Development overview, Tui area, Taranaki Basin

C C Stewart

Project Director, Tui Area Development Project Management Team and Principal, Alpha Petroleum Services, Suite 200, 507 N. Sam Houston Pkwy, Houston, Texas, 77060
Email: ccrandys@alphapetroleum.net

Exploration history

The PEP 38460 permit (Fig 1) is a 3797 sq. km. area located 50 km west of the North Island of New Zealand in the Taranaki Basin in water depths of 125 meters. This permit was awarded to New Zealand Oil and Gas (NZOG) and partners in September 1996 with a 5 year term and a work commitment of 2D seismic acquisition, processing and one exploratory well. Regional mapping of the 2D seismic grid resulted in the identification of several large prospects named Hochstetter, Hector, Pukeko, Tahuroa, and Tui. The Hochstetter-1 was the first prospect drilled by NZOG (2000). It penetrated thick, high quality sands in the Kapuni "D" and Kapuni "F" intervals but found no commercial hydrocarbons. Initial work commitments were completed and the permit was renewed in September 2001 for an additional 5 years.

New Zealand Overseas Petroleum Limited (NZOP), farmed into the permit in November 2002 as operator with a 45% interest, in partnership with AWE New Zealand Pty 20%, Mitsui E & P New Zealand 12.5%, Stewart Petroleum Company 12.5% and WM Petroleum 10%. NZOP drilled the first Kapuni "F" discovery well, the Tui-1, on the Tui prospect in early 2003. In 2004, NZOP began a multi-well drilling program to appraise the initial discovery and to evaluate other structures on

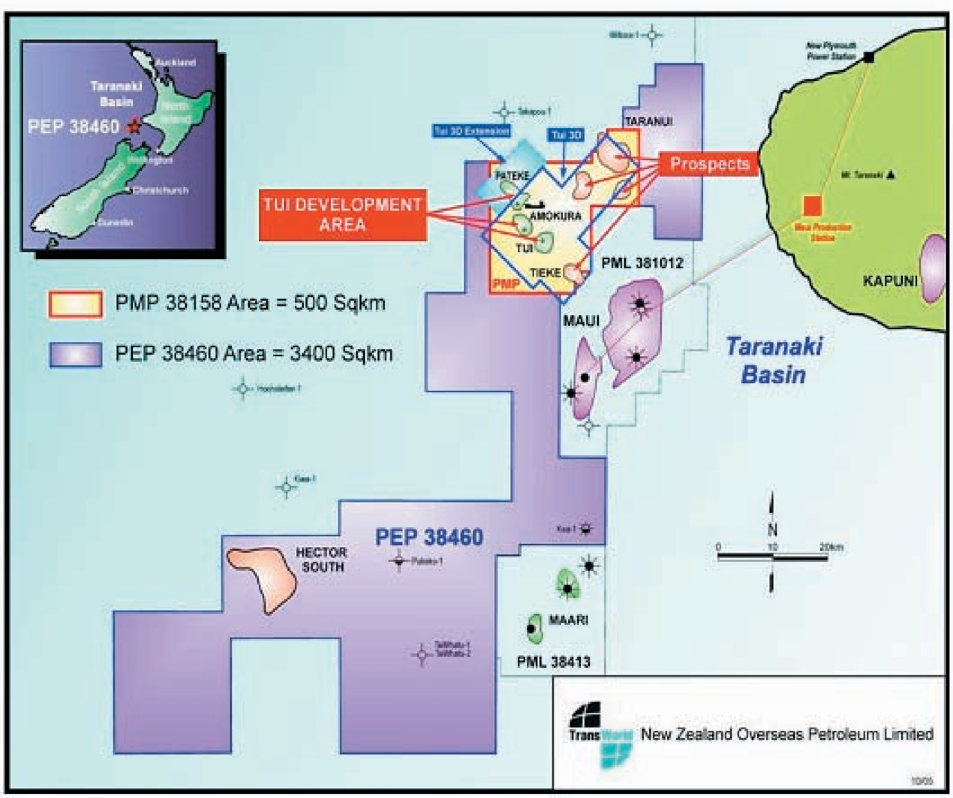


Figure 1: PEP 38460 Location Map

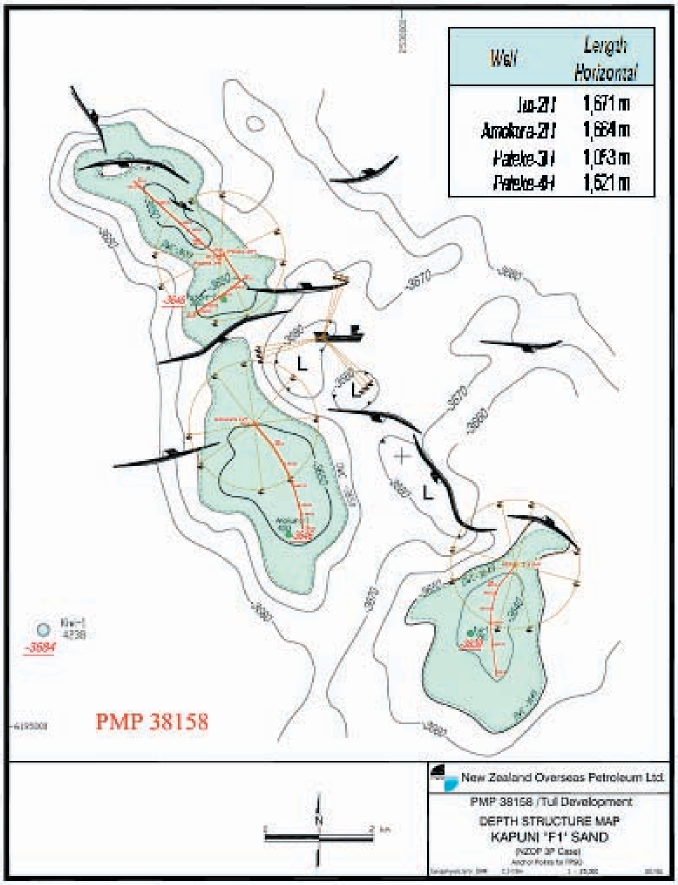


Figure 2: Structure Map of Kapuni "F1" and Well Paths

Table 1 – Tui Reservoir Properties

Petrophysical	
Porosity, %	18 - 21
Permeability, md	1,100 - 2,000
Water Saturation, %	20.8 - 31.7
Fluid Properties	
STO Density (° API)	41.4 - 43.4
Gas Oil Ratio (scf/STB)	372 - 375
Bubble Point pressure @ 122ºC (psia)	1576 - 1725
Reservoir fluid viscosity @ 122ºC (cp)	0.52 - 0.76
STO viscosity @ 14.7 psia and 15.6ºC (cp)	3.0 - 3.8
Wax Content (wt %)	11 - 17
Cloud Point (° C)	41.7 - 47.8
Pour Point (° C)	20 - 21.1

the license. Two more Kapuni "F" discoveries, Amokura-1 and Pateke-2, were made, penetrating 12 m. oil columns and resulting in combined recoverable reserves estimated at 20-30 MMBO. These three discoveries form the basis for the Tui Area Development Project. A fourth exploratory well, the Kiwi-1 (Fig 2), drilled in a separate accumulation southwest of the Pateke pool, resulted in a dry hole. The 2004 drilling locations (Amokura, Pateke and Kiwi) were mapped with a 350 sq. km. Tui 3D seismic survey acquired in late March through early May 2003. (Fig 1 – yellow w/ blue outline)

Reservoir and reserves description

The Kapuni "F" reservoir was deposited in a beach and surf zone setting with propagation towards the WNW along a WSW-ENE striking shoreline. The reservoir sands are found at a depth of approximately 3,650 m. Reservoir quality in the oil column is excellent with typical porosities of 18-21%, permeabilities of 1.1-2.0 darcies and water saturations of 21-32% (Table 1.) The three separate oil accumulations in the uppermost Kapuni "F" sands have relatively thin columns above a strong aquifer, with very little structural relief. The crude oil in these accumulations is 41o–42o API gravity, is highly undersaturated (GOR = 375 scf/bbl) and, typical of New Zealand crudes, contains 11-17% wax. Bubble point pressures of 1,500-1,600 psia versus initial reservoir pressure in the range of 5,200 psia suggest negligible risk of creating a secondary gas cap. The oil viscosity is 2-3 times higher than the formation water viscosity at reservoir conditions, creating an unfavorable mobility ratio. The critical flow rate, (the point at which water moves preferentially to oil within the reservoir), will be exceeded at a drawdown of only 3 psi. Therefore, Tui Area production will be characterized by early water break through and sustained high water cuts (Fig 3.) Over the expected life of the Tui Area accumulations, ten times more water will be produced than oil.

The most likely oil-in-place volume for the Kapuni "F" sand at Tui has been determined to be 56.8 million barrels. This is based on structure and isopach maps (Fig 2.) The Kapuni "F" Sands consist of 77,000 acre-feet of high quality reservoir sand spread between the three separate structures. A reservoir simulation model was constructed based on the results of the 3D seismic and the log, petrophysical, and core data from the exploratory wells. The simulator confirmed early water breakthrough, rising rapidly to 85 percent water cut, and extended field life at water cuts above 90 percent (Fig 4.) The model also defined the Tui Area accumulations as maximum-contact reservoirs, suggesting that ultimate recovery would be proportional to the length of wellbore contact with the reservoir. This led to consideration of long horizontal wellbores.

The simulation work suggested the optimal development solution to be one horizontal well on each of the Tui and Amokura structures, and two horizontal wells on the Pateke structure, for a total of four producing wells.

The recoverable reserves of the individual oil accumulations in the Tui Area (Amokura, Tui and Pateke) are insufficient for commercial development on a stand-alone basis. The substantial capital and operating costs of development can only be profitably recovered by the co-development of the three separate accumulations, taking advantage of their proximity to one another. The simulation results forecast a technical recovery of 29.3 million barrels over a ten year life with a recovery efficiency of 51.5% (Table 2).

Table 2 – Tui Production Volumes

Tui Area Development

				ANNUAL		CUMULATIVE		
Project Year	Oil (B/d)	Gas (Mcf/d)	Water (B/d)	Oil (MMB)	Gas (Bcf)	Oil (MMB)	Gas (Bcf)	Water (MMB)
1	29,400	11,000	79,100	10.7	4.0	10.7	4.0	28.9
2	12,900	4,800	107,100	4.7	1.8	15.4	5.8	68.0
3	8,900	3,300	111,100	3.2	1.2	18.7	7.0	108.5
4	6,800	2,600	113,200	2.5	0.9	21.2	7.9	149.8
5	5,500	2,100	114,500	2.0	0.7	23.2	8.7	191.6
6	4,500	1,700	115,500	1.6	0.6	24.8	9.3	233.8
7	3,800	1,400	116,200	1.4	0.5	26.2	9.8	276.2
8	3,300	1,200	116,700	1.2	0.5	27.4	10.3	318.8
9	2,900	1,100	117,000	1.1	0.4	28.5	10.7	361.5
10	2,500	1,000	116,800	0.9	0.3	29.3	11.0	404.1

Boundary conditions

The main drivers for evaluating development options for the PEP 38460 discoveries include:

1. Absence of petroleum development infrastructure (i.e. pipelines, offshore platforms, etc.) offshore New Zealand.
2. Limited petroleum exploration and development activity offshore New Zealand in past years means drilling, construction, and support equipment is not readily available. High mobilization/demobilization costs ($8-10 million from Western Australia) will be incurred to bring equipment in from more active areas.
3. Water depths of 125 meters and harsh met-ocean conditions present difficult design conditions for production structures.
4. Absence of readily available onshore oil storage facilities with tanker export capabilities.
5. Difficulty transporting the Tui area crude long distances in subsea pipelines due to the high wax content and low water temperature. The problems of wax formation, hydrates and asphaltene deposition are of special interest.
6. Requirement for artificial lift to produce the Tui Area discoveries to depletion. The normally pressured reservoir (5,200 psia) will produce high volumes of water. Water production begins within a few weeks and by end of year one the water cut is 85% (Fig 3.)

7. Due to the large field areas (700 - 1300 acres), low structural relief (<16m), and relatively high operating costs (first year-$73mm), economic production of the Tui Area fields requires high well production rates and good areal coverage of the structures via long horizontal wells. Early water breakthrough and rapid initial oil rate decline drive the need for high total liquid flow rates and processing capacity over most of the producing life. There is no economic way to produce these reservoirs below the critical coning rate and oil recovery is predicted to increase with increasing oil and water production rates, with much of the production coming in a long tail at high water cuts – 48% of total recovery occurs in years 3-10 at water cuts greater than 91%. (Fig 4)
8. Advanced state of decline for the nearest operating oil field, eliminating the option to develop the Tui area with subsea tie-backs.
9. The three oil accumulations discovered to date are not located in one central area that would allow economic development of all production wells from a single site.

The drivers identified above force all practical field architecture solutions to recognize the following:

- A structure to process production in the immediate vicinity of the wells is required to efficiently produce the wells on artificial lift. This requirement is reinforced by the difficulties expected transporting the high wax crude for long distances through subsea pipelines.
- The use of some form of offshore storage and offloading system is required to economically handle the production.
- Floating structures have to be designed to handle harsh and variable met-ocean conditions.
- High mobilization/demobilization costs for construction vessels needed to install fixed platforms and pipelines have a major impact on field development costs.
- High mobilization/demobilization costs for floating drilling units, both for initial drilling and completion and subsequent well intervention, will have a major impact on development and operating costs.

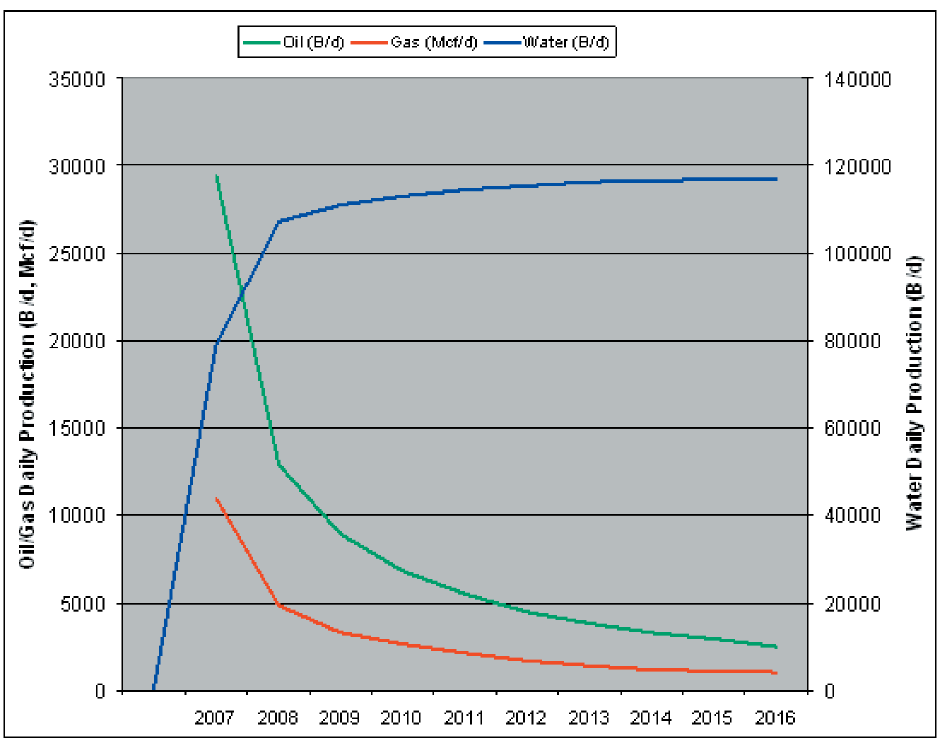


Figure 3: Average Daily Production Profile

Selection of development concept

Based on detailed analysis of the project development options, the following conclusions were formulated concerning the choice of development concept:

1. The preferred development option is a Floating Production Storage and Offloading facility (FPSO) with subsea wells.
2. Simplicity of design and use of proven technology are necessary to maintain high reliability.
3. To maximize oil recovery, field life must be extended to circa ten years. Given oil cuts of less than nine percent from year 2 forward, total fluid producing rate must be high in order to keep oil rate above the economic limit, as determined by operating costs and oil prices.
4. Artificial lift will be required. The preferred method is gas lift, which has investment and operating cost advantages, and higher reliability than other methods.
5. Gas production for Tui Area is too small for commercial viability as a sales stream. Gas produced will be used for gas lift (in a closed loop) and power on the FPSO. Any excess gas will be burned.

The preferred Tui Area development concept is based on producing four subsea wells to a central production processing facility. Because none of the existing exploration wells can be used for production, four new wells will be drilled. The reserves in each oil accumulation and the distances between subsurface well targets make it impractical to employ a single subsea drill center. Instead, wells will be drilled as essentially vertical holes located on the targeted structure to define the oil-water contact. Then a long horizontal section (1,000 to 1,700 m) will be drilled in each well to achieve maximum oil recovery.

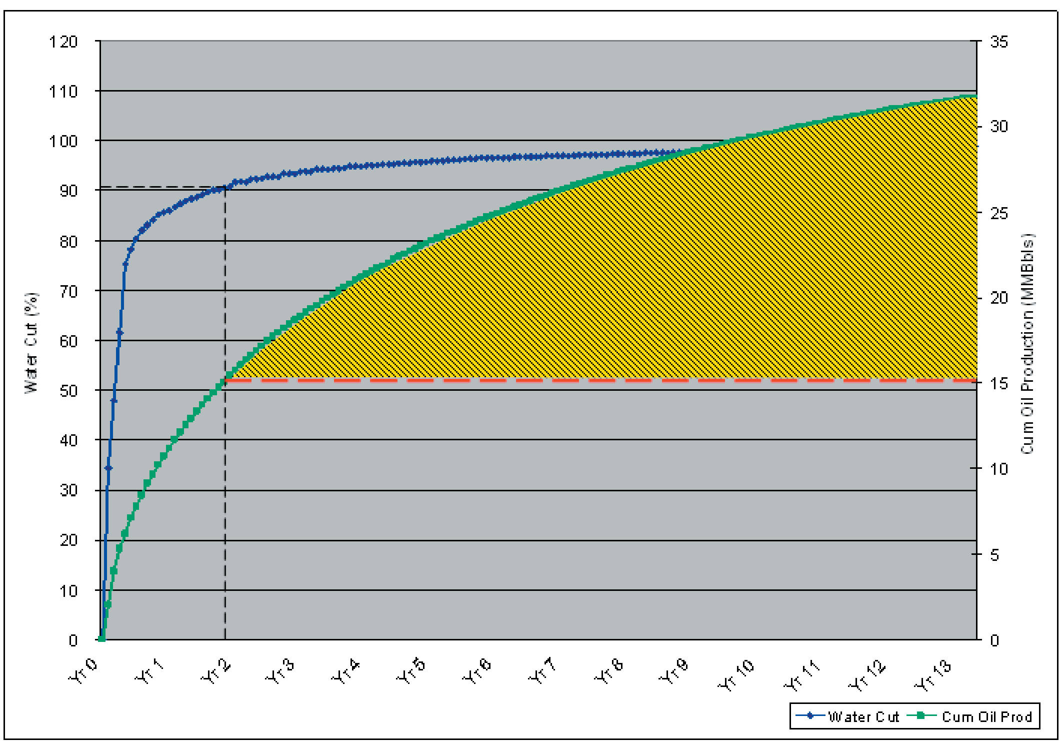


Figure 4: Cumulative Oil Production vs Water Cut

Field architecture

Subsea

To achieve production through subsea wells requires a system providing the following elements for each well:

1. A topsides control system
2. A gas injection line (for gas lift supply)
3. A flowline
4. An umbilical
5. A subsea control module
6. A subsea tree

The subsea control system comprises both topside and subsea equipment. The **topside control components** include the master control station (MCS), the hydraulic power unit (HPU), the electrical power unit (EPU), and Topside Umbilical Termination Assemblies (TUTAs). The MCS controls and monitors the complete subsea system. It contains an industrial PC-server running all applications, a single user interface monitor, and a modem rack and associated equipment. Its functions include interface and communications with topside equipment, umbilical monitoring, subsea well status, tree mounted instrumentation monitoring, choke control and monitoring, interlocks and shutdown sequencing. A remote operator station is provided for placement in the main FPSO control room. The HPU supplies hydraulic power for all hydraulic functions and for SCSSV operation. It operates automatically under the control of its own programmable logic controller (PLC.) The EPU provides power and communication between the MCS, the HPU and the subsea control module (SCM) on each well. The EPU is equipped with a PLC to allow MCS control and monitoring of the MCS functions. TUTAs provide the hydraulic and electrical interface point between the umbilicals and the FPSO. They house the necessary equipment to provide termination, isolation and monitoring of the umbilicals.

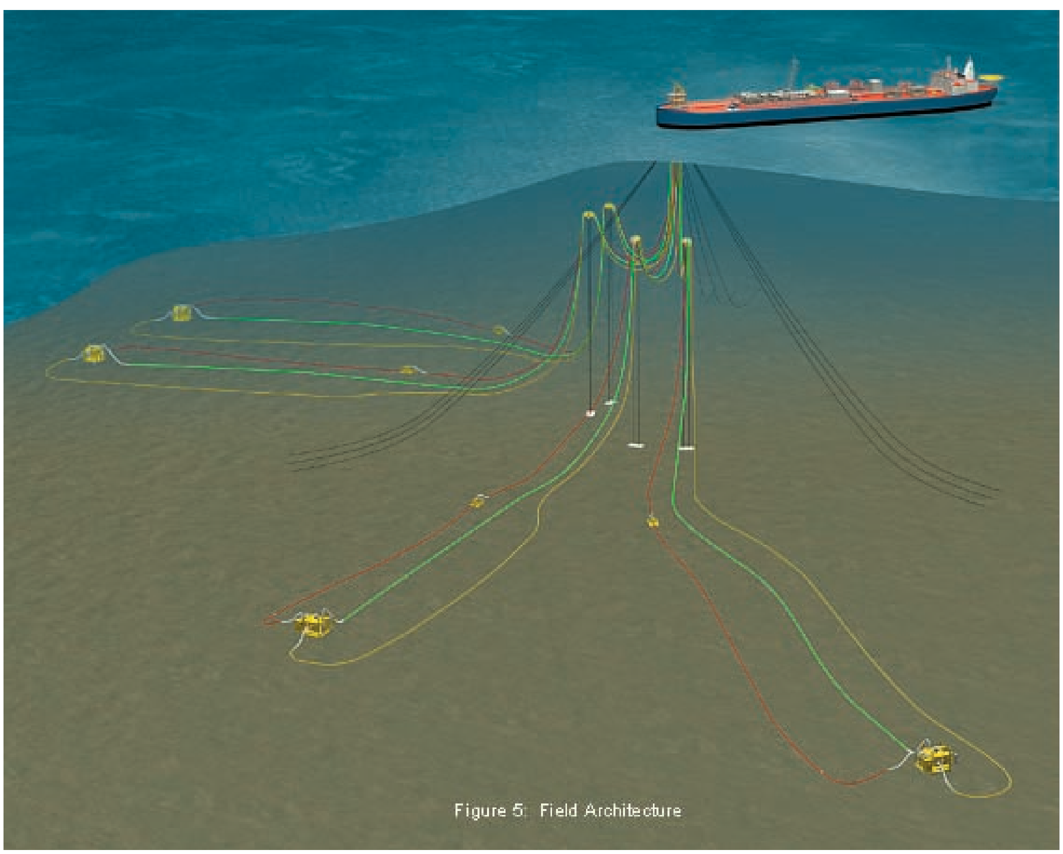


Figure 5: Field Architecture

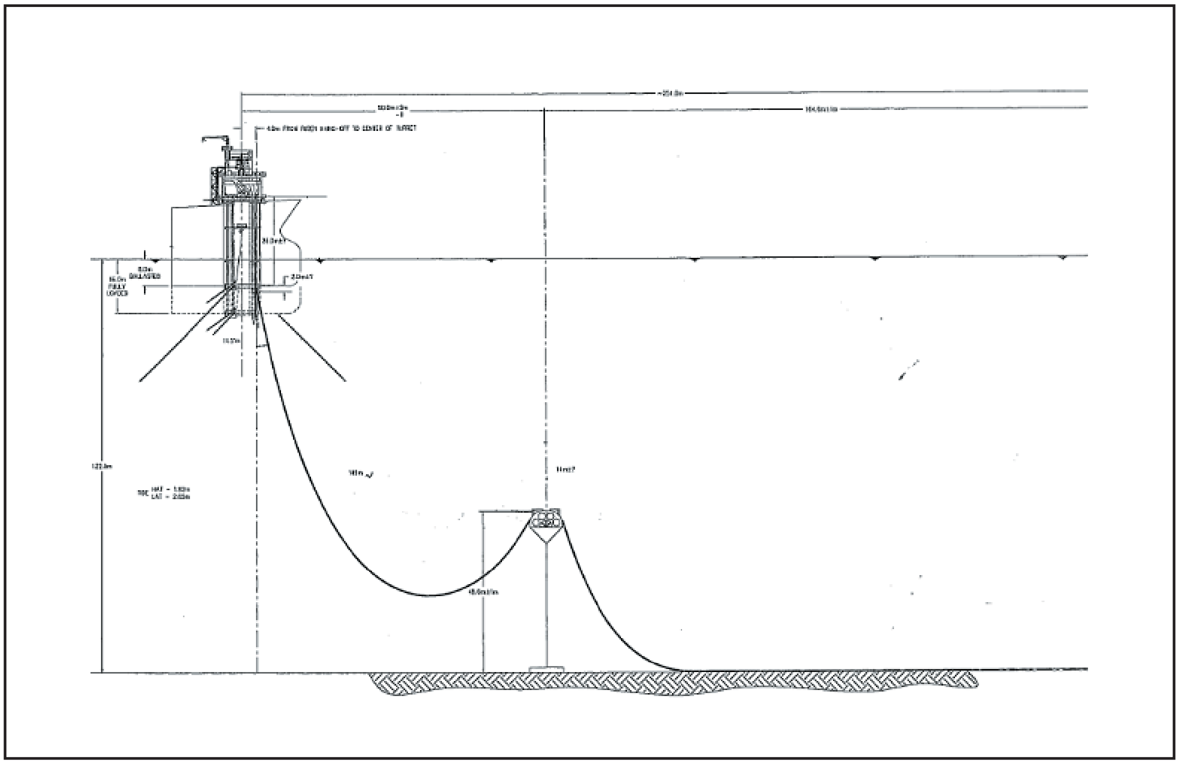


Figure 6: Mid-Water Arch

For a single well, the description of the Tui subsea system starts at the FPSO geostationary turret (Fig 5.) Here the **production flowline riser** (green), the **gas-lift injection riser** (red) and the **electro-hydraulic umbilical** (yellow) depart the FPSO in a pre-determined dynamic catenary to the seabed. The met-ocean conditions of the Tui area prohibit the use of steel catenary risers as currently available products could not achieve the required fatigue design life. Therefore, the dynamic sections (from the FPSO to the seabed) of the production and gas-lift injection flowlines are manufactured as flexible flowlines. Given the harsh metocean conditions of the Tui area and the possible FPSO excursions during design life, the flexible elements are specifically designed to offer fatigue life far in excess of the proposed field life. Mid-water arches (Fig 6) are used on each riser and umbilical to help reduce compression and abrasion of the dynamic element at touchdown. Due to their differing weights, the risers and umbilicals will deflect differently with the FPSO motion and seawater currents. This can create clashing of the elements which is not desirable. The mid-water arch also solves this problem. Each dynamic element is secured in a separate saddle that runs across the arch. The arch also provides control of the minimum bend radius by varying the radius of the saddle provided for each component as it passes over the arch. To transition between the dynamic and static sections on the seabed, riser-to-flowline transition sleds will be used. This is an industry standard method of connection between a rigid steel flowline (which is used only for the gas lift injection line) and its companion flexible riser. Umbilicals and flexible pipe, which was selected for the entire length of the flowlines, both provide full dynamic fatigue life and hence do not require a transition sled.

The **subsea control components** include the subsea control module (SCM), tree-mounted pressure/temperature transducers, tree-mounted logic plate and the Cobra head umbilical termination assemblies. The SCM operates actuated valves/chokes and monitors instrumentation. It is equipped with 100% redundancy of the subsea electronics. It has bladder accumulators to maintain minimum operating pressure during actuator operations. The SCM can be retrieved using a wireline multi-purpose running tool if required. Where the umbilical terminates at the tree, the Cobra head provides the mechanical, electrical and hydraulic connectors to interface with the umbilical. All hydraulic lines from the umbilical are routed from the Cobra head to the SCM through a tree mounted logic plate. The logic plate can be retrieved by ROV and allows reconfiguration of the hydraulic hoses to utilize the spare if it is ever required.

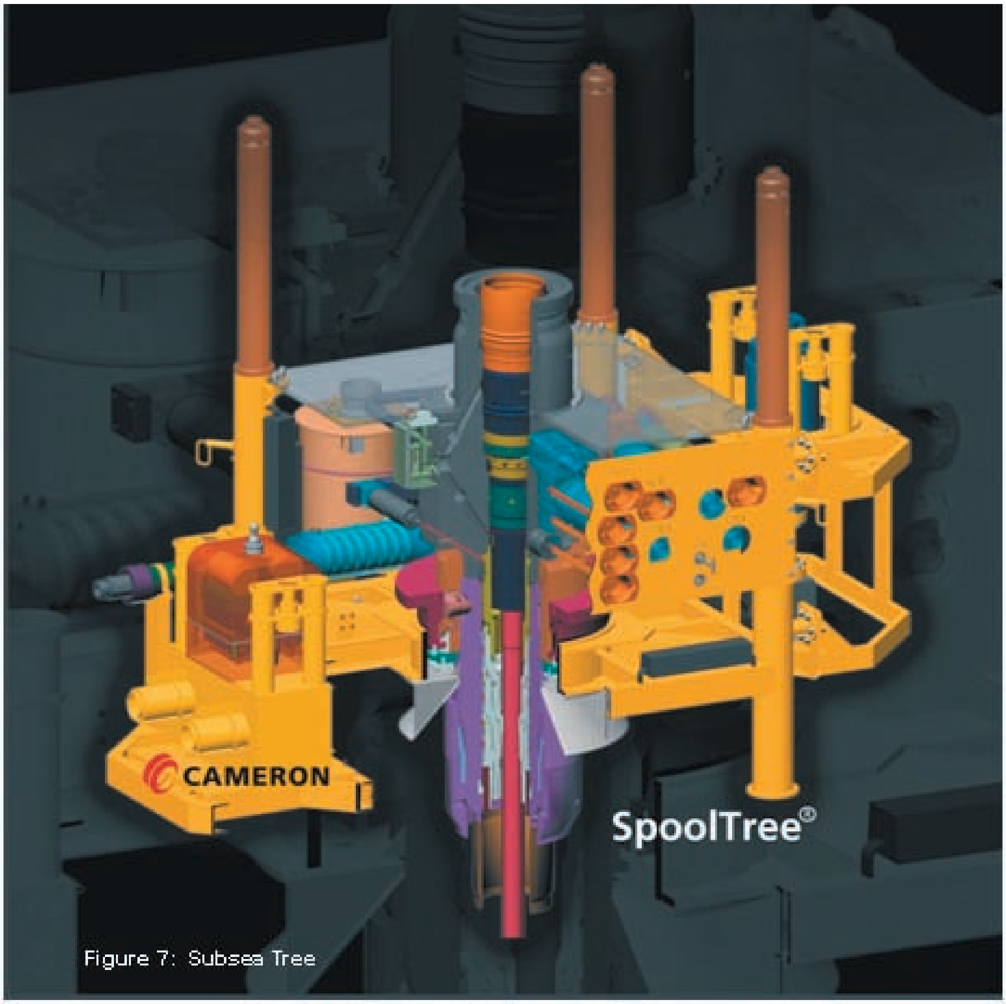


Figure 7: Subsea Tree

Both monobore & horizontal **trees** were deemed acceptable for the Tui subsea application, with neither having a clear technical advantage. A 5"x 2" bore, 5,000 psig working pressure, Cameron horizontal tree (Fig 7) was selected to equip the four producing wells. Diverless subsea connections were selected over diver-assist connections for installation (and intervention) based on a significant economic advantage when viewed in the context of simultaneous operations between the various on-site vessels, the weather downtime factor, and mobilization costs. The multiplexed electro-hydraulic control system will control the tree functions through the umbilical to the topsides control modules. Chokes, which include ROV retrievable inserts, will be installed to manage flowline pressures during well starts. Hydraulically actuated valves are designed to fail closed. All wetted surfaces will be HH trim with Inconel cladding to prevent material erosion. External coating of the tree is supplemented with cathodic protection for corrosion protection. Provisions are made for injection of methanol, corrosion and scale inhibitors, wax inhibitors and pour point depressants. An annulus connection will be fitted for gas lift injection.

FPSO

The need for a central processing facility with offshore storage and offloading capability drove the selection of an FPSO concept. The FPSO will provide:

- Production facilities required for processing and treating the produced fluids.
- Gas compressors that can deliver high-pressure lift gas to the subsea wells.
- Heating coils in crude storage tanks.
- Tandem offloading to shuttle tankers up to 100,000 dwt.
- Accommodations for 41 persons.

The FPSO hull, mooring system, and accommodations will be classed by a classification society, and must be capable of staying on location for ten years without dry-docking. The FPSO will be designed and fabricated to perform the following functions:

1. Receive hydrocarbons from wells
2. Control and manage wells and equipment
3. Process oil and gas
4. Store produced crude oil (cargo)
5. Offload cargo to off take tankers
6. Provide utilities required for operations
7. Ensure personnel safety
8. Meet environmental protection requirements
9. Meet classification requirements

An experienced FPSO Contractor will build, own, operate and maintain the FPSO for the Tui Area Development. A long term charter for lease and operations of the FPSO has been executed for an initial term of five years plus five one-year options. The FPSO lease rates include one price element for a bareboat charter and another element for the FPSO operations and maintenance. The FPSO Contractor will be responsible for the design, repairs, life extension, conversion, outfitting, mobilization,

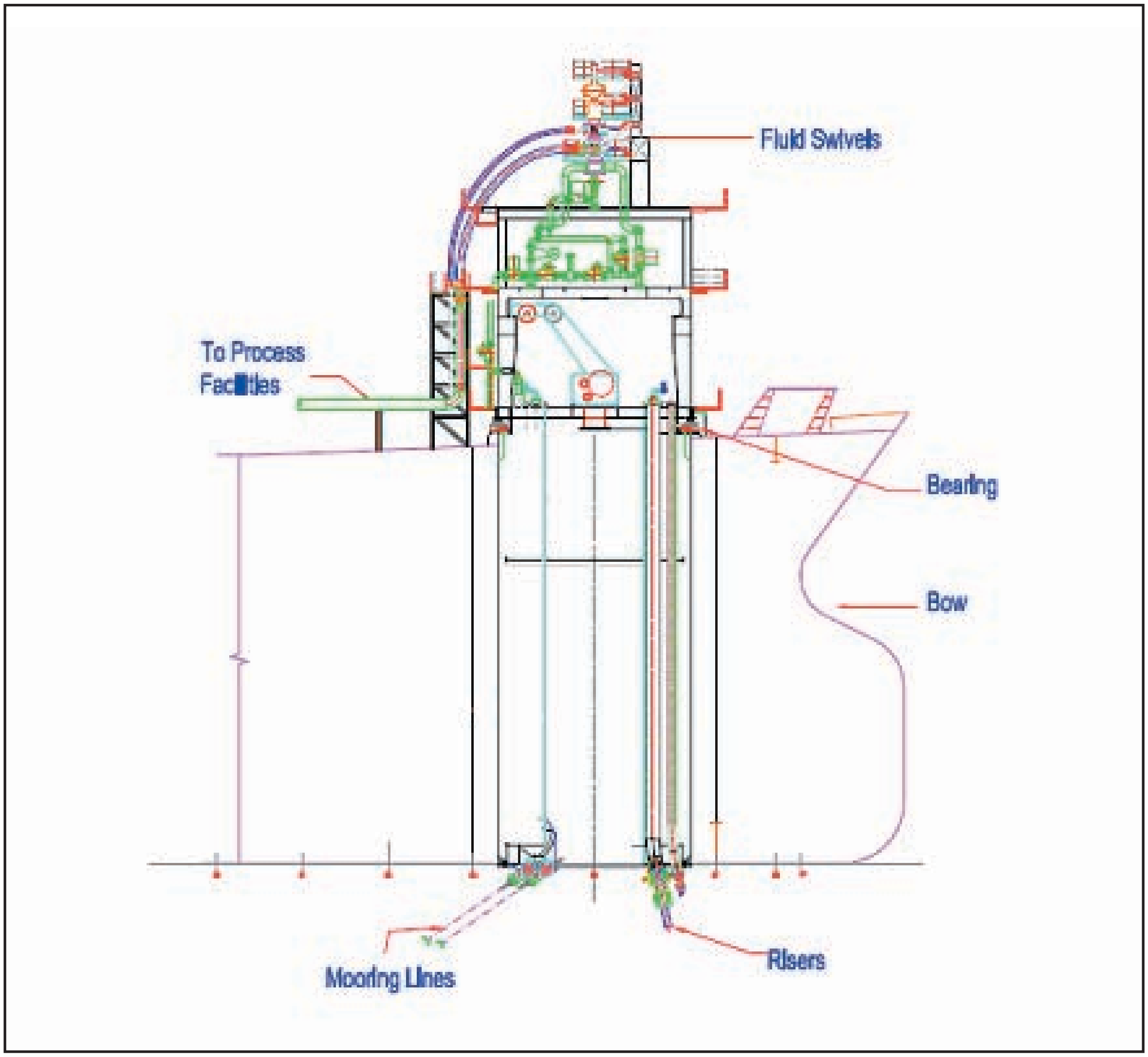


Figure 8: General Arrangement of the Internal Turret

offshore installation, hookup, and final commissioning of the FPSO. The proposed FPSO will have a storage capacity of approximately 770,000 barrels of crude storage. The FPSO will have a turret mooring system and topsides facilities designed for production rates of 50,000 bopd, 25 MMSCFD of gas, and 120,000 barrels of total liquid per day. It is projected that the processing facilities will provide uptime of at least 96.7 %.

Turret mooring system

The FPSO will be equipped with a fixed (geo-stationary) internal turret mooring system that allows the FPSO to weathervane 360 degrees around the mooring axis with changes in the directions of the wind, waves, or currents, and to accommodate roll, pitch and heave motions of the FPSO (Fig 8.) The turret will be located in the forepeak tank area at the bow of the FPSO. It will be equipped with a geostationary manifold deck below the multi-product fluid swivel to minimize the number of swivel modules. An internal turret has been chosen to minimize induced loads in the vessel structure and to minimize the dynamic effects of the FPSO roll motions. The turret will utilize proprietary technology of the FPSO Contractor and will withstand 100-year environmental conditions. Suitable riser slots and fluid handling facilities are arranged on the top of the turret, above the main deck level. The turret includes sixteen riser slots to handle as many as five production risers, five gas lift risers and five subsea control umbilicals (for four current wells and one future well).

Process description

Process facilities are provided to handle the specified flow rates and conditions described in Table 3 following.

Table 3 – Tui Process Design Basis

Production Fluid Inlet	
Total Fluids Rate	120,000 BLPD
Oil Production Rate	50,000 BOPD
Produced Water Rate	117,500 BWPD
Produced Gas Rate	25 MM SCFD
Crude Oil To Tanker	
Basic Sediment and Water (BS&W)	≤ 1.0%
Reid Vapor Pressure	≤ 12 psia
Oil Export Temperature	≤ 140 °F
Oil Storage Capacity	770,000 BBLS
Tanker Loading Rate	≥ 25,000 BBLS / HR
Produced Water Overboard	
Maximum Excursion Oil Concentration	50 ppm
Maximum Monthly Average Oil Concentration	30 ppm
Gas Lift System	
Delivery Pressure	4,000 psig
Delivery Temperature	≤ 140°F
Maximum Water Content	5 lbs / MM SCF

The processing equipment consists of ten skidded modules:

1. Separation (one production train and one test train)
2. Oil and Water Treating (including crude de-gassing)
3. Gas Dehydration
4. Utilities
5. Vapor Recovery (VRU)
6. Booster Compression
7. Gas Lift Compression
8. Flare Scrubber
9. Methanol/Chemical Injection

These modules will be arranged a minimum of 3 meters above the main deck level on suitable steel structures designed to withstand the site environmental and transient conditions. All of the process equipment will be suitable for service in a corrosive, salt-laden, harsh offshore environment and designed for expected environmental forces. Equipment design will be specified for a minimum 10-year operating life with all modules incorporating appropriate spill and leakage containment. All critical compressors and pumps will be spared using an N+1 unit sparing philosophy (N = number of units to provide 100% capacity). Compressors and pumps will be driven by high-voltage electric motors.

Artificial lift considerations

High producing rates (in normally pressured reservoirs) with high water cuts usually require artificial lift, which adds cost and complexity to development options. There is little industry experience with artificially lifting 35,000 barrels of fluid per well per day in an offshore environment. Tui Development selected three artificial lift options as being potentially viable:

1. Gas lift (GL) is by far the simplest, easiest to install, easiest to operate and the least costly from capital and operating cost viewpoints. Gas lift experience also demonstrates high reliability, lessening the probable need for workover/well intervention.
2. Electrical submersible pumps (ESP) have some recent history of being used in full field subsea developments but not at the rates required for the Tui development. This option can yield higher production rates than gas lift, but incurs much higher investment and operating costs.
3. Hydraulic submersible pumps are a recent development and have limited field history. Although the hydraulic pumps offer some advantages over ESPs, the major draw back lies in the requirement to handle large volumes of produced water. With power fluid requirements being 70% of the produced fluid requirement, the fluid handling requirements for Tui Area would have exceeded 200,000 barrels per day.

Comparison of expected field-life costs led to selection of gas lift for lifting the wells. Flow assurance work determined a need for supply at 4-6 mmscfd per well. Gas lift distribution lines of 3.5-inch coiled line pipe are needed to deliver these injection rates.

Well design considerations

Extensive work was completed during the FEED process to optimize the drilling and completion design. Geomechanical studies show the Kapuni “F” sand to be sufficiently competent at Tui that open-hole completions are feasible and formation sand production should not be a problem. However, slotted liner completions will be used. Since the wells will be large bore and relatively simple completions, much of the work focused on design of the horizontal sections of the wells, including reservoir simulation to optimize the length of horizontal section for each well and evaluation of geo-steering techniques required to maintain the optimal wellbore position near the top of the reservoir. Studies were also conducted to evaluate fluid selection to minimize formation damage, torque and drag analysis and

Development Chronology

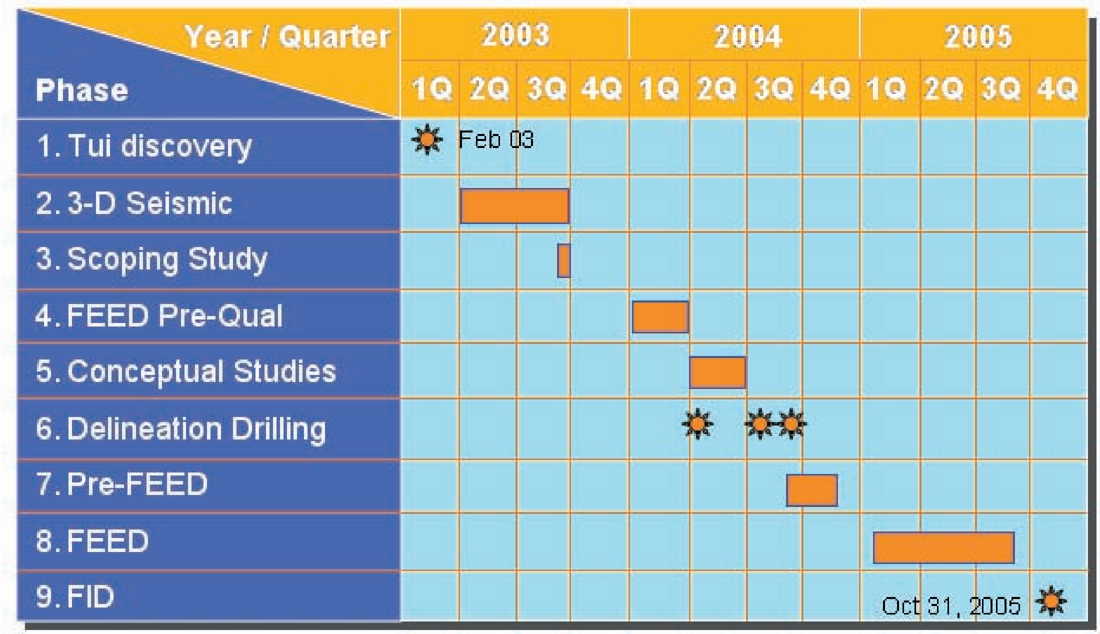


Figure 9: Project History

methods to maintain horizontal wellbore stability. The results of all studies point favorably towards the successful drilling and completion of the Tui Area wells.

Well design criteria include:

- Four horizontal wells with horizontal well bore lengths varying from 1,000m to 1,700 m from a TVD of approximately 3675 m.
- Uncemented 6-5/8” slotted liners with .015 inch slots over 2% of the pipe area in an 8-1/2” well bore.
- 7” 13-Chrome production tubing with 5-1/2” accessories.
- Wells to be artificially lifted with gas lift through a single (1-1/2”) valve set at ±3,000 m.
- Each well capable of producing up to 35,000 BFPD.

Project execution schedule

The time frame from the initial discovery of Tui to final investment decision (FID) was less than three years inclusive of appraisal drilling (Fig 9.) The Tui Area Development PMT (Project Management Team) applied an unconventional project planning model in order to accelerate schedule and deliver a lower cost project. Some detailed design, the tender process, and preliminary contracting were all rolled into the FEED (Front End Engineering and Design) process, when generally those activities occur after FEED. Therefore the project was much better defined in terms of cost at the end of FEED, and contracts were substantially ready for award. Early commitments were obtained from contractors and vendors well ahead of the Financial Investment Decision; hence contractors were able to quickly initiate project activities upon project sanction. This is possible with a small project where interfaces can be managed within a centrally organized team. A significant contracting objective was to competitively lump-sum bid all the major components. This has been achieved on all non-drilling work packages.

Other features of the planning model framework were also instrumental in moving the project forward and reducing the capex requirements despite a difficult market environment for oilfield goods and services.. The PMT focused on fit-for-purpose designs, (i.e. proven technology, simplicity in design and economy of design specific to a certain function.) Contractor knowledge and expertise were leveraged for much of the design effort in order to utilize existing design concepts, thereby decreasing

Engineering/Procurement/Installation Schedule

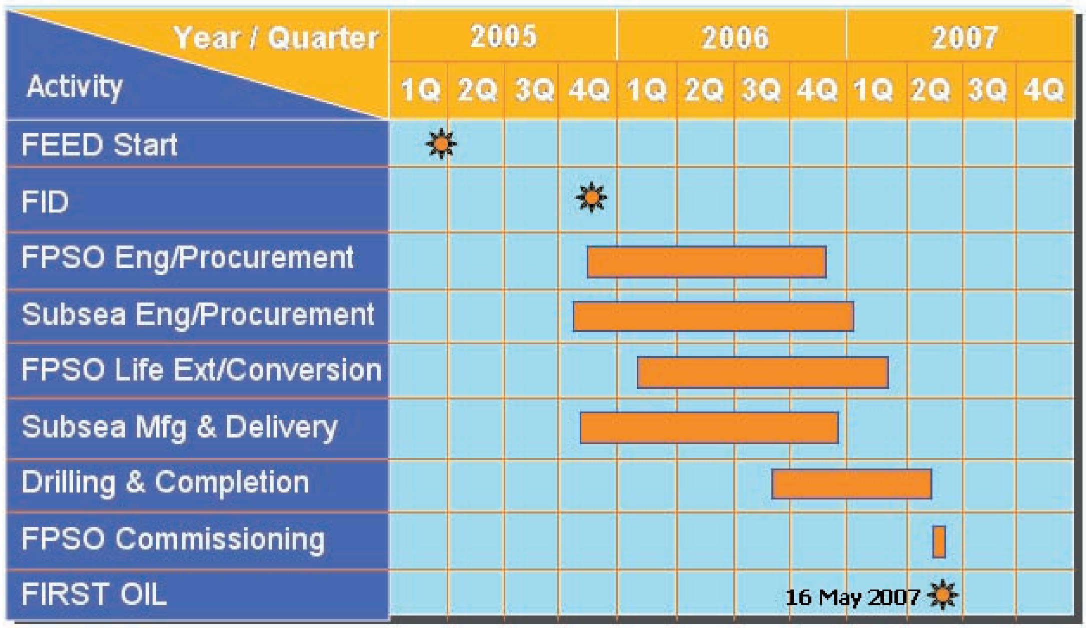
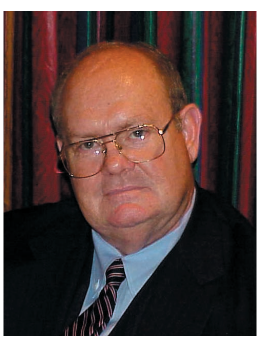


Figure 10: Execution Schedule

potentially lengthy design timelines. Most of the subsea facilities, for example, were lump-sum bids on items that are standard designs or simple fabrications. The PMT remains open to opportunities that arise for any innovative use of proven technology and installation methods that can reduce total field-life costs and minimize risk to schedule.

The FPSO conversion and installation and offshore installation activities comprise the critical path for the project execution schedule (Fig 10.) All major contracts have been executed and major purchase orders placed. Petroleum Mining Permit 38158 was issued on November 25, 2005. The Ocean Patriot drilling rig is expected to arrive in the field in early November of 2006 and finish drilling and completion activities early in the second quarter of 2007. Production will commence in the same quarter.

Author



C. C. (Randy) Stewart had almost thirty years of experience in the energy sector when he retired from Kerr-McGee in 1995 to pursue personal investments, family interests and provide limited consulting. In August 2001 he and L V McGuire decided to work together for the third time, creating Alpha Petroleum Services to furnish project management, drilling and completions, and general management expertise to the industry.

Stewart started his career with Humble Oil & Refining (Exxon) in 1967, working eleven assignments in seventeen years in surface and sub-surface production engineering, reservoir engineering, field operations, major projects, and general management. During 1977-79, he was assigned to Esso Europe, London, as Operations Manager, and in 1979, transferred to Esso Europe Headquarters as Corporate Planning Manager.

He joined Hamilton Oil Corp as Vice-President Production in 1984 with functional responsibility for worldwide production operations, and in 1988 returned to London as Sr. Vice President-Technical. In 1990, he joined Kerr-McGee as Sr. Vice President, Production with functional responsibility for worldwide operations. Stewart became Group Vice President for Kerr-McGee in 1993 with continuing responsibility for upstream operations, plus Kerr-McGee Coal Corp and downstream petroleum operations (200 kb/d refining and 400 kb/d product sales.)