OTC 7245

Subsea Processing System Ready for Gulf of Mexico Field Conditions

P.M. Lovie, Bardex Subsea Corp.; V.E. Baugus, Oryx Energy Co.; M.G. Grecco, Unocal Corp.; and D.S. Schutter, Chevron Research & Technology Co.

This paper was presented at the 25th Annual OTC in Houston, Texas, U.S.A., 3–6 May 1993.

ABSTRACT:

Use of subsea processing (i.e. subsea separation and single phase pumping) to produce smaller more remote oil fields has been the subject of field tests and studies since 1969, reported in 9 OTC papers from 1974-1992.

The advance in GLASS [a] is to create a relatively "low tech" and proven solution. Although originally intended for the Gulf of Mexico, it may be applicable in Brasilian, North Sea and other areas. Parallel with the engineering development, composite judgements have been developed for the economic performance for CAPEX and OPEX using recently available probabilistic methods. Connector advances in 1991-1992 may further simplify use of this system design.

Application is relatively insensitive to water depths, e.g. 300-3,000 ft. Offset distances from a host platform may be in the region of 5-50 miles. The system was developed for a Base Case in 1,500 ft. of water with 12,000 bopd initial production with 8 wells from a 25 MMBBL recoverable reservoir, with GORs in the region of 1,000 scf/bbl. Installation equipment comprises the semisubmersible drilling unit and standard offshore service vessels, implying economy and flexibility for use in worldwide application. Hydrate, sand, shutdown and startup operating conditions were addressed.

---

[a] Goodfellow Lovie Associates Subsea System. Was developed in 2 phases during 1990-1991 by Goodfellow Lovie Associates, Inc. in Houston as a joint industry project: GLASS participants are: Chevron, Marathon, Oryx and Unocal. In August 1992 Bardex Subsea Corporation acquired the GLASS intellectual property.

References, figures, tables at end of paper

PRECEDENT SINCE 1969:

The first trials for a subsea processing system were the experiments in 1969-1971 offshore Abu Dhabi at the Zakum field, conducted by BP and Total when they installed a subsea separator and booster pump in about 72 feet of water and operated the system over a three year period, including a year long period when about 1.7 MMBBL of oil was produced. OTC paper no. 1942 in 1974 outlined this pioneering effort.

That prior work was systemized and updated for North Sea field conditions in the GA-SP project (e.g. 30,000 bopd from 4 wells in 984 ft. of water), culminating in full scale prototype trials in a dry dock in 1990 on behalf of eight operators: it was reported in OTC papers 6722, 6766 and 6767 in 1991. This system design used water injection hydraulic power to drive the booster pump, a 4 level component arrangement and a multiple stage subsea separator to provide oil of export quality from a hypothetical arrangement of 4 producing wells with 4 water injection wells, with GORs of about 450.

Another series of experiments with a subsea separator was made in live offshore conditions in about 248 ft. of water, near the base of a platform in the North Sea operated by Hamilton Brothers. This test series with the BOET separator design is reported in OTC paper nos. 5922 and 6423 in 1989 and 1990, respectively.

It would therefore appear that significant precedent now exists for subsea processing - indicating it is concept whose time has arrived.

ENHANCED RECOVERY FROM REDUCTION IN WELL BACK PRESSURE:

A major benefit of the use of subsea separation and boosting in deep water is that the back pressure on the wells can be reduced and total recovery can be enhanced. In this instance it means that the hydrostatic head of 1,000 to 3,000 ft. is taken care of by the booster pump. In the Base Case of 1,500 ft. water depth in the Gulf of Mexico, this corresponded to an increase in total recovery of about 27%, i.e. 31.7 MMBBL recovery v. 25 MMBBL without subsea boosting. Where well productivity is higher, this effect may be even better. Reference 6 calculates an improvement in recovery in about 1,000 ft. water depths for typical North Sea well productivities of 76 MMBBL v. 42 MMBBL without subsea processing, i.e. about 81% additional recovery.

DESIGN REQUIREMENTS:

This paper is intended as the industry record to report on work on development of a system design known as GLASS during 1990-1992 for deep water and field conditions typical of the Gulf of Mexico. The basic configuration is shown in Figure 1: a small reservoir in deep water that is a difficult economic proposition to develop with existing options but which might be produced back to an existing host platform in shallower waters.

GLASS started from a "clean sheet of paper" with the objective of developing a subsea processing system to satisfy the Gulf of Mexico field parameters. Although intended for the smaller more difficult reservoir conditions of the Gulf of Mexico, GLASS also responds to market needs in other parts of the world for a means of exploiting smaller deep water remote fields.

The field parameters in Table 1 were chosen by the oil company participants in GLASS as being typical of Gulf of Mexico conditions: relatively low productivity, fairly high gas oil ratios, hydrate and sanding likely, paraffin not significant. Sour or acid gas conditions were assumed to be absent.

Operational requirements investigated included:

Startup;
Shut down;
Hydrate control;
Pigging;
Sanding.

Procedures were developed to offer reliable operation at each stage of the field life and a basis for system design developed by discussion among participants, as outlined in Table 2. The economic pressures of Gulf of Mexico field conditions focused attention on simplicity, e.g. single stage very simple gas-liquids separation was a goal, as opposed to use of more sophisticated separation equipment and higher quality separation.

During Phase 1 of GLASS the concept was developed. Installation was based on heavy lift vessels with appropriate deep water capability. Phase 2 refined the design, explored the limits of applicability, developed further vendor and contractor input and adapted installation to avoid use of specialized heavy lift vessels. Existing equipment components, installation methods and technology are used, with input from major contractors (McDermott, Rockwater and Sonat) and from many oil field vendors.

The system design is now believed by the representatives from its oil company sponsors (Chevron, Marathon, Oryx and Unocal) to be ready for pilot plant installation and operation.

CHOICE OF CONFIGURATION AND INSTALLATION METHODS:

The configuration was taken to be suitable for diverless installation and operation, even though the design might at times be used in diver accessible water depths. It was felt more likely that water depths would exceed diver depths and in any event it was desirable to avoid potential risks and liabilities to the operator from diver operations.

The choice of satellite straight hole wells with flow lines from each well and MODU relocation for drilling each well was made to give a more difficult economic and engineering scenario, as opposed to a drilling template with directional wells and a single MODU location. The idea of combining a drilling and a processing template was discarded (1) for safety reasons and (2) to reduce the size of the subsea templates and thereby improve ease in installation.

Guidelineless operation was chosen for water depth reasons and for simplicity in multiple module installation. Ultimately the module design turned out to be relatively simple, provided a piping connector was available to allow simple module disconnection, removal and re-installation.

Both horizontal and vertical module connections were considered initially. The choice of vertical module connections was made for ease in installation and later removal of modules for service.

The number of component levels was evaluated: 4 or more levels implied complexity but the possibility for improved module access and retrievability. The computer generated perspective view in Figure 2 shows the compromise chosen of 3 levels:

No.	Level	Installation/Retrieval
1.	Primary modules, in slots in Main Distribution Module (top level in Figure 2)	Easily removable for service by d.p. offshore service vessel of convenience
2.	Main Distribution Module ("MDM") (middle level in Figure 2)	Removable if really necessary, by MODU
3.	Template (bottom level in Figure 2)	Base: permanent installation, piles drilled in by MODU

Installation of these three levels of components is in two steps. First, the drilling semisubmersible keel hauls the Template from load out from a submerged barge adjacent to the fabrication yard, to the GLASS location where it would be lowered by drill string. After drilling in the piles and levelling the Template, the MODU would return to the bank for the second step. The assembly of the Main Distribution Module and the primary modules is then keel hauled and taken to location by the MODU and lowered as a single lift by the drill string. The weight of the assembly in air exceeds some drill string capacities but in water with due operating allowance for the masses and dynamics, the lift becomes feasible with any of the larger semisubmersible MODUs. The risk of delay for the availability of a heavy lift vessel and its high cost are thus avoided.

The connectors between the primary modules and the Main Distribution Module have seals on both sides. It is possible to replace seals on the lower (removable) MDM side of the connectors by retrieving the MDM. The alternative to this arrangement is to use insert retrievable valves in the piping in the MDM, accepting the need to flush lines and possibly then combine the MDM and Template as a single unit, i.e. only the primary modules would then be removable and only 2 levels of components would be used.

Production lines from the Template to the host platform are planned as a cased bundle of 3 lines, each of 8 in. dia.: gas lift, gas export and liquids export (oil+water). The bundle would likely be towed out in two approximately equal lengths, to cover the 15 mile distance from the Template to the host platform. Gulf of Mexico and other successful tow out experience is applicable, again avoiding the use of capital intensive installation equipment. Pull in and connection would use McPac or similar equipment and experience.

Flow lines from the satellite wells to the Template would be flexibles.

TURNKEY DRILLING & INSTALLATION:

In order to offer a "cap" on the capital investment on an innovative project such as this, GLASS was shown to leading turnkey contractors with experience similar to what GLASS would need. Input from Sonat indicated that the installation of the Template and MDM/modules assembly, together with all drilling and completion, could be contracted on a turnkey basis. Similar discussion with McDermott indicated that supply of all equipment, fabrication, pipelines, platform modifications and all related installation could also be contracted on a turnkey basis, given adequate project definition.

So the element of risk in contracting for delivery of a complete GLASS system may be contained by turnkeying virtually the entire project.

EQUIPMENT AVAILABILITY:

Multiple vendors were found for all equipment items before they could be specified. A key objective achieved in the GLASS project was determining that all equipment requirements could be reasonably well satisfied "off the shelf", possibly requiring engineering for the application but avoiding any risk of the use of "rocket science".

The pump is a conventional 3,500 rpm centrifugal pump with a MTBF specified at 5 years or better, marinized for subsea service. It was found that there was plenty of experience with long operating service for pumps of this size and type used in hostile environments in other industries (e.g. mining and process). Since water injection is not envisaged and this source of high pressure hydraulic power was therefore not available, power to drive the booster pump is a.c. electric.

Choke valves are located at the top of the primary modules with retrievable inserts accessible by ROV.

The sand separator was a pragmatic solution to the sanding problem: if sanding occurs, it fills up the drum in the sand separator (71 cu. ft. capacity) and then the sand separator module is retrieved to the surface, emptied and replaced. Non polluting subsea sand discharge was not believed to be practical.

CONNECTORS:

Historically connectors have been a critical practical link in subsea systems and GLASS is no exception.

The Valved Multiported Connector is a device for joining and valving a number of lines simultaneously. It is the preferred device for making module and pipeline connections since it offers a single datum "plug it in, turn it on" compactness and convenience that simplifies piping and valving.

When the GLASS development effort started the VMC was not commercially available and so alternate solutions were created using combinations of proven multibore connectors and separate valves. These resulted in much more complex module connection arrangements. During 1992 establishment of a manufacturing agreement under license from the owner of the VMC technology (Scottish Enterprise in Aberdeen) meant that the VMC is now commercially available worldwide.

Figure 3 is a photograph of the prototype VMC which was designed for a total of 10 lines, 5 @ 8 in. dia. and 5 @ 4 in. dia. This device can be used in vertical mode for joining modules and in the horizontal mode it can be used to join bundles of flexible flow lines. If production from the subsea installation is exported to a floating vessel, the VMC can join bundles of flexible risers, offering integrated valving and quick connect and disconnect capability. The VMC can be manufactured to be able to pass spherical pigs. It was developed and tested in Aberdeen during 1987-1990 and then tested in submerged operations in a dry dock in 1990.

Subsea wet mateable electrical power connectors are believed to be recently proven with a number operating successfully in the North Sea at power and voltage ratings well in excess of that required here (e.g. 50-100 kW and 3.3 kV).

Fiber optic connections are specified for the signal lines between the manifold and the controls cabin on the platform. Again, these connectors are now believed available and fairly well proven in marine service.

Umbilical connectors are proven for joining the multiple chemical injection and hydraulic supply lines needed.

PROCESS AND CONTROLS:

Figure 4 shows the flow diagram for the system. The emphasis was on simplicity so that although it was technically feasible to separate oil, water and gas subsea and treat emulsions to provide export quality oil, the choice was made to separate liquids and gas only concentrating on solving the problem of transport of the wellstream back to the host platform. Thus oil and water flow in the same export line.

The separator design was simplified and oversized on the basis that the separator vessel itself was a relatively simple and low cost component in relation to the costs of getting it to its final subsea location.

A single separator vessel is used for production from all 8 wells.

Sand is separated upstream of the separator to avoid sand filling the separator and depositing in the export lines. The practical extent of sanding was the topic of some debate and so was resolved using a sand separator capacity that was guessed to be adequate for several months of "worst case sanding".

Level control is monitored by redundant nucleonic level measurement devices. The pump is an a.c. electric fixed speed unit: variable speed frequency control problems are avoided, although suppliers maintain that such equipment can be reliably operated. Duplicate programmable logic controllers are in retrievable pods subsea with operating control maintained from a cabin on the host platform. Process calculations showed that the modulating valves controlling the subsea levels and pressures did not have to be located subsea and could be installed on the host platform where they are easily serviceable. The gas line is controlled by pressure while the liquids line is controlled from the level instruments.

The use of the electric power line as a communication channel was considered but discarded on the basis of the distance and the preference to communicate over about 300 channels without having to package information and risk delays. Real time operation is assured through using fiber optic communications system.

Valve actuation is electro-hydraulic, with a biodegradable hydraulic fluid system allowing exhaust to sea. Hydraulic supply is via the umbilical with an accumulator subsea.

Several chemical injection lines to suit field conditions are included in the umbilical, sized to allow hydrate control during startup and shut down at any stage in the field life.

RETRIEVAL AND MAINTENANCE OF EQUIPMENT MODULES:

Each of the primary modules is retrieved vertically by a handling frame lowered from a service vessel. Module weights are between 23 and 40 tons in air and 19 to 32 tons in water. Retrieval of modules for maintenance would be by use of a joystick control d.p. offshore service vessel of convenience, using an operator owned spread of a skid mounted motion compensating winch and a module handling frame with lights, TV, thrusters and a rental ROV. Calculations showed that this was controllable for guidelineless module installation and retrieval in typical Gulf of Mexico sea conditions for more than 90% of the year in the 1,000 to 3,000 water depths envisaged.

In this fashion the sand separator could be removed for emptying, the pump module could be removed for maintenance, along with any of the control pods or other primary modules.

Pigging is achieved through launching pigs from the platform and retrieving them at the platform, avoiding the use of subsea pig launchers. Operation is by inserting the pig in the gas lift line and returning by either the gas export or liquids export line. Routing is achieved with a retrievable pigging module with switching capability using existing proven equipment.

REGULATORY BODY INPUT:

Repeated detailed meetings were held with the Minerals Management Service to establish that what was being proposed would meet MMS approval and that surprises would not be encountered at the project stage. While no blanket approval could be reached at this stage, no basic design or operation problems were uncovered in GLASS that might conflict with MMS requirements. It was concluded that design approval for a field application should be a relatively straightforward matter.

ECONOMICS:

From the outset the participants in GLASS emphasized the crucial nature of the Gulf of Mexico economics and acceptable risk exposures: the reservoirs were generally small and so management could allow no margin for error and experiments.

Capital and operating cost data for a new project was difficult to find and laborious to develop.

CAPEX figures for GLASS were arrived at after substantial debate, being essentially a compromise between the views of different operators, input from North Sea and Gulf of Mexico experience, all adjusted as the combined judgement of the team of individuals involved would indicate. This was an important but controversial issue since unless the economics were sensible, there was no point in proceeding with developing the technical approach.

Relatively user friendly software has become available in the last 2 or 3 years that will allow use of Monte Carlo simulation methods and risk assessments without consuming too much engineering time in learning to apply these tools: this was very useful in assessing the economics of this proposed system. The economic model was developed using Lotus 1-2-3$_{TM}$ v. 2.3 with the @RISK$_{TM}$ add in and was run on 286 and 386 personal computers.

Plus and minus uncertainties were used on all significant capital and operating cost expenditure categories in order to avoid pyramiding contingencies and still maintain risk assessment, as shown in Table 3.

The use of probabilistic methods was found to be a useful method of preserving the judgements of all parties involved without compromising anyone's interests or burdening the project with high contingencies from cautious judgement. For example, capital expenditure was expressed as a bell shaped curve centered about the total figure of about $149 million, as illustrated in Figure 5. Initially the bell shaped curve was relatively flat until more confidence was established in the components that made it up, some of which were riskier than others. The drilling cost was the largest single CAPEX component (see pie chart in Figure 5) and was also subject to one of the larger uncertainties (+20%, -10% in Table 3). In contrast, equipment purchase uncertainties are estimated as +15% and -10%, while offshore installation work was taken to be the most uncertain: estimated at +30% and -5% for tasks involving template, module, pipeline and umbilical installation.

The cost figures used in the economic model are the result of discussion among GLASS participants over a period of several months, in effect being an application of the Delphi method where a panel of knowledgeable individuals is polled to discern the outcome of a future untried event. Experience has shown in a number of different industries that use of such careful deliberations by a group of experts is a sound way of predicting future performance of new techniques of prospective actions. So while these economic projections are obviously conjecture, they are believed to be as good a guess as can be obtained, particularly when viewed with the calculations of risk assessments that are included.

The economics calculations allow for funding all negative cash flows with debt at 12% interest and for paying royalty at 16.67%. Consistent with typical industry practice as at 1990, sunk costs are ignored in the economic model here. Operator overhead charges and insurance costs are also ignored. Thus the rate of return and recovery cost figures shown will err on the low side on a true "arm's length" economic basis.

No allowance was made for taxes since the characteristics of each project and operator would likely be different. Oil prices were taken as fixed in real terms) in the figures here with gas exported or used in gas lift being costed as fixed in real terms. Inflation of 5% was taken to apply to capital expenditures, operating costs and revenues. On the basis of all these assumptions, rate of return indicati[illegible] were computed as:

Oil price, \$/bbl	Gas price, \$/MCF	Rate of return, %, after royalty and interest
25.00	2.35	50.4
20.00	1.90	42.5
15.00	1.43	23.6

The composition of the total capital expenditure shown in the pie chart in Figure 5, demonstrates how the subsea Template and Modules still is only about a quarter of the total capital expenditure, while the well costs represent the largest component (31.1%).

Typical results from the economic analyses are given in Figure 5, showing how bell shaped curves are used to indicate the most probable values for the total capital investment and for the recovery cost. The cash flow from the project is given as a probable spread which allows for downtime, short term fluctuation in oil and gas prices and for expected uncertainties in production from the wells: the mean line in Figure 5 is bordered with one stan[illegible] deviation up and down, and with the 5% and [illegible] percentile lines.

GLASS operating costs are based on typical Gulf of Mexico operator experience and are believed to be relatively predictable. These costs were found to be reasonably consistent with published operating costs (subsea and non subsea) for North Sea production rates which are generally higher per well than the Gulf of Mexico, e.g. reference 11 indicates about 1.00 UK pounds per barrel v. $1.72/bbl for GLASS. The large unknown in these GLASS operating cost estimates is the cost of well service which in the Gulf of Mexico is historically said to be high. Some operators have indicated that this cost may be reduced once the urgency of improved well design for reduced future subsea servicing becomes developed and demand for improved subsea well servicing increases.

APPLICABILITY ENVELOPE:

In the physical and economic environments of the Gulf of Mexico, it appears that applicable water depth ranges for GLASS would be something like 1,000 to 3,000 ft. On the lower end of the water depth scale in the Gulf of Mexico (e,g, say 300-1,000 ft.), other development options such as traditional platforms can offer economic advantages. At the deeper waters, e.g. 3,000+ ft. water depths, installation of modules and Template becomes much more difficult. In contrast, in the North Sea, and some more remote areas, applicable water depths may be less.

It is conceivable that GLASS may find application in areas where the surface environment is harsh and production might be back to an export point that is on shore. Examples might be remote locations that are without offshore infrastructure such as west of the Shetlands in UK North Sea waters, offshore Tierra del Fuego or the Falkland Islands and in some Russian Federation locations.

Where the transport of the wellstream can proceed back to the export point without slugging then there is no need for GLASS, such as for dry gas. Where more and more condensate is involved, there reaches a point where slugging flow occurs and GLASS is needed, generally around a GOR of 8-10,000 SCF/BBL for the pressures and offset distances in GLASS. At very low GOR values, separation may not be needed although pumping to transport the wellstream is necessary.

Applicable reservoir sizes appeared to be from around 5-10 MMBBL on the low end up to something in the region of 60 to 70 MMBBL. Larger reservoirs could be tackled by a GLASS system but more probably in the near term would use other techniques made attractive by the economies of the larger reserves.

ENGINEERING COMPARISON WITH OTHER SUBSEA PROCESSING METHODS:

Natural drive is a basis of comparison and obviously is used if at all possible. However the field conditions specified in GLASS would result in slugging flow and hence additional energy was needed to improve drive and operability. A slug catcher at the base of the host platform might have allowed brief initial production but further measures were progressively needed to sustain production:

a. Separation only;
b. Separation plus gas lift;
c. Separation plus gas lift plus single phase pumping.

All were not needed simultaneously at each stage of the field life: separation alone was adequate for the first three years or so, while in later years separation, gas lift and booster pumping were all needed, to maintain enough energy to produce the field and maintain operability throughout field life.

The configuration chosen was believed to be the simplest for the specified field conditions as well as conforming to "traditional oilpatch conservative" guidelines preferred by Gulf of Mexico operator management.

There are other subsea processing methods under development, e.g. using a more complex vertical separator in a conductor pipe in the well (VASPS, reference 8. below). Substantial engineering and testing is underway on using subsea separation, pumping and gas compression in a single lightweight module (Kvaerner Booster Station, reference 10). A recent innovation in a three stage reciprocating separator system has been under development by Aker (reference 9).

Multiphase pumping was examined as an alternate but at the GOR values of 1,000 scf/bbl or greater for the field conditions here, no suitable multiphase pump could be found. The power requirement computed to produce the GLASS Base Case field conditions using a multiphase pump was 1,000 to 2,000 kilowatts, i.e. about 20 times the power requirement for a single phase pump. The practical implications are significant since 50-100 kW may be available from existing equipment on a Gulf of Mexico host platform but 1,000 to 2,000 kilowatts would likely need new generating capacity - even another platform. This option was ruled out as unpractical for the field conditions considered here.

ECONOMICS COMPARISON WITH OTHER FIELD DEVELOPMENT OPTIONS:

An economic comparison was made for use of GLASS versus other development options that might be used in deep water Gulf of Mexico field conditions. The comparison basis was: 50 MMBBL reservoir, produced through 15 wells at 1,000 bopd each initially, back to a host platform 30 miles distant. Operator data was collected from a number of design studies for developments in 935 through 3,000 ft. water depths for the following options:

(i) Conventional Gulf of Mexico steel tower
(ii) Compliant and guyed towers
(iii) TLP
(iv) Floating systems: tanker based, semisubmersibles

Table 4 gives the comparative CAPEX and OPEX data, drawing on data developed in reference 2 for different Gulf of Mexico deep water development options and using the same assumptions as in the economics calculations for GLASS above.

In this instance GLASS was taken to be a combination of 2 installations as illustrated in Figure 6. The first GLASS installation would have 8 wells and the second would have 7 wells, brought into production sequentially such that: (a) the MODU with supporting services would be continuously employed under a long term contract, and (b) results from initial production would be used to set drilling programs for subsequent wells. For conservatism in these economics calculations it is assumed that there are no common production lines or other facilities that are shared between the two GLASS installations.

A true "apples and apples" recovery cost comparison between the options is difficult since GLASS relies on a host platform and the other options do not. Although the cash flow and investment is somewhat less than the other options, the big difference is in the risk exposure since the second half of the GLASS system does not necessarily have to be committed for until favorable results are seen from initial production.

On the basis of all these assumptions, rate of return indications for this dual application of GLASS were computed as:

Oil price, $/bbl	Gas price, $/MCF	Rate of return, %, after royalty and interest
25.00	2.35	28.0
20.00	1.90	22.2
15.00	1.43	12.6

The higher investment with 15 wells instead of 8 and lower productivity per well reduced the prospective returns on investment over the Base Case GLASS example above. GLASS offered both the lowest recovery cost and the lowest operating cost of all options in this case study. It is important in thiis comparison to recognize:

I. Taking advantage of the reduction in back pressure on the wells, GLASS offers a greater total recovery than any of the other options;

II. The relatively low operating costs shown GLASS are counteracted by well service costs where it is necessary to bring in a service vessel as opposed to using well service equipment that may be located on the tower, TLP or floating production vessel. In the years when well service or workover is needed, GLASS operating costs jump to equal or exceed the other options;

III. The low recovery and operating cost figures are also counteracted by the technology risk for GLASS as opposed to the other options that generally have more precedent.

CONCLUSIONS:

(a) A system such as GLASS offers greater overall recovery since it takes advantage of the reduction in back pressure on the wells. In the field conditions modelled that increase in recovery was about 27%, i.e. about 31.6 MMBBL recovery instead of 25.0 MMBBL recovery with existing development options.

(b) Conservative, "off the shelf" equipment selection is feasible, i.e. while GLASS may be a novel system to now use in live applications, the technology risks believed to be modest and uncertainties from equipment availability are substantially reduced over 2-3 years ago;

(c) Major contractors are willing to turnkey the drilling of the wells and all equipment supply, fabrication and installation, given reasonable project definition. Good confidence levels can be had in the practicality of installation and in obtaining a "cap" on capital investment;

(d) Overall field development cost calculations indicate recovery costs in the region of $4-5/bbl, exclusive of sunk costs, insurance and operator internal costs. This approaches $6/bbl as offset distances reach 50 miles;

(e) Retrieval of modules for immediate replacement or onshore service is projected as within the capabilities of a standard joystick control d.p. offshore service vessel, i.e. a DSV or MODU is not required.

(f) Operating costs are believed to be competitive with surface facilities, with the big unknown being well servicing. Well design and operation thus remain a key issue in containing operating costs over the field life.

) Engineering development by GLASS participants, coupled with 1991-1992 advances by suppliers in field proving equipment design and technology would imply that this system may be more practical than ever before for field use and may be a timely response for operator requirements for exploitation of smaller reservoirs in deep water offshore.

ACKNOWLEDGEMENT:

The authors wish to thank Chevron, Marathon, Oryx and Unocal for their support and participation in GLASS, and for their permission to publish this paper.

REFERENCES:

1. Goodfellow, R.; Webb, A.; Harbonn, J.: "Subsea Experience Gained at Zakum", Offshore Technology Conference, Proceedings, 1974, paper no. 1942, pp. 79-88.

2. Grecco, M.G.: "Deepwater Development Economics", Offshore Technology Conference, Proceedings, 1987, paper no. 5545, pp. 519-529.

3. Songhurst, B.W.; Edwards, W.: "Subsea Separation: An Economic Method for Submarginal Fields", Offshore Technology Conference, Proceedings, 1989, paper no. 5922, pp. 405-416.

4. Songhurst, B.W.; Eyre, G.P.: "Experience Gained rom the First U.K. Subsea Separator", Offshore Technology Conference, Proceedings, 1990, paper no. 6423, pp. 43-50.

5. Appleford, D.E.; Dick, P.; Felton, J.: "Modularisation and Installation, Maintenance and Repair Aspects of GA-SP Technology", Offshore Technology Conference, Proceedings, 1991, paper no. 6722, pp. 239-247.

6. O'Connor, J.J.; Lovie, P.M.; Sarshar, M.M.: "An Overview of the GA-SP Project: Field Applications and Economics", Offshore Technology Conference, Proceedings, 1991, paper no. 6766, pp. 611-626.

7. Nordvik, H.S.; Sarshar, M.M.; Taylor, M.: "Subsea Processing and Control System in the GA-SP project: Testing of the Prototype System", Offshore Technology Conference, Proceedings, 1991, paper no. 6767, pp. 611-626.

8. Entress, J.H.; Pridden, D.L.; Baker, A.C.: "The Current State of Development of the VASPS Subsea Separation and Pumping System", Offshore Technology Conference, Proceedings, 1991, paper no. 6768, pp. 627-635.

9. Giset, A.M.; Woulfe, T.F.: "The Three Stroke Separation and Transportation System", Offshore Technology Conference, Proceedings, 1992, paper no. 7039, pp. 503-508.

10. Queseth, P.O.; Dahl, D.G.: "Dynamic Remote Control System for Subsea Well Stream Boosting", Offshore Technology Conference, Proceedings, 1992, paper no. 7042, pp. 531-540.

11. Schneider, G.: "Acreage Portfolio Management", Journal of Petroleum Technology, September 1992, pp. 978-983.

Parameter	Units		Value
Distance from GLASS to platform	miles		15
Water depth at GLASS	ft		1,500
Water depth at platform	ft		300
Number of oil wells	—		8
Average well peak production rate (after allowance for downtime)	BOPD		1,500
Average field peak production rate (after allowance for downtime)	BOPD		12,000
Average depth of wells	ft		9,000
Recoverable reserves (conventional recovery)	MMbbl		31
Field life	years		12
Crude oil composition	mole %	C1	60
		C2	5
		C3	4
		C4	3
		C5	1
		C6+	27
Approximate stock tank GOR	scf/bbl		1,000
Approximate stock tank gravity	°API		35–40
Water cut at SOF	%BW/BO		0.0
Water cut at EOF	%BW/BO		80
Gas lift injection rate, total field	MMscf/d		up to 5
Water injection			none
Shut-in wellhead pressure at SOF	psia		5,000
Flowing wellhead pressure at SOF	psia		1,000
Minimum gas pressure on platform	psia		60
Minimum oil pressure on platform	psia		80
Minimum seabed temperature	F		40

Table 1: Field Parameters Specified by GLASS Participants

Factor	Downside	Upside	Application
Downtime, percent/year	Varies according to year: 20.0 percent decreasing to 5.0 percent increasing to 20.0 percent		
Production rate, BOPD	-20%	+20%	Allows for reservoir unknowns
Oil price	-20%	+15%	Applied in each oil price scenario, allows for fluctuations in trend
Well costs	-10%	+20%	Used for drilling, well service and workover costs
Equipment purchase	-10%	+15%	
Template/modules fabrication	-5%	+15%	
Purchase lines and umbilicals	-10%	+15%	
Platform modifications	-10%	+15%	
Install a test Template/module	-5%	+30%	
Install lines and umbilicals	-5%	+30%	
Pig/test/chemicals/operate	-15%	+15%	Used in operating cost calculations

Table 3: Uncertainty Values Applied to Economics

Product Export	Minimum delivery pressure at platform
Product Requirements	No specific requirements for the quality of the oil/water mixture exported to the platform other than those demanded for acceptable transportation by pipeline.
Modularization	All key components retrievable either as individual units or as part of a retrievable module.
Modules	All equipment housed in open frames in wet condition, exposed to seabed environment.
Equipment/Components	All components selected to be based on the use of available products as much as possible.
Installation Philosophy	Operations based on available equipment and facilities available in the Gulf of Mexico as much as possible. Facilities available from other parts of the world can be considered with cost implications included.
IMR Operations	Maintenance and repair operations based on: • Diverless and guidelineless techniques; • ROV intervention based on present state of art.
Field Life	12 Years
Overall Life Cycle	Elapsed Time, years — Tasks: 4 — Engineering, Drilling, Fabrication, Installation 12 — Production 1 — Field Abandonment 17
Standards	API and typical US GOM practice MMS, USCG regulatory requirements
Chemical Injection	No particular requirements specified. Provisions for chemical injection at the following points are included to demonstrate implications on the system. • Wellhead; • Upstream of chokes and separator; • Gas export line.
Pigging	Pigging required for gas export and oil/water export line. Frequency of pigging unknown but assumed to be a few times per year in each export line.

Table 2: Basis for Design

Design Type	Total Inv., $million	Water Depth, ft.	Recovery Cost, $/bbl	Comparison v. GLASS	Operating Cost, $/bbl	Comparison v. GLASS
Steel Platform	249.2	935	4.98	0.891	2.72	1.520
Steel Platform	391.0	1350	7.82	1.399	2.72	1.520
Steel Platform	431.9	1350	8.64	1.545	2.72	1.520
Steel Platform	511.6	1600	10.23	1.830	2.72	1.520
Guyed Tower	322.9	1500	6.46	1.155	2.72	1.520
Guyed Tower	391.7	2000	7.83	1.401	2.72	1.520
TLP	388.2	1600	7.76	1.389	3.36	1.877
TLP	493.7	3000	9.87	1.766	3.36	1.877
Semisubmersible	356.5	1800	7.13	1.275	5.20	2.905
Semisubmersible	383.5	3000	7.67	1.372	5.20	2.905
Compliant Tower	391.7	2000	7.83	1.401	2.72	1.520
Tanker based	362.0	2000	7.24	1.295	5.73	3.201
Tanker based	369.0	3000	7.38	1.320	5.73	3.201
GLASS	335.5	1500	5.59	1.000	1.79	1.000

Table 4: Indicative Economic Data on Comparable Deep Water Development Methods

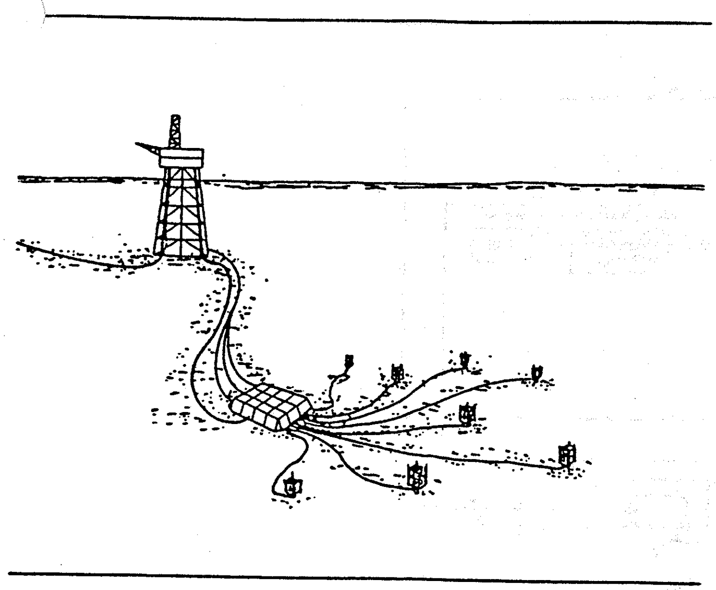

Figure 1: Configuration of GLASS

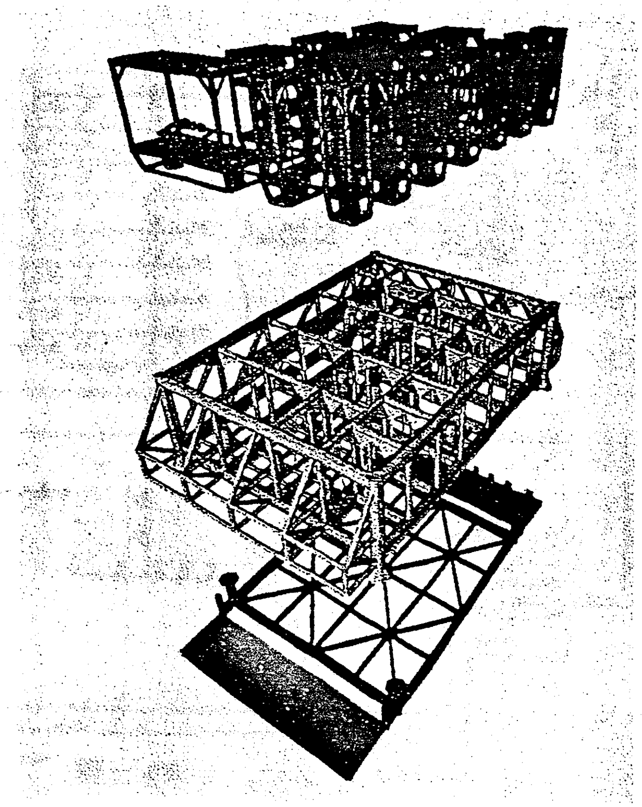

Figure 2: Perspective View of Subsea Template, Main Distribution Module and Primary Modules

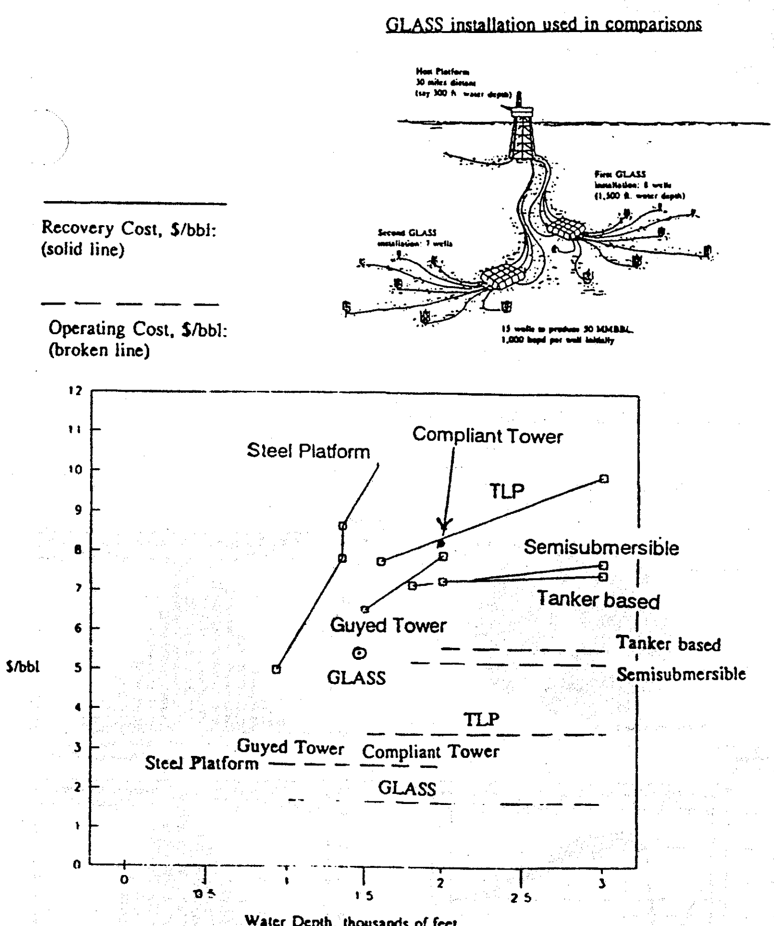

Figure 6: Trends in Economics of Different Deep Water Development Options v. GLASS

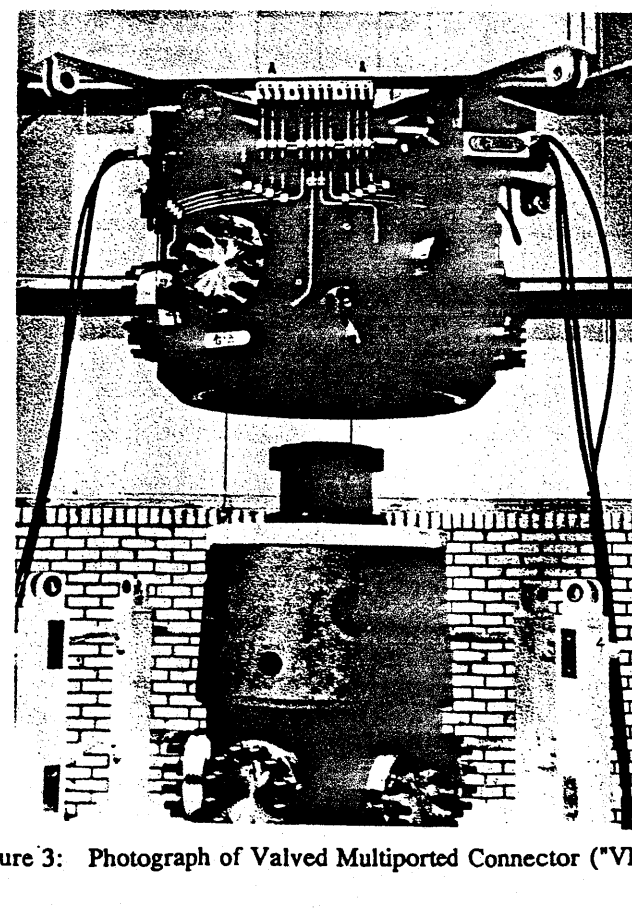

Figure 3: Photograph of Valved Multiported Connector ("VMC")

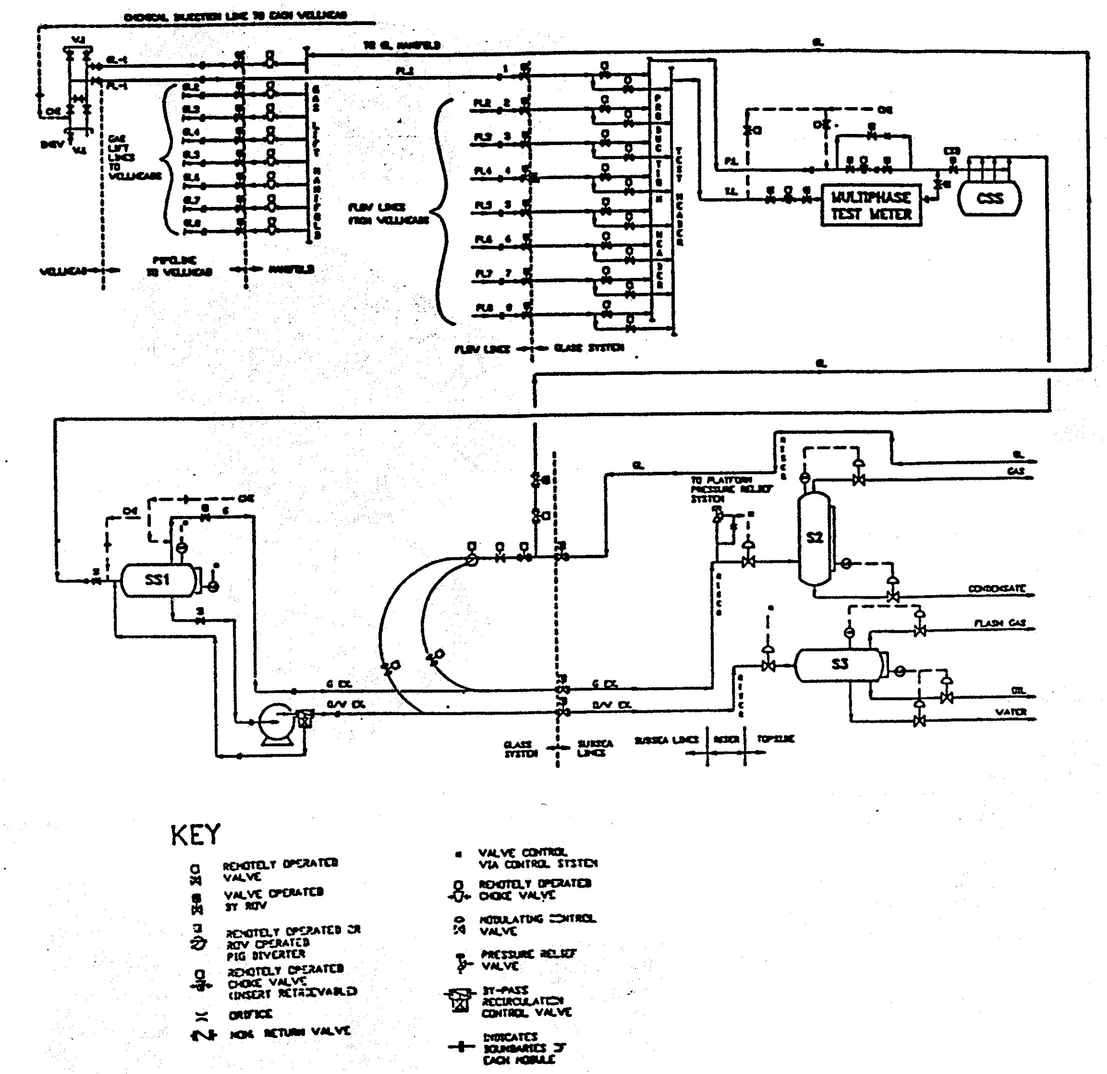

Figure 4: Flow Diagram for GLASS

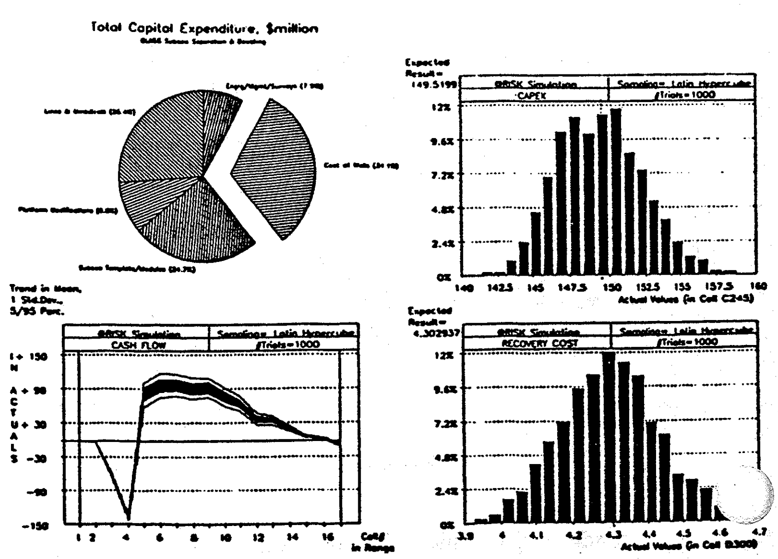

Figure 5: Typical Results of Economics Analyses