UNDERSEA INSPECTION OF SUBSEA PRODUCTION SYSTEMS

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TABLE OF CONTENTS

TABLES

PREFACE

The primary objectivies of this study were to identify Subsea Production System (SPS) underwater inspection requirements and the techniques available and envisioned to conduct such inspections. Secondarily, the subjects of SPS maintenance and repair were to be addressed to the detail possible at this time. Specifically, the following topics were to be covered:

- Identify and describe SPSs now in operation and those conceived in the foreseeable future.
- Forecast the near-term (through 1990) growth by depth and operating environment.
- Describe the techniques and the level of detail to which inspection and maintenance of SPSs is currently performed and what is conceived in the near-term.
- Identify potential failure and/or problem areas of SPSs foreseeable in inspection/maintenance requirements.
- Based on current underwater Non-Destructive Examination (NDE) state-of-the-art, identify and describe areas where technical inadequacies are foreseeable and recommend research and development to alleviate potential inadequacies, particular attention will be placed on the arctic.

This study was conducted from the offices of Busby Associates, Inc., Arlington, Virginia. Data were collected from three sources: 1) published material in pertinent trade journals and conference proceedings; 2) manufacturers and operators of SPSs and underwater service companies, and 3) activities which may be involved in the formulating of SPS inspection requirements including government agencies (national and international) and private classification societies.

Published sources from which data were obtained are listed in Appendix II. Activities and personnel contacted are listed in Appendix IV.

ACKNOWLEDGEMENTS

Numerous individuals contributed freely of their time and knowledge to this report. We would especially like to acknowledge Mr. Ronald L. Geer, Shell Oil Company, who provided a host of individual's names who are involved in various aspects of Subsea Production Systems. Mr. Geer, as he did in many of our past efforts, also shared his extensive knowledge of this field and his experiences therein. Mr. Ernst E. Sjoholm, Technical Services Manager, CanOcean Resources Ltd., provided extensive and comprehensive data on his company's operations and experiences with dry SPSs, we are indebted to him for sharing this information with us and his hospitality.

Many other individuals and organizations provided us with data and insights that were invaluable to the goals of this study. To the following we would like to express our thanks and appreciation: Dana Beebe, Arctic Technology Section, Gulf Oil Exploration and Production Company; W. Pat Rickey, Roger Huffaker and Phillip Abrams, Exxon Production Research Company; B.C. (Burt) Carlson, Frontier Production Group, Shell Offshore Inc.; Frank Wang, Conoco, Inc.; Robert M. Hill, S&H Diving Corporation; F. Richard Frisbie, Oceaneering International; Phil Nuytten, Can-Dive Services, Ltd.; Drew Michel and John Harter, Taylor Diving and Salvage Company; Ed. Lewis and Al Wedel, Cameron Iron Works; Graham R. Stone, FMC Corp., Wellhead Engineering Division; Dr. David Partridge, Offshore Supplies Office, UK Dept. of Energy; T. Hamilton and J.R. Petrie, Petroleum Engineering Division, UK Dept. of Energy; D.E. Carlisle, Lloyds Register of Shipping; Per Bonam, Det norske Veritas; Dr. Raymond J. Smith, Energy, Mines and Resources Canada, and to the Vetco Offshore Group.

The vast majority of this report consists of parapharasing and quoting the papers and reports of numerous individuals. We would like to acknowledge the many authors from whom we liberally extracted information and observations. Hopefully, we have duly credited these individuals whenever we have used their work. If we have missed, we offer our sincerest apologies.

EXECUTIVE SUMMARY

GENERAL

Since 1960 a total of 292 Subsea Production System wells have been installed, an additional 77 wellheads are assembled and/or on order. (For comparative purposes, there are some 3,600 fixed offshore production platforms worldwide, some drawing from dozens of wells.) The SPS units installed consist of wet (274) and dry, 1-ATA (18) structures. Some of the wet structures are single satellite wellheads while other are multi-wellheads grouped within a template. The functions of SPSs are to collect gas and oil or to inject water. A number have been installed for test purposes and are now abondoned. The growth of subsea productions has been slow, but steady. The most optimistic projection puts the number at 1,000 by 1990. This pace will be governed by the price of oil, not by technological constraints.

The greatest water depth of SPS installation to date is 293 meters. The average depth of SPS installations worldwide is 88 meters. These are within the 300 meter depth range generally accepted as the present limits for diver intervention. Two single SPSs are scheduled for installation in depths beyond diver intervention: the Montanazo field (762m) and the Casablanca field (488m), both in the Mediterranean.

PERFORMANCE

Published reports of SPS performance and reliabilty show percentage up time figures ranging from as low as 51 percent annually to as high as 96 to 99 percent. The majority of reports quote the latter percentages. Ten wellheads in the Molino field, offshore California, were retrieved after 20 years service with no reported breakdowns. A detailed inspection of one of the wellheads showed that it could have gone on producing for, perhaps, several more years.

Problems encountered with SPSs are ascribed to unreliable control systems; downhole electronics; unsatisfactory data handling techniques; manifolds not designed with maintenance in mind; inadequate sensors; unreliable electrical connectors, and sticking subsea valves.

The most severe damage, and of greatest concern to the operators, is that which would be imposed by contact with trawls; dragging anchors, and/or dropped objects. The solution to this latter problem has been to enclose the SPS within a protective framework, install it within a hole excavated deep enough to avoid impact (i.e., icebergs or ice islands), or to design it such that it can withstand any forces likely to be encountered other than impact by a submarine.

INSPECTION PROGRAMS

The Norwegian classification society, Det norske Veritas, is the only organization that offers a formalized post-installation in- spection program for SPSs. The manufacturers of SPSs also recom- mend inspection/maintenance programs for their particular sys- tems, but these are at the liberty of the operator to pursue or ignore. The operators interviewed in this study see little or no need for inspection since wellhead pressures, product flow and temperatures are continuously monitored. Further, short of a major im-pact, the past history of SPSs show more than adequate structural integrity as long as a proper corrosion protection system is em-ployed. The results of marine fouling have shown to be more cosmetically unpleasing than damaging.

The greatest inspection effort on the part of the operators is performed before the SPS is installed. These programs can - and many do, begin at the component level and extend through to cover the entire system before it is placed in the water. In many instances the system is operated ashore to identify deficiencies. Other operator requirements call for quality assurance monitoring at all phases of manufacture and assembly of components; system configuration be based on proven hardware and concepts, and that components have a proven record of tolerance for rough handling, contaminated hydraulic fluid and other adverse conditions which commonly occur in practice.

INSPECTION AND MAINTENANCE INTERVENTION TECHNIQUES

There are three primary underwater intervention techniques in use and available for SPS inspection and maintenance: the diver; the manned submersible, and the remotely operated vehicle or ROV. The premier intervention technique is the diver, mainly because few of the early SPSs were designed for other than human interven- tion, and also because the diver can respond to unforeseen maintenance more adroitly and more quickly than diverless techniques. Since there is no standardization between wellheads, nor is there any compelling reason to recommend such, there are no standard maintenance tools that can be applied across the board from one wellhead to another. Field experience, and tests and evaluation with diverless techniques demonstrate that a wellhead which is designed for diverless intervention, coupled with a vehicle modified to intervene on that particular wellhead, can be provided with adequate diverless inspection and mainte- nance. These are the procedures being followed on the two SPSs planned for installation beyond the depth of diver intervention.

RECOMMENDATIONS

The wide variations in configuration and capabilities of present subsea production systems precludes recommendations for research and development in the areas of inspection and maintenance. What might enhance the conduct of these operations on one SPS may not have application to any other. The strongest recommendation is that SPSs which will be beyond or at the margins of diver intervention, be designed with the designer, the operator and the intervention contractor working concurrently. In essence, that the structure be designed for the vehicle and the vehicle be designed or modified for the structure and the environment. The absence of this practice has been the chief reason for the inadequate performance of diverless techniques.

An area that shows some promise for overall inspection of large and small subsea production systems is large area television coverage. Field demonstrations have produced images encompassing areas of the bottom averaging 2,000 square meters. Research in this area is seeking to expand this to areas 500 meters square. Large scale imaging of this type may provide a diverless technique capable of externally examining an entire satellite wellhead or template for impact damage, scouring or debris accumulation rapidly and comprehensively.

1.0 HISTORY OF SUBSEA PRODUCTION SYSTEMS

1.1 SUBSEA PRODUCTION SYSTEMS DEFINED

An official definition of a SPS has yet to evolve. Indeed, since the early 1960s, when the predecessors to the current varieties of undersea SPSs first appeared, systems performing the same function were also called Subsea Completion Systems (SCSs). Today both terms are used interchangeably throughout the offshore oil and gas industry. Arbitrarily, the term SPS is used in this report when refering to the generic system. As the acceptance and utilization of SPSs increased, specific systems were developed and given a designation that would distinguish a particular SPS from another. This development added a variety of acronyms to the SPS vocabulary, such as, DIMOS (Diverless Installable and Maintainable Oil Production System; ESP (Early Subsea Production System); GASP (Goodfellow Associates Submerged Production System); SAS (Subsea Atmospheric System); SAS (SEAL Atmospheric System); SIS (SEAL Intermediate System); SWOPS (Single Well Offshore Production Unit), UMC (Underwater Manifold Center), and others. Since the field has essentially just reached puberty, it can be anticipated that the jargon will increase in proportion to future growth.

One of the first published definitions of an SPS was in 1975 (ref. 13) which defined "a `true` subsea completion as the completion of a producing well in which the producing Xmas tree and all other primary well controls, either exposed to the water or fully encapsulated, are located on the ocean floor."

Expanding on the above definition, a 1979 author (ref. 65) defined SPSs according to their design: wet vs dry systems. A wet system being one where the Xmas tree and other components are exposed to ambient sea floor conditions. Hydraulic valves, control system components and other pressure or water sensitive items are either compensated or protected with enclosures. When the control system requires electrical power, the connections are completed with subsea cables and `wet` electrical connectors. In a dry system, Xmas tree components and key subsystem controls remain dry because they are housed in a wellhead chamber that is maintained at one atmosphere of pressure. The chamber is equipped with penetrators and hydraulic connectors to allow connection of the chamber to the wellhead and connection of the flowlines, electrical cable and hydraulic lines. These chambers are insensitive to water depth and remain at one atmosphere at all times. Therefore equipment within the chamber need not be pressure compensated. When service is performed on a dry system skilled (but not diver trained) technicians perform the service work without decompression or special training.

Butler et al (ref. 108 further refined the definition of an SPS by stating that the well completion equipment (Xmas tree and controls) must be located on the sea floor, and that systems in which the wells were pre-drilled from a floating drilling vessel and subsequently tied-back to well completion equipment at the surface are not SPSs. These authors provided a description of the functional requirements of the components of a deep water SPS (they state that a shallow water system would be similar) which is as follows:

SUBSEA SYSTEM COMPONENT	FUNCTIONAL REQUIREMENT
Subsea well (including the subsea completion or Xmas tree, and the control equipment on the tree).	Conduct reservoir fluids from the producing horizon to the sea floor, with the capability for control of the rate of flow.
Flowlines (Not required if subsea wells are drilled from a single template; i.e., clustered).	Conduct produced fluids from remote well location to central riser/production manifold location.
Production /Injection Manifold (located either subsea or at the surface facility).	Gather produced fluids from several wells, distribute gas lift gas or water or gas for reservoir injection to individual wells, direct well production to test facilities.
Production Riser.	Conduct produced fluids from the sea floor to the surface.
Production (processing) equipment.	Separate produced fluids into oil, gas and water; treat water for disposal or injection; condition gas for sales, injection or flaring; provide power, support systems and control.
Intrafield Pipeline.	Conduct products (oil/gas) to transportation system.
Offshore Production Terminal or Trunkline (Pipeline).	Ship oil and gas to market. Transportation facilities include storage and offloading equipment in the case of oil shipment by tanker.

Thus (ibid.), a subsea production system is composed of subsea wells, flowlines, a production injection manifold, a production riser, production equipment, intrafield pipelines and transportation facilities. For an oilfield the transportation facilities could be either a pipeline to shore or an offshore production terminal including storage and offloading. The authors point out that any particular SPS configuration may not contain all of these elements. A clustered well, for example, does not require intrafield flowlines.

A 1981 report (ref. 150) groups SPSs into two types within the wet and dry systems: satellite systems and templates. Satellite systems being a single wellhead installed on the sea floor connected to the production facility by a flowline; then carrying production or injection fluids with a control umbilical providing remote control of the wellhead. Template being a structure placed on the sea floor containing slots through which a number of wells can be drilled. This report also places SPSs into time-dependent categories: Short life (2-5 years); Medium life (5-10 years) and Long life (15-30 years) fields.

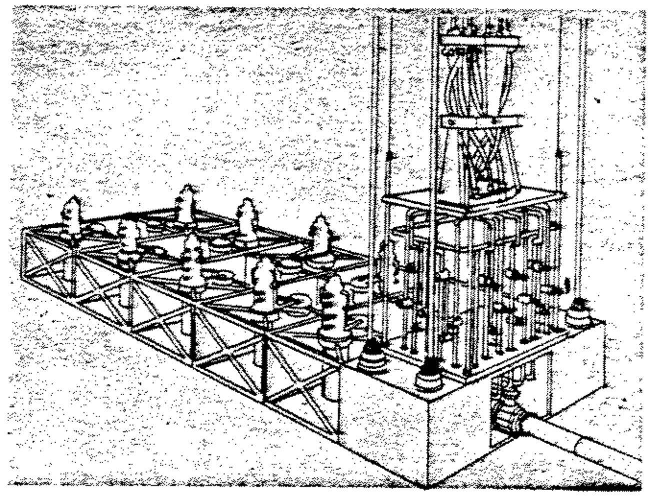
The Norwegian classification society Det Norske Veritas (DnV) issued a set of preliminary "Rules for Certification of Subsea Production Systems" in May 1982. In these rules DnV defined a SPS as "... systems on the sea floor or embedded in the soil and related to the production of hydrocarbons or injection of gas or water". The following parts and systems are covered by DnV's certification and, in effect, define a SPS's components:

- Downhole safety valves
- Wellheads
- Christmas trees
- Subsea manifolds and valves
- Subsea storage tanks
- Surrounding, supporting and protecting structures and foundations
- Production risers

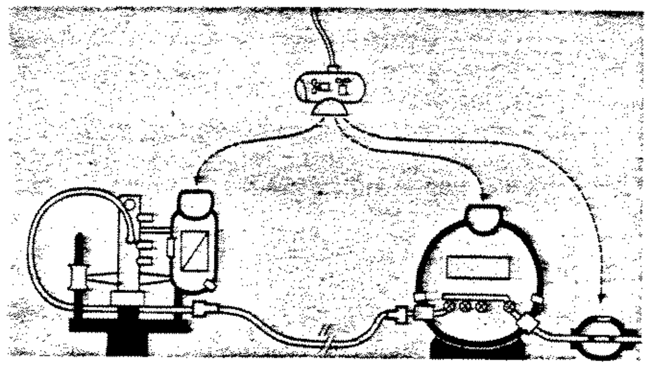
More recently, in 1984 Husemoen (ref. 219) provided, what he terms, a `practical` definition of an underwater production system (SPS) for the Norwegian industry that includes all equipment from and including wellheads to the upper part of a production riser or the connection of the production flowline to a fixed platform. The elements, whose use, design and arrangement can vary largely from one installation to another, are as follows:

- Template
- Wellhead System
- Manifold System
- Riser with connectors
- Flowlines with connectors
- Pull-in and Guide Equipment
- Control and Monitoring Systems

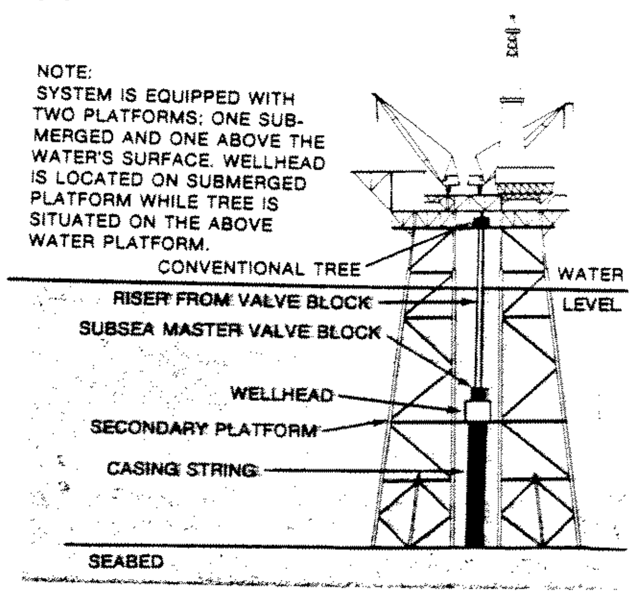
From the foregoing it is apparent that the definition of an SPS can take a variety of forms which will depend upon the function and design of the system. Examples of the different generic types of subsea production systems are presented in Fig. 1.



Wet system



Dry system



Hybrid system

FIG. 1. SUBSEA PRODUCTION SYSTEM TYPES (Ocean Industry, July 1977)

1.2 THE JUSTIFICATION FOR SUBSEA PRODUCTION SYSTEMS

The most numerous production platforms in the offshore oil industry are steel and concrete structures that are fixed (by piles) into- and supported by the sea floor and extend upward to some distance above the sea surface.There are some 3,600 of these platforms throughout the world. If the oil and gas industry had restricted its production to relatively shallow, ice-free waters, and if the costs of constructing and installing such structures had not shown a phenomenal increase, the application of SPSs would be few,if any, in offshore waters. This was not the case, however, and the environments and economics of offshore oil and gas production, commencing in the 1960s, created the opportunity for subsea production to debut and, more recently, begin to flourish.

Virtually any new capability or product finds initial application based on one or more perceived advantages over conventional methods or products. Once the new capability comes into use many more advantages begin to appear that were not originally foreseen. This is the case with subsea production. The following reasons for employment of SPSs are the summation of over 20 years experience. The case initially given for using a SPS was, that as the depth of oil production increased to beyond about 300 meters, the cost of fixed production platforms would force the oil producers into the SPS camp. This was pre-1974 (or pre-OPEC) thinking, and it might have proven correct had not the price of oil risen from $2.59/barrel in 1973 to $28/barrel by May 1980 (Saudi Light, source: American Petroleum Institute). This unforeseen increase permitted oil producers to economically extract oil using fixed platforms in far greater water depths than originally estimated. Nonetheless, by 1974 sufficient experience with SPSs had been gained to provide the operators several different vantage points than the one of construction cost. The following reasons for employing a SPS are, therefore, somewhat different than the initial justification and certainly far more wide ranging.

Marginal Fields: SPSs, when serving as preliminary production systems, can be used to test production rates on marginal fields. (ref. 65). SPSs have also been employed in fields (e.g., Brazil's Badejo Field) where the proven reserves did not meet the initial estimates and, therefore, a bottom-supported production platform was not economical.

Utilize Exploratory Wells: Discovery and delineation wells, which are normally plugged, can be turned into subsea satellite producers. Often some of the wells are edge wells which can be used for both production and floods. (ref. 45)

Produce Oil and Gas From Incompetent Floors: There are areas of the ocean where the bottom will simply not support a production platform. (ref. 45)

Reservoir Depth and Configuration: If the reservoir is irregularly shaped selection of central drilling and production sites will be difficult. If the reservoir is relatively shallow it may be difficult to reach field extremities by directional drilling from one or more central sites. (ref. 18)

Flow Rates: Very high flow rates, 20,000 barrels of oil per day (bopd), favor conventional platform development due to easier maintenance of platform wells with very large tubing strings. Lesser flow rates (up to about 15,000 bopd) can realistically be accommodated by tubing and flowline sizes that lend themselves to subsea completions and to well maintenance with TFL tools. Subsea wells located directly below a tension leg platform (TLP) and producing through individual, vertical risers would also be suitable for very high flow rates. (ref. 18)

Fluid Composition: The presence of sand, wax and corrosive agents may indicate the liklihood of frequent and costly well maintenance. High viscosity fluids may dictate close well spacing. These conditions favor platform development. Conversely, gas production, low-viscosity oil, minimum sand and wax content, and relatively non-corrosive amounts of carbon dioxide and hydrogen sulphide result in reduced maintenance needs and improves the economics of subsea wells.

Artificial Lift and Pressure Maintenance: Artificial lift requiring downhole pumping will generally dictate platform development with wellheads above the water and easily accessible. One exception is reservoir conditions suitable for the use of hydraulic jet pumps which can be installed and retrieved with TFL procedures. Gas lifting can be effected in either platform or subsea wells with approximately the same results and operating conditions. Pressure maintenance requirements may frequently favor the subsea approach, especially where peripheral water injection wells may be located long distances from centrally-positioned platforms. (ref. 18)

Reduced Expenditures: In many cases subsea development can be expected to cost less than conventional (platform) development. Subsea drilling and operating costs will almost certainly be greater than for platforms, but high initial costs for platforms will frequently more than make up the difference. (ref. 18)

Early Production: Bottom-supported platform designs are highly dependent on factors such as bottom conditions, water depth, weather and sea conditions and reservoir characteristics. In most cases it is not practical to finalize design and construct platforms before selecting actual installation sites and determining oceanographic and geologic data. This dictates a long time lag between exploratory drilling and commercial oil production.

The design of SPS equipment can be relatively independent of the variables noted above. For a small cost premium, construction of 'universal' subsea well equipment could begin as soon as a lease is obtained. Such equipment could be ready for installation within 12 to 18 months and could effectively provide for the majority of production and pressure maintenance requirements. Consequently, development drilling couild begin as soon as exploratory data have been obtained and analyzed. Similarly, jack-up or floating production stations could be readied based on standard designs. Such stations could be very mobile and could be installed shortly after development drilling commences. (ref.18)

Salvage Value: In the event where a SPS has been used on a small field with limited life, the system can be removed and installed in another field. In virtually all instances a bottom-supported platform is removed and scrapped for a fraction of its value. (ref. 31 and 45)

Location: A field within 9 to 18 kilometers of a physically hospitable shore would make complete subsea development a feasible option. Submarine pipelines would be short and relatively inexpensive. Well maintenance could, in many instances, be conducted from onshore sites with the use of through flowline (TFL) servicing procedures. Long distances from shore necessitate some sort of surface expression for production handling facilities and well maintenance. (ref. 18)

Water Depth: Water depths beyond 90 meters are adequately satisfied by a variety of bottom-supported platforms. With increasing depths the designs become more involved, construction times become longer and installations are more complex. Conversely, SPSs are relatively unaffected by water depths down to diver limits. The increasing popularity of diverless designs makes subsea wells suitable for depths beyond diver limits with little additional costs. (ref. 18)

Augment Production: Satellite subsea wells can be used to add neighboring reservoirs or pockets to existing production facilities aboard fixed platforms. (ref.24)

Ice Avoidance: In areas where the sea surface is covered by ice or subject to intrusion by icebergs or ice islands, SPSs might offer the only alternative to unimpeded production in deep water. This approach might also be the most economical in certain shallow water areas where the ice cover does not extend to the bottom and where the distance from shore is relatively short.

1.3 DEVELOPMENT AND DEPLOYMENT HISTORY

The first reported application of a Subsea Production System was not in the sea, it was off the shoreline of Southern Ontario in Lake Erie (ref. 208). In 1914 Union Gas Co., Glenwood Natural Gas Co. and Dominion Gas drilled a number of wells 90 to 250 meters off the shores of Port Alma. These locations were completed above water level from bottom-supported platforms set on clusters of wooden piles accessible by a "catwalk" from shore.

By 1943 Consolidated West Petroleum completed a well in slightly over ten meters water depth some 1,800 meters from shore. This well and five more were drilled from bottom-supported platforms, but owing to the long distance from the shoreline and the severe ice conditions at this location, the wooden structures were pulled and sub-surface wellheads were installed. All sub-surface work was conducted by divers and remains the case to this day. By 1983 360 completions had been made in water depths to 60 meters. Between 1970 and 1983 900 km of sub-surface pipeline had been installed on the bottom to carry the gas ashore. For further protection from ice, trawlers and ship's anchors, the pipelines were buried below the bottom and caissons were set 3.6 meters into the bottom wherein the wellheads were placed and a protective lid placed over the caisson (ibid.).

The first ocean deployment of an underwater production system was in the Gulf of Mexico in 1960. By mid-1984 292 subsea wellheads (including oil/gas production, water injection, monitoring, test, experimental and hybrids) had been installed throughout the world. An additional 77 have been either constructed and awaiting installation or are on order (refs. 148 and 210).

The development and deployment of SPSs did not proceed at a uniform, orderly pace throughout the world. In some countries this technique for exploiting oil or gas was adopted and accepted almost immediately. In other countries the technique was implemented initially as test or experimental facilities which led to greater acceptance as the technique proved itself. The rate at which implementation occured was, and still is, governed by environmental conditions, the nature of the oil/gas reservoir and/or the prevailing economic climate. Since all of these factors vary from country-to-country and from one point in time to another, it is difficult to trace the development/deployment history of SPSs concurrently on an international basis. Instead, this topic is dealt with on a country-to-country basis, which provides a somewhat more manageable and understandable approach.

1.3.1 North America

1.3.1.a Canada

Since Canadian production of offshore (ocean) oil and gas has been minimal, so also has its involvement with SPSs. To date there has been only one subsea well installed offshore Canada. This well (Drake F-6), a wet, diverless, satellite gas well with dual flowlines was installed by Panarctic Oils Ltd. in the the Beaufort Sea in 55 meters water depth. This was the first offshore Arctic installation drilled from a floating ice platform. The well was installed in 1978 and produced success- fully for seven months before it was shut-in. It was also one of the first subsea wells to be controlled remotely from a shore-based facility. To avoid damage from ice the wellhead was located within a "glory hole", that is, an excavation in the sea floor wherein the wellhead is placed such that it is entirely below the level of the bottom.

It is possible that SPS employment in the Canadian offshore may see an increase in the relatively near-future off the coast of Newfoundland in the Hibernia field and offshore Nova Scotia. The Hibernia field in particular is subject to frequent intrusions by icebergs and a submerged production facility appears as a potential alternative to a conventional bottom-supported production platform. At this time, however, there have been no public statements made regarding the type of production facitity that will be installed.

1.3.1.b <u>United States</u>

The U.S. offshore has been the scene for SPS development, testing, and production for the past 25 years. The first SPS installed in the world was in the Gulf of Mexico by Shell oil Co. in 1960. Since then approximately 75 SPSs were installed off the Gulf Coast and the coast of California and another four are presently assembled or on order.

The greatest SPS activity has been in the Gulf of Mexico where some 130 subsea wellheads were installed between 1960 and 1984. (Table 1). The Gulf coast served as the initial test grounds for many of the subsea production techniques that would emerge in the 70s and 80s, and was the first area to see deployment of both wet and dry systems. Two projects in particular were significant pioneering efforts: the Lockheed (now CanOcean Resources Ltd.) /Shell dry wellhead technique and Exxons's wet Submerged Production System (SPS). These are discussed later in this section.

Installation of SPSs offshore California began in 1962 and continued through 1973. Since 1973 implementation of subsea production systems has stopped, although one wet tree has been ordered for eventual deployment offshore Santa Barbara. All SPSs offshore California have been of the wet variety. To date, 37 units have been installed, but many of them have been abandoned or removed over the years of operation. All of the California subsea production units are single or multiple trees, and do not incorporate the large manifold centers found in the Gulf of Mexico, offshore Brazil or the North Sea. Five operators have been involved with SPSs off California: Texaco (20 units), Chevron (7 units), Shell (5 units), Philips (4 units) and Arco (1 unit). The depths of installation have ranged from 18 meters (Summerland field) to 73 meters (Molino field). The depths of installation did not increase progressively, in fact, the deepest was installed four years before the shallowest. No reason has been forwarded as to why subsea production facilities have not been installed off California for the past 12 years. There is some speculation that SPSs might be employed in the forthcoming years when the discoveries off Point Arguello are exploited. Of significance to the question of inspection and maintenance of subsea production systems has been the experience of operators in the Molina field where wellheads have been recovered after 20 years of continuous underwater exposure and production. Reportedly, all of the units recovered, in spite of substantial external fouling, exhibited excellent internal condition and

TABLE 1. SPS DEPLOYMENT IN THE U.S. OFFSHORE

YEAR	DEPTH (M)	FIELD	OPERATOR	NO. WELLS	REMARKS
1960	17	West Cameron Gulf of Mexico	Shell	1	
1962	64-72	Gaviola California	Chevron	3	
	6	Callou Gulf of Mexico	Texaco	1	Exp. Abnd. 1973
	20-46	Conception California	Texaco	18	Installed 1962-73
1963	61	Molino California	Phillips	4	
	73	Molino California	Shell	5	Installed 1963-66
1964	67	Molino California	Arco	1	
	71	Gaviola California	Chevron	1	
1966	25	Block 175 Gulf of Mexico	Arco	4	Installed 1966-69
	39	So. Marsh Is. Gulf of Mexico	Shell	1	
1967	18	Summerland California	Chevron	2	Abnd. 9/75
1968	36	Grand Isle 47 Gulf of Mexico	Conoco	1	
	NA	Romero Pass Gulf of Mexico	Chevron	1	Test
	35	Ship Shoal Gulf of Mexico	Placid	1	
1969	68	So. Marsh Is. Gulf of Mexico	Shell	1	
1970	103	Main Pass 290 Gulf of Mexico	Shell	1	
	36	Ship Shoal Gulf of Mexico	Kerr-McGee	1	
1971	65	Santa Barbara California	Chevron	1	Exp.
1972	20	Conception California	Texaco	2	Abnd. 1973
	114	Main Pass 290 Gulf of Mexico	Shell	1	1-ATA
1973	45	Eugene Island Gulf of Mexico	Shell	1	
1974	64	Ship Shoal Gulf of Mexico	Shell	1	
	14-16	Eugene Island Gulf of Mexico	Placid	29	Hybrid*
	52	West Delta Gulf of Mexico	Exxon	3	SPS (Pulled in 1980)
1975	31	Ship Shoal Gulf of Mexico	Tennaco	1	

TABLE 1 (CONT.)

YEAR	DEPTH (M)	FIELD	OPERATOR	NO. WELLS	REMARKS
	70	Eugene Island Gulf of Mexico	Shell	2	1-ATA. 1 shut-in; 1 abnd.
	27	Eugene Island Gulf of Mexico	Placid	48	Hybrid*
1976	43	So. Timbalier Gulf of Mexico	Gulf	1	
	32	Eugene Island Gulf of Mexico	Tennaco	1	1-ATA. Abnd. & removed
	61	Ship Shoal Gulf of Mexico	Union	1	1-ATA
1977	60	Vermillion 302 Gulf of Mexico	Shell	1	1-ATA
1978	29-35	Grand Isle 41 Gulf of Mexico	Conoco	5	Gas
	38	Vermillion Gulf of Mexico	Mobil	1	
1980	36	Grand Isle 43 Gulf of Mexico	Conoco	1	Gas
	98	High Island Gulf of Mexico	Mobil	1	
	27	So. Timbalier Gulf of Mexico	Tennaco	1	
1981	36	Grand Isle 43 Gulf of Mexico	Conoco	1	Gas
	40	Vermillion Gulf of Mexico	Tennaco	1	
1984	61	Eugene Island Gulf of Mexico	Amoco	1	
--*	NA	NA Gulf of Mexico	Mobil	1	
--**	46	So. Marsh Is. Gulf of Mexico	Tennaco	2	
--***	70	Santa Barbara California	Phillips	1	

* SPS beneath a platform with a secondary tree in the same tubing string on the same platform.
** Wet trees assembled but not installed.
*** Wet trees on order.
Abnd.: Abandoned
NA: Information not available.
Exp.: Experimental
1-ATA: Encapsulated, dry, 1-atmosphere wellhead.

Source of Data: Refs. 146 and 210

could likely produce for many more years without failure.

SPS activity in the Gulf of Mexico has been ongoing for over 20 years. Unlike offshore California, the types of undersea production units in the Gulf encompass a wide variety: wet trees, dry trees, and hybrid units. Similar to Californian activities, the Gulf coast SPSs did not progressively venture into deeper and deeper waters, but were installed when and where they were more advantageous than conventional production platforms. The depths of Gulf coast SPS range from as little as six meters (Callou field) to as much as 114 meters (Main Pass 290). The number of operators of SPSs is also greater in the Gulf coast, where 13 companies have employed subsea production units. Placid Oil, with 77 hybrid units and one wet tree, is by far the greatest user of SPSs in the Gulf coast region. Following Placid is Shell (6 wet; 4 dry wellheads), Conoco (7 wet), Tennaco (3 wet; 1 dry), Arco (4 wet), Exxon and Mobil (3 wet each), Union (1 dry), and Chevron, Texaco, Kerr-McGee, Gulf and Amoco each with one wet unit. SPS deployment in the Gulf has slackened in the past few years with only one unit having been installed since 1981 and two more scheduled in the foreseeable future. The Gulf of Mexico was, however, the scene of two of the more highly publicized SPS projects of the 1970s, these projects saw the debut of the dry wellhead and the Submerged Production System. Since these two projects played a major role in advancing SPS technology and acceptance, they warrent a more detailed discussion.

Dry Wellhead/Manifold Encapsulation

In this technique the wellhead is encapsulated within a dry, 1-atmosphere chamber or cellar wherein installation of equipment and subsequent inspection and maintenance can take place in a shirtsleeve envionment. For multi-well operations a bottom-mounted, 1-atmosphere manifold is provided. Transportation of technicians to and from the cellar or manifold center is accomplished via a Personel Transfer Capsule (PTC) which is launched and retrieved from a surface support ship. All breathing gasses, power and communications are provided to the PTC through a unitized umbilical from the surface ship which docks and mates on the cellar or manifold center.

The origin of this technique began at Lockheed Missiles and Space Company's Ocean System Division in 1966 when the initial study of a 1-atmosphere SPS was initiated. In 1969 the program direction was assigned to Lockheed Petroleum Services, Ltd., Westminister, B.C., Canada. a subsidiary of LPS. (In 1979 Lockheed Petroleum Services changed its name to CanOcean Resources Ltd.) In 1970 a demonstration offshore Vancouver Island was given using a dummy wellhead chamber and hardware to 45 meters depth and a PTC to 274 meters depth. In 1971 Shell Oil Co. purchased a wellhead chamber for installation over a well and CanOcean was contracted to install the chamber and to provide subsequent servicing. The wellhead chamber was installed in 1972 in a depth of 114 meters some 180 km southeast of New Orleans. The wellhead chamber was re-entered in 1974 after more than a year of production. There was a small leak of control fluid which was repaired by replacing o-rings in a solenoid valve, otherwise these was no evidence of appreciable corrosion, no significant marine growth and ultrasonic measurements of the cellar hull and all pressure piping showed no anomalies. Prior to this, work on the well had been performed using through flowline (TFL) tools and acidization techniques to restore the lower zone to its original condition.

In 1975 Shell installed two more dry chambers in 70 meters of water in the Eugene Island field and another one in 60 meters of water in the Vermillion field in 1977. In 1976 Tennaco installed a dry chamber in the Eugene Island field (32 m. depth) and Union installed one in the Ship Shoal field in 61 meters of water. Of the five wellhead cellars installed one was subsequently shut-in and two were abandoned. No further dry chamber installations have taken place in the Gulf of Mexico since that time.

During the seventies two other groups sought to enter the dry wellhead field, one was a consortium called SEAL (Subsea Equipment Associates Ltd.,) and the other was Cameron Iron Works.

SEAL was formed in 1970 by British Petroleum, Compagnie Francaise Des Petrole, Westinghouse and Groupe DEEP. The goal of SEAL was to carry forth a research and development program in SPSs for eventual marketing to the oil industry. In 1971 Mobil Oil Co. joined the SEAL group to expand and include development of a domestic SPS that was previously being developed by Mobil and North American Rockwell. Three, 1-atmosphere submerged systems were developed by SEAL:

> <u>Seal Intermediate System (SIS):</u> The SIS was designed for large subsea wells in water depths over 90 meters and producing between 1,000 to 10,000 bopd. By 1973 this system was in the final stages of testing and development.
>
> <u>SEAL Shallow System (SAS):</u> This system was designed for use with conventional subsea wellheads (Xmas trees) or with a specially designed SEAL Xmas tree.
>
> <u>SEAL Atmospheric System SAS:</u> This system incorporates a dry, subsea manifold.

In 1972 testing of the SAS Subsea Wellhead Enclosure (SWE) and the Personnel Transfer Bell (PTB) was completed. The prototype SWE was installed in 76 meters of water in the Gulf of Mexico adjacent to a Sun Oil Co. production platform at Main Pass 283A. Eight flexible flowlines connected the SAS to the platform and testing began on live oil wells in 1973. The system remained on the botom until 1977 when it was recovered. During the four year period the SWE was entered over 50 times using the PTB to transfer personnel for production testing and launch and recovery of paraffin tools. The SWE was internally equipped to handle two wells during this testing, but it was capable of handling production equipment and operations for 16 wells. Subsequent inspection of the system showed that it was reuseable, most connections and piping were found to be in good condition, free of fishing nets or lines, and marine fouling (ref. 36). No further application of the SEAL system in the Gulf of Mexico has been reported.

In 1977 Cameron Iron Works introduced their dry, 1-atmosphere system designated Subsea Station Cameron. The Station consisted of a six meter long, 3.6 meter ID chamber weighing 60,000kg which could encapsulate a wellhead to depths of 550 meters. Equipment up to 107 cm (42 inches) diameter and flowlines of any size could be accommodated. There have been no published reports of utilization of Subsea Station Cameron in the offshore oil industry.

Submerged Production System (SPS)

The SPS was an Exxon test project that began with the 1974 installation of the system in 52 meters of water in the Gulf of Mexico's West Delta field, and terminated in 1980 when the SPS was recovered. The goal of the project was to prove the technique by producing from a three well system. The full SPS field development system included a template system, flowlines, production riser, and a processing and storage vessel. Wells were drilled and completed through the template using standard floating drilling equipment. Production was comingled in a production manifold surrounding the wellbays and routed to pipeline connection areas at the ends of the template. Flow was then routed through the flowlines, up a production riser and was processed on a permanently moored vessel that also provided storage of the crude. Shuttle tankers were used to take the crude ashore. Production operations were controlled remotely from the storage vessel. The SPS was designed to provide all producing operations from discovery to abandonment of a field. It SPS was also designed for oil production in water depths to 1,500 meters and for a field life of 20 years minimum. One of the key features of the SPS was the use of diverless methods for installation and maintenance (ref. 142).

The lessons learned from the SPS experience were put into practice on the Shell/Exxon Underwater Manifold Center (UMC) which was installed in 1982 in the North Sea's Cormorant field.

1.3.2 South America

1.3.2.a Brazil

The only offshore oil or gas producing country in South America that utilizes SPSs is Brazil. The first SPS installation offshore Brazil was in the Garoupa field, located in the Campos Basin some 250km east-northeast of Rio de Janeiro. This 1977 installation (Table 2) was the first of what would eventually be nine subsea wellhead cellars and a manifold center constructed by CanOcean Resources Ltd. and completed by 1979. Although this project constututes only 9 of the 50 SPSs that

TABLE 2. SPS DEPLOYMENT OFFSHORE BRAZIL

YEAR	DEPTH (M)	FIELD	OPERATOR	NO. WELLS	REMARKS
1977	120-166	Garoupa	Petrobras	9	1-ATA. Installed 1977-1979
1979	189	Enchova	Petrobras	1	
1980	176	Enchova	Petrobras	1	
	118	Enchova	Petrobras	1	
	113	Garoupa	Petrobras	1	
	123	Garoupa	Petrobras	1	
1981	125	Pampo	Petrobras	1	
	146	Bicudo	Petrobras	1	
1982	85	Badejo	Petrobras	2	
	131	Bicudo	Petrobras	2	
1983	137	Pirauna	Petrobras	1	
	210-264	Corvina	Petrobras	4	
	88	Badejo	Petrobras	1	
1984	37	NA	Petrobras	1	
	107	Pampo	Petrobras	3	
	131	Bicudo	Petrobras	2	
	125	Pampo 3	Petrobras	1	
	209	Bonito (Enchova)	Petrobras	3	
	191	Bonito (Enchova)	Petrobras	6	
	107	Pampo	Petrobras	2	
	293	Pirauno	Petrobras	4	Deepest SPS installed by 1984
1984	137	Pirauna	Petrobras	1	
	95	Badejo	Petrobras	1	
*	125-128	Pampo & Bicudo	Petrobras	2	
	91	RJS-100	Petrobras	1	

* Wet trees assembled but not installed.
NA: Information not available.
Source of Data: Refs. 76, 148 and 210

would dot offshore Brazil by 1984 it was, and still is the most ambitious dry, wellhead cellar/manifold installation in the world.

In 1976 Petrobras (Petroleo Brasileiro S.A.) the national oil company of Brazil, selected the dry, 1-atmosphere SPS approach for the Garoupa field. The selection of a SPS was based on the need to produce quickly to meet Brazil's oil import requirements and to better define reservoir conditions. It was estimated that conventional field development (bottom-supported production platform) might take as much as eight years before production began, the SPS approach was estimated to begin producing in two and one-half years after discovery. Initially, the installation was to be completed in 1978, but delays extended this date to 1979. First production was in February 1979 and full production was reached in June 1980.

The Garoupa dry completion system is comprised of nine outlying wells which deliver gas and oil to a manifold center (MC) in about 130 meters of water. From the MC the oil and gas is fed to a tanker moored to an articulated floating process tower where it is then transferred to a second tower for tanker loading. (The second tower was eventually replaced by a single buoy.) The system collects gas and oil from three distinct reservoirs: Garoupa, Namorado and and unspecified reservoir RJS. Although the system was intended primarily for early production , it was planned to be a permanent feature of the field. In 1980 a bottom-supported platform was installed to act as a center for other Campos fields.

Since 1980 all of the SPSs installed in the various Brazilian fields have been of the wet type (Table 2). According to ref. 185, the use of wet Xmas trees and direct hydraulic control systems has established itself as a simpler, more reliable alternative . Earlier problems in the Garoupa field development demonstrated that direct hydraulic control, though slow, is the most dependable and reliable solution. The reasons for extensive use of SPSs in the Brazilian fields resides in reservoir size and depth of water. The Badejo field was originally planned to have a bottom-supported production platform, but completion of the drilling program revealed that insufficient reserves were present to economically justify a bottom-supported platform. For Petrobras, the principal factor in the economic-technical comparison of a fixed platform and a system using a floating collection station is the water depth (ibid.). The cost of a bottom supported platform increases with water depth, for the floating station it remains almost constant. For water depths over 120 meters a floating station or semisubmersible is considered definitely advantageous. From 90 to 120 meters water depth there is a gray area where both approaches can compete favorably. For water depths less than 90 meters the bottom-supported platform is most advantageous.

A review of Table 2 shows the Brazilian SPSs to be in greater average water depths than those in any other waters and, as of 1984, the deepest SPS installed in the world was in the Pirauna field at a depth of 293 meters.

1.3.3 The North Sea

The North Sea is the center of the most intense SPS activity in the world today. The first employment was initiated in Norway's Ekofisk field in 1971, by 1984 there were 93 wet systems and 34 hybrid systems distributed throughout 15 fields, and another 47 wet systems assembled or on order to accommodate an additional eight fields (Table 3). Not only are the numbers of SPSs impressive, but many of the engineering techniques and solutions has and will continue to provide foundational data upon which future SPSs may be designed. For this reason the following description of North Sea SPS deployment singles out and describes some of the fields where more or less unique solutions were applied.

1.3.3.a Ekofisk

This first North Sea SPS was installed in 70 meters of water by Phillips in 1971. It is reportedly (ref. 45) the most noteworthy application of SPSs that make production possible within one or two years after the discovery of a field. The discovery well was drilled in 1969 and after delineation wells had been drilled the operator estimated that it would require an expenditure of well over $1 billion to bring the field into optimum production. Phillips felt it would be highly desireable to learn more about the reservoir characteristics and installed subsea wellheads on four of the exploratory wells. Two 10cm (4 inch) lines from each well were affixed to the jack-up drilling rig, GULF TIDE, which served as a temporary production platform. Subsequently, lines were laid to two single point mooring buoys which produced about 42,000 bopd into tankers. This operation provided Phillips with substantial information concerning the reservoir and revenue from some 30 million barrels of oil before the permanent production platforms were completed. (ibid.). The wells were plugged and abandoned in 1976.

At about the time of the Ekofisk installation this type of production technique began being referred to as: Early Production Facilities or Systems; Temporary Production Systems, or Floating Production Systems.

1.3.3.b Argyll

Argyll was the first field in the U.K. sector of the North Sea to employ a SPS. The operator, Hamilton Bros., considered the field as marginal by North Sea Standards and the geology was complex and varied from well-to-well. At then current prices the field would be uneconmical to develop by conventional methods which would have cost an estimated $100-$150 million. Instead, the operator opted for a subsea system which could produce the field

TABLE 3. SPS DEPLOYMENT IN THE NORTH SEA

YEAR	DEPTH (M)	FIELD	OPERATOR	NO. WELLS	REMARKS
1971	70	Ekofisk	Philips	4	
1974	29	Dutch Sector	Placid	1	
	27	Dutch Sector	Placid	34	Hybrids 1974-1981
1975	76	Argyll	Hamilton Bros.	2	
1976	118	Beryl	Mobil No. Sea	1	
1977	76	Argyll	Hamilton Bros.	1	
1978	113-119	Buchan	BP	7	
	76	Argyll	Hamilton Bros.	1	
	118	Beryl	Mobil	1	
	116	West Scotland	Vickers/Intertek	1	Test
1979	113-119	Buchan	BP	8	
	140	Ninian	Chevron (UK)	1	
	76	Argyll	Hamilton Bros.	2	
	118	Beryl	Mobil	2	
	40	North Hewett	Phillips	2	
1980	76	Argyll	Hamilton Bros.	3	
	153	Murchison	Conoco	3	
	155	So. Cormorant	Shell Expro	1	
1981	119	Buchan	BP	1	
	185	Magnus	BP	1	
	112-118	No. Claymore	Occidental	3	
	142	Tartan	Texaco (UK)	2	
	73	Fulmar	Shell Expro	6	
1982	76	Argyll	Hamilton Bros.	4	
	142	Tartan	Texaco(UK)	2	
	152	Cormorant	Shell Expro	9	
	186	Magnus	BP	7	Installed 1982-1984
1983	91	N.E. Frigg	Elf Aquitaine	6	
1984	116	Buchan	BP	2	
	152	Central Cormorant	Shell Expro	4	8 by 1984
*	30	Montrose	Amoco Prod. UK	2	
	30	Morecombe Bay	Amoco Prod. UK	2	
	83	Duncan	Hamilton Bros.	2	
	15	Central Cormorant	Shell Expro	4	
	152	Central Cormorant	Shell Expro	2	
	142	Tartan	Texaco (UK)	1	
**	30	Morecombe Bay	BGE	2	
	83	Duncan	Hamilton Bros.	2	
	140	Balmoral	No. Sea Sun Oil	19	
	140	Gullfaks	Statoil	5	
	137	Highlander	Texaco (UK)	6	

* Wet trees assembled but not installed.
** Wet trees on order.
BP: British Petroleum
BGE: British Gas Engineering
NA: Information not available.
Source of Data: Refs. 148, 189 and 210

more quickly and then be salvaged.

The inspiration for the Argyll SPS approach was Ekofisk. However, the lack of an available jack-up rig led Hamilton Brothers to elect a semi-submersible vessel (TRANSWORLD 58) instead. This decision created a new set of problems: since the semi-submersible would not be bottom-supported, it would lack the necessary stability to support a fixed production riser against winter storms. Consequently, it was necessary to develop a new system that would be retrievable during storms. The design and construction of both the riser and the subsea trees was performed by National Supply Co.

The Argyll field, similar to Ekofisk, uses satellite trees connected by subsea pipelines to a collecting station located on the bottom beneath TRANSWORLD 58. The collecting station (Fig. 2) consists of a permanent base which provides attachments for the flowlines and an upper, detachable manifold section which is attached to the riser system. Oil flows from the subsea trees to the manifold, up the riser, and thence into the processing equipment aboard the semi-submersible. The oil is transfered through a loading line on the riser to a Single Point Mooring (SPM) buoy for subsequent loading aboard tankers. Connections between the permanent base and the riser are designed for diverless placement and/or removal. In actual field use the Argyll approach has allowed production for about 70 percent of the year without interference from weather. (refs. 14 and 29).

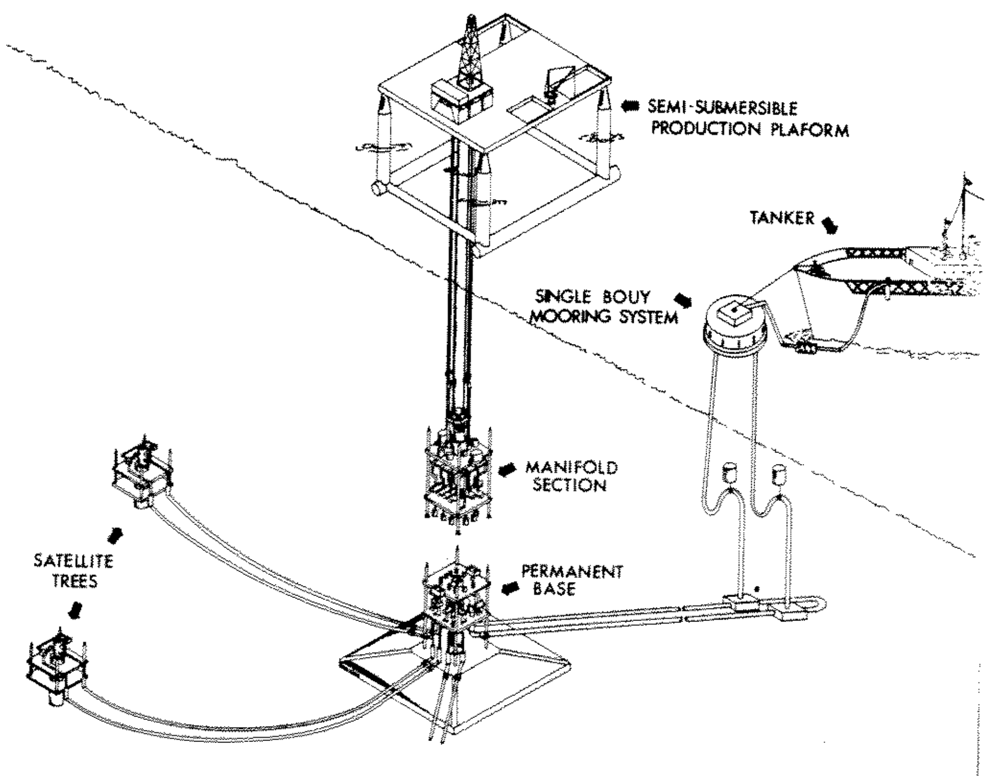


FIG. 2 THE ARGYLL FIELD SPS (from ref. 14)

1.3.3.c Buchan

The Buchan field (Fig.3) is a prime example of applying a SPS to a marginal field. The field had 50 million bbls of recoverable reserves and a life expectancy of five years. The operator, BP, was faced with the twin problems of a field that was so small that no risks could be taken using unnecessary innovative equipment and that a cash return was required as soon as possible.

Buchan is considered to be a refined version of the Argyll system. The immediate obvious refinement is the application of a seabed template, the first North Sea field in which one was installed. The major advantage sought was to concentrate the wells at a single point for ease of maintenance, as opposed to Argyll where the wells are spread apart. Buchan produces its oil through seven wells. It was initially planned that all but two of these wells would be through the template, but drilling at the template fell behind schedule and one well was transferred to a remote position so that two wells could be drilled simultaneously. One of the two original remote wells is an exploration well merely six meters from the template, the second remote well is 17,000 meters away tapping a separate flank of the heavily fractured reservoir. The subsea trees at Buchan are non-TFL and have the novel feature that each tree is spilt so that the upper half can be brought to the surface for maintenance.

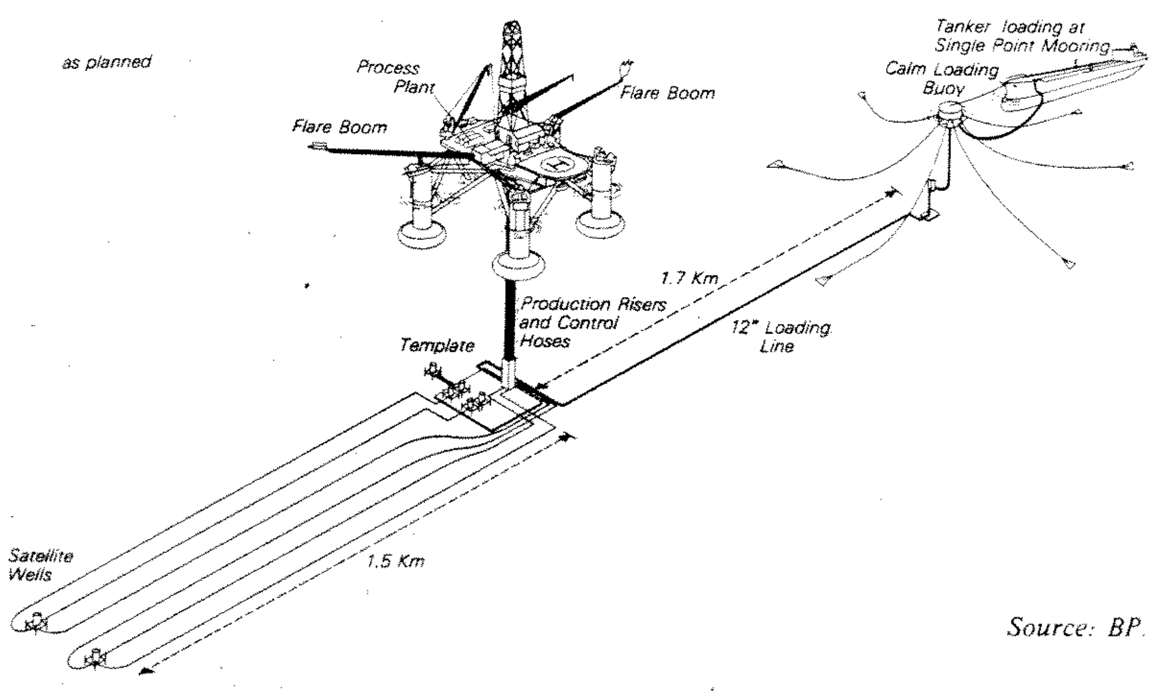


FIG. 3 Buchan Field SPS (from Noroil)

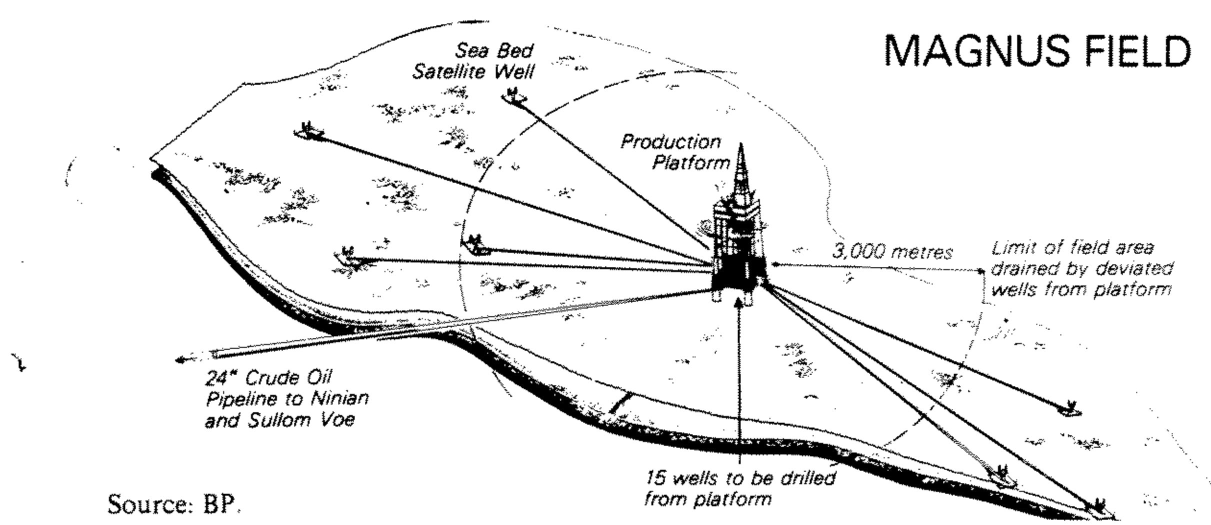
1.3.3.d North Hewett

This gas field came onstream in 1969, (originally designated as Big Dotty, Little Dotty and Deborah) and peaked at 8.1 billion cu m in 1976. In 1978 it produced 6.4 billion cu m. In 1979 the operator, Phillips, decided to install two subsea satellite wellheads and tie them into the established platforms. The goal was to regain the ten percent production shortfall through production from the satellite wells. While the equipment used in North Hewett was not unique, the application of an SPS in this manner was. One of the main advantages of SPSs is to permit bringing a reservoir online earlier than conventional techniques, in this instance, the role was reversed and the SPS was introduced after the conventional approach was taken to augment flagging production.

1.3.3.e Magnus

According to Noroil (1978), the Magnus field in the UK sector of the North Sea has three distinguishing characteristics: 1) it is the most northerly oilfield developed to date in European waters; 2) it is the deepest water where a field has been developed in the North Sea, and 3) the field sits on the threshold of deep water zones where fixed steel platforms may prove uneconomic and where floating platforms may take over together with SPSs.

The Magnus production scheme consists of a bottom-supported production platform (in 185 m water depth) from which a total of 15 wells can be drilled. The field is long and narrow, and would normally require two production platforms to obtain the same quantity of oil if subsea wellheads had not been employed. The subsea wellheads are positioned outwards from a 3,000 meter radius circle which consitutes the limits of the field area that can be drained by deviated wells from the platform (Fig. 4). The economics of the field were constructed around a rapid rise to peak production in 1983. The early production came largely from the satellite subsea wellheads.



Source: BP.

FIG. 4 THE MAGNUS FIELD SPS

1.3.3.f Murchison

The Murchison field, similar to Magnus, began as a conventional bottom-supported production scheme. Preliminary studies revealed that by utilizing three wells drilled for exploratory purposes (two for oil production; one for water injection) in conjunction with two wells drilled from the platform, early production and an accelerated production rate buildup could be obtained.

In 1974 Conoco conducted an extensive engineering study for deep water production systems which concluded that satellite subsea wells failed because of : 1) complex subsea control systems; 2) downhole safety valves and 3) inadequate flowline laying, connecting and burying methods (ref. 112). Conoco's answers to these problems were to develope an hydraulically-operated control system that was operated directly from the platform, with no subsurface controller at all; retrievable safety valves were employed, and flowline bundles were constructed onshore and towed beneath the surface 475 km to the field where the entire flowline was suspended in neutral buoyancy when the connections were made. These accomplishments, according to ref. 112, "truly began a new era for Submerged Production Systems".

1.3.3.g Cormorant

In mid-May 1982 the 2,100 tonne Underwater Manifold Center (UMC) was installed in 152 meters of water in the Cormorant field. The UMC is a joint Shell/Esso project which grew out of the experiences with the Submerged Production System of the seventies. The project is considered a test program that, if successful, could result in a technique whereby millions of additional barrels of oil can be produced commercially from small reservoirs beyond the reach of existing platforms and from marginal fields lying in deep water and sometimes in combination with floating production systems. The project began production in 1983 and is scheduled to continue its tests until 1986. Although the UMC is in water depths accessible to the diver, its design is such that it is capable of working in several thousand feet of water safely without diver intervention and with minimal maintenance. Earlier, in 1980, a subsea satellite well was installed in the South Cormorant field and brought online in 1981. This well incorporated many of the features that are employed in the UMC, such as the control panel, downhole equipment and Xmas tree (ref. 134).

The 52m x 42m x 15m UMC can accommodate up to nine wells, each of which can be used for production or injection. The wells can be drilled through the template, or satellite wells can be tied into the manifold by flowlines or spool pieces (Fig. 5). The unit is designed to operate in 300 meters water depth, handle 56,000 bopd and 56,000 bpd injection water and has an anticipated lifetime of 25 years (ref. 123). Both the UMC and the satellite wells are designed for TFL servicing. Well servicing beyond the scope of TFL capabilities, such as replacement of the subsurface safety valves, is by vertical access from a semi-submersible vessel

(STADRILL) positioned over the UMC or the satellites. Most of the critical valves and control system components are replaceable using a surface-deployed, structurally-reliant ROV manipulator system called the Remote Maintenance System (RMS).

1.3.3.h Northeast Frigg

Much like the UMC project and its relationship to the Gulf of Mexico's SPS effort, the N.E. Frigg field drew heavily on the experience of a previous Elf Aquitaine project in the Grondin field off Gabon in the mid-1970s. The N.E. Frigg field is a small satellite of the giant Frigg gas field located in the North Sea in some 100 meters of water. This is, according to ref. 133, the first major underwater gas production project ever attempted in the North Sea. Production from the six wells in this field began fully in the summer of 1983.

The N.E. Frigg production facilities are comprised of four major components (Fig. 5):

- A subsea template which houses and protects six wells and a manifold
- A 16 inch gas line which links the manifold to the Frigg Field Field Treatment Platform
- A Field Control Station (FCS) whose main function is to control the subsea equipment.
- Treatment, metering and booster modules installed on the TCP 2 platform to process 6 million cu m of gas/day.

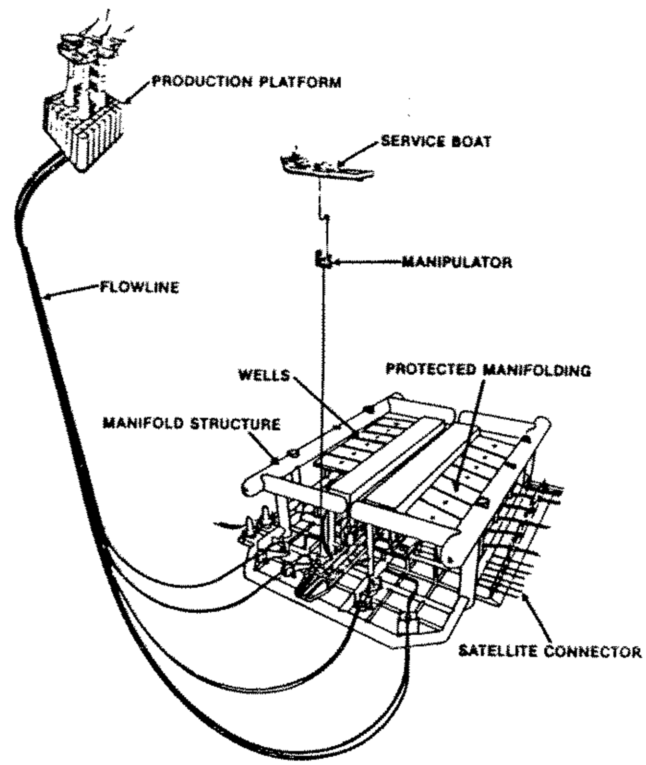
One of the more novel aspects of the N.E. Frigg arrangement is the control of the wellheads. This is accomplished from the Frigg field through a radio link with the N.E. Frigg Control Station, an articulated column structure where remote commands are converted to direct hydraulic valve operations. The seabed facilities have been designed to operate throughout the field's five-year lifetime and will be occasionally inspected by divers.

1.3.3.i Near-Future Fields

There are several fields in the North Sea that are scheduled for production using wholely or partly Subsea Production Systems within the next few years; these are: Balmoral, Highlander and Gullfaks. Following is a brief description of the planned SPS activites within these fields.

Balmoral

The Balmoral field is to be developed using a floating production system. Production is planned to take place from 13 wells, with six peripheral water injection wells to maintain pressure and maximize recovery, these will be predrilled before installation of the floating platform (ref. 192). The semi-submersible will be



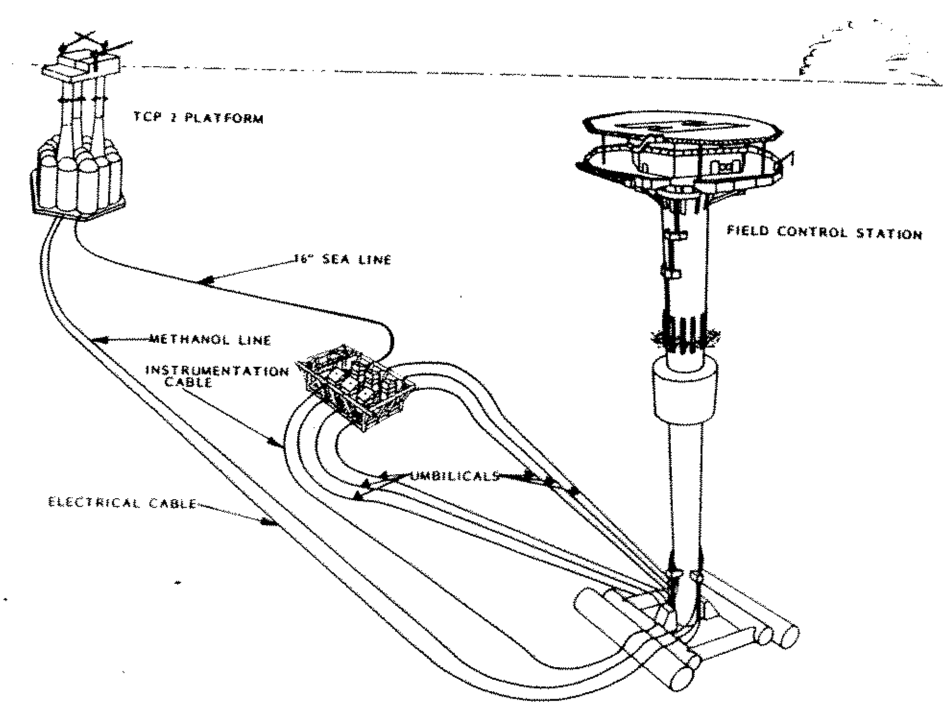


FIG. 5 THE UMC (Top). N.E. FRIGG FIELD (bottom)

moored over a 14-slot template in the central area of the field and will be connected to the template by means of a flexible riser. The entire subsea system will be electro-hydraulically controlled.

Highlander

Formerly called Sail, the Highlander development will closely follow that of the UMC. Utilizing a multi-well manifold template, Highlander will also feature gas lift, water injection and chemical treatment facilities. At present, five producing wells and two water injection wells are scheduled (ref. 192). Five pipelines will link the manifold to Texaco's Tartan platform where production has yet to reach the levels initially anticipated. First production is scheduled for early 1985. The template will measure 43m x 18m x 9m and will have 12 well slots and three satellite wells.

Gullfaks

The Gullfaks production approach will be centered around a fixed, bottom-supported production platform that will use five subsea completed wells for accelerated production and to improve overall first-phase economy. The subsea wells are scheduled to begin production in 1987 and 1988. All subsea wells will be of the wet satellite type, non-TFL, with individual flowlines and umbilicals. The system has been designed as diverless, although it is within diver depth (140m). Design life of the wells ranges from five to ten years. The design of the Gullfaks wellheads will incorporate features to improve compatibility with ROV and diver intervention. The trees and control system will be protected by an open framework structure which will permit ROV or diver access.

Oseborg

The Oseborg field is in the Norwegian sector of the North Sea. It will be developed partly by conventional platforms and partly by SPSs. The subsea wells will be employed to: 1) provide for accelerated production; 2) reach the reservoir outside the platform area and 3) reduce overall investment.

The field center will be located in the south consisting of a processing and quarters platform (Fig. 6) and a drilling and water injection platform ("B" Platform). "C" Platform, in the north, is for drilling, water injection and quarters. A total of 16 subsea wells will be drilled, ten will be production and six will be for water injection. Fourteen of these wells will be arranged in clusters as shown in Fig. 6. The remaining two wells, plus three wells in the south will be arranged as satellite wells and will be tied into the field center. The links between the subsea wells and the platforms will include production flowlines, water injection lines, inhibitor injection lines (corrosion, wax, hydrates), testlines and control cables. The distance between the satellite wells/clusters ranges from four to eight kilometers.

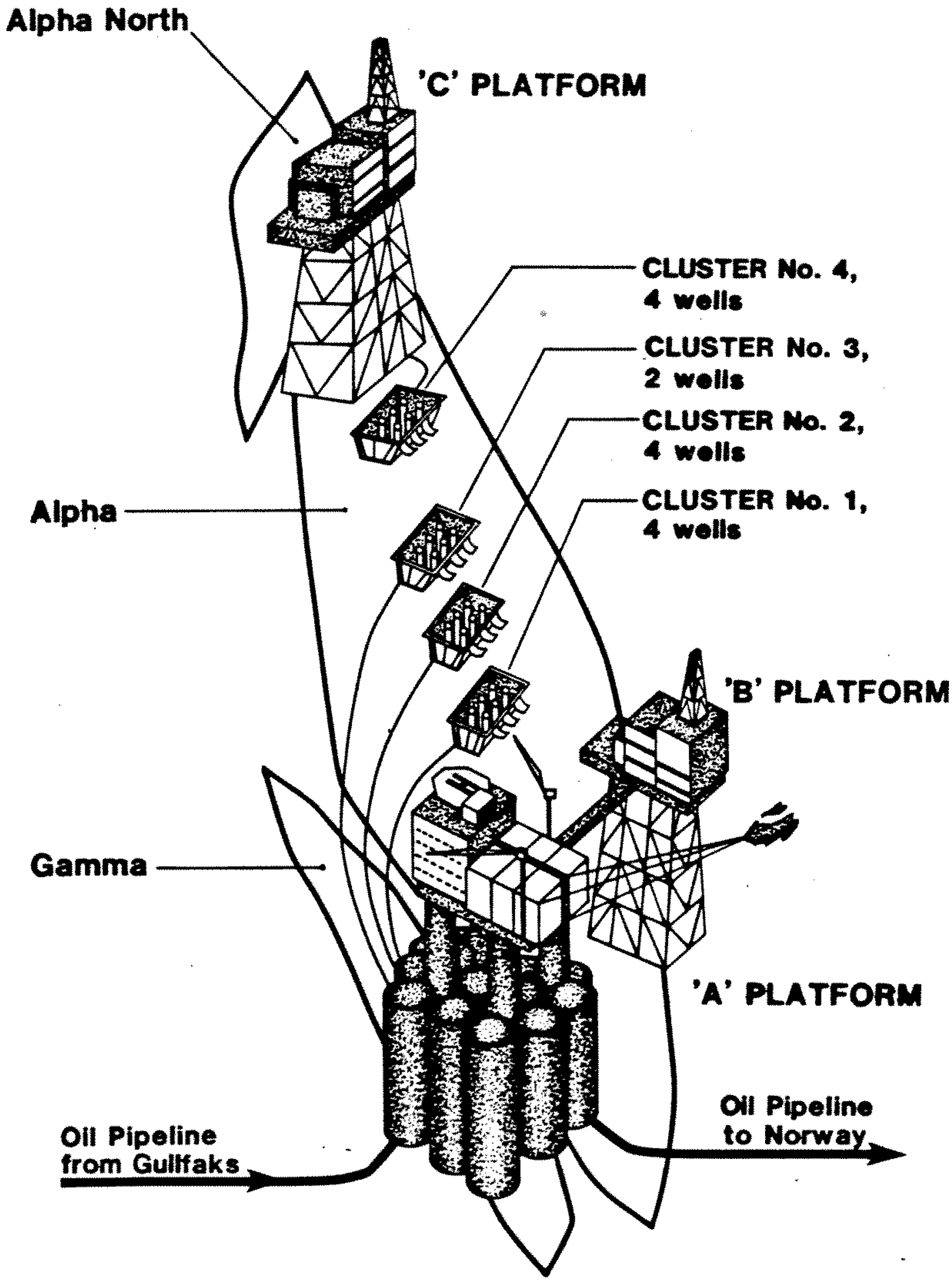


FIG. 6 OSEBORG FIELD COMPONENT CONFIGURATION (from ref. 212)

One production well and two water injection wells are scheduled for start-up by April 1989. The two southern satellites are scheduled for completion in 1990. The clusters are scheduled for production at a rate of one per year from 1992 through 1995.

1.3.4 Mediterranean

There have been ten subsea wellheads installed in the Mediterranean and another four are assembled for installation or on order (Table 4). The subsea techniques employed do not significantly diverge from those described above, and the reasons for utilization are also similar. One of the more unique aspects of Mediteranean SPSs will be in the Montanazo field where the deepest subsea installation, 762 meters, is scheduled to take place in the summer of 1985. This depth will be approximately two and one-half times deeper than any other presently operating wellhead.

The Montanazo satellite will be tied into Eniepsa's Casablanca platform some nine kilometers distant. The depth of this satellite is well beyond present or even distantly foreseeable diver capabilities. The actual components of Montanazo are similar to other wellheads (ref. 156), and the selection of components was based on the proven technology of the Casablanca field and involves no input of untried technology. One of the more unique features of this installation is the close interaction between the equipment vendors and contractors in other disciplines and oil company operations to integrate the total sequence of requirements for installation, operations and maintenance.

After reliability, maintainability was the second most important factor affecting the design. The subsea part of the system is designed not to require routine maintenance, when maintenance is required all active components can be retrieved or replaced by a ROV. The ROV will also be able to retrieve or install any subsea control pod independently of the subsea tree, flowline base or any other pod. The ROV SCORPIO will be the primary tool for conducting troubleshooting and maintenance operations. During initial installation, the vehicle will be used as backup only and will not be required for installation procedures. To facilitate ROV access, Hughes, the designer and manufacturer of the system, has included intervention manifolds for operating hydraulic functions in both the completion/workover and production modes. All hydraulically actuated valves within the system have mechanical overrides, and special design considerations simplify their accessibility to the ROV (ref. 194).

1.3.5 Middle East

Subsea completion systems in the Middle East are located in the Arabian Gulf. Since 1968 22 subsea wellheads have been installed and are used for both production and water injection. Most of the wells are in shallow water (around 30 meters depth) and none exceed 72 meters.

TABLE 4. SPS DEPLOYMENT MEDITERRANEAN/MID-EAST/AFRICA

YEAR	DEPTH (M)	FIELD	OPERATOR	NO. WELLS	REMARKS
1968	24	Grondin	Elf Aquitaine	1	W. Africa
	21-39	Bul Hanine	Qatar Gen. Petrol.	12	Mid-East 1968-1981
1969	21	Zakum	ADMA-OPCO	2	Mid-East
1972	69-71	Raksh	Iranian Offshore Oil	4	Mid-East
1976	61	Grondin	S.N.E.A. (P)	1	W. Africa
	30	Grondin	S.N.E.A. (P)	2	W. Africa
1977	117	Castellon	Shell Espana	1	Med.- Spain
1978	15-21	Umm Shaif	ADAM-OPCO	5	
	68-72	Raksh	Iranian Offshore Oil	2	Mid-East Water injec.
1979	134	Casablanca	Chevron	1	Med.- Spain
1980	134	Casablanca	Chevron	1	Med.- Spain
	94	Dorado	ENIEPSA	3	Med.- Spain
	91	Nilde	AGIP	1	Med.- Italy
	76	Emilio	AGIP	1	Med.- Italy
	77	Lavinia	AGIP	1	Med.- Italy
1981	152	Espoir	Phillips	2	W. Africa
1982	152	Espoir	Phillips	6	W. Africa 1982-1984
	182;243	Tazerka	Shell Tunirex	2	No. Africa
	35-36	MM15, MM16	Qater Gen. Petrol.	2	Mid-East
1983	61	Mila	Montedison	2	Med.- Italy
1984	73	Ashtart	SEREPT (ELE)	2	No. Africa
	73	NA	S.N.E.A. (P)	2	No. Africa Test
*	19-26	Umm Shaif	ADAM-OPCO	5	Mid-East
	119	Castellon	Shell Espana	1	Med.- Spain
	NA	Port Harcourt	Mobil Oil Nigeria	1	No. Africa
	152	Espoir	Phillips	1	W. Africa
	66	Ashtart	Elf Aquitaine	2	No. Africa
	149-179	Tazerka	Shell Tunirex	2	No. Africa
**	117	Casablanca	ENIEPSA	1	Med.- Spain
	488	Casablanca	ENIEPSA	1	Med.- Spain
	762	Motanazo	Chevron	1	Med.- Spain Deepest SPS Scheduled

* Wet trees assembled but not installed.
** Wet trees on order.

Source of Data: Refs. 148 and 210

1.3.6 Africa

Subsea wellheads have been installed off the coasts of Tunisia, Gabon and the Ivory Coast, and one is scheduled for installation off the coast of Nigeria. Eighteen wellheads have been employed and five more are planned for the future. These installations, much like their counterparts elsewhere, were made to either reach early production or to tap marginal fields. Two of the fields off the African continent warrent some discussion owing to their role in the subsequent development of SPSs or their sophistication at the time of installation, these are the Grondin field and the Tazerka field.

Grondin

The Grondin installation was a subsea experimental station. The subsea station consisted of a 23m x 6m x 2m, 43 tonne template used to support three wellheads and located some 1,500 meters from the bottom-supported Grondin production platform. The template was equipped with manifolds, flowlines and control cables necessary to tie the station into the Grondin platform's production facilities. Wellhead functions were remotely controlled from the platform. The template (Fig. 7) was installed in 1976 and the first well was drilled in the same year. Two additional wells were drilled in 1977 and 1978 and the test ended in February 1981.

The station had two objectives:

- Produce oil from the northeast extension of the Grondin field.
- Permit experimentation to prepare Elf Aquitaine (the operator) for producing oil in deep waters (>600m) and in difficult locations.

Since diver assistance in over 600 meters of water is not possible, Elf initiated a research program to develop experimental tools and diverless intervention techniques. One of the experimental tools developed and tested during the tests was a rail-mounted manipulator system called TIM (Telemanipulateur d'Intervention et de Maintenance) which was deployed and operated from a surface vessel.

The testing program revealed adequacies and inadequacies in subsea wellhead components and the techniques employed for remote maintenance. These lessons were implemented later by Elf Aquitaine in the design and implementation of the Northeast Frigg field in the North Sea in 1983.

Tazerka

The Tazerka field is located 83 kilometers off the coast of Tunisia in 138 to 244 meters of water. The SPS is a multi-well floating production, storage and offloading system. The system uses production and related facilities aboard the tanker MUREX.

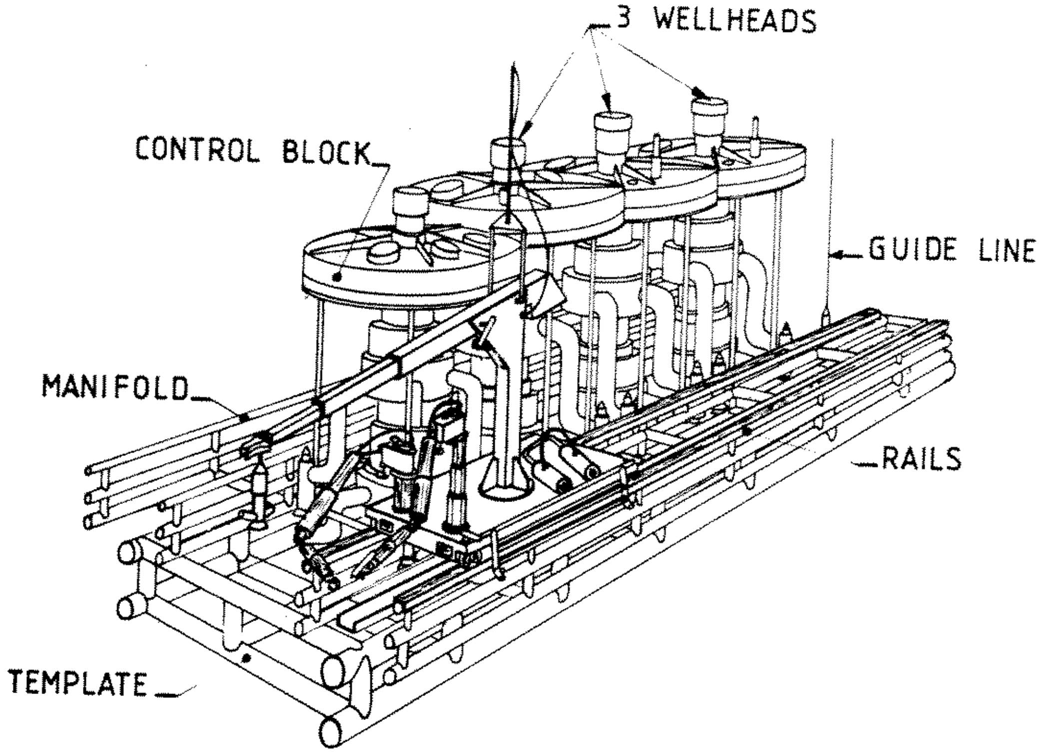


FIG. 7 THE GRONDIN TEMPLATE (from ref. 116)

The tanker is moored to a Single Anchor Leg (SALS) consisting of a rigid riser structure connected by a universal joint to a gravity base on the seabed. The tanker can weathervane about the riser gimbal and the riser is depth tensioned by positive buoyancy of a submerged tank on the tanker yoke. The riser and its gravity base were designed by SBM Inc. under the guidance of Shell International Petroleum Mij (SIPM) for the operator Shell Tunirex in a joint venture with Enterprise Tunisienne d'Activities Petrolieres (ETAP) and AGIP Africa.

The Tazerka SPS is designed to serve up to eight subsea wells which may be regulated individually by sequential hydraulic controls. Production capacity of the system is 20,000 bopd. The crude is stored in the tanker and at regular intervals an export tanker takes on the crude for transportation to the shore facilities.

1.3.7 Southeast Asia and the Phillipines

Countries in these areas that have SPSs include Brunei, Indonisia and Malaysia. The total number of subsea wells is 16, and the water depths in which they are situated are shallow relative to other areas by averaging 53 meters, with the deepest being 95 meters (Table 5). The justification for employing SPSs in these areas is similar to other areas, in that, they are the most economic approach to marginal fields. Three fields, SW Ampa, Attaka and Cadlao, have been adequately reported for discussion.

TABLE 5. SPS DEPLOYMENT SOUTHEAST ASIA/PHILIPPINES/AUSTRALIA/ INDIA AND THE IONIAN SEA

YEAR	DEPTH (M)	FIELD	OPERATOR	NO. WELLS	REMARKS
1968	27-30	SW Ampa	Brunei Shell Pet.	3	Brunei 1968-1969
1970	76	Baronia	Sarawak Shell Berhad	1	Malaysia
1971	72	Baronia	Sarawak Shell Berhad	1	Malaysia
1974	61	Fairley A	Brunei Shell Pet.	1	Brunei
1975-1977	33-40	Fairley C	Brunei Shell Pet.	4	Brunei
1979	76	Cobia 2	Esso Australia Ltd.	1	Bass Strait Australia
1980	41	SW Ampa	Brunei Shell Pet.	1	Brunei
1981	95	Cadlao	Amoco Philippines	2	Philippines
1982	50-64	Attaka	Union Oil of Indonisia	3	Indonisia
*	73	Bombay High	ONGC	1	India
	61	Vega	Montedison	1	Ionian Sea
**	17	Pepper	Western Mining Corp.	6	Bass Strait

* Wet trees assembled but not installed.
** Wet trees on order.
Source of Data: Refs. 109, 148, 169, 172, and 210

SW Ampa

This field first employed a subsea completion system in 1968, however, in 1980 Brunei Shell Petroleum, the operator, installed a "below-the-floor" wellhead that is believed to be a solution to many of the mechanical damage problems encountered by SPSs (ref. 108). The wellhead is termed a low-profile, caisson completion system that has application in Arctic waters where ice is a problem or where anchors, trawler fishing or falling debris could damage the wellhead. The completion equipment was designed to fit into a 30 inch (76cm) conductor (Fig. 8). New designs were required for the wellhead connectors and master valves. The new slimline connector permits installation inside the conductor. The connector is hydraulically locked and unlocked. If the primary unlock circuit fails, a secondary hydraulic unlock feature is provided. A mechanical unlock system is included in the event that there is a total hydraulic failure.

Equipment innovations resulting from this project include: 1) an improved 3 1/2 inch TFL pump-down completion system with deep set safety valves; 2) dual detachable packer head for simplified workover, and 3) a hydraulic sequencing valve for both tree control and remote flowline connection. A standard subsea BOP stack was used for drilling operations. The system has a working pressure of 5,000 psi, except for the subsurface safety valve control lines which are 7,500 psi. The upper tree structure can be unlatched from the master valve block and pulled without disturbing the flowline if a re-entry is needed.

Attaka

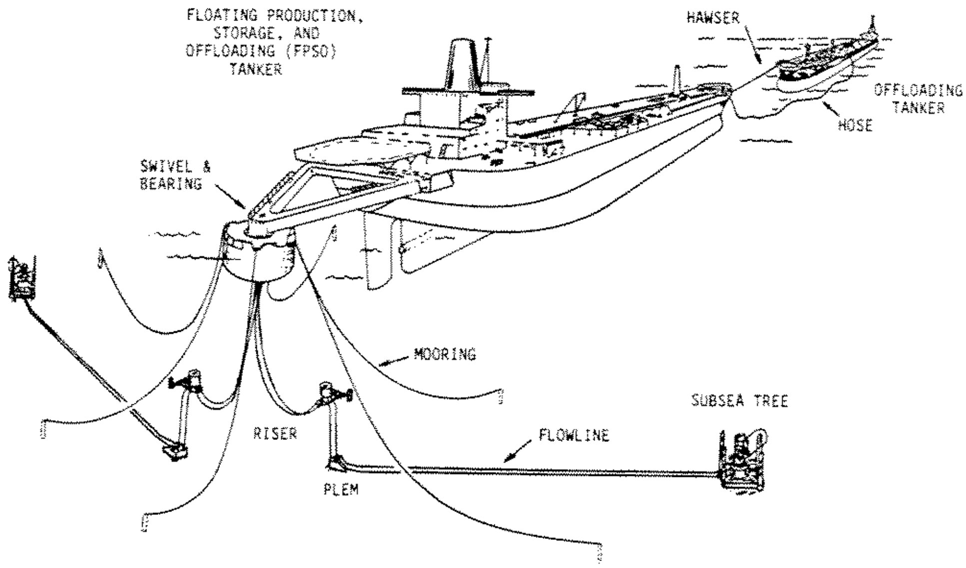
This field is located in the Makassar Strait, 22 kilometers offshore Tanjung Santan, East Kalimantan, Indonesia. Discovery was in 1970 and production peaked in 1977 at 117,000 bopd. Exploratory and delineation drilling on the edges of the Attaka field resulted in the discovery of oil and gas accumulations not in communication with the main field reservoirs. These potential reserves could not be developed from existing field platforms, and the quantities were not large enough to economically justify the installation of a platform for development. Three of these wells were selected to be completed using a simple subsea completion system to confirm the viability of this method for development of marginal reserves (ref. 172).

Reasons for the choice of the three wells were threefold. First, all wells tested substantial oil rates from reservoirs equivalent to those in the main Attaka field. Water depths (50 - 64 m) to the wells would permit diver assistance without saturation diving equipment during the well completion and maintenance stage. The three wells are relatively close to existing production facilities and range from 1,400 meters to 2,000 meters distance. The subsea trees used (Fig. 8) were produced by FMC Corporation and tied into the existing production platforms. After ten months of producing time the downhole safety valves and tree valves were still operating, and no malfunctions had occurred (ibid.).

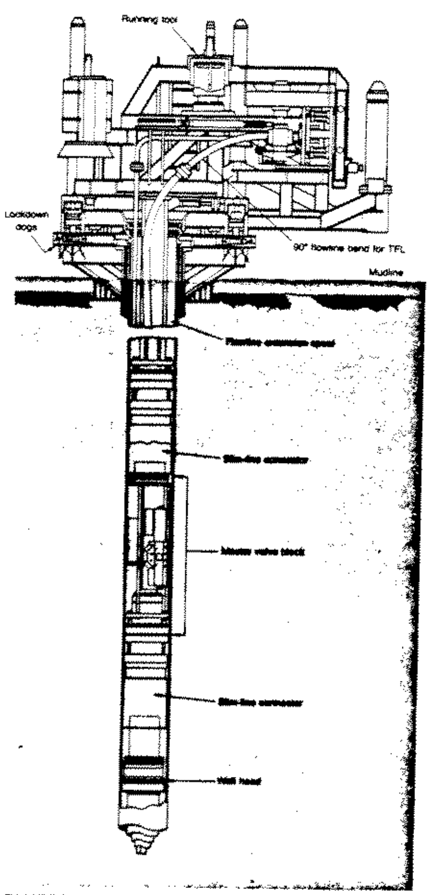
Cadlao

This field is located offshore Palawan Island in the Philippines. Production is from two subsea completed wellheads to an integrated floating production, storage, offloading system (FSPO) owned and operated by Terminal Installations Inc. and under lease to Amoco Philippines Petroleum Company (ref. 169). The field development scheme is shown in Fig. 8. The two subsea well completions are approximately two kilometers from the FSPO which is designed to weathervane around its permanent mooring. The dual 6-inch (15 cm) flowlines and risers terminate at the seafloor pipeline end manifold (PLEM) bases. Tree control and bottom hole monitoring are conducted from aboard the FSPO through subsea umbilical links. Production from the two wells passes through the stacked buoy swivels to manifold chokes located on the deck of the 125,000 DWT single point moored tanker (ibid.).

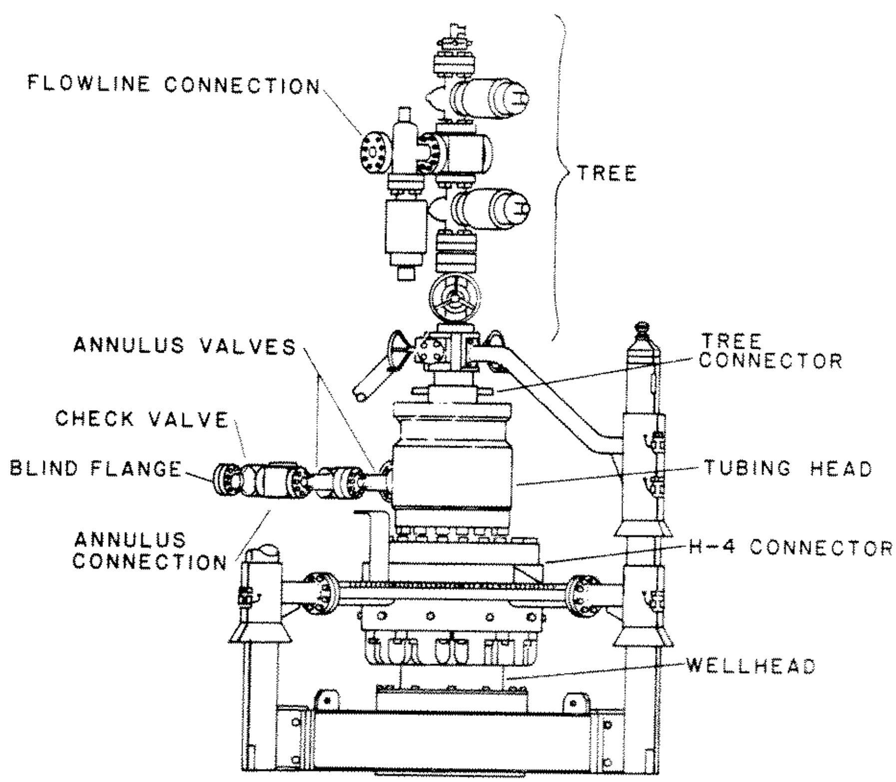
In the conceptual phase of the design, the primary objectives were to keep the equipment costs down; to meet the established schedule; to minimize subsea complexity; to make the facility safe, and to retain the needed versatility to permit additional wells to be tied-in or relocation of the entire facility to another field. In view of the remoteness of the field and the intention to use only onboard personnel for maintenance and repair, reliability was given high priority. The panels and circuits were to be straightforward with maximum use of hydraulics and pneumatics.



CADLAO FIELD DEVELOPMENT SCHEME



CAMERON subsea caisson system installed off Brunei.



TREE EQUIPMENT - ATTAKA 11 AND 14.

FIG 8. SW AMPA, CADLAO, AND ATTAKA FIELDS: SPS COMPONENTS

After 18 months from commissioning in 1981 production downtime at Cadlao was less than one percent. According to ref. 165, the unsophisticated control system contributed significantly to this performance. The design philosophy of this system was to have the complexity on the surface for easy repair. Direct hydraulic control of the trees and downhole safety valves was selected for Cadlao primarily to avoid underwater control devices.

1.3.8 Other Areas

There are three other areas in the world where SPSs are reported being in use or planned for installation: The Cobia field in the Bass Strait (1 installed; 6 on order for the Pepper field); the Vega field in the Ionian Sea (1 assembled but not installed) and the Bombay High field offshore India (1 assembled but not installed). No further published information is available concerning these installations, other than they are all in less than 76 meters water and therefore with the range of divers.

1.4 FUTURE PREDICTIONS FOR SPS APPLICATION

The future for increased application of Subsea Production Systems is definitely positive. The rate of growth is speculative. As with many new or innovative undersea technologies, the concept and actual installation of SPSs has not yet lived up to the amount of interest they have generated in the trade journals and at conferences/exhibitions. Actual application of underwater production systems began in the Canadian portion of Lake Erie in the same decade as did the first application of a fixed, bottom-supported production platform offshore. J. Delacour, Director of Exploration & Production for IFP, provides some sobering statistics: there are currently some 3,600 fixed platforms throughout the world, but only about 260 subsea completions (ref. 222). Although the trend towards SPSs is growing, and the depths and environments of new discoveries certainly favors employment of SPSs, this 14:1 ratio of fixed platforms to SPSs should be kept in view to maintain proper perspective.

Almost all of the future projections for SPS application have come, not from the sector who would do the actual purchasing of the hardware - the operator, but from observers of the industry. The predictions, therefore, are based on levels of acknowledged interest and expressions of possible intentions. Consequently, there is frequently some divergence in interpreting the future of this very dynamic industry. The following is a chronological account of the way in which the growth and acceptance of SPSs has been interpreted by industry observers, and it provides, to some degree of accuracy, a window into the future.

1975 "Subsea Completions Continue To Grow" (ref. 13)

At this point in time the author, K. Doerner, simply reported the number of subsea completions to date (60) and observed that six more would be completed in 1975 with another six planned for the following year.

1977 "Subsea Completions Make Rapid Progress" (ref. 40)

"Subsea completions are in the process of being more widely used in North Sea fields. In fact, all major operators now seem to accept the fact that the corresponding technology, after many years of development, has reached the point where it can be considered as a potential way of developing a field, totally or partially. In early technical/economic studies, as well as in definite plans on field development, the possibilities of subsea completions are now included, which was not the case in the North Sea only two or three years ago."

1979 "North Sea Heads Towards New Horizon" (ref. 79)

"As the North Sea continues the transition from exploration into production on its second generation of discoveries, a new day is dawning: the Day of the Subsea Completion. No company operating in the North Sea can afford to ignore the potential of subsea completions. Virtually every company is involved-most, actively, the others at the study and inquiry stage. On another level it is most probable the subsea completion will take oil production past the 600-ft (183 m) water depth."

1980 "Wet Systems Dominate As Market Surges" (ref. 90)

"Technological advancement, and political and economic climates are conspiring to make subsea production the most exciting growth prospect in the oil service market in the next five years - a growth which the 1979 figures indicate is already accelerating."

In this article the author, D. Booth, quotes a May 1977 report by the Houston firm Underwood, Neuhaus which projected the near-future subsea wellhead market:

"We believe the market for subsea equipment is very bright... since the market for subsea equipment is still relatively small in terms of dollars, it is difficult to estimate when and which companies will develop a significant volume of subsea business. It appears that the market will not be large enough to create significant business for all the hardware companies. We expect the list will narrow from the current ten participants (hardware producing companies) to three or four.

The important thing to note about the subsea market is its current dynamics. Technology and economics have come together and we believe it is only a matter of a few years before this is a $100-250 million per year market. The market growth between now and 1985 will be about the most rapid for any oil service market. The financial rewards for those companies which gain a dominant market position will be large. We believe the stock market will also reward those companies."

1981 "Subsea Production Systems: Boom Is Still In The Future"

(ref. 103)

"After several years of bullish outlook in which the trade press and industry generally contended that a boom in seafloor completions was `just around the corner' spurred by deeper waters and/or shallow overburdens, the market still appears to be somewhere in the future. One explanation is that advancing oil and gas prices increase the economic depth of platforms. Some industry authorities say the market for subsea completions will decline and plateau in the period 1984-1985, while other market watchers say the drop and slow growth rate is here now."

"Observes one subsea production expert, `The market is going to drop unless another Brazil comes along soon.' This authority predicts that at about $32/bbl oil the growth rate for sea floor systems will be about seven to eight percent/year, but growth will not reach a 20-25 percent rate without another hot spot like Brazil."

1982 (Jan.) "The Infant Prodigy Comes Of Age" (ref. 120)

"There is a feeling around the industry that 1982 is going to be that year we have all been talking about - the year that subsea production came of age. I would like to suggest that 1982 is the start of the age of (SPS) utility. The apprenticeship is over, and the era of the journeyman has arrived. Subsea production has now grown up and is now working out. The rewards it will earn will grow as each year of maturity passes. The venture into deeper and deeper water will be a stepwise progression based on the confidence gained with each successful project. I am convinced, 1982 is the year we have all been talking about."

D. Booth

1982 (Oct.) "Development Trends In Subsea Production Systems" (ref. 147)

"Annually it has been stated by the industry that `next year' there will be a subsea boom. This has not happened, simply because of the economical consequences for the operators stemming from potential reliability factors. Most operators therefore take a more precautious approach characterized by one-step-at-a-time. This precaution in field development is matched by a dual emphasis on major R & D work on subsea systems, as all parties realize that such systems are needed.

Accordingly, instead of a subsea boom, there has been a steady and continuous growth in applications of subsea systems over the last decade, including a significant shift from utilization of individual satellite wells to focusing on template clusters with subsea manifolding. Subsea system development has over recent years passed its infancy, and is now generally considered to be a proven method."

1982 (Oct.) "What's Ahead For Subsea Completions" (ref. 131)

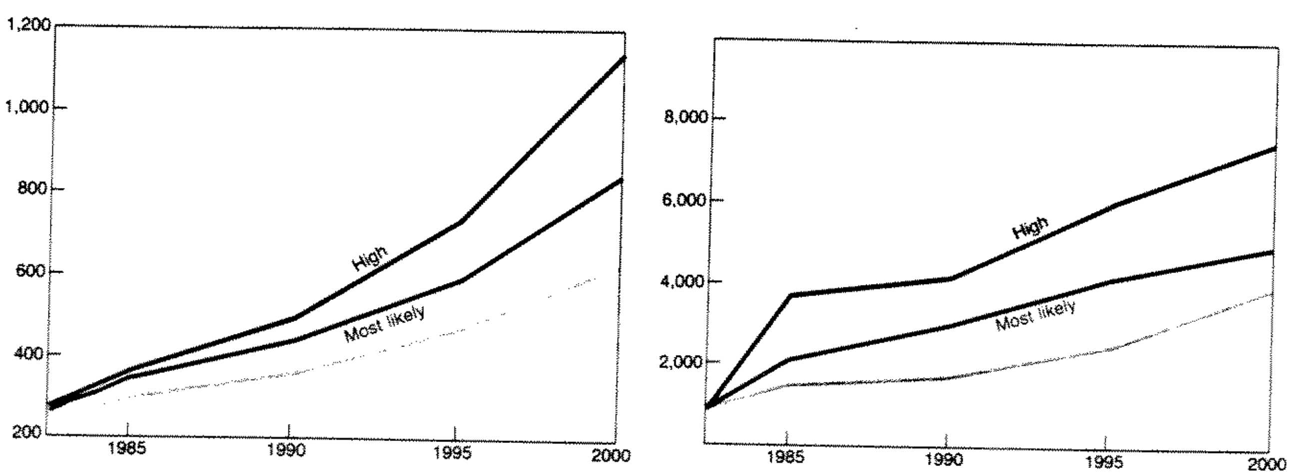
The following statements are abstracted from the above article which was based on a survey of manufacturers and major oil companies concerning the short and long-term future of subsea completions.

"Survey respondents differed in their expectations about the pace of growth during the coming five and ten-year periods. Two large manufacturers and one engineering design firm said five-year prospects are flat or erratic, while one oil company sees modest growth. A majority of respondents, however, felt steady growth would be achieved in the near-term. All respondents expect subsea completions to achieve a steady growth over the next ten years."

"One oil company stated: 'The biggest detriment to subsea growth is floating drilling costs. Technical issues will be solved and reliable, low-maintenance operation is achievable. If the gap between platform rig and floating rig costs were not so large, subsea would be extremely attractive economically. Also, significant increases in oil prices could greatly accelerate subsea activity'."

"A manufacturer noted that because subsea completions are most applicable to field developments involving marginal production possibilities, very minor changes in the economic climate or price of oil can have an immediate effect. A slight softening of the oil market can cause marginal projects to be deferred, but any strengthening can bring them back on line again".

This article presented several tables which projected future trends related to subsea production systems. Two of these trends, the future for subsea wellhead installations and the estimated greatest water depth for subsea completions are presented below.



A B

FIG. 9. A: FUTURE FOR WET AND DRY TREES, HYBRID INSTALLATIONS, SHUT-IN WELLS. B: ESTIMATED GREATEST WATER DEPTH FOR SUBSEA COMPLETION. (from ref. 131)

1983 "Subsea Completions" (ref. 155)

"Manufacturers are reluctant right now even to guess about next year's prospects. Some have no firm orders on the books for 1984. Estimates of total industry-wide installations for 1984 from three respondents were: 35; 10-12 to perhaps 25, and 20-30. One manufacturer estimated total orders placed industry-wide in 1984 would number 69. The consensus is that market volume will remain at about the 1983 level, but that some increase could occur if oil companies make early decisions about possible applications. Tax incentivies in the UK could produce a spurt in that area."

1984 (April) "Subsea Completions Come Of Age" (ref. 189)

"A frequent complaint of subsea engineers is that :`Every year we hear that next year will be the big one for subsea completions, and next year never comes.' Recently, however subsea completions are beginning to figure more prominently in conceptual designs and UK Annex B field development submissions.

It cannot be denied that until recently subsea production has been something of a neglected stepchild of the North Sea offshore industry. Abroad, it has flourished, chiefly off Brazil where there is a tremendous impetus for early production to floating installations while reservoirs are still being appraised and conventional jackets built."

1984 (Sept.) "The future Of Subsea Production" (ref. 228)

"The tendency (toward fixed, bottom-supported structures) must be reversed when the technical complexities and/or construction cost of platforms becomes prohibitive. This may occur in two cases: 1) ...production from a field is too limited to justify installation of a fixed platform and 2) water depths and environmental constraints are such that a fixed platform is practically unfeasible. The figures (3,600 fixed platforms vs. 260 subsea completions) prove that these two causes, although they have not yet had any very strong consequences, nonetheless show the start of a movement which, although proceeding slowly, is now irreversible. Indeed, the share of the medium-size and marginal fields discovered in relation to the larger fields will continue to increase, and the economic situation will work in favor of their being exploited."

1984 (Nov.) "1,000 New Subsea Completions Expected By 1989" (ref. 206)

"Historical performance of subsea completions shows a growing acceptance of this technology. H.O. Mohr & Associates recently prepared a repot in association with Subsea-Data-Services, entitled Future Development of Offshore Oil and Gas Fields by Subsea Production Methods. This study identified 423 current, pending, probable and possible completions-within the next ten years-that are under consideration by offshore operators for presently discovered fields.

Of the total, 71 percent were identified for installation in the North Sea. Further, the report projects an additional 575 completions during the next ten years for unannounced and undiscovered fields. The data indicate 35 percent of these will be in the Gulf of Mexico."

This paper contained several tables pertaining to the distribution of subsea equipment and participation of various contractors and operators. Two of these tables are presented below.

TABLE 6
Basic Types of Subsea Trees Installed

	Number
Wet Trees	258
Dry Trees	15
Experimental	1
Other*	20
Total	294

TABLE 7
Subsea Completion Distribution by Type of Service

	Number
Oil Production	213
Gas Production	40
Other**	41
Total Installed	294

* Includes dump flood equipment, neutrabaric, production through BOPs, etc.
** Includes dump flood, injection and pressure test equipment.

1985 "It has been interesting to follow the development of fixed production platforms for deeper and deeper waters. Right now, however, I feel fairly confident that we are at parting of the ways, from fixed solutions to novel subsea concepts. In fact, I think we will see extensive subsea production systems in the North Sea and off the coast of North Norway sooner than expected."

Inge Johansen, Chairman
Statoil
(ref. 242)

From the foregoing it is apparent that SPSs definitely have a future in offshore oil, but to just what extent and when will the boom, if there ever is one, occur, is open to speculation. One observation made above is of great interest at the present time; that is, that development of marginal fields by SPSs will be governed by the price of oil, and if there is a slight softening in the oil market marginal projects will be deferred. After reaching a spot market high of $36/bbl (Saudi light) in 1982, oil is now fetching $28/bbl, back to where it was in May 1980. This is definitely a softening of the market, whether this is soft enough to forestall development of marginal fields should be seen in the very near future.

2.0 SYSTEM COMPONENTS/CONFIGURATIONS: PRESENT AND PLANNED

There are three basic types of Subsea Production Systems: wet; dry and hybrids. While hybrid systems do exhibit some features common to wet and dry systems, they are totally reliant upon a fixed production platform for support and operation, and do not provide the capabilities offered by SPSs not bound to a fixed structure. For this reason, and because the inspection of a hybrid system's critical components can be almost wholly accomplished above water, they will not be discussed in any detail.

The previous chapter outlined the deployment/acceptance history of SPSs. This chapter describes in more detail the hardware which constitutes the undersea portion of a SPS and describes some of the major forthcoming and reported projects wherein subsea production systems will be deployed.

2.1 PRESENT SYSTEMS

Excluding hybrid systems, some 289 subsea completions have been installed and another 76 have been assembled or are on order. Of the total 365 trees, nine are dry. The operational status of these systems (listed in Tables 1-5) is shown in Table 8 and was obtained from the references noted in Tables 1-5.

A wet subsea completion consists primarily of five major components: wellhead, tree, valves, flowline connectors and controls. Dry systems are comprised of the same components, but also include a pressure-resistant capsule in which the major components are enclosed. Manufacturers of the major subsea completion components are listed in Tables 9 through 13, the numbers following each name represents the number of components they have reportedly provided as of 1984. As is evident in these tables, some manufacturers provide only one or several components, while others provide the full range.

TABLE 8. LOCATION AND STATUS OF WET AND DRY SUBSEA COMPLETIONS

	Active	Shut-in	Abandoned	Assembled	On Order
Canada		1			
United States	23	15	32	2	1
Brazil	46		2	3	
North Sea	70	3	6	13	34
Mediterranean	9		1	1	3
Middle East	17	6	5	5	
Africa	11	3	2	6	
Southeast Asia	14				
Phillipines	2				
Austrlia	1				6
India				1	
Ionian Sea				1	
Total	193	28	48	32	44

TABLE 9. MANUFACTURERS OF SUBSEA WELLHEADS

Cameron	(92)
CanOcean	(9)
Deep Oil Technology	(3)
FMC	(11)
Hughes Offshore	(3)
McEvoy	(10)
National	(62)
NL Industries	(9)
Regan	(5)
Vetco	(143)
NA*	(18)

TABLE 10. MANUFACTURERS OF SUBSEA TREES

CBV	(9)
Cameron	(110)
CanOcean	(4)
Chevron	(4)
Deep Oil Tech.	(5)
FMC	(16)
Hughes Offshore	(16)
McEvoy	(19)
National	(33)
NL Industries	(20)
Regan	(11)
SEAL	(1)
Vetco	(83)
WKM	(9)
NA*	(25)

TABLE 11. MAUNFACTUR- OF SUBSEA VALVES

Cameron	(131)
CBV	(9)
FMC	(17)
McEvoy	(16)
National	(13)
Vetco	(60)
Vetco/FMC	(3)
WKM	(85)
NA*	(31)

TABLE 12. MANUFACTURERS OF FLOWLINE CONNECTORS

Cameron	(26)	HydroTech	(5)
Cameron/Payne	(2)	McEvoy	(4)
CanOcean	(6)	National	(2)
Coflexip	(19)	Regan	(6)
Comex	(2)	Rockwell	(1)
DOT	(1)	Santa Fe	(2)
FMC	(1)	Vetco	(44)
Gray Tool Co.	(2)	Weco	(4)
Hughes	(3)	NA*	(239)

TABLE 13. MANUFACTURERS OF SUBSEA CONTROL SYSTEMS

Cameron	(51)	Koomey	(7)	SEAL	(1)
Chevron	(6)	Matra	(6)	TRW	(31)
DOT	(4)	NL Industries	(72)	TRW/Ferranti	(25)
FMC	(1)	NL/Marconi	(9)	TRW/Gen. Elec.	(3)
Hughes	(1)	Prod. Ctrls. & Services	(5)	Vetco	(31)
Hydril	(27)			Vickers-Intertek	(1)
				NA*	(82)

* Information not available.

Note: Full names and addresses of companies are contained in Appendix III

2.1 PRESENT

2.1.1 Wet Systems

There are at least 35 different individual and combined manufacturers of wet subsea completion system components. While each system generally contains the basic components noted above, the arrangements and capabilities of these components within a specific system can vary widely. Cameron Iron Works, for example, has manufactured a minimum of 13 differently arranged subsea completion systems, and Vetco a minimum of ten. To depict and describe all of the various completion systems would verge on the encyclopaedic. Therefore, the descriptions of SPSs herein are general and selective, and aimed at providing an appreciation, rather than a detaqiled knowledge, for the various SPS configurations which have been installed or are ready for installation.

The various underwater components which may constitute a SPS are shown in Fig. 10. (Dry manifold chambers are not shown in this figure, they are discussed in section 2.1.4). The trees that constitute the wet type systems may be installed as satellites or as a group mounted within a template.

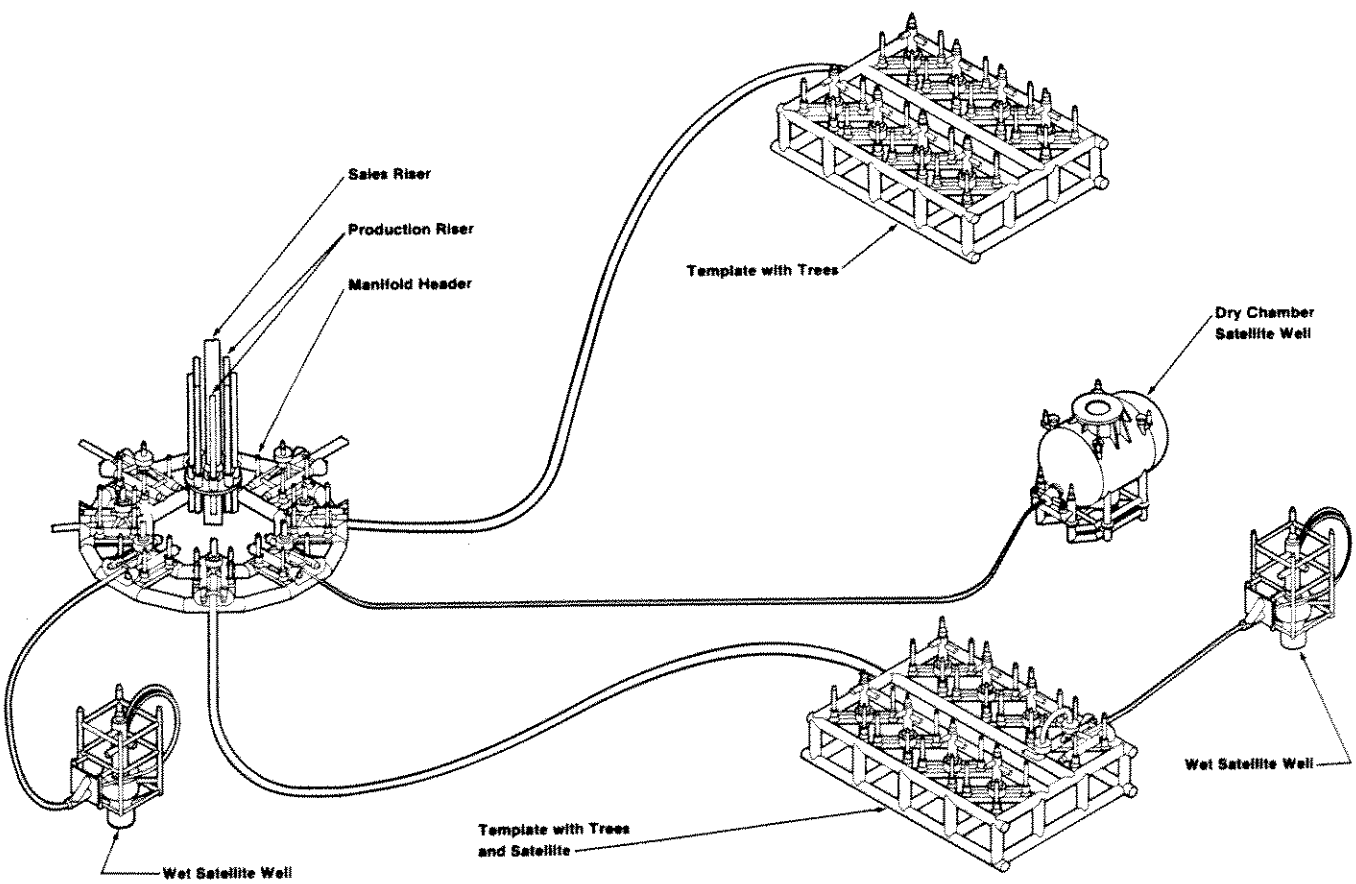


FIG. 10. SUBSEA PRODUCTION SYSTEM WELLHEAD CONFIGURATIONS
(courtesy Cameron)

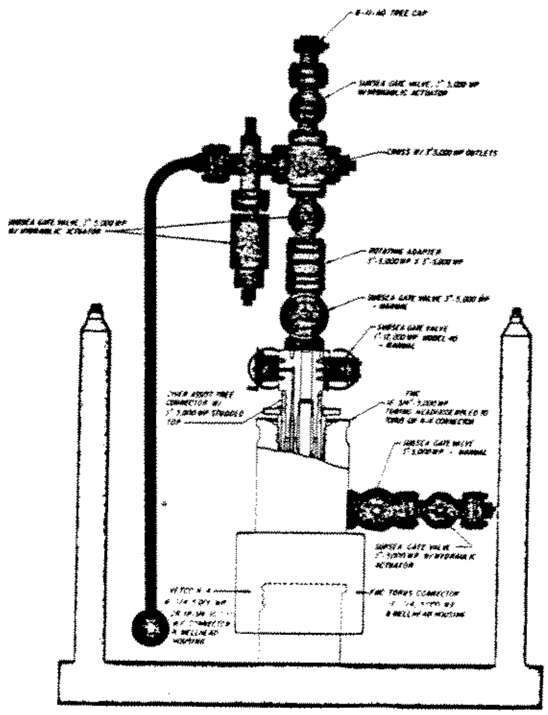
2.1.1.a Satellite Trees

Subsea satellite trees permit completion of exploratory or development wells. These single well completions can be connected by flowlines to a platform, tanker, pipeline, central gathering manifold, template-mounted manifold, shore facility or floating production facility. The satellite tree is essentially an adaption of the conventional surface tree, but is packaged to permit installation and protection in the subsea environment.

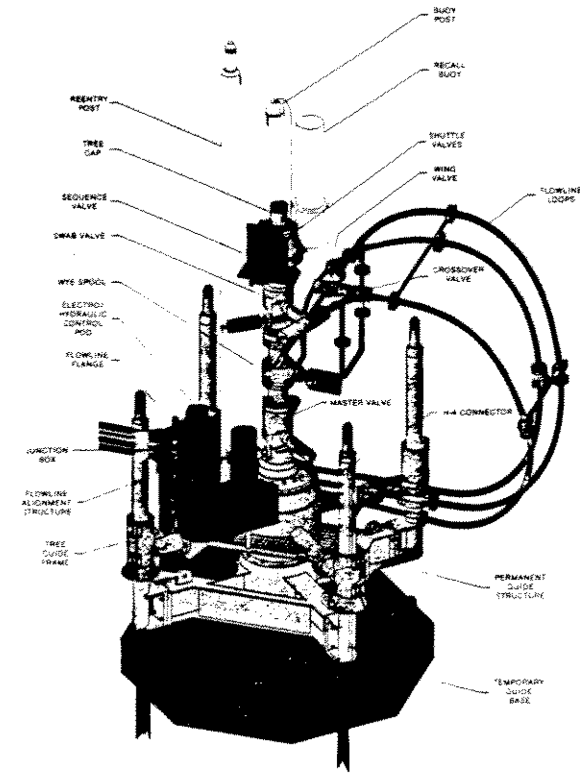
There are two basic types of satellite trees: TFL and non-TFL, both of which may be either diver assist or diverless trees (Fig. 11). The diver-assisted non-TFL completion includes features of the more sophisticated remote tree, but still retains diver control over certain functions. In the Cameron diver-assisted tree, the lower connection to the well head is a manual clamp connector made up by the diver, or a remote hydraulic connector. The master and swab valves are usually manually actuated, while the wing valves are equipped with hydraulic actuators controlled from a central platform. The top connection for vertical re-entry into the tree is either a union-type or a coarse thread, both of which require diver make-up. The diver-assisted tree is dependent upon a diver for installation and downhole service must be performed by wireline methods. Its application is generally confined to areas where water clarity is good; where the depth will permit reasonably long on-bottom time and when the well conditions indicate a minimum amount of downhole service work.

The diver-assisted TFL completion includes features of the non-TFL completion with addition of the equipment necessary to perform TFL servicing. The most significant difference between these completions is the requirement for the circulation line to pump the TFL tools into and out of the completion. In a single completion this requires a second line from the completion to the production platform. For dual completions the secondary production line normally doubles as the TFL circulation line. A device known as the H member is installed in the production tubing lines at the maximum depth that can be reached by the TFL tool string to provide a circulation path between the tubing lines. The tree TFL equipment includes the wye spool, diverters, diverter orienting sub, crossover valve, and flowloops. As in the non-TFL diver-assisted completion, its use is generally confined to diver depths. However, the TFL capability provides for a broader range of well conditions.

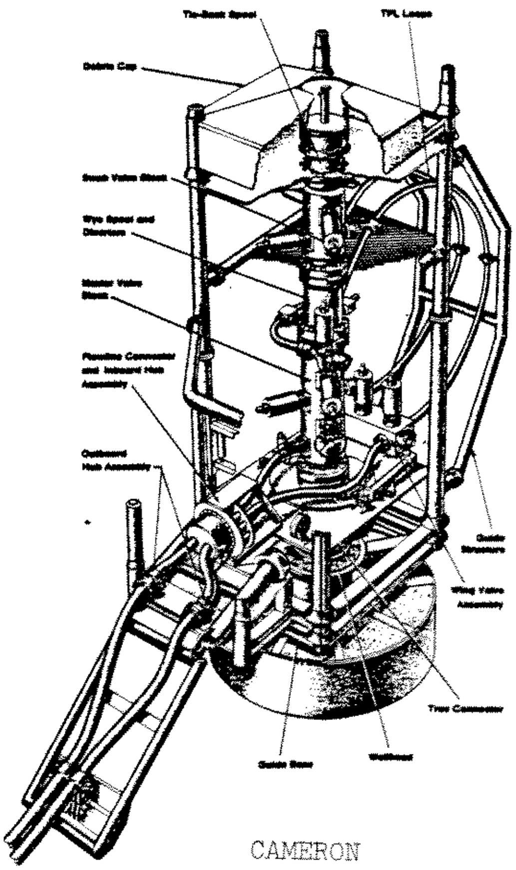
The more sophisticated diverless completions feature remote installation and re-entry capabilities through the use of hydraulically actuated collet connectors, remote hydraulic flowline connectors, hydraulically-actuated valves, remote guideline reestablishment tools, and, for very deep water, guidelineless guidance equipment.



FMC



VETCO



CAMERON

FIG. 11.
SUBSEA COMPLETION TREES: TFL (Vetco, Cameron) AND NON-TFL (FMC).

The major components of satellite trees are (from ref. 172) the: Support Base, Wellhead, Tubing Hanger, Wellhead Connector, Valve Assembly, Tree Cap, Flowline, and Controls. Several of these components are graphically depicted in Figs. 12 and 13, the functions of these and other components are briefly described below and were obtained from the preceeding reference.

Support Base

Designed to carry the combined weight of the conductor and casing strings, the subsea Blowout Preventer (BOP) equipment during drilling and also provides guidance for the subsea BOP stack and, ultimately, the production tree assembly.

Wellhead

Supports the casing strings, BOP stack, tubing hanger and production tree assembly.

Tubing Hangers

Designed to be run inside the subsea BOP stack and to seal and lock down inside the wellhead assembly. Commonly, a single tubing string is suspended from the tubing hanger in the subsea well with provision in the hanger for annulus access and the hydraulic control of downhole safety valves. Profiles in the tubing hanger through bores allow wireline plugs to be installed for the safe removal of the BOP stack before installation of the production tree assembly.

Wellhead Connector

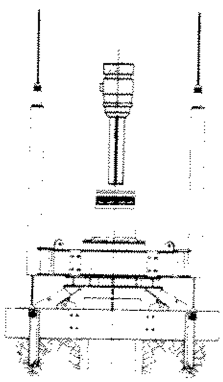
Locks and seals the production tree assembly on the subsea wellhead housing. An integral hydraulic system permits the connector to function while an AX ring gasket inside the connector effects a seal inside the wellhead.

Valve Assembly

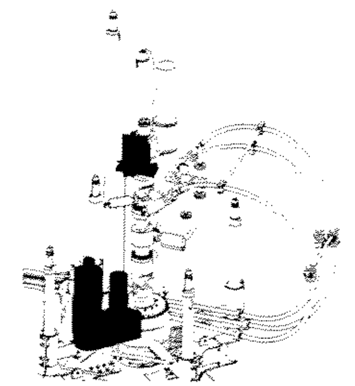
Controls and directs the produced hydrocarbons into the flowline system. Options to the basic valve assembly include the addition of a "wye" spool to allow smooth passage of TFL tool trains for downhole servicing.

Tree Cap

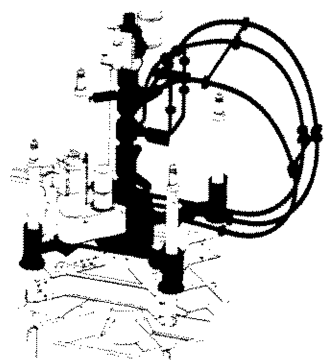
Acts as a protective cover for the re-entry mandrel, and can be used as a backup seal to the upper (swab) valves on the master valve block. It may also be used to form part of the production tree control system by housing the necesary control valves, filters, accumulators, etc.



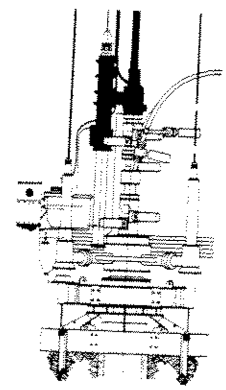
Tubing Hanger System



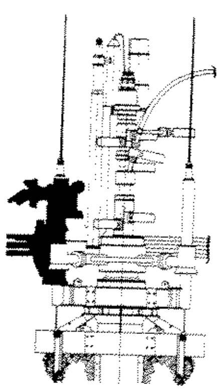
Tree Control System



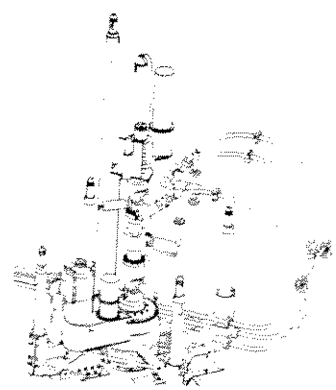
Production Tree
Assembly



Tree Installation and
Workover System



Flowline Connector
System



Re-entry System

FIG. 12. SIX BASIC SUBSEA COMPLETION COMPONENTS (from Vetco)

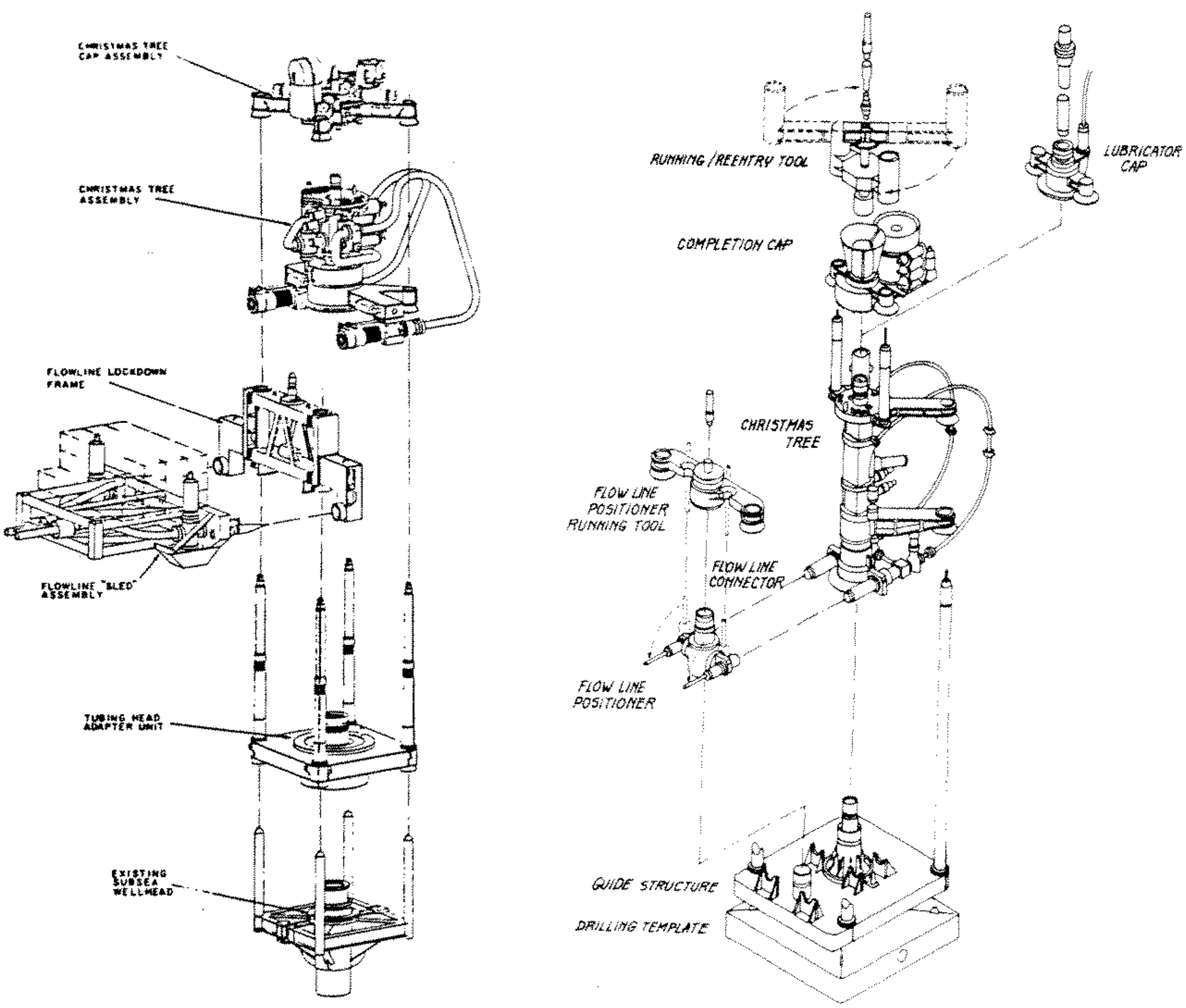


FIG. 13. EXPLODED VIEW OF THE CASABLANCA FIELD SCS (LEFT) AND THE ENCHOVA FIELD SCS (RIGHT). (from refs. 132 & 143, respectively)

Flowline

The conduit through which the produced hydrocarbons are carried from the tree to the production facility. The connection between the flowline on the tree and the line to the production facility can take many forms. The simplest is for a diver to make up a conventional API (American Petroleum Institute) flange, but more sophisticated systems are available that employ, for example, an hydraulically operated vertical stabbing connector or even a fully diverless pull-in and remote make-up connection.

Controls

The control system is used to actuate valves or operators on the subsea system. There are four basic types of control systems: manual, hydraulic, electro-hydraulic, and multiplexed electro-hydraulic. Direct hydraulic is used on less complex completions because of the need for individual control lines from the control station on the production facility to each operator on the subsea system. Long distances between the trees and the control station result in extended response time and slow closing of the tree valves. Electro-hydraulic systems have a control module on the tree which contains a series of solenoid valves that direct hydraulic fluid to the selected tree operators. Response is greatly improved over the direct hydraulic technique and only a single hydraulic supply line and multi-core electrical cable are necessary between the tree and the control station. A multiplexed electro-hydraulic control system is used on the more sophisticated completion systems incorporating template and satellite trees, manifolds, sensors, etc. Closing response times are in the order of the electro-hydraulic systems, but the large volume of information which must be handled make multiplexing the best solution in many instances.

Although there are only four basic control systems, there are a wide number of variations on each theme, these are as follows:

Hydraulic

-Direct Hydraulic
-Workover Hydraulic
-Production Sequence Hydraulic
-Sequential Hydraulic
-Sequential (Pod) Hydraulic
-Discrete Hydraulic

-With Sequential Override
-With Direct Override
-Integral Direct Control
-Integral
- Piloted

Electro-Hydraulic

-Multiplex
-With Sequential Backup
-With Sequential Hydraulic Override

The foregoing identified and briefly described the typical components of a subsea completion satellite tree. It is emphasized that there is no "standard" satellite tree, nor is there a standard tree configuration. Furthermore, the capabilities of trees are varied, in that, some have TFL capability and some do not; some have remote flowline pull-in capability and some do not. An appreciation for the many different types of subsea trees and their varied configurations/capabilities can be gotten by reviewing the different types produced by Cameron and Vetco which are shown in Figs. 14-19. (Note: There is no significance in the repetitive use of two or three manufacturer's products as examples in this report. It only signifies that these manufacturers responded more comprehensively to requests for information.

One of the more unique completion systems is the cassion completion developed by Cameron Iron Works. The cassion completion is designed, according to the manufacturer, to provide maximum tree security and requires little or no modification to current offshore drilling systems. It is adaptable to guideline or guidelineless driling systems. A schematic of the caisson completion's development and components is shown in Fig. 20 (below), a dome shaped shield is also available to provide additional protection above the bottom.

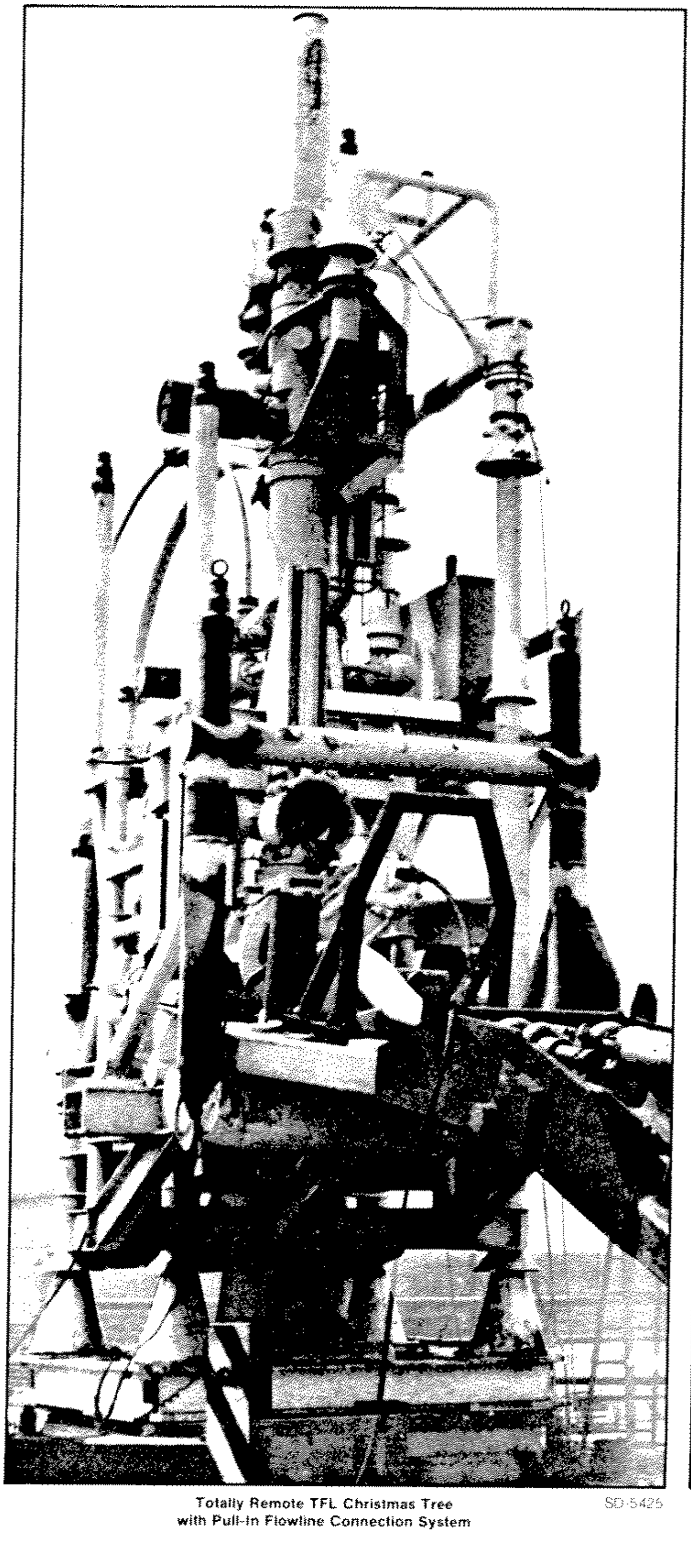
2.1.1.b Templates

The subsea template provides the base through which subsea wells are drilled. It also serves to space and align the wellhead equipment. Three different types of template designs can be used with subsea well- head and tieback equipment, these are: 1) Spacer templates, 2) unitized templates and 3) modular templates.

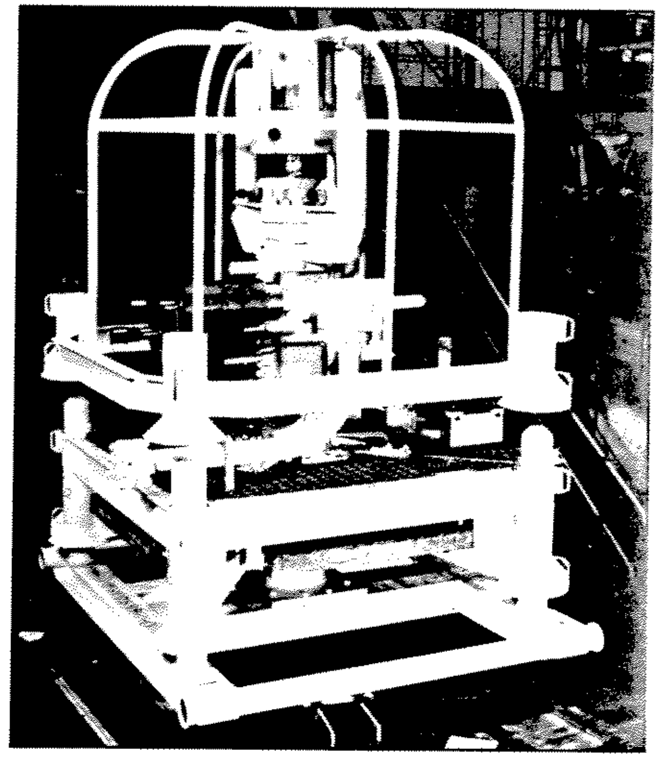
The following descriptions of the three different types of templates and their functions are of those provided by Vetco Offshore Inc. Other template designs are shown in Figs. 24 and 25.

Spacer Templates

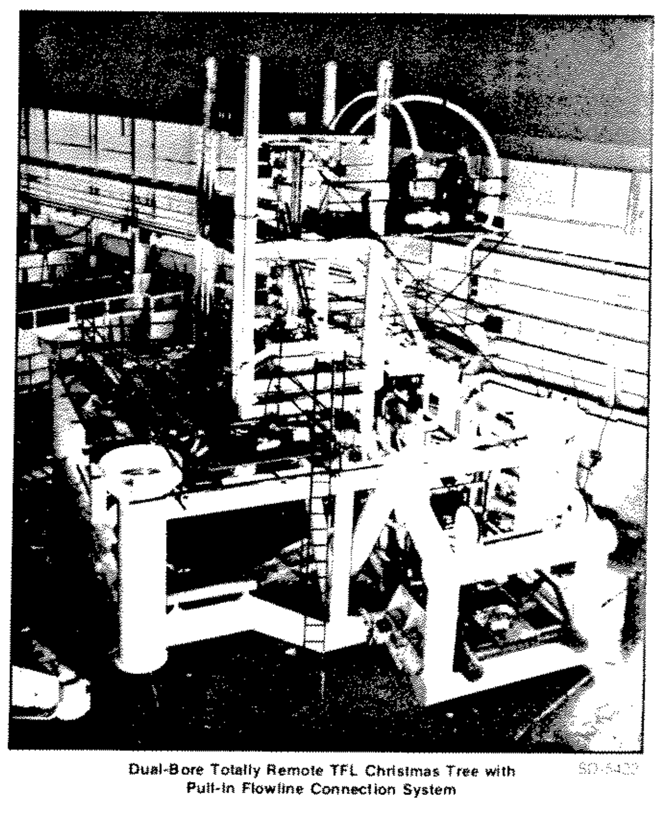
The spacer template (Fig. 21) is the simplest type of template used with platform tie-back completions. Each well slot on the template is topped by a funnel on which a retrievable guide structure is landed. Since it is normally a small template, and the wellheads are gimballed, it does not require leveling if the bottom slope is less than three degrees. Spacer templates are recommended (by Vetco) for use with six or fewer wells and are designed to accommodate standard six foot (1.8m) radius guideline drilling equipment and BOP stacks. These templates are generally small enough to be lowered through most moonpools without the necessity of keelhauling the template. Spacer templates can also be used from a jack-up rig with mudline suspension equipment.



Totally Remote TFL Christmas Tree
with Pull-In Flowline Connection System SD-5425

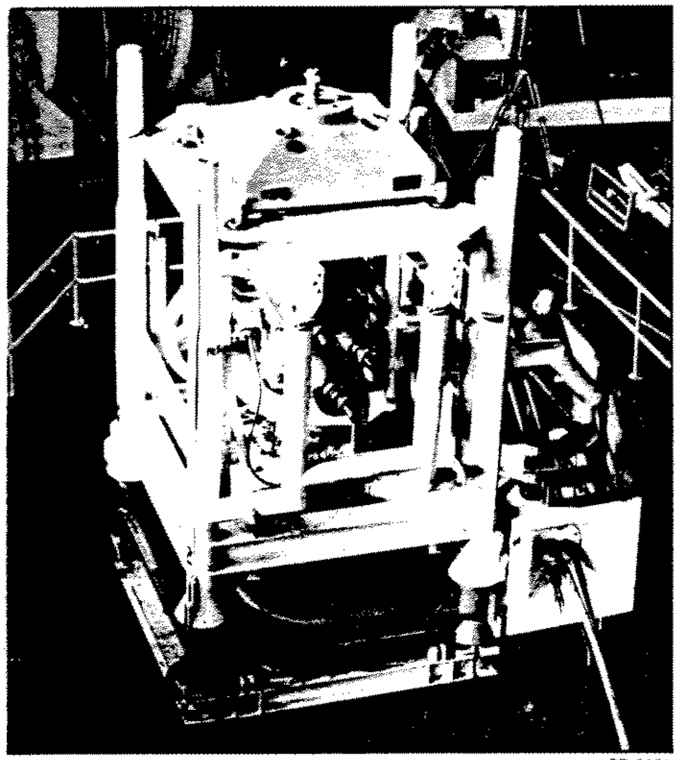


Non-TFL Christmas Tree with Diver-Assist
Flowline Connection System SD-5419

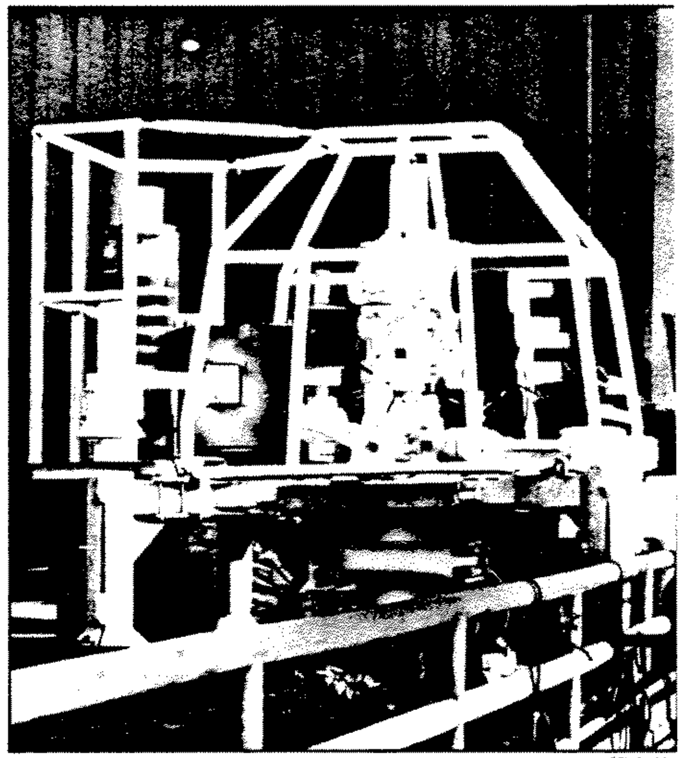


Dual-Bore Totally Remote TFL Christmas Tree with
Pull-In Flowline Connection System SD-5422

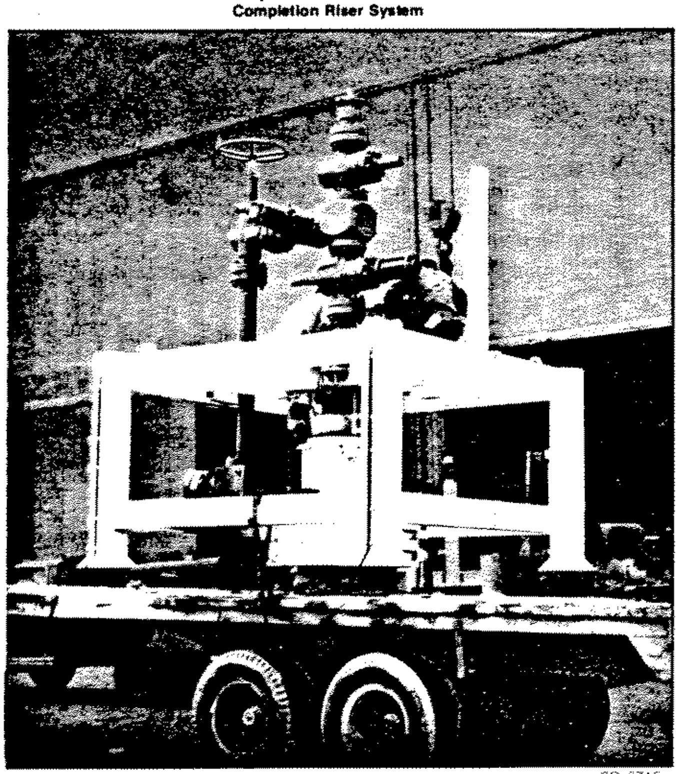
FIG. 14. EXAMPLES OF CAMERON SUBSEA COMPLETION TREES.



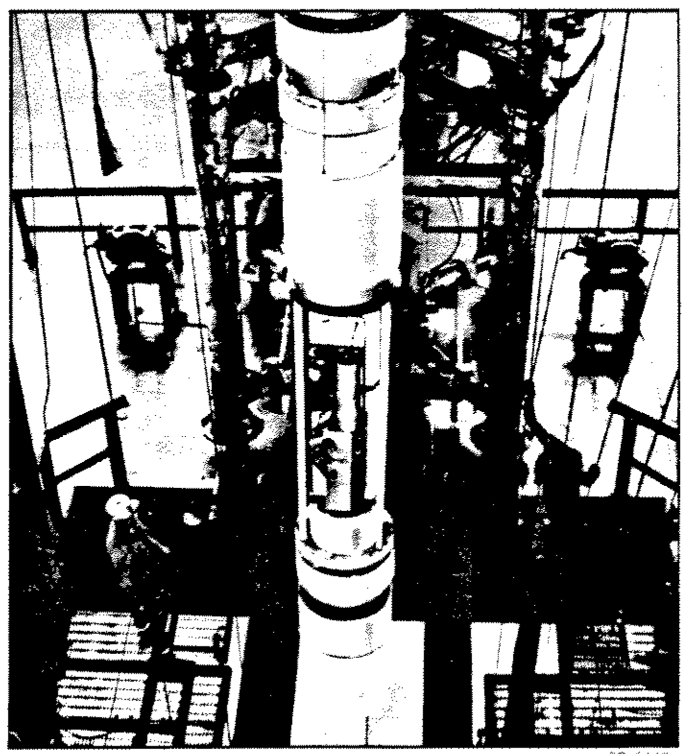
Non-TFL Christmas Tree with Vertical Flowline Connection System, Wireline BOP Stack, and Completion Riser System SD-5421



Non-TFL Christmas Tree with Diver-Assist Flowline Connection System SD-5420

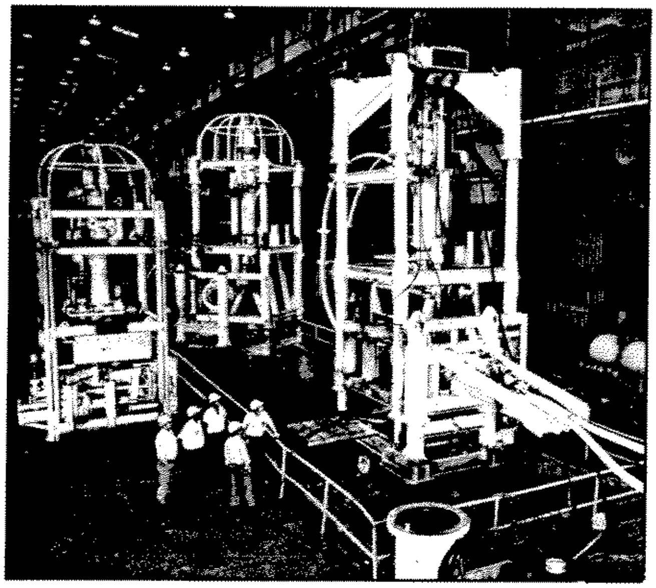


Simple Subsea Christmas Tree Adapted From Land Production Equipment SD-3715

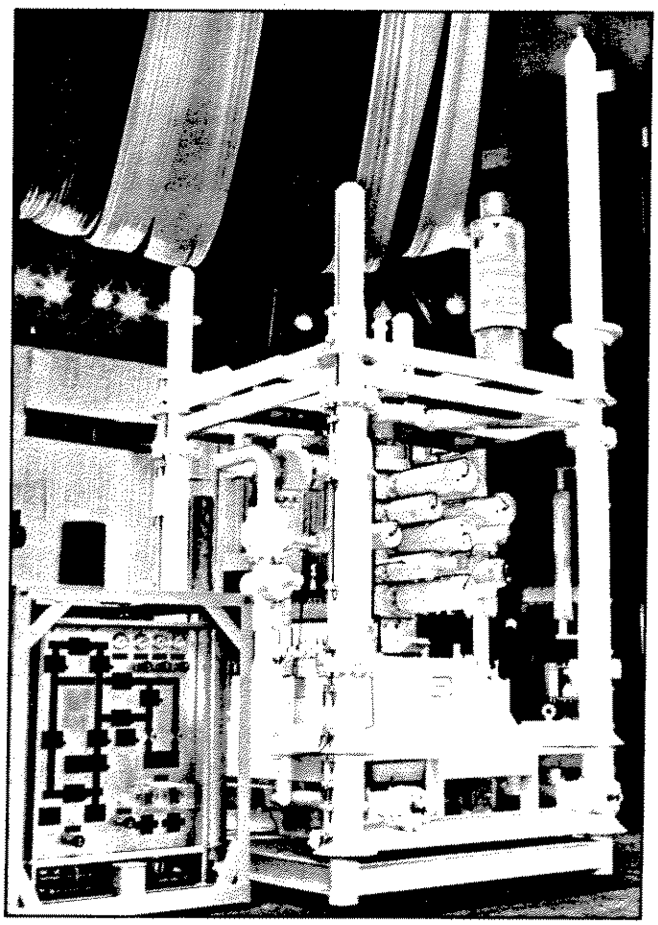


Caisson Completion Master Valve Block Installed on Slimline Riser SD-5440

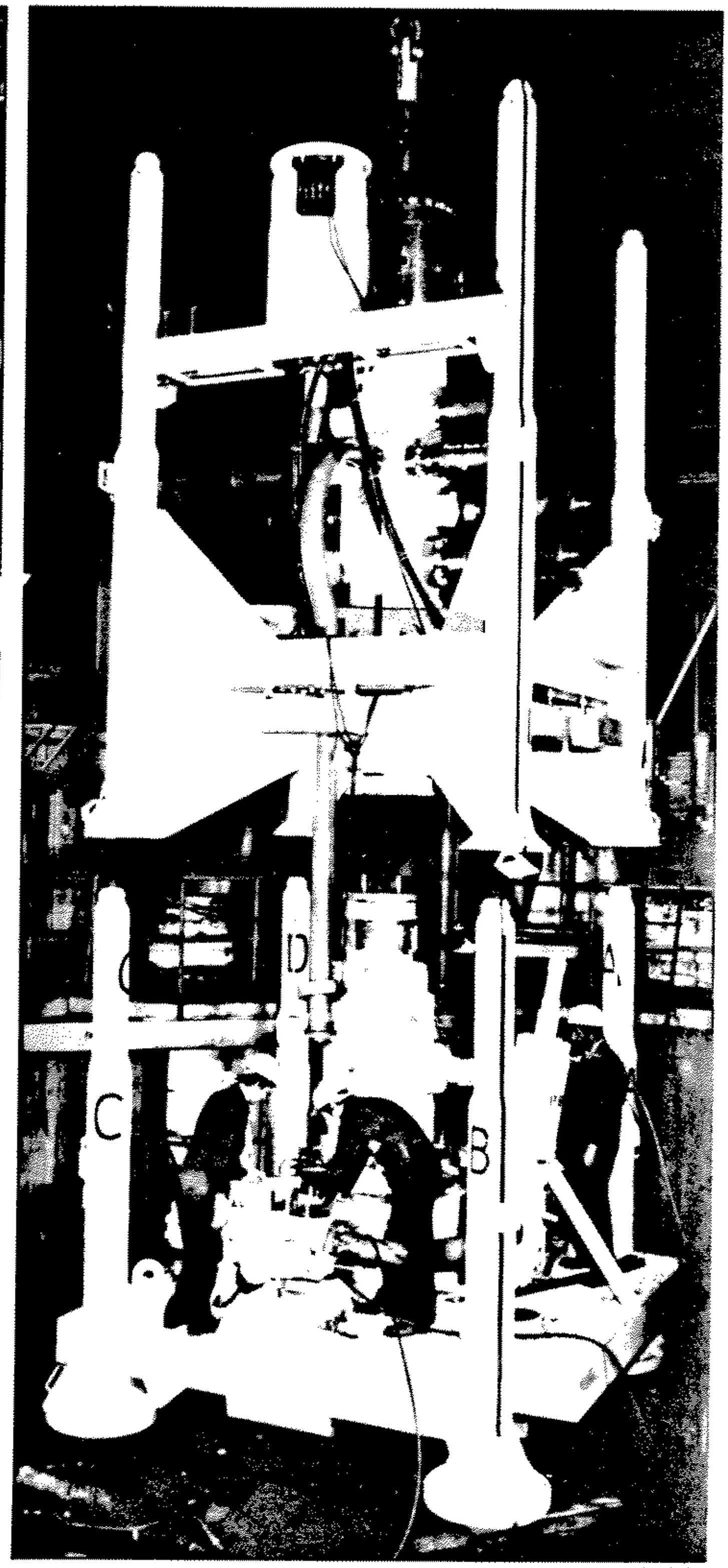
FIG. 15 EXAMPLES OF CAMERON SUBSEA COMPLETION TREES.



Totally Remote TFL Christmas Trees
with Lay-Away Flowline Connection Systems SD-868

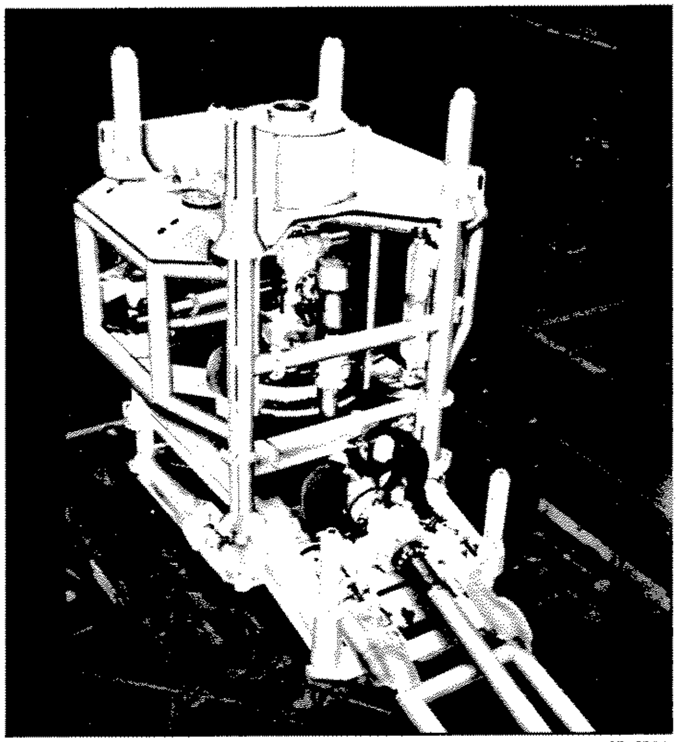


Non-TFL Christmas Tree with Diver-Assist Flowline Connection
System and Workover Control Panel SD-5423

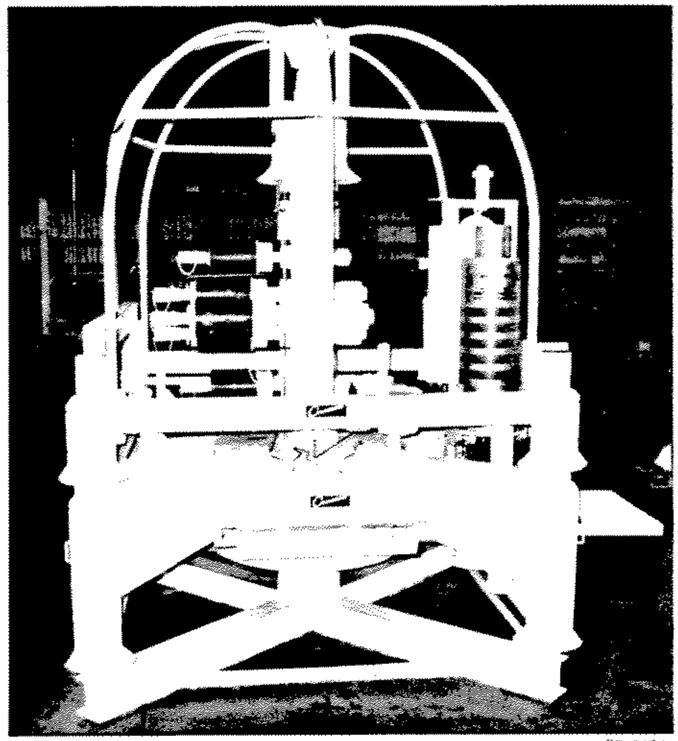


Non-TFL Split-Tree Christmas Tree with
Vertical Flowline Connection System SD-5426

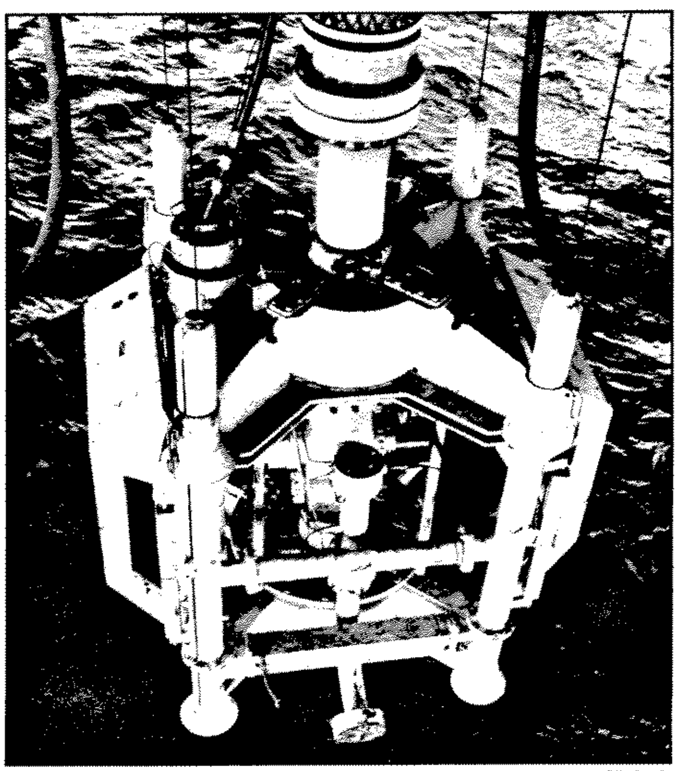
FIG. 16. EXAMPLES OF CAMERON SUBSEA COMPLETION TREES.



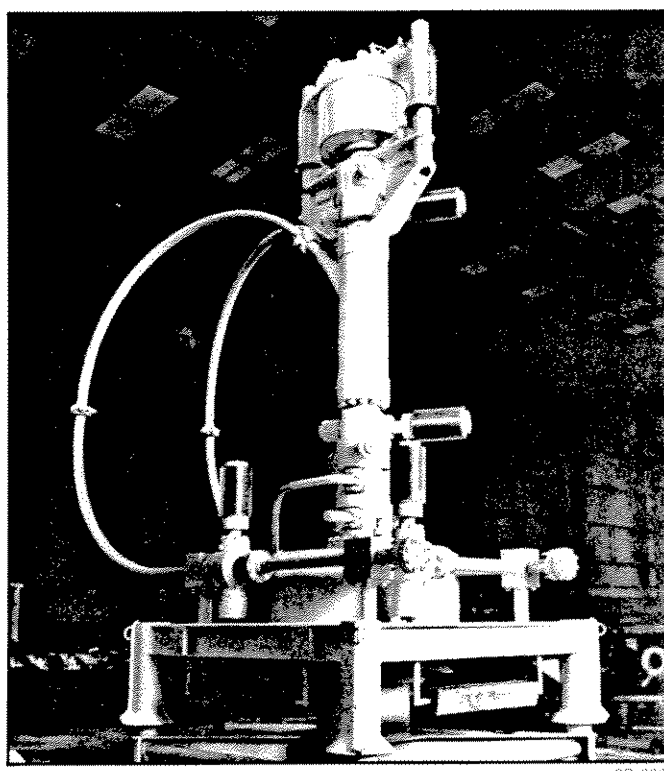
Plain Jane Christmas Tree with
Pull-In Flowline Connection System SD-3701



Non-TFL Christmas Tree with Diver-Assist Flowline
Connection System SD-5424

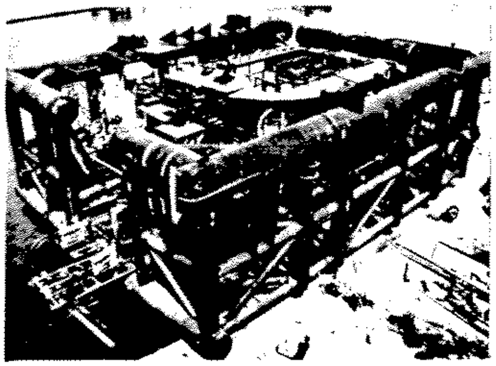


Plain Jane Christmas Tree Installed on Rig Drilling Riser SD-5418

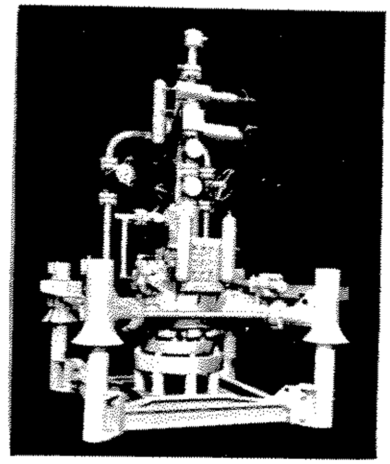


TFL Christmas Tree with Diver-Assist
Flowline Connection System SD-889

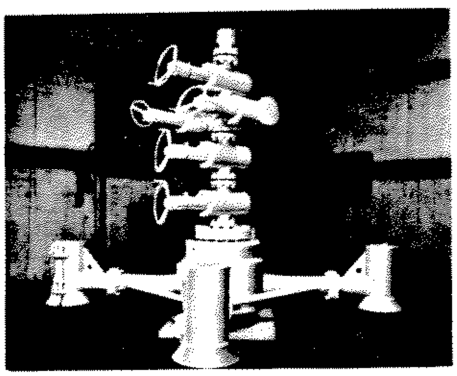
FIG. 17. EXAMPLES OF CAMERON SUBSEA COMPLETIONS.



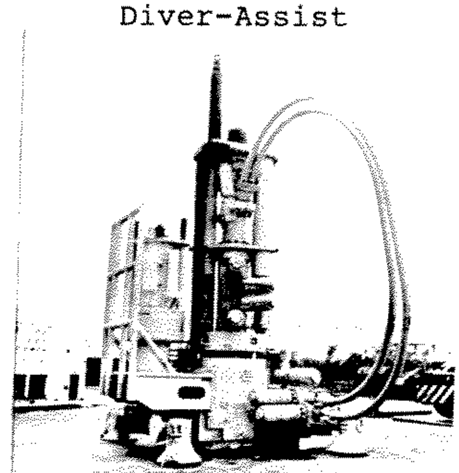
3-Well Diverless Template



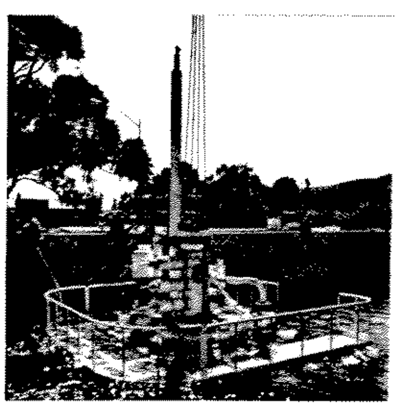
Single Well, Wet Tree
Diver-Assist



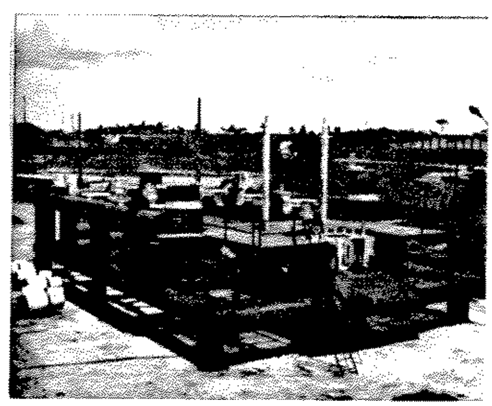
Single Well Wet Tree
Diver-Assist



5 Diverless Satellite
Trees

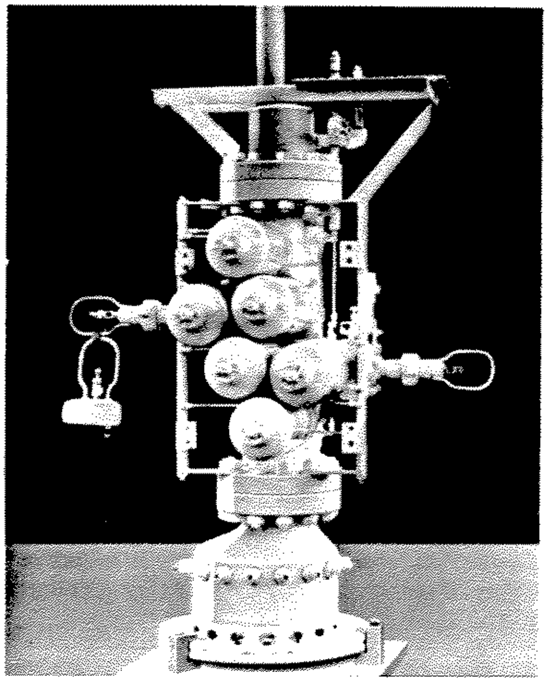


Single Well Diverless
Wet Tree

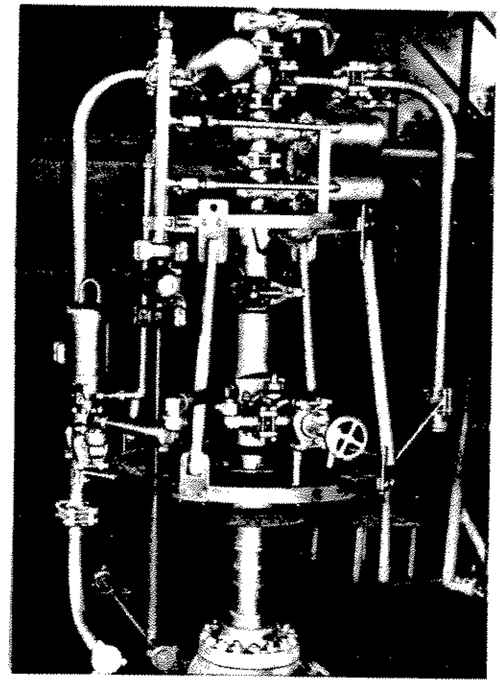


10-Well Capacity Template

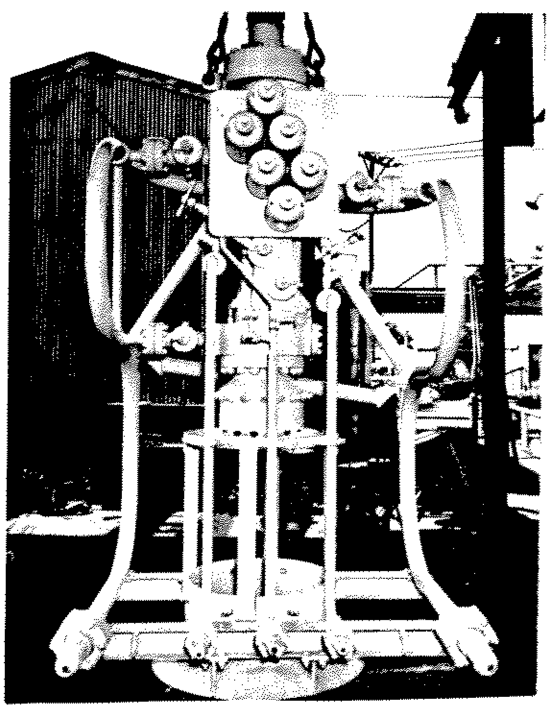
FIG. 18. EXAMPLES OF VETCO SUBSEA COMPLETION TREES.



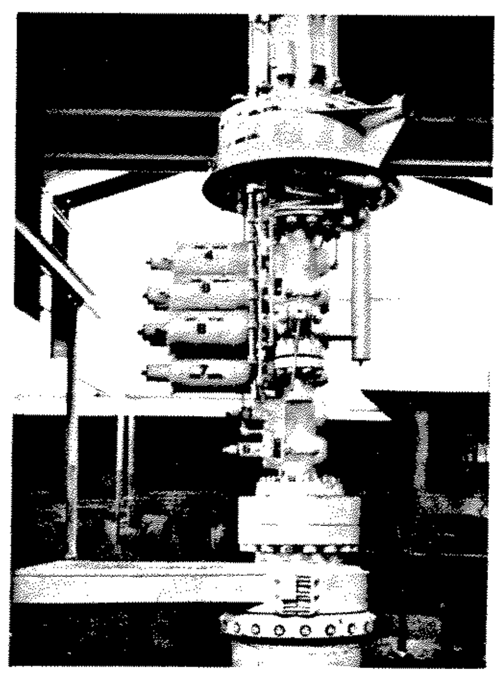
Single-Well Wet Tree
Diver-Assist



Single Well Wet Tree
Diver-Assist



Single Well Wet Tree
Diver Assist



Single Well Wet Tree
Diver-Assist

FIG. 19. EXAMPLES OF VETCO SUBSEA COMPLETION TREES.

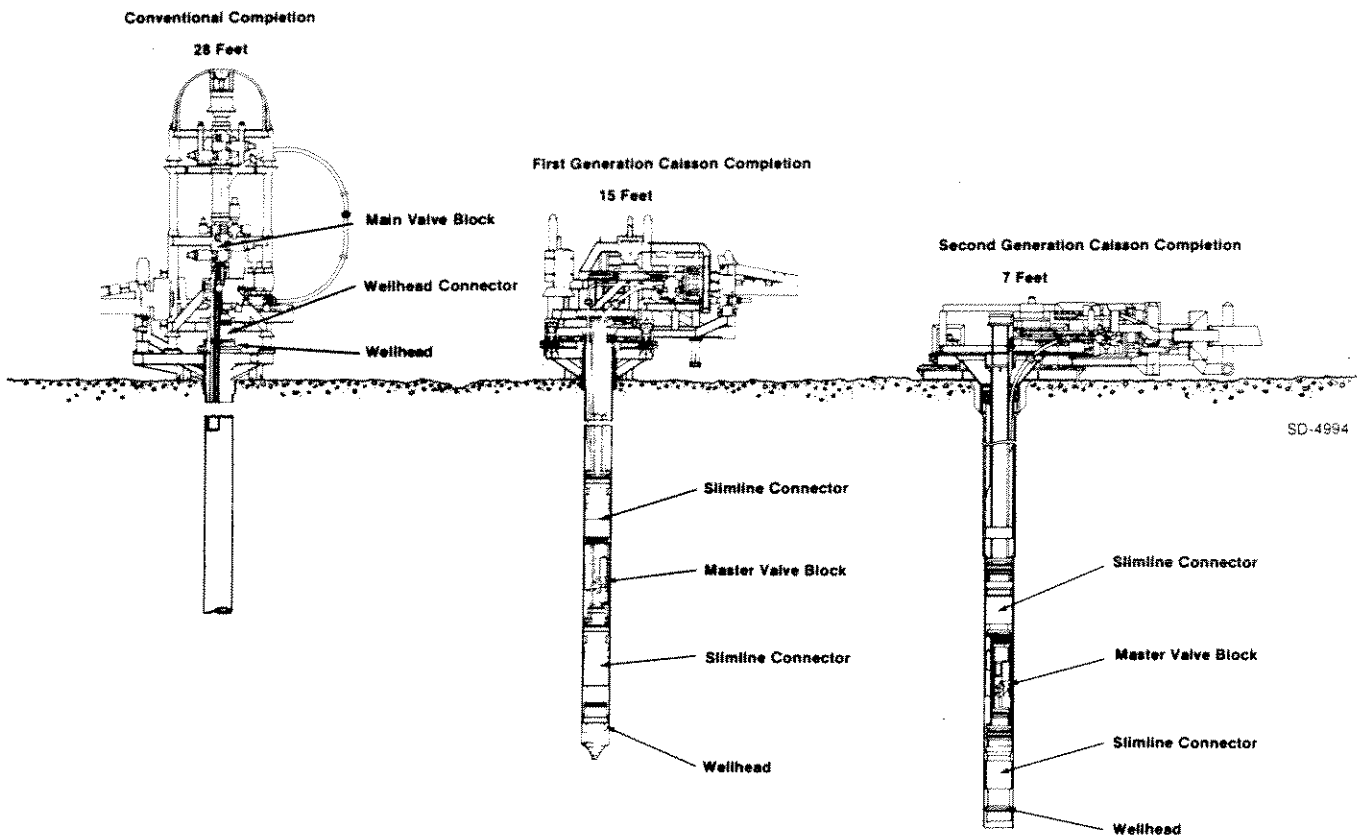


FIG 20. EVOLUTION OF THE CAMERON CAISSION COMPLETION SYSTEM. (Cameron)

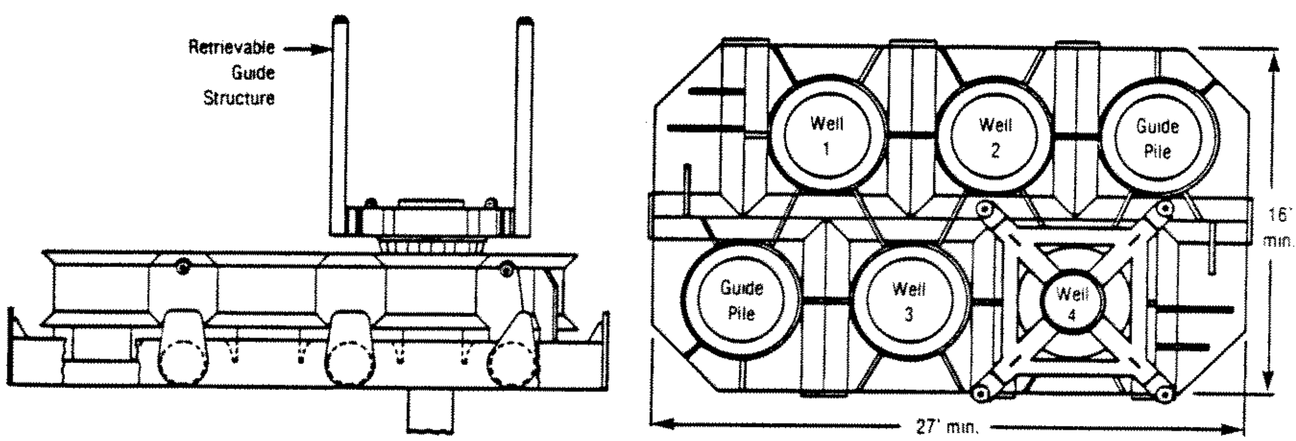


FIG. 21. SIDE AND TOP VIEWS OF A 4-WELL SPACER TEMPLATE WITH RETRIEVABLE GUIDE STRUCTURE AND TWO GUIDE PILE RECEPTACLES. (Vetco)

Unitized Templates

This type of template is generally recommended for use with six or more wells. It is fabricated from large tubular members and incorporates a receptacle for each well and a three- or four-point leveling system. Guidance for drilling equipment is achieved through the use of integral guide posts or retrievable guide structures.

The basic components of unitized templates are the:

- Basic template structure.
- Pile leveling receptacles to receive the pile guide housings with slips inside for template leveling.
- Wellhead receptacles which receive the wellhead housings.
- Cantilever bumper pile modules for locating and drilling the jacket bumper or guide piles.
- Replaceable guide posts mounted on the template in guide post receptacles.

A nine-well unitized template with a three-point leveling system and integral guide posts is shown in Fig. 22.

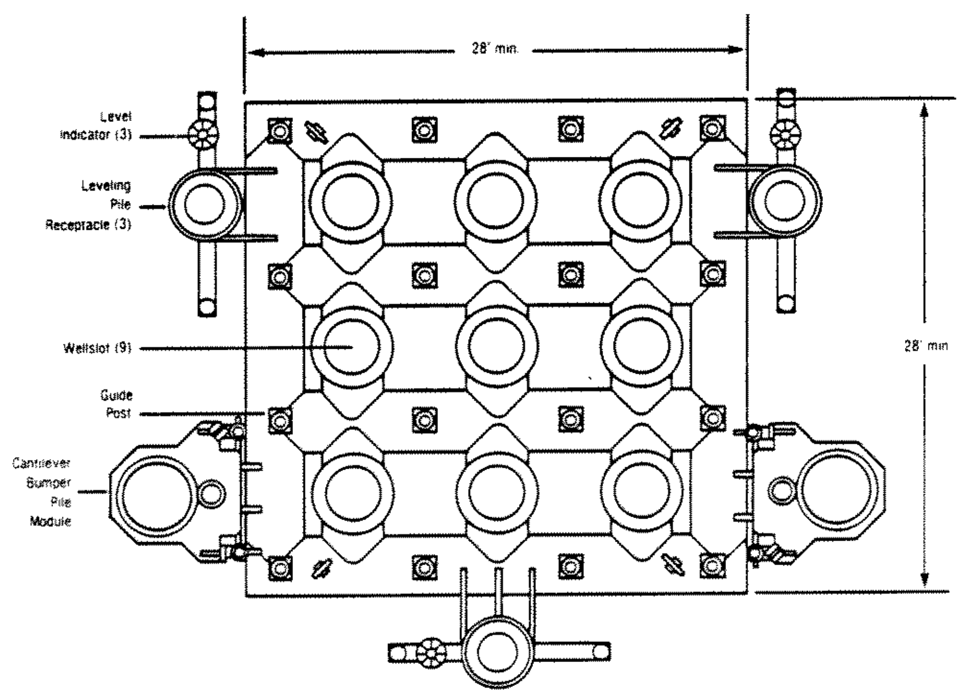


FIG. 22. NINE-WELL UNITIZED TEMPLATE WITH REPLACEABLE GUIDEPOSTS, PILE LEVELING RECEPTACLES AND CANTILEVER BUMPER PILE MODULES FOR PLATFORM LOCATION. (Vetco)

Modular Templates

This type of template is recommended for guideline drilling; systems and for use with drilling programs where flexibility is required. The modular template system employs a template structure that is smaller than the unitized template system and is made up of several interlocking modules (Fig. 23). These are generally selected for employment when the number of wells to be drilled has not been firmly established prior to commencement of the drilling program. These also require a lower capitol investment to determine reservoir characteristics while providing the capability to expand the system. It can also take the place of a standard permanent guide base, allowing the operator to index additional well slots, enabling production from either a tie-back or subsea production system after the exploratory well has been drilled. A flowline module is cantilevered from the base structure for a single-well subsea production system or a combination of well and plumbing modules is used for a multi-well system. The components of a modular template system are installed through the moonpool of the drilling vessel.

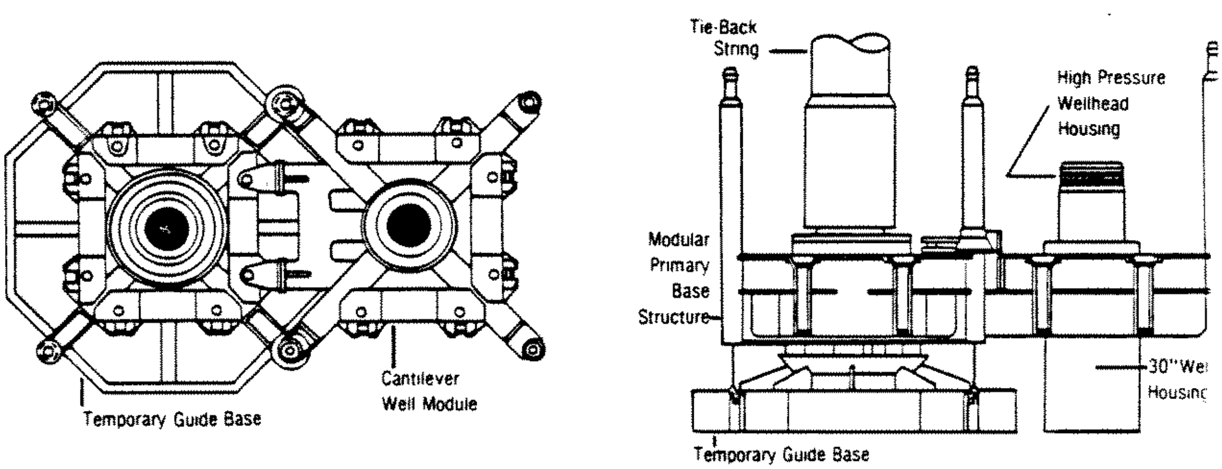


FIG. 23. MODULAR PRIMARY BASE STRUCTURE WITH ONE CANTILEVER WELL MODULE ADDED. (Vetco)

2.1.2 DRY SYSTEMS

There have been three manufacturers of dry subsea production systems: CanOcean Resources Ltd. (originally Lockheed Petroleum Services, Ltd.), Cameron Iron Works, and the SEAL Group. The CanOcean design is the only one that is still in use. The SEAL design was installed in the Gulf of Mexico for test and demostration and was subsequently retrieved. The Cameron design has not been employed to date. Other designs contemplated for North Sea application, are discussed in Sections 2.2.3 and 2.2.11

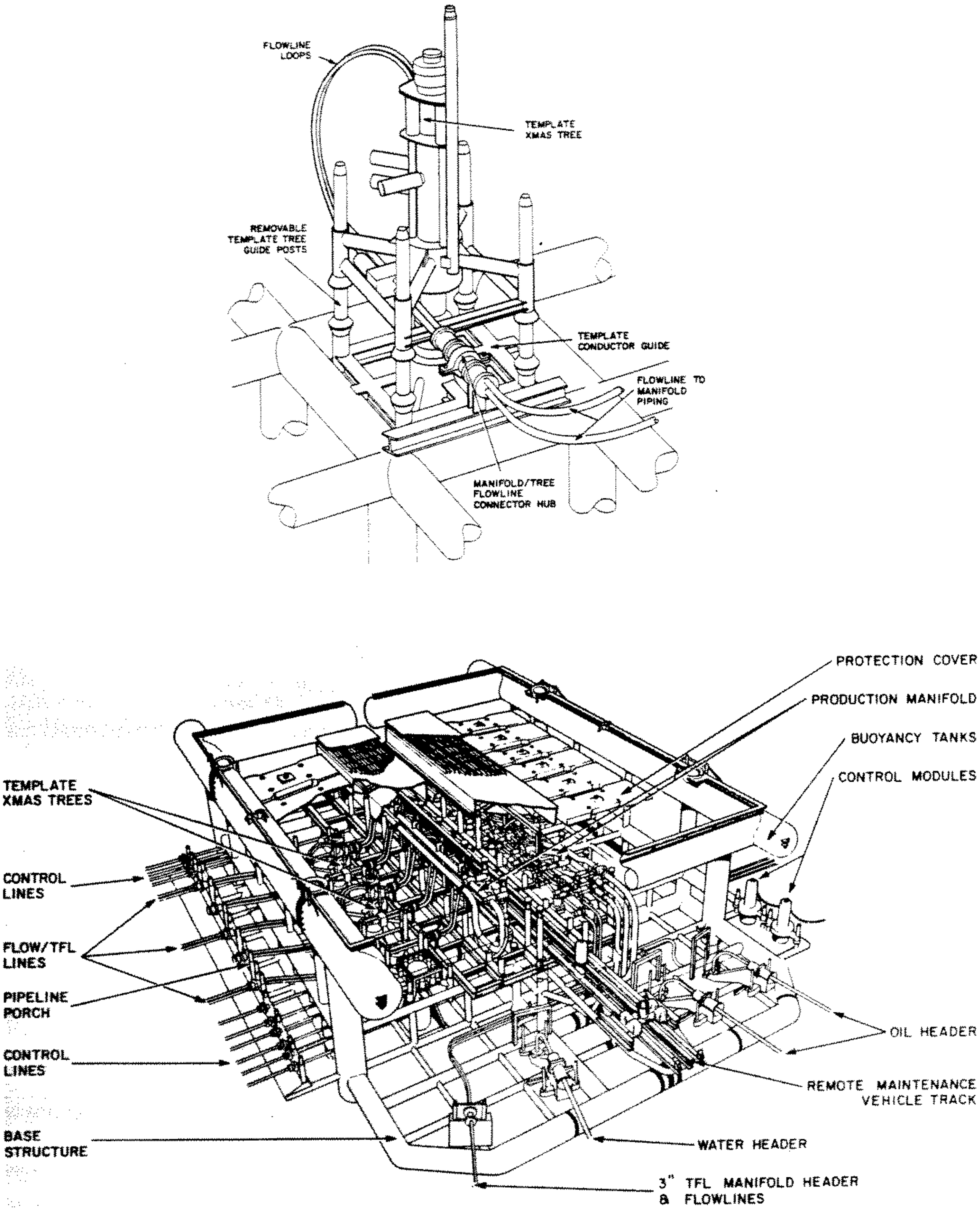


FIG. 24. THE CORMORANT FIELD UMC TEMPLATE AND XMAS TREE. (from ref. 120)

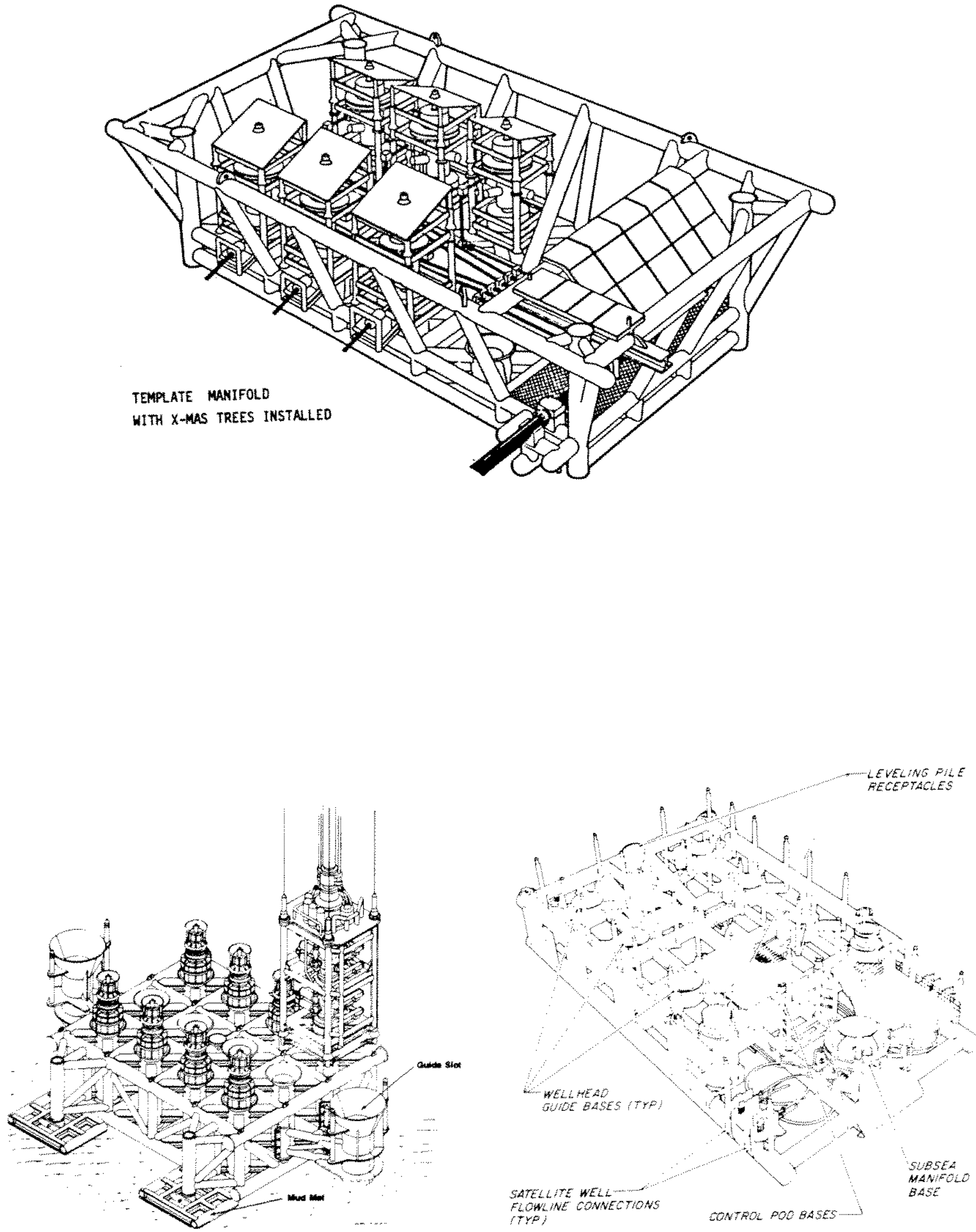


FIG. 25. NE FRIGG FIELD TEMPLATE MANIFOLD WITH XMAS TREES INSTALLED (ref. 133), CAMERON TEMPLATE WITH ONE TREE (left) AND THE ENCHOVA FIELD TEMPLATE. (ref. 70)

Schematics of the SEAL and the Cameron dry wellhead chambers are presented in Fig. 26. Since the SEAL chamber is no longer in operation and the Cameron chamber has not been used in the field, a description of these chambers and their operation will not be given. Instead, a description the CanOcean chamber (from ref. 76) will serve as representative of dry wellhead chambers in general.

The general arrangement of the Garoupa field where the CanOcean system is used is shown in Fig. 27. Also included in this figure is a schematic of the service capsule (SC) which is employed to transport maintenance personnel to and from the manifold center (MC) and the wellhead cellar (WHC) which are shown in Fig. 28.

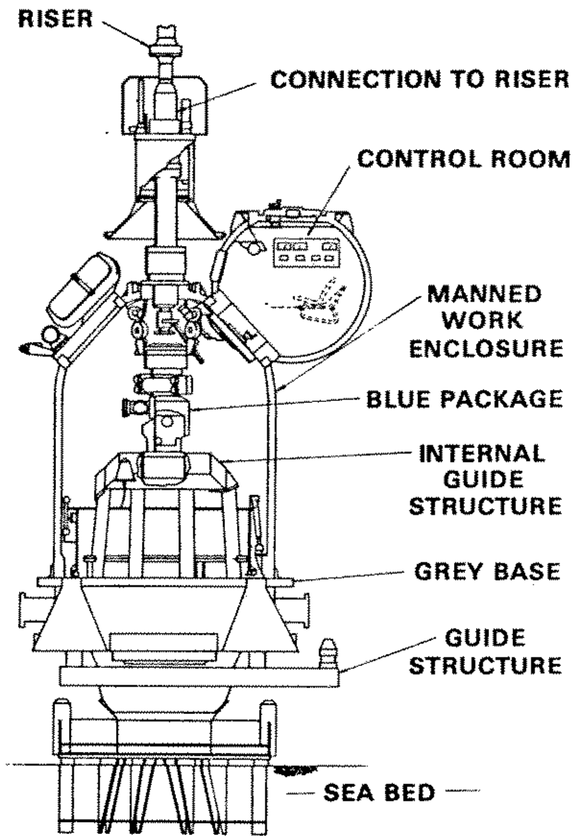
Manned access to the WHC and the MC is by means of the SC which operates from a surface support vessel moored over the chamber or center. The SC locks onto the chambers to permit access to the interiors for servicing the enclosed equipment in a shirtsleeve environment.

The WHCs are horizontal cylinders with semi-elliptical heads measuring 3.2 meters in diameter and five meters in length. A vertical trunk atop the chamber permits mating of the SC to the WHC. At the base of the WHC is a 425 mm spool penetration to which is attached either a 346 mm, a 425 mm or 540 mm connector. There are three connectors of each type on the Garoupa WHC. Each WHC contains the Xmas tree and control system for the well. The Xmas tree is a forged, two-block design. The lower block contains the manual valves, the upper block contains the hydraulically-operated master valves.

Production through both the 114 mm main production line and the 60 mm (OD) service line is made possible by a hydraulic crossover valve. Individual remotely operated pig launchers enable flushing and a variety of pigging operations through the flowlines. Well control is provided via a multiplexed electro-hydraulic control system with hydraulic override. The well control system is connected to the MC by a 25 mm hydraulic line and a separate electrical cable. The system monitors full range pressure, temperature and valve position.

The MC is a 4.6 meter diameter, 24.4 meter long horizontal cylinder. It is rated for manned occupancy to a depth of 122 meters. Eleven 457 mm and thirteen 254 mm bullnose ports are provided in the MC hull for pipeline and hydraulic/electrical line pull-in. Ten 254 mm ports are spares. Well production flows into the MC where it is mixed in a header. It is then delivered through two 273 mm lines to a process mooring tower.

The MC contains equipment for controlling well flow rates, well testing, inhibitor injection, pigging, and gas lift. The production in the MC is sized to handle a total production of 45,000 bopd with a GOR of 700 scf/bbl. The design incorporates piping headers, hydraulically-operated valves and multiple orifice flow control chokes which control and commingle the production from all wells.



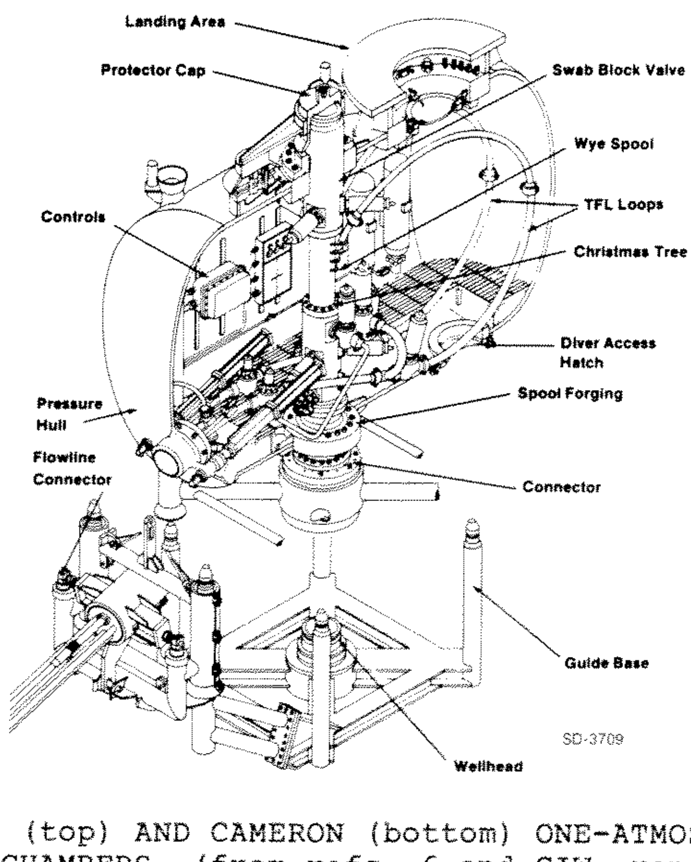


FIG. 26. SEAL (top) AND CAMERON (bottom) ONE-ATMOSPHERE WELL-HEAD CHAMBERS. (from refs. 6 and CIW, repectively)

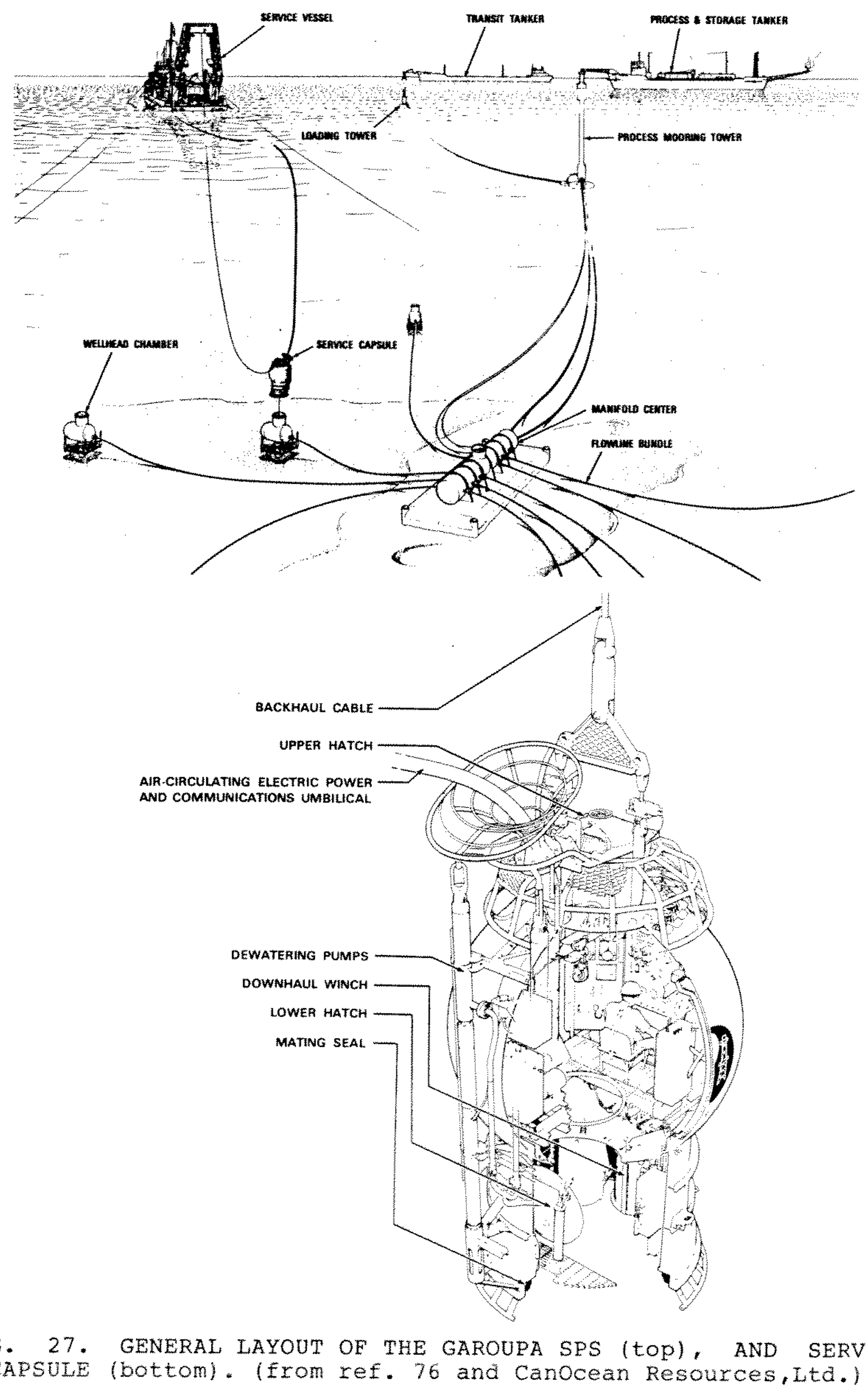
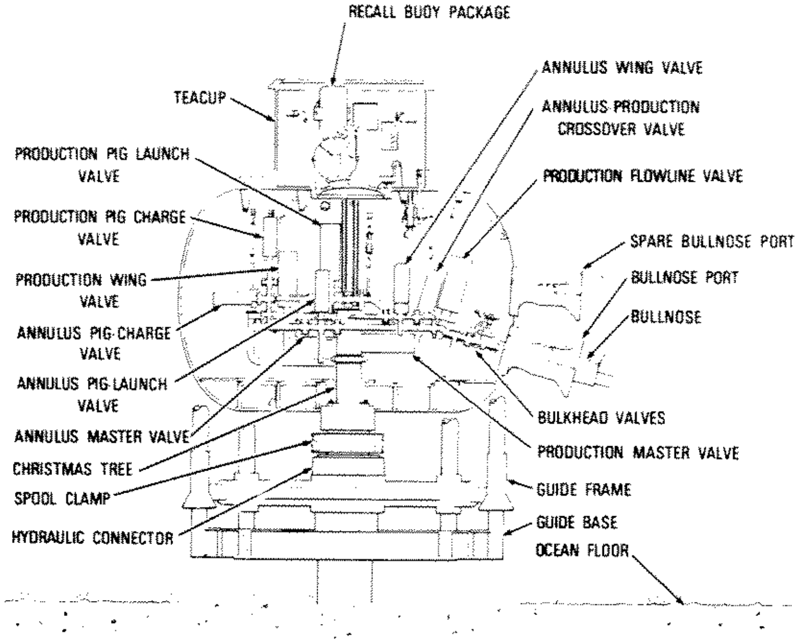


FIG. 27. GENERAL LAYOUT OF THE GAROUPA SPS (top), AND SERVICE CAPSULE (bottom). (from ref. 76 and CanOcean Resources,Ltd.)



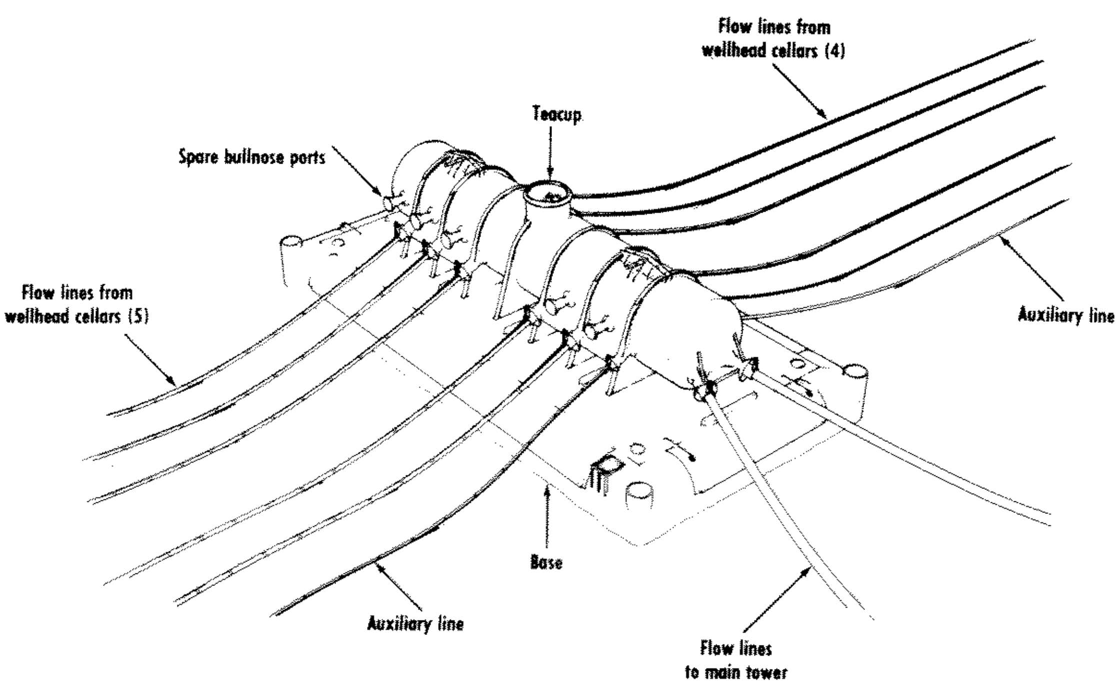


FIG. 28. GAROUPA WELLHEAD CHAMBER (top) AND MANIFOLD CENTER (bottom). (from ref. 76 and CanOcean Resources, respectively)

The MC is designed to hold a one-atmosphere, dry environment during all phases of its installation on the sea floor and during connection of pipelines and electrical cables. During unmanned periods the internal environment of the MC is kept inert with nitrogen. A gaseous and liquid waste disposal system prevents pressure or fluid buildup in the chamber.

The Garoupa MC was equipped with a base structure that also served as a barge for the tow from shore to the offshore field. The structure is divided into four hard tanks, four soft tanks and four trim tanks. The soft tanks and trim tanks are equipped with manual flood valves. The hard tanks with hydraulically-operated flood valves.

2.2 PLANNED AND DESIGNED SYSTEMS

2.2.1 Balmoral Field

The Balmoral field will be developed by North Sea Sun Oil using a floating production system based on the GVA 5000 semi-submersible. Production is planned to take place from 13 wells, with six peripheral water injection wells to maintain pressure and maximise recovery. These will be pre-drilled prior to installation of the semi-submersible.

The semi-submersible will be moored over a 14-slot template in the central area of the field. It will be connected to the template by means of a flexible riser, an application, according to Sun Oil, unique to the North Sea, but similar in concept to systems used elsewhere in the world. The entire subsea system will be electro-hydraulically controlled. The template will be built by Kestral Marine and measures 32 m x 34 m x 11 m with a weight of 860 tons. Vetco will supply the marine riser and the workover riser, 19 subsea trees for production and injection, including running and test tools, 16 (each) 352 kg/sq cm wellhead systems with tools, and three template-mounted subsea manifolds. (ref. 192).

2.2.2 Concrete Covers

Norwegian Contractors has initiated the development of an integrated SPS called Doughnut. The unit is intended for use as a template, mainfold system and as a protective shell for Xmas trees and control systems. The concept is to construct the concrete, toroidal-shaped Doughnut in a dry dock, tow it to the field and install it prior to drilling. The drilling operation will have been completed before the production platform has arrived and the two will be linked together by a production pipeline. The system is a hybrid in the sense that the wellheads will be wet, while the manifold area can be de-watered for access and maintenance. This also applies to the pipeline tie-in module, but the control system is enclosed within a dry, one-atmosphere chamber.

The Doughnut will be made up of compartments that will be either water-filled or can be de-watered, or will always be dry. Production equipment is classified according to reliability and located in the appropriate compartments. Technical data (from ref. 98) are presented below. A graphic representation of the concept is presented in Fig. 29.

Principal Characteristics

Diameter overall	33.6m
ID, torus	7.8m
OD, torus	8.8m
Diam. center compartment	8m
OD, center column	2m
ID, center column	1.4m

Water Depth

Operating depth	150m

Displacement

Tow-out, installed	76.4kN

Wet Weight

Concrete Structure	46kN
Ballast, solid	3kN
Production Equip.	5kN
Ballast Water	580kN
Total Wet Weight	40.4kN

Production

No. producing wells	2
Max. prod. rate	17,000bopd
GOR	1,200
Spare oil	2

Injection

Number	1
Maximum flow	15,000bopd

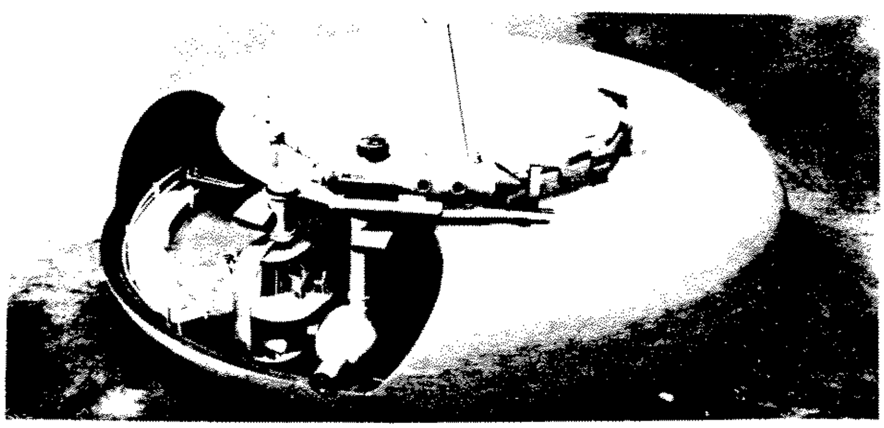


FIG. 29. ARTIST'S CONCEPT OF DOUGHNUT. (from ref. 98)

2.2.3 Satellite Manifold Center (SMC)

The SMC was developed by the UK consortium Deep Sea Production Systems (DSPS) composed of Sir Robert McAlpine & Sons Ltd., Humphreys & Glasgow Ltd., Rolls-Royce Ltd. and BICC Ltd. with financial support from the EEC Energy Directorate and the UK Department of Energy. The system was designed to 300 meters depth in 1981 and a feasibility study was underway at that time for development of a system to 1,000 meters.

The SMC's function is to develop marginal satellite reserves through a link to a central processing platform on the surface. Reportedly (ref. 105), the North Sea and other offshore areas contain marginal reserves that do not justify individual production platforms, but lie close enough to larger fields with existing or planned platforms that can perform a centralized production and process function. The competiveness of this technique, according to the project's manager, depends upon factors that include type of crude, reservoir pressures and flowing characteristics, water depth, and distance to the central processing platform.

The SMC pressure hull will be composed of reinforced concrete and will provide a dry, one-atmosphere interior for enclosed equipment. The reference design (Fig. 30) is based on six production wells and four water injection wells. The chamber is operated unmanned and is remotely controlled from the surface process platform. The chamber will weigh 2,850 tonnes in air. Manned intervention will be required for the initial commissioning and about annnually thereafter for inspection and maintenance.

All production wells are manifolded to receive TFL tools launched from the surface platform. Two production lines are looped within the chamber to enable pigging, also from the surface. The one-atmosphere environment within the chamber is continuously ventilated through umbilicals from the central processing facility. Electrical heating is provided during shutdown, and seawater cooling during production. The chamber's controls area is separated from the production area by a gas-tight dividing wall with air-lock entry doors. The area contains emergency life support facilities and can be ventilated with breathable air during manned intervention. The production area is continuously purged with nitrogen. When manned intervention is required in this area the occupants must be equipped with a portable breathing device or built-in-breathing system (BIBS). Life support and safety facilities are provided for three to five people. Personnel access to the chamber is by tethered capsule or by a free-swimming, submersible with dry transfer capability. The vehicle remains mated to the chamber during the intervention.

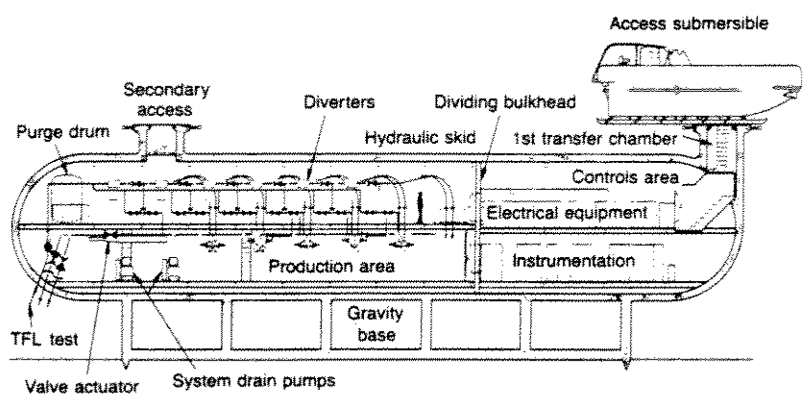


FIG. 30. THE SATELLITE MANIFOLD CENTER. (from ref. 105)

2.2.4 Diverless Installable and Maintainable Oil Production System (DIMOS)

DIMOS has ben designed by Norske Shell to obtain oil production in water depths beyond hyperbaric diving range . Initially it was planned for deployment in the Troll field, but that has been ruled out and its application is now aimed at a theoretical 21st century oil field (ref.202). The design study for DIMOS was finalized by Shell in 1982 and Kongsberg Vapenfabrikk was subsequently contracted to conduct a concept study of the manifold center which constitutes the heart of the system.

DIMOS is designed to permit production of up to 60,000bopd from 12 subsea caisson-completed wells. Eight water injection and six gas injection wells are also included.

DIMOS consists of nine major components: the guidelineless insert tree system (GLLITS); pipelines and control lines; manifold centers; a riser base; a free-standing riser; a flexible fluid transfer system; a semi-spar (Shell's floating production, storage and tanker loading platform); a tethered maintenance vehicle, and a Multi-Service Vessel (MSV) used to deploy the maintenance vehicle.

Flow and control line bundles will connect every satellite Xmas tree to one of two subsea manifold centers. This permits the transport of hydrocarbons as well as the control and TFL servicing. The bundles will also permit the supply of appropriate injection fluids.

The manifold center will collect the produced well fluids and will distribute gas or treated sea water to the reservoir injection wells. It will also direct the TFL tools for maintenance of well completions. Additionally, the center serves as an alignment and support structure for the control and valve equipment plus the pipework and pipeline or control line connections. Four pipelines will connect each manifold center to a common riser base. The piled riser base and multi-bore riser will provide the links between seabed lines and the surface facilities. (ref. 228)

2.2.5 Deepwater Subsea Production System (DSPS)

The DSPS is an extension of Vetco's Early Production System (ESP), both of which rely upon a floating production platform. The ESP systems consisted of the modular template system and the unitized template described in sect. 2.1.1.b and ref. 54, and a multi-well satellite system (several individual subsea wells tied to a production riser base with subsea flowlines and control lines). The ESP systems were designed to use guideline techniques for re-entry operations throughout the drilling, completion and production phases of field development. The DSPS, however, is designed to employ guidelineless re-entry techniques. Also, the ESP systems were designed to interface with standard semi-submersible drilling vessels converted for use as production platforms.

For DSPS applications a specifically designed floating production platform is desireable. This unit must have dynamic positioning (dp) and facilities to unload procesed fluids at the surface. Its size must be tailored to enable it to support the treatment facilities to handling production from a large number of wells.

Guidelineless re-entry is made possible by the use of sonar and TV to align and orient the mating subsea components. To compensate for the margin of error inherent in sonar systems, a mechanical funnel is provided at each wellbay for final alignment and orientation. In instances where equipment of sizable mass is to be landed, a latch bumperhead technique is used to prohibit lateral movement and consequent damage to nearby equipment. The technique employs an alignment tool that extends considerably below the equipment to be landed. The tool is stabbed into, for example, the wellhead housing and provides a mechanical link along which the equipment can be guided while being restrained from lateral movement during the final stages of installation. The latch bumperhead is retrieved on a drillpipe running string after the equipment has been landed.

The DSPS (Fig. 31) is comprised of a predetermined number of individual wellhead clusters each consisting of a template with receptacles for six subsea wells. These clusters are connected to a centrally located riser manifold template by a pipeline, two

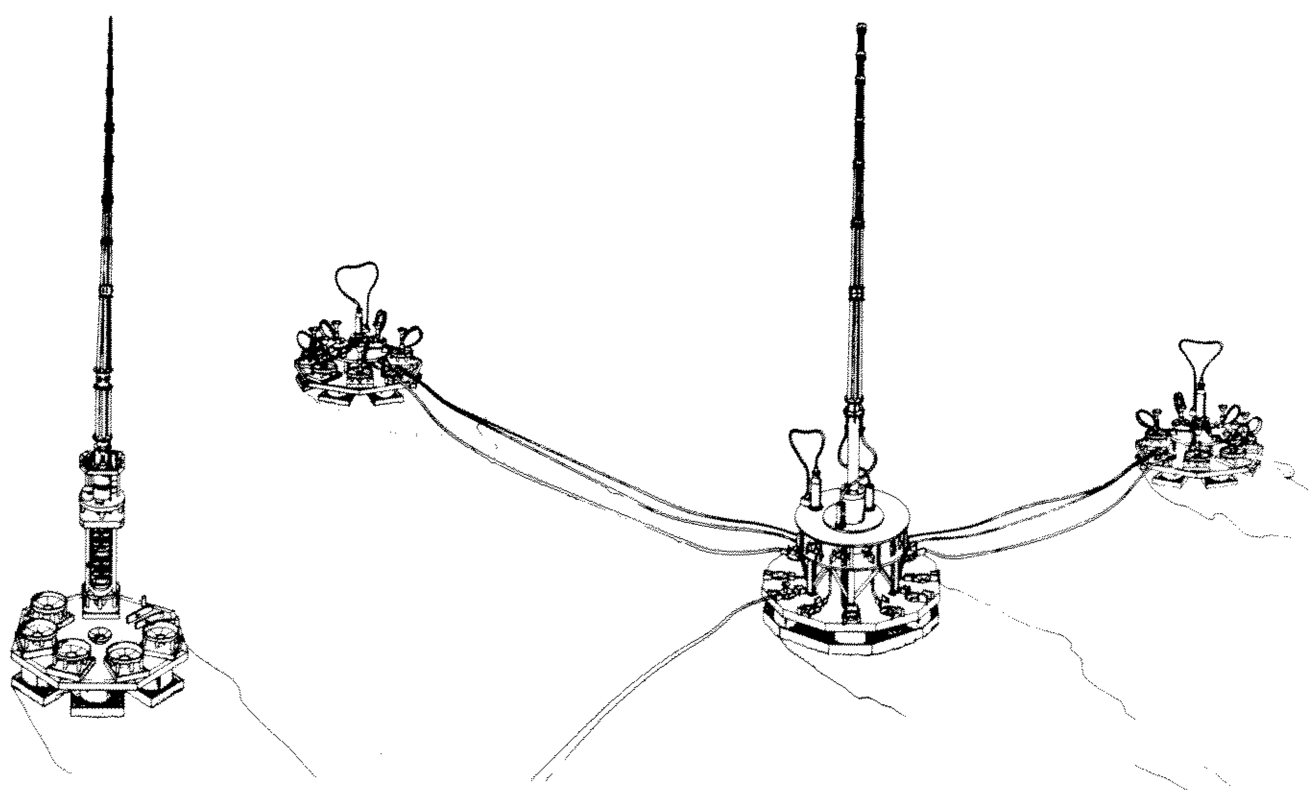


FIG. 31. THE DEEPWATER SUBSEA PRODUCTION SYSTEM (from ref. 59)

service lines and a control line. In this manner production from a number of subsea wells can be collected at the base of a single production riser system. The production riser is connected to a floating production platform from which the processed fluid is loaded into tankers.

Five major sub-systems form the deepwater production system:

The single-well drilling and completion system which includes the wellhead equipment and completion trees.

The drilling and production templates, each providing receptacles for six wells and accepts a retrievable manifold unit.

The production riser manifold template which serves as the anchor point for the production riser system. The pipelines, service lines and control lines from the well clusters converge at its perimeter.

The deepwater production riser whose center core transports production fluids from well to surface, while the service lines and control lines are supported alongside.

The floating production platform. Specifically designed to handle the production riser system, perform first-stage production fluid treatment and TFL well maintenance.

(The foregoing description was taken from ref. 59.)

2.2.6 Goodfellow Associates Submerged Production System (GASP)

The objectives of the GASP design are lower maintenance costs, lower production costs and minimal downtime for development of marginal fields. The GASP system is based on a subsea template/manifold with three to six wet trees tied back to an articulated offshore loading column. The manifold is operated from a control center on the column through a multiplexed electro-hydraulic system. Production from the manifold will be in the neighborhood of 40,000 bopd with up to eight days storage at the base of the column. The system may also be used for development of oil condensate and gas fields. Three vertical separaters installed on the manifold would separate off sand and water before the gas was piped to a nearby platform.

The manifold would be maintained ideally once every two years from a special workover riser deployed from a service vessel. The manifold might also be incorporated on a semi-submersible or work barge which would then be submerged and placed over a subsea template. For maintenance or when the field is depleted the submersible or barge could be retreived and re-employed in another field. (Offshore Engineer, Sept. 1983)

2.2.7 Gullfaks Field

Concept studies for the Norwegian Gullfaks field established that the best production solution for this field would be a diverless, non-TFL, wet satellite system. The satellite wells are located out of reach of the platform wells, and six wellheads are anticipated. Five wells will provide accelerated production, the sixth will be used for backup and replacement if necessary. Two of the wells will commence production in the summer of 1987, the remainder are scheduled for 1988. The design life of the first two wells is five years, the remaining wells are designed for ten years. A generalized layout of the entire Gullfaks field is presented in Fig. 32.

The subsea wellheads will feature:

- Metal-to-metal seals throughout the permanent production equipment.
- Minimum maintenance requirements.
- Diverless operations (although the 140 m depth of the wellheads is within diver depth) and compatibility with ROVs.
- Maximum amount of field-proven equipment.

Piloted hydraulic and multiplexed electric techniques have been selected for control and monitoring of the subsea components. The trees will be monitored by the control system and valve positions will be inferred from pressure supplied to the actuators. The actuators interface with a single insulated flowline via a diverless flowline connection system which will also be used for the hydraulic umbilical and electrical control cable. The trees and control system will be protected by an open frame structure that will permit either diver or ROV access to the trees. (from refs. 192 and 213)

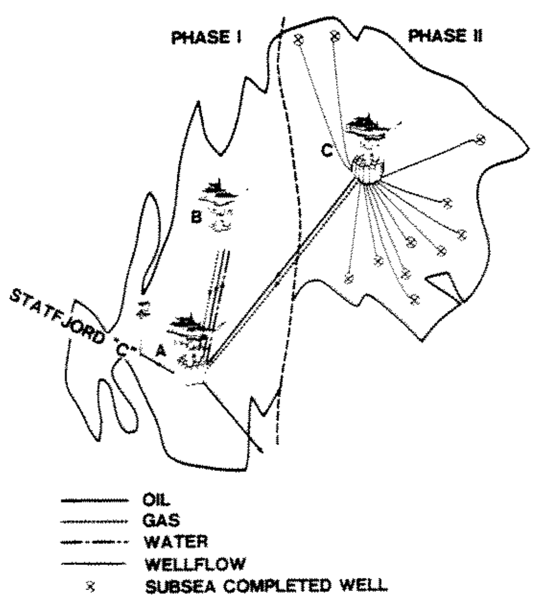


FIG. 32. GULLFAKS FIELD DEVELOPMENT. (from ref. 213)

2.2.8 Poseidon Project

The Poseidon project is being conducted by Statoil, IFP (Institut Francaise du Petrol) and Total. Its goal is to develope the second generation of subsea production techniques. According to Noroil (June, 1984), first generation subsea developments tested the efficiency and reliability of such technology located only a few kilometers from treatment facilities. After these tests proved successful, the next phase was to initiate the following developments:

- single or clustered subsea wellheads compatible with downhole multi-phase pumping.

- Flowline from the wells to a subsea manifold.

- An entirely retrievable, modular subsea station including polyphasic boosters with ancillary equipment, valves and a subsea pig launcher.

- A multi-phasic pipeline from the manifold to an onshore process unit.

- A power supply and remote control line from shore to manifold.

The system is based on the availability of an original pump developed by IFP and Total . The pump is capable of pumping two-phase fluids with high GORs. A pumping system of this type would be installed directly on the seabed with the cluster of the wellheads and the manifold. It would provide the energy required to transport the product at distances up to 200 kilometers through a single pipeline running to the shore.

The project associates believe that successful attainment of these goals will be the key to future offshore development because: 1) in water depths of less than 200 meters, within 200 km from shore, it could more than halve development costs; 2) for small fields with a high GOR it could prove to be the only possible development scheme; 3) for large fields Poseidon becomes more appropriate if the environmental conditions are difficult, and 4) investment and operating costs are better balanced and financing is progressive.

Difficulties reportedly still exist, such as, erosion/corrosion, reliability monitoring of the full technique, etc., but the project investigators feel that applications will be found within five to ten years from now. (from Noroil, June 1984)

2.2.9 Single Well Offshore Production System (SWOPS)

The SWOPS is not a SPS, but may serve as a surface component of one. SWOPS is a low-cost, production/storage system designed to extract oil directly from subsea wells and to provide an inexpensive method of conducting well tests. The system, contemplated primarily for application to marginal fields, consists of the following components: 1) a dynamically-positioned tanker fitted with integral processing equipment and storage; 2) a conventional subsea well completed to accept a SWOPS riser, and 3) a rigid riser system operated through a moonpool in the center of the vessel.

Construction of the system is planned by BP and Harland & Wolff, and, at this time, it is figured for its first application in the North Sea`s Cyrus field. The vessel will be completed in mid-1987 It will have a length of 250 meters, a beam of 37 meters, draft of 10.6 meters, a processing plant of 15,000 bopd and a dynamic positioning system capable of station-keeping in Beaufort Force 9. The riser will be attached by remote control to the wellhead. The SWOPS vessel will have facilities for two-stage separation. The crude will be loaded into cargo tanks and the water produced with the oil will be diverted to special slop tanks for treatment. Some of the gas produced during loading will be used to power the vessel while on-station.

Once an exploratory or appraisal well is completed in the conventional manner from a drilling vessel, the wellhead is then lowered on conventional guidelines and capped with a SWOPS reentry hub. The design permits re-entry and connection of the production bore with the riser without rotational orientation of the riser connector before mating with the wellhead.

Although originally intended to produce from a single well, the present design now allows for commingled production from two deviated wells drilled from the same location. (from ref. 198)

2.2.10 Subsea Atmospheric System (SAS)

The SAS is a completion system that combines both wet and dry subsea technology. Being developed in a joint effort between Mobil Research & Development Corp and Kvaerner Engineering, the system may see its first application in the North Sea`s Beta reservoir in the Statforjd field.

The SAS is the central component of a deep water production package for use in a variety of combinations. It comprises a circular template through which up to nine wells can be drilled, and a central, circular one-atmosphere chamber housing control equipment and production valves. Oil and gas production, as well as water and gas ejection, would all be controlled remotely from the surface. Workers will be able to enter the atmospheric chamber from a submersible which mates onto a hatch at the top of the chamber for periodic maintenance. The atmospheric chamber is split in two: the upper control section is air-filled, while the lower service section which houses all valves and flowlines is filled with nitrogen to reduce the risk from fire or explosion. Up to 14 control and flowlines will connect the SAS either directly to a nearby platform or to a riser manifold designed to receive produced fluids from as many as four SAS units. From the riser manifold fluids will either be piped to a nearby platform or, via a compliant riser system, to a floating production facility. Conventional wet Xmas trees will surround the chamber. Similar to the one-atmosphere, dry SPS installed in the Garoupa field, a manned submersible will be used to transport men and materials to and from the SAS.

The SAS is designed to operate to a depth of 800 meters, but has the potential for operating to 2,000 meters. The system is designed to be installed and operated without employing divers and consists of five major components plus a manned submersible. From the seabed up, these components are as follows:

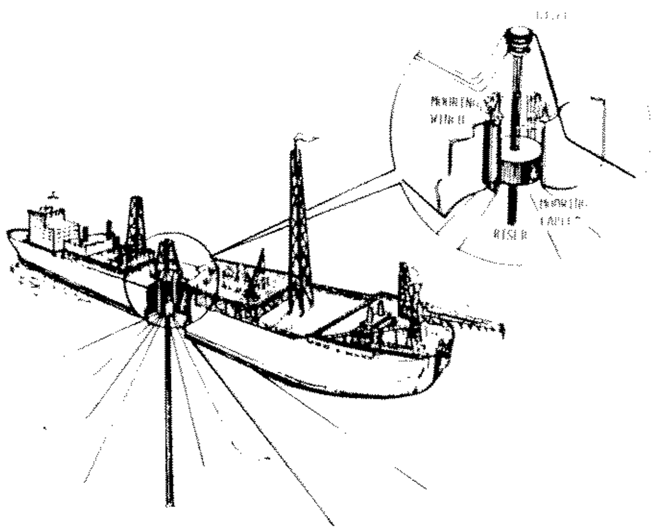
- Subsea Atmospheric System: Consisting of the well template and manifolding center for nine wells. (This has been built and tested.)
- Deep Water Flowline: A flowline bundle connecting the SAS and the riser manifold and containing production and control fluids and life-support gasses.
- Subsea Atmospheric Riser Manifold (SARM): The habitat at the riser base which comingles fluids from up to four SAS units.
- Deep Water Compliant Riser: The connecting link of production, control, life support piping and control cables between the ocean floor and the surface. (Has been model tested and fatigue tested.)
- Floating Production Facility (FPF): This is the moored vessel which is the heart of the system and accommodates production, storage and offload facilities.

The preceding components are depicted in Fig. 33. The foregoing information was taken from ref. 176 and 195.

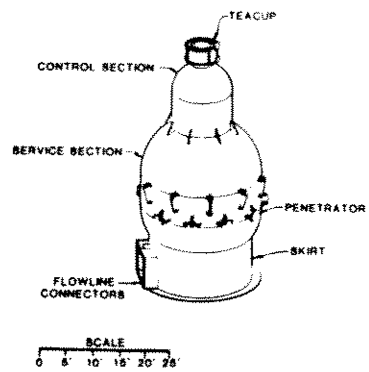
2.2.11 Subsea Wellhead Installation and Maintenance System (SWIMS)

Under contract to CEPM, the French engineering firm Technip Geoproduction has developed a revised version of the SWIMS which was originally and successfully tested in 1978 by Comex in the North Sea. The original system design was not compatible with present day engineered wellheads, but modifications which include an adapter to convert an ordinary tree cap receptacle into one which accepts a SWIMS tree cap have been made.

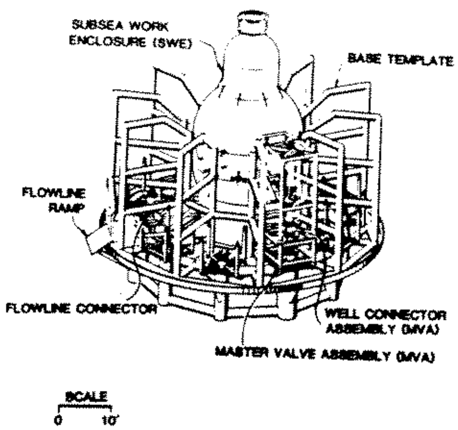
The SWIMS cap requires guideline installation, but the re-entry running tool is diverless, and contains a hydraulic connector which fits into the upper subsea tree profile with corresponding production and annulus bores. Other components of the running tool comprise a spacer, subsea BOP and an emergency disconnect system.



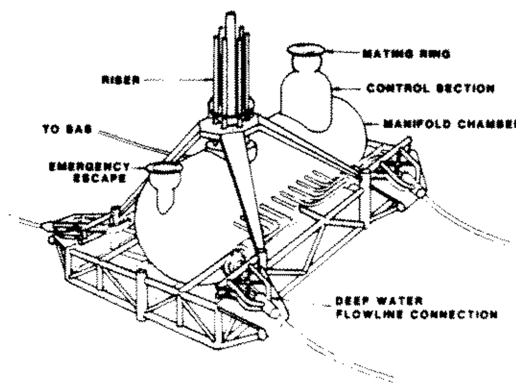
Floating Production Platform



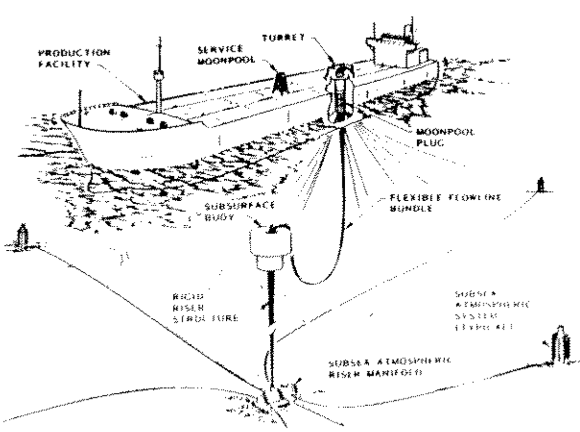
Subsea Work Enclosure



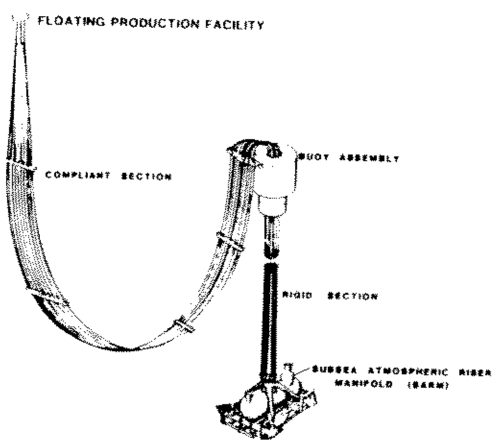
Subsea Atmospheric System



Atmospheric Riser Manifold



Deepwater Production System



Compliant Riser

FIG. 33. MAJOR COMPONENTS OF THE SUBSEA ATMOSPHERIC SYSTEM. (from ref. 176)

A riser unit is utilised for both installation, maintenance and repair requirements of subsea trees. Some of the main functions include: downhole wire operations; in-well circulation, and subsea tree installation or recovery. Maintenance of subsea production hardware, such as the control pod, acoustic beacon, choke, etc., and SWIMS can also be used for pig launching. The system provides for guidelineless and diverless re-entry of the riser unit and the use of non-specialized dynamically-positioned (dp) support vessels. Intervention is now designed for existing trees previously fitted with an adapter equipped with a SWIMS re-entry profile. (from Noroil, Sept. 1984)

2.2.12 Troll

The Troll field is located in the Norwegian sector of the North Sea at a maximum water depth of 340 meters. The operator, Shell, presently leans toward seven four-well and two two-well subsea templates to complete the field, but may reduce the number of four-well templates and increase the number of two-well templates or single-well satellites. The four-well templates, in Shell's opinion, offer maximum reservoir coverage with minimum sea floor and platform congestion.

Preliminary evaluations indicate that wireline well servicing has considerable advantages for the Troll field. This decision was based on the low demand for bottom hole pressure monitoring, reliability of tubing retrievable subsurface safety valves, and the high probability that a semi-submersible will be available in the field area to meet rapid intervention requirements The system will be diverless and will rely on maintenance by a ROV and modular replacement. (ref. 191).

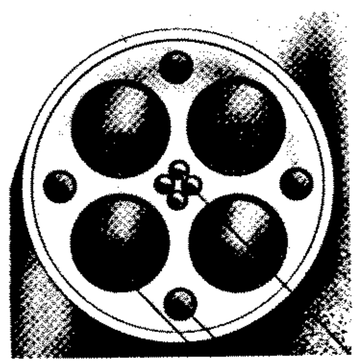


FIG. 34. Projected flowline bundles. The bundle (66cm OD) contains 15cm oil lines, 5cm gas lines and 2.5cm injection lines for chemicals. (from ref. 191)

Specific areas where significant advances in the state-of-the-art technology have been identified by Shell, and they are considered as being primarily associated with flowline bundle (Fig. 34) installation and flowline hookup techniques. Three techniques for installation are being evaluated: mid-depth tow, reel barge and J-lay. The "first-end" connection at the production platform will be made using the J-lay technique. But the "second-end" connection at the subsea template is reported to represent a significant technical challange beyond the level of current proven technology.Problems associated with the second-end connection are: the 340 meter depth, which precludes diver intervention and reduces the degree of control that can be exercised by a surface vessel; strong, variable bottom currents, and the size of the flowline bundles which create complications regarding minimum bend radius, stiffness and submerged weight.

2.2.13 The Neutrabaric System

This system was designed and constructed by Vickers-Intertek, and combines aspects of both the wet and dry systems. Ref. 33 defines the neutrabaric system as a combination of water-filled, subsea-located pressure vessels containing equipment to which manned access is required. Within these vessels the pressure may be reduced to a nominal one-atmosphere (absolute) pressure by mating on a dry, one-atmosphere (absolute) pressure, air-filled personnel transport unit and using its reference pressure to effect the neutrabaric depressurazation. Personnel may then enter the vessel and work within the one-atmosphere, water-filled chamber as if they were in a swimming pool and incur no decompression penalties.

The system (Fig. 35) encapsulates a Xmas tree within a spherical chamber some three meters in diameter and the chamber is filled with sea water at ambient pressure. A second water-filled chamber is required to house control and auxiliary equipment and is inter-connected to the first chamber. A third chamber or a submersible which is dry, and at one-atmosphere, can mate to the control chamber.

Sea trials of this system took place in August 1978 off the west coast of Scotland. The three-week long trials (sponsored by nine British, Norwegian and U.S. organizations) were carried out in two phases: a shallow test in 25 meters and a deeper test in 130 meters. Reportedly, there has been renewed interest in the technique and it is scheduled for installation in the North Sea in the near-future.

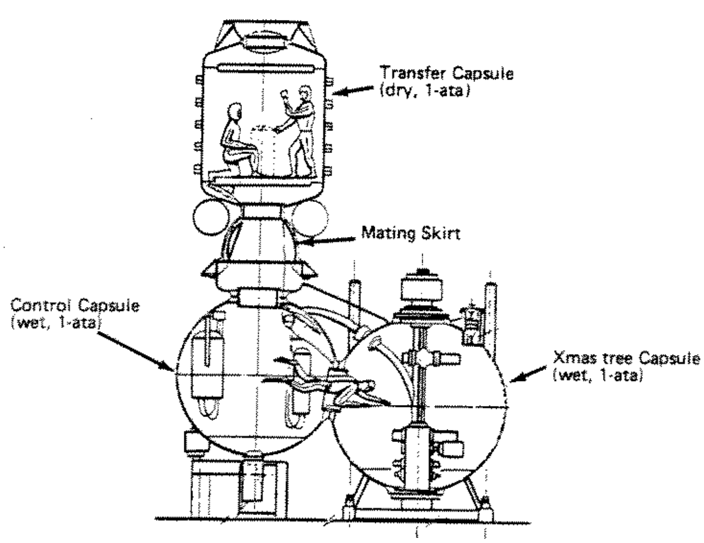


FIG. 35. THE NEUTRABARIC SYSTEM (from ref. 33)

3.0 UNDERWATER INSPECTION PROGRAMS

The objective of current underwater inspection programs for offshore platforms is to assure that the structure has maintained its structural integrity within prescribed limits. A fixed platform is subject to variable and dynamic forces that constantly operate to its detriment; while it is striving to support a massive load above the water's surface. Underwater platform inspection programs, therefore, are primarily assessing the structure's capability to support the surface components. If this support should fail, then there may be a consequent reflection in terms of human safety, environmental impact or loss of production. The SPS, on the other hand, has no such load to support; the "dry" systems are only infrequently visited by human beings, and, for the most part, the SPS is beyond the influence of sea surface dynamics, strong water currents, severe marine fouling and ramming by supply boats, barges or icebergs. As the depth of SPS deployment increases, the factors which work to the fixed platform's detriment decrease. Currents lessen, water temperatures are more constant, sea and swell can become insignificant, fishing (i.e., trawling) activities decrease, ramming by ships and icebergs and ice islands decrease, and the possibility of fouling by ship's anchors can be reduced to almost nil. When and if a "wet" SPS fails the consequences might be to the detriment of the environment and are definitely to the detri- ment of production. Except for the dry systems, SPS inspection is aimed at assuring continuous, safe product flow, and is much less concerned with the system's capacity to support a load.

Although SPSs have been in use since the 1940s, it has only been within the past few years that the subject of post-installation underwater inspection has arisen. It is important at this point to re-emphasize that the concern herein is underwater inspection. It does not treat inspection of the riser or the product collection/processing platform on the surface. It is also important to note that there are a host of regulations that deal with inspection of the "floating" elements of a subsea production system.

Similar to fixed platforms, underwater inspection programs for SPSs can evolve from two sources: the operators of the SPS and the governments within whose waters they are operating. Before reviewing the progress within these areas, it is instructive to examine the performance of SPSs to date in order to identify which components of the system are critical to inspect, and to gain an appreciation for how well the current inspection procedures are working.

3.1 SPS PERFORMANCE

The following information was obtained from published reports and interviews from operators of SPSs. Being only human, these sources tend to (in the words of an old song) "accentuate the positive and eliminate the negative". Consequently, the data should be considered skewed to some degree to the affirmative.

3.1.1 Reliability

Although the problem of reliability was recognized in the very early days of SPS employment, it was not until the mid-seventies that published reports of the problem became public. A 1978 article in the trade journal Noroil, stated:

> "There is apparently unanimous agreement in the industry, at least among the oil companies, that control systems are not reliable enough. Shell identifies these along with reliable switchgear and valves, better hydraulics and electrical systems, and fatigue problems for flowline risers as being areas for more development. `Corrosive fluids, troublesome reservoir conditions and certain artificial lift problems could make an improperly designed or equipped subsea completion project disasterous from a maintenance standpoint,' wrote a trio of experts from Phillips Petroleum and Guy Management services in a recent journal of Petroleum Technology.
>
> Certainly maintenance work on the Beryl subsea completion installed by Mobil on the single Brent system and other experimental units has been extensive, and there is growing concern in government and industry over the vulnerability of seabed pipelines and flowlines to fouling by service vessels in congested infield areas."

The reliability of "diverless" SPSs posed an even more difficult problem since, if the system failed, human intervention to effect repairs could be impossible. Offshore (ref. 79), reporting on the reliability question stated that present (1979) diverless installations are not reliable enough never to require manual intervention. The article mentioned Shell Expro's intensive research program to develope a wet SPS with high reliability, this was part of the preliminary research and development that preceeded deployment of the UMC.

Apparently somewhat prematurely, Phillippe de Panafieu, Technical Director of Flexservice, France, is reported (ref. 68) to have said that the subsea equipment (in 1979) is proving its reliability and what problems that have arisen have tended to be more from external influences, such as trawl boards cutting control lines, than from the equipment itself.

Exxon conducted a survey in 1980 to determine the producing well availability of those subsea systems for which operating and maintenance information were available. The data covered less than 200 well-years of operating experience, considered much less than what was necessary to establish reliable statistical trends. Nonetheless, the well availability of subsea systems in the North Sea and the Gulf of Mexico, located in water depths ranging from 10 to 150 meters, reached the 80 to 90 percent range in some instances. Well availability was not noticeably different between mild and heavy weather conditions or between shallow and deep water. (ref. 108)

In a 1982 article the magazine Ocean Industry (ref. 129) presented the results of a survey conducted by its staff. Respondants to the survey expressed more concern about the reliability problem than any other single technical problem. Half of the respondents mentioned the reliability of one or another component or subsystem as a problem to be solved before subsea completions will become widespread. Controls were the components most often described as unreliable. Two manufacturers were concerned about flowline connections and tie-in systems, and one about make-and-break electrical connectors.

In ref. 151 the statement was made that the quality of underwater trees is rarely questioned, but the durability or efficiency of control systems can pose a considerable problem. The early hydraulic systems functioned well over short distances, but over longer distances response times became unacceptable because of expansion characteristics of hydraulic hose.

In an article describing North Sea subsea completions (ref. 163), Mr. P. Grange stated:

> "The reason that operators have been slow to take up the subsea process in the past is chiefly lack of confidence in reliability and the continuing need for maintenance including diver access. They still doubt equipment manufacturers' claims that all the old bugs have been ironed out. However this problem has now largely been overcome and over the next few years the longstanding contest between theoretically cost-effective, high technology equipment and traditional, field-proven completion systems will be resolved. The two concepts will tend to merge and already such concepts as multiplexed, electro-hydraulic controls are becoming accepted for even diver-inaccessible locations."

3.1.2 Field Performance

In view of the foregoing, it is interesting to review the published reports regarding performance of SPSs that have been subjected to the stresses of long term production and testing. In a 1981 article Booth (ref. 107) related statistics (from Woodward, A., 1981 "Logic can predict catastrophic subsea production leaks." Subsea Production Annual Review) that the generally accepted figure of no leaks occurring during a 90,000 hour production life of the original completion is about 96 chances in 100. This article further noted that more fires and uncontrollable blowouts occur during workover than during drilling and completion, and every time original joints are parted and made up again their risk to subsequent leakage increases and their service life between further workovers is reduced. A workover, according to Woodward, will achieve about 0.9706 of the stated reliability or worse.

3.1.2.a Comex Seal SAS

The 1-ATA Comex Seal SAS remained four years underwater at 76 meters depth in the Gulf of Mexico. According to R. Seid (ref. 36), there were only two occasions when intervention was necessary to effect repairs. The first was to correct a hydraulic leak in the control room section of the SWE. One month later a fuse blew within the SWE which shut down communication with the supervisory control system. This fault was also repaired. Several of the flowlines failed completely. After conducting tests to assure suitability of flexible flowlines, and to determine the exact reasons for failure, replacement lines were manufactured and subsequently installed. More than 50 entries were made into the SWE over a one year period. During these entries, in addition to other chores, inspections revealed no other breakdowns.

The SWE was retrieved in 1976. Prior to retrieval a diving inspection was conducted to determine the actual status of the SAS after the four years submergence. Results of the survey, according to Seid, showed the SAS to be in remarkably good condition. Most connections and piping were found to be in good condition, free of fishing nets, lines, marine growth or fouling. The greatest fouling was found on flowlines and it was determined that clamps would have to be disconnected by burning off the securing bolts. Divers reported marine growth on the base, but did not report visible damage from corrosion. They did, however, report that eight 5 cm. vent valves and four 7.6 cm. flood valves on the base appeared to be frozen open. An internal test of the SWE control section was carried out which indicated that the interior was dry and slightly above atmospheric pressure by 3.115 psi. The SWE power and control cable was checked on the surface and results showed that installation and continuity were good.

3.1.2.b Argyll

The Argyll field came onstream in 1975, the following table (from ref. 82) summarizes its operational history.

YEAR	1978	1979	1980	1981	1982	1983	1984*
Total downtime %	39	33	33	49	34	25	22
Occasions riser pulled	6	3	5	4	6	4	1
Occasions loading shutdown	19	16	22	21	17	38	14

* To 1 October

The major influence on output was the capability of tankers to moor and load at the SBM. Waiting on the weather to abate typically accounted for around one quarter of annual downtime.

Significant major events have included repairs to the platform in 1978, 1980 and 1981 and to the SBM in 1978 and 1979. SBM faults have caused at least one-third of all downtime over a period of several years. In 1978 a crack was found in the loading line to the SBM which was enclosed by the modular manifold. The entire manifold was replaced in 1979. In November 1981 a seven week break in production began when a weak link in one of the rig's 12 anchor chains failed during a storm that approximated design conditions. This break triggered progressive failure of the remaining moorings and resulted in a two day drift of 40 kilometers. (ref. 82)

3.1.2.c Garoupa and Other 1-ATA Wellheads

The following data relates to the experiences of CanOcean's 1-atmosphere wellhead chambers and manifold centers, the greatest numbers of which are located in the Garoupa field, but also in the Gulf of Mexico. (This information was provided by E.E. Sjoholm of CanOcean Resources Ltd. and from ref. 121)

First production in the Garoupa field began on 11 February 1979 and the total production through 1 December 1981 was 16.9 MMbbl (estimated). Lost production due to subsea maintenance (miscellaneous gas leaks, downhole safety valve replacement, bottom hole pressure survey, control system remote terminal unit servicing) to December 1981 was 1.3MMbbl. The up time for this first well was 92.52 percent, and it was anticipated that this performance would improve once the initial startup period was completed. This forecast proved quite accurate as evidenced by the % Time Availability of the Garoupa field in Table 14. Also included in this table are summaries from other fields utilizing 1-ATA wellhead chambers.

3.1.2.d Cormorant

The performance of a single satellite subsea wellhead installed in 152 meters in the Cormorant field is presented in ref. 134.

Prior to startup of the well on 1 January 1981, extensive functional and pressure tests were carried out to confirm the integrity of all systems. The well produced from this date to 24 April 1981 when the platform was shut-in for major hook up work unrelated to the satellite well. The well had cumulatively produced 630,000 bbls of oil with an average rate during the period of 6,500 bpd. During this production period downtime on the well averaged less than five percent with half of this being due to platform-generated alarms unrelated to the subsea producing system.

Production recommenced on 11 October 1981. By the end of 1981 the well had produced over a million barrels of oil and continued to have an uptime rate ranging from 96 to 97 percent. The authors of this report felt that a major contributing factor to the success of the well was the extensive testing of all components prior to going offshore.

TABLE 14. SUMMARY OF CANOCEAN RESOURCES 1-ATA SPS PERFORMANCE

FIELD	DAYS ON PRODUCT	DAYS TO FIX	MTBF DAYS	% TIME AVAILABLE	REMARKS
GAROUPA					
MC	1994	33.1	199	98.16	Mainly controls
NA1	1861	18.9	372	98.73	
NA2	1546	29.5	193	97.82	Frequent valve leaks
NA3	1606	38.4	201	97.27	Same as above
GP7	1525	19	508	98.13	
GP8	1994	135.6	181	92.52	Major downhole problems
RJS9A	1634	11	409	99.10	
RJS19	1676	37	186	97.52	Frequent valve leaks
SUMMARY	13836	322.5	271	97.62	
GULF OF MEXICO					
SHELL					
MC	1017	22.5	170	97.35	Abandoned after test completion
SAT1	1131	9	377	98.81	Same as above
SAT2	1258	4	419	99.52	Same as above
290B	4343	15	869	99.57	
010	2666	34	533	98.41	Methanol leaks
TENNACO	1426	17.5	238	98.53	Recovered
UNION	2966	24.5	494	99.01	Rumored watered-out 30 June '84
GOM SUMMARY	14807	126.5	529	99.11	Hard to beat
SUMMARY PERFORMANCE	28643	449	367	98.41	

MTBF: Mean Time Between Failures
GOM: Gulf of Mexico

3.1.2.e Molino

The Molino gas field wet trees were installed in 73 meters of water off the California coast in 1963. A total of ten trees were installed which produced more than 630 million cubic meters of gas and 4.4 million bbls of condensate over a 20 year period. One of the trees (No. 4, belonging to Phillips Petroleum) was intensively examined after it was brought to the surface. The results of this examination were presented by Gundersen (ref. 232), from which the following data were extracted.

The Vetco-supplied tree was installed in 1963. It was pulled during a workover in September 1968 and subsequently returned to service. In January 1983 the tree was pulled for detailed examination and evaluation. The primary objective of this examination was to investigate in detail the condition of a tree that had produced for 20 years.

The inspection and evaluation of the tree included:

- External inspection
- Non-destructive testing
- Tree functional testing
- Pressure testing of the tree and valves
- Dismantling and inspection of components, i.e., flanges, piping, connectors, control system, valves and operators
- Laboratory analysis
- Evaluation and documentation

(A detailed description of the tree components and the nature of the inspection and test methods is contained in aforementioned reference. Tree and control schematics are presented in Fig. 36.)

The external inspection of the tree showed no major damage and indicated a good overall condition. Rust and corrosion appeared to be limited and control plumbing and accumulators showed no noticeable leakage or blockages. Visible seal elements indicated a good condition and only a secondary wellhead seal element was seen to have minor damage from installation. Almost the entire tree was covered with marine growth that included barnacles, corals, scallops and sheets of anemones. Five percent of the surface was encrusted by hard shelled marine growth, the remaining surface by soft anemones. The barnacles concentrated at the tree cap and valve operators. Both corals and barnacles were, in some instances, tightly wedged between nuts and fittings. Subsea water blasting might have removed most marine growth, but a diver or an ROV with an advanced mechanical cleaning device was thought to be required for removing valves. Operation of the manual override feature on the valves and the connector lockdown arrangement could be easily accomplished by divers with a minimal cleaning effort.

Ultrasonic examination of the tree was conducted after it was cleaned. Uniform corrosion was limited to 0.05 cm to 0.09 cm in loss of material. The complete inner and outer tree surfaces were also attacked by pitting ranging from 0.08 cm to 0.33 cm deep, most commonly 0.15 cm. Corrosion/erosion was observed in two locations in conjunction with a weld root and on the production swab valve gate. The degree of this degradation was low and did not impact function or safety. Galvanic corrosion was not observed in the entire tree system or the valve components. Crevice corrosion was not observed in conjunction with O-ring grooves, seal surfaces or attachments. The amount of erosion found in the tree system was limited to a minor cavity behind a connection in the production line.

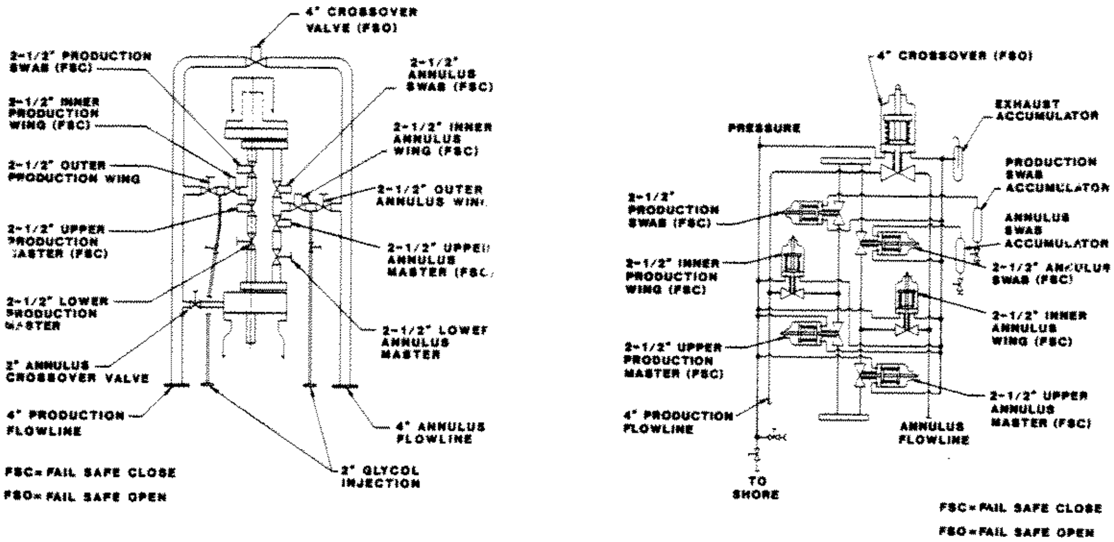


FIG. 36. PHILLIPS MOLINO SUBSEA TREE (LEFT) AND CONTROL (RIGHT) SCHEMATICS. (from ref. 232)

Operation of manually and hydraulically-operated valves, wellhead connector, tree cap and control valves, showed that these components were in excellent condition. Activation of the manually-operated valves and use of the manual override on the hydraulic operators did not require excessive force. Pressure activation of the hydraulic operators demonstrated that moving the valve from a closed to a fully opened position required a pressure range from 13 to 28 kg/sq cm (180 to 400 psi). Operation of conductor, wellhead connector and treecap lockdown screws was easily accomplished. The needle valves used in the control systems and on the treecap operated easily and maintained pressure capability after operation. The misalignment union used for flowline attachment was easily dismantled with a hydraulic wrench.

Pressure tests were conducted on valve gates, tree bores and connectors for 141 kg/sq cm (2000 psi). The W-K-M production valves maintained pressure, except from small leakages at the production swab valve and crossover valve. Pressure testing of the control manifold, wellhead connectors, needle valves in the treecap, control systems and valve operators showed them all to be in good condition.

The component inspection was rigorous and included dismantling and inspection of the following components: flowloops, crossover valves, glycol injection lines, control plumbing, valve block, bonnets, wellhead connector, valves and operators, sectioning loops, control manifolds and accumulators. Only the production swab and annulus swab gates contained general surface corrosion, particularly on the side exposed to the tree mandrel. Light pitting was observed on the gate exposed to production. During dismantling of the production swab and annulus swab valves, minor irregularities were observed on the anti-rotation key located between the valve stem and stem nut. The set screw holding the anti-rotation key for the manual override in the annulus swab valve was loose, and the key and set screw for the production swab valve were found inside the spring cartridge. This did not affect the tree safety, but did indicate that long-term operational vibrations might have occurred. Some galling was found on the seat of brass and gate faces. One needle valve, exposed to sea water during its lifetime, showed light pitting which did not affect its pressure-holding integrity. The remaining components showed no indications of wear or degradation that would have jeopardized the tree's safety or operation.

The investigators attributed the design of the cathodic corrosion protection system as being a major factor in maintaining the wellhead's integrity. The experience with this tree will be incorporated into future Vetco designs.

3.1.2.f Control System Performance

One of the most frequently discussed problems with SPSs is the control system. G.A. Fabbri, Engineering Manager, TRW Ferranti Subsea Ltd. presented some statistics and observations on the performance of control systems manufactured by his company which have been installed on North Sea SPSs (ref. 216). The following data is taken from Fabbri's paper.

A subsea control system , whether simple hydraulic or electro-hydraulic, is defined as a system which has some active components subsea. The control system permits the control of valves and chokes in subsea completions, templates, manifolds, pipelines and also permits retrieval of data. It may include safety features which will automatically prevent dangerous occurrences and the pollution of the environment. It can allow monitoring of the status of production by indicating temperatures, pressures, sand detection and other parameters.

According to Fabbri, electrical connections are considered by most people to be the most critical item in any subsea control system. The mistrust of wet make/break connectors has delayed the acceptance of subsea electro-hydraulic systems. Inductive couplers have replaced conductive connectors in most advanced subsea applications. Inductive couplers are ideal for making and breaking underwater since the transmission of energy from the primary to the secondary is based on an electro-magnetic field which is not affected by water. The history of inductive couplers, which can be traced as far back as the 1968 SPS installed in the Gulf of Mexico by Shell, is, again according to Fabbri, one of success. TRW Ferranti have produced more than 500 inductive couplers which have been installed subsea. Only one failure has ever been recorded (in 1978) in over 13 million hours of service. This failure was found to be due to a material incompatibility which was corrected.

Fabbri also presented statistics regarding the performance of electrical cables used on the TRW Ferranti control systems, these are presented below.

ELECTRIC CABLE FAILURES

APPLICATION	Life, Service (Years)	No. of Failures
Exxon SPS	5.0	0
Shell P1	3.5	0
Chevron Ninian	4.0	0
Shell UMC	4.0	0
Esso Cobia	4.5	0
Shell Brent	2.0	0
TOTAL	23.0	0

Assuming a confidence level of 50 percent, the mean time between failures calculates to 33.18 years. The author points out that there are many other factors to take into account in a reliability analysis such as the above, but it is very difficult to quantify such important factors as the installation, corrosion and reliability of mechanical devices such as flexible hoses.

3.1.2 Failure Modes, Problems and Constraints

The foregoing presents a decidedly upbeat view of the SPS and its components. Preparatory to writting this report 243 articles and papers were reviewed and personal interviews with 20 operators, manufacturers and servicers of SPSs were conducted. Paradoxically, in only a few instances have operators acknowledged the occurrance of any problems, yet the trade journals are replete with a litany of problems and constraints regarding the SPSs' performance and the impact this will have on future applications.

Unfortunately, there are few details that accompany the problems or failures reported. Technical papers describing successful performances of SPSs tend to go into some detail relating these events. But when the system has experienced a failure, the event is simply noted and the efforts to repair the fault are dealt with briefly. Significant, however, for the objectives of this study, there are only a few problems that have occurred wherein an underwater inspection program would have noted that the situation was deteriorating and that a failure was imminent. Such incidents are in the areas of anchor dragging, trawler damage or displacement of flowlines, or objects dropped on the SPS.

The following problems and constraints are grouped within three categories: General (where the problem is primarily one of policy in terms of the manufacturing technique or assumptions made preliminary to fabrication); 2) Specific (where a specific component of the SPS is at fault) and 3) Field Specific (where the problem is identified with a particular gas or oil field).

3.1.2.a General

Problems or constraints noted in this category are:

- Improbable technology transfer from land to subsea. (ref. 160)

- Unreliable components. (*ibid.*)

- Unacceptable quality control of components for the duties demanded. (*ibid.*)

- Manifold systems must be designed with maintenance in view. (ref. 130)

- More efficient tie-in techniques are required. (*ibid.*)

- Improvements in control systems for multi-function templates at remote locations are needed. (*ibid.*)

- Systems must be protected from vertical impact. (*ibid.*)

- Control systems are the weakest part of SPSs. (ref. 46)

- Workover problems need solving. (*ibid.*)

- Downhole electronics and risers present major problems. (ref. 120)

- "The most difficult problem of subsea completion, according to Elf Aquitaine, is installing a flexible riser in water depth of more than 200 meters." (ref. 85)

- "The greatest gremlin of subsea completions is the behaviour of gas mixed with liquid fractions and transported through pipelines." (*ibid.*)

3.1.2.b Specific

- A major cause of damage is from anchor dragging or trawl boards. (ref. 46)

- Better fluid viscosity in hydraulics is needed to reduce operator response time. (ref. 101)

- Better data handling techniques required. (*ibid.*)

- Better subsea sensors required. (*ibid.*) This commentator pointed out that the UMC, in spite of its sophistication, cannot tell the operator if a valve is open, but only that a signal has been sent. Following a shut down it could be vital to know which valves were opened or shut in preparation for starting.

- Although manufacturers state that they have solved the electrical connector problem, it still exists. This is particularly so in the make/break connectors and is a critical problem. (ref. 150)

- Hydraulic controls continue to present the critical issue. Response time is too great as offset distances from wellhead to surface increase. (ref. 180) This commentator noted that in the Garoupa field, where direct hydraulic control is used, it takes approximately five minutes for a valve to actuate after the command has been given.

- Better control systems are needed with regard to supplying position indicators for valves. (ibid.)

- Development of a more dependable downhole pressure transducer is required. (ibid.)

- If a flowline is pulled out of position, this is not detected by the SPS operator. (B. Carlson, Shell Offshore)

- Subsea valves have a tendency to stick, and they generally stick in the closed position. (ibid.)

3.1.2.c Field Specific

Garoupa (refs. 121 & 141)

- Downhole safety valves and tubing hanger plugs leaking.

- Misoriented tubing hangers.

- Severe casing hanger damage from dragging anchor.

- Unseated bore dirt entry prevention plugs.

- Lost production due to:

  Gas leaks;

  Downhole safety valve replacement;

  Bottom hole pressure survey, and

  Control system remote terminal unit servicing.

Argyll (ref. 101)

- Downhole safety valve must be replaced every two years: too expensive when wirelining from a semi-submersible at $1 million for each replacement.

- Wellhead maintenance required about twice each year: too expensive.

- Length of flowlines makes them vulnerable to damage from anchors and trawl boards.

- Crack in riser at manifold. (ref. 82)

- Anchor chains parted, rig adrift. (ibid.)

Cormorant (refs. 134 & 176)

- "It appears that one pressure sensor line is periodically blocked, either by hydrates or debris, which, on occasion, results in unreliable pressure data being transmitted from one string."

- "Of problems experienced to date, only two were significant. The first concerned a subsea valve, the second a subsea control module. These faults were corrected by divers who closed the valve and replaced the module."

SPS - Gulf of Mexico (ref. 73)

- "An initial difficulty encountered in pipeline certification pressure tests arose due to a number of valves in the subsea manifold with leaks across their gates. Troubleshooting with the remote control system enabled identification of the faulty valves. The valves were replaced by the manipulator and the pipeline certified. The faulty valves suffered both from design and quality control deficiencies."

- "During the pilot test, the production bypassed the subsea pump/separator unit. Extensive troubleshooting using both the manipulator and the remote control system identified the pump/separator as a major fault in the 2300-volt power distribution system that prevented the subsea start-up of this optional system. No repair effort on the pump/separator was attempted."

- "Generally, the work string has been used for tasks that were not accessible to the manipulator and were the result of running tools failing or equipment being dropped or improperly handled."

3.2 OPERATOR/MANUFACTURER INSPECTION REQUIREMENTS/RECOMMENDATIONS

3.2.1 Operator Inspection

Not one oil or gas operator was identified who conducted regularly-scheduled external inspection of their subsea completions. Regularly-scheduled maintenance, yes. But the need for inspection, as is performed on fixed structures, was viewed as unnecessary. While this may appear presumptous at first glance, the reasoning becomes clearer when one reviews the steps that the operator takes preliminary to SPS construction; preliminary to installation, and during operation. Further, reviewing the list of problems and constraints presented in the foregoing section reveals only, perhaps, three or four incidents where external underwater inspection might have proved useful, these are: damage caused by anchor dragging, trawl boards or dropped objects; crack in a riser; displacement of flowlines, and detection of gas or oil leaks. The last of these incidents depends upon where the leak is located and its size.

The philosophy of the operators interviewed - regarding the need for regularly-scheduled inspection - is significant. The first question they pose is: Why? And then proceed to present the basis for their response. The following discussion is extracted from interviews with oil/gas operators, and summarizes the lines of reasoning they follow to arrive at the question: Why?

Almost all operators acknowledge the need for periodic visual (direct or via optics) inspection of an SPS and of its cathodic protection system. All operators also agree that when the SPS is in a heavily fished area (some believe that the trawl boards should be from 4 to 6 tonnes before becoming concerned), or where ships anchor, or when a large object has been dropped in the near vicinity of the wellhead or flowlines, then there is a need to, at least, visually inspect the system. In the first two cases the inspection might be from time-to-time; in the latter instance it should be conducted forthwith. None, however, saw the need for a regularly-scheduled inspection. They point out that there are many areas where SPSs are located that ships do not anchor and fishing does not take place. Also when an object is dropped, it is normally dropped from a vessel supporting the SPS or from the platform above, and not surreptitiously, hence, the operator should be aware of the incident. The operators also make every effort to appraise the shipping and fishing industry that subsea equipment is on the bottom and cables (flowlines, etc.,) are in the area.

Concerning the potential problem of the wellhead being snagged or caught by an anchor, it was pointed out that wellheads are designed to experience the heaviest load that can be anticipated. Consequently, the structures are heavily membered to withstand heavy physical impact. They are also designed to withstand the potential bending moments that might occur if the drillship drifts off station and places strain on the wellhead via the drillstring. One operator stated that such bending moments are so great that any other loads are relatively insignificant. If the structure is properly designed, it should be able to withstand any impact short of collision with a submarine.

The crux of the operational life of a SPS is embedded in the cathodic protection of the structure, such that it will not corrode to failure during its lifetime. The operators point out that considerable corrosion testing of all materials that compose most, if not all, SPSs has been carried out. Over two decades of experience has been accumulated on the performance of materials underwater and cathodic protection systems installed thereupon. The corrosion testing that has been - and is being performed looks not only at the external components of the SPS (from fouling and sea water), but equally as well at the internal components wherein the product flows and where corrosion will normally be greatest. As one operator pointed out, structural damage can only be seen if it is catastrophic, most of the wear (corrosion/ erosion) is on the inside of the structure. Consequently, deterioration will not necessarily be reflected on the external parts. Anodes are not regularly inspected because of the knowledge gained from testing and experience with operating SPSs. Consequently, the wellhead is monitored for corrosion and corrosion potential protection commensurate with whatever has been the experience with this potential problem in the area in which the SPS is installed. The location of anodes and the provisions made for maintenance of components of the SPS that are critical to the product passage are the most important areas of concern. Thought must be given to in situ replacement of critical components or complete removal to the surface where they can be serviced, repaired or replaced.

One of the stronger arguments against regularly-scheduled inspections is the fact that an SPS is continuously monitored from the surface control panel. At the least the surface monitors internal pressure and product flow. There is also the capability to monitor temperature, wellhead inclination, TFL passage detector and valve position (ref. 211). If there is a crack or fault which produces a leak in the product flow system it should immediately be reflected in loss of pressure. The developers of the UMC have gone a step further by installing covers or roofs over the structure which are intended to serve two functions. One is to protect the components from objects dropped from above; the second is to monitor for leakage of hydrocarbons. If a leak was to occur, the roof sensors would automatically stop production and sound an alarm. Any oil or gas entrapped under the roof can then be collected and fed to the platform via the service pipeline. The sensors can shut down the entire UMC or individual wellheads.

Routine tests are performed on SPS systems to assure that the pressure is maintained, the product flowing and the valves working. One operator acknowledged that such tests do not reflect minor structural damage, such as the flowline being pulled off route or the degree of pit or surface corrosion. It was also noted that during workovers the wellhead and attendent system components are rigorously inspected. The SPS situation is quite different from a fixed platform. Mention was made earlier that the fixed platform's supporting members do their job independently of the equipment required to obtain the product. Like the foundations of a building, they are critical to the building's presence, but essentially immaterial to its function. The SPS is a more active partner, in that, the product flows virtually throughout the entire system. A surface-breaking crack in the supporting member of a fixed platform could go undetected for the life of the structure (providing it didn't propagate), the same crack in SPS components involved in direct product transportation would likely be expressed by loss of pressure. The experience gained to date has assured most operators that the supporting cast in a subsea wellhead (e.g., drilling template, guide structure, Xmass tree and cap assembly, flowline "sled" assembly, etc.,) will perform admirably for the life of the field.

An additional note on periodic inspection was offered by several operators in regard to system maintenance. No operator was optimistic enough to believe that an SPS will need no maintenance whatever during its production lifetime. Indeed, SPSs are designed to permit such tasks, either by a diver or by mechanical manipulation. During these maintenance periods it is common to perform a visual inspection on the system overall just to assure that it has maintained its external integrity. It is also common to occasionally check the corrosion protection system to see that it is functioning within prescribed limits.

3.2.1.a Pre-Installation Requirements and Testing

One aspect of SPS inspection that all operators emphasized was the intensive inspection and testing given the system before it is assembled, after it is assembled and after it is installed. These inspections and tests, believe the operators, account for the good performance of many currently operating SPSs. Additionally, the operators can - and do define certain requirements with which the components must comply. In the Montanazo field Chevron, in addition to other design features, required the following of the electro-hydraulic control system:

- System configuration be based on proven hardware and concepts,
- Components have a proven record of tolerance for rough handling, contaminated hydraulic fluid and other adverse conditions which commonly occur in practice,
- Test procedures for all components will include integration testing with other hardware, and
- Quality assurance authorities monitor all phases of manufacture and assembly of components. (ref. 179)

The testing procedures may begin at the component level and extend through to the entire system before the completion is placed into the water. One of the more extensive pre-test programs was that conducted preparatory to implantment of the UMC. Testing for the UMC began with installation of the SPS in the Gulf of Mexico in 1974. The SPS, although it was a producing completion, also provided the testbed experiences upon which subsequent developments proceeded. Prior to installation of the UMC, the operators installed a single wellhead in the Cormorant field (where the UMC would be placed) containing components similar to those that would be used on the UMC. This single wellhead (referred to as the P-1 well) was subjected to various land tests that extended through about a one year period.

All equipment ordered for the P-1 was first given a Site Receipt Test (SRT) to verify conformance of the equipment to the specifications, and to check the validity of the certification documents. After the SRT's the equipment was integrated with other equipment to check the interfaces, and subsequently be operated to test its performance. A land test site was constructed to perform the equipment integration tests. The principal features of the test site were:

- A 152 meter well to test wellhead stackups,
- A 1,524 meter well to simulate downhole conditions for Tubing Retrievable Type Subsurface Safety Valve (TRSSSV) and TFL work,
- A test base to perform integration and stack-up tests,
- A TFL test loop which can be connected to the wells, and
- Pull-in winches to carry out the pull tests.

The tests proved to be essential since deficiencies were recognized that would have made the offshore installation difficult. A detailed description of these tests and the techniques employed is presented in ref. 132, from which the above information was taken.

Component testing for P-1 was, in some instances, exhaustive. Testing of the TRSSV, for example, began in 1975 on two such systems manufactured by Otis Engineering Corp. Both Shell Expro and Shell Internationale Petroleum Maatschappij B.V. (SIPM) purchased different TRSSVs for in-house testing. The test results were disappointing, which led to a joint manufacturer/operator program to develope a unit that could meet the demanding conditions. The test program (described in detail in ref. 137) ran for a four year period and included numerous tests, disassemblies, examinations, reassemblies and retesting. The safety valves are reported to have worked flawlessly since installation.

After this testing and after the UMC was fabricated and assembled it was subject to further testing, this time as a system. Some 15 months (and about $12 million) were devoted to on-land tests in Rotterdam. The tests were divided into four sections:

- Simulation of the entire unit working on the seabed during piling, pipeline connection, drilling, start-up and shutdown routine maintenance,
- Ensuring that even the most mundane items fitted accurately and did not obstruct other equipment, and that standard equipment, such as Xmas trees were fully interchangeable,
- Collection of data on system response times and operating characteristics to help calibrate systems and diagnose faults, and
- Training of personnel.

Of the total 365 tests, 150 went as planned, 200 required minor on site modifications to equipment and 15 highlighted more-or-less serious problems that required major alterations. (ref. 151) The final installed system is, like its SPS predecessor, also considered a testbed leading toward development of a subsea completion system for application in waters beyond diver depth.

3.2.2 Manufacturer's Recommendations

Most manufacturers of SPSs can and do provide an inspection and maintenance program for their hardware. It is the operator's decision whether or not to follow this program. More often the operator will perform whatever inspection or maintenance he feels necessary using his own, the manufacturer's or contractor personnel. The techniques the operator might employ and the scope of the inspection/maintenance are also his decision, and they might differ from those the manufacturer recommends. The reason for any differences that might occur are simply a reflection of the operator's more lengthy and detailed involvement with SPSs. Not that the manufacturer is unconcerned, but, as one major Xmas tree producer explained: "After we install a subsea tree, maintenance is usually performed by the oil company, and we usually don't hear about it. They have records, but they are buried in archives somewhere and (the operator) either can't or don't want to take the time to retrieve them. From verbal communication with individuals, we hear that the tree usually outlasts the well."

An example of one manufacturer's, CanOcean Resources, Ltd., inspection/maintenance program (schedule) for a 1-ATA, dry wellhead system is contained in Appendix V. The program, however, has not been adopted by any of the operators. Interestingly, the performance of the CanOcean subsea completions (Table 14) could hardly be much better if the operator did decide to go with the recommended program.

Most of the major manufacturers also offer training courses to assure that their equipment is being used properly. Cameron, for example, offers a three day orientation course designed for drilling contractors and operating personnel who require an understanding of equipment and procedures for floating drilling. The course includes a total system approach covering the BOP stack, lower riser assembly, riser, and hydraulic control system. Recommended maintenance and functional testing of all drilling and wellhead system components are covered, as are the basics of subsea completions and platform tie-back systems.

3.3 GOVERNMENT AND CERTIFYING SOCIETIES

No government involved in offshore oil or gas production has issued regulations requiring regular or periodic underwater inspection of subsea production systems. This does not imply a lack of interest in the subject, nor does it imply 100 percent confidance in the systems. It is more a case of the various governments present philosophy of permitting the operator's to "police" themselves.

All of the Government activities that have an interest in SPS operations and safety are closely monitoring developments in this field, but none have made any attempts to regulate its activities in regards to underwater inspection and maintenance. Mr. T. Hamilton (Operations and Safety Branch, Petroleum Engineering Division, UK Department of Energy) stated (personal communication) that whatever rules they might have would be contained in the licensing, and that they would be of a general nature since this is a developing technology. Broadly speaking, the DOE follows the guidelines presented in API 14, although they are working on the subject and will produce their recommendations within the next few years.

The Norwegian classification society Det Norske Veritas (DNV) is the only activity that has produced a document specifically addressing the inspection of SPSs. In May 1982 DNV issued their "Rules for Certification of Subsea Production Systems". These were promulgated to the offshore operators and manufacturers of SPSs as Preliminary Rules Proposal, SPS, (Rev 2) for review and comment. They were subsequently published in 1984 as "Tentative Rules for Certification of Subsea Production Systems"

The DNV rules have three goals:

- To provide a systematic approach to verification of a given safety level,
- Provide minimum requirements/guidelines considered reasonable for both operators and surveyors, and
- Serve as a guide to operators in ordering supplies during the design and fabrication stages.

Section 12 of the Rules (Retention of Validity for Certificate of Approval) deals with the underwater inspection necessary to retain certification. It states that periodic surveys are necessary on an annual basis, and that the frequency of the survey may be altered by DNV depending on the findings and the owner's report on trend analysis. The long term survey program is to be scheduled such that the whole SPS is covered in a period of five years, that is, before renewal of the Certificate of Approval. Every six months the results from the trend analysis are to be submitted for review. In the event of an accident, discovery of damage or deterioration, modifications or any other noted or possible change of the SPS that may affect its safety, a special survey may be required.

In due time ahead of each periodical survey the owner is to submit to DNV, for approval, a detail proposal for the survey. The proposal is to contain a description of the following:

- Systems and items included in the survey,
- Tests to be carried out, and
- Inspections and corresponding preparations and means.

Normally the surveys are to include:

- Testing of standby systems, safety systems, emergency systems, and possible communication systems,
- Pressure and leakage testing,
- Check of the corrosion protection system,
- Check of condition monitoring systems,
- Check of hydrocarbon for possibile alteration of its corrosive and erosive properties,
- Check of possible material deterioration and incipient cracking,
- Check of possible damage by accidental loadings,
- Check amount of marine growth and presence of debris in contact with the structure, and
- Check the foundations for scouring or buildup of seabed substances.

The survey also includes a check of the owner's filing system for findings from his maintenance, inspections and testing, and his trend analysis related to safety.

The DNV rules go into some detail regarding SPSs where manned intervention is necessary for operation, testing, survey or maintenance. The rules deal exclusively with requirements regarding safety of the personnel; not with items of the production system that are to be inspected. (Appendix VI)

The American Petroleum Institute has formed a committee that is composed of representatives from the operators, manufacturers, suppliers of SPSs and the U.S. Government (MMS). This committee began writting "Recommended Practices for Design and Operation of Subsea Production Systems" in 1984. The target date for submission of the final version is June 1986.

The England-based UEG, a part of CIRIA - The Construction Industry Research and Information Association presented a report which was undertaken to determine whether there is a need for design guidance of subsea installations, and if so, to prepare an outline of the topics to be included.(ref. 238) The working group on this study was composed of a mix similar to the API study.

Representatives of the underwater engineering industry were canvassed to determine their demand for guidance on the design of subsea installations. Over three-quarters of the responses obtained indicated that some form of non-legislative guidance would be of use. It was the majority of opinion, according to ref. 238, that the document should contain sufficient detail to complement and implement specific aspects covered in existing documents. In areas neglected by previous publications practical guidance and realistic "base line" data should be provided. The usefullness of such a document, for the majority of the respondants, would be in providing:

- A catalog of existing codes, standards and requirements

related to subsea installations,
- An aide-memoire to the engineer wishing to accommodate technologies outside his specialist knowledge, and
- A means of reducing some of the practical problems he encountered in subsea operations.

The UEG report concluded that the concensus opinion saw more immediate value in producing a document which will aid the designer of subsea installations in relation to inspection, maintenance, repair and intervention. The report concludes with a preliminary outline of the a document dealing with this subject.

4.0 INSPECTION/MAINTENANCE INTERVENTION TECHNIQUES

Inspection and maintenance (I&M) of Submerged Production Systems is not a new subject. For over 20 years I&M of SPSs has been conducted by a variety of techniques. In most instances the diver has been the premier intervention technique, while in others, specially designed vehicles or vehicles modified to accommodate the structure were employed.

Although not new, very little has been published regarding SPS I&M relative to the volumes of material on I&M of fixed platforms. There are several reasons for this, the most obvious being the far fewer numbers of submerged production systems vs. the large numbers of fixed platforms. A second reason is that many of the I&M techniques employed on SPSs were developed by the operator for his specific structure and his specific requirements. In these instances the operator may consider the technique proprietory, or he may simply elect not to make the information public. A third possible reason is that I&M of subsea completion systems to date, according to the literature available, has not involved much more than visually inspecting flowlines or the structure for signs of damage. While this serves a most important function, there is really not too much one can write about unless the inspection resulted in averting a potential catastrophy. Finally, inspection of fixed platforms is a legal requirement in the North Sea; this results in a built-in level of undersea inspection effort for every platform. So, where SPS inspection is a potential market, platform inspection is a real, multi-million dollar market which has spawned the reams of reports one can consult today.

There are three primary means of intervention which can be used to perform underwater I&M: Human intervention; Remotely Operated Vehicles, and hybrid systems. This chapter describes specific capabilities within these techniques that have been developed for SPS I&M. At this time there are SPS I&M capabilities being developed by at least two service companies that are aimed for application on a specific future structure. Details on these capabilities were sought, but not obtained. It is likely that there are other such projects, but the operator wishes to maintain confidentiality.

4.1 HUMAN INTERVENTION

There are two basic means of placing the human being at a subsea wellhead. One procedure is to provide him (or her) with the proper equipment to permit diving at the work site pressure and in contact with the water (ambient pressure diving). A second means is to enclose the human in a pressure-resistant, dry, 1-atmosphere (1-ATA) chamber that will transport him to the work site and: a) permit him to transfer from the chamber into another 1-ATA, dry chamber that encapsulates the wellhead, or b) permit him to work on the wellhead without leaving the chamber by equipping it with viewing ports, manipulators/tools and thrusters. A third technique combines both of the foregoing means, in that, the diver is transported to the work site within a mobile, dry, 1-ATA chamber that mates with a sea water-filled chamber enclosing the wellhead, the pressure of the water within the wellhead chamber is brought to 1-ATA, and the diver exits the transport chamber to work in contact with the water. This last technique has been termed Neutrabaric diving.

4.1.1 Ambient Pressure Diving

Saturation and non-saturation diving techniques are so well known that they will not be described in any detail herein. Present diving capabilities can provide virtually any IM&R service for periods ranging from a few hours to several weeks. Working in conjuction with his support ship, a diver can perform a simple visual inspection of an SPS, or completely relocate a wellhead to the surface for workover. The major limitations to diving intervention are imposed by working depth or the weather.

The safe working depth of today's divers and the ultimate limit of ambient pressure diving is a matter of considerable speculation. According to Comex President Henri Delauze (at Divetech '84 in London), some 95 percent of today's working dives are between 100 and 200 meters, and a significant number have been made to 300 meters. As of this writing (May 1985) Comex is successfully conducting an experimental diving mission in 450 meters water depth. Many of today's diving service companies and equipment developers believe that 300 meters is about the effective limit of diving. O. C. Andersen, of Statoil (ref. 211), stated "...current operational experience indicates that the proven offshore depth limit for general diving tasks is 250 meters or less." Andersen also stated that it may be possible to employ hyperbaric divers for offshore intervention work to 500 meters depth.

As far as currently operating subsea completions are concerned, 300 meters diving depth capability is more than adequate. Of the 369 subsea wellheads identified in this report (Chapter 1), 367 are in water depths less than 300 meters, the deepest being in Brazil's Pirauna field at 293 meters. The Two exceptions will be in the Montonaza field at 762 meters depth and the Casablanca field at 488 meters depth. Consequently, the diver can safely reach any presently operating subsea completion, and will only be depth prohibited in the future.

Weather imposes a penalty on the diver, as it does on almost every other intervention technique, by excluding his deployment in high sea states. It is very difficult to place an exact limit on the sea states within which a diver can be safely deployed. Sea States 4 and 5 are limits which were usually accepted in the past. However, today's diving support vessels have extended this limit considerably. A recently reported (Ocean Industry, April, 1984) pipeline repair job by divers in the North Sea stated that the diving company (Wharton-William-Taylor) performed the repairs over an 11 day period, during which time winds of Beaufort Force 9 (equivalent to Sea State 8, a strong gale) were encountered, but did not prohibit the work from being conducted. This work was supported by the MSV (multi-service support vessel) SAFE KARINA which was in an eight-point moor and was equipped with thrusters to improve its station-keeping capability. Obviously, or it would not have been a newsworthy item, diving operations are not routinely carried out under such severe weather conditions. It is also important to note that ROVs, manned submersibles or hybrid vehicles would likewise make news working within such sea conditions. The only intervention technique that can potentially deploy divers or ROVs within and above Sea State 8 will be the French-developed autonomous submersible SAGA, currently under construction and discussed in section (4.3).

4.1.2 1-ATA Intervention (Dry)

4.1.2.a Habitat/Transfer Vehicle

This technique involves transporting skilled technicians to a dry, 1-ATA, encapsulated wellhead, mating with the wellhead, and then transferring the technicians to the wellhead to perform inspection and/or maintenance. (The procedure is referred to as "dry transfer".) The CanOcean SERVICE CAPSULE and the procedure followed is described in Section 2.1.2 and a schematic of the capsule is presented in Fig. 27 (bottom) and its characteristics in Table 15. Current dry transfer techniques rely upon a winch affixed to the bottom of the positively buoyant capsule to reel the capsule down to the wellhead where mating takes place. The technique closely parallels that of the U.S. Navy's McCann rescue chamber which was introduced to the submarine forces some 50 or more years ago.

Given the fact that present day 1-ATA manned submersibles are operating to depths of 6,000 meters with sea water pumps that will operate at these depths, there is no foreseeable time in the near or distant future when this technique cannot be employed. One limitation is sea state since the capsule must be launched/retrieved from a support ship. CanOcean Resources (ref. 75) conceived an alternative to the present service capsule in the form of a maneuverable, tethered manned vehicle capable of dry transfer (Fig. 37). Although the submersible they envisioned was not identified, there are several commercially available vehicles that are capable of dry transfer if equipped with a mating skirt compatible with the wellhead mating surface. One of the major advantages of this technique is that the personnel transported to the wellhead need not be trained divers, nor are they constrained by age or physical condition. Consequently, the most highly skilled technicians can be brought to the job.

4.1.2.b 1-ATA Submersible (Untethered)

This type of intervention technique is representative of the conventional manned submersible. The vehicle is untethered, battery-powered, equipped with thrusters that provide 3-dimensional maneuvering, mechanical manipulators, and viewports or a viewing dome forward which permits near-panoramic viewing. The vehicle is operated by a trained pilot and can carry one or two observers within a dry, 1-ATA pressure hull. Support for the submersible is

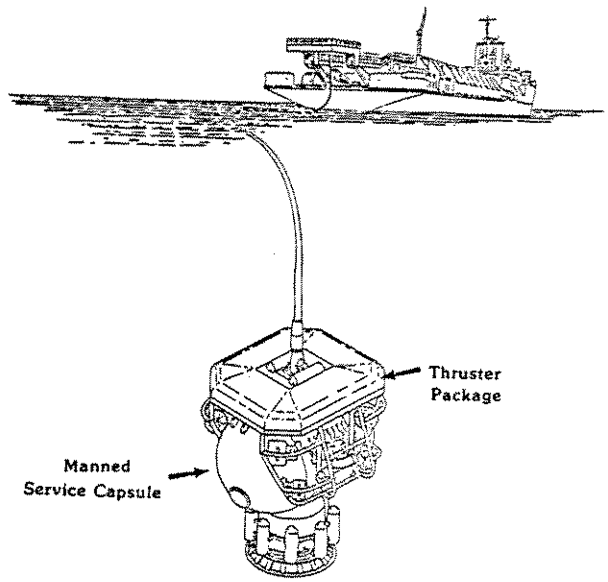


FIG. 37 CANOCEAN CONCEPTUAL WELLHEAD TRANSFER UNIT (from ref.247)

provided by a surface platform that launches/retrieves the vehicle and maintains it after each dive. There are over 70 commercially available manned submersibles of this type. While all provide the basic ingredients outlined above, they are quite different with respect to size, weight, viewing capability, instrumentation, crew capacity, power capacity and life support endurance. All of these vehicles can reach the depth of any operating SPS and virtually all SPSs that are planned for the future. There are two such vehicles currently employed in ocean research which operate to depths of 6,000 meters.

One major variation, and a critical consideration with regards to SPS inspection and maintenance, is the manipulator with which the vehicle is equipped. Manipulators are of two types: Rate-Type and Spatially Correspondant. The majority of the manpulators used on underwater vehicles today are of the rate-type. Rate-type can be translated to on/off, which means that when the control switch for moving a particular segment of the manipulator (e.g., shoulder swing motion) is activated, hydraulic fluid flows and that segment moves at a pre-set rate. When the switch is turned off the hydraulic fluid ceases to flow and the manipulator becomes rigidly locked. There is a separate control switch for each individual motion, but the motions are sometimes all controlled from a single joystick. A slightly more advanced manipulator of this type is the proportionate speed rate manipulator wherein the speed of manipulator motion is proportionate to the displacement of the operator control.

The spatially correspondant manipulator uses a control unit or "master" arm which resembles the "slave" manipulator arm which it controls, duplicating every joint and arm segment. The method of controlling the manipulator parallels the human arm. The operator grasps the controller arm in such a manner that it follows the line of his arm. Each time he moves his arm, the control arm moves with him. The manipulator receiving commands from the master controller arm duplicates the operator's arm movements.

Some spatially correspondent manipulators have a force feedback capability which combines compliancy and a sense of tactility. Compliancy is obtained because the manipulator yields when pushed or struck. The tactility sense is obtained since forces on the manipulator in any direction are transmitted back to the master and operator's arm in a proportional relationship. Although it is not in common use, some manipulators also are fitted with a hydrophone which can hear the manipulator as it strikes or slides against an object.

The only reported application of this type intervention technique to subsea completion systems was in the Grondin field where the barge ARGUILLE carried a manned submersible with a tool-carrying manipulator to open and close valves and operate hydraulic locking devices. This particular vehicle was SEA CAT belonging to a Marseille-based French firm. Another vehicle of this type was used in an evaluation test at the Norwegian Underwater Tests Center (NUTEC). This vehicle was MERMAID IV which is pictured in Fig. 38 and its characteristics are presented in Table 15. MERMAID IV is a diver lockout submersible, in that, the forward pressure hull is at 1-ATA, but the aft hull may be presurized to ambient to permit egress/ingress of diver.

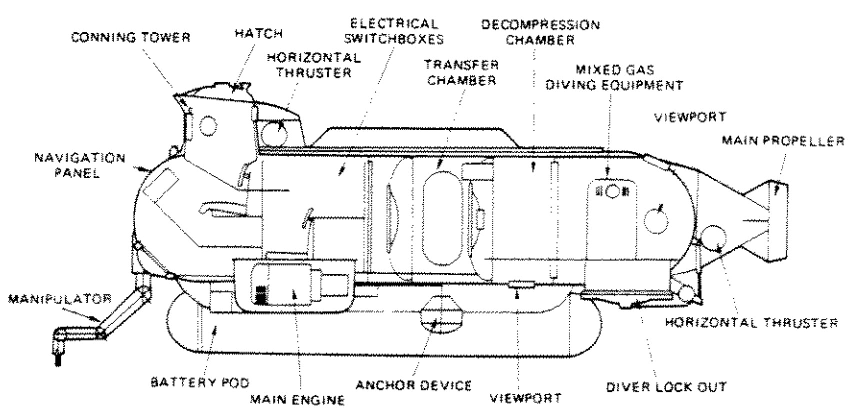


FIG. 38. MERMAID IV (Courtesy Brucker Meerestechnik)

As mentioned above, there are 70 commercially available 1-ATA, untethered, manned submersibles, all of which vary widely in design and capabilities. The follow data defines the boundaries of these vehicles:

Operating Depth:	150m - 3000m
Crew:	1 to 10
Weight in Air:	1.0 tonnes to 168 tonnes
Minimum-Maximum Length:	1.85m - 28.5m
Minimum-Maximum Width:	1.83m - 4.2m
Minimum-Maximum Height:	1.40m - 7.5m
Payload:	200kg to 4,500kg
Electrical Power:	4.5KWH to 740KWH
Life Support Duration:	48 man-hours to 89 man-days
Maneuverability:	3-dimensional
Manipulators:	1 to 3 (rate-controlled and spatially correspondant)

4.1.2.c 1-ATA Submersible (Tethered)

This type of vehicle provides the same capabilities as the 1-ATA untethered vehicles except for three major differences: there is only one vehicle of this type; it carries only one passenger (the pilot), and a tether to the support ship provides electrical power and hardwire communications.

The one vehicle in this category is MANTIS, produced by the OSEL Group, Gt. Yarmouth, Norfolk, UK. Eighteen of these vehicles have been constructed, 16 are operational (see Fig. 39 and Table 15 for characteristics). The operator or pilot of MANTIS is an individual trained in its operation. The vehicle's umbilical, in addition to carrying power and communications, also includes a conductor for TV signals which are transmitted back to a surface monitor when the vehicle is operating. The small size of MANTIS permits it access to quite confined spaces that are generally too small for tethered submersibles.

The MANTIS vehicles were designed to support drilling rig operations, consequently, it relies heavily on its manipulators. Drilling support jobs have included the following:

- Cutting and removing old guide wires,
- Stabbing in new guide wires,
- Removal of guide posts,
- Removal of AX rings,
- Replacement of AX rings,
- Connecting and disconnecting hydraulic units,
- Opening and closing valves,
- Removing riser clamps,
- Conducting bottom surveys around wellheads,
- Locating wellheads for re-entry,
- Removing shackles,
- Attaching and removing wires, and
- General work around the wellhead.

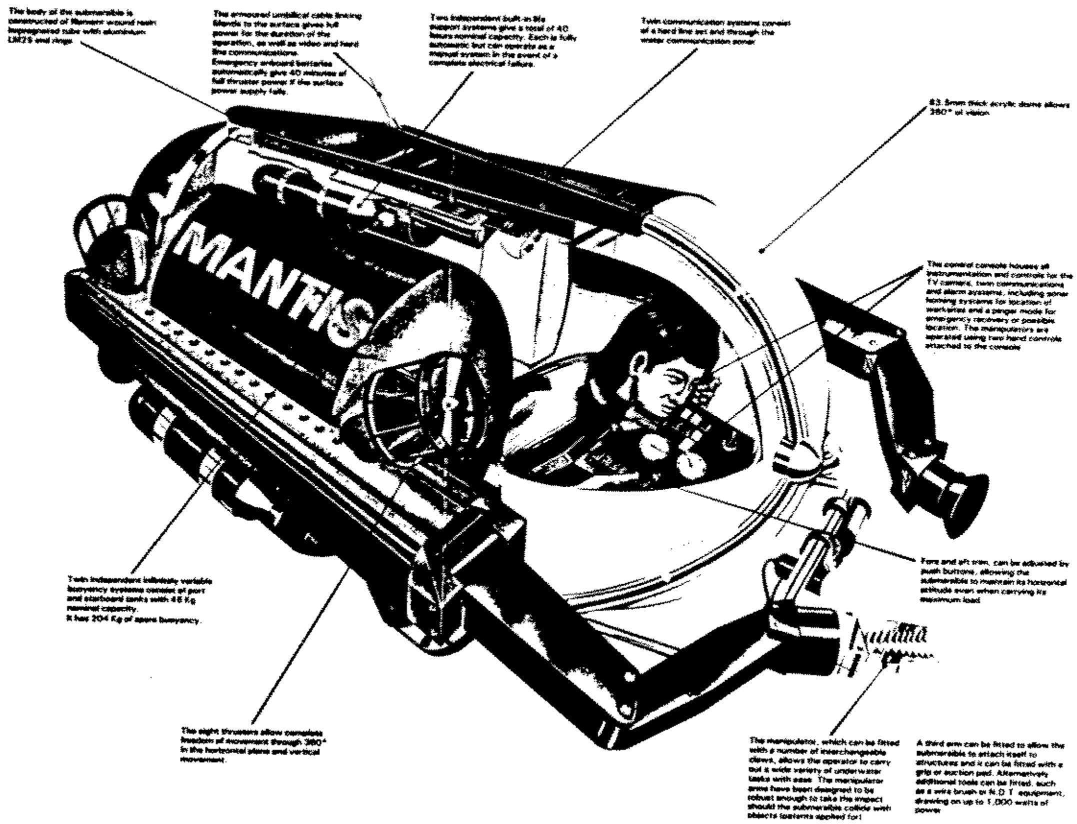


FIG. 39. MANTIS (Courtesy The OSEL Group)

4.1.2.d Observation/Work Bells

In this type of vehicle the occupants are also at 1-ATA pressure in a dry pressure-resistant capsule. The capsule is fitted with a plastic viewing dome that allows near-panoramic viewing forward; thrusters that provide precise maneuvering, and manipulators of various types which may include one for grasping a structure and holding firm while the other(s) are used for working. These vehicles receive their electrical power from the surface via an umbilical or from onboard batteries. In both instances, the Observation/Work Bells (O/W Bells) are always connected by a cable or umbilical. This type of vehicle was designed to provide support for drillships and work on subsea wellheads.

One O/W Bell that has been used for SPS inspection and was designed for assistance in their operation is the Norwegian-based CHECK MATE operated by Molleroden A/S. The vehicle is based at the Norwegian Underwater Technology Center (NUTEC). The vehicle (See Fig. 40 and Table 15) has an acrylic plastic pressure hull which provides direct viewing in almost any lateral plane and obliquely up/down. It carries two people and has maneuverability in 3-dimensions within a 100 meter radius of the surface support vessel. The vehicle has three manipulators, two are 5-function rate type and one is 7-function which works off a master-slave relationship. An umbilical cable supplies 65KW (85KW peak) from the surface.

In addition to CHECK MATE, there are 14 other O/W Bells that provide, except for the plastic pressure hull, near-similar capa-

WELLHEAD SERVICE CAPSULE

LENGTH	3.2m	LIFE SUPPORT DURATION	From Sfc.
BEAM	3.2m	TOTAL POWER	From Sfc.
HEIGHT	5.55m	SPEED: CRUISE	NA
DRAFT	4.5m	MAX	NA
WEIGHT IN AIR	20.8t	CREW: PILOTS	1
OPERATING DEPTH	366m	OBSERVORS	0
COLLAPSE DEPTH	NA	DIVERS (1-ata)	5
HATCH DIAMETER: PILOT	63.5cm	COLOR: HULL	White
LOC	91.46cm	SAIL	Orange
PAYLOAD	1814kg	LAUNCH DATE	1970

PRESSURE HULL: Spherical configuration composed of HY 80 steel. Cylindrical HY 80 mating skirt attached to bottom. Sphere ID 321cm, thickness 1.9cm. Skirt ID 216.8cm, thickness 1.9cm.
POWER SOURCE: Electrical power is generated on the support platform and supplied to the vehicle via a cable. Power provided is 440vac, 3-phase, 60Hz. Power is required for 2 dewatering pumps, an hydraulic pump, a sump pump, ventilation and air conditioning, lights, controls, monitors, alarms, communications and welding equipment.
MANEUVERING CONTROL: The vehicle has no thrusters. It is positively buoyant at all times and is drawn to the wellhead mating collar by an onboard winch that winds on a cable attached to the wellhead. The vehicle is positively buoyant by 680 to 1179kg.
LIFE SUPPORT: Breathing gasses are supplied from the surface by an umbilical cable which is also used to remove cabin air. CO_2 and O_2 partial pressure, cabin pressure, temperature and humidity are monitored. A methane analyzer and an explosive gas analyzer is also carried. Cabin atmosphere can be made inert in the event of a natural gas leak by purging with nitrogen.
VIEWING: Two acrylic plastic viewports. One is located on the forward side of the vehicle in front of the Pilot. The second is located in the lower hatch cover. CCTV cameras are carried to monitor the interior of the vehicle and docking procedures between the vehicle's skirt and the wellhead.
MANIPULATORS: None
SURFACE COMMUNICATIONS: None
SUBSURFACE COMMUNICATIONS: Primary: via hardwire in the umbilical cable. A thru-water communications system is carried for emergency use (8-12kHz and/or 25-30kHz).
SONARS:
- Scanning - None
- Pinger - One for emergency use (10 & 27kHz) incorporated in underwater telephone.
- Echo Sounder - None
- Transponder - None
- Directional Hydrophone - None
- Doppler Sonar - None

STATUS: Operational
CLASSIFICATION/CERTIFICATION: American Bureau of Shipping
OWNER: CanOcean Resources, Ltd., New Westminister, BC, Canada
OPERATOR: Same as owner.
BUILDER: Same as owner.

MERMAID IV

LENGTH	8.48m	LIFE SUPPORT DURATION	168 man hrs
BEAM	1.8m	TOTAL POWER	36 kWh
HEIGHT	2.7m	SPEED: CRUISE	1.5 kts
DRAFT	2.0m	MAX	2.8 kts
WEIGHT IN AIR	11.8t	CREW: PILOTS	1
OPERATING DEPTH	260m	OBSERVERS	1
COLLAPSE DEPTH	450m	DIVERS	2
HATCH DIAMETER: PILOT	60cm	COLOR: HULL	Gray & White
LOC	NA	SAIL	Orange
PAYLOAD	250kg	LAUNCH DATE	1976

PRESSURE HULL: Cylindrical shape with hemispherical end caps, composed of ST E 43 steel, ID 125cm; length 630cm.

POWER SOURCE: Lead acid batteries in two pressure-resistant pods, 56 cells, 330 amp-hr cell, 110 v.

MANEUVERING CONTROL: Dynamic: Stern screw-type propeller, ten hp, reversible and trainable 90 degrees p/s. Two vertical (p/s) and two lateral (fwd/aft) thrusters of 1.5 hp each. Static: 299kg Hard Ballast Tanks and anchor for lockout operations provide vertical movement.

LIFE SUPPORT: O_2 and HE carried externally. One CO_2 scrubber in pilot's sphere and LOC, scrubber in LOC heated. Scrubbing compound is LiOH and/or soda sorb, emergency power for scrubber (24 V, 36 amp-hr). Monitoring devices for O_2 and CO_2.

VIEWING: Plastic bow dome of 110 cm diam., five 17cm diam. two 8cm diam. viewports in conning tower. Four 17cm diam. viewports in LOC.

MANIPULATORS: None

SURFACE COMMUNICATIONS: NA

SUBSURFACE COMMUNICATIONS: One VHF radio transceiver, channels 6, 9, 16 & 33.

SONARS:
- Scanning - None
- Pingers - None
- Echo Sounders - None
- Transponders - None
- Directional Hydrophones - None
- Doppler - None

STATUS: Inactive
CLASSIFICATION/CERTIFICATION: American Bureau of Shipping
OPERATOR: Same as above
BUILDER: Bruker Meerestechnik GmbH, Karlsruhe, W. Germany

MANTIS

LENGTH	2.05m	LIFE SUPPORT DURATION	92 man hrs
BEAM	1.37m	TOTAL POWER	Indefinite
HEIGHT	107m	SPEED: CRUISE	2 kts
DRAFT	0.7m	MAX	2 kts
WEIGHT IN AIR	1,179kg	CREW: PILOTS	1
OPERATING DEPTH	701m	OBSERVERS	0
COLLAPSE DEPTH	NA	COLOR: HULL	Black
HATCH DIAMETER	58.4cm	SAIL	Yellow
PAYLOAD	150kg	LAUNCH DATE	1978

PRESSURE HULL: Cylindrical shape. Main body composed of filament wound resin impregnated tube.
POWER SOURCE: All electrical power is normally supplied from the surface through an armored umbilical cable. Emergency on board batteries provide full thrust for 40 minutes if surface power fails.
MANEUVERING CONTROL: Ten thrusters provide movement in the vertical and horizontal plane. Thrusters are controlled by hand. Buoyancy can be controlled by 'soft' tank compressed air system which provides plus or minus 27kg variation.
LIFE SUPPORT: Nominally 92 hours are provided by an automatic system. An oral-nasal face mask can be used in the event of a power failure. Partial pressure of O_2 is continuously monitored. Audio alarm system provides warning of high or low cabin pressure to the pilot and the surface.
VIEWING: A 6.35cm thick acrylic plastic bow hemisphere provides panoramic viewing. CCTV is provided on manipulator which can be monitored by the surface using the umbilical cable for transmission. Monitor is also fitted in the sub.
MANIPULATORS: Two, six degrees-of-freedom, with lift capacity of 40kg at full extension on bow.
SURFACE COMMUNICATIONS: Hardwire communication through umbilical.
SUBSURFACE COMMUNICATIONS: Hardwire communication through umbilical, plus an acoustic, thru-water communications system to be used in the event of cable failure.
SONARS:
- Scanning - None
- Pingers - Yes for emergency location.
- Echo Sounders - Yes, digital.
- Transponders - None
- Directional Hydrophones - Yes, system for pinger location-/homing.
- Doppler - None

STATUS: Eighteen vehicles have been constructed, 16 are operational.
CLASSIFICATION/CERTIFICATION: Lloyds Register of Shipping
OWNER: Scan Dive, Stavanger, Norway; Dolphin Services A/S, Tananger, Norway; Nordex Willco; HMB Subwork, Gt. Yarmouth, Norfolk, England; International Underwater Contractors, City Island, New York, U.S.A.
OPERATOR: Same as above
BUILDER: OSEL Group, Great Yarmouth, Norfolk, England

CHECK MATE

LENGTH	3.25m	LIFE SUPPORT DURATION	240 man hrs
BEAM	2.6m	TOTAL POWER	65 kW
HEIGHT	3.15m	SPEED: HORIZONTAL	3 kt
DRAFT	3.15m	VERTICAL	2 kts
WEIGHT IN AIR	7,000kg	CREW: PILOTS	1
OPERATING DEPTH	325m	OBSERVERS	1
COLLAPSE DEPTH	1,100m	COLOR: HULL	Black
HATCH DIAMETER	535mm	SAIL	None
PAYLOAD	400kg	LAUNCH DATE	1979

PRESSURE HULL: Spherical shape 1,900mm ID, 79mm thick of plastic
POWER SOURCE: Power is cable-supplied from support vessel. The umbilical comprises 2 coax RG 59 (1 is spare) and 2 twisted pairs (1 pair is spare). Installed power (main hydraulic power unit for propulsion) in 65 kW (85 kW allowed peak load for 2 minutes) at 600 V, 60Hz. Emergency batteries of sealed lead acid type of 24 V, 108 amp-hrs are located inside the pressure hull.
MANEUVERING CONTROL: Three horizontally acting hydraulic thrusters of 16 hp each are equally spaced and act tangential to the hull. Three vertically acting hydraulic thrusters of 8 hp each are located on both sides and aft of the hull. The vehicle is controlled by two joysticks. Heading and depth are stabilized. Buoyancy is controlled by fixed ballast and 2 hard - air operated - variable ballast tanks of 100 liters each.
LIFE SUPPORT: Three O_2 flasks of 3,000 std cu m at 200 bars each are carried outside of pressure hull. CO_2 is removed by scrubbing through HP sodasorb or LiOH. Monitors for O_2 (Draeger), CO_2, temperature, humidity and pressure. Back up (tubes) for O_2 and CO_2. Alarm for O_2 level.
VIEWING: The total pressure hull is transparent. Trainable TV simultanously in submersible and at surface control.
MANIPULATORS: Two hydraulically powered, not jettisonable, rate-type manipulators, 6 degrees-of-freedom, 1.5m max. extension. Parallel jaws type claw, 50 kg lift fully extended. One hydraulically powered, not jettisonable, master-slave working manipulator, 7 degrees-of-freedom, 2.5m max. extension, parallel jaws with adaptors. Lifting capacity 80 xp at 75% extension.
SURFACE COMMUNICATIONS: VHF transceiver (VHF/BDR FM-1606M, (2 w) and hardwire system.
SUBSURFACE COMMUNICATIONS: Hardwire system and underwater telephone (Felt Telefon TP-6N LB/CB rear cover). Mesotech underwater telephone (18 kHz) for emergency use.
SONARS:
- Scanning - Mesmar (SS140S).
- Pingers - None
- Echo Sounders - None
- Transponders - None
- Directional Hydrophones - 38 kHz (RNN)
- Doppler - None

STATUS: Operational
CLASSIFICATION/CERTIFICATION: Det Norske Veritas
OWNER: A/S Mollerodden, Haugesund, Norway
OPERATOR: Same as above
BUILDER: Same as above

TABLE 15. CHARACTERISTICS OF 1-ATA (DRY) INTERVENTION VEHICLES

bilities. The following presents the characteristics of vehicles within this category:

Operating Depth:	300m to 1000m
Crew:	2 to 3
Weight in Air:	3.5 tonnes to 9.5 tonnes
Minimum-Maximum Length:	2.2m - 3.25m
Minimum-Maximum Width:	2.2m - 2.6m
Minimum-Maximum Height:	2.0m - 3.15m
Electrical Power:	24KWH to 29.4KWH (unlimited with umbilical cable)
Life Support Duration:	96 man-hours to 478 man-hours
Maneuverability:	3-dimensional (within 100m radius of the support vessel)
Manipulators:	1 to 3

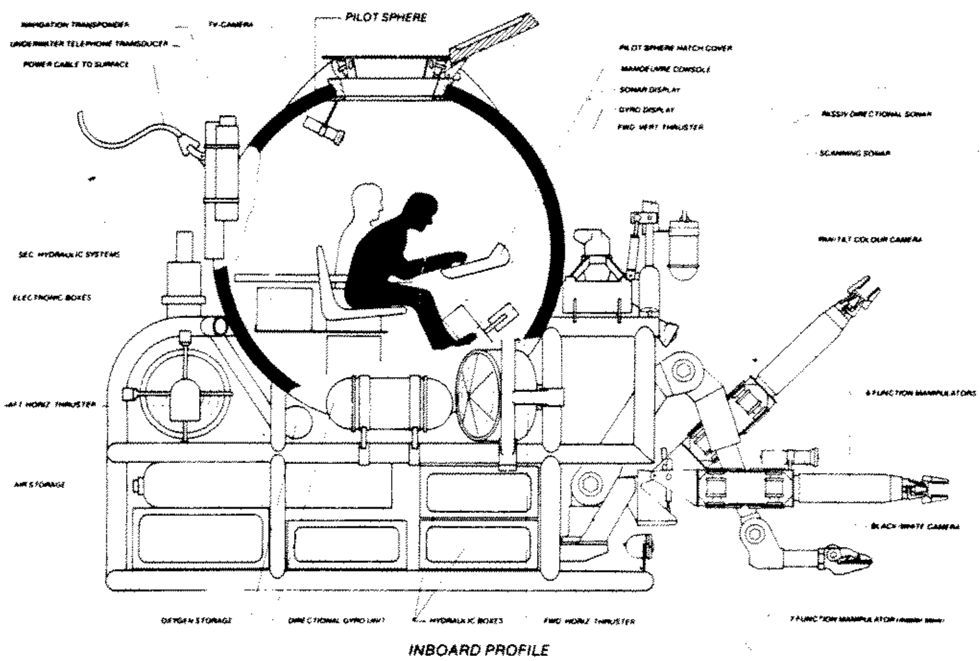


FIG. 40. CHECK MATE (from ref. 220)

4.1.2.e Atmospheric Diving Suits

There are six different types of Atmospheric Diving Suits (ADSs). The most numerous are the JIM and WASP varieties which number 18 and 14, respectively. The JIM variety receives both propulsive power and manipulative power from the operator; the WASP variety receive manipulative power also from the operator, but thrusters are used for maneuvering. These two vehicles are pictured in Fig. 41 and their characteristics are presented in Table 16. These vehicles carry only the operator, are at 1-ATA pressure and receive power for instrumentation from the surface via an umbilical. The method of propulsion for JIM is similar to walking; hence, it requires a stage to transport it to the work site and a foundation upon which to walk. WASP "flys" in 3-dimensions and has a variety of ways in which it can station-keep around or within a structure. The manipulators of these vehicles are human powered. The operator inserts his arm within the vehicle's "arm" and, within certain limits, the arm follows his movement. The operator has a sense of force feedback and gross sensory perception. The tasks these vehicles have conducted parallels those of the MANTIS and, in a few instances, exceeds it in variety.

Over 40 ADSs have been constructed, of which there are six different types and five varieties of JIM. The following presents the major characteristics of these vehicles.

Operating Depth:	229m - 700m
Crew:	1
Weight in Air:	95kg - 1089kg
Minimum - Maximum Height:	1.9m - 2.08m
Minimum - Maximum Width:	0.89m - 1.2m
Minimum - Maximum Thickness:	0.92m - 1.2m
Electrical Power:	Unlimited with umbilical.
Life Support Duration:	20 man-hours to 80 man-hours
Maneuverability:	x-y axes (JIM, Galeazzi-type and NEWTSUIT) x-y-z axes (all others)
Manipulators:	2

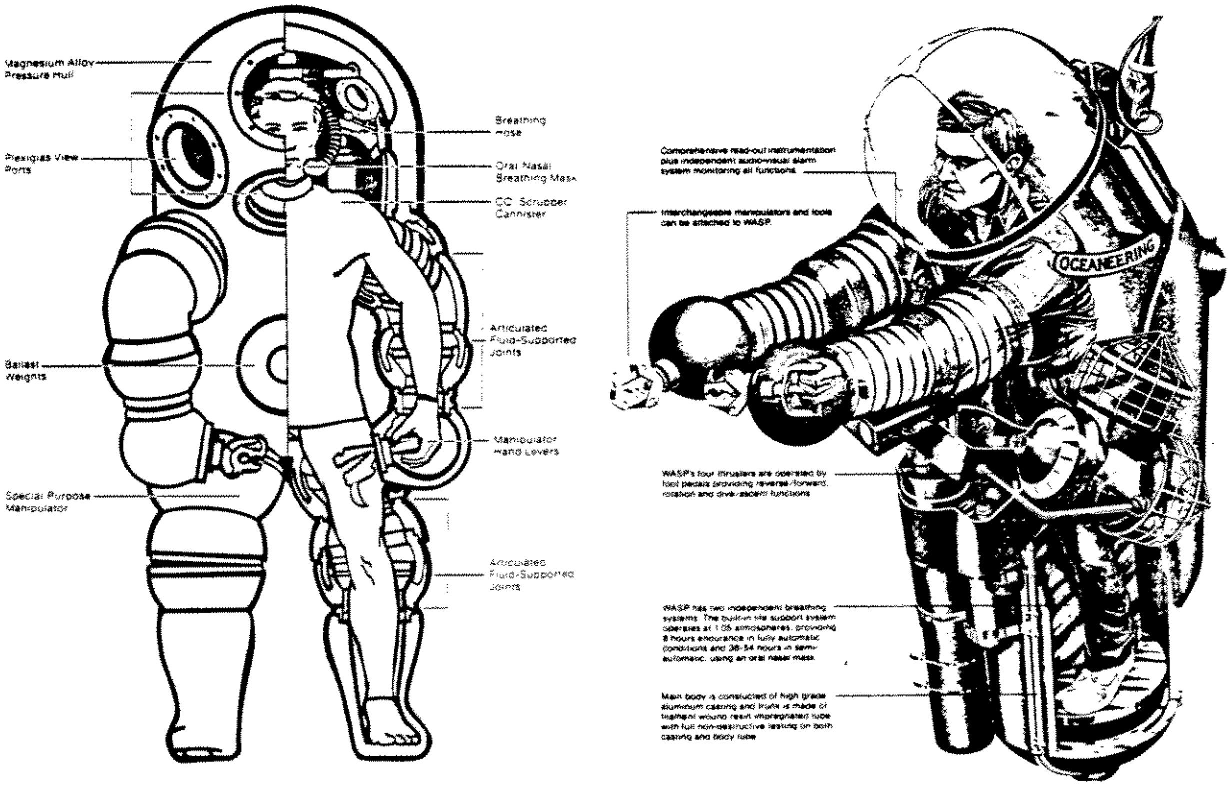


FIG 41. JIM (left) AND WASP (right) (Courtesy Oceaneering International)

JIM (Type II)

HEIGHT	2.05m	PAYLOAD	Various
WIDTH (FRONT)	2.0m	LIFE SUPPORT DURATION	20 man-hrs
WIDTH (SIDE)	1.0m	TOTAL POWER	Manual
WEIGHT (DRY & EMPTY)	339kg	CREW: OPERATOR	1
WEIGHT (DRY W/OPERATOR)	409kg	COLOR	White
OPERATING DEPTH	457m	LAUNCH DATE	1973
COLLAPSE DEPTH	NA		

JIM (Type III)

HEIGHT	190cm	PAYLOAD	Various
WIDTH (FRONT)	89cm	LIFE SUPPORT DURATION	20 man hrs
WIDTH (SIDE)	92cm	TOTAL POWER	Manual
WEIGHT (DRY & EMPTY)	245kg	CREW: OPERATOR	1
WEIGHT (DRY W/OPERATOR)	310kg	COLOR	White
OPERATING DEPTH	305m	LAUNCH DATE	NA
COLLAPSE DEPTH	NA		

JIM (Type IV)

HEIGHT	198cm	PAYLOAD	Various
WIDTH (FRONT)	102cm	LIFE SUPPORT DURATION	20 man hrs
WIDTH (SIDE)	113cm	TOTAL POWER	Manual
WEIGHT (DRY & EMPTY)	354kg	CREW: OPERATOR	1
WEIGHT (DRY W/OPERATOR)	431kg	COLOR	White
OPERATING DEPTH	610m	LAUNCH DATE	NA

PRESSURE HULL: Human configuration split at neck (Types II & IV are split at waist). Main body and dome, knee spacer and boots are composed of magnesium alloy (Type III: aluminum alloy; Type IV: GRP). Joints, elbow spacers and hand enclosures composed of an aluminum alloy which are fluid-supported at a pressure in excess of ambient water pressure.

POWER SOURCE: Manual. Batteries supply power for CO2 scrubber, UWC, pingers, flashing light.

MANEUVERING CONTROL: JIM is lowered and raised to the work site by a lift cable. Types II and III employ a 9mm, 7-core cable, 362kg test. Type IV employs a 12mm, 9 conductor cable, 452kg test. On site the operator is capable of maneuvering as would a human on the surface. The underwater weight can be varied to meet varying conditions.

LIFE SUPPORT: O2 is carried externally in two flasks of 800 l. total capacity and is bled continuously into the suit. The operator inhales normally and exhales through an oral/nasal breathing mask. A one-atmosphere pressure is automatically maintained by a control valve which supplies O2 at the rate required to maintain desired pressure. CO2 is removed by scrubbing (two units) through soda lime. Monitors for O2, pressure and temperature (inside suit and on surface).
VIEWING: Four acrylic plastic viewports in the dome, two look

JIM

WASP (Series I)

HEIGHT	2.03m	PAYLOAD	Operator plus 10kg
WIDTH (FRONT)	1.01m	LIFE SUPPORT DURATION	40 man hrs
WIDTH (SIDE)	1.0m	TOTAL POWER	Indefinite
WEIGHT (DRY & EMPTY)	405kg	CREW: OPERATOR	1 kt
WEIGHT (DRY W/ OPERATOR)	500kg	COLOR	Yellow/black
OPERATING DEPTH	610m	LAUNCH DATE	1977 (prototype)
COLLAPSE DEPTH	NA		

PRESSURE HULL: Cylindrical shape. Main body constructed of aluminum casting. Trunk is a filament-wound, resin-impregnated tube. Bow or top is a hemispherical macrilon protective dome, over a polycarbonate dome.
POWER SOURCE: All power is provided through a surface-connected umbilical cable (Series I: 220 vac; Series II: 440 vac) of 4,536kg (Series I) and 5,443kg (Series II) test. Batteries provide 20 minutes of power at full thrust.
MANEUVERING CONTROL: Series I - two vertical and two horizontal thrusters controlled by operator's feet. Series II - two vertical, two horizontal and two boost-horizontal thrusters controlled by feet or hands.
LIFE SUPPORT: A built-in, fully-automatic system provides 8-hours endurance for Series I, 12 hours for Series II. An oral/nasal face mask can provide 36-54 hours for Series I, 60 hours for Series II.
VIEWING: Polycarbonate bow dome provides 360 degrees of vision.
MANIPULATORS: Two articulated arms into which the operator places his arms. Arms will follow motion of the operator.
SURFACE COMMUNICATIONS: Hardwire through umbilical.
SUBSURFACE COMMUNICATIONS: Hardwire communications through umbilical. Acoustic communications for umbilical failure.
SONARS:

- Scanning - None
- Pingers - One
- Echo Sounders - None
- Transponders - None
- Directional Hydrophones - None
- Doppler - None

STATUS: Operational (12 vehicles)
CLASSIFICATION/CERTIFICATION: Lloyds Register of Shipping
OWNER: Oceaneering International, Houston, TX
OPERATOR: Same as above
BUILDER: Osel Group, Great Yarmouth, England
REMARKS: WASP Series II is described below, all other characteristics are similar to Series I.

WASP (Series II)

HEIGHT	2.13m	PAYLOAD	Operator plus 10kg
WIDTH (FRONT)	1.06m	LIFE SUPPORT DURATION	72 man hrs
WIDTH (SIDE)	0.81m	TOTAL POWER	Indefinite
WEIGHT (DRY & EMPTY)	405kg	CREW: OPERATOR	1
WEIGHT (DRY W/OPERATOR)	454kg	COLOR	Yellow/black
OPERATING DEPTH	610m	LAUNCH DATE	1977 (prototype)
COLLAPSE DEPTH	NA		

WASP

TABLE 16. CHARACTERISTICS OF 1-ATA (DRY) INTERVENTION VEHICLES

4.1.3 1-ATA Intervention (Wet)

4.1.3.a Neutrabaric Diving

The Neutrabaric technique, developed by Vickers-Intertek, is described in section 2.2.13 and shown in Fig. 35. The technique is, in certain respects, a hybrid system, in that it combines both the diver and the lockout manned submersible. To transfer the divers/technicians to the encapsulated and flooded wellhead, a capsule similar to the WELLHEAD SERVICE CAPSULE or MERMAID IV can be used. Modifications to these vehicles would be necessary to permit depressurization of the encapsulated sea water. Calculations by the developers show that only 11.6 liters of sea water need be pumped from the wellhead chambers (after mating of transfer capsule and chamber has been effected) to bring the encapsulated water to 1-ATA. This calculation is based on a wellhead chamber of about 14 cubic meters volume at 213 meters water depth. Theoretically, there is no limit to the depth at which this technique can be employed. The U.S. Navy's Deep Submergence Rescue Vehicles (DSRVs) use a similar technique to de-water the mating skirt chamber between the rescue vehicle and a stricken submarine to depths of 1,500 meters. But in this instance the transfer chamber is pumped dry to reach 1-ATA. The only practical limits are those imposed by the volume of the tanks into which the encapsulated water is pumped and the power capacity of the pumps. Neither of these are inhibiting factors. The developers point out that gas leakage in a dry chamber means poison, but in the Neutrabaric system the water would absorb many of the gasses.

4.2 REMOTELY OPERATED VEHICLES

There are two types of ROVs which have been used or developed for inspection and maintenance of subsea wellheads: structurally reliant vehicles and tethered, free-swimming vehicles. A third type of ROV, the untethered or autonomous vehicle, is considered by its developers to also have application to SPS I&M.

4.2.1 Structurally Reliant

This type of vehicle is connected to the surface by an umbilical cable which provides electrical power, and transmits control and data signals. All of these vehicles have a TV camera and one or two manipulators. The term structurally reliant refers to their method of propulsion or operation, in that, they are in contact with the structure they are inspecting or maintaining or rely upon cables for maneuvering in at least one, and sometimes two axes.

All of the vehicles described in this section have been designed for wellhead support; they include: the Manipulator Maintenance System (MMS); the Tele Manipulator d'Intervention et de Maintenance (TIM); the Remote Guidance System (RGS), and BANDIT.

4.2.1.a Manipulator Maintenance System

The MMS was developed by Exxon Production and Research Company to provide inspection and maintenance in 1974 for the Gulf of Mexico's SPS. The system, after modifications, is now in use on an experimental basis on the UMC in the North Sea and is referred to as the RMS (Remote Maintemance System). The following description of the MMS is taken directly from Butler and Rickey (ref. 142).

The MMS (Fig. 42) was designed to maintain the manifold and control system components on the SPS. Manifold gate valves and control modules can be replaced by the MMS without any surface lift equipment. Larger equipment packages, such as the electro-hydraulic control skids, would be lifted by a surface vessel, with the MMS assisting in connections and attaching a lift line. The MMS uses a track installed around the subsea manifold to gain access to the components. When locked into position on the track for replacement operations, the MMS work tool or end effector can move up 2.7 meters, out 1.5 meters toward the manifold, and 0.75 meters along the track. The valve replacement tool is capable of 20,300 newton-meters of torque for valve makeup and a calculated 81,400 newton-meters of impact torque for breakout. The lift capability is about 1.5 tonnes. The end effector can move passively approximately 3.2 centimeters vertically and horizontally, +/- 5 degrees in roll and +/- 10 degrees in pitch and yaw without active alignment change. This feature allows a valve or control module to be accessed without perfect alignment.

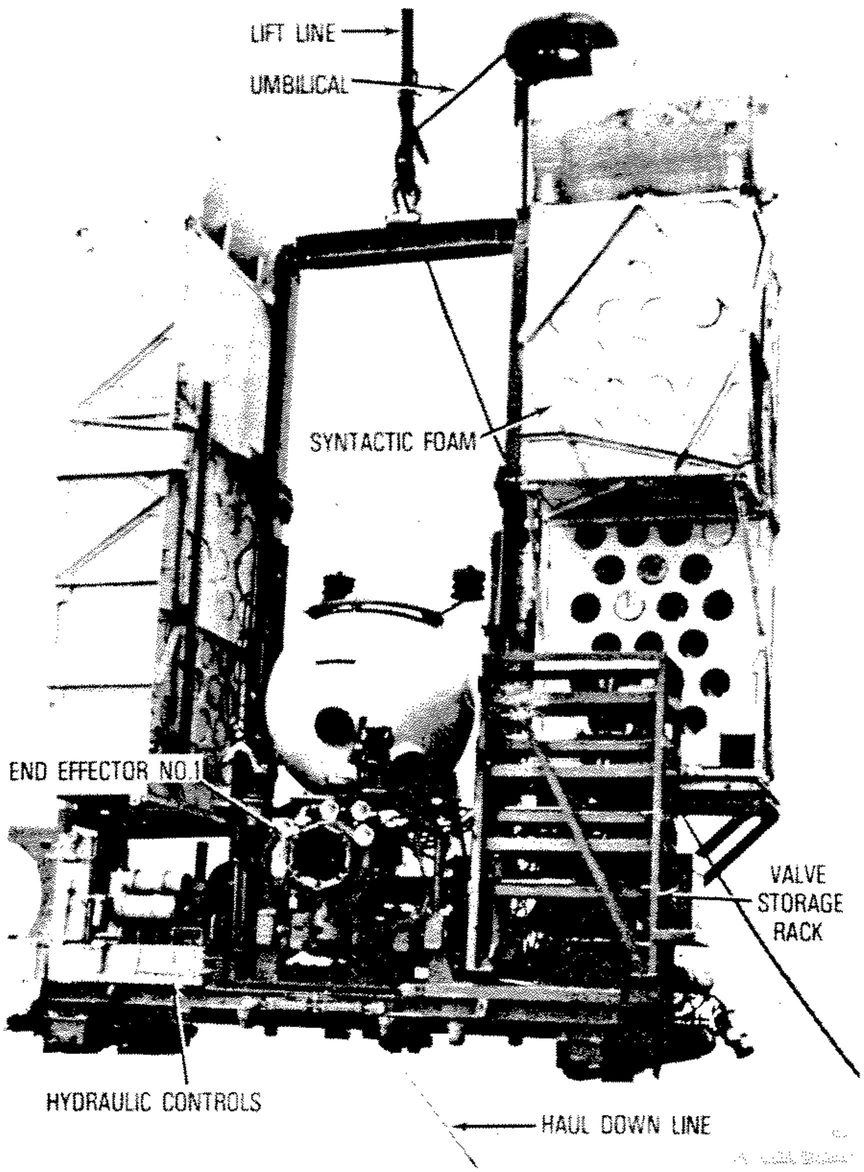


FIG. 42. THE MANIPULATOR MAINTENANCE SYSTEM (Courtesy Exxon)

The MMS is controlled from the surface through an umbilical cable that provides communications and power for the hydraulic pumps on the MMS. A battery powered electrical backup power unit is mounted on the MMS and an emergency hydraulic unit is available in addition to two redundant hydraulic power units. If the umbilical is severed, an emergency sequencer issues a pre-determined set of commands designed to bring the MMS back to its landing area and permit it to come to the surface for retrieval.

The MMS measures 8.5 x 2.5 x 7.5 meters and weighs about 30 tonnes in air. It consists of a main frame carrying the end effector that replaces a failed component, an equipment storage rack, hydraulic controls, and provides support for syntactic foam blocks that provide the MMS with positive buoyancy. A lift line is used only during launch and recovery of the MMS. The MMS uses a haul down line to attach itself to the SPS. A haul down line buoy on the side of the MMS is attached to the track of the SPS after completing an operation to provide a new line for future missions. The haul down line winch and take-up drum are on the rear of the vehicle.

For a typical operation the MMS and its support equipment would be stored onshore and mobilized as needed. The MMS would be placed onboard a vessel and brought to the work site. When the vessel arrives on site the haul down line buoy is acoustically released and brings the line to the surface. The subsea end of the haul down line is attached to an anchor which is the landing point for the MMS. The buoy is brought aboardship and the hauldown line is attached to the MMS via its winch and take-up drum. The following steps then occur:

- The MMS is launched using a stern-mounted A-frame. The winch system is activated and the MMS begins its descent. The MMS can approach the anchor and landing area in any orientation about the vertical axis. The clear landing on the SPS is a truncated cone that facilitates docking in 0.5 knot of current.

- The MMS lands on the anchor which has an orientation device that aligns the MMS along the track. The MMS picks up the anchor, which makes it negatively buoyant, and carries it along as it drives along the track and works.

- The MMS drives to the location of the defective component and positions itself visually using its video system. The end effector extends, removes the valve, stores it in the equipment rack, picks up a new valve, inserts it into the receptacle, torques the valve to energize the metal seal, and then pressure tests the connection.

- The MMS then drives back to the landing area, stabs a new haul down line buoy to the track and attaches the subsea end of the new line to the anchor. It then sets down the anchor, releases the brake, and floats to the surface, paying out the old haul down line as it ascends.

- With the MMS aboardship, a release weight is threaded onto the old haul down line and allowed to free-fall to the anchor. When it arrives it releases a latch and allows the old line and the release to be retrieved. The SPS is left with the buoy in place to be recalled as required.

The MMS uses two basic tools or end effectors for performing its work tasks: a valve replacement end effector, and a control module replacement end effector. The valve replacement end effector is a large hydraulic socket wrench that swallows the valve during a replacement operation. The wrench engages a large castellated nut on the valve to make or break the connection. The leading edge of the valve is tapered to allow the forward thrust of torque on the nut to load the metal seal against the mating surface of the receptacle on the manifold and to make up hydraulic connections. A hydraulic port at the rear of the valve allows pressure to be applied to an annular space between the metal seal and an O-ring just larger in diameter than the seal ring. If no pressure decay occurs, the seal is confirmed.

The control module replacement end effector combines two wrenches to operate a two-bolt clamp with lifting prongs similar to those on a fork lift. This tool engages specially designed hardware on the control module for its replacement. The lift prongs are inserted into cylindrical tubes of the control module and hydraulic latch fingers secure the grip on a plate just above the tubes. The wrenches engage jackscrews on the control module which open and close a two-bolt clamp on the module. The clamp has tapered surfaces which provide vertical make-up force to pre-load metal seals in the hydraulic couplers.

The MMS was successfully used for maintenance of the SPS. It was mobilized five times and completed a total of 85 missions. The MMS successfully accomplished all of the planned maintenance and several unplanned tasks, such as performing diagnostic tests to help identify the source of an electrical problem. The replacement of two valves was typically performed during one mission in a four to six hour period.

4.2.1.b TIM

This system was developed for experimentation on the Grondin field SPS (see Sect. 1.3.6) in 1979-80 by ELF Aquitaine. In addition to TIM , a 1-ATA manned submersible, SEA CAT, was equipped to carry a set of tools which were also aimed at SPS maintenance. Both experiments will be described.

TIM is composed of three major elements: a rail-mounted carriage; two manipulators, and a telescoping crane. (Fig. 43) The carriage supports the manipulators, the telescoping crane, a hydraulic power pack supplied with electrical power from a surface-connected umbilical, and TV cameras and lights. The carriage size is 4.2 meters length by 2.3 meters width and it weighs about 12 tonnes. The Grondin SPS was equipped with a pair of rails on each side of the template and integral with the manifolds. The carriage can move on these rails by means of six supporting rollers,additional driving rollers propel the carriage. Hydraulic brakes on the rollers avoid the risk of skidding. Motion speeds were 25 cm/sec. (max.) and 5 cm/sec. (min.). The carriage also carried automatic obstacle detectors and shock absorbers. The carriage was designed to provide a large free space on its deck to carry tools and other equipment. The hydraulic power unit was installed inside the frame of the carriage and provided 175 bars (max. pressure) and 150 bars (working pressure). Five TV cameras and ten floodlights were installed at various locations on the carriage. One panoramic camera was on the top of the crane; two on the manipulators; one on the carriage deck, and one under the carriage. The lights were 500 watts each, some were in a fixed position and others were mounted on a pan/tilt device.

Two identical manipulators were fitted to the carriage. Each could be installed to either end of the four carriage corners using a multiple hydraulic connector. The manipulators were provided with five independent elements: a telescopic column; a rotating head; a raising shoulder; a forearm, and a wrist. Specific tools could be fitted to the wrist and then activated through an hydraulic power pick up located on the manipulator. Available power was ten liters/minute at 140 bars hydraulic fluid pressure. Only one movement on each manipulator can be performed at one time.

The telescopic crane was mounted in the center of the carriage. It consisted of a rotating column and an articulated telescoping jib. The jib tip was fitted with a grip. The load capacity of the crane was 1,500 kg suspended 4.8 meters from the column axis.

A push button console was located on the surface support vessel (the barge ANGUILLE) which was equipped with four TV monitors, and command and monitoring displays. This was housed in an air conditioned room.

TIM was constructed and pool-tested before leaving France to begin it field tests. Five on site tests were sucessfully completed. These included:

- Installation and connection of a jumper pipe between a Xmas tree and the mainfold,

- Installation and connection of a jumper electrical cable,

- Installation and Connection of a jumper hydraulic hose,

- Operation of a local safety valve, and

- Removal and/or displacement of a guideline.

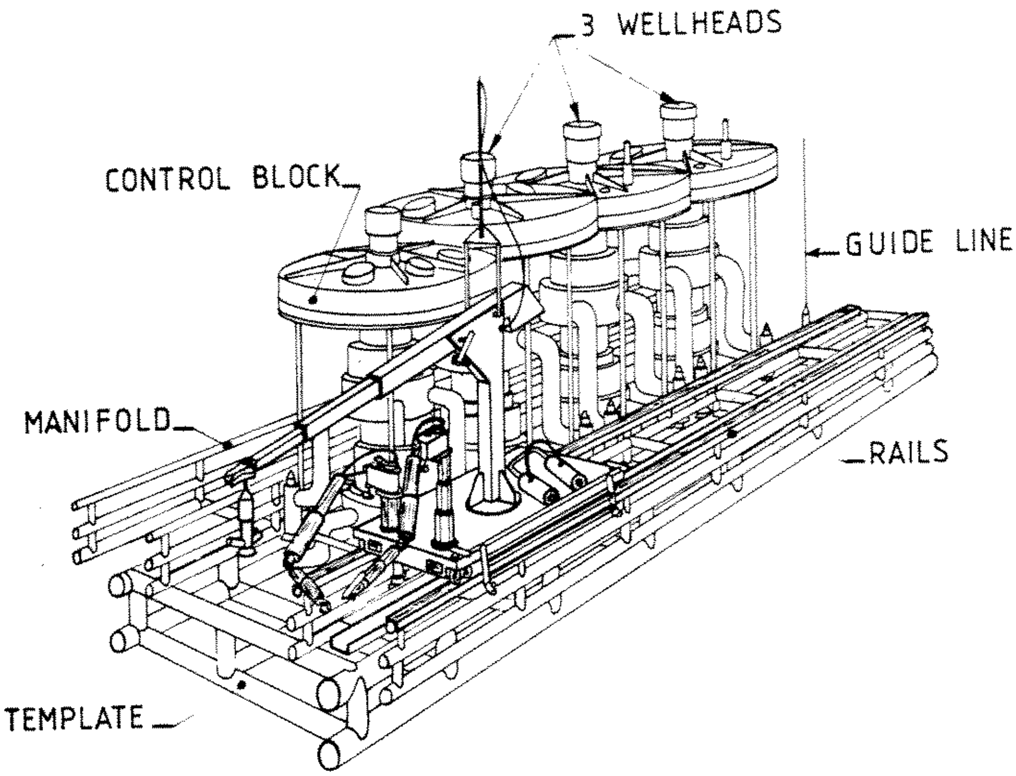
The manned submersible SEA CAT was used in the Grondin field to obtain three main objectives:

- Through acoustic positioning, a blind navigational approach would be attempted to reach the SPS installation,

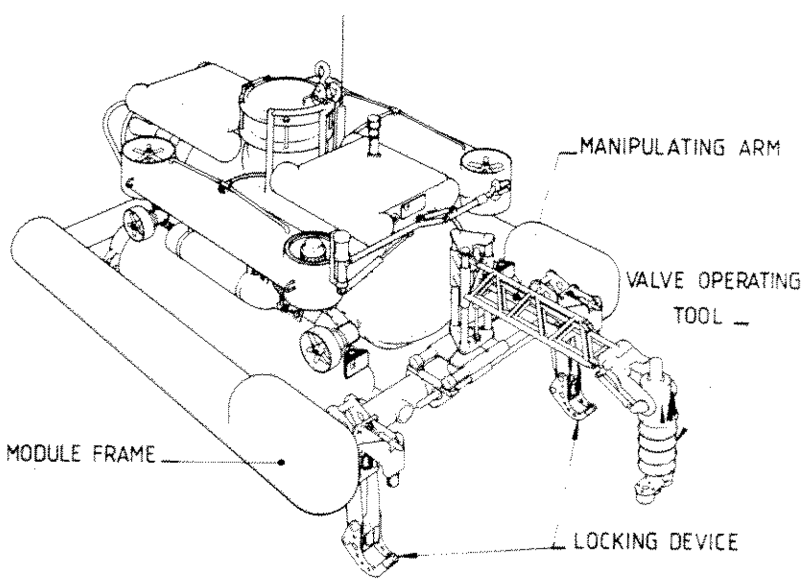
- Locking the submersible to the SPS, and

- Performing manipulative tasks remotely from within the submersible.

The submersible was equipped with a manipulating assembly that consisted of four major elements (Fig. 43): 1) a module frame (containing a hydraulic power unit powered by the submersible's batteries); 2) locking devices to secure the submersible to the SPS; 3) a manipulator (five degrees-of-freedom and a 3 meter reach), and 4) a valve operating tool. The valve operating tool was fitted to the manipulator tip to operate gate or ball valves. The tool was equipped with an electric motor and a gear



TELEMANIPULATEUR D'INTERVENTION ET DE MAINTENANCE



SEA CAT

FIG. 43. TIM AND SEA CAT. (From ref. 106)

reducer. The number of revolutions needed to operate the valve could be selected on the control console. An impact wrench could be employed to break out a stuck valve.

At the Grondin field the submersible was launched 500 meters away from the SPS and reached it using acoustic beacons for navigation and positioning. The vehicle then locked on the manifold and various safety valves on the Xmas trees and manifold were operated by its manipulator. During the rail-mounted carriage (TIM) experiments, the submersible was used as a backup control system to operate the carriage after making an electric cable connection between both vehicles.

4.2.1.c Remote Guidance System (RGS)

The RGS is an integrated acoustic and propulsion system designed to stabilize the lateral and rotational motion of a payload being lowered to a precise location on a sea floor template without the use of guidelines. The system was designed to avoid several inherent problems in using guidelines in deep water, such as, difficulty in handling and stabilizing the lines, risk of entanglement, accumulation of debris if they should break, and the fact that very heavy lines and large tension requirements are needed to support the line weight and provide the required tension at the sea floor target. The following description of the RGS is taken directly from Butler and Rickey (ref. 142).

The RGS was developed by Exxon Production and Research Company. It consists of two major subsystems: a positive reference system and a propulsion system. As a payload is being lowered to the sea floor, the reference system acoustically locates the template on the sea floor and precisely measures payload location relative to the landing target. The propulsion system provides thrust to isolate the payload from vessel excursions to move it to the exact target location for landing. The propulsion system will normally be controlled directly by the surface unit using the output signals from the position reference system. This type of control is employed to minimize the amount of manual intervention.

The major elements of the RGS (Fig. 44) are a thruster platform, an acoustic positioning system, and a surface control console including thruster power supplies and controllers. The top portion of the assembly is the RGS subsea propulsion system and acoustic positioning system. The lower portion is a docking frame used as the payload for offshore tests. The thruster platform consists of a structural frame, four thruster motor assemblies with 1.5 meter propeller and ducts, two redundant electric bottles, and a junction box that breaks out and distributes the electrical condutors in the umbilical. Combinations of the thrusters can provide up to 7,100 newtons of thrust in any horizontal direction. The propellers are reversible and are driven by 20hp motors. The electronics package gathers information on thruster motor RPM and gyroscope heading, multiplexes this information and transmits it to the surface control panel. The

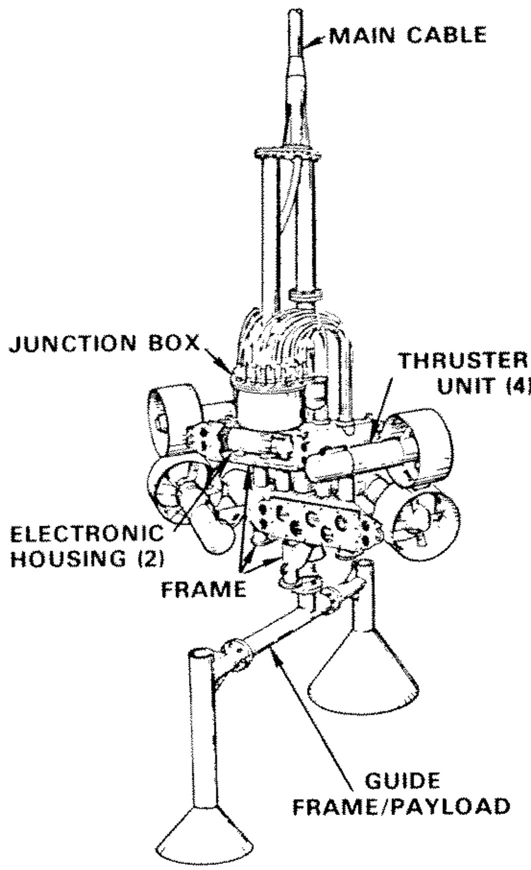


FIG. 44. REMOTE GUIDANCE SYSTEM (from ref. 142)

umbilical cable terminates into the junction box, which routes cables to thrusters, the television cameras, electronic bottles and acoustic system components. The RGS and its payload can be lowered on drill pipe, wire rope or its own electro-mechanical umbilical depending on the total weight of the deployed package.

The acoustic posisitoning reference system is used to provide data for calculating the RGS location relative to the target, using a transponder array on the SPS template and an interrogating/receiving unit mounted on the RGS and its payload. The RGS transmits an acoustic signal (110 - 160 kHz) to the transponders on the SPS; they, in turn, respond with an acoustic pulse. These signals are received at the RGS and transmitted to the surface where slant range determinations are made. Using at least three concurrent slant ranges the surface computes the RGS position, and any change required in thruster output. The interrogator/receiving units also measure and provide water temperatures to provide an accurate determination of acoustic velocity.

The surface control equipment includes processing equipment, display monitors and control mode selection and operation hardware. The processing equipment computes position and heading locations on the payload from the acoustic system and gyroscope data and provides for control of the subsea thrusters to move the payload toward the target location. The operator can select an automatic operational mode, enter the target information, and monitor the position and heading using the CRT display and graphics terminals. Alternatively, he can control the system manually using a joystick hand controller and TV monitor.

In practice, the RGS and payload would be lowered from a surface vessel. The dynamically positioned vesel would initially be positioned using the production riser and permanently moored treatment and storage vessel as a reference. After the package is in the water, a commercially available, long-range acoustic positioning system is used for the initial approach to the SPS. During this approach the surface vessel is moved to a position approximately over the target area. If there is a significant current, the vessel is positioned up-current to compensate so that the RGS is centered approximately above the target. When the package is within 100 meters of the target, the long range system is turned off and the more accurate RGS positioning system is activated. In automatic mode, the RGS would automatically center the package above the target. Vertical position of the RGS is controlled by its lowering/raising winch on the vessel. Docking over the guidepost is monitored by the CRT or TV camera or both.

A full-scale prototype RGS has been developed and tested offshore to demonstrate its ability to dock with a subsea target in 1,000 meters of water. The objectives of the test were to demonstrate capability to control position and heading using acoustic input from transponders on the target in both automatic and hand-controlled modes, and to demonstrate the ability to dock the payload with an ocean bottom target.

4.2.1.d BANDIT

BANDIT is a 1983 development of the Deep Ocean Technology Corp. of Oakland, California. (ref. 239) There are four of these vehicles in operation and three additional under construction. BANDIT (Fig. 45) was developed to provide working access and visual inspection for all sections of a standard BOP or production tree utilizing the system's guidewires for assistance in a manner similar to that used for wellhead TV cameras and running tools. Future versions of the system will be tailored for guidewireless operation. A clump system will allow for an alternative use of the vehicle if all guidewires are broken. According to the developer, unique features of the BANDIT are exceptional stability, visual and enhanced sensory feedback, highly dexterous and powerful manipulators, and the ability to work under adverse currents, visibility and sea state.

The BANDIT is held in a deployment cage for launching and is lowered by a winch and electro-mechanical cable to the working depth. During deployment, sensory systems warn of contact with the riser, and TV cameras observe the riser above and below. Thrusters and manipulators may be used to maneuver at any time. Once the deployment carriage docks onto the guidepost, BANDIT is lowered to the desired working height. A cable clamp on the

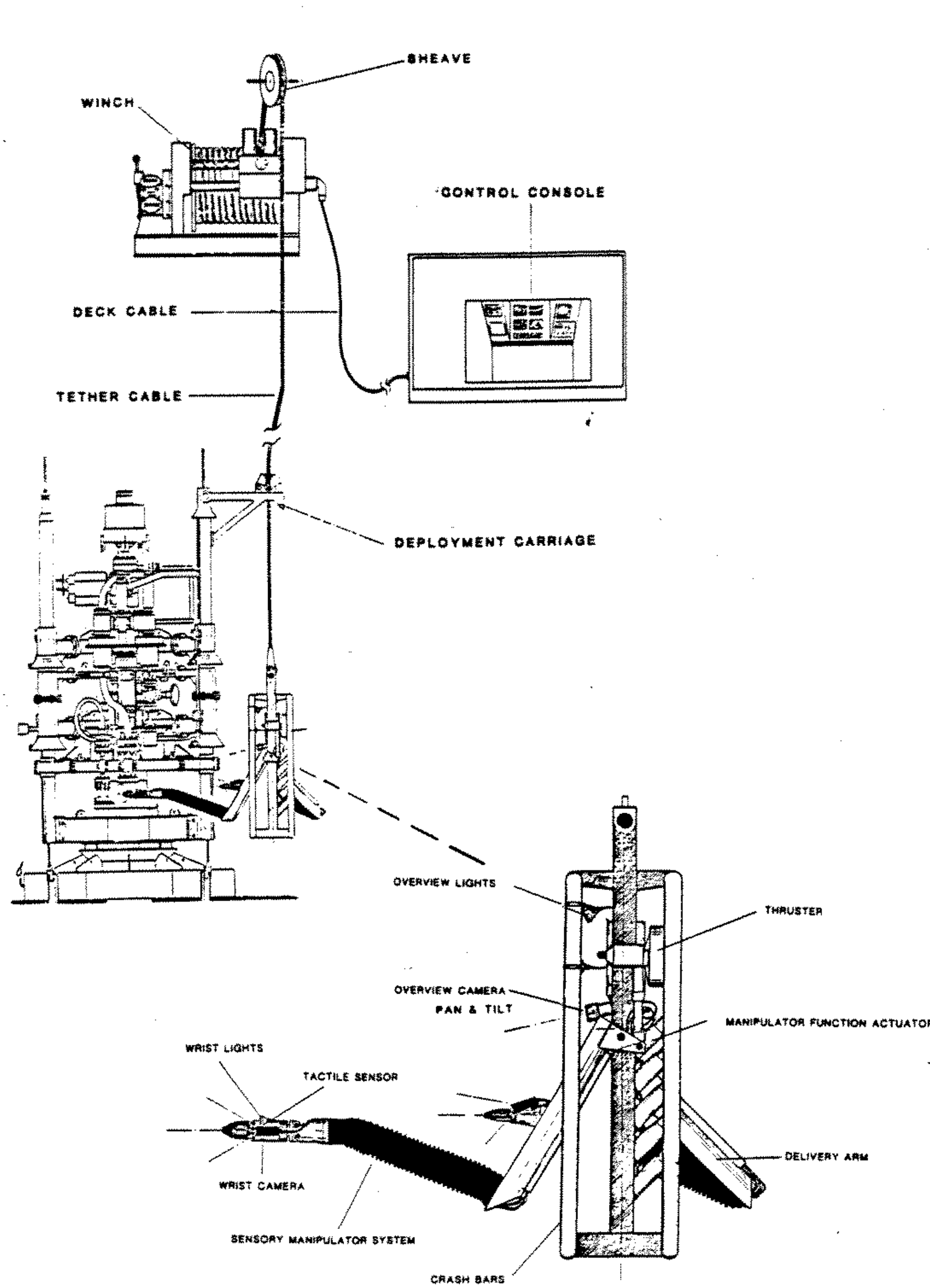


FIG. 45 THE BANDIT SYSTEM. (Courtesy Deep Ocean Technology)

deployment carriage isolates the system from surface movement. By using thrusters for rotation and the winch/clamp for height adjustment, full working access is obtained to 20 centimeters beyond the centerline.

The main TV camera and lights and the two wrist-mounted TV cameras and lights provide an overview and close-up inspection capability. The manipulators provide sensory feedback of force, motion and touch. Each, according to the manufacturer, can position an A-X ring to within 0.002 inch and can literally feel for different materials, textures, scratches and other subtleties. Further, the sensory manipulators can detect the vibration from oil flow, electric and hydraulic motors, and operating valves.

4.2.2 Tethered, Free-Swimming

This type of ROV constitutes the vast majority of vehicles being used in support of offshore oil/gas activities. All have at least one closed circuit TV camera with appropriate lighting, maneuverability in three dimensions, and are cable-connected to a surface or subsurface platform from which they are controlled and to which they transmit data and observations. All of the commercial vehicles receive their electrical power from the support platform. These vehicles are designed to operate in the water column, not in contact with the bottom or a structure, although they may occasionally do so to accomplish certain tasks. They are generally positively buoyant when submerged and rely on a vertical thruster for depth control. The tethered, free-swimming vehicle is part of a system which consists of: an electrical power source (ship's power or a dedicated generator); a control/display console (to monitor the vehicle's condition and through which the vehicle is controlled); a handling system that launches and retrieves the vehicle and manages its umbilical cable; a launcher or cage (which is optional) within which the vehicle is launched/retrieved and from which it is deployed on a tether at the working depth; and the vehicle itself.

This type of vehicle can operate in two modes. One mode is with the support ship or platform to station-keeping above the vehicle (e.g., by mooring, anchoring or dynamic-positioning) while the launcher/vehicle works at a specific location below. A second mode is termed "live boating", in which the support ship station-keeps and slowly progresses with the vehicle as it transits along the bottom or a bottom structure, such as a pipeline or cable.

A recent count of the tethered, free-swimming, commercial vehicles shows in excess of 353 have been manufactured since 1975, of which at least 300 are operating. There are 27 known manufacturers of tethered, free-swimming ROVs from 11 different countries who have produced a minimum of 69 different models. The range of capabilities and dimensional characteristics is considerable, the following data provides some appreciation for the diversity:

Operating Depth (max):	100m to 2,500m
Vehicle Size (LxWxH):	
Minimun -	75cm x 55cm x 35cm
Maximum -	500cm x 140cm x 270cm
Vehicle Dry Weight:	25kg to 5,500kg
Maximum Operating Current Speed:	0.5 knots to 3.2 knots
Total System Weight:	
Minimum -	34 kg
Maximum -	55,000 kg

The diversity of instrumentation and tooling these vehicles can carry and employ ranges just as widely as their dimensional characteristics. The recently-launched RTV-100 (produced by Mitsui Engineering and Shipbuilding) is equipped with a color TV camera and light, and a diver's type depth gage and compass. The newly-launched SOLO (produced by Slingsby Engineering Ltd.) is equipped with - and can deploy the following:

- Obstacle avoidance sonar
- Gyrocompass
- Depth sensor
- Altitude sensor
- Current meter
- Acoustic velocimeter
- Pipe tracking system
- Transponder/interrogator
- Transponder/responder
- Side scan sonar
- C-P probe
- Transponder place/remove tool
- Hydraulic tool package
- Still camera
- TV cameras (3 ea)
- Flood & strobe lights
- Fiber optic package
- 3-function grabber
- Work manipilator
- High pressure water jet
- Low pressure jet silt remover
- Alignment measurement tool
- AX ring remove/fit tool
- Guidepost manual release tool
- Specialized lifting tools
- 80hp hydraulic power pack
- Guidepost explosive release

The cost of these vehicle systems (not necessarily the two identified above) ranges as widely as their capabilities, from slightly less than $27,000 to well over $1.5 million (USD).

The cumulative work experience of tethered, free-swimming ROVs in support of the offshore oil/gas industry has grown considerably since their first introduction to this arena in 1975. From a wide variety of sources and vehicles, the following represents the oil/gas related work tasks accomplished to date.

<u>Drilling Support</u>

- Site survey/location of well or objects by sonar
- Observe pilot hole for gas
- Re-entry aligment
- Observe stack and LMRP orientation, heave, etc.
- Check cement returns
- Check guide base level
- Riser angle confirmation
- Check connector latch indicator
- Inspection of riser and stack
- Perform temperature/current profiling with depth
- Place/recover acoustic beacons
- Clear debris from well or stack
- Clean level indicator (Bullseye)
- Cut cable or soft lines
- Recover dropped equipment
- Emergency release of hydraulic connectors
- Replace rings in hydraulic connectors
- Place explosive charges
- Attach lines to icebergs for towing

Survey

- Bottom sites
- Cable/pipeline routes
- Pipeline trench profiling
- Wellhead debris mapping

Monitoring

- Observe grouting operations
- Observe piling installations
- Conduct structural alignment and orientation measure-
- ments
- Observation of pipeline pull-ins

Observation/Inspection

- Leak detection
- Structure cleaning
- Determine pipeline tie-in positions
- Wellhead integrity checks
- External examination of concrete platforms
- Pipeline/cable configuration checks
- Check pipeline weighting effectiveness
- Platform NDT inspection, includes
  - Fouling identification/population and densities
  - Sea floor scouring observations
  - Sacrificial anode measurements
  - Thickness measurements (steel and concrete)
  - Ultrasonic flaw/crack detection
  - Detection of bent/broken members
  - Debris accumulation mapping
- Pipeline inspection, includes:
  - Concrete coating examination
  - Detection of suspended members
  - Corrosion-protection measurements
  - Detection/documentation of damage from anchors, trawls, etc.,
  - Observe/measure depth of pipeline burial
- Biological assays
- Geological reconnaissance
- Location/identification of lost and abandoned articles

Maintenance

- Visual structural integrity checks
- Removal of fouling organisms
- Sacrificial anode installation

Diver Assistance

- Support ship positioning
- Locate and mark (with beacon) dive site
- Evaluate site for diving safety
- Initial in-water check of diving gear

- Augment surface understanding of working conditions and progress
- Assist diver in monitoring hardware installation
- Monitor/inspect diver's work
- Document (photo or video) diver's work
- Assist in diver rescue

Hardware Installation/Retrieval

- Retrieval of small objects
- Large equipment/component/debris recovery assistance
- Provide depth and orientation measurements during hardware installation
- Provide assistance during BOP installation
- Assist in cable retrieval and repair

While much of the above work has direct application to SPS inspection and maintenance, there has been very little published regarding the application of tethered, free-swimming ROVs to this task. A survey of the major diving companies in the U.S. resulted in only a few instances of SPS work and these were for straightforward inspection and video documentation.

Two vehicles have been identified for direct application to SPS inspection/maintenance: Ametek/Straza's SCORPIO, and International Submarine Engineering's (ISE) TROV S-7.

SCORPIO (Fig. 46) has been identified as the support vehicle in the Montanazo field when it begins operation. Since the wellhead will be at 762 meters depth, it is far beyond the range of diver intervention. The Montanazo wellhead has been modularized and designed into component parts which can be installed and retrieved by SCORPIO (refs. 156 & 185). The tree cap design was coordinated by the tree manufacturer (Hughes), the control system manufacturer (Marconi Avionics N/L) and ROV consultants (Subsea Offshore. Ltd.). It contains the main ROV intervention points and consists of four hydraulic manifolds. ROV access has been especially designed into the structure and all hydraulically-actuated valves have manual overrides. Also, all ring connector seals have a hydraulic release which can be activated by the ROV.

The most recent report of the role SCORPIO will play in the Montanazo field, and the considerations that led to defining its role, are summarized by Molland in ref. 207 and were presented by J. Bodine of Chevron Oil Co. Based on an increase in demonstrated reliability and use of ROVs on Chevron's part, the company established a study team to define the objectives for an ROV and the nature of the SPS design that would permit obtaining the defined objectives. The study team was composed of the participants noted above and also included the vehicle's manufacturer. The study group had the following objectives:

- Determine the feasibility of the proposed operations
- Development of essential interfaces
- Develop functional specifications

- Evaluate existing systems as opposed to requirements
- Identify development areas
- Develop schedules and costs
- Develop design specifications
- Identify long lead items

The work scheduling for the ROV which would eventually be deployed consisted of three primary areas:

Visual Inspection

- Observation, mobile TV, platform, photographic records
- Survey of pipelines and risers
- Check component alignment
- Check corrosion and (fouling) growth

Light Work

- Debris clearence
- Corrosion-potential (c-p) survey
- Wireline cutting
- Structural cleaningh

Heavy Work

Operating manual overrides
- Hydraulic actuation intervention
- AX ring changeout
- Assisting pod deployment
- Large debris clearence

In designing the Montanazo tree the valves, where possible, were sited in a single-facing direction. Valve actuation is by hexagonal nut operation. The framework around the tree and the tree itself is equipped with docking ports (female) and the ROV is fitted with docking probes. Control pods on the tree were designed for vertical change-out with the replacement unit being steered into position by the ROV.

SCORPIO is to be equipped with a full range of tools with T-bar handles for carrying out various manipulator operations. These include a specially designed AX ring change-out device for the flowline connector, and a main wellhead AX ring change-out device. Bodine (ibid.) stated that the selection of a SCORPIO ROV was based on its worldwide availability and the work packages they would accommodate. He also noted that the ISE-manufactured DUAL-HYDRA vehicles could also be adapted for the proposed work.

The second vehicle, TROV S-7, operated by Oceaneering International, was one of several types of underwater intervention techniques (others included JIM, WASP and MANTIS) subjected to a variety of underwater trials to ascertain their strengths and weaknesses with regards to SPS I&M. The test and its published results are presented in the following chapter. The TROV S-7 vehicle is shown in Fig. 46.

Two other tethered, free-swimming ROVs have been designed and developed for wellhead intervention; these are Slingsby Engineering Ltd.'s (SEL) TROJAN (ref. 243) and Sonat Subsea Service's CHALLENGER. These two vehicles, and the characteristics of all four ROVs identified in this section, are presented in Fig. 46 and Table 17, respectively.

Earlier in this section it was noted that 69 different models of tethered, free-swimming ROVs have been produced. To describe each of these vehicles is beyond the scope of this study. The four vehicles mentioned above were only choosen because they have been either selected for SPS intervention or tested for such intervention, or their developers have made such intervention an objective of the vehicle. They have not been selected because they are the only vehicles or because they are superior vehicles.

4.2.2.a (DSSV) Drill Ship Support Vehicle

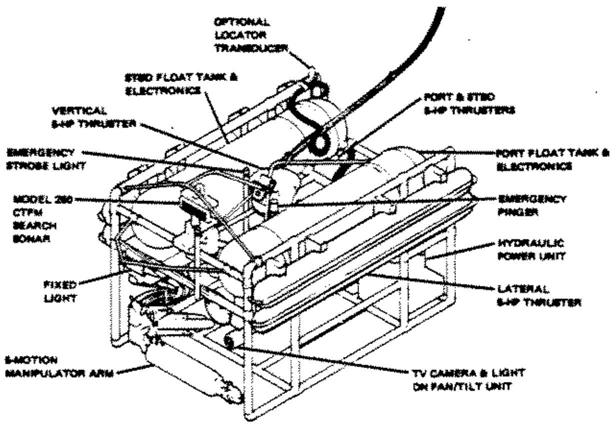
The DSSV is a Hydro Products development that underwent pool testing in April 1985 and was scheduled for field tests thereafter. Designed for drillship support, the vehicle has the capability for application to SPS I&M to depths of 610 meters.

The vehicle system consists of the following major components: deck winch with armored cable, an overboarding sheave, telescope and guide frame, RCV-225 launcher, RCV-225 (a tethered, free-swimming ROV), manipulator and control module, and control consoles for the RCV-225 and the manipulator. A schematic of the DSSV is presented in Fig. 47. The components identified are shown in this figure and their functions are self-explanatory.

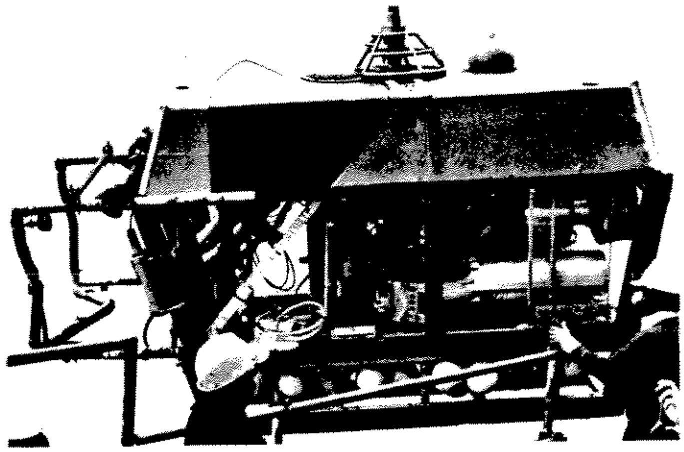
A major thrust in the design was to make the system a direct derivative of field proven equipment. The deck winch, overboarding sheave, and telescope and guide frame were adopted from Hydro Product's WS-125 Wellhead Inspection System which has been in use on drill ships for several years. The armored cable is common to both the WS-125 and the RCV-225, and the RCV-225, developed in 1975, was the first commercially-available ROV of this type. The manipulator will be a commercially-available item that will have position control, 7 degrees-of-freedom, a 2.4 meter maximum length and lift a maximum of 45 kg. Portions of the system requiring new development were the manipulator control console and manipulator control module.

Anticipated capabilities in the initial design include

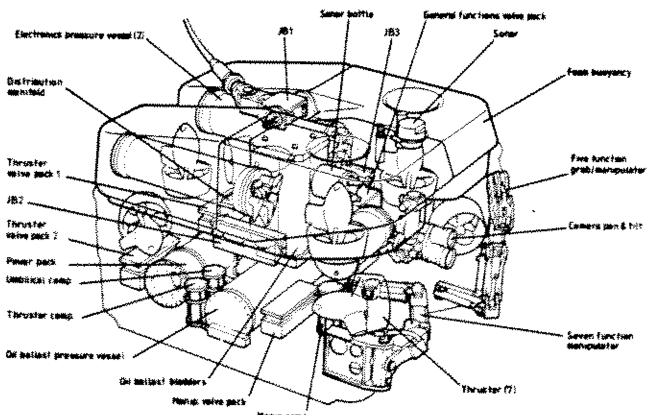
- Performance of pre- and post-drilling site surveys
- Wellhead and riser television inspection
- Stabbing assistance
- AX/VX ring replacement
- Guidewire replacement assistance
- Debris removal



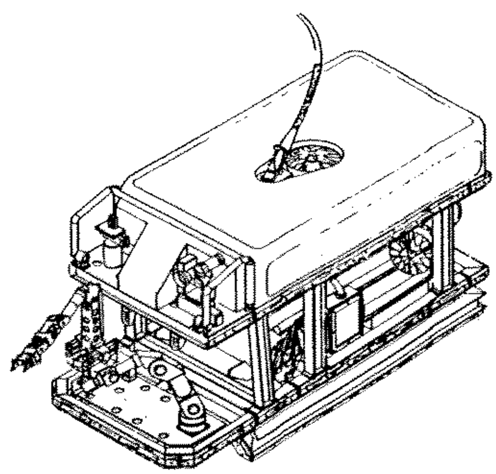
SCORPIO
(Courtesy Ametek/Straza)



TROV
(Courtesy ISE, Ltd.)



TROJAN
(Courtesy SEL)



CHALLENGER
(Courtesy Sonat Subsea)

FIG. 46. REPRESENTATIVE TETHERED, FREE-SWIMMING ROVS

OPERATING DEPTH: 914m
DIMENSIONS (LXWXH): 223cm x 122cm x 163cm
LAUNCHER (LXWXH): None
WEIGHT IN AIR: Vehicle - 680kg
Launcher - 0
SPEED: Max Surface - NA
Max Operating Surface - 1 kt against 1 kt current at depth (approx)
STRUCTURE: Two pressure resistant flotation tanks atop of - and enclosed within - an open tubular aluminum framework. Electronics are housed in removable chassis drawers in buoyancy tanks.
BUOYANCY CONTROL: Vehicle is positively buoyant. Negative buoyancy is dynamically controlled by vertical thruster.
POWER REQUIREMENTS: 440 vac, 60Hz, 3-phase, 50 kW.
PROPULSION: Four proportionally controlled high velocity, hydraulic thrusters each delivering 113kg thrust; 2 axial, 1 vertical, 1 lateral.
INSTRUMENTATION: Underwater TV camera mounted on pan and tilt mechanism CTFM (Ametek Straza 250) sonar mounted on upper front frame for 360 degree search and obstacle avoidance. Sonar also tilts 90 degrees downwards for bottom search and survey. Hydraulic five-motion manipulator extends from bottom front frame. Automatic heading and depth control. Cable turns counter. Acoustic pinger and strobe flasher to assist in emergency subsurface and surface recovery. One 250 w thallium iodide light and one 250 w tungsten quartz iodide light.
NAVIGATION: CTFM sonar, short baseline acoustic positioning system.
SHIPBOARD COMPONENTS: Control console with portable control box for visual launch and recovery of vehicle, sonar, TV and locator displays, operator, bridge, winch station communications sets, power distribution unit, winch and cable reel and spare parts. Power generator and launching frame are optional.
SUPPORT SHIP REQUIREMENTS: Enclosed area for control console and operators (can be supplied as optional item). A suitable power source with a rating of 440 to 480 VAC, 60Hz, 3-phase and 75 kW is recommended for operation of the vehicle and cable winch motors. A smaller (e.g., 50 kW) power rating is possible. A crane, boom or A/0 frame is required to launch and recover vehicle (can be supplied as optional item); should have capacity to handle vehicle maximum weight of 907kg which includes optional sensors/tools. Good station-keeping ability for live-boat operations. Deck space 6.1m long by 3.3m wide required for vehicle, winch and flotation hose.
OPERATING/MAINTENANCE CREW: Three to four, 6 for extended periods
TOTAL SHIPPING WEIGHT: 4,536kg maximum
TOTAL SHIPPING VOLUME: 17cu m depending on spares and options.
STATUS: Operational
BUILDER: Ametek Straza.

OPERATOR: Various
REMARKS: None

SCORPIO

OPERATING DEPTH: 366m
DIMENSIONS (LXWXH): 182.8cm x 175.2cm x 152.4cm
LAUNCHER (LXWXH): None
WEIGHT IN AIR: Vehicle - 513kg
Launcher - 0
SPEED: Max Surface - 3 kts
Max Operating Current - 1 kt at 366m
STRUCTURE: Open, rectangular-shaped, aluminum framework encloses and supports all components.

BUOYANCY CONTROL: Floodable ballast tanks emptied by compressed air.

POWER REQUIREMENTS: 460 vac, 60Hz.

PROPULSION: Two 5 hp electric motors powering 2 main controllable pitch propellers. Vertical and lateral thrusters powered by three 0.125 hp electric motors.

INSTRUMENTATION: Television camera, two 55 watt quartz halogen lights, magnetic compass, echo sounder, transponder interrogator. Manipulator, hydraulically-powered, scissors-type claw, 4 degrees-of-freedom, 45kg static lift capacity.

NAVIGATION: By compass bearing and visual sighting. Can interrogate two bottom-mounted transponders concurrently for relative positioning using a Mesotech system.

SHIPBOARD COMPONENTS: Control/display console, cable winch, power pack for control console, spare power pack (batteries) for vehicle.
SUPPORT SHIP REQUIREMENTS: Various support ships with 3.6t of containerized support needing 37sq m of deck space (including craft, winch and generator), air supply of 5.7cu m at 172.4 bars and electrical power supply of 460 VAC, 60Hz.

OPERATING/MAINTENANCE CREW: Two

TOTAL SHIPPING WEIGHT: 1,315kg

TOTAL SHIPPING VOLUME: 2.9cu m

STATUS: Operational

BUILDER: International Submarine Engineering Ltd.,
Port Moody, BC, Canada
OPERATOR: Various.

REMARKS: The exact distribution of these vehicles was unattainable. As of 1980 seven had been constructed. Since then several have been retired and some reconfigured.

TROV

OPERATING DEPTH: 1000m
DIMENSIONS (LXWXH): 220cm x 160cm x 160cm
LAUNCHER (LXWXH): 240cm x 290cm x 380cm (optional)
WEIGHT IN AIR: Vehicle - 1800kg
Launcher - 1.5 tonnes
SPEED: Max Surface - 2.5kts
Max Operating Current - NA

STRUCTURE: Rectangular configuration, open metallic framework encloses and supports all components. Syntactic foam block atop of framework.

BUOYANCY CONTROL: Vehicle is positively buoyant underwater. Vertical thruster is used for depth control.

POWER REQUIREMENTS: 70KVA, 380-480V, 50-60Hz, 3-phase.

PROPULSION: Four vectored, horizontal thrusters, and three vertical thrusters. Automatic heading, pitch/roll, depth and altitude sensor.
INSTRUMENTATION: Camera (B&W Osprey OE 1311), hydraulic pan/tilt mechcanism (plus 45 deg./minus 135 deg. tilt; plus/minus 90 deg. pan). Four, 250 watt lights, dimmable in pairs. UMEL submersible strobe. Pinger (HELLE). Seven function master/slave position feedback (TA9) manipulater and five-function grabber.

NAVIGATION: Fluxgate compass and gyro compass (CL11).

SHIPBOARD COMPONENTS: Control/display console, and cable winch.

SUPPORT SHIP REQUIREMENTS: Power supply, open deck space, enclosed area for control/display console, and crane for vehicle handling.

OPERATING/MAINTENANCE CREW: NA

TOTAL SHIPPING WEIGHT: 3.3 tonnes (vehicle and cage)

TOTAL SHIPPING VOLUME: 32cu m (vehicle and cage)

STATUS: Operational

BUILDER: Slingby Engineering Limited

OPERATOR: BUE Subsea Ltd., Leith, Scotland

DATE VEHICLE LAUNCHED: 1985

REMARKS: The operator reportedly placed an order for 11 of there vehicles in Julv 1984.

TROJAN

LENGTH............	3.25m	LIFE SUPPORT DURATION....		240 man hr
BEAM..............	2.6m	TOTAL POWER..............		65 kW
HEIGHT............	3.15m	SPEED:	HORIZONTAL.......	3 kt
DRAFT.............	3.15m		VERTICAL.........	2 kts
WEIGHT IN AIR....	7,000kg	CREW:	PILOTS...........	1
OPERATING DEPTH..	325m		OBSERVERS........	1
COLLAPSE DEPTH...	1,100m	COLOR:	HULL.............	Black
HATCH DIAMETER...	535mm		SAIL.............	None
PAYLOAD..........	400kg	LAUNCH DATE..............		1979

PRESSURE HULL: Spherical shape 1,900mm ID, 79mm thick of plastic
POWER SOURCE: Power is cable-supplied from support vessel. The umbilical comprises 2 coax RG 59 (1 is spare) and 2 twisted pairs (1 pair is spare). Installed power (main hydraulic power unit for propulsion) in 65 kW (85 kW allowed peak load for 2 minutes) at 600 V, 60Hz. Emergency batteries of sealed lead acid type of 24 V, 108 amp-hrs are located inside the pressure hull.
MANEUVERING CONTROL: Three horizontally acting hydraulic thrusters of 16 hp each are equally spaced and act tangential to the hull. Three vertically acting hydraulic thrusters of 8 hp each are located on both sides and aft of the hull. The vehicle is controlled by two joysticks. Heading and depth are stabilized. Buoyancy is controlled by fixed ballast and 2 hard - air operated - variable ballast tanks of 100 liters each.
LIFE SUPPORT: Three O_2 flasks of 3,000 std cu m at 200 bars each are carried outside of pressure hull. CO_2 is removed by scrubbing through HP sodasorb or LiOH. Monitors for O_2 (Draeger), CO_2, temperature, humidity and pressure. Back up (tubes) for O_2 and CO_2. Alarm for O_2 level.
VIEWING: The total pressure hull is transparent. Trainable TV simultanouely in submersible and at surface control.
MANIPULATORS: Two hydraulically powered, not jettisonable, rate-type manipulators, 6 degrees-of-freedom, 1.5m max. extension. Parallel jaws type claw, 50 kg lift fully extended. One hydraulically powered, not jettisonable, master-slave working manipulator, 7 degrees-of-freedom, 2.5m max. extension, parallel jaws with adaptors. Lifting capacity 80 kp at 75% extension.
SURFACE COMMUNICATIONS: VHF transceiver (VHF/BDR FM-1606M, (2 w) and hardwire system.
SUBSURFACE COMMUNICATIONS: Hardwire system and underwater telephone (Felt Telefon TP-6N LB/CB rear cover). Mesotech underwater telephone (18 kHz) for emergency use.
SONARS:
Scanning - Wesmar (SS140S).
Pingers - None
Echo Sounders - None
Transponders - None
Directional Hydrophones - 38 kHz (RNN)
Doppler - None
STATUS: Operational
CLASSIFICATION/CERTIFICATION: Det Norske Veritas
OWNER: A/S Mollerodden, Haugesund, Norway
OPERATOR: Same as above
BUILDER: Same as above

CHALLENGER

TABLE 17. CHARACTERISTICS OF TETHERED, FREE-SWIMMING ROVS

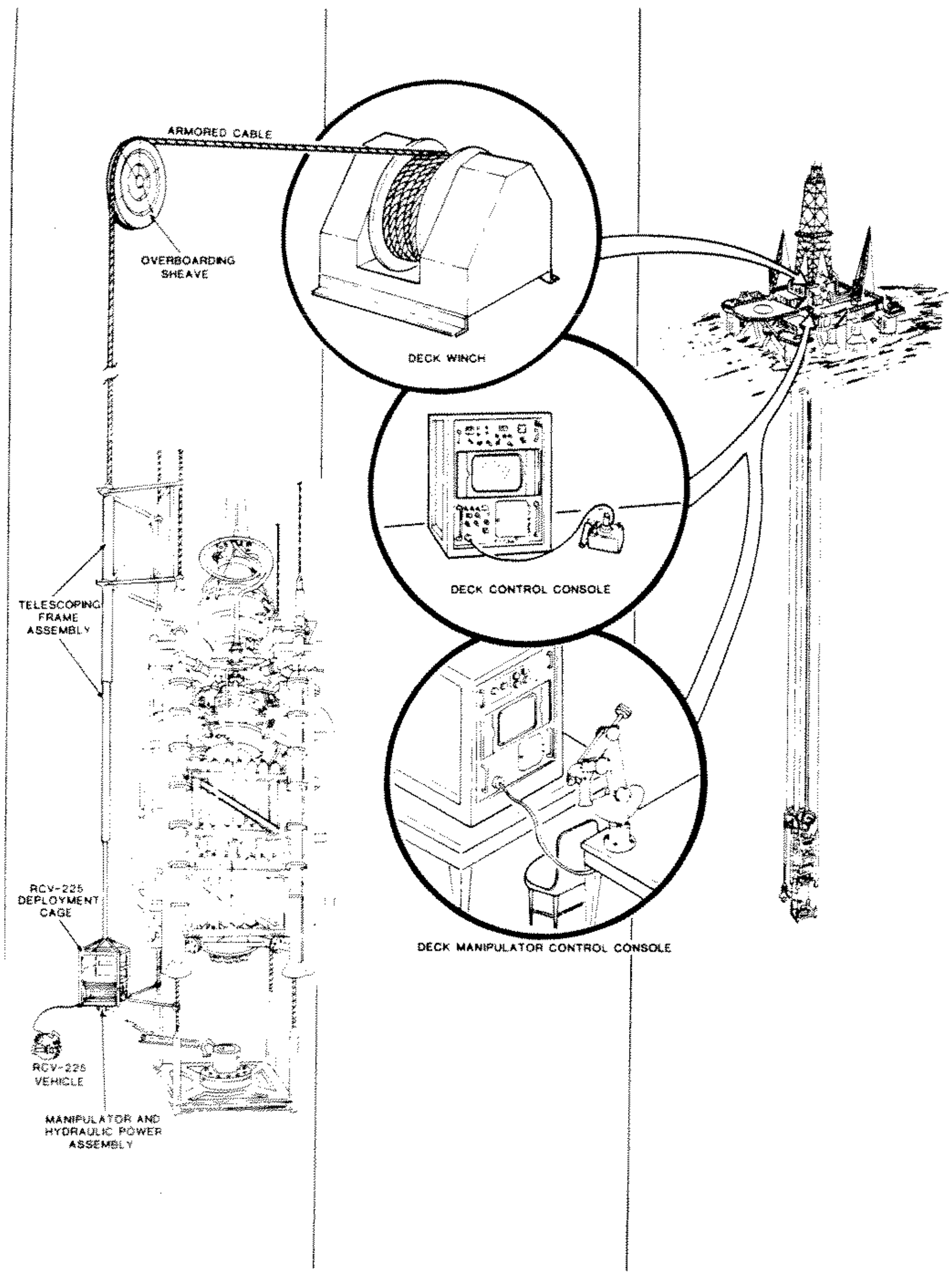


FIG. 47. THE DRILL SHIP SUPPORT SYSTEM (from ref. 244)

4.2.2.b The DIMOS Maintenance ROV

The DIMOS project is described in section 2.2.4. One component of the system will be a maintenance vehicle designed to carry out module installation and retrieval on the manifold centers. The vehicle (Fig. 48) is a tethered, free-swimming ROV that will be positioned via a long baseline acoustic navigation system. The vehicle will also have a variable ballasting capability permitting it to adjust buoyancy when handling replacement modules. The manifolds are designed on a "maintenance by replacement" philosophy. Consequently, all control and valve equipment is housed in retrievable modules which connect the pipelines with the manifold pipework. If any item of equipment should fail, the module can be retrieved and replaced by the purpose-built maintenance vehicle. Each module is located in a receptacle which provides protection and facilitates the docking and attachment of the maintenance vehicle to the module. Connection and disconnection of a module to and from its associated pipework is achieved by retractable connectors which are remotely operated by the maintenance vehicle.

The manifold pipework is housed in piperacks that, in the event of their damage, can be retrieved and replaced by the maintenance vehicle. A crane vessel would deploy a purpose-built lifting frame to which the maintenance vehicle would be attached. Guidance and positioning of the replacement piperacks would be achieved using the maintenance vehicle's thrusters and a system of docking cones and funnels. Subsea connection and disconnection of the liftframe and piperack would also be controlled by the maintenance vehicle.

4.2.3 Untethered (Autonomous) Vehicles

This type of ROV is mainly in the development stage, although several have been produced as operational prototype models. The vehicles do not have a tether to the surface and are self-powered. For these reasons they are sometimes referred to as autonomous vehicles. Maneuverability is generally three-dimensional and the data the vehicles collect are generally stored onboard. Only the French vehicle EPAULARD presently has the capability of transmitting TV signals thru-water at a rate of one image per every eight seconds. Two of the vehicles presently under development (ELIT and TM-308) will also have the capability of transmitting TV signals thru-water acoustically. Untethered vehicles may operate according to a pre-programmed schedule, or they can receive course and depth change commands or data acquisition commands from the surface via an acoustic link.

There are some 17 or more different autonomous ROV projects underway at present, only five of these are for the commercial sector, the remainder are military oriented. The application of the commercial vehicles will be towards pipeline, cable or structural inspection. The advantage these vehicles offer is their capability to operate within close confines and not run the

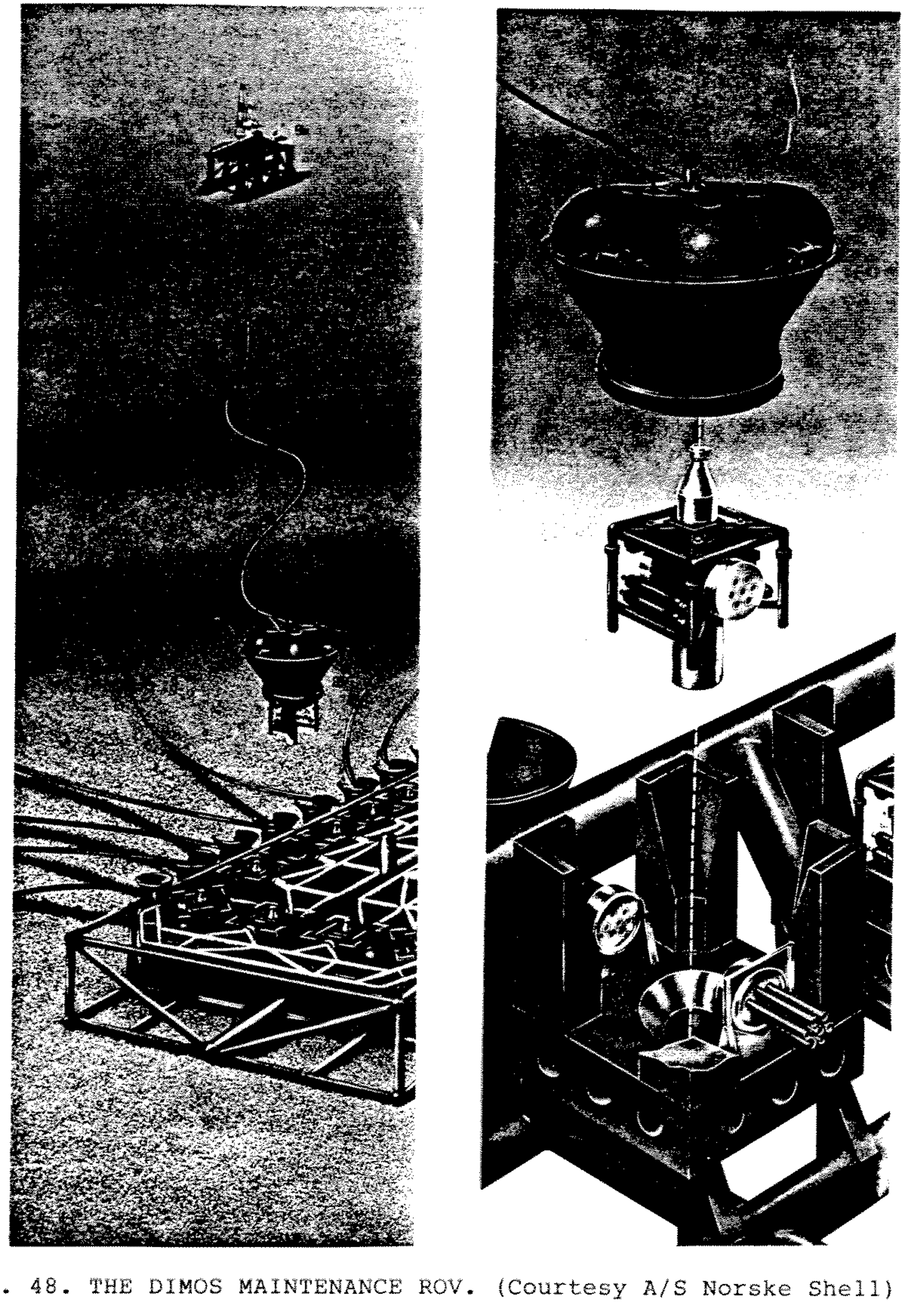


FIG. 48. THE DIMOS MAINTENANCE ROV. (Courtesy A/S Norske Shell)

risk of cable entanglement. Because they are primarily developmental they cannot, except in the case of EPAULARD, routinely be used for SPS inspection at present or in the immediate future. EPAULARD is an operational ROV, but it is designed for bottom topographic measurements and photography. Its only application, therefore, may be towards flowline and cable inspection.

The following descriptions of the various vehicles being developed for structure inspection are presented primarily for consideration towards future SPS inspection. In some instances the vehicle has been developed to the point where its final characteristics have been defined, where this is the case, the characteristics are given in tabular form. Most of the operating depths given are for the prototype only, these depths can be increased significantly in the operational vehicle.

4.2.3.a ELIT

This vehicle is under joint development by the French government agency IFREMER and the French underwater service firm COMEX. The goal is to produce a tetherless vehicle that can perform in the vicinity of congested areas and in deep water. Design depth goal is greater than 1,000 meters. ELIT will be remotely controlled by acoustic signals and will be equipped with cameras and other instrumentation not yet designated. According to the vehicle's developers, the novel features of the vehicle are:

- High speed acoustic transmission of digitized contour mapping profiles in real-time, producing a live image of the sea floor and obstacles.

- Bottom controlled navigation intelligence that allows the vehicle to react in real-time to the environment and to adapt its pre-programmed parameters.
- High capacity batteries, and lightweight launch/recovery system.

4.4.3.b EPAULARD (Fig. 49)

Design Purpose: Deep sea photography and topographic profiling.
Operating Depth: 6000 meters
Dimensions (LxWxH): 4m x 1.1m x 2m
Weight in Air: 3 tonnes
Speed: 2 knots

Buoyancy Control: Syntactic foam provides all positive buoyancy. Descent and ascent weights (80kg) are employed to bring the vehicle to the bottom and to surface. A drag rope maintains the vehicle at near-constant altitude (5 to 10 m) above the bottom.

Control: The vehicle's course is pre-set prior to launching, but can be changed during the mission. Four command signals can be transmitted to the vehicle: heading, speed, weight drop, and photograhic functions. The vehicle will answer that it has received the commands. The vehicle can measure and relate to the surface its heading, depth, altitude and weight condition. Various coded alarms are automatically transmitted to the surface. These include: flooding, position malfunction and sonar malfunction. When an obstacle is encountered the vehicle will automatically stop and reverse its course.

Power: Pressure-compensated, lead acid batteries provide 200 KWH power. A typical mission duration to 6,000 meters depth will be provided with eight hours propulsion time.

Propulsion: Horizontal propulsion is provided by a single, stern-mounted electric thruster which provides forward/reverse control. A rudder associated with a magnetic compass provides heading control.

Instrumentation: Slow-scan, thru-water TV (8 second frame rate), 35mm still camera, strobe light, radio beacon, pressure/depth gage, transponder, echo sounder, obstacle avoidance sonar.

Navigation: The vehicle is tracked by interrogating the transponder which also transmits the vehicle depth.

4.2.3.c EAVE EAST (Fig. 49)

Design Purpose: Pipeline and platform inspection.
Operating Depth: 91 meters
Dimensions (LxWxH):
Weight in Air: 272kg
Speed: 1.5 knots

Buoyancy Control: Vehicle is positively buoyant underwater. Depth is controlled by vertical thrusters.

Control: EAVE EAST is a system for the development of technology for untethered vehicles. The central focus of the program is the use of a microprocessor system dedicated to mission performance and to the control of distributed processors. The slave processors interface with the vehicle environment and actuate appropriate responses.

Power: Lead acid batteries provide 1,260Whrs and a six hour mission duration.

Propulsion: Six thrusters each of 0.25 hp. Four provide thrust and sway, two provide heave. Five degrees of maneuverability are obtained.

Tools/Instrumentation: Navigation computer, thruster computer, bubble memory computor, 6800 command computor, depth sensor.

Navigation: Three acoustic transponders are fitted atop the vehicle which form an equilateral triangle. Each transponder operates on a different frequency and a different turnaround time. They receive an acoustic signal and process it in such a fashion as to provide a position relative to the transmitter. A magnetic fluxgate compass is also carried. For pipeline following a sensor suite consisting of an array of 12 transducers is mounted on the bottom of the vehicle. The transducers insonify the sea floor and the pipeline is sensed by differential measurements in vehicle altitude by the transducer array.

Developer: Marine Systems Engineering Laboratory, University of New Hampshire, Durham, New Hampshire.

Remarks: The developers feel that the ability to follow a pipeline with this vehicle has been demonstrated and that the required technologies for futher development exist. Tests have been successfully completed demonstrating the vehicle's capability to navigate within a structure.

4.2.3.d ROVER

Design Purpose: Structural inspection.
Operating Depth: 100 meters
Dimensions: 1.34m x 0.63m x 0.54m
Weight in Air: 120kg
Power: Four 20 amp-hr lead acid batteries
Propulsion: Two horizontal thrusters, and two vertical and lateral thrusters.
Tools/Instrumentation: TV camera (CCD), lights (2@ 12v, 55w, variable intensity).
Navigation: Magnetic compass.

Development of ROVER began in 1982. The present goal is to develop a small, untethered vehicle that is carried to the work-site by a larger "mother" ROV. Standing off a safe distance from any potential hazard, the mother vehicle will launch the tether-less ROVER. TV pictures of ROVER's objective are transmitted through the water acoustically back to the mother ROV where they are amplified, processed and transmitted back to the surface through an umbilical cable. Initially the radius of ROVER's operation will be restricted to about 100 meters, at this range very high frequencies (typically 600 khz) can be used; thereby providing a relatively wide bandwidth for the transmission of slow scan TV pictures. Picture quality will be varied by means of adaptive resolution techniques so that the information content can be matched to the needs of the surface operator.

The following aspects of ROVER development have been, and are being addressed:

Vehicle Operations:

- Propulsion, buoyancy and control.
- Launching and docking.
- Underwater navigation
- Computergraphic display of launching/docking under low visibility.
- Implementation of control algorithms for two independent

vehicle motions.

Intelligence Guidance and Control:

- Guidance and control.
- Sonar interpretation (robot vision).

Through-Water Communications for Video, Data and Command:

- Bandwidth reduction techniques.
- Experimental acoustic command and video link.
- Coordinate addressable frame storage for video link.
- Coded CCD TV camera-frame storage.
- Electro-magnetic wave short range underwater communications.

Developer: Underwater Technology Group, Dept. of Electrical and Electronic Engineering, Heriot-Watt University, Edinburgh, Scotland.

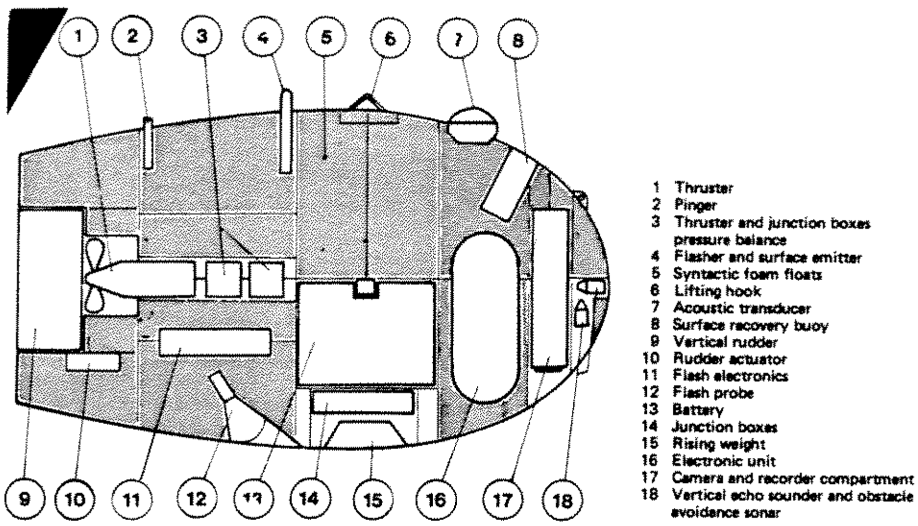
4.2.3.e TM 308 (Fig. 49 and ref. 245)

Design Purpose: Structure inspection.
Operating Depth: 400 meters
Speed: 2.4 knots (max. operating current)
Power Duration: 10 to 12 hours.
Limiting Sea State: Beaufort 4
Power Supply: An underwater anerobic generator based on a closed cycle engine supplied by oxygen stored at high pressure is envisioned. The configuration identified will supply the required vehicle power duration and a peak power of about 50 KW.

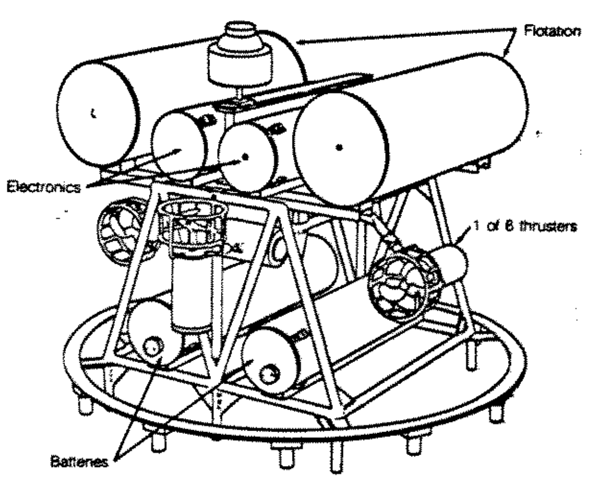
Vehicle Control: The final vehicle control objective is for the operator to be responsible only for high level tasks, such as programming and supervision. Vehicle-to-surface and return communications will be via an acoustic link. Owing to the low capacity, propagation delays and signal blockage, the vehicle will have a degree of autonomy. For example, if communications are lost, the vehicle will automatically stop and maintain position. Since almost all of the control loops cannot be closed through the operator, a control strategy has been adopted based on: a surface controller (interfaces with the operator and provides real-time representation of the system's state); an onboard controller (executes activation of control loops and transmits information to the surface), and a communications system (channel transmission characteristics: 5-10 Kbit/sec.).

Design of this vehicle began in 1983. The goal of the project is to provide a prototype, tetherless ROV purpose-designed for structural node inspection and slow maneuvering within a platform. The target is to reach a daily productivity rate equal to that of a saturation diving team.

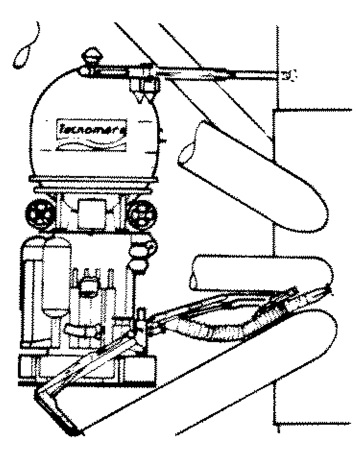
The preliminary vehicle system configuration envisions the following:



EPAULARD



EAVE EAST



TM-308
(from ref. 247)

FIG. 49. THREE UNTETHERED (AUTONOMOUS) ROVs

- a vertical body containing the engine, fuel and ballast tanks, oxygen vessels, thrusters and hydraulic units for the cleaning system and actuators,
- a bow equipped with four docking arms fitted with suction pads; inside the bow one working manipulator is mounted,
- the vehicle surface support, divided into modules, will consist of a control room, oxygen generation storing and loading, service power generation, launching system and warehouse,
- the vehicle will be launched within a protective garage that also acts as a communication link point with the surface, and
- the vehicle will be fitted with TV cameras, various sensors (e.g., cathodic potential measurement, thickness gauge), a water jet cleaning system and other equipment, such as, grinders and brushes. Fixtures on the work manipulator can be replaced by means of hydraulic connectors.

Developer: Technomare, S.p.A., Venice, Italy. Sponsors and funders of the development are: Agip, Micoperi, CCE, and Instituto Mobiliare Italiano.

4.3 HYBRID VEHICLES

This type of vehicle combines either the control or propulsion features from two of the foregoing vehicles into one. They can, for example, be operated by a diver and/or remotely from the surface. They may be towed in mid-water until an object of interest is sighted, at which time they can bottom and operate as a bottom crawling vehicle. Or they may operate as a bottom crawling vehicle, but be controlled by an onboard pilot within a pressure-resistant hull. The combinations are numerous and there is little, if any, commonality in appearence, dimensions or mode of operation between vehicles.

There are 18 hybrid vehicles, most of which are operational and several are under construction. The vehicles described in this section are those considered as having the potential to perform either inspection, maintenance or repair tasks on subsea production systems.

4.3.1 SAGA (Fig. 50)

SAGA is a long duration, untethered submersible designed such that one section of the vehicle is at 1-ATA pressure, while another adjoining section may be pressurized to ambient for lockout of divers. It also carries a tethered, free-swimming ROV that is used to observe in areas too large for the submersible and preparatory to dispatching divers. The vehicle is now under construction and is scheduled for completion by 1987. It will be capable of operating submerged for upwards of eight days and will have a cruising range of 400 nautical miles. The lockout section can support six divers in saturation for a maximum of 72 hours. The project is funded by the French government agencies IFP and IFREMER. The vehicle is being constructed by Comex Industries.

The combination of SAGA's capabilities will permit inspection, maintenance and repair of SPS's by divers to 450 meters depth and inspection by ROVs and human observers to 600 meters. Characteristics of the vehicle are provided below.

Length	28.06m	Life Support Duration	7800man/hrs
Beam	7.40m	Total Power	6,475-10,570kWH
Height	8.50m	Speed: Cruise	4kts
Draft	3.65m	Max	6kts
Weight in Air	545t	Crew: Piloting/Operations	6
Operating Depth	600m	Observers	1
Diver Lockout Depth	450m	Divers	6

Pressure Hull: Composed of four compartments: a main, 1-ATA compartment for control and operations; a diver lockout compartment; spherical transfer locks, and a releasable rescue bell that can carry the crew to the surface in an emergency.

Power Source: A Stirling engine utilizing liquid oxygen provides up to 9,870 kWH. Batteries provide 700 kWH. Surface propulsion and power is provided by a 235 hp diesel engine.

Maneuvering Control: Two stern screws in Kort nozzles. Two lateral and two vertical thrusters.

Sonars: Scanning, pinger, echo sonder, directional hydrophones, doppler (bidirectional).

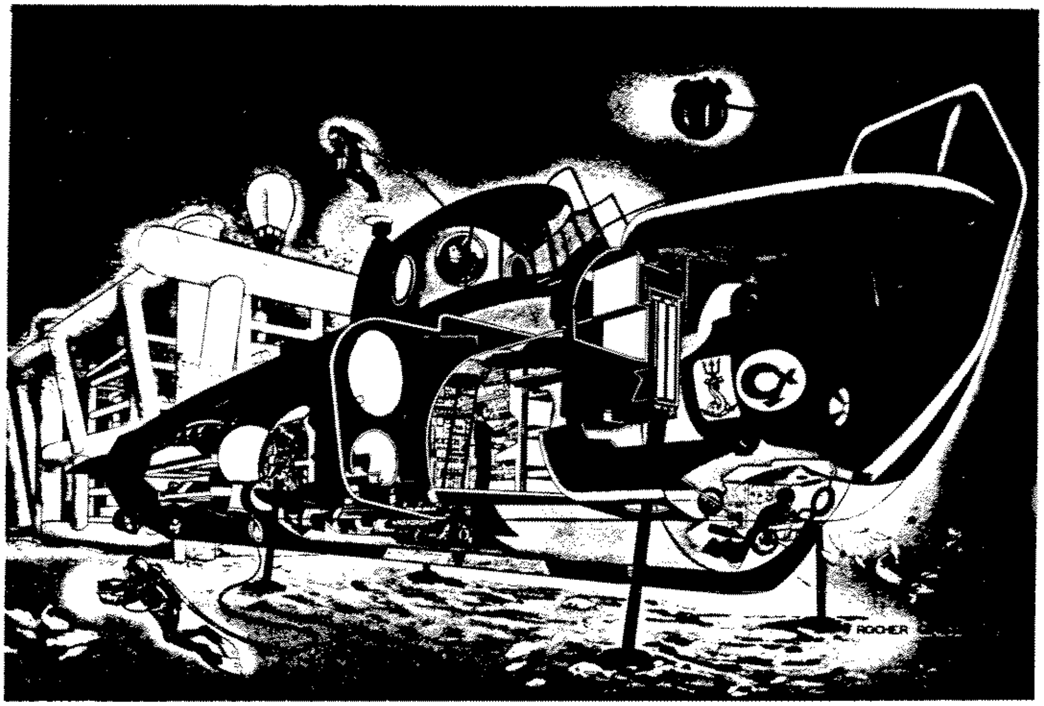
4.3.2 SUPRA (Fig. 50)

SUPRA (Submersible Underwater Pipeline Repair Apparatus) is in the construction stage and is scheduled for completion in 1985. The vehicle combines the capabilities of a conventional saturation diving system and a dry, 1-ATA or ambient pressure welding habitat. Although SUPRA is designed for repair of pipelines, its capabilities can be used for repair of an SPS and its attendant flowlines.

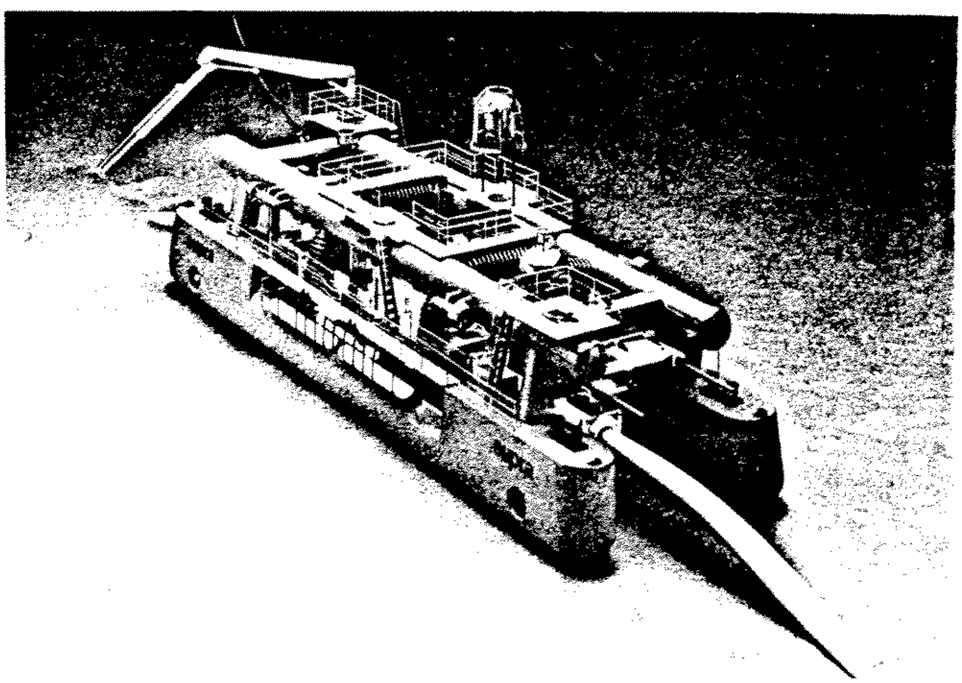
The vehicle will be towed to the work site by a small diver support ship. At the work site the vehicle descends and maneuvers to the bottom by an integrated ballast and propulsion system. The divers reach the vehicle by means of a conventional diving bell. Transfer of divers to SUPRA is made via a 1-ATA transfer chamber. Power is supplied to the vehicle by the support vessel. In addition to the hyperbaric welding habitat, the following work equipment will be carried:

- Four pipeline alignment frames.
- Pipe handling clamps.
- One or two gantry cranes.
- A telescopic swivel crane.
- Plugs for hydraulic and electric energy.
- 16 TV cameras on pan/tilt devices with appropriate lights.

The external work systems can be operated by divers or remotely



SAGA-1



SUPRA

FIG. 50. THE HYBRID VEHICLES SAGA-1 AND SUPRA

from inside the vehicle. Surface-operated remote controls can be provided.

Operating Depth: Unmanned-500m, manned-420m
Dimensions (LxWxH): Structure-34m x 12.6m x 7.35m, Habitat-3m x 2.8m x 3.5m
Weight in Air: 360 tonnes
Draft: 2.7m
Payload: 20 tonnes
Speed: 2.5 knots (cruising)
Propulsion: Ten thrusters. Four horizontal, four lateral, two vertical.

SUPRA is a joint project of the ARGE SUPRA Consortium composed of the following West German firms: Ocean Consult GmbH, Ferrostaal AG, Howaldtswerke-Deutsche Werft AG, Haux Life-Support GmbH, and Schiffko GmbH.

4.3.3 FLYING BELL (Fig. 51)

The FLYING BELL is designed for structure inspection, maintenance and repair. It is a mobile diving bell fitted with six thrusters (four horizontal; two vertical). The vehicle is tethered to the surface and receives all electrical power and breathing gases from the surface. It is equipped with a variable ballast system (+/- 700kg), navigational aids and locating equipment. The vehicle can maneuver horizontally and vertically within the limits of its umbilical, a radius of some 400 meters from the support vessel. A clamp allows the vehicle to attach itself to the structure for mid-water work. The pressure chamber consists of two hemispherical endcaps with an intermediate cylindrical section. Its dimensions are 3.7m H x 3.2m diameter. The operators/divers will be at ambient pressure within the bell. The operator/supervisor on the surface has a TV monitor, color sonar display, full instrumentation including depth and heading references and a tracking display. Information from the sonar, TV and tracking systems is not directly available to the operators/divers, but can be communicated to them from the surface. It is possible to operate the FLYING BELL remotely from the surface or directly from within the vehicle itself. The vehicle is designed for operations under Beaufort 8 conditions and within a two knot current.

Two FLYING BELLS are being constructed by Brucker Meerestechnik of Karlsruhe, West Germany for Stana AB, Gothenburg, Sweden. They are scheduled for launching in mid-1985.

4.3.4 MOBILE DIVING UNIT (Fig. 51)

The MOBILE DIVING UNIT (MDU) is a combination of the diving bell and the Observation/Work Bell. It consists of two pressure hulls vertically configured with a tubular steel support frame. The upper hull is at 1-ATA pressure. Beneath and joined to it by an interconnecting hatch is the lower hull which is capable of being pressurized to ambient and locking out divers as they would be from a conventional bell. Each hull has its own access hatch and a complement of nine viewports, including a large panoramic viewport in the upper chamber. An umbilical cable from the surface supplies all electrical power, breathing gasses and communications link. The vehicle is fully equipped to perform structural inspection and maintenance tasks, and can also, with its divers, perform repair tasks. It is designed to hold station in a 0.5 knot current at 305 meters depth and in a two knot current above 150 meters. MDU is equipped with three manipulators, two are multi-function manipulators for performing intricate work tasks, the third is a large grasping clamp that holds the vehicle to a structure. Characteristics of the MDU are presented below.

Length...........3.6m	Life Support Duration....422 man-hrs
Beam.............3.6m	Total Power..............Unlimited
Height...........4.5m	Speed: Cruise..............1.5 kts.
Draft............ NA	Max.................2.0 kts.
Weight in Air....1,089kg	Crew: Pilots.................. 1
Operating Depth..305m	Observers.............. 2
Payload..........272kg	Divers.................. 3

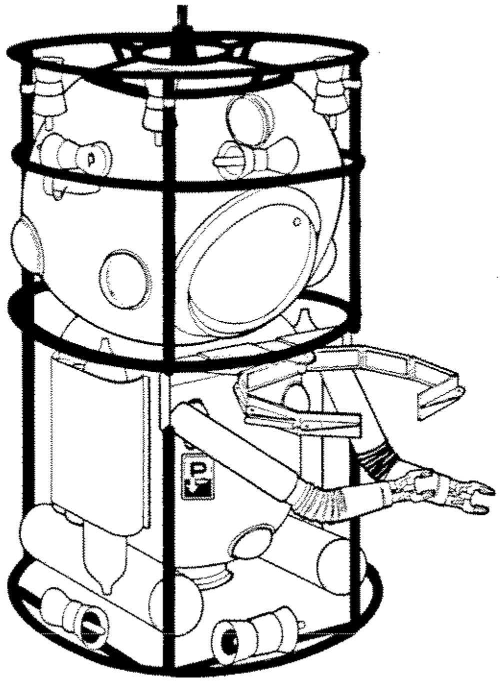
The MDU is operated by Occidental Petroleum, Aberdeen, Scotland from the support ship THAROS.

4.3.5 MAGNUM (Fig. 51)

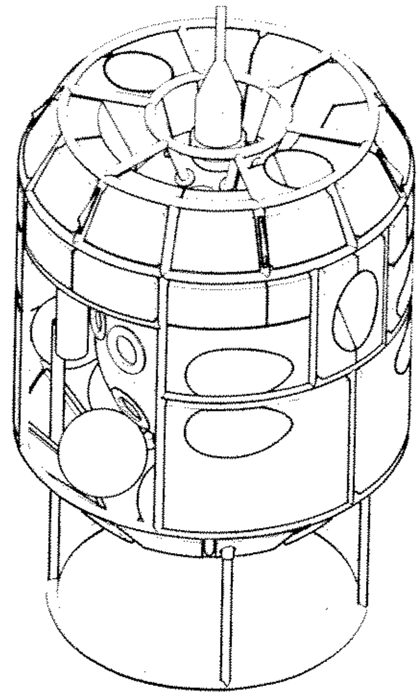
MAGNUM is a combination of a tethered, free-swimming ROV and a structurally-reliant ROV. It is designed to be transported to a pre-selected point on a structure atop a tethered, free-swimming vehicle where it is placed on the structure. At this point MAGNUM "grasps' the structure with magnets and proceeds to "walk" to the node or location where work is to be performed. The vehicle is primarily designed to perform structural cleaning tasks, but its equipment suite and manipulative capability can have applicability to some SPS inspection and maintenance tasks. The vehicle was completed in April 1985 and is currently undergoing sea trials at its builder, the OSEL Group, Great Yarmouth, Norfolk, UK. Characteristics of MAGNUM are presented below.

Operating Depth: 610 meters
Dimensions (LxWxH): 76cm x 51cm x 46cm
Structure: The vehicle is constructed as two independent frames. The outer and larger frame (dimensions given above) serves as the mounting platform for equipment. The inner frame is positioned centrally within the larger.

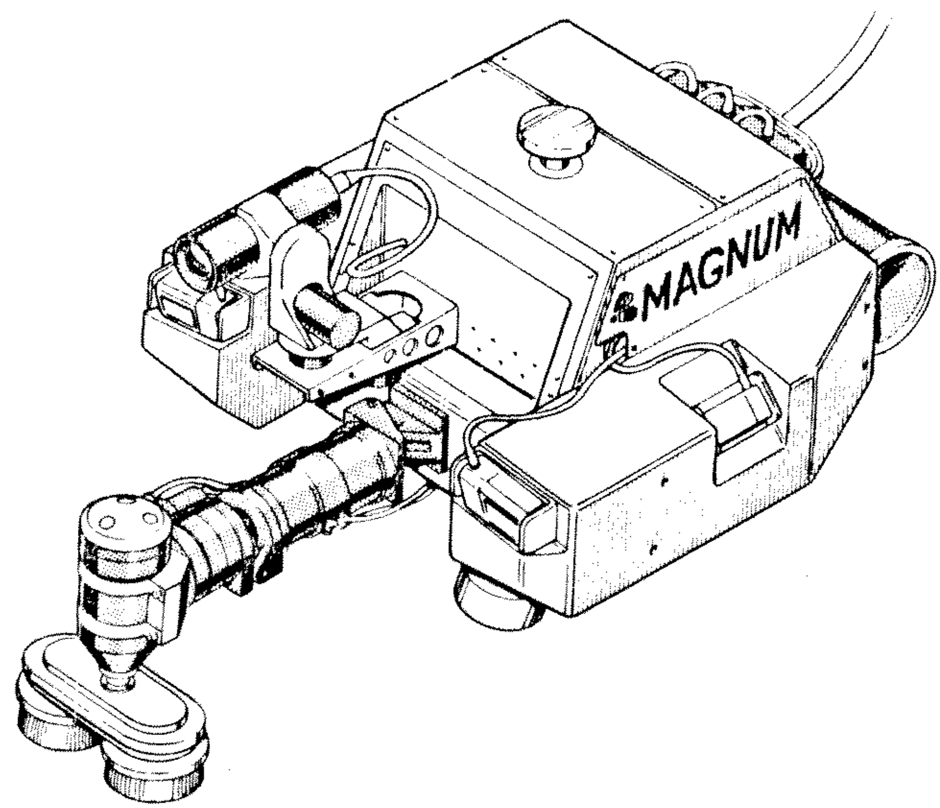
Propulsion: Each frame has three motion magnets. They are arranged (in plan view) as the corners of two triangles, one inside the other. The inner three are able to move relative to the outer three axially 35.5cm, laterally 30.5cm, vertically 10cm and rotationally 90 degrees. After the vehicle is placed on a ferrous structure it will become "live", and is unlatched and deployed. The magnets are electrically energized with power coming on when



MOBILE DIVING UNIT



FLYING BELL



MAGNUM

FIG. 51. THE HYBRID VEHICLES MDU, FLYING BELL AND MAGNUM

contact is made with the metallic surface and switched off when contact is broken. The holding force of each magnet is 225kg. On command to move in an axial or lateral direction, a negative force is applied to the inner magnet frame, lifting it from the structure and de-energizing the inner three magnets. Lifting force is supplied by a hydraulic cylinder. When the vertical movement has reached its limit the inner frame is free to move. Each direction of movement is actuated by a horizontally-mounted, hydraulic cylinder. When either cylinder is actuated the inner frame is moved in the required direction a pre-determined distance and, once in position, the vertical cylinder is operated in the opposite direction to re-energize the magnets. When the outer or inner frames are in the free position a fourth cylinder provides rotational movement.

Instrumentation: TV camera and light, power unit, manipulator, cleaning brushes.

Navigation: Visually by TV.

Operator: Uvitek (UK), Aberdeen, Scotland

4.4 SPS NAVIGATION/POSITIONING TECHNIQUES

There is a wide array of acoustic positioning techniques for divers and undersea vehicles that can guide the particular intervention technique to a subsea production system. These include long, short and supershort baseline systems, pingers/ pinger receivers, responders and transponders. In the final analysis the intervention technique can, if necessary, visually follow a riser or flowline or a call-up buoy to the SPS. The positioning task, therefore, is not one of finding the structure, but locating one's position about and/or within the structure.

Having once established where the diver or vehicle is located on the structure, the task then evolves into one of identifying components of the structure. On a single satellite well identification of the components is - in the absence of severe fouling and in water with several meters visibility - relatively easier than on a multi-well template or manifold. The interior of the UMC, for example, at 52m x 42m x 15m (LWH) could present a formidable problem for component identification in excellent visibility. In poor visibility, say one or two meters, the location task could be hopelessly time-consuming.

While acoustic techniques can be used to place one on a structure, they are unreliable within the structure owing to the multi-path problems created by the structure itself. The most reliable, if not the only, tool at present for component identification on a SPS is visual observation, either directly by the human eye, or indirectly by the TV camera. Using a visual approach to navigation and identification relies on positively identifying the components, for this there are several solutions, all of which depend upon marking the SPS with easily identifiable symbols.

A review of the various techniques for marking underwater structures is presented by Miller (ref. 246), these include: steel cut-offs; Glass Reinforced Plastic panels; reflective markers; fluorescent/luminous markers; paint; light modules; weld beads, and anti-fouling markers. All of these techniques, except the anti-fouling markers, may be subject to deterioration in their effectiveness with the colonization and growth of marine fouling organisms or by abrasion. Certain of the anti-fouling paints reportedly provide upwards of five or more years effectiveness, while the anti-fouling markers are said to offer some 20 years productivity.

Markers are used for a variety of functions: signposts; reference points; routing, and measurements. The following examples are taken from the above reference.

As a signpost markers serve to confirm the location on the structure and to enable navigating to the work site. Such signposts may be placed at each major leg node, on pile guides, or on peripheral structural members of an SPS.

Reference points notify the diver or vehicle that it is definitly at a given point. These points can identify valves, key welds, and key anodes. Miller reported that hand wheels of one SPS were marked to avoid opening an incorrect valve. To confirm that the diver was turning the correct wheel, an ROV was used to monitor him step-by-step as the task unfolded. Reference point markers have been placed on SPS templates to ensure correct connection of flowlines or hydraulic hoses. Both termination and connection points might typically be marked.

As a routing technique markers can be so arranged to provide a pathway for the diver or vehicle to enter a structure and then to lead him or it out of the structure. (There was an unpublished incident occurring in the late 1960s whereby a manned vehicle became so hopelessly lost within a Gulf of Mexico platform, that divers had to be dispatched to lead it out.)

Using markers as a measurement technique involves configuring it into a sort of ruler which is attached to a structure to indicate long term trends in settlement or scouring. This approach can also be employed to observe the degree of expansion of a riser or spoolpiece.

Two examples of SPS markings are presented in ref. 247: 1) the UMC on which over 250 markers have been installed to serve as signposts and reference points for divers and ROVs and 2) on the Sun Balmoral template where over 300 markers have been installed for the same purposes.

5.0 PERFORMANCE OF PRESENT INTERVENTION TECHNIQUES

Virtually all published reports or technical papers in the open literature that describe the demonstrated performance of the various intervention techniques described in Chapter 4 were written by the manufacturers or the service companies supplying the technique. Consequently, it is only human for the authors to concentrate on the successes of the technique and to often gloss over or ignore its failures. Another characteristic of these reports is a tendency to be somewhat over enthusiastic regarding the technique's application to other associated work tasks. This frequently leads to disappointment and frustration on the part of the customer when he discovers that the technique does not operate quite as simply or reliably as he was led to believe. Conversely, the supplier of the technique frequently finds that the conditions under which he must operate are not quite those that were described in the office, nor are the tasks as straightforward as they were outlined.

This was and, in many instances, still is the situation with many of the underwater intervention techniques employed for platform and pipeline inspection. However, with increasing experience on both the part of the service company and the customer, disappoints are becoming fewer. One of the major reasons is that the concept of a general purpose technique, one that can, for instance, perform surveys, inspection, maintainence and even repairs, has yielded to techniques specially designed for a particular task. Except for the diver, there is no all purpose intervention technique that will perform all tasks with complete satisfaction. The evolution of ROVs, for example, has shown a close parallel with the aircraft industry. The first order of business in that industry was to fly. Having attained that goal, aircraft then began to diversify and specialize to produce the wide array of designs we can see today. The first order of business with ROVs was to reliably observe and maneuver. Having attained this goal, other tasks began unfolding for which a straightforward observation vehicle was inadequate. When the inadequacies became evident, manufacturers and the service companies themselves began producing vehicles specifically designed for pipeline or platform inspection, platform maintenance, platform cleaning, drilling support, pipeline repair and other specialized tasks. This evolution is still taking place and will continue to do so.

There is every reason to suspect that intervention techniques for SPS inspection and maintenance will follow a course parallel to that of platform inspection and maintenance. It would be presumptuous to expect that any of the current ROVs or manned vehicles can be applied to SPS I&M as is, and perform perfectly. As is evident in Chapter 2, SPSs have assumed a wide variety of configurations and functions; some of which are amenable to intervention techniques other than the diver, some of which are not. For this reason most of the current techniques will fall short of expectations when applied to SPSs which were not designed to be compatible with the technique. While this may appear to be a rather obvious conclusion, there will undoubtedly be instances in the future where the obvious will be missed. Many of the present shortcomings of manned and unmanned vehicles are as predictable as the rising sun. Unless the vehicle is designed for the SPS and the SPS is designed for the vehicle, inadequacies will be forthcoming. Even in instances where both vehicle and structure were designed specifically for each other, problems have occurred that were not anticipated until the two were put to use in the field. Subsequently, with modifications to one or the other or both, a successful vehicle/structure system evolved.

At this point in time the use of intervention techniques other than the diver on SPSs has not been extensive. Even in those instances where dedicated intervention systems have been employed (the MMS, TIM and CanOcean's PTC) there are only a few, if any, references to their performance. One example is found in ref. 207. when the operator of the MMS was asked what level of downtime had been experienced with the vehicle, the response was "reasonable". Not too much can be gleaned in the way of vehicle performance from such data.

Undoubtedly the most extensive effort at assessing manned and unmanned vehicles as SPS inspection and maintenance assets was begun in 1981 by Det norske Veritas. This program, called the Diverless Underwater Intervention Project (DUIP), evaluated the capabilities of both manned and unmanned vehicles to perform various maintenance tasks on a subsea wellhead in deep and shallow water. The project and the results that are available are discussed at the end of this chapter. Whatever intervention technique is employed for SPS inspection or maintenance, there are several problems common to all. These are: sea state; underwater visibility; currents; ice and icebergs; access to and within the SPS, and, in the case of manned systems and divers, human safety. Most of these problems are so longstanding and common that there is little need for a detailed discussion, others are either unique to SPSs or to particular environments such that they warrent greater discussion.

Sea State: In sect. 4.1 the capability to deploy a saturation diver and work in sea state 8 was discussed. The fact that this was newsworthy emphasizes the dependence of any surface-oriented intervention on sea state. The "weather window" is probably the severest limitation to all currently operating intervention techniques. With each passing year advances in technology have opened the window a bit further. But there are areas such as the North Sea where the window is jammed tight and opening it just the slightest is a major effort. The French-built SAGA-1 is designed to open the window to the fullest by supporting diver and ROV operations below the surface, not on it. This vehicle will be launched in 1987 and, if it lives up to its developer's claims, will offer a diver alternative to 450 meters depth regardless of sea state.

Underwater Visibility: So far the limits of visibility have not been reported as a problem except in a few unusual instances where schools of fish obstructed viewing. This may not always be the case. Certain areas of the arctic and sub-arctic are subjected to periods where river discharge, such as occurs from the MacKenzie for example, can produce zero visibility. In some instances sediment from the Mackenzie have been observed as much as 160 kilometers seaward of its mouth.

Currents: Water currents are an obvious constraint to underwater intervention. Fortunately, they have not been reported as a serious deterrent to present SPS inspection and maintenance. This may not continue to be the case as SPSs are installed in increasingly greater depths. Although ocean currents generally decrease with depth, tethered vehicles must still contend with the entire current profile (surface-to-bottom). Virtually all tethered vehicles, particularly unmanned vehicles, operate from a launcher or garage. Among other functions, the garage serves to take up the effects of drag on the umbilical while the vehicle itself works out from the garage on a shorter, thinner tether cable. On very deep SPSs, one example being the Montanazo field at 754 meters, the drag on the umbilical cable could be of sufficient magnitude to make station-keeping exceedingly difficult. However, the service company that has been chosen to provide the inpection/ maintenance chores has operated in depths in excess of 2,000 meters for drilling support, and it has undoubtedly made an allowance for current effects. A number of devices and/or procedures have evolved to assist a vehicle in station-keeping on a structure in the presence of currents. These include specially-designed manipulators that grasp the structure or an appurtenance, magnetic or suction "stickey feet", and built-in docking points on the vehicle that hold it stationary against the structure while thrust is applied.

Ice and Icebergs: The presence of ice provides an entirely new set of circumstances to undersea intervention techniques. Ambient pressure diving and manned/unmanned vehicle operations have been taking place in the arctic and sub-arctic for upwards of 20 years. As far as can be determined, these operations have been carried out on a schedule convenient to the operators and at times when ice effects are minimal. An exception to this is the drilling program offshore eastern Canada in the Hibernia field where icebergs present a seasonal threat. Other than this exception, underwater intervention in support of the oil and gas industry is conducted when conditions are optimum and terminated when environmental conditions deteriorate. If SPSs are employed in the arctic (there is only one non-producing subsea completion presently installed), it may very well be possible to continue scheduling inspection, maintenance or workovers at optimum times, providing, of course, that nothing unforeseen and critical to the SPSs operation occurs. However, if serious problems do arise during mid-winter and immediate remedial action is required, the presence of an ice cover will present some unusual problems.

All of the intervention techniques described in the foregoing chapter, with the exception of the untethered manned submersible, rely upon an umbilical cable or bundle to supply power, data transmission, control signals, communications, breathing gasses or diver heating. To deploy these systems on a year-round basis in the arctic the capability must be available to cut and maintain a hole in the ice which can be four to five meters thick. Such capabilities are available and have been successfully employed. The major problem is that the ice cover can and does migrate and the hole must be maintained or the intervention vehicle might simply run out of cable. Pack ice in the arctic drifts at an average rate of 2.5 kilometers/day, and has been reported to reach rates of 25 kilometers/day. Even at the slower rate it would only be a matter of perhaps a day or two before the systems reaches the end of its umbilical and must be removed. At the highest rate it might be only a matter of hours. One alternative is to continuously cut and maintain a hole above the work site. While this may be feasible, it would be a frightfully expensive and astounding engineering accomplishment.

The most appropriate alternative would appear to be an untetherd technique, either manned or unmanned. Manned, untethered vehicles operating underice present some unique problems. The first problem is that of human safety. While manned vehicles have compiled an impressive reliability record over the years, they have always had the option (unless the vehicle becomes entangled or loses its ability to become positively buoyant) of surfacing if life support becomes critical or if its propulsion system or one critical thruster fails. In some vehicle designs where port/starboard thrusters supply propulsion, the loss of one can result in the vehicle's having no more capability than to maneuver in circles. A total power loss, the worst case, could mean that the vehicle has only the capability to surface under the ice. Manned submersibles have operated underice in the past, but always with a line attached to the surface that can pull the vehicle to safety or be used as a guide to find it and apply corrective measures if it is restrained. Also, the operating duration of virtually all untethered, manned vehicles is from six to eight hours, ten at the most. The vehicle must then be recovered and its batteries charged. During the entire operation the ice pack will be drifting, which means that the entire support facility must be moved and a new hole must be cut to redeploy the vehicle. An exception to the limited operation duration is the vehicle SAGA-1. With an operating range of 400 kilometers and a life support duration of 25 days, it might be dispatched from a shore base and thereby circumvent the host of problems encountered when working through the ice. Still the problem of reliability is critical and the introduction of navigational problems becomes equally critical.

A more appropriate solution might be found in the form of the untethered (autonomous) ROV which could work at long distances from its deployment point and without concern for human safety. Such vehicles might provide an inspection capability (either through photographic means or by video tapes or thru-water transmission of video signals). There is also the possibility that an autonomous vehicle might be capable of performing manipulative tasks, such as proposed for vehicle TM-308. It is also conceivable that the vehicle can store a maintenance program in its memory that it will cary out after it has reached and recognized the structure. These are all viable potentials, but they are a long way from realization.

Structural Access: Instances have arisen where the intervention vehicle or the diver could not physically get at the component or the work site on an SPS simply because he or it was too large. In a refreshingly rare moment of candor for the oil/gas industry, Mr. R. Wilson of Mobil Oil (ref. 43) admitted to this problem on a wellhead in the Beryl field: "We intended little or no diver work and didn't design the wellhead to allow simple diver access. When divers were needed they could not always get at what was needed."

Such oversights, while not generally reported in the open literature, are probably not rare on other SPSs, particularly those installed ten or more years ago prior to the advent of the ROV and many of the manned intervention vehicles. While the vehicles may have the capability of reaching the structure, critical components and/or inspection points may be in spaces too small for the vehicle to enter, or too far away for the vehicle's manipulators to reach. Current SPS designers seem to have taken this problem into account in the diverless system designs. However there are some critics of the entire diverless approach. D. Thornton of British Petroleum, in 1981 (ref. 101) stated: "Industry has always had the diver option, but is not prepared for the stage where he cannot be used." Favi and Dahl (ref. 143) supported this contention a year later by stating: " The number of calls (requests for) on `diverless' systems proves the limited reliability of remote operations for the time being." Mr. Bjorn Vedeler of DnV (ref. 120) found it unlikely that the goal of eliminating the diver from underwater operations could be achieved in the near future. If these critisms are correct, then it would appear that the designers of SPSs to be installed within diver depth, "diverless" or not, would be prudent to provide access for both the diver and the undersea vehicle. This is the approach that has been taken on the Shell/Exxon UMC, even though the structure is designed to be diverless.

5.1 PERFORMANCE OF INDIVIDUAL INTERVENTION TECHNIQUES

The most widely applied underwater intervention technique on SPSs has been the ambient pressure diver. More recently, discussions concerning SPS inpection and maintenance have centered on the tethered ROV and the ADS. Although some doubt has been voiced, as quoted above, regarding the efficacy of these diverless systems, there are few available publications which detail their shortcomings. This is particularly the case in SPS support as opposed to platform support where a wealth of experience has been amassed over the past decade. (It is perhaps appropriate to note that the first ROV designed for offshore oil/gas support, the RCV-125, made its debut in 1975.) Much of this experience has been recorded and made publically available. (See, for example, the Marine Technology Society's Operational Guidelines for ROVs, 1984.)

The performance of these diver-alternative techniques to SPS I&M is, therefore, either lacking or proprietory. The results of DnV's DUIP trials, for example, which discuss individual vehicle performances and compares one vehicle to another are restricted in their distribution. Service company failures, as discussed earlier, are also not generally advertised. As a consequence, there is very little publically available data from the user community regarding, not only diverless intervention techniques, but the diver's performance as well.

The remainder of this section presents what information is available regarding underwater intervention performance and potential areas of inadequacies related to SPSs. In view of the lack of reported problems, and the undocumented uneasiness concerning diverless alternatives, the section is relatively brief. Some of the potential problems identified in the following sections are derived from experiences on platforms which are germane to SPS inspection and maintenance.

5.1.1 Ambient Pressure Diving

The diver is presently the ultimate underwater intervention technique. Particularly since he can respond to unforeseen maintenance and perform repairs rapidly and with a background of industrial experience. Three aspects of the diver's capabilities do, however, contain constraints that will impact on his present and future performance: depth; cold, and psychology.

The diver's depth capability was discussed in section 4.1.1. As was noted, there is some question regarding, not only his depth capability in the future, but his present capability as well. It was also noted that Comex is currently conducting 450 meter deep diving trials. Regardless of the success of this project, the subject of long-term effects must be addressed. One aspect of SPS support by divers is almost a certainty; the potential for intervention beyond 450 meters is in the distant future. Even beyond 300 meters, as has been shown, is questionable. This reality has been accepted by the offshore oil industry, as evidenced in an observation by J. Glaser of Early Production Systems (ref. 101) "...as we move to 300 meters, 500 meters and beyond, 1-atmosphere (intervention) is almost certain to come in, maybe first with 1-ATA suits and submersibles." There is, however, a present diving capability to service every operating SPS (at 293 meters depth the Pirauno field's wellheads are questionable). When installed the Montanazo wellhead and the Casablanca field's wellhead will be the only two beyond the diver's reach.

Another aspect of the environment that may limit the diver's depth capability is water temperature. According to D. Clark of Wharton-Williams-Taylor (Offshore Engineer, Feb. 1983), the equipment is not available to maintain the diver in safe thermal equilibrium at 450 meters depth and deeper. Nor is equipment available in a lost bell at 450 to 650 meters. While this may be an accurate statement, it must be viewed in light of other factors: 1) as far as SPS diving is concerned, there is no present need for support at this depth and 2) with no need there is no market. Consequently, until there is a market, there will be no equipment. Development of diver heating equipment, challenging though it might be, does not appear to require a major technological breakthrough.

One aspect of the diver's capabilities - and all manned intervention techniques, for that matter - that is rarely discussed, but is critical to his performance, is psychological. It is inconceivable that a human being, particularly one exposed to every hostility the ocean can offer, can concentrate 100 percent on the job and totally ignore his vulnerability. Even when protected by a pressure-resistant shell, the human occupant finds it impossible not to be affected by his circumstances. P. Nuytten of Can-Dive Services supplied an interesting observation to this aspect (ibid.). "We have run tests on different operators in the WASP ADS simulating an entrapment. To our surprise, we found the operators undergoing bouts of severe depression. Perhaps partly brought on by discomfort, but more likely by some psychological confinement syndrome. Even though these trained operators knew that the situation was merely a test and not a real life-threatening situation, by the end of 18 hours, some of the operators were in a mental state where they could not be relied upon to make a critical judgement of the type, for example, that might be required to assist rescuers."

This situation could have grave repercussions in SPS maintenance, not only to the diver, but to production as well. With some portion of his mind on himself and some portion on the job, it is not inconceivable that a diver may turn a wrong valve, pull the wrong component or perform some other task incorrectly that impacts on product flow. One safeguard against this is the practice of some companies to have a small ROV accompany the diver to provide the surface with a real-time video monitoring capability to prevent such an occurrance.

5.1.2 1-ATA Intervention (Wet)

The only system employing this type of intervention is the Vickers-Intertek neutrabaric technique. No reports of this method's performance have been made available other than it has been successfully demonstrated on several separate occasions. In light of the paucity of data, it would appear that the only foreseeable problems could occur through fouling on the mating skirt or some other irregularity in its surface that would prevent the transfer vehicle from making a perfect seal. Fouling, of course, can be removed and debris can be cleared. As long as the seal can be made, maintained and broken as designed, the system would appear to offer no insurmountable problems. Monitoring of the diver's activiies by TV is a desireable feature in this operation also.

5.1.3 1-ATA Intervention (Dry)

One of the few reported uses of manned submersibles toward SPS intervention was that of the vehicle SEA CAT in the Grondin field (sect. 4.2.1.b). All of the tasks the vehicle was slated to perform were performed as planned. These included locating the SPS; mating to it, and performing various manipulative tasks. It is significant that the tools employed by this vehicle were specially designed for the tasks. In short, the vehicle was made compatible with the structure, and the tasks were within the vehicle's known performance capability.

- In another test program the diver lockout submersible MERMAID IVA was evaluated for its capability to perform various wellhead chores (Ocean Industry, July 1982). Sponsored by a group of oil companies and held under the aegis of DnV , the program was designed to analyze the accessibility of different subsystems when using a relatively large manned submersible. The following tasks were included in the evaluation:

- Inspection of tree components by a surveyor within the vehicle.
- Video documentation.
- Operating a release buoy.
- Actuating ball valves for system controls.
- Connecting/disconnecting hydraulic hot lines.
- Removing and replacing corrosion caps on master valves.
- Operating master valves.
- Cleaning a completion cap mandrel with a rotary brush.
- Exchanging an AX gasket on a Xmas tree.
- Cleaning a concrete structure for visual inspection.
- Connecting a lifting line to a shackle.
- Cutting guide wires with a hydraulic cutter.
- Cleaning hydraulic connectors for a completion cap with a specially designed brush.
- Assembly/disassembly of an electrical cable connector.
- Disassembly of screws and bolts with an impact wrench.

According to the source of this information, it was demonstrated that a manned submersible equipped with adequate manipulators and tools can service subsea trees rapidly and with no diver intervention. It should be emphasized that the tests were conducted on a single, isolated Xmas tree, not a manifold center, and not a tree within a template.

In an operational situation, Vetco's designed-in intention for maintenance of 16 subsea trees installed offshore Brazil was with the ADS JIM. After tests with JIM the template enclosing the trees was specifically designed to provide enough access for both JIM and a davit or hoist mechanism to perform wellhead maintenance. But, to date, none of the 16 trees have required maintenance. JIM's intervention was designed to be conducted in currents of 3 to 3.5 knots.

In the DnV tests it was reported (ref. 157) that there was a drop in performance noted for the ADS units (JIM and WASP) from the first trials at 25 meters depth to the second trials at 300 meters depth. There was no ready explanation for this decrease in performance, but psychological factors were suggested.

E.E. Sjoholm (ref. 141) presented data regarding the performance of CanOcean's 1-ATA transfer capsule in the Garoupa field during commissioning and maintenance of the field. The program anticipated the employment of saturation diver and ROV intervention in addition to the transfer capsule.

Table 18 present the number of work interventions conducted by the three techniques during installation of the subsea components (commissioning) and during the three year period after the field began producing in 1979.

TABLE 18. GAROUPA WORK INTERVENTIONS

	TO COMMISSION PLANNED	UNFORESEEN	TO MAINTAIN	EMER-GENCY	TOTAL	% TOTAL
INTERVENTION METHOD						
Transfer Capsule	520	235	252	0	1007	85.5
Sat. Divers	33	56	14	4	103	8.7
ROV	2	8	57	1	67	5.8
TOTALS	555	299	323	5	1177	100.0
FOR MANIFOLD CENTER ONLY						
Transfer Capsule	168	0	39	0	207	83.1
Sat. Divers	15	10	5	0	30	12.1
ROV	2	2	8	0	12	4.8
TOTALS	185	12	52	0	249	100.0

Commenting on the data in the above Table, Sjoholm presents the following observations:

- All essential work, as planned to commission the field, could have been planned for the transfer capsule only.

- The 33 diver interventions were pre-planned. Since a diving capability would have been present in any event, significant time savings were possible.

- The work tasks planned for divers had mainly to do with hooking up pull-in cables for flowline connections.

- ROV interventions were pre-planned to visually confirm the final orientation of the manifold center during installation.

- The unforeseen work for the transfer capsule was due exclusively to down hole problems.

- The significant unforeseen diver interventions were mainly due to a serious breakage of the capsule's down haul lines. The task to reestablish the lines was completely taken over by an ROV (SCORPIO) during the field maintenance phase as well as most of the inspection tasks.

- Three events led to emergency situations, these were:

  1. A fouled down haul cable on the winch. (The transfer capsule could have cut the line from inside, but it was deemed safer to deploy divers.)

  2. The back haul line broke with the capsule mated to the chamber. (It was considered safer for divers to re-connect the lines rather than to allow the capsule to surface and then try to lasso it on the surface.)

  3. The capsule caught on one side of the access trunk with a clamp mistakingly deployed and the capsule was prevented from mating by a wire rope over the mating surface on the opposite side. (In the process of clearing this problem the back haul line was broken and re-connected. Both the ROV and divers were used to observe.)

Commenting further on the diver interventions, Sjoholm stated: "Essential tasks performed by divers, instead of the transfer capsule with an ROV which would have been as effective, were numerous. The number of occasions when down haul lines had to be re-established is clearly indicative of a system shortcoming. Even though the ROV is capable of re-establishing a line, it is a very time consuming process. Without the use of divers establishing cables is very time consuming. This would be a worse constraint in deeper water because the method relies on feeding out the pull-in cable from the chamber and buoying it back to the surface for hook-up to the flow line end, and then winching back a length equal to double the water depth. With restricted power the speed (of winching) is limited."

At a point subsequent to commission of the field an ROV was added to provide general inspection and a simple manipulative capability to support the chamber work.

Modifications to provide additional performance capabilities for achieving effective diverless operations on the dry, 1-ATA wellhead and manifold center approach to SPSs were given as:

- Eliminate the down haul line.

- Design for operation from a dynamically positioned vessel.

- The transfer capsule or service bell should be self-propelled and with an accurate and flexible positioning capability.

- Provide a manipulative capability to allow the connecting of hoses to chambers and the in-line stab connecting of wire ropes.

- Provide a back-up vehicle with an observational and a manipulative capability equal to the main service unit. (For this vehicle MANTIS is considered to be preferable.)

The type of vehicle CanOcean considers as better suited for a transfer unit is shown in Fig. 37. It is a design based on the ARMS and OMB Observation/Work Bells. The main performance highlights of the optimal system were given as follows:

- Surface support facilities completely enclosed for all weather operations.

- The unit should be launched through a three-point, high speed winch system with overside or through-moonpool launch from a movable cantilever. (Fig. 52)

- The air/sea interface is crossed with the vehicle latched to a depressor weight.

- All winches should be heave-compensated.

- Optional gas umbilical for purging and inerting subsea chambers.

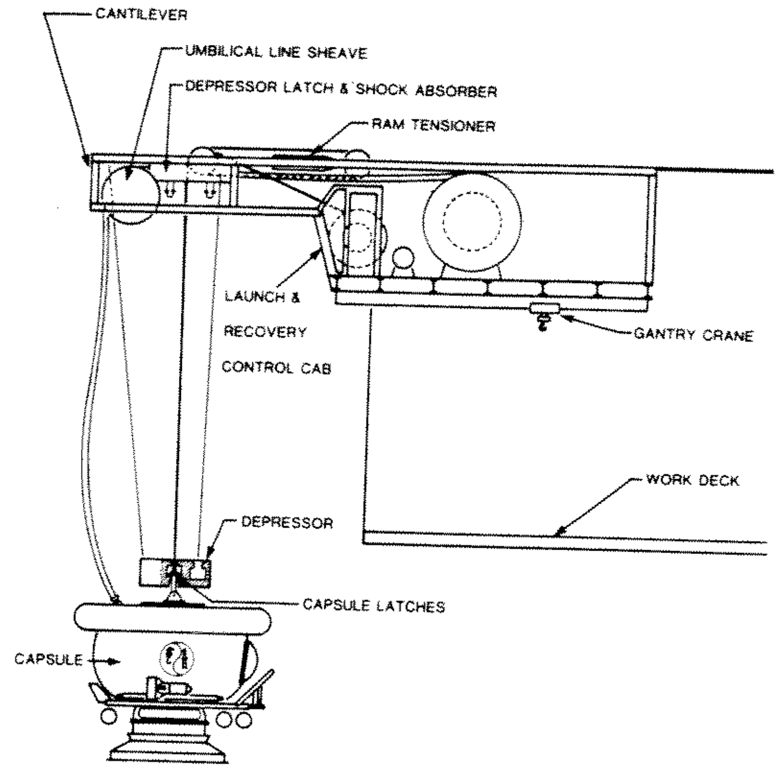
- 60kw, 3-phase power supply for propulsion and utility.

- Variable buoyancy capability to compensate for high payload variability.

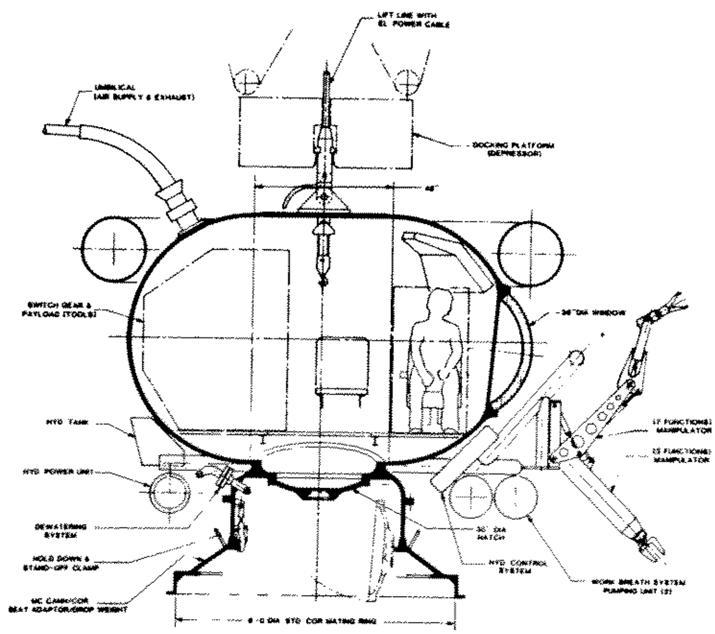
- 3-man nominal crew - 4 possible.

- Joystick propulsion control with auto heading and auto depth control.

- Dual manipulators.



SUPPORT SYSTEM



VEHICLE FEATURES

FIG. 52. CANOCEAN RECOMMENDED SYSTEM SUPPORT FEATURES AND VEHICLE FEATURES FOR DRY WELLHEAD AND CHAMBER SPSs. (from ref. 141)

- Nominal depth capability of 914 meters sea water, limited by the hull structural design only.

Sjoholm concludes that work can safely and effectively be performed beyond diver depths with state-of-the-art technology. To do so, however, he cautions that certain conditions be kept clearly in mind. The principal one being that the work system must have significant reserve capability over and above that which the best estimate mission profile has defined, because unforseen situations must be considered unavoidable. The most important aspect of the reserve capability is the integration of an independent back-up vehicle into the system, as the availability of call-out rescue systems beyond diver depth is questionable in most parts of the world.

The foregoing represents the reported and available data regarding the performance of manned submersibles in support of SPS inspection and maintenence. There are certain environmental and operating factors that will influence the performance of any manned submersible working in and around structures. Most of them are quite obvious to those who have been involved in this type of work, but they are presented for the benefit of those who are not.

Launch/Retrieval: Manned submersibles are almost always heavier and larger than ROVs and diving bells. Consequently, launching and retrieving these vehicles is a more complex task. Since there are from one to three or four humans inside the vehicle, safe launch/retrieval is more critical than launching/retrieving an unmanned ROV. The sea state limit for launch/retreival of submersibles is about 5, although at times this may be exceeded. The result is that in hostile environments the weather window for operations can be quite short. Although all interventation techniques that are deployed from a surface vessel are weather sensitive, manned vehicles are particularly vulnerable.

Operator Psychological Aspects: The psychological aspects of both ambient pressure diving and 1-man submersible diving has been discussed. There are no published reports of crew effectiveness in multi-crewed submersibles. It is the opinion of the writer of this report that the presence of others in the submerged craft provides a measure of assurance to each, and that the level of effectiveness, as far as the psychological aspects are concerned, will be higher in a vehicle carrying two or more people.

Access: Being generally larger than most ROVs, the manned vehicle, particularly the multi-crewed vehicles, will find it more difficult to access components within a structure. If the critical components are mounted with this problem in mind, the vehicle should experience no insurmountable obstacles.

Station-Keeping: In order to perform a task on a component of a structure that is not located such that the vehicle can bottom and work from that position, the vehicle must have some means of attaching or immobilizing itself against the structure. The concept of simply hovering in mid-water and performing even simple manipulative tasks is misleading. First, hovering motionless in a specific spot is difficult in itself; second, the slightest force applied against another object requires an equal and immediate counterforce by the submersible. In time, a submersible might complete a manipulative task by hovering in midwater, but the time consumption could prove cost-ineffective.

Manipulative Capability: All off-the-shelf manipulators, whether on a manned vehicle or an unmanned vehicle, have standard grasping terminations (i.e, hands or claws). These terminations in no way equal the versatility of the human hand. Indeed, the designation of a "diver equivalent" manipulator is possibly one of the greatest misnomers in the field today. While manipulators have advanced considerably in the past decade, their alledged capabilities should and must be studied - preferably demonstrated - before the vehicle is dispatched to do the job. It is more than likely that most of the components that a manipulator will be required to manipulate on an SPS will not be compatible to the configuration of the grasping termination. The obvious and most common solution to this problem is to develope a compliant interfacing device between the grasping device and the object to be manipulated. The increase in the effectiveness of manipulators can be considerable by development of such interfaces (ref. 162a).

Entanglement: The possibility of a vehicle or a vehicle's tether entangling or fouling a structure is always present, regardless of whether it is manned or unmanned. Subsea production systems, particularly the wet systems, appear to offer an excellent opportunity for this to occur in view of the numerous protruding appendages. Tethered, free-swimming ROVs are frequently snagged, and often lost due to entanglement within the structure on which they are working or in the screws of the ship providing their support. Manned vehicles have also fouled on a structure or other large objects, but none have been lost. Vehicles with tethers are the most likely of the manned submersibles to be fouled. In the event of fouling, some companies always operate with a second vehicle standing by to provide rescue assistance. The second vehicle may be a sister to the first, or it may be an ROV with manipulative capability. Most entanglements result in lost time while another vehicle or a diver is dispatched to release the vehicle. As noted with ROVs, the worst case is loss of the vehicle. With manned vehicles the worst case is loss of human life.

The possibility of losing a human involved in offshore oil support has sometimes swayed the client to unmanned systems when a manned system might be a better alternative. The concern for safety is a real one, but it is interesting to review the history of submersible diving to put the concern in proper perspective. The era of the contemporary manned submersible can be placed at about 1959 with the introduction of the DIVING SAUCER. Over 175 manned vehicles of all varieties have been constructed since then. The total number of dives made for industrial, military and scientific purposes must number in the tens of thousands, ALVIN alone has made over 1,000. The total number of human fatalities caused by vehicle entanglement, collision or operator error over this 26 year period is four. None of these deaths occurred in support of offshore oil or gas. This is not to suggest that there is little or no possibility of danger. It is simply to allay the fears that some hold in regards to any form of manned intervention.

5.1.4 Remotely Operated Vehicles

Most of the current philosophy regarding SPS inspection and maintenance centers around the use of ROVs. Here also, there is a paucity of published data regarding their application to these tasks. The following critiques, although limited, indicate that the performance of ROVs designed to work on a specific SPS has been adequate, while the performance of those designed for the overall industrial underwater market has been adequate to disappointing.

5.1.4.a Structurally Reliant Vehicles

Three of the four ROVs identified in this category were specifically designed for the SPSs they service. These are the MMS, the RGS and TIM. The fourth vehicle, BANDIT, was designed for drill rig support.

The MMS and RGS were developed by Esso for support of their Submerged Production System and, subsequently, their Underwater Manifold Center. Both have been fully tested offshore. According to ref. 142, the MMS is considered fully developed for commercial application. Likewise, the RGS offshore tests were successful, with no significant operating problems and, based on the positive results of the efforts to date, it is considered to be an adequate diverless work system for a commercial project. (ibid.)

There is a somewhat more detailed appraisal of TIM's performance by Ladecky and Weill in ref. 116. To reiterate, there were five tasks the vehicle performed: 1) install and connect a jumper pipe between a Xmas tree and the manifold; 2) install and connect a jumper electric cable; 3) install and connect a jumper hydraulic hose; 4) operate a safety valve, and 5) remove or displace a guide line. All of these tasks were successfully completed and the authors presented their initial conclusions concerning the system's design. Two kinds of improvements are envisioned to improve the operation:

- Increase and improve the visual aids to the operator. This can be obtained by either installing additional TV cameras or by improving the quality of the monitoring. Color pictures, stereoscopic views and acoustic cameras should extend the operator's capability and skill.

- Reduce the size of the umbilical by using a multiplex transmission signal that will facilitate handling and storage of the umbilical and will increase the transmission capacity. The use of a fiber optic transmission link is also an attractive alternative.

- It is necessary to provide the vehicle operators a specific and intensive training program prior to on-site operations.

- Further improvements in the vehicle's manipulative performance could be derived by adapting subsea equipment to remote manipulation and by adapting specific manipulator tools to subsea equipment.

The authors concluded that the TIM system appears as the first step in the development of a remotely operated manipulator which will be able to perform essentially all of the tasks which currently require divers or a manned submersible.

The operations conducted by BANDIT in its first nine months of commercial application are presented in ref. 239. According to the vehicle's manufacturers, BANDIT established a performance record of nearly 4,000 hours of operation with virtually no maintenance required. The developers point out that BANDIT, being 765 kg negatively buoyant in water, can be launched/retrieved in higher sea states than other ROVs (which are inherently positively buoyant) since it passes through the air/sea interface more quickly. Also, the guide wires to which it is attached provide stability during launch/retrieval and in the presence of high currents. Examples of the work performed include:

- Cleaning the drilling rig's "bullseye" leveling devices.

- Performing the work of a wellhead TV through 24 hours/day monitoring.

- Stabbing open hole running tools.

- Placing explosives down the wellhead to blow off casings.

- Untangling, cutting, and replacing guidewires.

- Recovering AX ring.

- Recovering and replacing a 100kg beacon from 365 meters depth.

- Replacing lifting wires on hydraulic control pods.

- Untangling a control pod's cable so that it could be recovered.

- Removing debris from control pod receptacles so the pod could be reseated after repair on the surface.

- Locating hydraulic leaks that were inaccessible to standard wellhead TV systems.

- Providing compass readings of the temporary guidepost orientation relative to the surface.

- Deploying surface elevators subsea to grasp and recover 110 meters of dropped drill string.

That the BANDIT has enjoyed a modicum of success is indicated by its sales, seven of these vehicles have been purchased or ordered by service companies in the past two years.

5.1.4.b Tethered, Free-Swimming Vehicles

The applications, new designs and tooling/instrumentation for this type of ROV has increased dramatically since their introduction to the commercial market in 1974. Of the 168 technical papers presented at the Marine Technology Society's ROV '83, '84 and '85 conferences, some 70 percent describe the merits and improvements in tethered, free-swimming ROVs. Similarly, the proceedings from other national and international conferences in the U.S. and the North Sea bordering countries produce equal results. In view of such successes and accomplishments, one might draw the conclusion that these vehicles are a proven and demonstrated capability which, with a few modifications, are ready to tackle the problems of SPS inspection and maintenance.

That this type of ROV has demonstrated its capabilities to provide reliable and satisfactory support for platform and pipeline inspection, drill rig support, route and site surveys and a host of other industrial tasks, there is no doubt. After a good number of years spent in trial and error trying to identify and solve the problems associated with these tasks, the vehicles were made ready to cope. This, it seems, has not been the case with SPS inspection and maintenance. Possibly because divers are mostly employed for this work, possibly because there have been no real successes to report and possibly because the customer of these services did not wish to have the work reported. Whatever the cause, in the more than 400 technical papers and reports reviewed in the course of this study, only three papers, references 141, 143 and 157, specifically deal with tethered, free-swimming ROVs and their use for SPS support. In the first instance the support was for producing wells; in the latter two it was to evaluate this type of vehicle on a test structure.

Sjoholm (ref. 141) reported the use of an ROV during installation and early production in the Garoupa field. The ROV interventions were pre-planned to visually confirm the final orientation of the manifold center during installation, and later, for unforeseen tasks related to re-establishing down haul lines for the MC's transfer capsule. Regarding its performance in the latter task, the author reports: "Even though the ROV (not identified) is capable of re-establishing a line, this is a very time-consuming restraint. All essential tasks beyond the scope of the existing service system require a free-swimming, mid-water observation and manipulative ability; in fact, beyond what the existing ROV can provide." In the same paper Sjoholm writes: "The task to re-establish lines has now been completely taken over by the availability of a SCORPIO ROV during the field maintenance phase as well as most inspection tasks." It is therefore understood that the first ROV employed was not up to the job.

Favi and Dahl (ref. 143) describe a series of tasks various ROVs were dispatched to perform on the test wellhead used in the DUIP program. (See section 5.2.) The authors do not, however, present the results of these comparative tests, but only discuss their methods of evaluating the data obtained. In a subsequent article (ref. 157) Ocean Industry reported that all the vehicles analyzed (both manned and unmanned) were able to perform almost all of the tasks proscribed, although there were some qualitative differences in their performance. The only tasks that posed a substantial problem was the assembly/disassembly of a Vetco valve, characterized as a complex task. The article summarizes: "One primary conclusion drawn from this stage is the benefit of combined planning by vehicle operators and equipment manufacturers. Through good planning and preparation of tools to fit special tasks, the operator can overcome most of the limitations inherent in underwater vehicles and reduce alterations needed on a Xmas tree to a minimum."

Most of the problems ROVs confront during platform inspections will also be faced in SPS inspection. In 1983 Kristiansen and Sletten (ref. 183) presented results of evaluations of five ROVs used to carry out non-destructive examination (NDE) inspections on steel platforms, risers and pipelines, again under the DUIP program. The following conclusions are taken from the above reference.

Weather Dependence in the Launch/Retieval Phases

The maximum operating sea state for a specific ROV system depends on whether the support station is a fixed platform, a floating drill rig or a vessel. With a fairly stable vessel, operations through sea state 5 are now unrealistic. However, this is not the case for the majority of existing ROVs, mainly owing to the following:

- Pendulum motion of the ROV/Launcher is not sufficiently prevented.

- High snap-loading is imposed on the hoisting line when retrieving launcherless ROVs through a turbulent interface.

- The umbilical is very vulnerable to entanglement and destruction when a separate hoisting line for the ROV/Launcher is used.

- Without a heave-compensated umbilical winch ROV homing and securing to the launcher is difficult and hazardous.

- The ROV/Launcher combination is insufficiently protected by fenders. Components not firmly mounted to the ROV are vulnerable to impact.

Reliability

The report noted that reliability of ROVs had increased noticeably in the past years. Based on the evaluations, the following components were listed in order of their failure frequency:

- Lights.
- Electrical connectors, cables and cable terminations.
- Electric motors.
- Vehicle electronics.
- Vehicle hydraulics.

Maneuvering and Positioning

Aspects of these areas that were felt in need of improvement were:

- Navigation and track plotting (to and within the platform)
- Entanglement avoidance.
- Access to the inspection locations.
- Handling and positioning of tools and sensors.
- Vehicle stabilization during inspection execution.
- Operation in currents.

There are a number of other aspects of ROVs and their operations in ref. 183 that are worthy of consideration, but many of them are concerned with the particulars of vehicle maintenance and support vessel layout, beyond the scope of this report.

Not surprizingly, the report stated: "The most important conclusion is that completely purpose-designed ROV systems are inevitable in order to increase the efficiency and quality in execution of the simpler tasks and in order to be able to execute more complex inspection tasks at all. It is not sufficient to add sensors and tools to the existing multi-purpose ROVs."

The value of pre-planning, careful evaluation to match the vehicle to the job, the need to provide some time for the vehicle to de-bug the inevitable malfunctions it will experience and some time for the operators to develope a workable operational technique, cannot be overemphasized. H.L. Shatto (ref. 240) described the experiences Shell Offshore accumulated employing the DUAL HYDRA ROV system from the drillship DISCOVERER SEVEN SEAS at 2,286 meters depth. Prior to selection of an intervention vehicle, an examination and evaluation of the options proposed by the contractors was conducted. The HYDRA system, a tethered, free-swimming, cage-deployed ROV, was selected based on the conditions anticipated in the working environment and the expected performance, delivery, and cost of the contractor and system.

Since the DUAL HYDRA system was designed for the general offshore industrial market, and not specifically for drilling support from the DISCOVERER SEVEN SEAS, at over 2,000 meters depth and in the two knots of current anticipated, there were obvious changes necessary. Syntactic foam for additional buoyancy had to be added, an additional lateral thruster was added, modems for long line data transmission were added, an anchor and winch were included in the cage and a current meter attached to its top. Sea trials were conducted with the modified vehicle system which permitted many of the initial and inevitable problems that would have occurred on the drillship to be identified and corrected. Most of the deficiencies were minor. One major deficiency was not obtaining the thrust or current sustaining capability of the vehicle. Although ample hydraulic power was available (a third 10 hp hydraulic power pack had been added), the motor and propeller characteristics were not matched properly to make use of it. Further, the additional syntactic foam and components, such as the hydraulic power pack, increased the vehicle drag. Modifications were made, but the vehicle still could not meet the requirements for a two knot current, although it was able to perform the job in the currents encountered. Other modifications to the vehicle's manipulator and to the support vessel were also required. DISCOVERER SEVEN SEAS arrived on station with the ROV system almost exactly one year after the request for quotes had been sent to prospective bidders.

Arriving on station the system was deployed in drilling support for the next seven month period. Problems were still encountered: flooded motor cable; tether sheave malfunction; levelwind failure; loss of video and telemetry; shorting and burning out of one of the coax cables, and poor performance of the automatic depth control. A plot of the dives performed by the ROV system is presented in Fig. 50. According to Shatto: Many of the dives plotted in this figure were less distinctly successes or failures than indicated. When the system failed after completing essentially all the work it was sent to do, the dive was considered complete. If not, it was considered aborted even though some work was done. Seven of the total dives were test dives either to check the system after repairs, or to familiarize new crew members with the operation of the system; these were plotted either as completed or aborted as appropriate.

One of the more interesting features of Fig. 53 is that it provides an example of a typical learning curve. Although it is not stated in ref. 240, it is assumed that neither the contractor nor the client expected to arrive on station and complete the job without confronting some problems. Paper drills and sea trials identified the major deficiencies; the list could not be considered complete until the job was underway. Shatto concludes: "Almost all of the tasks originally anticipated for the ROV have been demonstrated, and several that were not anticipated have been added." He goes on to point out deficiencies in the manipulators and TV viewing that plague not only the DUAL HYDRA system, but the field overall and offers some suggestions for improvement.

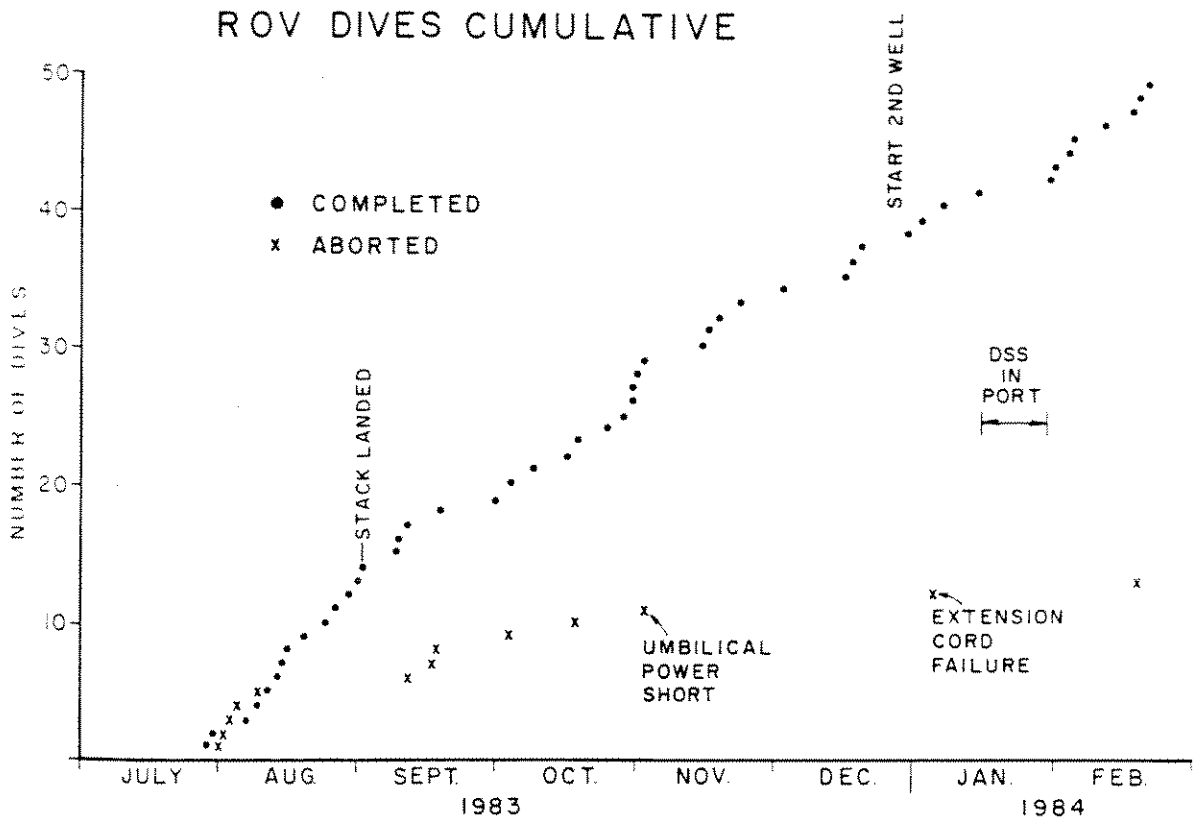


FIG 53. DUAL HYDRA DIVE SCHEDULE FROM DISCOVER SEVEN SEAS. (from ref. 240)

5.1.4.c Untethered Vehicles

Since this type of ROV is still in the developmental stage, as far as support to the offshore oil/gas industry is concerned, no operational experience has been gained. Remarking on the potential of this type of vehicle toward platform, riser and pipeline inspection, Kristiansen and Sletten (op. cit.) saw a definite advantage by virtue of the avoidance of the cable entanglement problem. They point out, however, that the high amount of power needed to accomplish some of the tasks might increase a vehicle's dimensions to the point where access could be a problem, and the bandwidth requirements for thru-water transmission of TV signals to meet line resolutions provided by cabled TV would be formidable. These same advantages and disadvantages would apply to using untethered ROVs in SPS inspection and maintenence.

5.1.5 Hybrid Vehicles

There is only one of the hybrid vehicles described in section 4.3 that is presently operational: the MDU (Mobile Diving Unit). The remainder are under construction. Since MDU combines the capabilities of an Observation/Work Bell and the ambient pressure diver, it will meet the same general constraints as described for these two capabilities in sections 5.1.3 and 5.1.2, respectively. MDU does offer a capability that none of the other hybrids supply. The attachment of a mating skirt to the diver lockout chamber can provide the capability for dry transfer of personnel to and from a dry, 1-ATA wellhead chamber.

5.2 CURRENT RESEARCH AND DEVELOPMENT

The foregoing sections identified virtually all of the current research and development that is aimed, directly or indirectly, at SPS inspection and maintenance. It is important to emphasize that there are undoubtedly other projects, much like the Montanazo field and DIMOS, wherein research and development is taking place and is aimed at a specific SPS. But, for reasons of confidentiality the developers do not wish to reveal their details.

The great surge in research and development in tools, instrumentation, intervention vehicles and supporting systems that was triggered by the North Sea requirements for platform inspection has not happened in the SPS arena. There are several reasons for this, a main one being that the effort which went into development-and is still underway-of tools and techniques for platform I&M produced a wide variety of tools and techniques applicable to SPS I&M. Also, during this period, a great number of the new and novel ideas and concepts that would not stand the test of field application had to be identified and culled from those which were practical. Unfortunately or fortunately, depending how you look at it, a number of undersea equipment and vehicle manufacturers, service companies and existing vehicles were also culled. Today's offshore oil operator and the companies that service them gained invaluable experience during this period. They are much wiser in the ways and means of underwater intervention, particularly with ROVs. This is not to imply that everything is working to perfection. It isn't, and there are still many improvements to be made. What it does imply is that the operators of SPSs are approaching I&M with a greater appreciation for the capabilities at their disposal and with a greater degree of input from the people who will provide the I&M services. Witness, for example, the Montanazo field where development of the wellhead included input from the designer, the operator and the service company. Or in the Garoupa field where the structures were designed for intervention by the ADS JIM.

Another major reason for the apparent lack of urgency in SPS inspection and maintenance R&D is owed to the fact that the vast majority are within diver depth. This permits application not only of the diver, but virtually every tool or instrument that has ever been developed for underwater visual and non-destructive examination, maintenance and, additionally, repair.

Finally, to some undeterminable degree, the performance of SPSs in terms of structural reliability seems to be quite remarkable. Section 3.1.2 presented the published statistics of SPS performance. According to the performance record of the SPSs where data were available, there has been very little need for inspection and maintenance. Considering the fact that the forces acting to warrent frequent inspection and maintenance on SPSs are much fewer and less frequent than those present on fixed platforms, this might well be the case.

In another vein, some SPS operators have for years been carrying on R&D and test programs for I&M. Shell/Exxon's present MMS for servicing the UMC began as a test project in the Gulf of Mexico on the Submerged Production System 11 years ago. It is still considered as a test project on the UMC preparatory to installation of subsea production systems beyond diver depth. ELF Aquitaine's TIM is another example of this approach.

There is, of course, almost continual R&D being expended on the tools and instrumentation that might be used for SPS I&M. This would include: TV and still cameras; manipulators, NDT devices, cleaning devices and others. While the improvements in such components are not specifically or solely aimed at the SPS market, the end result is applicable thereto.

5.2.1 The Diverless Underwater Intervention Project (DUIP)

The DUIP is the only major R&D program into overall SPS inspection and maintenance that was identified in this study. The program was not R&D, however, as much as it was an evaluation of available intervention capabilities provided by diverless techniques. (The following description of this project is taken from ref. 143.)

That portion of the DUIP concerned with SPS I&M is called Diverless Installation and Maintenance of Subsea Production Systems in Deep Water. It began in 1981 with the participation of AGIP, Chevron, FINA, Hispanoil, Norsk Hydro and TOTAL. The evaluation was under the aegis of DNV. The project included a theoretical phase which was completed in 1982 and full scale sea trials which began thereafter and were completed in 1983.

The purpose of the project was:

- To investigate the potential applications of underwater intervention on SPSs.

- To evaluate the present underwater vehicle capabilities in performing assistance and maintenance tasks.

- To guide future development of vehicles/subsea systems in order to improve intervention capabilities.

- To compare different maintenance concepts and system design philosophies.

The analyses were carried out on two Xmas trees: a prototype system built for Chevron and a Vetco single well completion system. The Chevron tree was used in the field trials. A failure mode effect analysis (FEMA) was performed on the two trees to identify critical sub-operations, the components/systems involved in these operations and to identify the types of failures that make underwater intervention necessary. From this analysis the vehicle intervention evaluation program was developed. (Fig. 54)

Five intervention vehicles were selected for evaluation: the tethered, free-swimming ROV TROV S7 (Fig. 46) ; the ADSs JIM and WASP (Fig. 41) ; the untethered, 1-ATA submersible MERMAID IV (Fig. 38), and the tethered, 1-ATA submersible MANTIS (Fig. 39). Trials were conducted in 25 meters and in 300 meters depth.

A number of modifications were made on the Xmas tree to enable performance of the planned tasks. In the original tree design most of the maintenance tasks were meant to be conducted by pulling the tree or the completion cap out of the water. The modifications were developed on the results of the theoretical analyses and with cooperation by the operators of the selected vehicles. The modifications included: walking stages for JIM; installation of an underwater replaceable insert valve and a wet make/break underwater electrical connector, and other modifications or installation of other components that would more accurately reflect the type of Xmas tree these vehicle would be called upon to service.

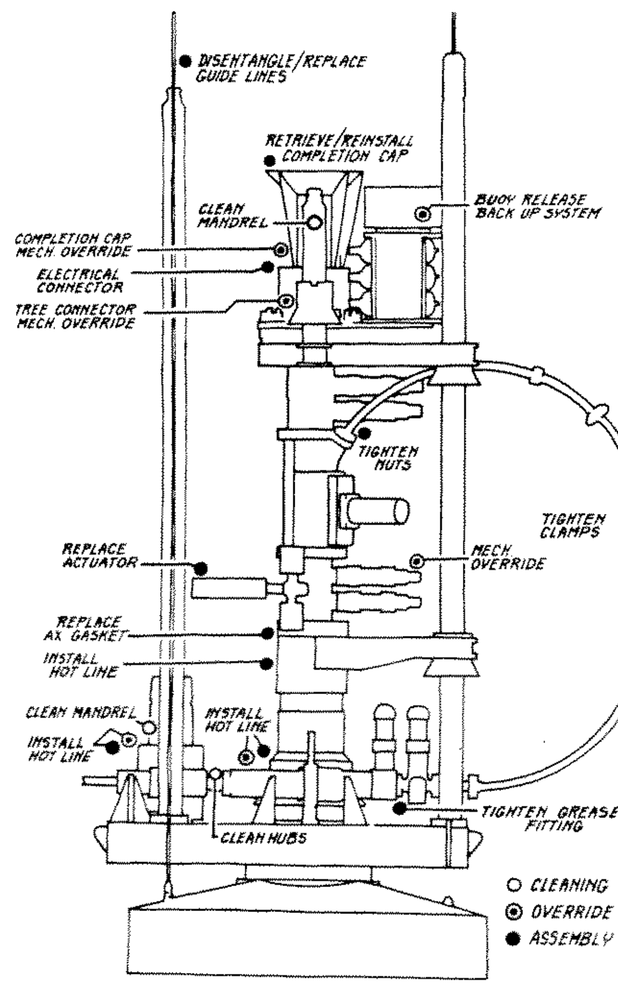


FIG. 54. DUIP INTERVENTION PROGRAM TASKS. (from ref. 143)

The vehicle operators were given the time to develope various tools that would be capable of conducting the tasks proscribed. According to ref. 143, this was considered to be a basic point in the project philosophy. The authors state: "Being given time to design tools and decide the approach to the various problems, the operator can overcome most limitations inherent in the under vehicles, even reducing to a minimum the alterations necessary on the Xmas tree. This consideration strongly affects the time needed for performance of the tasks." They further note that the combined efforts of the vehicle operators and manufacturers and the Xmas tree designers can push performance of the vehicles to competitive levels comparable to other maintenance methods.

6.0 CONCLUSIONS AND RECOMMENDATIONS

The information obtained and presented in this report, regarding inspection and maintenance of subsea production systems, indicates that there are ample intervention techniques and tools now available to conduct these tasks. This is because all of the presently operating SPSs identified are in water depths of 300 meters or less and, therefore, accessible to the diver. Current diving trials and physiological research being conducted by Comex may soon extend the diver's range to 450 meters.

The major deficiencies, as far as can be determined from the data available, are mainly brought about by high expectations and inadequate preliminary evaluation of the intervention technique to identify its weaknesses and required modifications. The fault can be placed on all the participants: the SPS designer for not anticipating the possibility of both the diver and diverless intervention; the SPS operator for not spending the time and effort necessary to evaluate the vehicle options and testing the vehicle before it is deployed on the job, and the vehicle operator for overestimating his vehicle's capabilities. The foregoing chapter demonstrated that when all three parties work together, a very high degree of success can be obtained.

The foregoing data also showed that present and planned SPSs are highly individualistic. While there are some wellheads that may be similiar in design, many are not. Consequently, where it is possible to recommend research and development that might improve the performance of diverless I&M techniques on a specific subsea completion, the improvements would not necessarily be applicable to any other wellhead or any other intervention technique. Standardization of SPS design is a tempting recommendation, but it assumes that one design is superior to all others in all the varied environments and circumstances under which a wellhead must perform. Standardization, at this point in time, would appear more crippling than beneficial in this still-emerging area of technology. This is particularly true of future systems that might be beyond the range of divers and, therefore, must maintain a high degree of design flexibility to accommodate the wide array of diverless intervention techniques.

A more appropriate option appears to lie in the area of purpose-designed vehicles and SPSs designed to accommodate these vehicles. Where this approach has been taken the published results indicate a high degree of success. This does not imply that there must be a new diverless intervention vehicle designed for each new SPS. The field experiences and evaluations that have accumulated point to several measures that can vastly improve the I&M performance of "off-the-shelf" vehicles. The most critical measure is to design the SPS for I&M in conjunction with the service company that will conduct these tasks. This is to assure that there will be no major or, at worst, insurmountable obstacles in the way of the selected technique. The second measure is to modify the vehicle where necessary to accommodate the structure and the operating environment. Thirdly, develope interfacing tools that make the vehicle's manipulative capabilities compatible with the SPS's manipulative requirements. This procedure was sucessfully followed by Shell to develope a drilling support capability in record-breaking water depths. (ref. 240) It is also being followed by Chevron in the development of its 762 meters deep wellhead intervention system in the Montanzo field. In both of these examples the intervention vehicle was selected from a wide variety of vehicles developed for deep water oil support in general; not specifically for the tasks they were called upon to perform.

Reliability of subsea completions to date has reportedly been extremly high. Some, such as those in the Molinos field off California, have operated for as long as 20 years without a breakdown, and analyses on the wellheads indicated that they could have performed satisfactorily for several more years. Since SPSs are not subjected to the same dynamics as are fixed platforms, the major deterioration is caused by corrosion. In this respect structural engineers feel that the mechanics of corrosion are adequately understood to the point where an anti-corrosion system can be designed for virtually any ocean environment. Marine fouling organisms can be prolific on an SPS. Many of the foulers wedge themselves between nuts and fittings to the point where access to these components is impossile. However, high pressure water jetting and other advanced cleaning techniques seem more than adequate to remove the organisms. The effect of fouling on SPSs seems more cosmetic than it is an operational deterrent.

Reviewing the data presented in Section 3.1 reveals that the major problems to date are not ones that would be detected by an inspection performed by any of the present diver or diverless intervention techniques. These problems have been primarily ones having to do with reliability of SPS components, not necessarily the structure itself. They involve wellhead control systems, switching gear and valves, hydraulic and electric systems, corrosive fluids, and certain artificial lift problems. These are problems that occur inside the SPS, not externally where they could be located by current inspection tools or techniques. They are also problems which, for the most part, are detected by non-performance of the component, and they do not announce their presence by affecting the structure's integrity. Since most SPSs are continuously monitored with respect to product flow, temperature and pressure, and generally contain devices that inform the operator whether or not a particular valve, switch or control performed as directed, non-performance is almost immediately detected remotely from the surface. (Providing, of course, that the detecting system works.)

One of the areas of SPS integrity that is of great concern to the operator is the possibility of physical damage to the flowlines or the structure brought about by trawling activities, dragging anchors, or dropped objects. These are problems that can be detected by external examination, since the damage is reflected externally on the structure through bends, warps or fractures. The detection method is by direct or optical viewing; documentation of the damage is by still photography and TV. These techniques provide adequate data from which any damage can be detected and assessed. The only major deficiencies are in the limited field of view the conventional techniques provide. All of the techniques for photo or video documentation are designed to capture only a relatively small area, measuring, at most, by two or three meters on a side, more commonly less. This can result in the taking of quantities of exposures which then must be overlapped or oriented in some fashion to reproduce the whole. While this can be accomplished, it is time-consuming; not all of the exposures will be at the same distance from the structure, nor will they have the same quality of lighting. The technique also requires a precise knowledge of where each exposure was taken, not always an easy task. The net result can be a series of exposures that are adequate for inspecting specific areas of the structure, but are difficult to format into a mosaic that provides a picture of the structure as a whole. The analogy of not being able to see the forest for the trees is appropriate. In the case of looking for damage caused by the physical impact of anchors, trawls or large dropped objects, it might be better to look first at the forest (i.e, the wellhead or template) and, if closer inspection is indicated, then look at the trees. Techniques have been developed to provide such large area photography. These might be applied to wellhead inspection to save time and to obtain a better appreciation for any damage the structure might have sustained.

6.1 LARGE-AREA TV COVERAGE

The development of techniques for large-area subsea photography began in the late sixties at the U.S. Naval Research Laboratory. The technique was labeled LIBEC or Light Behind the Camera. The LIBEC approach was used by the Navy for inspection and identification of large objects (ships, aircraft, equipment arrays, etc.), and by both the Navy and the scientific community for search and survey. The technique has been refined and its coverage expanded in recent years by the Woods Hole Oceanographic Institution (WHOI) on the ARGO instrumentation platform. (ref. 241)

In its present configuration ARGO is designed to be towed through the water at a speed of about one knot. The LIBEC technique can, however, be employed just as well from a stationary platform. The following is a description of the ARGO system and the WHOI goals and results as presented in ref. 241. While the WHOI project is aimed at optical imaging through the use of TV cameras, the same technique applies as well to still photography to obtain higher resolution images.

The ARGO is a towed sled capable of operating at depths of 6,000 meters. It is towed by a "standard" coaxial cable that also provides power for the lights and cameras. The cable has a usable bandwidth of 5 mHz, which is adequate, but will be updated by one containing three optical fibers which, according to the authors, will increase the bandwidth one hundred fold. It is also anticipated that the use of CCD cameras with intensifiers will, when available, greatly increase the image resolution. In operation, ARGO illuminates the ocean floor with high intensity strobe lights mounted on the main vehicle. Suspended 20 to 50 meters below the main vehicle is an imaging pod which may carry up to five TV cameras. Four cameras are wide angle, looking forward, to each side and straight down. The fifth is a telephoto camera that will look slightly down and slightly forward to obtain detailed information on sea floor topography. The four cameras provide a composite picture of an area 100 to 500 meters square. By using the low light level S.I.T. cameras, with an equivalent sensitivity of 200,000 ASA, WHOI hopes to extend the viewing range out to 100 meters. As the vehicle is towed the strobe lights flash every few seconds and an instantaneous video picture or "snapshot" is obtained. These snapshots are "grabbed" by electronic frame stores for viewing and digital processing. By firing the strobe light at the proper sequence pseudo-continuous coverage of the bottom is obtained by the overlapping snapshots.

In 1981 a similar wide angle imaging system was tested on the manned submersible ALVIN. From an altitude off the bottom of 15 to 20 meters and with the strobe lights suspended 50 to 100 meters above the submersible, WHOI obtained pictures of the bottom averaging 2,000 square meters in area. During this series of tests a submerged hydrophone tower 15 meters tall was imaged. The resultant image captured almost all of the structure which measured 9.1 x 9.1 x 15.2 meters (LWH).

An ARGO-like system might find application towards SPS inspection by providing, on one image, a picture of the entire wellhead or even an entire template such as the UMC. None of the satellite wellheads now used are larger than the size of the area covered by the ARGO technique. The UMC, measuring 52m x 42m, covers an area of 2,184 square meters, just larger than the 2,000 meter square area covered in the 1981 tests. All of the present and planned SPSs are within the minimum 100 meters square area (10,000 square meters) WHOI believes is possible using the ARGO system.

Using the ARGO technique one might obtain on five images the four sides and a vertical view of a wellhead or template with adequate resolution to determine whether or not the structure has sustained any damage from dropped objects, dragging anchors or trawl boards. The inclusion of a telephoto lens would permit the concurrent capability to obtain a more detailed image of a particular part of the structure. At best the ARGO technique may provide sufficient information to negate the need for a detailed, up close inspection. At worst it can forewarn the surveyor that damage has been sustained and that there is a need for more detailed observations and measurements. The same technique can be used to image flowlines and cables to determine whether or not they have sustained damage or displacement. While acoustic techniques can provide much of this information, they do not have adequate resolution to determine the presence or the nature or extent of damage that displacement might have caused. The technique could also have application in the installation of a SPS to observe its orientation after it has been installed.

It is recommended that consideration be given to the ARGO technique as an optional procedure for subsea production system inspection.

6.2 REPAIR BEYOND DIVER DEPTH

Repair of SPSs is beyond the scope of this study. However, during the course of the study the subject loomed as possibly one of the most significant problems which might be encountered when the structure is beyond the range of the diver. The offshore underwater contractors who have supported the oil and gas industry have shown a remarkable degree of ingenuity, imagination and skill in repairing underwater structures. To our knowledge, there are no reported incidents where a platform or wellhead had to be abandoned or shutdown because it was irreparable. The same holds true for pipelines. A major key to this success has been the diver. Since all of the presently operating SPSs are within the range of the diver, there is no reason to believe that repairs to SPSs will be less successful that they have been with platforms and pipelines. The same may not hold true for SPSs beyond diver depth.

There are several programs now being carried out by industry that are aimed at conducting underwater repairs remotely from the surface. Two of these are pipeline repair systems, one being developed by a French consortium and the other by an Italian consortium. These systems, when developed, will only apply to pipelines; as far as can be determined, there are no developments being pursued that aim at diverless repair of platforms or SPSs. The primary reason being that the diver has access to all presently installed platforms and all but one SPS. (The trans-Mediterranean pipeline, on the other hand, is well beyond the reach of divers.) In view of this, there is little or no incentive on the part of the underwater contractor to develop such techniques since there is no present market. This does not imply that there is no planning for the future, it is more reflective of an industry whose future is difficult to predict since it is so intimately tied to the price of oil. There is no doubt that diverless repair of platforms and SPSs will be necessary, but when?

In the case of diverless repair to SPSs, the question is not only when, but what? The latter question is critical since it determines the direction in which research and development should proceed. In some quarters the term "unforeseen maintenance" is euphemistically inserted in lieu of repair. The ephemism is apt since it implies the unpredictable. Therefore, it follows that when something is unpredictable, then how does one prepare to cope with it when it occurs. Naval vessels have the same problem trying to prepare for battle damage. They cope with the problem by analyzing past damage and trying to anticipate future damage based on the type of damage the adversary might inflict. (The marine salvage industry is in much the same predicament since no two salvage tasks will be exactly the same.) The solution is to carry an array of damage control materials and tools that is based, in part, on past applicability and additional equipment that attempts to anticipate the future.

The offshore oil industry has little historical precedent to draw on with regards to SPS repair. But all indications are that the major damage will be from impacting with anchors, trawl boards and objects dropped from the surface. Some, but not all, operators see a solution to the problem by placing a protective, i.e., sacrificial, structure around or over the wellhead or template. This appears to be as good an answer as any, but it prompts the question: how does one repair the sacrificial structure if it sustains damage? The problem is perplexing, but by no means hopeless. Possibly the first step is to hypothesize the type of damage a SPS would sustain from impact. There are ample historical examples of the type of damage trawls, anchors and dropped objects have had on platforms and pipelines. The next step would be to examine the steps that were taken to repair the damage and the tools that were employed. From this information one might extrapolate a potential solution for diverless repair of a SPS. This will, by no means, provide a solution to all "unforeseen maintenance", but it should at least define some of the boundaries of the problem, which is the first step in any solution.

6.3 PROBLEMS SPECIFIC TO THE ARCTIC

In 1983 the Minerals Management Service of the U.S. Department of the Interior published the report Arctic Undersea Inspection of Pipelines and Structures. This report discusses in some detail the problems which are unique to the arctic with respect to undersea inspection. Since the MMS report was published there has been nothing published elsewhere that significantly changes the conclusions therein. The interested reader is referred to that report for a full discussion of potential and actual problems in deployment of underwater intervention techniques under arctic conditions. The following is a capsulization of the MMS conclusions.

With respect to potential damage a SPS might encounter in the arctic, the same problems present elsewhere are also present here with the addition of damage by impact from ice islands or icebergs. The solution to this problem has been, with the one SPS in the arctic, to place the wellhead in a hole excavated to a depth which will place it out of range of the greatest anticipated keel depth of the island or berg. The same solution would apply to flowlines or cables connected with the wellhead. Similar to damage inflicted by trawls, anchors or dropped objects, damage by ice would be detectable visually and the same intervention techniques described in Chapter 4 of this report would apply.

The major and unique problem the arctic offers to SPS I&M is deployment and support of the intervention technique through the ice. This was discussed herein in Chapter 5 and concluded that the migration of the ice cap, depending on its rate of migration and the length of the I&M task, would present serious problems in deploying any intervention technique that relied upon a cable or any physical connection with the surface.

This problem has not yet arisen since there is no offshore production in the high arctic. In the U.S. arctic the commercial offshore discoveries that have been made and are planned for near-future development (the Endicott reservoir; the Seal Island discovery) are slated to produce from artificial gravel islands; not subsea production systems. Even the pipelines carrying the product ashore will be out of the water and supported by gravel causeways. The first foreseeable depths where the artificial island approach will not be economically feasible appears to be in the Navarin Basin, where water depths range from 90 to 180 meters. If this area lives up to its promise, then a choice will be made between an SPS or one of the many platforms designed specifically for arctic application. Fortuitously, the open water season lasts, in some sites, as long as 11 months. (ref. 248) In view of these developments, there seems no pressing need for recommendations regarding SPS inspection and maintenance in these areas. If the Navarin Basin does prove commercially acceptable, the depths are well within the diver's capabilities, and, while deployment and support of diving systems, or any other surface-supported systems for that matter, may not be easy, it will not be impossible.

In the Canadian Beaufort Gulf Canada has made two major discoveries: Tartsuit and Amauligak, both in water depths of 20 to 30 meters. According to ref. 248, Gulf envisions utilizing subsea completions in concrete-protected "glory holes" to defend against ice damage. In terms of inspection, the water depth is easily within the diver's domain. In terms of ice cover, it is seasonal with an operating window of 110 to 130 days between July and October. This would seem to be an adequate window for any scheduled inspection and maintenance tasks. Studies by Canadian undersea diving contractors and subsea completion equipment manufacturers have been conducted for several Beaufort area operators dealing with the accessibility aspects of structures within the ice-covered areas. These reports are not available to the public. They are mentioned, however, to note that the real and potential problems are being addressed.

While submerged production systems seem to provide a natural answer to the ice problem where artificial islands are impractical and the safety of platforms are doubtful, there are other factors that are as influential as the ice. Mobil Oil, in conjunction with five other partners/operators, has sought to begin development of a subsea completion, semisubmersible production and floating storage facility in the Hibernia field. The floating facility would be designed to disconnect in the event of imminent iceberg collision. Newfoundland's Petroleum Directorate favors a larger first-phase based on a concrete, gravity-type platform. Although unproven, it is argued that the platform will be rugged enough to deflect icebergs. A major factor in the selection process is that construction of the concrete platform would have a much greater local labor content. (_ibid._)

APPENDIX I

GLOSSARY

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ADMA-OPCO: Abu Dhabi Marine Operating Company
API: American Petroleum Institute

BMW: Below Mudline Wellhead
BOP: Blowout Preventer
bopd: barrels of oil per day
BOTM: Buoyant Off Bottom Tow Method (Conoco)
BUE: British Underwater Engineering

CALM: Cantilevered Anchor Leg Mooring
CEPM: Comite d'etudes petrolieres marines
CHRT: Casing Hanger Running Toll (Sii McEvoy)
CIW: Cameron Iron Works
CJU: Control Jumper Unit (Skuld)
COM: Connecting Module (Skuld)
CSC: Common Service Carrier (Skuld)

DHSV: Downhole Safety Valve
DIMOS: Diverless Installable and Maintainable Oil Production System (Shell)
DSPS: Deep Sea Production Systems (consortium composed of McAlpine; Humphreys & Glasgow; British Insulated Callender Co. and Rolls Royce)

ENIEPSA: Empresa Nacional De Investigacion Y Exploitacion De Petroleo, S.A.
EOR: Enhanced Oil Recovery
ESP: Early SubSea Production System (Vetco)
ETAP: Enterprise Tunisienne d'Activities Petrolieres

FAS: Flowline Alignment Structure
FLP: Floating Production Facility
FSPO: Floating Production Storage Offloading System
FSU: Floating Storage Unit (Shell Expro, Fulmar Field)

GASP: Goodfellow Associates Submerged Production System
GLLITS: Guidelineless Insertable Tree System (Shell)
GOR: Solution Oil/Gas Ratio

IFP: Institut Francais du Petrole

LMRP: Lower Marine Riser Package

MC: Manifold Center
MMS: Manipulator Maintenance System (Exxon)
MSV: Multi-Service Vessel
MTFB: Mean Time Between Failures
MWE: Manned Work Enclosure (SEAL)

NBMM: Non-Buoyant Maintenance Manipulator (Exxon)
NDT: Non-Destructive Testing

PCAHT:	Production Control Assembly Handling Tool
PLEM:	Pipeline End Manifold
PJU:	Production Jumper Unit (Skuld)
PTB:	Personnel Transfer Bell
RCVP:	Remote Controlled Vehicle Plough (UDI Group)
RGS:	Remote Guidance Systeem (Exxon)
RMS:	Remote Maintenance System (Exxon)
RMV:	Remote Maintenance Vehicle (Exxon)
ROV:	Remotely Operated Vehicle
RTV:	Remote Terminal Unit
SALM:	Single Anchor Leg Mooring
SALS:	Single Anchor Leg Storage
SALS:	Single Anchor Leg System
SARM:	Subsea Atmospheric Riser Manifold
SAS:	Subsea Atmospheric System (Mobil/Knaerner)
SAS:	SEAL Atmospheric System
SCS:	Subsea Completion System
SCSSV:	Surface Controlled, Subsurface Safety Valve
SC-TRSSV:	Surface Controlled Tubing Retrievable Subsurface Safety Valve
SEAL:	Subsea Equipment Associates Ltd.
SEL:	Slingsby Engineering Ltd.
SIPM:	Shell International Petroleum Mij
SIS:	SEAL Intermediate System
SMC:	Satellite Manifold Center
SPS:	Subsea Production System
SPS:	Submerged Production System
SPT:	Storage Production Terminal
SRT:	Site Receipt Test
SSU:	Surface Support Unit (SEAL component)
SSV:	Surface Support Vesel
SWAS:	Surface Well Access System (CanOcean Resources)
SWE:	Subsea Work Enclosure (SEAL component)
SWIMS:	Subsea Wellhead Installation and Maintenance System
SWOPS:	Single Well Offshore Production Unit
TFL:	Through Flowline
THROT:	Tubing Hanger Running & Orienting Tool
TIM:	Telemanipulateur d'Intervention et de Maintenance
TLP:	Tension Leg Platform
TMV:	Tethered Maintenance Vehicle (Exxon)
tonnes:	metric tons
TRSSV:	Tubing Retrievable Subsurface Safety Valve
TRSV:	Tubing Retrievable Type Safety Valve
UMC:	Underwater Manifold Center
VBR:	Variable Bore Ram
VES:	Vertical Entry Control System
WCA:	Wellhead Connection Assembly (SEAL component)
WCH:	Wellhead Cellar (CanOcean Resources)
WLRSV:	Wireline Retrievable Type Safety Valve

APPENDIX II

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APPENDIX II

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APPENDIX III

ACTIVITIES/PERSONNEL CONTACTED

APPENDIX III

ORGANIZATIONS CONTACTED

AMETEK/Straza Division
El Cajon, CA

American Bureau of Shipping
New York, NY

Cameron Iron Works, Inc.
Houston, TX

Comex Services
Marseille, France

Can-Dive Services, Ltd.
No. Vancouver, BC
Canada

CanOcean Resources Ltd.
New Westminster, BC
Canada

Conoco, Inc.
Houston, TX

Deep Ocean Technology, Inc.
Oakland, CA

Deep Oil Technology, Inc.
Long Beach, CA

Dept. of Electronic & Electrical Engineering
Heriot-Watt University
Edinburgh, Scotland

Det norske Veritas
Oslo, Norway
Energy, Mines and Resources
Canada
Ottawa, Canada

Exxon Production Research Co.
Houston, TX

FMC Corporation
Houston, TX

Gray Tool Company
Houston, TX

Gulf Oil Exploration & Production Co.
Houston, TX

Hughes Offshore Products
Torrance, CA

Hydro Products
San Diego, CA

IFREMER
Paris, France

International Submarine Engineering, Ltd.
Port Moody, BC, Canada

International Underwater Contractors, Inc.
City Island, NY

Lloyds Register of Shipping
London, England

Marine Systems Engineering Laboratory
University of New Hampshire
Durham, NH

McEvoy Oil Field Equipment Co.
Houston, TX

Minerals Management Service
U.S. Dept. of the Interior
Reston, VA

National Supply Company
Houston, TX

Oceaneering International
Houston, TX

Offshore Supplies Office
U.K. Department of Energy
London, England

OSEL Group
Great Yarmouth, Norfolk
England

Perry Offshore
Riviera Beach, FL

Petroleum Directorate
U.K. Department of Energy
London, England

Regan Offshore International
Torrance, CA

Shell Offshore, Inc.
Houston, TX

Slingsby Engineering Ltd.
Kirkbymoorside, Yorkshire
England

Sonat Subsea
Houston, TX

Sub Sea International
New Orleans, LA

Taylor Diving & Salvage Co.
Belle Chasse, LA

U.S. Coast Guard
Washington, DC

Vetco Offshore Group
Ventura, CA

Woods Hole Oceanographic
Institution
Woods Hole, MA

APPENDIX IV

CANOCEAN RESOURCES LTD.

RECOMMENDED INSPECTION PROGRAM

LOCKHEED PETROLEUM SERVICES LTD.
NEW WESTMINSTER BC CANADA

TENNECO WHC 006
WHC MAINTENANCE SCHEDULE

Sheet 1 of 4

SUBSYSTEM	COMPONENT OR REF. DESIGNATOR	FUNCTIONS REQUIRED	REFERENCE	SKILL CODE	INTERVAL EVERY MSN	1 YR	2 YRS	LAST SERVICE DATE
Hatch/Hatch Seat	Seals Sealing Surfaces Hinge Pins	Inspect/Grease Inspect/Clean Inspect/Grease	3.1.1	M M M	X X 	 X		
Mating Ring	Sealing Surface	Inspect visually	3.1.2	M	X			
Bullnose Port	Primary Seals	Inspect for leaks Check packing ring	3.1.3.1	M	X 	 X		
Spool	Seal surface Studs	Inspect for damage or corrosion Inspect for corrosion	3.1.4	M M	(When xmas tree removed)	 X		
Lighting	Lights, Fixtures Cables	Inspect visually	3.1.5	E		X		
Sump		Pump out	3.1.6	M	X (last dive)			
Cathodic Protection	Teacup "Galvalum" anode	Inspect and clean	3.1.7	M		X		
Paint (internal)		Inspect and note condition in log	3.1.8	M		X		
Hull and Teacup	Structure Walls Teacup Grating	UT measurements Inspect for corrosion	3.1.9	M M		X X		
WHC Interior		Inert	3.1.10	M	X (last dive)			
Acoustic Receiver & Power Pack	Helle	Function Check Factory Checkout Change Battery	3.2.1	E V E	X Every 4 years 	 X		

SKILL CODE: M - MECHANICAL E - ELECTRICAL V - VENDOR

TENNECO WHC 006
WHC MAINTENANCE SCHEDULE

SUBSYSTEM	COMPONENT OR REF. DESIGNATOR	FUNCTIONS REQUIRED	REFERENCE	SKILL CODE	INTERVAL EVERY MSN	INTERVAL 1 YR	INTERVAL 2 YRS	LAST SERVICE DATE
Explosive Release	Cameron #CE1001-I	Inspect visually Replace	3.2.2	E	X		 X	
Recall Buoy Nest	Arm Hydraulic Cylinder	Check movement Check operation	3.2.3	M M		X X		
Recall Buoy		Inspect visually	3.2.4	M	X			
Pilot Line		Inspect visually	3.2.5	M	X			
Downhaul Cable	Cable, button-stops	Inspect visually	3.2.6	M	X			
Cable Reel		Check operation Check for hydraulic leaks Inspect visually	3.2.7	M M M				
Tripod Assembly	Cable, fittings	Inspect visually	3.2.8	M	X			
Bridle Release Assembly	Actuators	Inspect visually Function test	3.2.9	M M	X X			
Teacup Hydraulics	Buoy release Bridle release Panel valves nipples and bladder	Inspect visually Inspect visually Inspect visually	3.3.1	M M M	X X X			
	Connector hydraulics	Re-establish pressure on lock line "E" (150-200 psig)	3.3.2	M	X			

SKILL CODE: M - MECHANICAL E - ELECTRICAL V - VENDOR

LOCKHEED PETROLEUM SERVICES LTD.
NEW WESTMINSTER BC CANADA

103253

TENNECO WHC 006
WHC MAINTENANCE SCHEDULE

SUBSYSTEM	COMPONENT OR REF. DESIGNATOR	FUNCTIONS REQUIRED	REFERENCE	SKILL CODE	INTERVAL EVERY MSN	INTERVAL 1 YR	INTERVAL 2 YRS	LAST SERVICE DATE
Teacup Hydraulics (cont'd)	Spool cavity	Record pressure and bleed		M		X		
Air Purge Assembly	Piping	Inspect visually	3.4.1	M		X		
	Worcester ball valve	Inspect visually		M		X		
		Change		M			X	
	Parker fittings	Inspect visually		M		X		
		Change		M			X	
	Teflon packing	Inspect visually		M		X		
Air Exhaust Assembly	Piping	Inspect visually		M		X		
	Worcester ball valves	Inspect visually	3.4.1	M		X		
		Change teacup ball valve		M			X	
	Parker fittings	Inspect visually		M		X		
		Change		M			X	
	Teflon packing	Inspect visually		M		X		
Vent Piping	Rupture disc and diaphrgm	Change	3.4.2	M		X		
	Worcester ball valve (inside WHC)	Inspect visually		M		X		
	Velan check valve	Inspect visually		M		X		
	Gaskets	Inspect for leakage		M	X			
	Worcester ball valve (in teacup)	Inspect visually		M		X		
		Change		M			X	

SKILL CODE: M - MECHANICAL E - ELECTRICAL V - VENDOR

LOCKHEED PETROLEUM SERVICES LTD.
NEW WESTMINSTER BC CANADA

103253

TENNECO WHC 006
WHC MAINTENANCE SCHEDULE

Sheet 4 of 4

SUBSYSTEM	COMPONENT OR REF. DESIGNATOR	FUNCTIONS REQUIRED	REFERENCE	SKILL CODE	INTERVAL EVERY MSN	INTERVAL 1 YR	INTERVAL 2 YRS	LAST SERVICE DATE
Vent Piping (ctd)	Whitey plug valve	Inspect visually		M		X		
		Change		M			X	
	Piping	Inspect visually		M	X			
Production Equipment Assembly	Piping	Inspect visually	3.5.1	M		X		
		UT thickness measurements	3.5.2	M		X		
	Piping hangers and supports	Inspect visually		M		X		
	Valves and Xmas tree	Inspect visually for leakage around bonnets hydraulics, flanges	3.5.4	M	X			
	Bullnose	Inspect visually for leaks and damage or corrosion to electrical connection	3.5.3	M, E		X		
	Tubing hanger subs and spool bushing	Inspect for damage to bushing, 'O'rings, subs	3.5.5	M	When xmas tree removed			
Production Control	Transducer isolators and interconnecting tubing	Inspect visually	3.6.2	M		X		
	Koomey control system	Refer to Koomey Service Manual	3.6.1					

SKILL CODE: M - MECHANICAL E - ELECTRICAL V - VENDOR

3.1.9 Hull Ultrasonic Thickness Test

Description

The hull structure including shell, heads, teacup and hatch were designed with a 1/8" corrosion allowance.

Following the painting of each WHC material thicknesses were measured ultrasonically.(Original thicknesses and location reference are included in Appendix F).

Maintenance

Surveys of the hull thicknesses should be conducted annually to give an ongoing record of the rate of hull corrosion throughout the life of the WHC. These thicknesses should be recorded on sheets similar to those in Appendix F.

3.1.10 Nitrogen Inerting

The atmosphere of the WHC is purged with nitrogen gas between servicing programs. This reduces the oxygen content to approximately 8% by volume. This oxygen level is insufficient to support combustion of petroleum products.

The WHC is nitrogen purged after the hatch is closed by partially evacuating and backfilling with nitrogen through the Air Exhaust Assembly (Dwg. 100776).

APPENDIX V

DET NORSKE VERITAS

TENTATIVE RULES FOR SPS INSPECTION

TENTATIVE RULES FOR CERTIFICATION OF SUBSEA PRODUCTION SYSTEMS

JANUARY 1984

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APPENDIX V

Foreword
After extensive consultations with the industry, the present document has been published in the form of Tentative Rules, in order that more experience can be gained and possible improvements made before eventual approval of the document as Rules (for the certification defined in the document).

Before these Tentative Rules have been approved as Rules, Veritas may issue a Statement of Compliance instead of the Certificate of Compliance defined in this document. Such a Statement will be replaced by a Certificate after the Tentative Rules have been approved as Rules, provided possible alterations of the requirements are complied with.

Tentative Rules apply to new fields, and the Society reserves the right in each case to grant exemptions or make additions in order to achieve the intended technical standard.

CONTENTS

Section 8
Flowlines, Piping and Mechanical Equipment

Section 9
Control and Safety Systems

Section 10
Electrical Systems

Section 11
Safety of Personnel

Section 12
Retention of Validity for Certificate of Compliance

SECTION 1
GENERAL REGULATIONS

1.1 General.

1.1.1 Application.

1.1.1.1 These Rules apply to the design, fabrication, transportation, installation, and maintenance of Subsea Production Systems for which a Certificate of Compliance (see 1.2) is requested.

1.1.2 Definitions.

1.1.2.1 Subsea Production Systems including Subsea Completion Systems are systems on or buried in the seafloor and related to production of hydrocarbons.

1.1.2.2 In the present Rules various references are given to other Veritas publications. These publications are in three levels, defined as follows:

Rules lay down basic requirements in connection with the certification defined in the Rules.

Appendices to the Rules, describe examples of accepted approaches in application of the Rules.

Technical Notes (TN) give guidelines on various problems related to fixed offshore installations.

1.1.3 Scope.

1.1.3.1 The following parts and systems are covered by Veritas' certification of Subsea Production Systems:

- Parts and systems surrounded by water or enclosed in a dry environment.
- Downhole completion including downhole safety valves, downhole pumps and artificial lift devices.
- Well heads.
- Christmas trees.
- Subsea manifolds and valves.
- Subsea storage tanks.
- Surrounding, supporting and protecting structures and foundations.
- Production risers and flow lines.
- Control and safety systems.
- Maintenance equipment and systems.

1.1.4 Rules in force.

1.1.4.1 Unless otherwise decided, amendments to the Rules will come into force six (6) months after having been approved by the Board.

1.1.4.2 Amendments to the Rules may be published at any time. When the amendment is made applicable to Subsea Production Systems under construction or which have already been approved by Veritas, this will be stated.

1.1.4.3 Application of amendments to Subsea Production Systems already approved, or in the porcess of approval, will be limited to cases where it is judged essential to safety.

1.1.5 Alternative design methods.

1.1.5.1 Veritas will consider alternative methods of design, fabrication, transportation, installation and maintenance to those given in these Rules, provided a standard of safety and serviceability equivalent to that of these Rules is documented.

1.1.6 Assumptions.

1.1.6.1 The Rules are based on the assumption that the Subsea Production System will be operated by adequately skilled personnel familiar with the system and according to the operation manuals.

1.2 Certificate of Compliance.

1.2.1 Issuance of Certificate of Compliance.

1.2.1.1 Upon request Veritas is prepared to issue a Certificate of Compliance for a Subsea Production System found to be built in accordance with these Rules.

1.2.1.2 The Certificate of Compliance will be issued upon satisfactory completion of the installation of the Subsea Production System and it will contain

- a statement that the Rules are complied with
- description of the main particulars for the Subsea Production System as installed
- the geographic location and orientation of the Subsea Production System
- description of main operational limitation and basic assumptions.

1.2.1.3 The Certificate of Compliance is valid from the date of issue. The validity of the certificate may, however, be retained provided the requirements in 1.2.2 are followed. Then the Certificate of Compliance will be renewed every fifth year.

1.2.2 Retention of Certification.

1.2.2.1 In order for a Subsea Production System to retain its Certification, it is to be subjected to surveys of the frequency and extent stipulated in Sec. 12. The term «survey» in this contex may cover various types of accepted methods that can be used to assure the surveyor about operability, reliability or safety of the system. In most cases direct visual inspection will not be practical. As an alternative, features may be built into the system allowing testing or condition monitoring.

1.2.2.2 If it is found that the structure or equipment which is covered by the Certification of Compliance does not meet the Rule requirements, the owner will be requested to perform the necessary repairs, modifications, tests or measures. Veritas will request this by a recommendation on any improvements, new surveys or other measures found necessary in order to retain the Certification, regardless of whether the conditions referred to have previously been approved.

1.2.2.3 If Veritas by significant justification deems it necessary to survey the Subsea Production System or to have technical measurements or other examinations carried out to ascertain whether damages have been sustained or are imminent, a recommendation hereon will be given.

1.2.2.4 Recommendations and memoranda related to Certificate of Compliance are as follows:

- Recommendations to be carried out, are recommendations to the effect that specified operations (e.g. repairs, adjustments, reinforcements) are to be carried out within specified terms (if necessary immediately).
- Memoranda for Owners, is information to the Owners that, for example, a damage has been surveyed and recorded. It has, however, not been considered necessary to call for repairs.

Note:
Recommendations may be issued on behalf of National Authorities.

1.2.2.5 Recommendations and memoranda are sent in writing to the Owners. Recommendations for immediate repairs can be made verbally, provided the representative of the Owners accepts the recommendation and will take immediate steps to carry it out.

1.2.2.6 Veritas may at any time alter a recommendation or memorandum if this is considered necessary.

1.2.2.7 The Owners may request that a decision by Veritas be reconsidered on the basis of a new survey by one or more Surveyors specially appointed by Veritas.

1.2.2.8 A written recommendation or memorandum will be deleted when Veritas by survey or other means has established that the requirements have been fulfilled. A verbal recommendation is revoked when a subsequent survey proves that the repair is satisfactory.

1.2.3 Withdrawal of Certification.

1.2.3.1 Veritas can withdraw the validity of the Certificate of Compliance if the Owner does not comply with his duty to request surveys and to give information, his obligations in connection with the survey, or if he does not rectify defects in accordance with the requirements of Veritas. Such withdrawal will be notified by a letter to the Owner and/or other bodies as relevant.

1.2.3.2 The withdrawal may be made conditional in that it will come into effect only if the Owner, within a stipulated time, has not rectified the conditions leading to the withdrawal.

1.2.3.3 If the conditions leading to withdrawal of the validity of the Certificate of Compliance no longer exist, Veritas may upon request reinstate the validity of the Certificate. As a condition hereto, Veritas can demand that the Subsea Production System be subjected to a survey or certain specified improvements.

1.3 Surveillance.

1.3.1 General.

1.3.1.1 The work carried out by Veritas is to ensure that the Subsea Production System is designed, fabricated, transported, tested, installed, and operated in accordance with the Rules. This work comprises appraisal of drawings, procedures and specifications, and inspection. The surveillance by Veritas is additional to, and not a replacement of quality control carried out by the contractor or manufacturer.

1.3.2 Surveillance during fabrication.

1.3.2.1 The contractor is to provide necessary access to the Subsea Production System for the Veritas Surveyor and the necessary assistance required for carrying out the inspection work.

1.3.2.2 When a Subsea Production System is fabricated under the surveillance of Veritas, Veritas will examine:

— that the dimensions, strength and safety and control functions of the Subsea Production System comply with the Rule requirements and the approved plans, and that the prescribed materials are used,
— that the materials and the systems which are used have been tested in accordance with the Rule requirements,
— that the work is carried out in compliance with the Rule requirements and to the satisfaction of Veritas, and in accordance with normal good practice,
— that satisfactory tests are carried out to the extent and in the manner prescribed in the Rules.

1.3.3 Surveillance during transportation, installation and comissioning.

1.3.3.1 Surveillance during transportation will be required when found necessary.

1.3.3.2 The installation, testing and comissioning is to take place under the surveillance of Veritas, in accordance with approved plans and specifications.

1.3.4 Surveillance during operation for retention of Certification

1.3.4.1 The subsea production system is subject to surveillance in accordance with the Rule. (See Sec. 12.)

1.4 Documentation.

1.4.1 General.

1.4.1.1 The total documentation will consist of both documentation which has to be submitted to Veritas before commencement of fabrication or any other specific phase, and of such documentation (reporting) which will be worked out during the various phases.

1.4.1.2 Depending on the nature of the documentation some will be subject to approval by Veritas, and some will not. Receipt of the latter will still form a basis for the approval of the Subsea Production System.

1.4.1.3 It is the Owner's responsibility to keep complete files of all documentation relevant to safety and durability of the Subsea Production System.
It is also his responsibility to keep complete files of reports regarding operation, surveys, repair, damages, and abnormal functions.

1.4.2 Documentation to be submitted before each respective phase.

1.4.2.1 The documentation listed in 1.4.2.2 up to and including 1.4.2.4 is to be submitted to Veritas in ample time before commencement of fabrication, transportation, installation or operation, whichever is relevant. The documentation is to be submitted in triplicate through the local Surveyor, unless otherwise agreed.

1.4.2.2 For a description of the conditions which are decisive to the design of the Subsea Production System , information is normally required on environment, product, use and treatment as follows:

Environment
— Water depth.
— Maximum and minimum seawater temperature.
— Maximum and minimum air temperature.
— Current and tide conditions.
— Wind and wave conditions.
— Corrosion conditions.
— Marine growth.
— Seismic activity.
— Ice conditions.
— Soil properties.
— Bottom topography.

Product
— Hydrocarbon description.
— Maximum pressure.
— Maximum temperature.
— Production rates.
— Contaminants produced and their possible effect on corrosion rate, wear and clogging such as water, H_2S, CO_2, sand, wax, etc.

Use and treatment
— Design life.
— Functional loads during the various phases, as relevant.
— Transportation and installation procedures.
— Maintenance system and re-entry sytems.
— Main operation characteristics.

1.4.2.3 For the purpose of verification that the proposed Subsea Production System satisfies the applicable requirements regarding strength, durability and serviceability, calculation and other analytical material will normally be required as follows:
— Necessary calculations for the determination of functional and environmental loads.

— Failure effect analyses.
— Structural analyses, including analyses of pressure containing components, and foundation analysis.
— Sea bottom stability analysis if applicable.
— Analyses regarding corrosion protection systems.

1.4.2.4 For description of the proposed Subsea Production System, information on design, materials, fabrication, procedures, corrosion protection, and testing procedures including proposed acceptance criteria is normally required as follows:

— Situation drawing showing the location of the Subsea Production System relative to platforms, shore, ship lanes, fishing areas and other installations or activities affecting the safety of the system.
— General layout drawings of the Subsea Production System including location of related equipment and systems on surface installations.
— Drawings showing supporting structures, pressure containing components, and protecting structures.
— Drawings showing piping systems, including valves and other piping components.
— Drawings showing flowlines and risers.
— Drawings and descriptions of control and safety systems.
— Drawings and descriptions of electrical systems.
— Drawings and description of test equipment.
— Drawings of main maintenance equipment.
— Material specifications.
— Welding specifications, welding procedures and other fabrication procedures as applicable.
— Fabrication procedure qualification reports for welding, metal spraying etc.
— Description of the main principles of the Manufacturers' quality assurance and quality control system.
— Qualification records for welders.
— Test program and procedures for non-destructive testing of major components.
— Test programmes for factory tests of individual sub-assemblies.
— Test programs for pressure and leakage testing of systems, testing for possible contamination in essential piping systems, and functional testing of control and safety systems.
— Test program for final tests upon completion. The program should include instructions related to shut down, start up, controlled by normal and redundant systems, remote and local, during simulation of failure conditions.
— Manuals for transportation, installation, and operation.

1.4.3 Documentation to be available during each respective phase.

1.4.3.1 During fabrication the following documentation is to be made available for examination and possible retention by the surveyor:
— Material certificates.
— Dimensional control reports.
— Non-destructive testing reports.
— Test reports according to the test programs in 1.4.2.4 as applicable.

1.4.3.2 During installation the following documentation is to be made available for examination and possible retention by the surveyor:

— Orientation and alignment reports.
— Photos or video tape of the main components after installation.
— As-built drawings of the main system showing the location of each main subsystem and main component with a reference for traceability to certificates and reports.
— As-built drawings of main subsystems.
— Reports on:
  — non-destructive testing,
  — post weld heat treatment,
  — dimensional control when relevant,
  — pressure- and leakage testing.
— Reports on:
  — cleanliness of hydraulic systems,
  — functional testing of control- and safety systems,
  — insulation resistance of electrical systems,
  — performance of corrosion protection system.
— Reports on excavation/protection.
— Final inspection report.

1.4.3.3 During the operational phase documentation related to in-service inspection is to be made available for examination and possible retention by the surveyor according to Sec. 12.

1.4.4. Operation manuals

1.4.4.1 The operation manuals (see 1.4.2.4) are to be systematically prepared and are to include information on the subsea production system, its installation and structure as well as on operation and maintenance.

1.4.4.2 Manuals for operation are to be kept at the control stand.

1.4.4.3 A system description is that part of the documentation which explains the design, function and mode of operation. The system description is to cover such items as:

1. Definition of symbols and nomenclature.
2. Functional description.
3. Operating instructions, normal condition.
4. Operating instructions, failure condition.
5. Man/machine communication system.
6. Back-up systems.
7. Monitoring.
8. Maintenance and periodical performance test.
9. Fault-finding procedures.

1.4.4.4 In addition to the self-explanatory items in 1.4.4.3 the items under the following headings should cover:

Functional description:
— The different functions including back-up functions are to be explained in detail.
— Estimates of the most probable critical failure modes are to be included.

Operating instructions
— Description of the normal operation of the equipment, including adjustments and change of limit values, possible modes of presentation, start up and shut down.
— Description of operation of the Subsea Production System in different operational modes including emergency.
— Description of transition from one operational mode to another.

Fault-finding procedures:
— Description of fault symptoms with explanation and recommended corrective actions.
— Instructions for tracing faults back to functional blocks or sub-systems.

1.4.4.5 Other particulars regarding operation and maintenance are also to be included for information, such as:
— overall testing philosophy
— list of maintenance tools
— lists of spare parts
— lists of suppliers' service network.

SECTION 2
GENERAL DESIGN REQUIREMENTS

2.1 Design Principles.

2.1.1 Safety requirements.

2.1.1.1 Subsea Production Systems are to offer acceptable safety against loss of life or health, significicant environmental pollution and major economic loss. When the Rules are complied with, safety of the Subsea Production System is considered to be acceptable.

2.1.1.2 A failure effect analysis is to be carried out. This analysis is to deal with the most probable failures, their probability and consequences. Such failure types may be technical, operational or due to accidental loading. The result of this analysis is to govern the design and the content of the operation- and in-service inspection and testing manuals. The extent of the analysis should depend on the complexity of the Subsea Production System and should in general contain the following:

- A breakdown of the Subsea Production System into functional blocks is to be carried out to an agreed level of detail. This level is to deal with failures in sub-systems and funtions and their effect on the main system and its functions.
- A description is to be made of each physical and functionally independent item and the associated failure mode with their failure causes related to normal operational modes of the item.
- A description of the effects of each failure mode alone on other items within the system and on the overall Subsea Production System performance.

The results from the failure effect analysis is to be presented on recognized forms. Guidance is given in Appendix 1.

2.1.1.3 Whenever practical, Subsea Production Systems are to be so designed that the effect of a single failure cannot develop into a situation that may cause loss of life or health, significant environmental pollution, and major economic loss.

2.1.1.4 The most probable failures, e.g. loss of power, failure in control systems, are to result in the least critical of any possible new condition (fail to safety).

2.1.1.5 Switch-over to stand by systems is to be simple, also in the event of failure in the control and monitoring system. Indication is to be given to the operator when redundant systems are activated.

2.1.2 Layout of the Subsea Production System.

2.1.2.1 The layout of the Subsea Production System is to ensure accessibility for:

- Safe operation.
- Maintenance.
- Inspection.
- Testing.

Guidance:
This may include space for access by divers, remote operated vehicles or special dedicated tools.

2.1.2.2 For drilling templates, due space for cutting return is to be provided.

2.1.2.3 Where high pressure piping is guided through a closed compartment, the compartment shall be designed either to resist the over-pressure caused by a possible leakage or to permit release of the over-pressure without damaging the structure, or provide adequate pressure monitoring and control to isolate pressure sources, thereby limiting compartment over presure potential.

2.1.3 Materials.

2.1.3.1 Materials in parts that are not designed for maintenance at the surface are to be selected with due consideration regarding the environment or for possible repair procedures. In particular this concerns the weldability under hyperbaric conditions when applicable.

2.1.4 Corrosion protection.

2.1.4.1 Structures are to be protected in order to avoid corrosion problems during their lifetime.

2.1.4.2 Methods, designs, materials, fabrication and installation of the corrosion protection system are subject to approval. Special precautions are to be taken to protect steel members in areas where accessibility for inspection and maintenance is limited.

2.1.4.3 Requirements to materials and welds with respect to environmentally induced cracking such as hydrogen induced pressure cracking (hydrogen blistering), sulphide stress corrosion cracking and chloride stress corrosion cracking are given in Veritas' Rules for Submarine Pipeline Systems.

2.1.4.4 Steel members in contact with seawater or mud/bottom sediments are to be protected by cathodic protection with sacrificial anodes or alternatively with impressed current. The cathodic protection system may be combined with a suitable coating. Other protective systems may be accepted upon special consideration.

2.1.4.5 Internal corrosion control is to be provided for pipeline systems transporting corrosive hydrocarbons and for storage tanks. Internal corrosion control may be achieved by one or more of the following methods:

- Application of corrosion inhibitors.
- Use of corrosion allowance.
- Use of internal coating.
- Application of corrosion resistant alloys or linings.

2.1.4.6 Detailed requirements to and guidance for the corrosion protection system (2.1.4.3—2.1.4.5) are given in the following Veritas' Rules and Technical Notes:

- Rules for the Design, Construction and Inspection of Offshore Structures.
- Rules for Submarine Pipeline Systems.
- TN B 111 Corrosion Control of Equipment and Piping Systems Handling Hydrocarbons.

2.1.5 Physical protection.

2.1.5.1 Subsea Production Systems are to be protected against accidental damage which might resonably be expected to occur by minimizing both the probability for and the consequences of the damage.

Guidance:
Installation and maintenance procedures should be made for reducing the probability of damage. The design should reduce the consequences of the possible operational errors during installation and maintenance and facilitate replacement of possible damaged components.
It may be practical to provide protection against lighter objects dropped from the surface, e.g. small anchors, anchor chains and trawling boards. Larger objects from which it may be unpractical to protect should not prevent the shut down of the system by the downhole safety valve(s).

2.2 Marking.

2.2.1 Identification.

2.2.1.1 Structural parts are to be marked in order to facilitate identification during inspection.

2.2.1.2 Supervisory and control equipment is to be marked in order to facilitate identification. Manually operated valves are to be equipped with position indicators, alternatively the position of the handle may serve as indicator.

2.2.1.3. All units, terminals, cable ends, pipe ends and test points are to be permanently marked. Transducers with actuators are to be marked with their system functions so that they can be clearly identified on plans and instrument lists.

2.3 Well-System Barriers

2.3.1 Safety Requirements.

2.3.1.1 Subsea wells are to be equipped with sufficient individual valves for shut down of each conduit capable of producing hydrocarbons.The valves are to be fitted in series and installed so that testing of the sealing capacity of each of the valve required is assured. The minimum number of valves is to be established by aid of the failure analysis.

Guidance:
By this approach some wells may be fitted with only one downhole safety valve and one X-mas tree valve for a conduit.

2.3.1.2 The system for killing of the wells is to be documented by the failure effect analysis.

2.3.1.3 The down hole safety(s) valve is to be installed at a safe depth underneath the seabed in each production, gas and water injection tubing. (Specific minimum depths are required by some natuional Authorities.)

SECTION 3
ENVIRONMENT

3.1 General.

3.1.1 Environmental phenomena.

3.1.1.1 All environmental phenomena which may impair the proper function of the system or cause a reduction of the system reliability are to be considered. Such phenomena include waves, currents, ice, seismic, geological, and geotechnical conditions, temperature, fouling, biological activities, chemical components of water, and internal system conditions.

3.1.2 Acceptable environmental data.

3.1.2.1 The environmental conditions are to be described using adequate data for the areas in which the system is to be installed.

3.1.2.2 Data supplied by generally recognized sorce will normally be accepted as a basis for design. Background information on data collection and derivation is to be submitted at Veritas' request.

3.1.2.3 The various environmental factors are to be described by characteristic parameters based on statistical data or long term observations. If sufficient data directly applicable to the location in question are not available, conservative estimates based on relevant data for other relevant locations may be used.

3.1.2.4 Statistical data are to be utilized in describing environmental parameters of a random nature (e.g. waves). Proper care is to be exercised in deriving such parameters in a statistically valid manner, and generally accepted methods are to be used.

3.2 Environmental conditions.

3.2.1 General.

3.2.1.1 Possible effects of the various environmental actions are to be taken into account to the extent relevant to the situation considered.

3.2.2 Tide.

3.2.2.1 Tides are to be taken into consideration when applicable.

3.2.2.2 The assumed maximum tide is to include both astronomical tide and storm surge. Minimum tide estimates should be based on the astronomical tide and possible negative storm surge.

3.2.3 Waves.

3.2.3.1 The effect of waves is to be taken into consideration for design of Subsea Production Systems. Examples of such effects are direct forces due to drag, lift and inertia effects, and forces due to vortex shedding and other flow induced instability phenomena. Possible liquefaction and transportation of sea bed material due to wave action is also to be considered.

3.2.3.2 If some parts of the system are positioned adjacent to other structural parts, possible effects due to disturbance of the flow field should be considered when determining the wave loads. Such effects may either be caused by changes in the wave particle kinematics, or by dynamic excitation caused by vortexes shed from the adjacent structural parts.

3.2.4 Current.

3.2.4.1 The effect of current is to be taken into consideration in design of subsea systems.

3.2.4.2 The assumed current velocities are to include possible contributions from tidal current, wind induced current, storm surge current, density current and possible other current phenomena.

3.2.4.3 The tidal current may normally be determined from analyses of recorded data, while wind induced, storm surge and density currents may be determined either from statistical analyses of recorded data, or from numerical simulations in lieu of specific studies.

Normally a wind induced surface current speed corresponding to 2 per cent of the 1 hour mean wind speed will be accepted.

3.2.4.4 In regions where bottom material may erode, special studies of the current conditions near the bottom including boundary layer effects may be required.

3.2.5 Corrosivity.

3.2.5.1 For the evaluation of the corrosion protection system the following properties, with seasonal variations of the sea water and soil representative for the actual location, are to be considered:

- temperature
- salinity
- oxygen content
- pH-value
- resistivity
- current
- biological activity (sulphate reducing bacteria etc.)

3.2.6 Ice.

3.2.6.1 In the case of an installation to be located in an area where ice may develop or drift, consideration of ice conditions and their possible effects on the Subsea Production System is to be made. The ice conditions should be studied with particular attention to possible:

- ice forces due to floating ice
- potential scour due to grounding icebergs
- ice problems during the installation operations.

3.2.7 Sea temperature.

3.2.7.1 Maximum and minimum sea temperatures are to be identified.

3.2.8 Marine growth.

3.2.8.1 The effect of marine growth on the subsea installation is to be considered, taking into account all biological and environmental factors relevant to the site in question.

3.2.8.2 For determination of the hydrodynamic loads special attention is to be paid to the effective diameter increase and the equivalent roughness of accumulated marine growth when determining the hydrodynamic coefficients.

3.3 Internal system condition.

3.3.1 Installation conditions.

3.3.1.1 A description of the internal conditions during storage, installation, pressure testing and functional testing is to be prepared. Of special concern is presence of contamination in hydraulic systems, the duration of exposure to sea water and moist air, and whether inhibitors and/or biocides are to be used.

3.3.2 Operational conditions.

3.3.2.1 The physical and chemical composition of the product, flow rates and the pressures and temperatures in any part of the system are to be specified.

3.3.2.1 Limits of temperatures and pressures, and maximum design concentrations of corrosive components for the product are to be specified. Of special concern is the content of:

— sulphur compounds
— water
— chlorides
— oxygen
— carbon dioxide
— hydrogen sulphide
— sand
— wax.

SECTION 4
LOADS

4.1 General.

4.1.1 Scope.

4.1.1.1 All loads that may influence the dimensioning of the Subsea Production System or parts thereof are to be considered in the design. This applies to all phases of the installation and life of the system.

4.2 Functional loads.

4.2.1 General.

4.2.1.1 Functional loads are loads which are natural consequences of the existence, use and treatment of the system in the various situations under ideal conditions. Ideal conditions means no waves, current etc. i.e. no dynamic environmental loads acting.

4.2.1.2 Functional loads which normally are to be considered for the operation and installation phases are given in 4.2.2 and 4.2.3.

4.2.2 Functional loads during operation.

4.2.2.1 Functional loads during operation will normally be those due to

- weight
- pressure
- thermal expansion and contraction
- prestressing
- reaction from mechanical functions (actuators, mechanisms).

4.2.2.2 Weight is to include:

- weight of structures, including coating and all attachments
- weight of contents
- buoyancy and ballast.

4.2.2.3 Pressure is to include:

- internal fluid pressure
- dynamic behaviour of the fluid in the system during normal, abnormal and emergency operations
- thermal expansion of an enclosed fluid
- external hydrostatic pressure
- soil pressure.

4.2.2.4 Thermal expansion and contraction loads are primarily to include the effect of product temperature on material temperature. Possible other causes of changes in material temperature are also to be considered. The temperature difference to be considered is that between material temperature during operation and material temperature during installation, shutdown and maintenance.

4.2.2.5 Thermal expansion or contraction loads do not have to be taken into account when they do not influence the capacity to carry other loads. Fluctuation in temperature may cause fatigue and be taken into account when checking fatigue strength.

4.2.2.6 Pre-stressing, such as permanent curvature or a permanent elongation introduced during installation, is to be taken into account to the extent it affects the capacity to carry other loads.

4.2.3 Functional loads during transportation, installation and maintenance.

4.2.3.1 The functional loads during installation and maintenance, may be grouped as

- weight
- pressure
- installation forces.

4.2.3.2 Installation forces are to include all forces acting on the structural parts due to installation operations. Typical installation and maintenance forces are hook up forces and other forces associated with entry or retrieval of parts of the Subsea Production System in normal and planned emergency modes.

4.3 Environmental loads.

4.3.1 General.

4.3.1.1 Environmental loads are loads due to waves, current and other environmental phenomena. Loads due to human activities independent of the Subsea Production System are also included, e.g. loads from fishing gear.

4.3.1.2 The environmental loads are random in nature and should in principle be evaluated by means of probabilistic methods. Natural, simultaneous occurrence of different environmental phenomena is to be determined by proper superposition of their individual effects, taking into acount the probability of their simultaneous occurence.

4.3.1.3 The environmental loads during normal operation are not to be taken less than the probable severest load in a time period of 100 years for the actual ocean area.

Guidance
If risers or other items are designed for disconnection at specified weather conditions, the probable severest loads in a time period of 100 years apply to the disconnected state.

4.3.1.4 For temporary phases the probable severest load in the design period is to be taken as three times the expected duration of the phase, but not less than 3 months.

4.3.1.5 The environmental parameters for determination of environmental loads in temporary installation and maintenance phases lasting 5 days or less, and which can be interrupted with a safe margin can be based on reliable weather forecast.

4.3.2 Wave loads.

4.3.2.1 Wave induced loads are to be determined by use of generally recognized methods taking proper account of water depth and the size, shape and type of installation.

4.3.2.2 In the analytical determination of wave loads, the hydrodynamic coefficients used in the analysis may be determined on the basis of published data, model tests, or full scale measurements.

For details on analytical determination of wave loads, see Rules for the Design, Construction and Inspection of Offshore Structures.

4.3.2.3 For structures of complex shape for which analytical determination of wave loads may not yield sufficient accuracy, the wave loads are to be determined by use of reliable and adequate model tests.

4.3.3 Current loads.

4.3.3.1 The current induced drag and lift forces on the subsea system are to be taken into account.

4.3.3.2 Where Morison's equation is applicable, the effects of current may be accounted for by a vectorial addition of the orbital water particle velocity due to the waves and the steady current velocity.

4.3.3.3 The possibility of flow induced cyclic loads caused by the current is to be considered. Guidance pertaining to this phenomenon is given in Rules for Submarine Pipeline Systems.

4.3.4 Ice Loads.

4.3.4.1 In areas where ice may develop or drift, the possibility of ice scouring and impact loads from drifting ice is to be considered.

4.3.5 Loads from fishing gear.

4.3.5.1 In areas with fishing activity, the possibility of loads due to impact from or hookup of fishing gear such as bottom trawl, pelagic trawl, purse seine etc. is to be considered.

4.3.6 Earthquake loads.

4.3.6.1 The effects of earthquakes are to be considered: see Veritas Rules for the Design, Construction and Inspection of Offshore Structures.

4.3.7 Accidental loads.

4.3.7.1 Accidental loads are to be classified as environmental loads, and they are to be taken into consideration for those parts of the system where such loads are likely to occure. Examples of accidental loads are given in the following sections.

4.3.7.2 The risk of explosion and fire in Subsea Production Systems enclosed in an atmospheric environment is to be taken into account in the design of the structure, by adequate pressure relief systems or by an evaluation of the consequences in relation to the probabilities.

4.3.7.3 Impact loads from dropped objects associated with the different activities in the installation and operation phases of the system are to be considered.

4.3.7.4 If the system needs a minimum internal pressure, gas or liquid to withstand the external pressure at a required safety level, an evaluation of pressure system safety is to be performed.

4.3.7.5 The possibility of load effects due to dragging of anchors is to be considered.

Guidance:
Guidance concerning protection philosophy is given in Sec. 2.

SECTION 5
FOUNDATIONS

5.1 General.

5.1.1 Application.

5.1.1.1 This section applies to the foundation of Subsea Production Systems and is limited to a general presentation of some of the problem areas which should be considered in the design. For more detailed requirements and guidance, reference is made to Veritas Rules for the Design, Construction and Inspection of Offshore Structures, its Appendix F and Technical Notes for Fixed Offshore Installations TN A 300.

5.2 Site Investigation.

5.2.1 General.

5.2.1.1 Site investigation should always be carried out. The investigation should at least include:

- a site geology study
- a bottom topography study
- a soil exploration programme with determination of relevant geotechnical properties of the foundation soils.

5.2.1.2 The physical extent of the site investigation is dependent upon type of structure, uniformity of the soil and the seabed conditions. The investigation should be sufficiently extensive to reveal all seabed features and soil deposits of importance to the structure.

5.2.1.3 Special attention should be paid to the characteristics of the seabed surface material in the area and the potential risk of mudslides and scouring phenomena.

5.3 Foundation Design.

5.3.1 General.

5.3.1.1 A Subsea Production Structure may be supported by piles, by the casings themselves (casings acting as piles), directly by the seabed, or combinations thereof.

5.3.2 Pile/casings supported Structures.

5.3.2.1 The foundation piles of a pile supported structure are to be designed for compression, tension and lateral loads, as applicable.

5.3.2.3 The structure should be properly connected to the pile/casings. This may be made by a mechanical device or by grouting the annulus between pile and sleeve.

5.3.3 Seabed supported Structures.

5.3.3.1 The foundation of a seabed supported structure should be designed to have sufficient vertical and horizontal bearing capacity for the loads in question.

5.3.3.2 Depending on seabed conditions high contact stresses may develop. This has to be considered in the design. Underbase grouting may have to be used to achieve the required stability and load distribution.

5.3.4 Buried Structures.

5.3.4.1 In the case of buried structures, the stability of the excavation is to be considered.

5.3.4.2 Buried structures are to be designed to resist the earth pressures.

SECTION 6
STRUCTURES

6.1 General.

6.1.1 Application.

6.1.1.1 This section applies to structures surrounding, supporting and protecting the main items of the Subsea Production System. The structures dealt with in the following are designed of steel or concrete. Other materials are subject to special considerations.

6.1.2 Materials and design.

6.1.2.1 For detailed requirements and guidelines reference is made to the following Veritas Rules:

- Structures in general:
  Rules for the Design, Construction and Inspection of Offshore Structures.
- Manned underwater chambers:
  Rules for Certification of Diving Systems.

6.1.2.2 A structural analysis of main members is to be carried out. The analysis is to include static and dynamic evaluations of safety against excessive yielding, fatigue, fracture, collapse and excessive displacement as applicable.

SECTION 7
RISERS

7.1 General.

7.1.1 Application.

7.1.1.1 Section 7 applies to the connecting piping system between the Subsea Production System and the surface installation for conveying hydrocarbons or injection fluids, or used for maintenance.

7.1.2 Definitions.

Supported production riser system — a piping system attached or built into structures.
Marine production riser system — a piping system suspended from a surface support without lateral supports between surface and seafloor.
Work over riser — a riser used during major maintenance of the well completion system.

7.1.3 Reference.

7.1.3.1 For suplementary guidelines reference is made to the applicable parts of:

- Veritas' Rules For Submarine Pipeline Systems.
- Veritas' Rules For The Design, Construction and Inspection of Offshore Loading Systems.
- Veritas' TN B102; Piping Systems
- API RP 2Q; Design and Operation of Marine Drilling Riser Systems.

7.1.3.2 For design of supported production risers the Rules for Submarine Pipeline Systems and TN B102 apply.

7.2 Design of Marine Production and Work over Risers.

7.2.1 General.

7.2.1.1 For marine production and work over risers, the motions and corresponding forces are to be taken into account. When connected to a floating platform, first and second order motion under wave, current and wind loads and their corresponding static and dynamic effects should be taken into account.

7.2.1.2 The response analysis of the riser under wave and current load should ideally account for dynamic, non-linear stochastic response. However, it may not be possible to account for all phenomena in the analysis. In this case the uncertainties should be resolved through model tests.. The type of analysis required is dependent on the design proposed for the riser.

7.2.1.3 The spacings between marine production risers are to be such that physical interference is results in no structural damage.

7.2.3 Tensioners.

7.2.3.1 Appropriate redundant systems are to be designed so as to ensure that the required tension is always applied to the riser. Tensioning devices are to be designed with a strength to carry the total load under maximum environmental design loads if one of the redundant systems is out of order.

7.2.4 Buoyancy.

7.2.4.1 If buoyancy elements are fitted, the damage of one element is not to influence the buoyancy of others.

7.2.4.2 Buoyancy elements made of synthetic materials and embedded spheres in a synthetic matrix are to have documented longterm properties for

- Density of materials
- Compressive strength
- Water absorption

Further specifications on the following are to be given:

- Type
- Method of attachment
- Instructions for storage and handling.

7.2.5 Disconnection and Re-entry.

7.2.5.1 The feasibility of disconnection and re-entry of the riser strings with due respect to safety for the Subsea Production System and the riser itself has to be documented, and if deemed necessary supported by tests.

SECTION 8
FLOWLINES, PIPING AND MECHANICAL EQUIPMENT

8.1 General.

8.1.1 Application.

8.1.1.1 Section 8 applies to piping and mechanical equipment used in hydrocarbon, utility and auxiliary systems on subsea production installations.
Included are pressure vessels, chambers, pipings, valves and well completion equipment.

8.1.1.2 Detailed guidance on design, materials, corrosion protection, fabrication and documentation is given in Veritas Technical Notes for Fixed Offshore Installations Volume B.
These Notes also refer to applicable API specifications and other standards frequently used.

8.2 Design and fabrication.

8.2.1 Pressure vessels.

8.2.1.1 The TN B 101 gives guidance for certification of pressure vessels based on recognized codes and standards.

8.2.1.2 In case of manned chambers the pipe penetrations should in general be fitted with internal shut-off valves, which are to be mounted directly on the chamber wall or close to the wall, provided the connecting pipe is well protected and has a minimum thickness according to the Rules for Certification of Diving Systems.

8.2.2 Flowlines and Piping.

8.2.2.1 For general guidance, reference is made to Veritas TN B 102, Piping Systems and Veritas' Rules for Submarine Pipeline Systems.

8.2.2.2 Flexible hoses are to have properties approved by Veritas and documented by tests.

8.2.3 Valves.

8.2.3.1 Design and arrangement of manual valves is to be such that open and closed positions are indicated, alternatively the position of the handle may serve as indicator.

8.2.3.2 Manual valves are to be closed with a right-hand motion (clockwise rotation).

8.2.3.3 Shut-off valves for high pressure oxygen and air are to be of types which need several turns to shut off. This is mainly applicable to life support systems of manned systems, and is to reduce the risk of internal pipe fires or explosions caused by heat from rapid gascompression at the presence of combustible contaminations or materials.

8.2.3.4 For automatic valves of fail-safe closed design, calculations for the valve with operator are generally required to verify the function according to the specific failure conditions.

8.2.4 Through flowline (TFL) pump down systems.

TFL systems should generally satisfy the recommendations laid down in API RP 6G.

8.2.5 Wellheads, Xmas trees, subsurface safety valves etc.

8.2.5.1 For guidance, reference is made to TN B 106.

8.2.5.2 Subsea completed wells are to be equipped with valves fitted in series according to sec. 2.3

SECTION 9
CONTROL AND SAFETY SYSTEMS

9.1 General.

9.1.1 General.

9.1.1.1 Section 9 applies to Control and Safety systems related to hydrocarbon production, including power supplies.

9.1.1.2 The general safety requirements for control and safety systems are given in sec. 2. The following specifies additional requirements.

9.1.2 Safety requirements.

9.1.2.1 Safety systems are required when hazardous conditions cannot be expected to be counteracted by manual intervention.

9.1.2.2 Those parts of the control systems with essential impact on the safety shall have high reliability. This is to be documented through the failure effect analysis.

9.1.3 Environement.

9.1.3.1 Possibilities for electro-magnetic interference from external sources are to be considered as well as vibrations, humidity, dust, and saltmist and temperature that may influence sensitive instrumentation.

9.2 System design.

9.2.1 Control stand.

9.2.1.1 There is to be control from at least one stand. From this stand all normal control and production monitoring is to be possible. The control stand shall give the operator all required status information to allow for safe operation.

9.2.1.2 When there is more than one control stand for remote operation, a system of preference is to be applied in order to prevent simultanous operation from different stands. A communication system shall exist between the stands.

9.2.1.3 The control stand is to indicate the expected system responses from operations executed.

9.2.2 Monitoring and alarm.

9.2.2.1 The extent of monitoring is to be based on the failure effect analysis.

Guidance:
This may concern possible parameters related to the production pressure in essential seperated cavities such as annulus, position indication, wear and tear and from instrumented riser joints.

9.2.2.2 An alarm shall be initiated for abnormal conditions when the consequence of a failure is critical for safety.

9.2.2.3 All alarms are to include visual and acoustic signals. For localization of faults, visual signals are to be given.

9.2.2.4 Performance tests of the alarm system are to be possible during operation.

9.2.2.5 Permanent switch-off of the alarm system must not be possible. In particular cases, however, partial disconnection may be accepted provided a visual warning signal is showing that it is disconnected.

9.2.2.6 The more frequent failures within the alarm system, such as broken connections to measuring elements, are to release alarm (normally closed circuit).

9.2.2.7 Display of one alarm shall not inhibit display of other alarms.

9.2.3 Safety functions.

9.2.3.1 As far as practicable the design of control systems shall be such that no significant reduction in the safety level exists during maintenance and repair of the control systems.

9.2.3.2 The control systems shall be designed for automatic shut down for pressure or flow in the Subsea Production System outside a preset level outside the alarm level.

9.2.3.3 The control systems are to be designed for automatic shut down on request from certain external signals (e.g. major emergency and fire on topside facilities)

9.2.4 Shut down valves.

9.2.4.1 The control systems for shut down of a Subsea Production System are to close the valves in case of:

- Shut down command.
- Loss of communication with the control stand over a specified period, unless as back-up system is functioning.

9.2.5 Control during maintenance.

9.2.5 If control is carried out from a maintenance vessel, extent of the control and safety systems is to be based on the failure effect analysis.

9.3 Component design.

9.3.1 Installation.

9.3.1.1 Equipment in one atmosphere submerged instrument chambers with dry environment shall be designed to operate with specification in a relative humidity of 100%. Electrical cable penetrations shall have seals against liquid (liquied block). This is to prevent liquid passing the chamber wall if the liquid has penetrated into any place in the cable.

9.4 Power supply.

9.4.1 General.

9.4.1.1 The capacity of the power supply systems is to be sufficient to handle maximum consumption during normal and emergency operations.

9.4.1.2 The power supply arrangements including prime movers are to operate satisfactorily under all relevant conditions.

9.4.2 Variations in supply.

9.4.2.1 The equipment is to function satisfactorily within prescribed limits. These limits are to exceed the tolerances for the power supply and variations due to the system design and operation.

9.4.3 Separation/Insulation.

9.4.3.1 Electric power to Subsea Production Systems shall be separated from top-side electrical power equipment by means of isolation transformers. DC equipment will be special considered.

9.4.4 Hydraulic power.

9.4.4.1 Pressure in hydraulic systems is to be kept within prescribed limits with regards to normal operational pressure and transient pressure peaks.

9.4.4.2 Hydraulic systems are to be fitted with filtering system with prescribed filtering properties, according to specification of applied hydraulic equipment.

9.4.4.3 Flowrates of hydraulic fluid and stiffness of piping systems are to be compatible with prescribed time limits between execution of commands and system response.

9.4.5 Emergency Power

9.4.5.1 The automatic safety valves for emergency shut down of production are to have adjacent power storage in addition to power supply. This storage may be by mechanical springs or hydraulic accumulators.

SECTION 10
ELECTRICAL SYSTEMS

10.1 General.

10.1.1 Standard.

10.1.1.1 All electrical equipment is to comply with a recognized standard, as far as such standards are available and relevant for the actual application. A complete list of the standards is to be submitted for the Society's approval. The International Electrotechnical Commission's (IEC's) standards are recommended.

10.1.1.2 All components for essential equipment are to be designed to operate satisfactorily with documented reliability. The documentation is to be made through an identification of the failure modes for the components together with frequency of occurrence of each failure. The data sources is also to be given, e.g. types tests, previous experience, manufacturing and quality control data, factory acceptance testing, engineering judgement etc.

Note:
For electronic systems the use is recommended of quality controlled components according to one of the following quality control systems:

a) IEC has put into operation January 1983 an international system, IECQ = «the IEC Quality Assessment System for Electronic Components».
b) A Western European system has been in operation since 1974, CECC = «CENELEC Electronic Components Committee». A CECC «Qualified Products List» is issued anually and updated quarterly.
c) The American system of MIL specifications and standards (which is the oldest of these systems), and the Military Handbook 217 D, «Reliability prediction of electronic equipment».

It should be noted that the data presented in these systems are valid only for the specified environmental conditions, e.g. atmospheric pressure in most cases. Components which are designed for atmospheric pressure only should not be used at hyperbaric pressure without verification of suitability.

10.2 Supply systems.

10.2.1 Electric power sources.

10.2.1.1 Electric systems for equipment related to safety are to be supplied by at least two independent power sources, each of sufficient capacity for the power demand in case one of the sources is out of action. This requirement may be deleted in case the redundancy requirement is met by using a non-electric back-up system.
Alarm shall be given on failure of an electric power source.

10.2.1.2 The voltage and frequency variations are to be kept within prescribed limits.

10.2.2 Insulation and Earthing

10.2.2.1 Insulated supply systems are generally to be used, whether A.C. or D.C. Earthed systems may be specially considered by Veritas.

10.2.2.2 When practicable (exluded are subsea systems with cable (umbilical) terminations including inductive couplers), an insulated supply system, including the secondary side of step-down or isolating transformers (or convertors) is to be provided with an automatic insulation monitoring device, actuating switch-off and alarm by insulation faults. Alarm only may be used if a sudden switch-off of the equipment may endanger the operation of the production system. This insulation monitoring shall be continuous, except that one common instrument with an automatic scanning device may be approved to monitor two or more electric systems.

Guidance:
A value lower than 1000 ohm per volt to initiate an alarm is frequently used above surface.

On earthed supply systems, if approved after special consideration, earth leakage circuit-breakers or relays are to be used for this purpose.

10.2.2.3 All exposed metal parts of equipment, which can be touched by personnel, are to be earthed.

10.2.3 Maximum Voltage.

10.2.3.1 The operating voltages are to be chosen after consideration of the power demand, the voltage drops and variations which can be tolerated, and should not be higher than necessary for the actual application. For permanently installed lighting equipment the voltage is not to exceed 250V. If necessary, step-down transformers (or convertors) are to be installed for this purpose.

For portable equiment supplied via flexible cables one may use:
D.C. (with max. 10% riple): Max. 120V.
A.C.: Max. 24 V, or
Max. 250 V when supplied via a separate isolating transformer for each piece of equipment.

10.2.4 Wet systems.

10.2.4.1 If enclosures filled with oil or other insulating liquids are used, and the possibility of a short-circuit in the equipment cannot be excluded (e.g. for electric motors or other equipment with windings or coils), it is to be ensured that the enclosure will not burst by an internal shortcircuit.

Note:
The pressure rise by a short—circuit in a liquid-filled enclosure will depend on the volume and on the energy which is developed, i.e. the magnitude and duration of the short-circuit current.

The insulating properties of such oil or other insulating liquid is to be checked either by periodical maintenance and service, or by some kind of continuous monitoring system.

10.2.4.2 If gas-filled enclosures are used for essential equipment, a water leakage alarm system is to be installed.

10.2.5 Production systems in atmospheric compartments.

10.2.5.1 The internal space of a dry system may be considered as a hazardous area Zone. For Zone 0 intrinsically safe equipment normally is the only type of electrical equipment which is allowed (in special cases other equipment which has been specially approved for Zone 0 installation by a recognized testing institution may also be considered), except when:
The internal space is filled with inert gas in normal operation, and with air or other oxygen-containing atmosphere only during maintenance and servicing operations.
In this case other types of explosion-protected equipment suitable for hazardous area Zone 1 or Zone 2 may be approved, after consideration in each case.
A gas detector installation for continuous monitoring of the hydrocarbon gas content during maintenance and servicing operations will be required in such cases.

10.3 Protection of divers.

10.3.1 General.

10.3.1.1 If it is intended to use divers for maintenance and servicing, it is to be ensured that all enclosures, cable armouring or other parts which may be touched by a diver in the water cannot become live or reach dangerous voltage levels under fault conditions such as by earth faults.

Note:
If possible, the system design and the diver's suit with accessories should be such that the possible fault current through the diver's body will not exceed the «perception level» which is about 0.5 mA A.C. or 2 mA D.C.

If this is not possble, it is to be ensured that the fault current through the diver's body will not exceed the «let-go level» which is about 9 mA A.C. or 40 mA D.C., unless special types of protective disconnection devices for the power supply are used, see below.

If the fault current through the diver's body could exceed the «let-go level» (9 mA A.C. or 40 mA D.C.), special protective devices are to be used (e.g. earth leakage circuit-breakers), which disconnect the electric supply quickly enough to prevent heart fibrillation. For this purpose time release characteristics, in relation to the magnitude of the possible fault currents, are given e.g. in IEC publication No. 479 (1974), «Effects of currents passing through the human body».

If these conditions cannot be met, the certificate for the Subsea Production System will contain a statement that divers are not allowed to operate in the water close to the production equipment when its electrical system is in operation.

SECTION 11
SAFETY OF PERSONNEL

11.1 General.

11.1.1 Application.

11.1.1.1 Section 11 applies to Subsea Production Systems intended for manned intervention for operation, testing, survey or maintenance. When a transfer vehicle for personnel is connected to the system, the Rules apply to the system including the vehicle.

11.1.1.2 The certificate for the Subsea Production System based on these Rules will not include general purpose transfer vehicles for personnel. The certificate will, however, contain requirements for such vehicles when the vehicle itself or systems in the vehicle are intended as substitute for systems or components required for the Subsea Production System.

11.1.1.3 If the vehicle is dedicated to the Subsea Production System, the certificate will include the vehicle. General guidance for certification of the vehicle is given in the applicable parts of Veritas:

- Rules for the Construction and Classification of Submersibles
- Rules for Certification of Diving Systems.

11.1.2 Arrangement.

11.1.2.1 Moving parts, high voltage components, outlets from vents or safety valves are to be located and/or protected so that hazard is minimized.

11.2. Life support systems.

11.2.1 Application.

11.2.1.1 11.2 only applies to Subsea Production Systems designed to house personnel inside compartment(s) at atmospheric pressure.

11.2.1.2 Life support systems are defined as the systems intended for safe support of the life of personnel such as systems for maintaining and controlling a breathable atmosphere, temperature, humidity and pressure.

11.2.2 Arrangement of compartments.

11.2.2.1 Subsea Production Systems manned when the transfer vehicle is not connected are to have a connected rescue vehicle with sufficient capacity to carry the maximum number of personnel that may be present. And it is to have at least two compartments separated by hatches with a diameter of at least 0,60 metres. Compartments and hatches are to be designed for possible pressure in the other compartments corresponding to the water depth and possible relief pressure to sea.

11.2.2.2 Hatches and compartment bulkheads intended solely for separation of inert/breathable environments may be designed to withstand the maximum pressure differential possible across the compartment bulkhead or with suitable pressure relief devices to prevent compartment overpressure.

11.2.2.3 Hatches between compartments are to be designed for operation from either side, and fitted with a system for equilization of a possible pressure difference between the compartments within reasonable time limits.

11.2.2.4 The size of the compartments closest to the escape hatches is to be sufficient to contain the maximum number of personnel that may be present in the Subsea Production System.

11.2.3 Design principles.

11.2.3.1 Life support systems are to be designed with systems that can replace each other in such a manner that the effect of a single failure cannot spread from one system to others thus causing a dangerous situation for personnel.

11.2.3.2 There are to be emergency life support systems. These systems are to have a capacity of at least 96 hours safe life support during normal operations. Emergency life support systems are to be independent of a surface support. For Subsea Production Systems installed some distance from a base that may contain rescue facilities, a larger capacity emergency life support system may be required.

11.2.4 Contamination of breathable atmosphere.

11.2.4.1 There is to be a mask available for supply of suitable breathing gas for each of the personnel. The masks are to be ready for use in case of contamination of the normal breathing gas, and are to have a capacity at least sufficient for all personnel during a period sufficient for reestablishing a normal breathing situation. The masks may be connected to either portable or permanent installed supply systems. In addition, and as a minimum one spare mask is to be available in each chamber.

11.2.4.2 There is to be a system for purifying or changing a contaminated atmosphere intended for breathing.
This system is to be designed for removal of contaminants due to normal and emergency operations. In emergency the system is to be designed in relation to 11.2.4.1 to avoid a significant pressure buildup in the compartment. The maximum allowable pressure will be a function of the design of the vehicle, possible decompression equipment for the personnel and, tolerances of O_2 partial pressure.

11.2.4.3 The contaminent level of a compartment is to be analysed prior to opening the hatch. While occupied each compartment is to have a monitoring, indication and alarm system for the gases that may contaminate the atmosphere intended for breathing due to failures. (O_2, CO_2, H_2S, hydrocarbon gases and inert gases etc. as applicable).

11.2.4.4 An indication system is to be arranged centrally to indicate contamination of the breathing gas in all compartments when occuied. The indication centre is to be in the transfer vehicle and/or in the compartment closest to the normal escape hatch when manned according to 11.2.2.1.

11.2.5 Design.

11.2.5.1 The requirements of Veritas' Rules for the Construction and Classification of Submersibles, section for Lifesupport Systems, apply as far as applicable.

11.2.5.2 The requirements of Veritas' Rules for Certification of Diving systems apply as far as applicable for oxygen systems.

11.3. Access and Egress.

11.3.1 Dry transfer of personnel.

11.3.1.1 It is assumed that the personnel transfer vehicle is continuously connected to a compartment when the Subsea Production System is manned or that an alternative rescue vehicle is continously connected.

11.3.1.2 Subsea Production Systems as defined in 11.2.2.1, are to have more than one access hatch. Each of the hatches and locking systems are to be compatible with the same transfer vehicle for alternative use.

11.3.1.3 For transfer systems where the transfer vehicles are locked to a sub-sea compartment, there is (are) to be system(s) that indicates to the personnel being transferred correct locking with regard to position, seal, and possible locking mechanism.

11.3.1.4 For transfer systems using a personnel transfer vehicle that is tethered from the surface, the depth dependant mating force or the possible locking systems between the sub-sea compartment and the vehicle and adjoining structures are to have a superior strength compared to the tether-system, to assure a broken tether-system before any damage of the connection of the vehicle. Alternatively an automatic yielding and final release system for the tether may be fitted.

11.3.1.5 A possible locking system between the personnel transfer vehicle and the sub-sea compartment is to have at least two independent alternative systems for operation, each of which is to be able safely to separate the vehicle from the sub sea compartment. One of the systems is to be independent of the surface supply.

11.3.1.6 The emergency buoyancy of a personnel transfer vehicle is to be sufficient to carry out an ascent with maximum payload even when a possible tether is broken in the least favourable manner with regard to its weight.

11.3.1.7 The transfer vehicle is to be equipped for internal release of a possible tether.

11.4. Fire protection for atmospheric oxygen containing environments.

11.4.1 Materials.

11.4.1.1 The use of combustible materials is to be avoided wherever possible. Combustible materials include materials which may explode, or ignite and burn or smolder independently in the gas environment applicable for the compartments.

11.4.1.2 Structural components, furniture and knobs, paint, varnishes and adhesives applied to these are not to be combustible unless satisfactorily protected against fire, as far as practicable.

11.4.1.3 Materials and arrangements are wherever possible to be chosen such as to avoid build-up of static electricity and to minimize the risk of spark production due to electrical failures.

Guidance:
In inner areas without electrical equipment, furniture and floors of electrically conductor material equipment may be used. For inner areas where powerful electrical equipment is used the materials and arrangements may be chosen such as to minimize contact with earthed metalwork.
A specific electrical resistance between 10^{7} and 10^{10} ohm.m. is considered to be suitable also for avoiding build-up of static electricity.

11.4.2 Fire Fighting Systems.

11.4.2.1 The fire fighting systems are to be based on evaluations made from the results of the Failure Effect analysis. (Sec. 2). The analysis is to contain evaluations on

- possibilities for and the effect of fire compared with common accepted offshore surface systems.

Possible items of concern are;

- The most probable fire sources and fire development scenarios.
- Fire detection system principles.
- Alarm system principles.
- Possible failure in detection and alarm systems and warning of faults: e.g. voltage failure, broken line, earth fault etc.
- Fire extinction system principles: coverage, capacity and control of the extinction process.
- Extinguishing agent: efficiency, storage properties and compatability with the emergency breathing plans.

11.4.2.2 The risk of fires, injuries and fatalities in this contex is not to be higher than accepted for surface production systems.

11.5. Communication and Location.

11.5.1 Surface/seafloor.

11.5.1.1 Between the Subsea Production System and the surface, at least two communication systems are to be arranged for direct voice communication. One of the systems is to be for emergency use and of a wireless type, for operation at a recognized frequency.

11.5.1.2 All major alarms are also to be given at surface.

11.5.2 Internal Communication.

11.5.2.1 Communication systems are to be arranged for direct voice communication between each of the compartments.

11.5.3 Location system.

11.5.3.1 A Subsea Production System manned according to 11.2.2.1. is to have two independant system for locating it.

SECTION 12
RETENTION OF VALIDITY FOR CERTIFICATE OF COMPLIANCE

12.1 General.

12.1.1 Owners duty.

12.1.1.1 The Retention of validity for the Certificate of Compliance requires that the Subsea Production System is subjected to periodical surveys, that it is operated, inspected and tested in accordance with the parts of the Operations Manuals related to safety and approved by Veritas, and that the owner promptly notifies Veritas of conditions, events or planned actions that may make it necessary to perform a special survey. «Survey» and «inspection» in this contex may differ from surface practice. A definition of survey is given in 1.2.2.1.

12.1.1.2 The owner is to carry out maintenance, inspection and testing as required to maintain the Subsea Production System in a safe condition.

12.1.1.3 The owner is to maintain files of the maintenance, inspection, testing and remedial measures taken, and make these files available to the Veritas' surveyors upon request. The owner is to make trend analyses based on the findings for possible correction of maintenance, inspection and test frequency.

12.1.1.4 The owner is to submit a summary report of the findings in 12.1.1.3 in relation to safety of the Subsea Production System prior to the Veritas survey.

12.1.1.5 The owner is to arrange for means accepted by the Veritas' surveyor to carry out inspection.

12.1.2 Manuals for owner's inspection.

12.1.2.1 Manuals for the owner's inspection, testing and maintenance are to:
- Identify tasks
- Describe procedures, sequences and frequency of the inspection, testing and maintenance
- Identify the means by which inspection and maintenance are to be carried out.

Guidance:
The inspections described in the manual may include:
- Testing of standby systems
- Testing of safety systems
- Testing of emergency systems
- Testing of possible communication systems
- Pressure testing
- Leakage testing
- Check of condition monitoring systems
- Check of corrosion protection system
- Check of the hydrocarbon for possible alteration of its corrosive and erosive properties
- Check for possible material deterioration and incipient cracking
- Check for possible damage by accidental loadings
- Check amount of marine growth and presence of debris in contact with the structure
- Check the foundations for scouring or buildup of seabed substances.

The frequency of these items may vary and some may be due pending on other findings or after abnormalities or accidental loads.

The manuals are to be submitted for approval as a part of the Operations Manual.

12.1.2.2 The method described in the manuals is to be based on generally recognized practice by reference to recognized codes/standards or by recognized testing carried out.

12.1.2.3 The frequency, items and systems for the owner's inspection and testing are to be selected according to the failure effect analysis, failure history and trend analysis from condition monitoring systems.

12.2 Surveys with Veritas.

12.2.1 General.

12.2.1.1 The owner is to notify Veritas in advance when periodical surveys are to be carried out and make all arrangements for a Veritas Surveyor to inspect to the extent necessary for completion of the survey in accordance with the Rules.

12.2.1.2 The frequency of the periodical survey by Veritas will depend on the system design, operation and maintenance plans. The owner is to propose a frequency as part of a survey arrangement. This arrangement is subject to approval by Veritas and may later be altered by Veritas depending on the findings and the owners reports.

Guidance:
Within a 5 year period it is to be demonstrated to Veritas that all systems and structural members related to safety are in order. This may be achieved by annual summary reports according to 12.1.1.4 and by surveys with a Veritas Surveyor during safety assurance of the most significant systems or items. These surveys should be carried out at least twice within the 5 year period.

12.2.1.3 In the event of accident, discovery of damage or deterioration, modifications or any other noted or possible change in the condition or operation of the Subsea Production System that may affect its safety, an additional special survey may be required.

12.3 Repairs.

12.3.1 General.

12.3.1.1 Repairs or rework (apart from planned maintenance) to parts that are subject to certification are to be approved and surveyed by Veritas.

12.4.1.1 The owner is to notify Veritas in advance of any such action and to submit the necessary plans and specifications for approval. The exact documentation that is to be submitted for approval or information purposes is to be decided in each particular case.

12.4 Conversion.

12.4.1 General.

12.4.1.1 Conversion will normally be subject to approval in accordance with the Rules for new constructions.

APPENDIX 1
FAILURE EFFECT ANALYSIS

General

This appendix is intended as guidance for one approach for the Failure Effect Analysis as described in 2.1.1.

Failure Effect Analysis

This comprises a systematic overview of the failure modes of the equipment and their effects on the safety of well control, personnel and equipment. Any method of analysis for obtaining the information may be used. Results presented on Failure Mode and Effect Analysis, FMEA, forms (example in table 1) and the total FMEA documentation should provide adequate basis for:

— Assessing the completeness of the FMEA. The FMEA is complete when all failure modes are identified for all main operational modes and at an appropriate level of detail (see below).

— Ensuring compliance with the Rules with respect to effects of failures on safety and detectability of failures.

Only failure modes affecting safety and associated system reliability need be included. The level of detail in the FMEA need not be high. Examples of what may be considered as components are:
— main connectors
— valves with actuators
— individual control/monitoring systems

The FMEA should consider the following modes of operation of the well:

— normal production (alternatively: injection) and production testing.
— maintenance by wireline, pumpdown tools or major workover by pulling tubing.
— possible pigging of flowlines
— production logging
— testing of valves
— kill well by mud circulation
— kill well by bull heading
— well pressure measurements on individual annular spaces
— possible disconnection of production riser

Only new conditions brought about by each mode of operation need be considered.

Within the limits stated above all modes of failure should be identified, e.g. technical failures, failures due to operations and accidental loading.

It should be documented how the possibilities for the individual failure modes and/or effects are taken into consideration through design, manuals for installation, operation and testing as well as through design, inservice inspection and maintenance.

Detailed FMEA.

There should be performed a detailed FMEA of dedicated safety barriers against loss of well control and, if applicable, safety measures for personnel in habitat systems. As a minimum, the detailed FMEA shall encompass the subsurface safety valve and the wellhead and hanger. Control and Monitoring Systems of these safety systems shall be included.

Similar analyses should also be made for other systems of special safety importance, e.g. evacuation systems in manned habitat systems, and riser systems.

The detailed FMEA should be laid out to identify failure modes that will reduce or destroy the safety function(s) of the equipment and in particular:

— common cause failures i.e. failures that are caused by the event(s) that make use of the safety barrier necessary
— failure modes introduced during normal operation and testing
— failure modes occurring when the system is in the activated mode
— detection possibilities of individual failures
— effects of the failures on safety.

Within the limitations stated above the FMEA should include all failure modes, e.g. technical failures due to accidental loading and operation.

Classification of Failure Modes

The failure modes of the analysis may be classified according to their effects shown in Table 2.

Failure modes with any effects in class 1 may then be listed separately as Very Critical Events (VCE). Failure modes with any effects in class 2 may be listed separately as Critical Events (CE).

The VCE list may be used as an appropriate document for approval from Veritas for each new application of the system. The VCE list should contain best estimates on the probability of any VCE occuring once or more during the entire time period during which the system is connected to a pressurized well. For some applications failure probabilities based on a broad statistical material will not be available. Best estimates on probabilities may however be obtained by extrapolation from related offshore activity and by justified engineering judgements.

The VCE and the CE should be separately listed in the operation manual along with descriptions of how the various failure modes will or may be detected in the control room during various modes of operation.

The operator should document that the VCE and the CE are known to the platform superintendents and the head of the platform of field operations. This information should be maintained by the operator and be less than one year old.

All common cause failures, i.e. failures of the safety systems having a cause that also results in need for using the safety system, should be treated as Very Critical Events.

Table 1 Example of a failure mode, effects and criticality analysis work sheet. Sheet no.............

Location/Field/Ident: ______________ System: ______________ Date: ______________

Equipment Name	Function Ident. No.	Failure Mode	Failure Cause	Failure Effect Local Effect	End Effect	Failure Detection	Alternative Provisions	Failure Probability	Criticality Ranking	Remarks

Table 2 Effect of failure mode

Class	Well control	Personnel	Equipment
1. (VCE)	Loss of control	Loss of life	N.A.
2.(CE)	One barrier remains or two barriers remain and working status of one unknown	Evacuation necessary[1])	Damage to surface platforms/requirement likely; or subsea damage to several wells; or at least one well and manifold damaged
3.	Reduced safety[2]) (but none of above)	Reduced safety (but none of above	Significant changes in loads on subsea production system

[1]) Only failure modes occuring when personnel are exposed.
[2]) Reduced redundancy and/or events destroying fail safe behaviour of any valve.