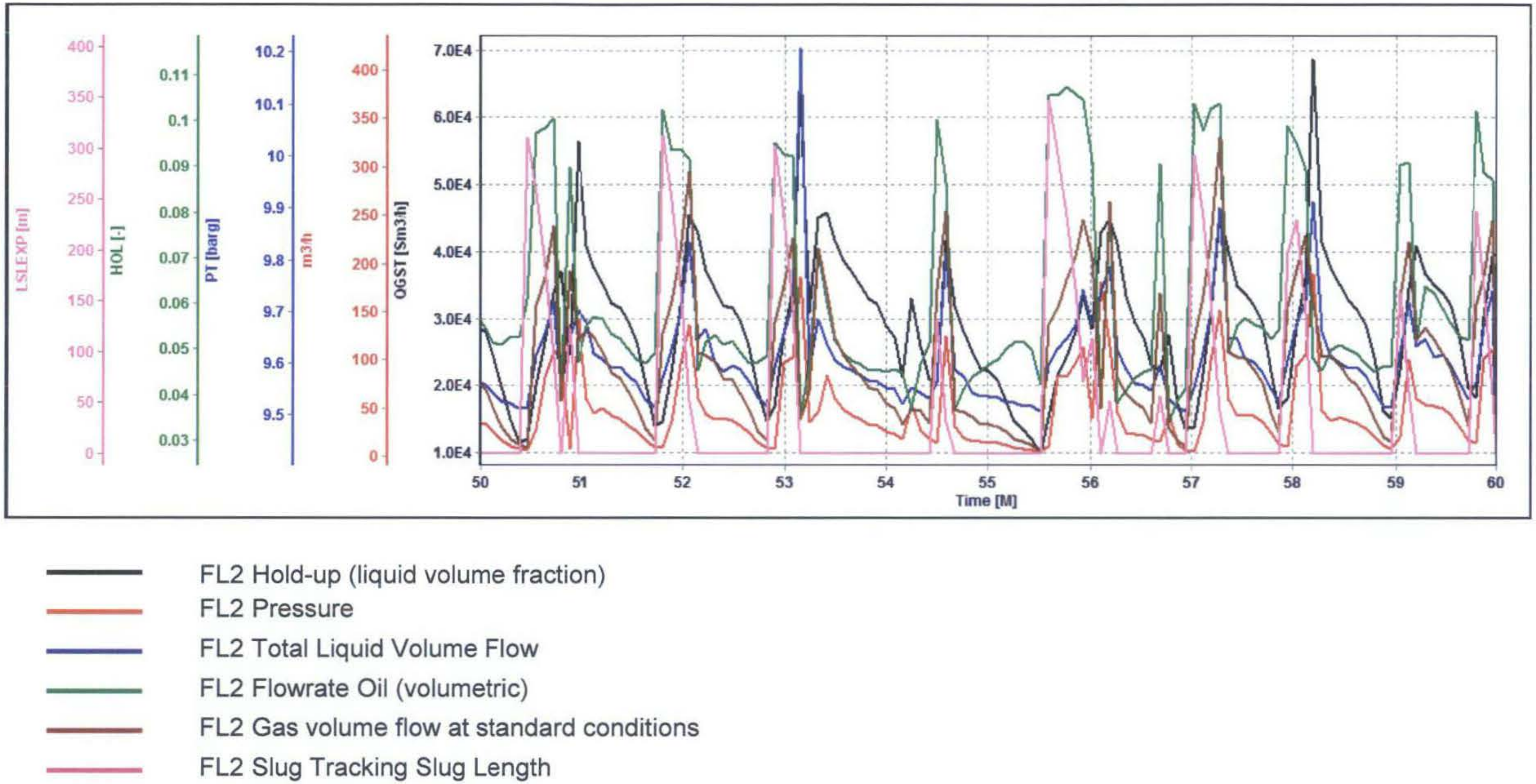


Figure 4-55: Sensitivity FL 2 April 2009 – Riser Choke Full Open

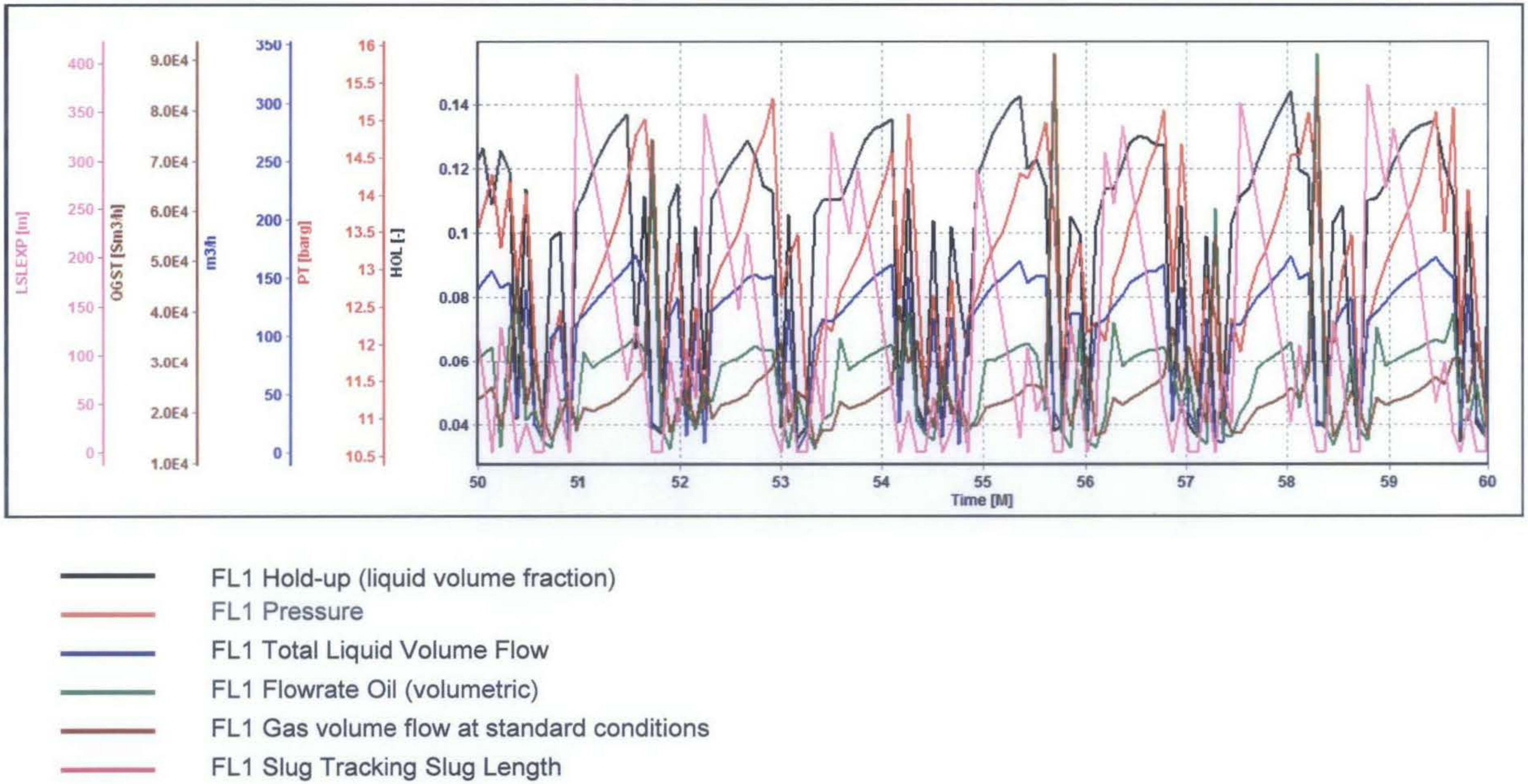
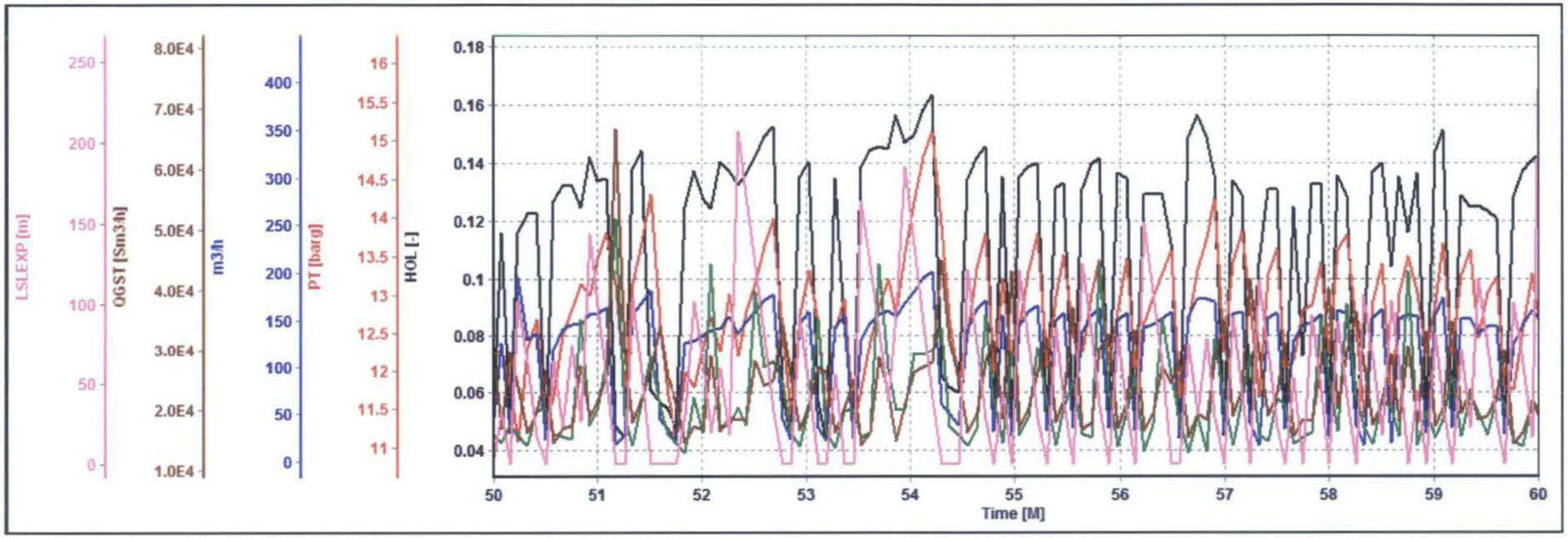


Figure 4-56: Sensitivity FL 1 April 2009 – Increase C18 Wellhead Choke Opening



FL1 Hold-up (liquid volume fraction)
FL1 Pressure
FL1 Total Liquid Volume Flow
FL1 Flowrate Oil (volumetric)
FL1 Gas volume flow at standard conditions
FL1 Slug Tracking Slug Length

Figure 4-57: Sensitivity FL 1 April 2009 – Restrictions Free Flowline

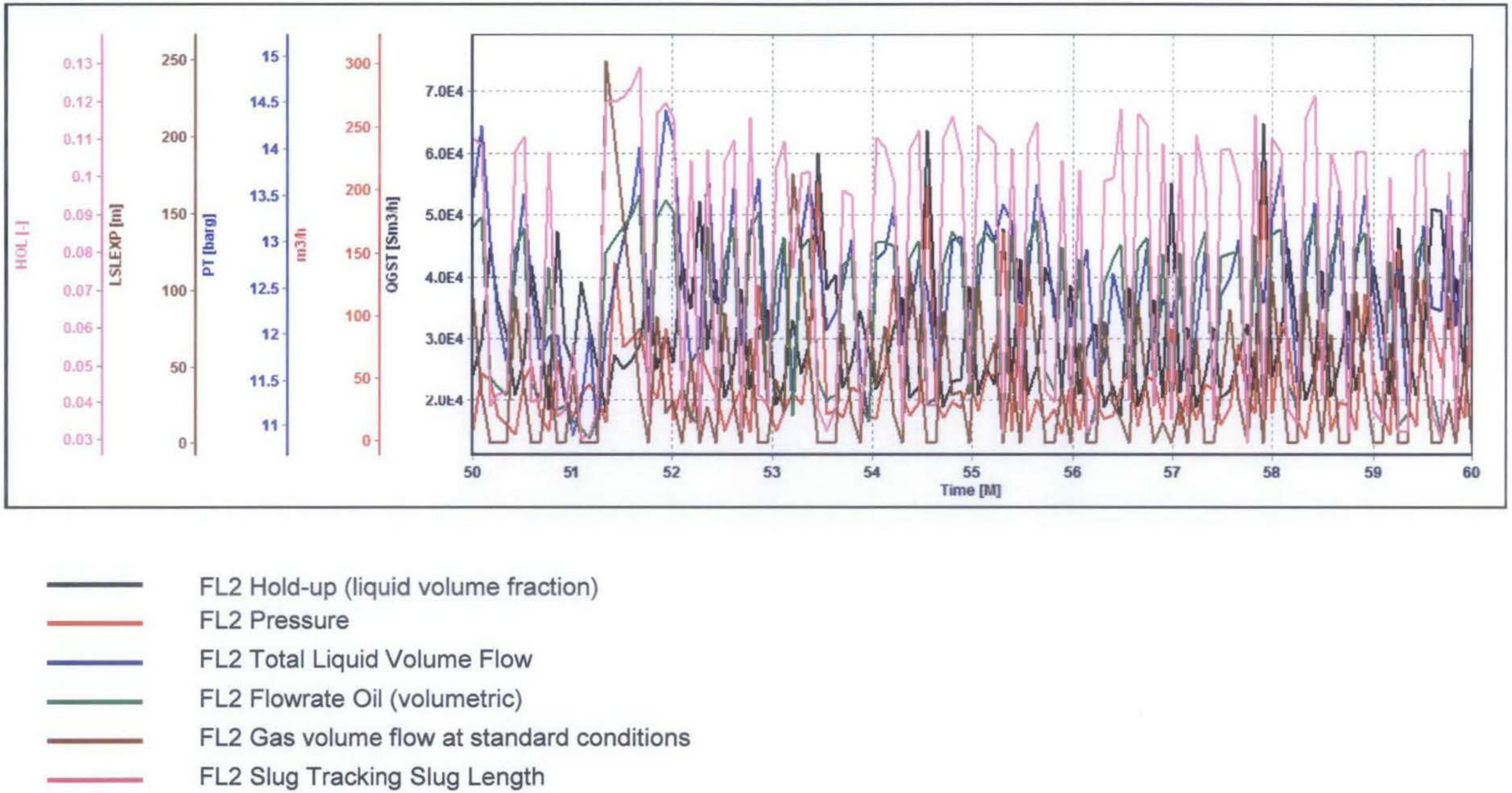
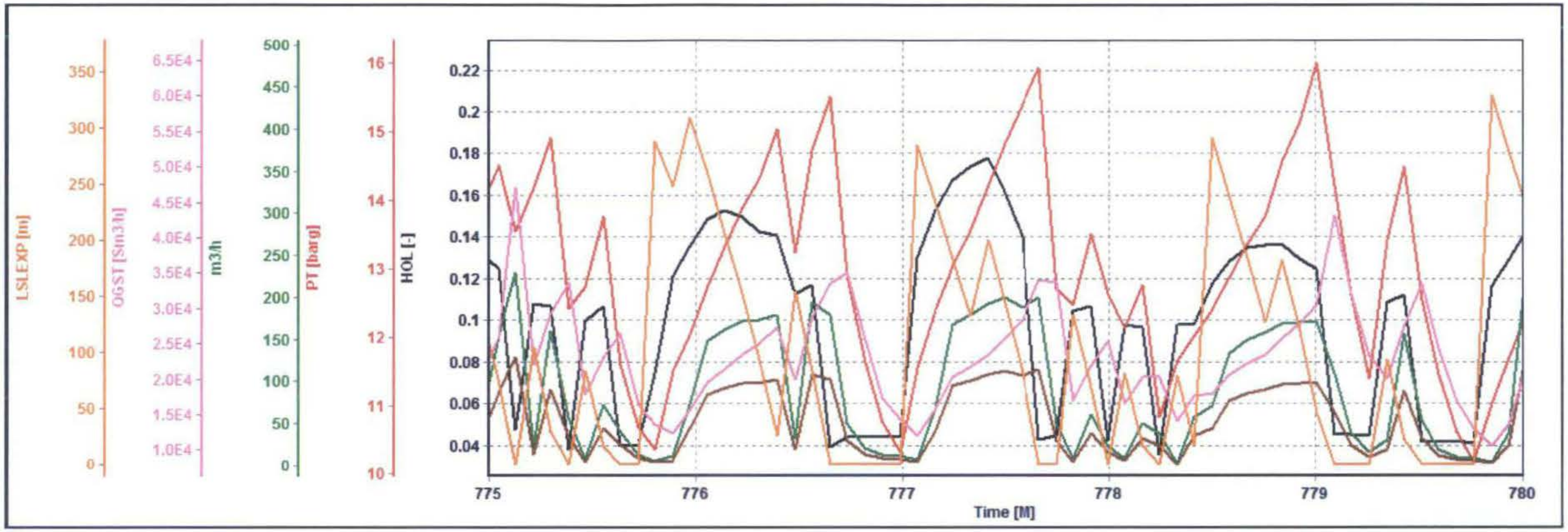


Figure 4-58: Sensitivity FL 2 April 2009 – Restrictions Free Flowline



FL1 Hold-up (liquid volume fraction)
FL1 Pressure
FL1 Total Liquid Volume Flow
FL1 Flowrate Oil (volumetric)
FL1 Gas volume flow at standard conditions
FL1 Slug Tracking Slug Length

Figure 4-59: Sensitivity FL 1 April 2009 – Riser Choke on Automated Control

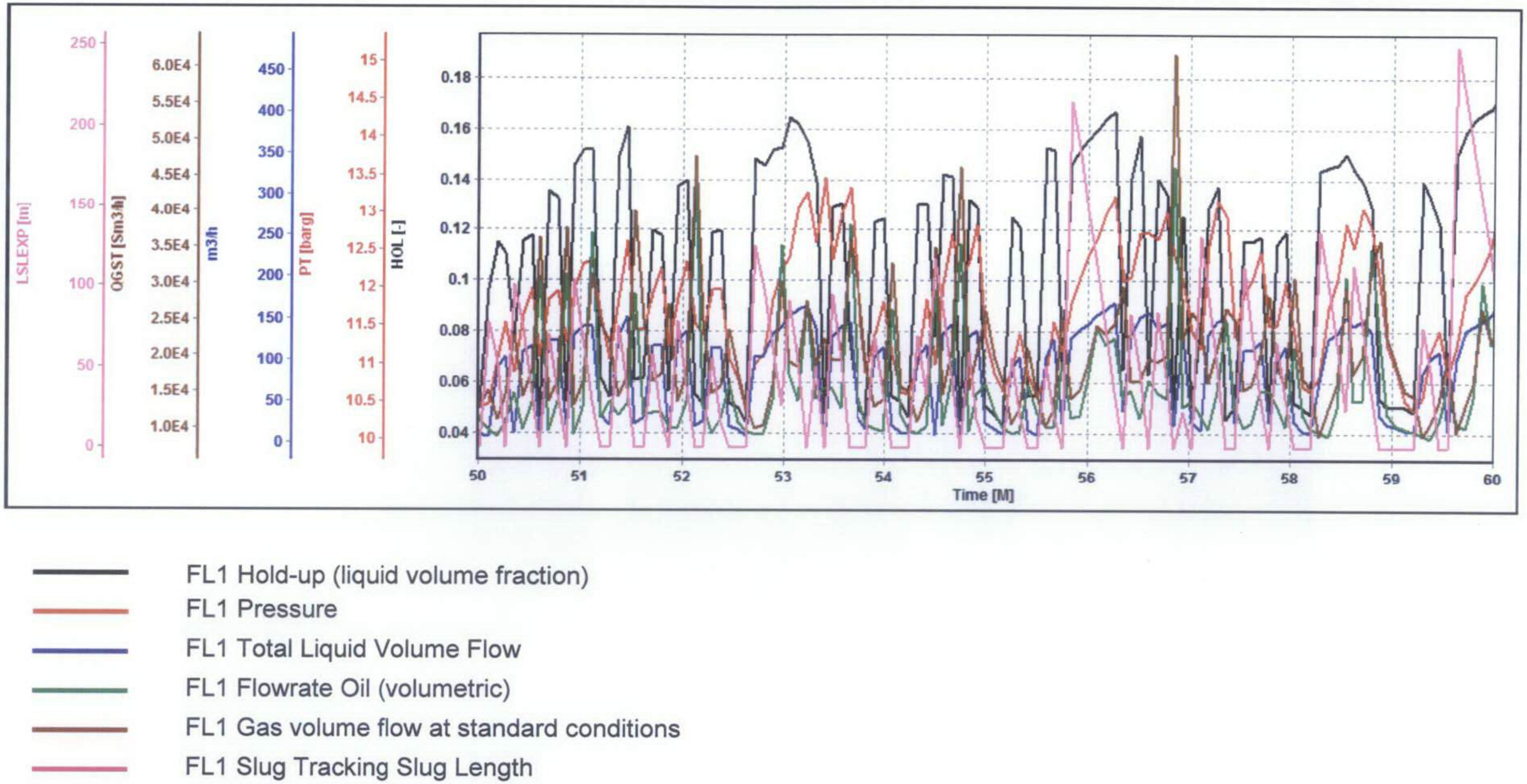
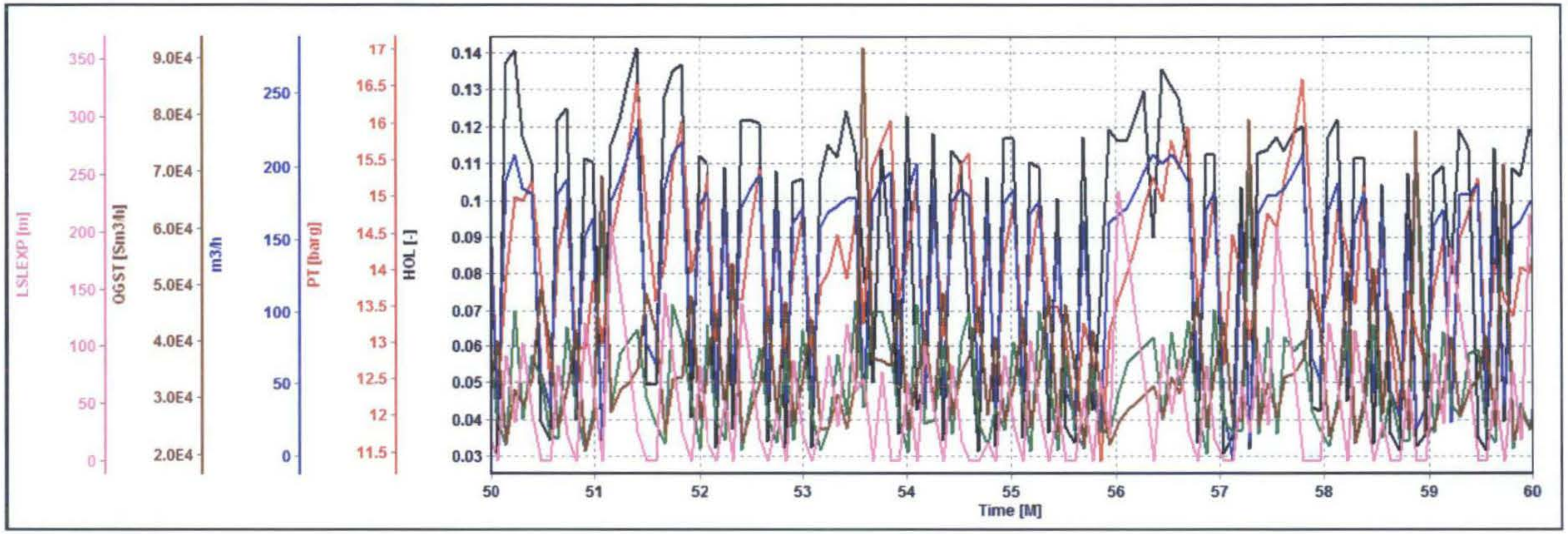


Figure 4-60: Sensitivity FL 1 Set 5 Restrictions Free Flowline



FL2 Hold-up (liquid volume fraction)
FL2 Pressure
FL2 Total Liquid Volume Flow
FL2 Flowrate Oil (volumetric)
FL2 Gas volume flow at standard conditions
FL2 Slug Tracking Slug Length

Figure 4-61: Sensitivity FL 2 Set 5 Restrictions Free Flowline

CHAPTER 5
CONCLUSIONS

CHAPTER 5

CONCLUSIONS

5.1 Conclusions

As the quest for energy advances into deeper waters, the flow instability in flowlines and risers of a subsea oil development is a great concern that has emerged on many fronts. With less energy for the fluids to overcome the system hydrostatic head, for that reason slugging phenomenon exists. This situation is further aggravated by the changes in the reservoir performance and behavior as a result of rapid natural depletion. Due to the changes in phase flow rates against the design capacity of the flowlines and risers, obviously the "oversized" oil transportation system will most certainly have an effect on slugging during the gas liberation (flashing) cycle. In addition, riser induced severe slugging may be a result of too large flowlines and risers, however as described in the basic theory, large riser size can actually prevent severe slugging Boe (1981) at the expense of increased pressure drop due to high liquid holdup. Thus, in this study two production data have been used as a comparison to determine the severity of slugging when the facility is new and with high phase flow rates and when the facility is experiencing rapid reservoir depletion that leads to reduction in phase flow rates.

Past work by researchers on slugging prediction and method has been a motivation in this study. The subject of multiphase flow in large diameter flowlines and risers is not well understood with nearly all the available data having been collected from experiments with diameters less than 5 inches. For the offshore oil and gas industry especially in deepwater, current design procedure relies on the unsubstantiated extrapolation of correlations on the results from these small diameter pipes to the larger diameter flowlines and risers used in practice. It is reasonable to believe that large diameter risers will give different flow characteristics than small ones. There will be less hydrodynamic slugging and more

annular flow in vertical large-diameter flowlines-risers than in smaller diameters Hewitt (1999).
Of all the flow correlations for modeling of multiphase flow in oil and gas production system, only OLGA correlations can claim to have been developed for flows of larger diameter Pickering et al., (2001). Hence, OLGA is the only multiphase flow simulation tool that was developed using data collected in the 8 inch SINTEF flow loop which include a 50 m riser.

Current available data that represents flow instability in flowlines and risers in live field conditions has not been published in any literature. The available data is mostly from laboratory controlled conditions or laboratory scale ideal condition. This study is considered to be unique and differs from past work done by researchers whereby it was carried out in real field instead of laboratory scale ideal condition. Model using laboratory conditions has limited capability that cannot be used to assess severity of slugging and flow instability.

In this work a methodology has been developed by using OLGA transient multiphase flow simulator to construct the models for FL1 and FL2 risers. To test the methodology that was developed, the models undergo serial of field validation and flow instability sensitivity analysis. Simulations were performed to examine the impact of various changes in operating conditions that include changes in well routings, gas lift injection rates and location of injection points, riser and well choke openings. The degree of fluctuations in liquid arrival rates and the characteristics of liquid slugs (length and frequency) were used to categorize the severity of flow instabilities for the different operating conditions. Finally, various strategies have been examined to mitigate the flow instability that could stabilize the phase flow rates with the ultimate aim to maximize oil recovery from the reservoir.

From the field implementation results, the slugging characteristics analysis indicated that the slugging frequencies and average lengths of the slugs varied with different well routing options as tabulated in Table 4-19 and Table 4-20. The stability index used to compare the relative flow instabilities for the different flow rates and conditions revealed that the entire production systems were highly unstable. The stability indices were

generally low in Set 2 and Set 5 indicating that the flows were more stable in Set 2 and Set 5 as tabulated in Table 4-16 in Set 2 of FL1 and Table 4-17 in Set 5 of FL2.
With further analysis, Set 5 was considered as the preferred option and it was put to field tests for about two weeks period. As shown in Table 4-22, the net oil production from the two flowlines was found to increase gradually from 9,400 to 10,600 barrels of oil per day (BOPD). The net oil production from the flowlines had stabilized in the range of 10,500 and 10,600 BOPD which was approximately 12% more than what was initially predicted by the OLGA model at 8%. With the stable production it reflects a significant economic value to the system as well as a prudent manner in managing flow instability.

One of the contributions of the research is the application of the methodology to assess severe slugging in deepwater flowlines and risers which are not only applicable to Chinguetti field, but it can be applied to other fields similar in nature as well. It is hoped that the research will promote widespread application of the developed methodology for the management of flow instability in deepwater flowlines and risers. Applying this will not only make the industries more efficient, but also globally competitive for the oil and gas operators to develop more deepwater oil and gas fields.

In concluding, this study has met its objectives in entirety whereby an engineering transient simulation model has been developed to assess the severity of slugging and flow instability in the subsea oil production systems. The model has been put to field trial to examine its robustness and capability in assessing slugging phenomena. The results from field implementation have indicated improvement in flow stability in flowlines and risers as well as able to maximize oil recovery from the reservoir. The success of this study was found to be dependent not only upon inputs and assumptions made in the production system models but also on the outcome of the field validation exercises, and the understanding of pertinent governing factors influencing slugging behavior.

5.2 Recommendations for Future Work

In order to improve on the outcome of this study and its overall impact on the subject of flow instability in deepwater flowlines and risers, the following future works are recommended:

- To revalidate the model once more reliable well performance from each individual well becomes available
- Adoption of the developed methodology for flow instability in deepwater flowlines and risers by field operators and other stake holders for future developments and enhancement
- Collaborative research with industry stakeholders in order to leverage on knowledge, obtain engineering, technological and economic data and harmonize perspectives of flow instability modeling in deepwater oil production system

6.0 REFERENCES

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6.1 APPENDIXES

6.1.1 Basic Equations of OLGA

Following are the conservation equations of the two-fluid model OLGA. Separate continuity equations for the gas, liquid bulk and liquid droplets are applied. Two momentum equations are used, combined one for the gas and possible liquid droplets, and a separate one for the liquid film. By introducing an average temperature for gas and liquid only one energy conservation equation is applied.

Conservation of Mass

Gas Phase:

$$\frac{\alpha}{\alpha_t}\left(f_{G\rho G}\right) = -\frac{1}{A}\frac{\alpha}{\alpha_z}\left[A_{fG\rho GvG}\right] + \psi_G + G_G \tag{1}$$

Liquid Phase at the wall:

$$\frac{\alpha}{\alpha_t}\left(f_{L\rho L}\right) = -\frac{1}{A}\frac{\alpha}{\alpha_z}\left[A_{fL\rho LvL}\right] - \psi_G\frac{f_L}{f_L+f_D} - \psi_e + \psi_d + G_L \tag{2}$$

Liquid droplets:

$$\frac{\alpha}{\alpha_t}\left(f_{D\rho L}\right) = -\frac{1}{A}\frac{\alpha}{\alpha_z}\left[A_{fD\rho LvD}\right] - \psi_G\frac{f_D}{f_L+f_D} + \psi_e - \psi_d + G_D \tag{3}$$

Where $f_{G,}f_L, f_D$ are the gas, liquid film and the liquid droplet volume fractions, ρ, v, p are the density, velocity, and pressure, and A is the pipe cross-section. Subscripts $G, L, i,$ and D indicate gas, liquid, interface and droplets respectively. $\psi_G$is the mass transfer rate between the phases; ψ_e, ψ_d are the entrainment and deposition rates and G_f is a possible mass source of phase f.

Conservation of Momentum

The momentum equations for gas and liquid droplets have been summed together, yielding a combined momentum equation. The gas/droplet drag terms will then cancel out. The momentum equations will then read:

Combined gas/droplet momentum equation:

$$\frac{\alpha}{\alpha_t}\left(f_{G\rho G v G} + f_{D\rho L v D}\right) = -(f_G + f_D)\left(\frac{\alpha_p}{\alpha_z}\right) - \frac{1}{A}\frac{\alpha}{\alpha_z}\left[A_{f G\rho G v^2 G} + A_{f D\rho L v^2 D}\right] -$$

$$\lambda_G \frac{1}{2}\rho_G |v_G| v_G \frac{S_G}{4A} - \lambda_i \frac{1}{2}\rho_G |v_R| v_R \frac{S_i}{4A} + \left[f_{G\rho G} + f_{D\rho L}\right] g \cos\alpha + \psi_G \frac{f_L}{f_{L+f_D}} v_\alpha + \psi_e v_i - \psi_d v_D$$

(4)

Liquid at the wall:

$$\frac{\alpha}{\alpha_t}\left(f_{L\rho L v L}\right) = -f_L\left(\frac{\alpha_p}{\alpha_z}\right) - \frac{1}{A}\frac{\alpha}{\alpha_z}\left[A_{f L\rho L v^2 L}\right] - \lambda_L \frac{1}{2}\rho_L |v_L| v_L \frac{S_L}{4A} + \lambda_i \frac{1}{2}\rho_G |v_R| v_R \frac{S_i}{4A} + +$$

$$f_{L\rho L g cos\alpha} - \psi_G \frac{f_L}{f_{L+f_D}} v_\alpha - f_L d(\rho_L - \rho_G) g \frac{\alpha_{fL}}{\alpha_Z} \sin\alpha - \psi_e v_i + \psi_d v_D$$

(5)

Where α is the pipe inclination with the vertical and the internal source is assumed to enter at an angle of 90° to the pipe wall, carrying no net momentum. S_G, S_L and S_i are the wetted perimeters of gas, liquid and the interface. The velocity, v_a, is equal to the liquid, droplet or gas velocity depending on whether an evaporation or condensation occurs. The relative velocity v_R is defined by a distribution slip formula. The interphase velocity, v_i, is approximately by v_L.

The Pressure Equation

In OLGA the problem is reformulated before discretizing the differential equations to obtain a pressure equation. This equation may, together with the momentum equations, be solved simultaneously for the pressure and phase velocities and thus allow a step-wise time integration.

The conservation of mass equations (1-3) may be expanded with respect to the pressure, temperature and composition, assuming the densities to be given as

$\rho_{f=}\rho_f(p,T,R_s)$

(6)

Where the gas-mass fraction, R_s, is defined by

$$R_s = \frac{m_G}{m_G+m_L+m_D}$$

(7)

m_G, m_L and m_D are the specific mass of gas, liquid film and liquid droplets respectively.

From the mass continuity equations (1-3) using (6-7) we obtain a single equation for the pressure and phase fluxes;

$$\left[\frac{f_G}{\rho_G}\left(\frac{\alpha\rho_G}{\alpha_p}\right)T,R_s+\frac{1-f_G}{\rho_L}\left(\frac{\alpha\rho_L}{\alpha_L}\right)T,R_s\right]\frac{\alpha_p}{\alpha_t} = -\frac{1}{A\rho_G}\frac{\alpha(A_{fG}\rho_G v_G)}{\alpha z}-\frac{1}{A\rho_L}\frac{\alpha(A_{fL}\rho_L v_L)}{\alpha z}-\frac{1}{A\rho_L}\frac{\alpha(A_{fD}\rho_D v_D)}{\alpha z}$$
$$+\psi_G\left(\frac{1}{\rho_G}-\frac{1}{\rho_L}\right)+G_G\frac{1}{\rho_G}+G_L\frac{1}{\rho_L}+G_D\frac{1}{\rho_L}$$

(8)

The Energy Equation

A mixture energy conservation equation is applied:

$$\frac{\alpha}{\alpha_t}\left[m_G\left(E_G+\frac{1}{2}v^2G+gh\right)+m_L\left(E_L+\frac{1}{2}v^2L+gh\right)+m_D\left(E_D+\frac{1}{2}v^2D+gh\right)\right]=$$
$$-\frac{\alpha}{\alpha_Z}\left[m_G v_G\left(H_G+\frac{1}{2}v^2G+gh\right)+m_L v_L(H_L+v^2L+gh)+m_D v_D\left(H_D+\frac{1}{2}v^2D+\right.\right.$$
$$gh+Hs+Q \quad (9)$$

Where E is the internal energy per unit mass, H is the enthalphy from mass sources and Q is the heat transfer from pipe walls.

Interfacial Mass Transfer

If the phase transfers term ψ_G is a function of pressure, temperature and composition

$$\psi_G = \psi_G(p,T,R_s) \quad (10)$$

ψ_G may be expanded by a Taylor series in p, T, and R_s:

$$\psi_G = \left[\left(\frac{\alpha R_s}{\alpha p}\right)T\frac{\alpha p}{\alpha t} + \left(\frac{\alpha R_s}{\alpha p}\right)T\frac{\alpha p}{\alpha z}\frac{\alpha z}{\alpha t} + \left(\frac{\alpha R_s}{\alpha T}\right)p\frac{\alpha T}{\alpha t} + \left(\frac{\alpha R_s}{\alpha T}\right)p\frac{\alpha T}{\alpha z}\frac{\alpha z}{\alpha t}\right](m_G + m_L + m_D) \quad (11)$$

The term $\left(\frac{\alpha R_s}{\alpha p}\right)T\frac{\alpha p}{\alpha t}$ represents the phase transfer from a mass present in a section due to pressure change in that section. The term $\left(\frac{\alpha R_s}{\alpha p}\right)T\frac{\alpha p}{\alpha z}\frac{\alpha z}{\alpha t}$ represents the mass transfer due to mass flowing from one section to next. As only derivatives of R_s appear in equation (11), errors due to the assumption of constant composition are minimized. The applied interface mass transfer model is able to treat both normal condensation or evaporation, and retrograde condensation, in which a heavy phase condenses from the gas phase as the pressure drops.