Appendix D

Examples of

Fixed Platforms

Floating Production Systems

And

Subsea Tie-Backs

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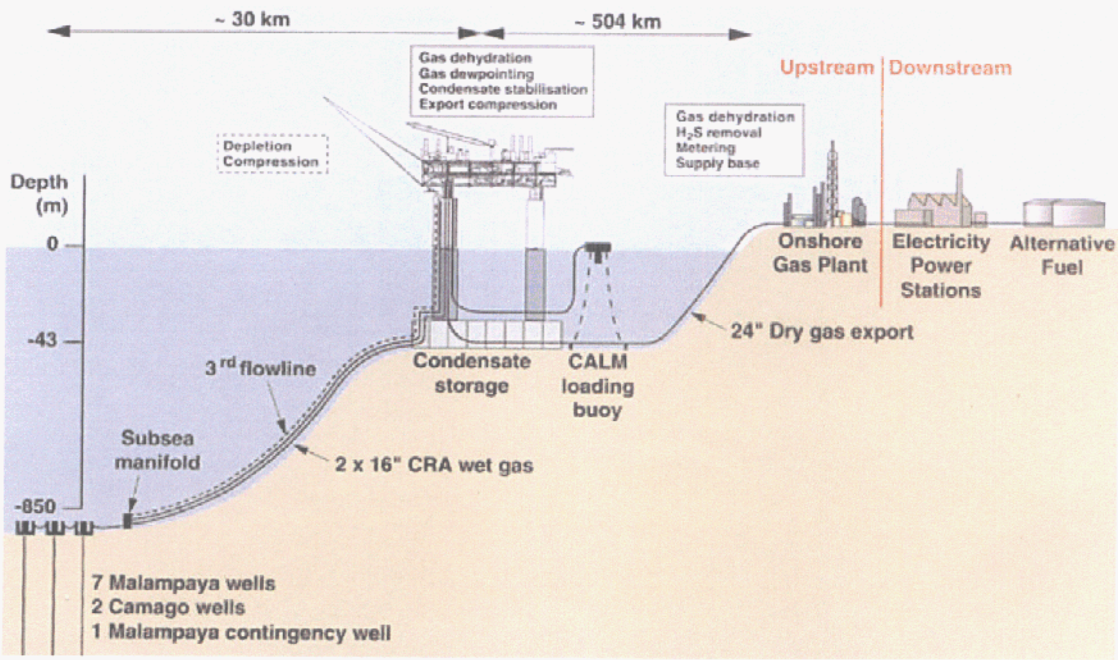
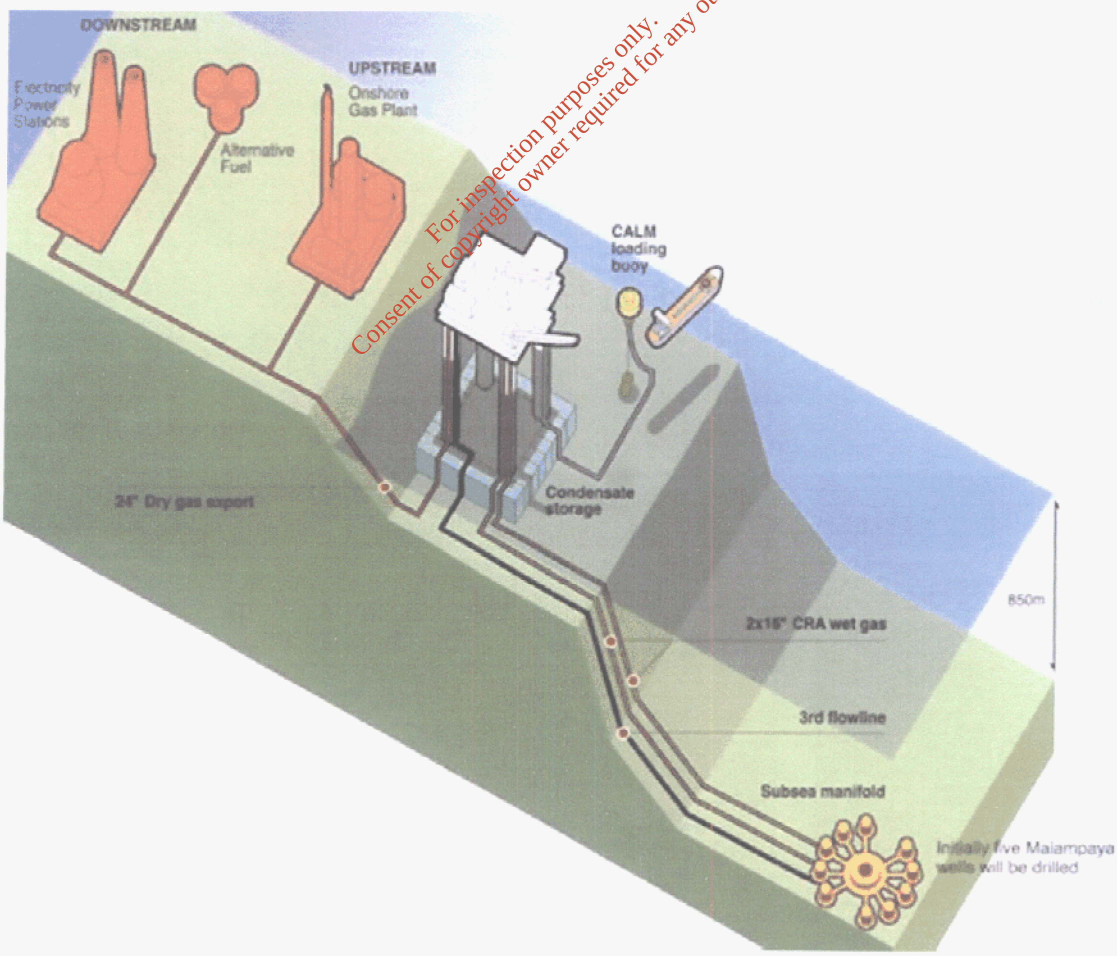
North America	North Sea
Baldpate Gulf of Mexico, USA	Alba Phase II North Sea Northern, UKingdom
Bombax Pipeline Development, Trinidad and Tobago	Åsgard North Sea Northern, Norway
Brutus Gulf of Mexico, USA	Balder North Sea Northern, Norway
Cantarell Oil Field, Mexico	Banff North Sea Central, United Kingdom
Canyon Express Gas Field, Mississippi Canyon, USA	Blake Flank, United Kingdom
Deep Panuke, Canada	Boulton North Sea Southern, United Kingdom
Devils Tower Gas Field, Gulf of Mexico, USA	Brigantine North Sea South, United Kingdom
Genesis Gulf of Mexico, USA	Britannia North Sea Central, United Kingdom
Gyrfalcon Gulf of Mexico, USA	Bruce Phase II North Sea Northern, U Kingdom
Hibernia Grand Banks, Canada	Caister Murdoch Phase 3, United Kingdom
Hickory Gulf of Mexico, USA	Captain North Sea Central, United Kingdom
Hoover Diana Gulf of Mexico, USA	Clair Field, Shetlands, United Kingdom
Horn Mountain Field, Gulf of Mexico, USA	Cook North Sea Central, United Kingdom
Magnolia Field, Gulf of Mexico, USA	Curlew North Sea Central, United Kingdom
Manatee Field, Gulf of Mexico, USA	Dunbar Phase II North Sea Central, UKingdom
Mardi Gras Oil and Gas Transportation System, USA	ECA North Sea Southern, United Kingdom
Mars Gulf of Mexico, USA	Ekofisk II North Sea Central, Norway
Matterhorn, Gulf of Mexico, USA	Elgin Franklin North Sea Central, U Kingdom
Mensa Gulf of Mexico, USA	Erskine North Sea Central, United Kingdom
Morpeth Gulf of Mexico, USA	ETAP North Sea Central, United Kingdom
Na Kika Oil and Gas Fields, Gulf of Mexico, USA	Gannet North Sea Central, United Kingdom
Nansen Boomvang Gas Field, Gulf of Mexico, USA	Glitne North Sea Northern, Norway
Neptune Gulf of Mexico, USA	Goldeneye Gas Platform, United Kingdom
Petronius Gulf of Mexico, USA	Gullfaks North Sea Northern, Norway
Ram Powell Gulf of Mexico, USA	Hanze F2A, Netherlands
Sable Island Scotia Shelf, Canada	Jade Oil and Gas Platform, United Kingdom
Serrano/Oregano Gulf of Mexico, USA	Janice North Sea Central, United Kingdom
Tahoe Gulf of Mexico, USA	Jotun North Sea Northern, Norway
Tanzanite Gulf of Mexico, USA	Kristin Deepwater Project, Norway
Terra Nova Grand Banks, Canada	Leadon North Sea Oil Field, U Kingdom
Thunder Horse Oil Field, Gulf of Mexico, USA	MacCulloch North Sea Central, U Kingdom
Troika Gulf of Mexico, USA	Magnus EOR, United Kingdom
Typhoon Gulf of Mexico, USA	Mikkel Deepwater Project, Norway
Ursa Gulf of Mexico, USA	Njord North Sea Northern, Norway
White Rose Oil and Gas Field, Canada	Norne North Sea Northern, Norway
	NUGGETS North Sea Northern, UK
	Ormen Lange North Sea Northern, Norway
	Oseberg Sør North Sea North, Norway
	Pierce North Sea Central, United Kingdom
	R Block Development North Sea, U K
	Ross North Sea Central, United Kingdom
	Shearwater North Sea Central, U Kingdom
	Sigyn Gas Field, Norw North Sea, Norway
	Siri North Sea Northern, Denmark
	Snøhvit Gas Field, Barents Sea, Norway
	Snorre North Sea Central, Norway
	South Arne North Sea Danish, Denmark
	Triton North Sea Central, United Kingdom
	Troll West North Sea Northern, Norway
	Valhall Flank Water Inj Platform, Norway
	Viking B North Sea Southern, UK
	Visund North Sea Northern, Norway
	Vixen North Sea South, United Kingdom

Africa & Middle East Abana Gulf of Guinea, Nigeria Agbami Discovery Well, Nigeria Bonga Deepwater Project, Niger Delta, Nigeria Ceiba Gulf of Guinea, Equatorial Guinea Ekpe Phase II Gulf of Guinea, Nigeria Espoir Field, Ivory Coast Girassol Luanda, Angola Kizomba Deepwater Project, Angola Mossel Bay Bredasdorp Basin, South Africa Scarab and Saffron, Egypt South Pars Field, Iran Yoho Oil Field, Nigeria Zafiro Gulf of Guinea, Equatorial Guinea	**Central Asia** Blue Stream Natural Gas Pipeline, Russia Kashagan Caspian Sea, Kazakhstan Sakhalin II Sea of Okhotsk, Russia Shah Deniz South Caspian Sea, Azerbaijan **North Atlantic** Corrib Gas Field, Ireland, Republic of Foinaven West of Shetlands, UK Liverpool Bay Liverpool Bay, UK Rivers Fields, East Irish Sea, UK Schiehallion West of Shetlands, UK **South America** Barracuda and Caratinga Fields, Brazil Bijupira and Salema Fields, Brazil Espadarte Campos Basin, Brazil Marlim Oil Field - Campos Basin, Brazil Marlim Sul Campos Basin, Brazil PROCAP 2000 Campos Basin, Brazil Roncador Campos Basin, Brazil
Asia and the Pacific Rim Bayu-Undan Timor Sea, Australia Buffalo Timor Sea, Australia Gorgon Northern Carnarvon Basin, Australia Laminaria Timor Sea, Australia Langsa Oil Pool, Straits of Malacca Indonesia Liuhua 11-1 South China Sea, China Lufeng 22-1 South China Sea, China Malampaya South China Sea, Philippines Stag North West Shelf, Australia Wonnich Carnarvon Basin, Australia	

MALAMPAYA SOUTH CHINA SEA, PHILIPPINES



Sectional Drawing of Malampaya Gas Works (Note Its 504km to OnShore Terminal)



3D View

Location
The Malampaya field is located 80km off the coast of Palawan Island, in the Republic of the Philippines. In August 1998, Shell Philippines Exploration BV awarded Brown & Root a US$432 million design, procurement, fabrication, installation and commissioning contract.

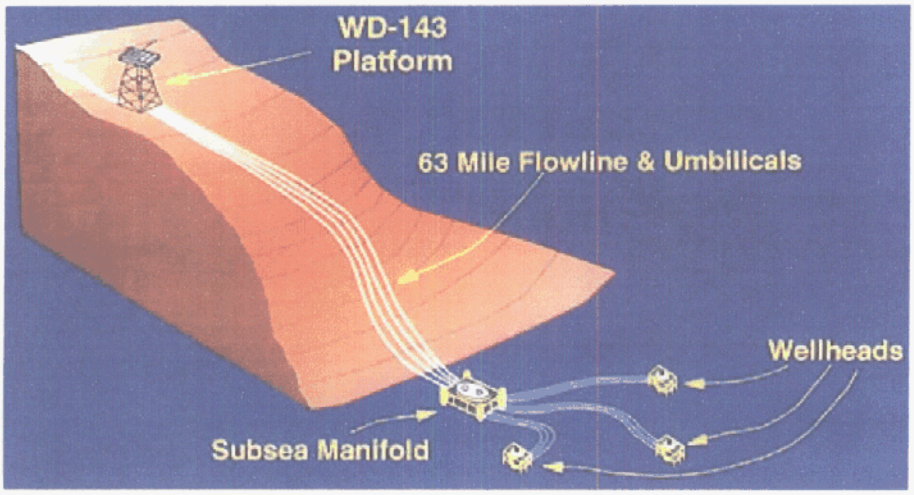
PLATFORM
The platform consists of a deck, supported by a concrete gravity sub-structure (CGS). The processed gas will be compressed and exported through a 504km pipeline to the Batangas onshore facility at Luzon Island, in the Philippines.

The condensate will be stabilised on the topsides, stored in the CGS and then exported to a shuttle tanker, through a catenary anchored leg mooring (CALM) system, located 3km from the platform. The design capacity of the integrated CGS and deck is 508 million ft3 gas and 32,800bbl of stabilised condensate per day.
The platform is located in water 43m deep and the deepwater subsea wells are at a depth of 850m.

TOPSIDES
The topsides were subcontracted to Sembawang Marine & Offshore Engineering (SMOE). This contract involved the fabrication, onshore commissioning and load-out of a three-level integrated deck, together with a living quarters module that can accommodate up to 44 people.
The topsides measure 40x90m in plan and reach 25m, from the base of the cellar deck to the helideck. The lower (cellar) deck, contains the major pumps, heavy wall vessels and workshops.
The middle deck (or production deck) contains the separation equipment and the electrical-control module. The equipment on the top deck (or weather deck) includes two export gas compressors, three power-generation gas turbines and a crane.
The initial operating weight of the topside is 13,000t. This equates to a loadout weight - excluding the transportation frame - of 10,000t and, as such, this will be the heaviest topside ever constructed by SMOE.
Fabrication of the deck commenced at Sembawang's yard, located in the north of Singapore, in June 1999 and is scheduled for completion and onshore testing by February 2001.

In December 2001, an extended well test of the thin oil rim beneath the field initially yielded about 8,000 barrels of oil per day (bpd). The well test was performed by the Atwood Falcon drilling rig and Stena Natalita floating storage unit. It is also believed to be the deepest horizontal subsea well test undertaken in the world at a depth of about 850m.

MENSA GULF OF MEXICO, USA



Mensa is located 140 miles south-east of New Orleans and encompasses Mississippi Canyon blocks 686, 687, 730 and 731. The water is approximately 5,300ft deep.

DRILLING
The discovery well was drilled using Sonat's drillship, Discoverer Seven Seas. One delineation well has been drilled and two remaining production wells are also planned. They will be drilled by the Transocean semisubmersible, George Richardson.

RESERVES
The target reserves are in the Upper Miocene '1' sand, at a depth of approximately 15,500ft. The average net thickness is approximately 100ft. Ultimate recovery from the field is estimated at 720 billion ft3 of natural gas.
The first Mensa well produced approximately 108 million ft3 of gas per day. A peak production rate of 300 million ft3 of gas per day was achieved in the second quarter of 1998.

SUBSEA ARCHITECTURE
The subsea system consists of three wells, connected to a subsea manifold five miles away, which is in turn tied back via a 68-mile 12in flowline, to the shallow-water platform West Delta 143. This is the longest tieback in the world, beating the previous record of 30 miles, established by the Troll Oseberg Gas Injection Project, in the Norwegian sector of the North Sea.

SUBSEA MANIFOLD AND TEMPLATE BASE
The manifold/template base has four well-receiver slots and eight utility service slots, including hydraulic umbilicals, glycol injection and hydrate remediation.The template base is located on the seafloor. It is not connected by piling to the seafloor, but relies on its mass for stability. It has a diameter of 94ft, is 12.5ft tall and weighs about 200t.The manifold sits on the template base. This is a separate assembly, which can be recovered independently of the template. It has a diameter of 16ft, is 16ft tall and weighs about 50t.

ELECTRICAL DISTRIBUTION STRUCTURE (EDS)
The EDS is located near the subsea manifold. It takes electrical power and communications signals from the platform at West Delta 143, amplifies the signal (which decreases over the 63 miles from the platform to the EDS site), and distributes it to each of the subsea wells, five miles away.SUBSEA TREESThe three subsea trees provide the interface between the wellheads and the infield flowlines. The trees are of a 10,000psi composite block guidelineless design, with a vertical-flow piping connection mandrel for mating with the well jumper.

FLOWLINES
The flowlines transport the gas from the wells to the manifold, then on to the platform at West Delta 143. The three infield 6in flowlines are five miles long. They are made of carbon steel pipe and connected to the manifold with a stab and hingeover termination, and to the tree via a laydown sled and rigid

jumper.The 12in interfield flowline is 63 miles long, made of carbon steel pipe and is connected to the manifold via a sled and jumper. It is connected to the West Delta 143 platform via risers.

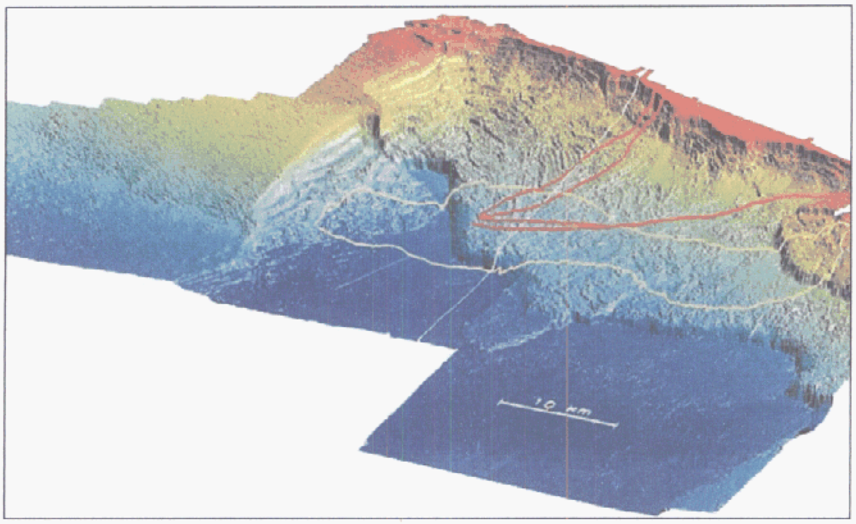
UMBILICALS

The hydraulic umbilicals are constructed of carbon steel, with zinc coating. They supply the hydraulic fluid and chemical injection (glycol).There are three seven-line, five-mile infield hydraulic umbilicals and one three-line, 63-mile interfield hydraulic umbilical.The electrical umbilicals are double-armoured cable and transmit electrical power and signals between the master control station on the West Delta 143 platform and the electrical distribution structure. There are three five-mile, infield electrical umbilicals and one 63-mile interfield electrical umbilical.The 3in glycol supply line supplies glycol to the subsea manifold, where it is distributed to the various wells.

MASTER CONTROL STATION

Located on West Delta 143, this computer-based system monitors operational status of wells and other subsea equipment and has the capability to open and close the wells.

ORMEN LANGE NORTH SEA NORTHERN, NORWAY



3D View (Note Vertical Cliff as the Line Approach the Shore Edge)

Ormen Lange is located in the Norwegian Sea, approximately 140km west of Kristiansund. The discovery lies across blocks 6305/4, 6305/5, 6305/6 and 6305/8. Preliminary estimates show that Ormen Lange is the second-largest gas discovery on the Norwegian shelf. The discovery well 6305/5-1 was drilled in 1997 and production is most likely to start in 2006.

DISCOVERY

Hydro and Shell Norway signed an agreement for sharing responsibilities for the field. Norsk Hydro will be responsible for the development phase, while Shell will be responsible for developing the transport of the gas and all the commercial relationships.

Norske Shell	16 per cent (production operator)
Norsk Hydro Produksjon	14.78 per cent (drilling operator)
Statoil	8.87 per cent
State's Direct Financial Interest (SDFI)	45 per cent
BP Amoco Norge	9.44 per cent
Esso Norge	5.91 per cent

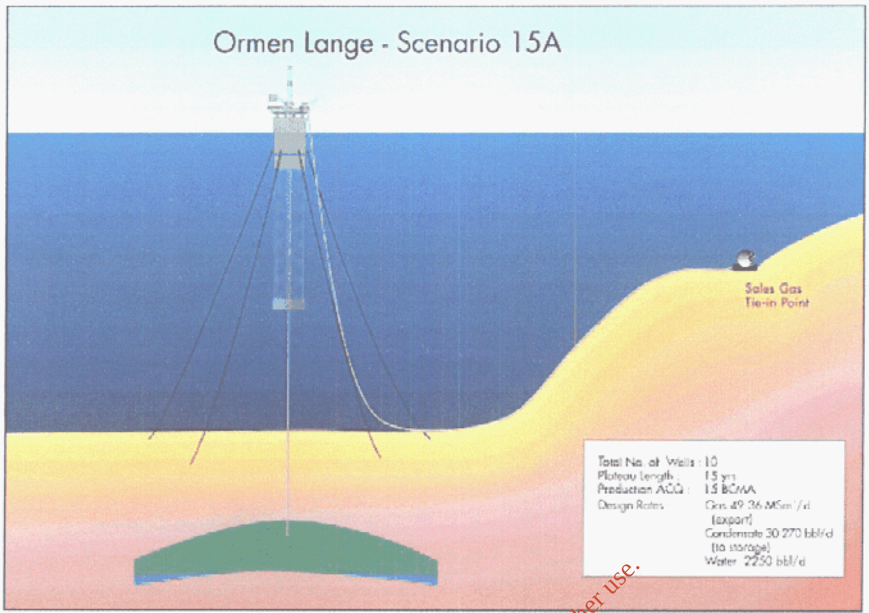
The main gas reserves lie in a reservoir in the Vale formation. Drilling has confirmed the original estimated resources of 315 billion m3 of natural gas.The difficulty in developing the field is due to the water depth and subsea topography. **The field lies in a depth of 800-1200m**, close to the steep back wall left by the Storegga submarine slide, which occurred 7,000-8,000 years ago.

The Storegga slide was probably triggered by a major earthquake caused as the land masses rose at the end of the Ice Age, combined with weak sedimentary layers.Norsk Hydro has carried out a programme of high-resolution seismic surveys, seabed mapping, shallow coring and deep geotechnical drilling. This programme is also used to: evaluate large-scale margin stability, identify slide release mechanisms, evaluate the risk of new large and small slides, assess the consequences of possible reservoir subsidence as a result of production, evaluate possible measures to reduce risk in the event of a development, as well as map the seabed to identify good pipeline routes out of the slide area.

DEVELOPMENT SCENARIOS

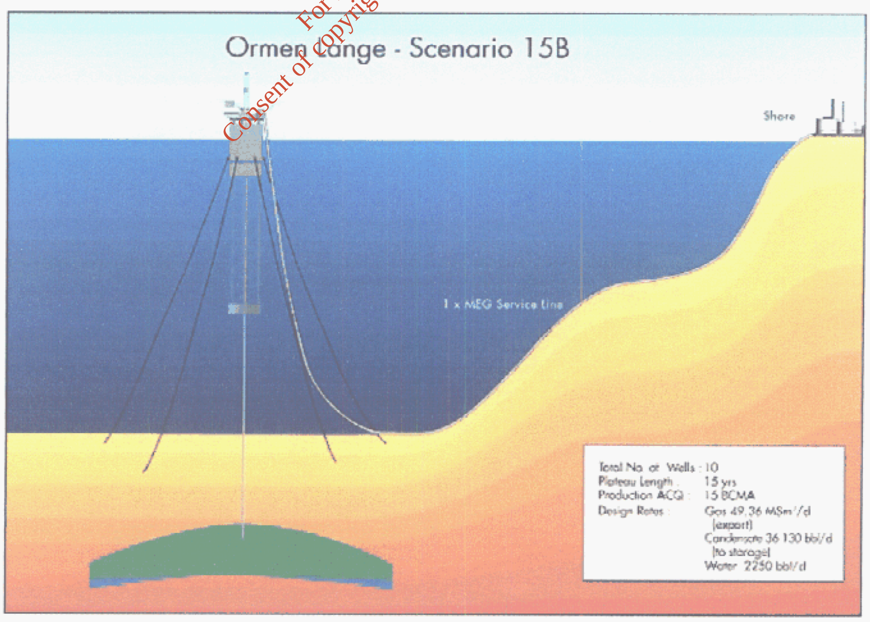
There are four potential development solutions, and a range of transport alternatives:

SCENARIO 15A



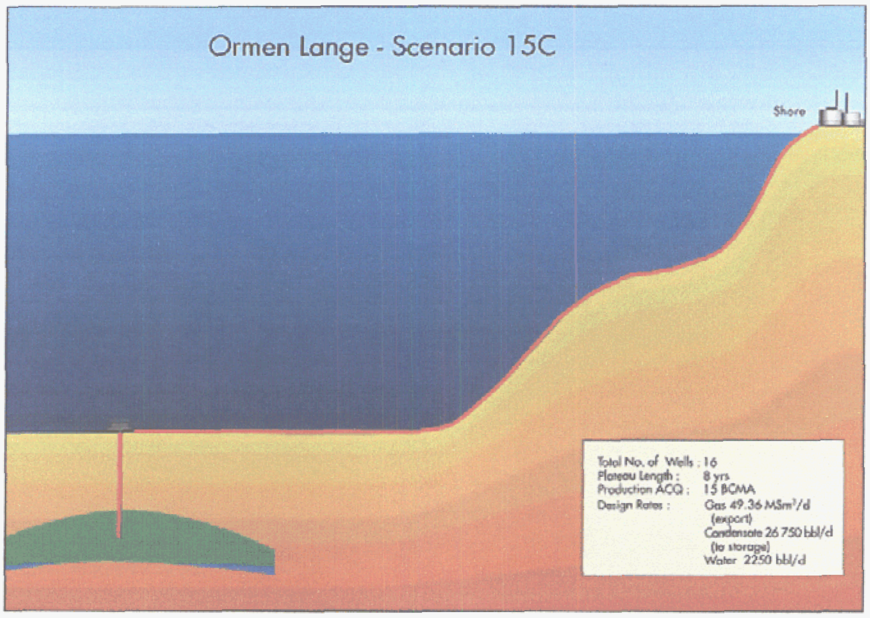
Scenario 15a consists of a spar moored to the seabed. Ten wells feed into the platform and the hydrocarbons are exported through a pipeline running to a subsea sales gas tie-in point. The design specifies exporting gas at a rate of 49.36M m3/day and storing up to 30,270b/d of condensate. The facilities can also process 2,250b/d of water.

SCENARIO 15B



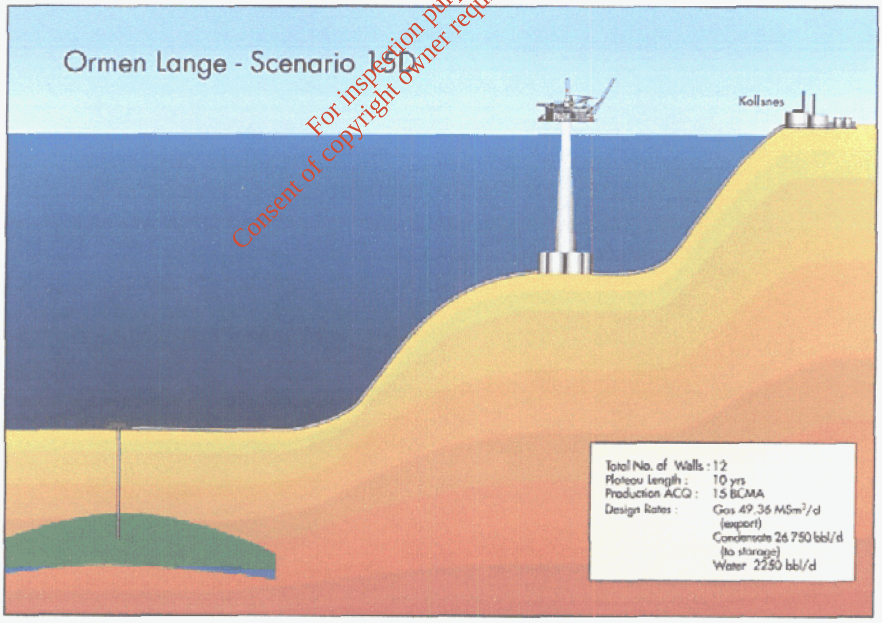
Scenario 15b is broadly similar to 15a, except that it will be developed using ten wells tied into a subsea template, then piped directly to the shore. The plateau production will be 15 years. The maximum gas- and water-production rates are the same as with 15a, but the storage specified is 36,130b/d.

DEVELOPMENT SCENARIOS (cont.)
SCENARIO 15C



This scenario produces Ormen Lange as a subsea completion, tied back to the shore. It would be developed using 16 wells and stay on plateau production for eight years. The gas export and water production would remain at 49.36M m3/day and 2,250b/d, respectively, but 26,750b/d of condensate would be sent for storage.

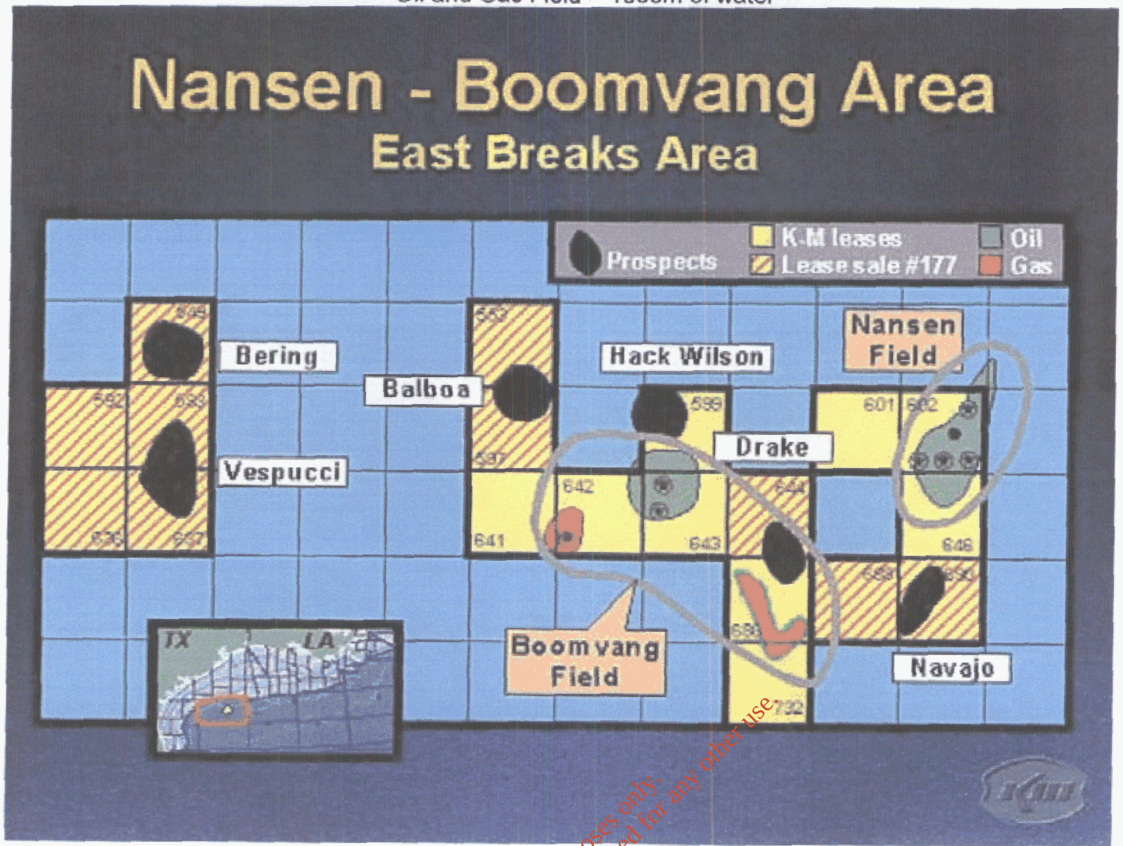
SCENARIO 15D



This envisages 12 wells being produced into a subsea template and piped to a concrete platform. Production would then be sent to the plant at Kollsnes. It would stay on plateau production for ten years. The gas export and water production would remain at 49.36M m3/day and 2,250b/d respectively, but 26,750b/d of condensate would be sent for storage. In August 2000, the extension well 6305/8-1 confirmed gas volumes and a thin layer of oil, measuring a maximum of three metres. Norsk Hydro drilled the well into a chalk formation to a total depth of 3,175m, using the rig Scarabeo 5.

NANSEN BOOMVANG GAS FIELD, GULF OF MEXICO, USA

Oil and Gas Field > 1000m of water



The Nansen and Boomvang fields lie in the East Breaks area of the Gulf of Mexico, approx. 150 miles south of Houston. Nansen lies in East Breaks block 602 and Boomvang lies in blocks 642, 643 and 683. Nansen lies in 3,678ft of water, while Boomvang lies in 3,453ft.

EQUITY

Kerr McGee operates the Boomvang field with a 30% working interest and the Nansen field with a 50% working interest. The other partners in Boomvang are Enterprise (now Shell - 50%) and Ocean Energy (20%). Ocean Energy holds the remaining 50% interest in the Nansen field.

DRILLING

Nansen was discovered in October 1999, in 3,680ft of water, approx. eight miles east of the previously announced North Boomvang discovery. Successful drilling of Nansen No 8 well, on East Breaks 602, extended the field to the south. At Boomvang, a second rig was secured to concurrently drill a total of up to seven wells at North and East Boomvang.

DEVELOPMENT

In Early 2002, Nansen achieved first production from the first of three subsea wells. Daily production from the Nansen field ramped up to a peak rate of about 40,000 barrels of oil and 80 million cubic feet of gas by the fourth quarter of 2002, as completion activities at the remaining nine dry tree wells were completed. Both Nansen and Boomvang are being developed by the world's first truss spars. Spars International was contracted to design the almost identical systems. The truss design replaces the lower cylindrical hull in order to reduce weight and cost. The open truss structure also reduces movement and three heavy plates enhance stability. The Spars are 543ft in length and weigh 17,000t each. Air chambers in the upper hull provide buoyancy for the floating structures.Each spar has a production capacity of 40,000b/d and 200 million ft^3/day of gas. The wells were completed beneath the spar and tied back through top-tensioned risers to dry wellheads and trees. Additional tie-ins are incorporated from subsea satellite wells. In total, there are nine top-tensioned production risers and associated equipment for Nansen and five for Boomvang.GAS

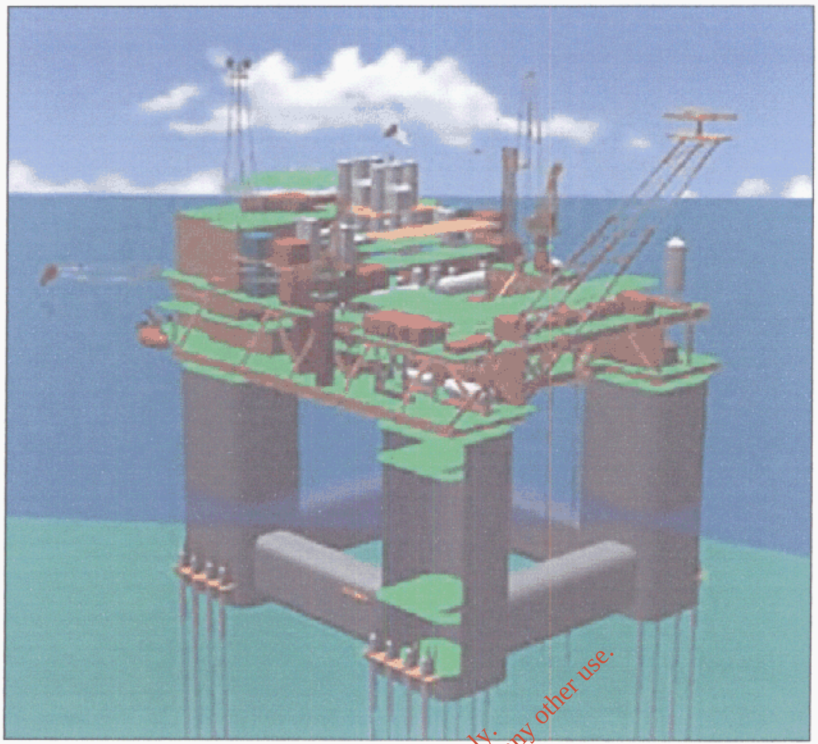
EXPORT

Williams constructed and operates the Seahawk Gathering System which moves all gas produced from Nansen and Boomvang. The Seahawk construction project includes 41 miles of 18in diameter line, connecting the spar platforms to a new shallow-water facility on the shelf in GAA-244. From there, a 55-mile, 24in-diameter pipeline has been laid for exporting the gas to an interconnection on Williams' Central Texas Gathering System in BA538.

OIL EXPORT
Williams constructed and operates the Boomvang and Nansen Joint Oil (BANJO) System to move all the oil. BANJO is a 16in diameter, 41 mile-long oil-export pipeline that extends from the Spar platforms to the shallow-water facility in GAA-244. From there it interconnects with ExxonMobil's Hoover Offshore Oil Pipeline System. Both the Seahawk and BANJO Systems include deepwater subsea junction facilities for gathering oil and gas from future deepwater.

PIPELINE
The main pipeline was subcontracted by Williams to Coflexip Stena. The company used its CSO Deep Blue newbuild. Cal Dive International installed infield flowlines using its reeled pipelay system deployed from the Sea Sorceress. Workscope covered the installation of approximately 100,000ft of 6in-diameter pipelines, five flexible production risers and 86,000ft of associated umbilicals, plus the jumpers and flying leads necessary to tie-in three subsea trees.Wellstream designed and supplied the 5.625in, 6,000psi flexible pipe production risers and tie-in jumpers for the project. The risers were installed in a catenary configuration, enabling the spars to be offset for future on-site drilling. Bridon supplied HDPE sheathing on the wire spiral strand to be used for the spar moorings.

PROCAP 2000 CAMPOS BASIN, BRAZIL



To enable PETROBRAS to produce oil and gas from offshore fields situated in **ultra deep waters (of 1,000-3,000m)**, with the aim of incorporating the reserves located at these water depths, Petrobras set up the PROCAP 2000 project. This project targets the pilot trial of a subsea multiphase pumping system and a subsea multiphase metering system.

DRILLING AND COMPLETION TECHNIQUES

The two main topics were concerned with underbalanced drilling and high-pressure jet drilling.

SUBSEA SEPARATION SYSTEMS

The objective was to decrease the well-head backpressure, by separating the gas and the liquid phases at the seabed, as near as possible to the production well. This project is based on a vertical annular separation and pumping system (VASPS) subsea separation system.

HIGHLY DEVIATED WELLS IN UNCONSOLIDATED LITHOLOGIES

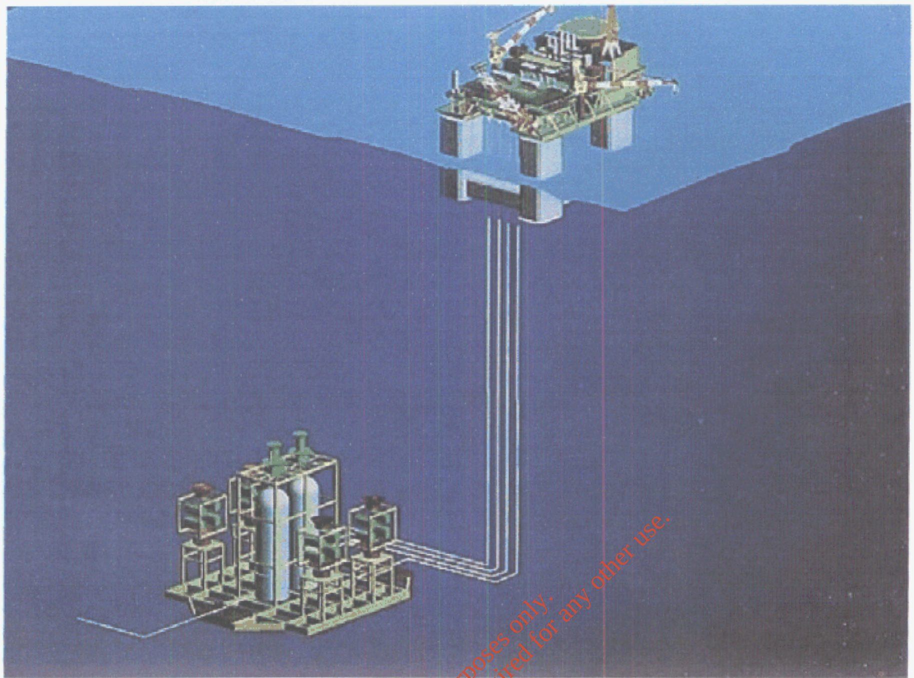
The aim of the project was to develop studies and tools for a better understanding of well instability, thus minimising its effect by guaranteeing cuttings removal. The problems relating to mechanical stability and cuttings removal are very well connected, as both are physically related. Due to the collapse of the formation, the cuttings fall into the well in great volumes.

STABILITY IN HORIZONTAL AND DEVIATED WELLS

The major concern has largely been restricted to poorly consolidated formations; perforated completions subjected to excessive drawdown; and wellbores intersecting tectonically active zones.

DEEPWATER SUBSEA EQUIPMENT

The main target is to promote the development of flexible pipes, accessories and installation procedures for **water depths up to 3,000m**, so as to evaluate and validate new flexible pipe design criteria and new material applicability. The sub-projects include horizontal christmas trees for water 2,500m deep; a drill pipe riser for ultra deep water; alternatives for drilling risers; slender wells for ultra-deep water; the shared actuator manifold - MacManifold; pig operation devices; and integrated system subsea equipment for the RJS396 area.



KICK AND BLOWOUT CONTROL IN DEEPWATER WELLS

The objectives are the development of theoretical and experimental studies, for helping in the definition of adequate well-control procedures, to minimise the possibility of blowouts. Considering the risks associated with gas influx control, early kick detection is a key factor.

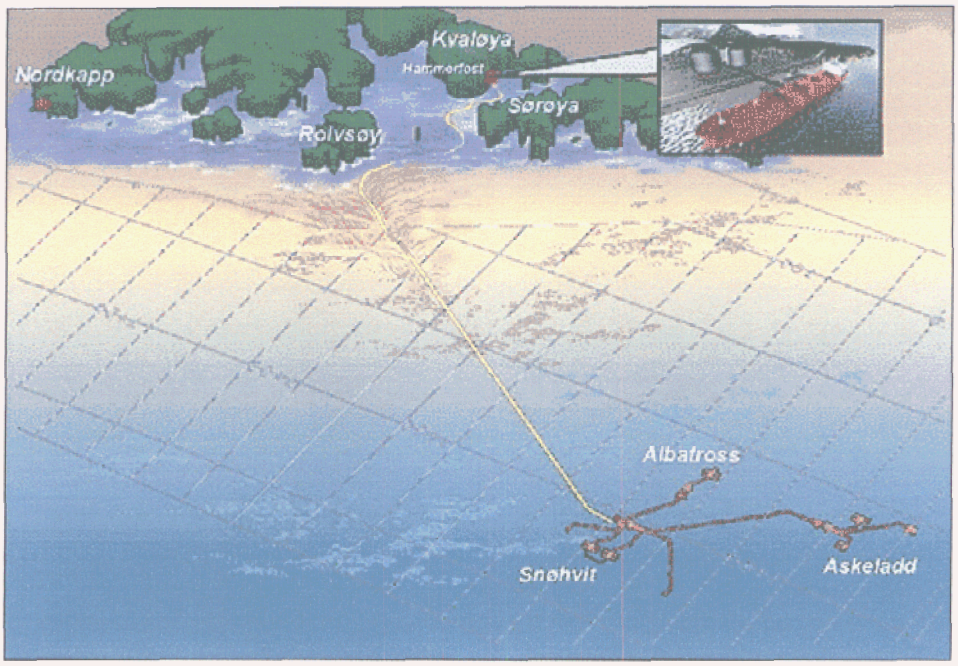
MOORING SYSTEM

The aim of this project is to develop technology to moor drilling, production and off-loading systems in water depths down to 3000m.

PRODUCTION UNITS WITH DRY COMPLETION

This will make available the **Spar Buoy** and TLP conceptual design for water depths from 1,000-3,000m, as well as evaluating the possibility of the SPAR to accommodate oil storage, identifying possible limitations.

SNØHVIT GAS FIELD, BARENTS SEA, NORWAY



The Snøhvit development comprises three fields - Snøhvit, Albatross and Askeladd. These lie in the Barents Sea, about **140km** north-west of Hammerfest in northern Norway. The fields were discovered in 1984 in **250-345m of water** and extend across seven production licences. It is operated by Statoil on behalf of Petoro, TotalFinaElf, Gaz de France, Norsk Hydro, Amerada Hess, RWE Dea and Svenska Petroleum Exploration. **All primarily contain natural gas** with small quantities of condensate. The accumulation exceeds 193 billion cubic metres of natural gas and 113 million barrels of condensate.

Snøhvit will be the first major development on the Norwegian continental shelf without a fixed or floating unit. Instead, a subsea production system on the seabed will feed a land-based plant on the north-western coast of Melkøya, at the entrance to the shipping channel into Hammerfest via a 68cm ID, 160km gas pipeline. In addition come two chemical lines, an umbilical and a separate pipeline for transporting carbon dioxide, which will be laid in the summer of 2005. Both the subsea production system located on the field and pipeline transport will be monitored and controlled from a control room at Melkøya, where operators will be able to open and close valves on the seabed 140km away with signals transmitted along fibre-optic cables, and with high-voltage electrical and hydraulic power lines.

The potential routes for the pipelines and cables have been mapped, as well as the areas where the subsea installations are to be sited in order to ensure the most favourable location for pipelines and equipment.

The work was carried out from the Normand Tonjer, which was followed by geotechnical surveys on the field and along the pipeline routes by the ship Bucentaur.

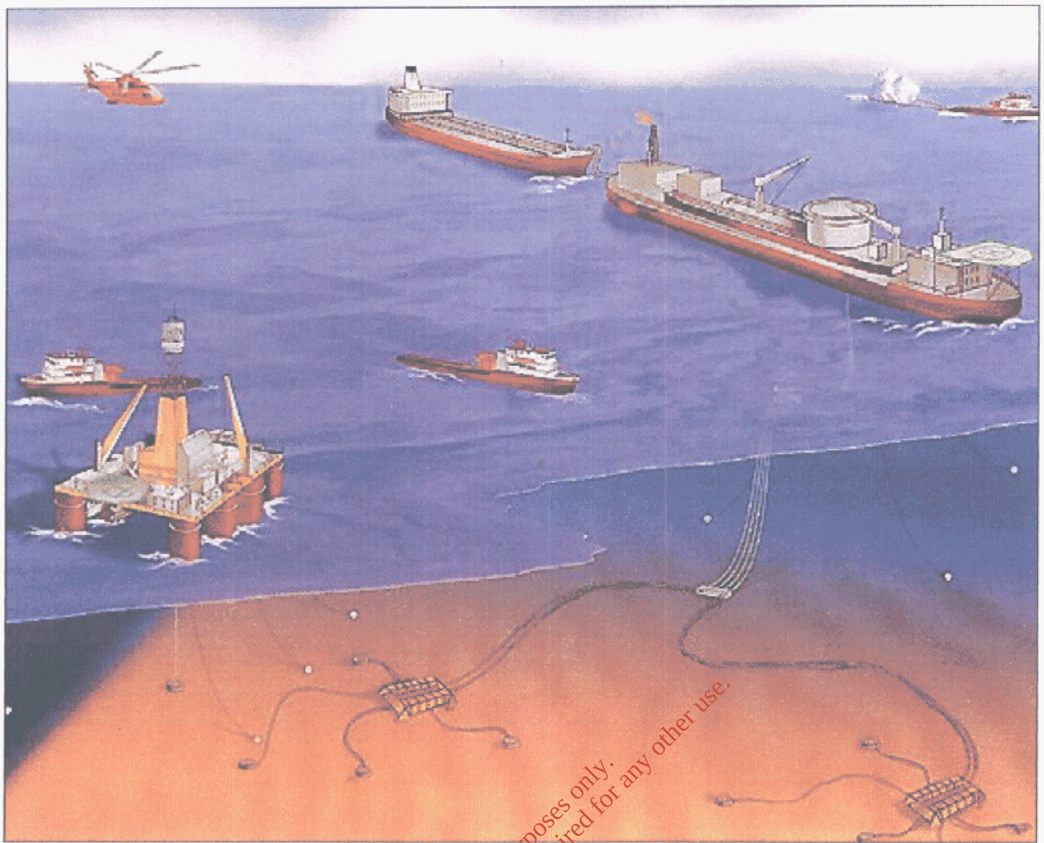
GAS LIQUEFACTION

The unprocessed wellstream arriving at Melkøya is separated and the gas cooled down to liquid form and exported. Gas from the Snøhvit area contains five-eight per cent carbon dioxide, which will be separated out at the land plant and returned in a separate line for storage underground beneath the seabed.A liquefaction plant will reduce its volume 600-fold by decreasing its temperature to -163°C. This will be carried out on a gas liquefaction barge, being built at the Spanish shipyard group Izar Construcciones Naval's yard in Ferrol in a contract worth about NOK 170 million. The barge will measure 9m high by 154m long and 54m wide.The chosen building approach greatly reduces the need for steelwork on Melkøya, and gives cost savings as well as higher productivity compared with constructing the plant on site.

Following completion, the barge will be towed to an outfitting yard where about 24,000t of process equipment for the gas liquefaction plant will be installed on its deck. From there, it will then be transported to Melkøya on a heavy-lift ship and installed in a dock blasted out in advance. About 70 cargos of LNG per year will be shipped out from Melkøya.

The annual exports are anticipated to be 5.75 billion cubic metres of LNG, 747,000t of condensate and 247,000t of liquefied petroleum gases (LPG). There are long-term contracts with Iberdrola in Spain and El Paso in the USA. The total investment will include NOK 34.2 billion for field development, pipeline and land plant and NOK 5.4 billion for ships. Snøhvit will start production in 2006.

TERRA NOVA GRAND BANKS, CANADA



Note
Same Process can now be done by producing Liquid Natural Gas (LNG) by GAS LIQUEFACTION similar to the SNØHVIT GAS FIELD,in Norway.

The Terra Nova field, located 350km ESE of St John's Newfoundland and 35km SE of Hibernia, was discovered in 1984 by Petro-Canada. Field reserves have been estimated at 406 million barrels (Mbbl).

ENVIRONMENT
Water depths are shallow - between 90m and 100m. The mean annual wind speed is 35kmph, with the strongest recorded wind speed being 145kmph and the largest recorded wave height being 25m.The area is characterised by the seasonal presence of floating sea ice, ranging in thickness from 0.5m to 1.5m, produced by the freezing of the ocean's surface layer and icebergs.

RESERVOIR
Terra Nova is subdivided into three major structural blocks: the Graben, the East Flank and the Far East. The field is estimated to contain over one billion barrels of oil in place, of which about 400Mbbl of oil are recoverable. (The Far East block, which is not yet drilled, is expected to add at least 100Mbbl of reserves to the 300Mbbl that have already been estimated within the Graben and East Flank). The estimated peak production rate is 125,000b/d from the Graben and East Flank portions alone. A total of 32 wells are planned for the Graben and East Flank blocks, including 20 production wells, ten water-injection wells and two gas injection wells. For the Far East, a total of 12 wells are planned, including six production wells and six injection wells. Field life is expected to be 18 years.

DEVELOPMENT
Petro-Canada selected the Grand Banks Alliance (SBR Offshore, Doris Conpro, PCL Industrial Constructors, Coflexip Stena, Halliburton Canada and FMC Canada) to carry out engineering, procurement, construction, installation, commissioning and possibly pre-development drilling activities up to the production of first oil. The project partners and Grand Banks Alliance consequently established a single alliance: the Terra Nova Alliance, with each company participating on a risk-and-reward basis.

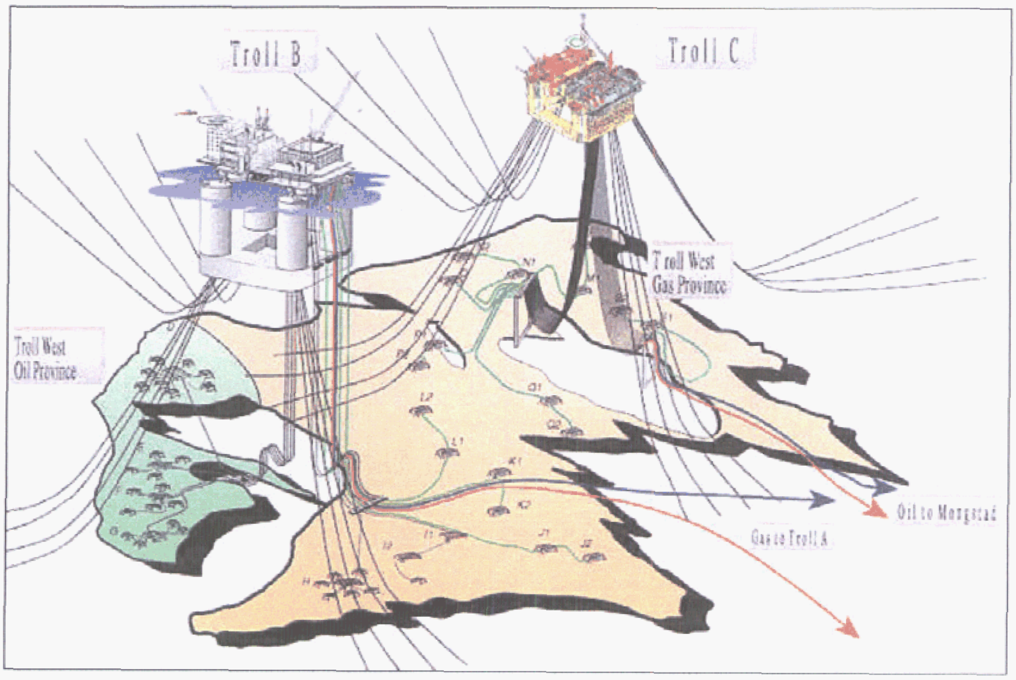
PRODUCTION
The subsea layout will consist of a production well feeding into a template, which, in turn, will be connected by flexible flowlines to a riser-base manifold (RBM). In order to protect the subsea wells from

iceberg scour, they will be set in glory holes - large holes drilled in the seabed in which equipment can be installed. Flexible risers will connect the RBM to an FPSO. The vessel will have a length of 280m and a width of 45m. The combination of low air and water temperatures with wind and wave action, makes superstructure icing a consideration during the winter months. This means that an allowance of several hundred tonnes of superstructure ice accumulation must be factored into weight and stability calculations. There must also be procedures for monitoring and mechanisms for controlling ice build-up on the structure and substructures of the offshore facilities.Low water temperatures require that fluids such as hydraulic control fluids be heated or treated to lower their freezing point. Similarly, low temperatures combined with the waxy nature of the crudes require that the flowlines and riser are insulated to reduce wax deposition. The FPSO is designed to operate in moderate sea ice, up to a limit of five-tenths coverage and to disconnect, as required, to avoid heavy pack ice and potential collisions with icebergs.The 9000t topsides facilities will be installed approximately 4.5m above the main deck. They will contain the necessary equipment to produce 150,000b/d oil, and inject 250,000bbl of seawater/day and 125 MMcf/d of gas. The FPSO hull will have an integrated storage capacity of 900,000bbl.

EXPORT

The export system will be a tandem offloading system for the transfer of crude oil from the storage tanks of the FPSO to ice-strengthened shuttle tankers, ranging in weight from 80,000t to 120,000t. The offloading system will be designed for connection to tankers in 5m significant-wave-height conditions.

TROLL WEST NORTH SEA NORTHERN, NORWAY



Although Troll is primarily a gas field, it also possesses significant quantities of oil, in thin zones under the gas cap, to the west of the field. West Troll can be divided into two major zones - the Troll West oil province and the Troll West gas province. Regular oil production from the 22- to 26m-thick reservoirs, in the Troll West oil province, began in late 1995. Now, the extensive use of advanced drilling technology and the experience of production and well management have allowed the development of the Troll West gas province to begin - where zones are only 12 to 14m thick.

TROLL WEST LOCATION

The field is located in blocks 31/2 and 31/5, within production licence 85. **It lies approximately 75km from the shore** and 32km from the Troll A platform. The water depth ranges from 315-345m.

DISCOVERY

Oil and gas were discovered by well 31/2-1 in 1979. This was followed by the drilling of 20 appraisal wells between 1980-93, all of which encountered quantities of oil and gas. In 1990, the horizontal test well 31/2-T1 was drilled in the oil province and this was followed, in 1991, by the horizontal test well 31/5-T 1 in the gas province.

DEVELOPMENT STRATEGY

The Troll West reservoirs are being drained by two platforms, Troll B and Troll C. These are both semisubmersible production units. Since it came on-stream, Troll B has been used to produce oil from the oil province and the southern part of the gas province. When it came on-stream in late 1999, Troll C started to deplete the Northern part of the gas province.

TROLL B - OIL PROVINCE

Production commenced on Troll B in September 1995, using eight predrilled wells in the oil province. Current production is 40,000-42,500m3/day, from 21 wells, in the four oil province well groups known as D, E, F and G. TROLL B –

GAS PROVINCE

The platform has also brought wells from the south part of the gas province on-stream. Altogether, there are 24 subsea satellite oil producers tied back to the Troll B platform - 12 wells are in the H-cluster and 12 in well group 1.

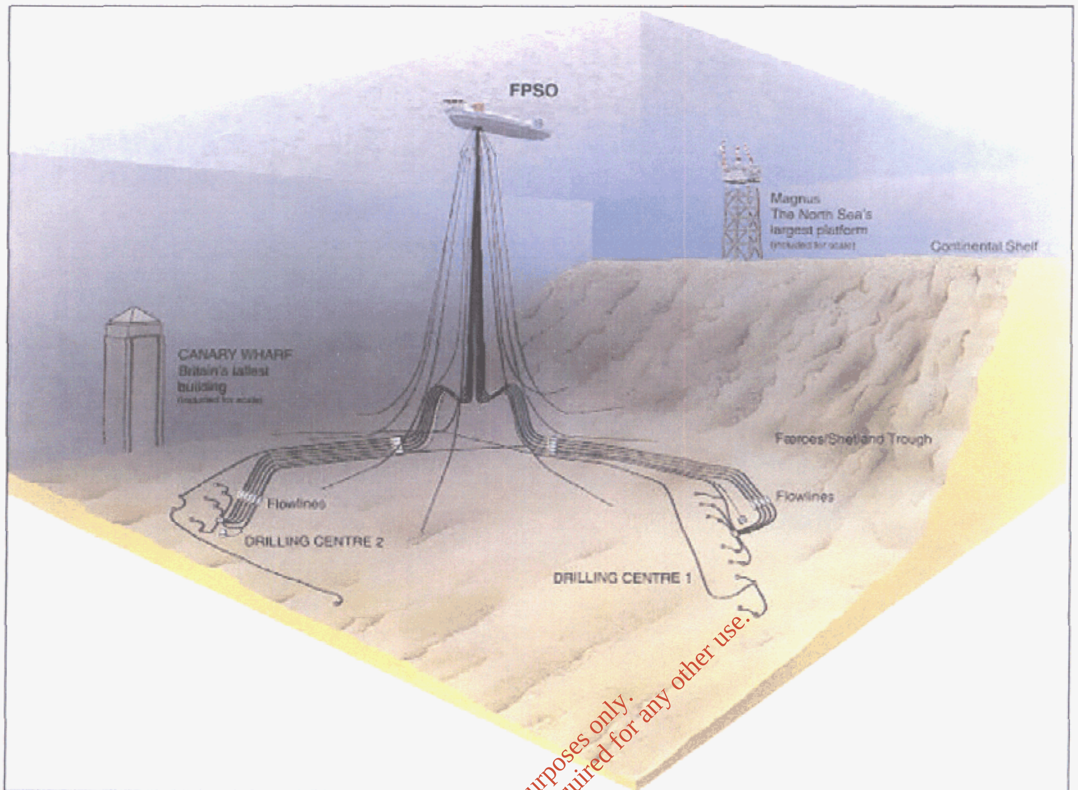
FUTURE PLANS

The remaining oil reserves of the gas province will be developed by 58 horizontal wells. Plans envisage that 14 of these will be drilled with two branches. These 58 wells will be arranged in ten well groups, each normally containing two templates. Between two and four wells will be drilled from each template. Three of these well groups - J, K and L, which will contain a total of 18 wells - will also be tied back to Troll B and use the spare tie-in capacity on the platform.

TROLL C

The remaining seven well groups will be routed to a new Troll C platform, which is located in the Northern part of the gas province. There will be no drilling facilities on Troll C. In early 1998, a second rig started pre-drilling wells in the gas province. Production from this part of the field commenced in late 1999. The drilling programme is planned for completion by the year 2002, but it may be extended, in order to find out the potential for improved oil recovery. Troll C has an oil-production capacity of 30,000m3/d, a water production capacity of 40,000m3/day, a liquid production capacity of 60,000m3/d and associated gas production capacity of 9 million m3/d. It has a total displacement of 52,750t and can accommodate 70 people.

FOINAVEN WEST OF SHETLANDS, UNITED KINGDOM



Note
Same Process can now be done by producing Liquid Natural Gas (LNG) by GAS LIQUEFACTION similar to the SNØHVIT GAS FIELD,in Norway

Foinaven is located in blocks 204/19 and 204/24a, which are operated by BP Exploration. Shell UK Exploration and Production is the co-venturer. These blocks lie some **190km** west of the Shetland Islands, in a water depth of between **400 and 600m**.

Recoverable reserves are estimated to be in the region of 250 to 600 million barrels of oil. The project is being carried out as a phased development. The first of these is based on the recovery of 200 millions barrels within the Foinaven field.

These developments centre on subsea wells completed on the seabed. They produce oil, via a manifold, which passes through rigid flowlines and then flexible risers into a floating production, storage and offloading system (FPSO), which is permanently stationed in the field. Shuttle tankers then export the crude oil.