I. BASIS FOR STUDY

The original concept envisioned for the use of Fischer-Tropsch processing (FTP) of United States associated natural gas in this study was to provide a way of utilizing gas which could not be brought to market because a pipeline was not available or for which there was no local use. Such situations could arise in remote areas of the U.S. or in deep offshore waters. U.S. regulations prohibit unrestricted flaring of gas, and this could conceivably prevent production of the crude oil with which the gas is associated. FTP could provide a means of utilizing the gas which would not require installation of a pipeline. The premium quality F-T hydrocarbons produced by conversion of the gas can be transported in the same way as the crude oil or in combination (blended) with it, eliminating the need for a separate gas transport system. FTP will produce a synthetic crude oil, thus increasing the effective size of the resource.

After our efforts to confirm the above concept (see Section III - **Survey of Associated Gas Resources**) we conclude that it has limited validity but that similar concepts, based on a more detailed picture of current commercial energy production activities, do provide a likely basis for the application of FTP to the enhancement of energy production.

The overall conclusion of the survey to locate areas where associated gas and oil are shut in due to regulations on flaring or due to the lack of a way to utilize the gas is that there are no such circumstances in United States territory at this time. It is technically possible onshore or offshore to build a gas pipeline from any oil field currently in production or under development. The cost of a pipeline is very project specific (See Section V - **Offshore Pipelines**) and so it is impossible to make a general comparison of the cost of FTP and pipelining. However, it is evident that pipelining will be less costly than FTP in a significant number of projects.

Also, in some instances, gas can be re-injected into the reservoir to allow oil production until a pipeline can be built. Gas re-compression for re-injection to the field is required. Produced oil would be stored in, and exported from, a moored floating production system. However, re-injection has its problems. It is often uncertain as to whether re-injection will enhance oil production over the life of the field or whether it will cause a net decrease in overall recovery of in-place oil. Moreover, gas compression/re-injection involves a significant cost. At the Hibernia field off Newfoundland, reinjection, if elected, was estimated to have a cost of $0.50/MCF, high because of field complexity and high downhole pressure. At other fields costs of the order of $0.25/MCF have been derived. Re-injection costs/10 MMCF/D are thus in the range $2,500 to $5,000/d. This is the equivalent, at $17/bbl, of 150 to 300 bbl/d of lost production. Said another way, it's a 1.5 to 3.0% loss on a field having a gas-to-oil ratio of 1,000 cf/bbl; 3 to 6% at a GOR of 2,000; 7.5 to 15% at a GOR of 5,000.

Another way of viewing 25 to 50 cent/mcf re-injection costs is to recognize that this means that the revenue realized on the first 150 to 300 bbls of daily crude production is spent to re-inject 10 mmcf/d of gas. Moreover, re-injection of 10 mmcf/d of gas re-injection of the oil equivalent of 1666 bbls (at 6,000,000 BTU/bbl); it is now seen that the total cost of re-injection is approximately 2000 bbls/10 mmcf re-injected. If, as is noted in Appendix A, 200 mmcf will yield 25,000 bbls of Fischer-Tropsch liquids, than 10 mmcf will yield 1250 bbls of F-T liquids. If F-T liquids are valued at $25 to $40/bbl then the lost revenue due to re-injection is the "re-injection cost" plus the "cost of lost sales"; \$3000 to \$6000 (150 to 300 barrels at \$20/bbl) plus \$31,250 to \$50,000 (1250 bbls at \$25 to \$40/bbl), a low side estimate of \$34,250 to a high side estimate of \$56,000 in lost revenues due to re-injection of but 10 mmcf/d.

So, while it is unlikely that any crude oil production will be prevented in the long-term by the lack of a way of disposing of associated gas, problems do exist when GOR's are not low. Pipelining can be very expensive, and re-injection is costly, and sometimes disadvantageous. These, and other reasons to consider FTP of associated natural gas are discussed further below.

II. REVISED CONCEPT

The trend in the U.S. Gulf of Mexico is toward development of deep water tracts. For the April 1996 lease sale, 44 % of the acreage leased was in 2701 feet of water or deeper[1]. Current Gulf of Mexico development approaches do not mesh well with the use of FTP for associated gas utilization. Semi-submersible drilling platforms (SSP) and tension leg production platforms (TLP) with pipelines for both crude and gas are the usual mode for recent deep water tract development. SSP's are sometimes converted from drilling to use as production platforms. Neither TLP's or SSP's have sufficient space or weight bearing capacity for FTP.

The trend elsewhere in the world for deep water development is to use Floating Production Storage and Offloading vessels (FPSO). This trend is expected to take effect in the Gulf of Mexico soon. This approach uses "ship-shape" vehicles (as contrasted with "platform shape") to carry the production systems and to store the crude oil until it can be off loaded to a shuttle tanker ship. While some FPSO vessels are built specifically for FPSO service, many are converted oil tankers. The best system for a particular project depends on many factors, but FPSO's tend to have a lower capital cost and quicker implementation than other approaches.

An FPSO has considerably more space and weight bearing capacity than a production platform and can be readily designed to accommodate FTP, without much added cost. There is thus a natural fit since FTP will add to the advantages of an FPSO in the above situations. FTP may solve the question of how to avoid flaring gas and still get into production rapidly without building permanent facilities. How rapidly an FPSO/FTP combination (FFTP) could be designed and built remains to be seen but once built it could be moved from project to project quite rapidly.

Behrenbruch, in an October 1995 Offshore article[2] indicates that FPSO's or an FPSO/ semi-submersible production platform combination are especially advantageous to obtain early production and cash flow and also for:

- remote developments (remote from infrastructure)

- small, marginal fields

- fields where extended (~ 1 year) well testing is urgently needed

Availability of the FFTP can allow a field to be brought into production early, just as quickly as a necessary threshold of reserves has been proven but before full field delineation is completed and the total of reserves determined. Cash flow thus generated will allow incremental and eventual full exploitation of the field's potential. Conceivably 'full exploitation' could mean added wells, one or more additional production platforms, even oil and gas pipelines tied back to existing infrastructure with the result that the FFTP is eventually relieved of service on the field, thus being made available for field development at a different site. Availability of the FFTP as a well production vessel allowing early recovery of investment will have proven critical in this instance to the affirmative field development decision.

Selection of deep water tracts for lease bidding and for development at the present time is influenced considerably by proximity of tracts to pipelines and other infrastructure. Availability of the FFTP system will give considerably more flexibility in selecting tracts and effectively increase the availability of oil resources.

The lower capital cost of an FPSO can make it suitable as the production approach for small fields. If gas utilization and/or re-injection are not sufficient to avoid gas flaring, FTP may be a solution. However, this will reduce the capital cost advantage of the FPSO considerably. If the reservoir characteristics of a small field are amenable to rapid drainage (short field life), then the ability to move an FFTP system at the end of the production period would give it an advantage over more permanent, immovable installations.

The "portable" nature of the FFTP will also make it suitable when extended well testing is needed to define the characteristics of a reservoir before deciding on what type of permanent facilities should be installed for maximum total production and minimum capital cost.

If the crude oil to be produced is "waxy" (high pour point), a relatively small additional processing step can be added to FTP to confer pour point depressant properties to the F-T product so that it can be blended with the crude and ease handling problems.

The way in which FTP is likely to fit into the energy production picture is a little different than that envisioned at the beginning of this study. However, the net effect of FTP's contribution will be the same as that hoped for, to economically increase the country's energy supply by expediting the production of crude oil, and converting difficult to utilize natural gas into premium liquid fuels.

III. ASSESSMENT OF FFTP VIABILITY IN DEEPWATER FIELD PRODUCTION

An assessment of FFTP viability as a Gulf of Mexico deepwater field production system was solicited of a major oil and gas company; the company is also a developer of deepwater gas/oil provinces and is a leaseholder of deepwater Gulf of Mexico tracts. The company, hereafter referred to as "Developer", has requested anonymity and that request is honored herein. The report of his analysis is presented in Appendix C as is the EI FTP and FPSO data on which his study is premised.

In the "Developer's" assessment of FFTP viability the "Developer" postulated development of a major oil/gas prospect at 6,000 ft water depth and 350 miles distance from the nearest available point of pipeline tie-in to the existing product delivery offshore-to-onshore pipeline transportation system. In this scenario he compared investment cost to produce the field via FFTP shuttle tanker versus investment cost to produce the field via a new but conventional pipeline system. It was found that the FFP shuttle tanker system would enjoy a half-billion dollar investment advantage vis a vis production of the field via pipeline, also, the field is produced by the FFTP approximately one year earlier than first oil is achieved via the pipelline system. The "Developer" concludes his assessment thus:

"In summary, if the Fischer-Tropsch process field-scale application will perform somewhat similar to the representations made by EI, it appears that commercial interest in the F-T process shuttle tanker development methodology is merited."

IV. SURVEY OF ASSOCIATED GAS RESOURCES

A survey was conducted to attempt to locate commercial size petroleum resources in the United States with significant associated gas for which there was no local use for most of the gas and no means to transport it to market. For such a resource, unless it is practical and economic to re-inject the gas produced with the oil, the only way to produce the oil would be to flare the gas produced with the oil. Since federal regulations prohibit gas flaring, it would not be possible to produce the oil.

Various federal and state agency representatives, industry associations, and private consultants knowledgeable about gas and oil resources and having access to resource data were contacted in the survey. Reports, tabulations, and maps on resources were obtained. The principal sources of information were the Minerals Management Service, U.S. Department of Interior; the Oil & Gas Division of the Railroad Commission of Texas; and the Louisiana Department of Natural Resources. Also contacted were various individuals and locations of the Department of Energy; the Federal Bureau of Land Management, the U. S. Geological Service, the Colorado Oil and Gas Conservation Commission, the Gas Research Institute, British Petroleum, ARCO, and the Independent Petroleum Associations of Mountain States. Team Reserves, Inc., Oklahoma City, a sub-contractor on the project, assisted with some of the contacts.

No resources of the type described were located, either onshore or offshore. None of the persons contacted knew of any domestic oil resource that is shut in because of a lack of a way to handle the associated gas without flaring it. Many expressed the opinion that there are no such situations. Some flaring of associated gas does occur, but it is limited, except in very nominal cases, to initial production, reservoir delivery evaluation periods, or to an emergency basis. Associated gas is either re-injected for reservoir pressure maintenance or is pipelined to market. In some cases, re-injection benefits oil production by maintaining reservoir pressure.

V. REGULATION OF FLARING

Federal responsibility for regulation of flaring covers production on federal lands and offshore outside of three miles (the latter represents 85-90% of known reserves). Wells with gas to oil ratios (GOR's) less than 1500:1 can generally be flared for testing purposes. Under certain conditions an extension can be obtained for up to one year. One general criteria used is any production above 250,000 cubic feet/day (MCFD) justifies installation of a compressor to capture the associated gas.

State agencies regulate flaring out to the three mile limit. Access to a gas pipeline is almost always readily available in these near shore areas, and as a practical matter, flaring is not a significant issue.

The texts of regulations covering flaring are given in Appendix B.

VI. OFFSHORE PIPELINES

Oil and gas exploration and production has been gradually moving farther offshore in the Gulf of Mexico. A question pertinent to this study is whether either the cost or difficulty of laying pipelines out to producing leases will increase with distance offshore or water depth to the point where pipelines will not be used for some projects. Some feel that for the immediate future at least, the answer is no. However, it seems that if viable alternatives exist, they will be given closer attention as both the distance and depth increase. The subject is complex, and this section attempts to put it in perspective by discussing some of the factors and considerations involved in installing offshore pipelines

A. Pipelay Capability

Capability to lay offshore gas pipelines pipe is a function of dead load, i.e., how much suspended weight can the specific lay barge tend. Dead load is a function of water depth, pipe diameter/gage and material (steel or flexible composite) and current drag. A question to be answered is: does development in the discovery field of interest confront a combination of these factors which would require design and construction of a lay vessel with new capabilities (e.g., Marlim Field required a dynamically positioned vessel of advanced capability for laying flexible pipe of 12-inch diameter into waters of 2000 meters; the Sunrise 2000 cost Petrobras $90,000,000 and it came available for deployment in 1995). A similar consideration will prevail when one or more lay barges of required capability exists but demand for them is so great that leasing them on ones preferred schedule becomes impossible; escalating day rates indicate this to be the current situation. (If the FFTP can be installed with existing equipment then the cost of both the pipelines and a 'new capability' lay barge are avoided, and possibly the field is brought on-stream at an earlier date which allows the developer to realize an increased internal rate of return).

B. Pipeline Cost

As a generalization pipelining costs can be expected to increase with pipeline diameter and the depth of laying. But the exceptions to this rule are as frequent, almost, as is compliance with it. Each lay job is different; that's why each is bid with such great care. Care is taken to define all parameters that impact cost -- bottom conditions, trenching requirements, ballast requirements, frequency and rate of elevation and direction changes, transit of shipping lanes, weather (wind and air temperature, waves and current), weather windows and lay schedules, fish trawling activity, line fluid operating pressure and line inspection requirements, fluid transport temperature (provision for line expansion, hence, deformation/failure avoidance), and in the north, ice scouring history, course and depth. To illustrate the cost impact of special factors:

Pipelay Scenario A - North Sea well tie-back to platform in nominal water depth of 100 meters (328 ft); steel pipe diameter 12 inches, lay distance 2.4 km (1.5 mi); 1986 cost including materials, mobilization/demobilization, down time, pipe lay and tie-in: $10,000,000 (cost/mile, $6,660,000).

Pipelay Scenario B - U.S. Gulf coast dual pipeline tie-back from Platform 1 in 2,200 ft of water to Platform 2 in 1,000 ft; one 12 inch steel line for 40,000 bbl/d oil, one 12 inch steel line for 120 MMCF/d gas; pipelay distance 53 miles, each line; project bid in 1992 and completed in 1994: $13,000,000.

PIPELINE COST ELEMENTS, EACH PIPELINE

Pipe		$5,000,000
Valving		110,000
Concrete coating		540,000
Flanges		62,000
Breakaway joint testing		45,000
Corrosion protection (anodes)		203,000
Spool-piece fabrication		20,000
Miscellaneous fabrication		31,000
Materials storage and handling		12,000
Lay barge service, 20d X 25,000/d		500,000
	TOTAL*	$6,523,000
	Cost/mile	$ 123,000

*Forecasted turnkey cost if bid today, 1996 = $18,000,000; $/mi =170,000 (escalation basis is $2,000,000 in materials cost and $3,000,000 in lay barge day rate charges; these reflect the current tight lay barge market).

Pipelay Scenario C - U.S. Gulf Coast single multiphase flow pipeline tie-back from 2,700 ft water depth to a platform in 1,350 ft of water; 10 inch pipeline of 0.910 wall thickness, 0.75 inch polypropylene insulation (to prevent freezing of entrained water), and 0.625 steel sheathing outer containment (pipe-in-pipe construction); quad joints are of 240 ft length with J-lay collars at each end; pipeline length is 14 miles; lay barge will require extensive, costly, modification to suspend pipe and pass collars through J-lay handling: the OME (order of magnitude estimate) cost = $1,200,000/mile.

The foregoing scenarios tend to represent extremes of costliness and economy in pipelaying. Of interest and somewhat supportive of the Scenario C result, the firm providing the Scenario B data also gave an estimate to tie-back 50 miles (non-multiphase flow) from a water depth of 9,200 ft (the deepest lease sale by DOI/MMS in April 1996) to a platform in 1,000 ft. The OME estimate was $1,000,000/mile and it was noted that a barge of new capability would be required to suspend the pipe without excessive list of the vessel. When the pipe has been carried from a depth of 9,200 ft to a water depth of 3,000 ft the job would likely be turned over to a lay barge of current capability. The pipeline cost in the project timeframe, 1999 - 2000, at a water depth serviceable by a lay barge of 'current' capability was projected to be $250,000 to $300,000/mile. These figures were given for comparison to the data in Scenario B.

It will be useful to report the result of one more pipeline project, now suspended, which has been under intensive research since the mid 80's, a starting point in time at which it would not have been feasible to construct it. The pipeline was to run from Oman to India, a distance of 715 miles, traversing chasms at depths of 1,350 ft. Two lines of 24 in. diameter would each have carried 25 mmcm/d (883 MMCF/d). Studies conducted at a cost of $70 million have confirmed the present day availability of the necessary technology to accomplish the project at a cost of $4 billion, a rate/mile of pipeline of $2,800,000. Unofficial statements indicate that insufficient gas is available to assure project financing.

Additional anecdotal data on offshore pipeline costs are given in Appendix D.

C. Pipeline Capacity

The FFTP evaluation reported here is focused on conversion of nominally 56 MMCF gas/d, i.e., the offset of any necessity to pipeline 56 MMCF/d to an interconnect with a subsea pipeline system. It was postulated that this pipeline might run 50 miles at a water depth of 2,500 to 10,000 ft. Scenario B would appear to indicate that a 12 inch line is of more than sufficient size. A current land-based pipeline project has recently sized and cost estimated a 70 mile pipeline to flow 40 MMCF/d at start of operations and reaching 85 MMCF/d in eight years. A 10 inch line costing $17,000,000 will accommodate the 40 MMCF/d requirement without necessity of in-line compression. Two in-line compression stations costing $5,000,000 each are required, installed at the 4th and 6th years, to handle the flow increase to 85 MMCF/d. An alternative design would use a mix of 12 inch and 16 inch line to accommodate the full 85 MMCF/d without resort to any in-line compression; the cost estimate for this line is $40,000,000. Pipeline pressure at the input end is 900 psig. Pressure available in the deep water fields will likely exceed this by quite a bit. It is a safe bet that a 10 inch line will suffice for transport of 56 MMCF/d for 50 miles; costs/mile will not differ significantly from those projected in Scenarios A-C.

VII. COMPETITIVE APPROACHES

The synthesis gas (H_2 and CO mixture) produced as an intermediate stream in the Fischer-Tropsch process can be used to manufacture other products besides the hydrocarbons considered in this study. The main product which has been considered in contexts similar to this study from time to time is methanol. Products like methanol lack two of the advantages of F-T hydrocarbons, compatibility with the petroleum materials also being produced, and similar handling techniques. In general, F-T hydrocarbons can be blended with petroleum cuts (although this has to be evaluated on a case basis), and the blend can be handled and processed thereafter in the usual fashion for petroleum materials. Of course, they can also be kept separate if the end use and/or market justifies it. If kept separate, F-T hydrocarbons are handled the same as petroleum materials are (keeping the high pour point for the heavier fractions in mind) and no special designs, hazard analysis, or unusual personnel training is required.

Methanol has to be stored, transported, and handled according to its particular characteristics. Special purpose designs, hazard analysis, and special personnel training are required. These factors, of course, are not over-riding, and economics and corporate objectives will be the deciding factors.

The U.S. Department of Transportation sponsored a study of the production of methanol from natural gas in a remote location by a methanol plantship[3]. The estimated cost for the plantship is $386 MM, which is of the same magnitude as the estimated cost for the FFTP. The report referenced is a summary report, and doesn't give enough detail to directly compare the cost of the two approaches. More information would have to be obtained and significant effort expended to determine which approach would be preferable for a specific potential project.

Natural gas can be liquified (LNG) and transported but to an even greater degree than methanol, LNG requires specialized systems and handling. It also requires economies of scale (e.g., must handle very large quantities of gas) and a capital investment that makes it impractical for most, if not all, offshore projects. The market for LNG is limited to areas that do not have low cost gas readily available.

An alternative method of transporting natural gas is to form and transport methane hydrates.[4] This method is still under development but preliminary reports indicate a lower cost than for LNG.

VIII. FISCHER-TROPSCH PROCESS

Gas to oil technology is a means of producing premium grade light hydrocarbons in the transportation fuel range from natural gas (or coal) through the catalytic conversion of carbon monoxide and hydrogen to the desired light liquid products. The carbon monoxide and hydrogen (synthesis gas) is produced either from the reforming of natural gas or, in the case of coal, by gasification technology. These gas to oil processes have been undergoing revitalization over the last 10 years as a result of the generally greater availability of natural gas relative to crude oil.

F-T catalyst systems involve some type of inert support system with one or more active metals deposited on the support. There are four metals generally considered as active ingredients for these catalysts. They are iron, cobalt, nickel, and ruthenium. Nickel is not commercially practical for several reasons in this application starting with natural gas. Ruthenium is much higher in cost than the other possible metals. Most F-T catalysts involve the use of iron or cobalt. EI's proprietary technology involves using cobalt as the primary active element. Cobalt acts differently than iron, the most significant difference being that it has a low water gas shift activity. This is important in the application in that high water gas shift activity produces a larger quantity of CO_2 which is undesirable and detracts from the economics. The loss of product yield can be acceptable where the feed synthesis gas has a low H_2 to CO ratio and the water gas shift reaction would produce additional hydrogen.

EI has developed a cobalt catalyst, ratio adjusted, slurry bubble column F-T process that is ready for immediate commercial application in converting off-shore or remote associated gas to high quality liquid products. While the technology is distinctly different from catalysts and processes heretofore used, EI has an extensive body of information that underpins this application. This data package includes large-scale fixed-bed demonstration plant results where a supported cobalt catalyst was scaled up from a micro-tubular reactor to the complete demonstration plant that operated successfully for a year, producing 35 BPD of high quality liquid products.

Major advantages to EI technology are described below:

1. Catalyst has low water gas shift activity -- this means higher overall efficiency.

2. Stable, rugged, regenerable catalyst with multi-year life means low catalyst cost.

3. Slurry bubble column reactor design is flexible, and simple to start up, shut down and operate.

4. Simple process design means it will be easily barge mounted for offshore locations.

5. Wax production contains no catalyst fines as tend to be present in product from iron catalyzed processes, and can be straight forwardly blended with crude oil.

IX. APPLICATION OF FISCHER-TROPSCH SYNTHESIS TO OFFSHORE OIL WITH ASSOCIATED GAS

A. Conceptual Description

A gas to oil synthesis facility of the appropriate size would be built on an FPSO vessel, towed to the off-shore location and moored. The associated gas would be piped to the unit as well as the produced oil. The liquids produced could be mixed with the produced crude oil and pumped to the gathering system as shown in Figure 1 or stored and transported separately. The units on the FPSO would include a waste water cleanup system that would allow any excess water produced, that was not exhausted as steam, to be discharged into the sea or re-injected without any contaminates. The recovered wastes would be burned to raise steam.

The idea is illustrated conceptually in Figure 1. The items shown on the drawing include the gas-liquid crude oil separator, the reformer/Fischer-Tropsch synthesis system; the dissolver circuit; and product stabilization.

B. Detailed Description

The following is a more detailed description of the process units included in the above description and shown on the process flow diagram of Figure 2. The facility has the following major processing steps:

1. Produced Oil and Gas Separation
2. Sulfur Removal
3. Steam Reforming
4. Carbon Dioxide Removal
5. Gas to Oil Synthesis and Liquids Recovery
6. Liquids Stabilization
7. Produced Oil and Liquids Blending
8. Waste Water and Boiler Water Treatment and Utilities

1. Produced Oil and Gas Separation

The crude oil and gas production is separated according to standard offshore techniques producing a crude degassed oil product and an associated gas product. The associated gas product contains methane, C_2's, C_3's, and some C_4's along with H_2S and other minor volatile compounds and inerts.

2. Sulfur Removal and Recovery

The crude associated gas is fed to a zinc oxide H_2S removal unit to protect the subsequent catalytic beds.

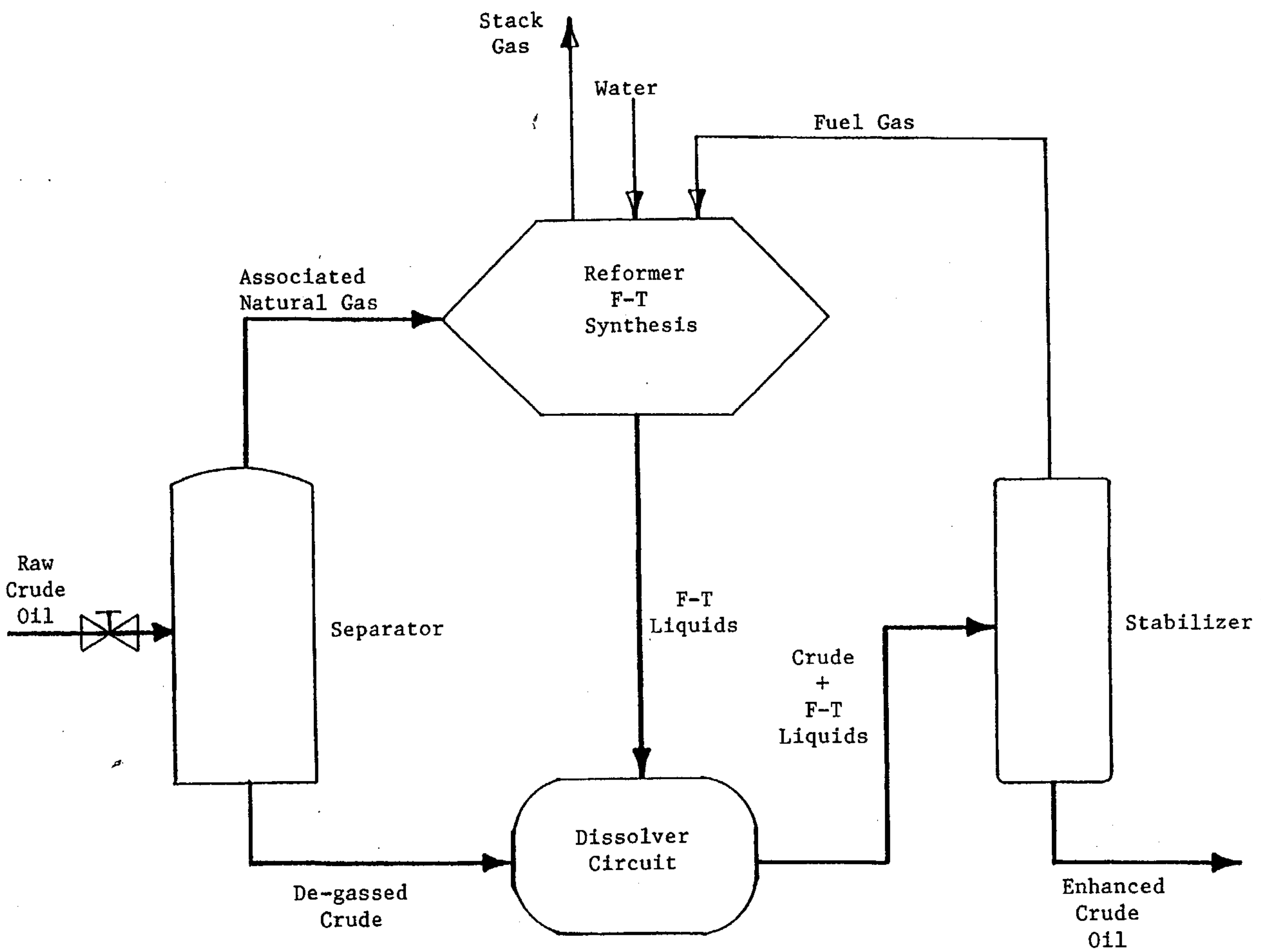


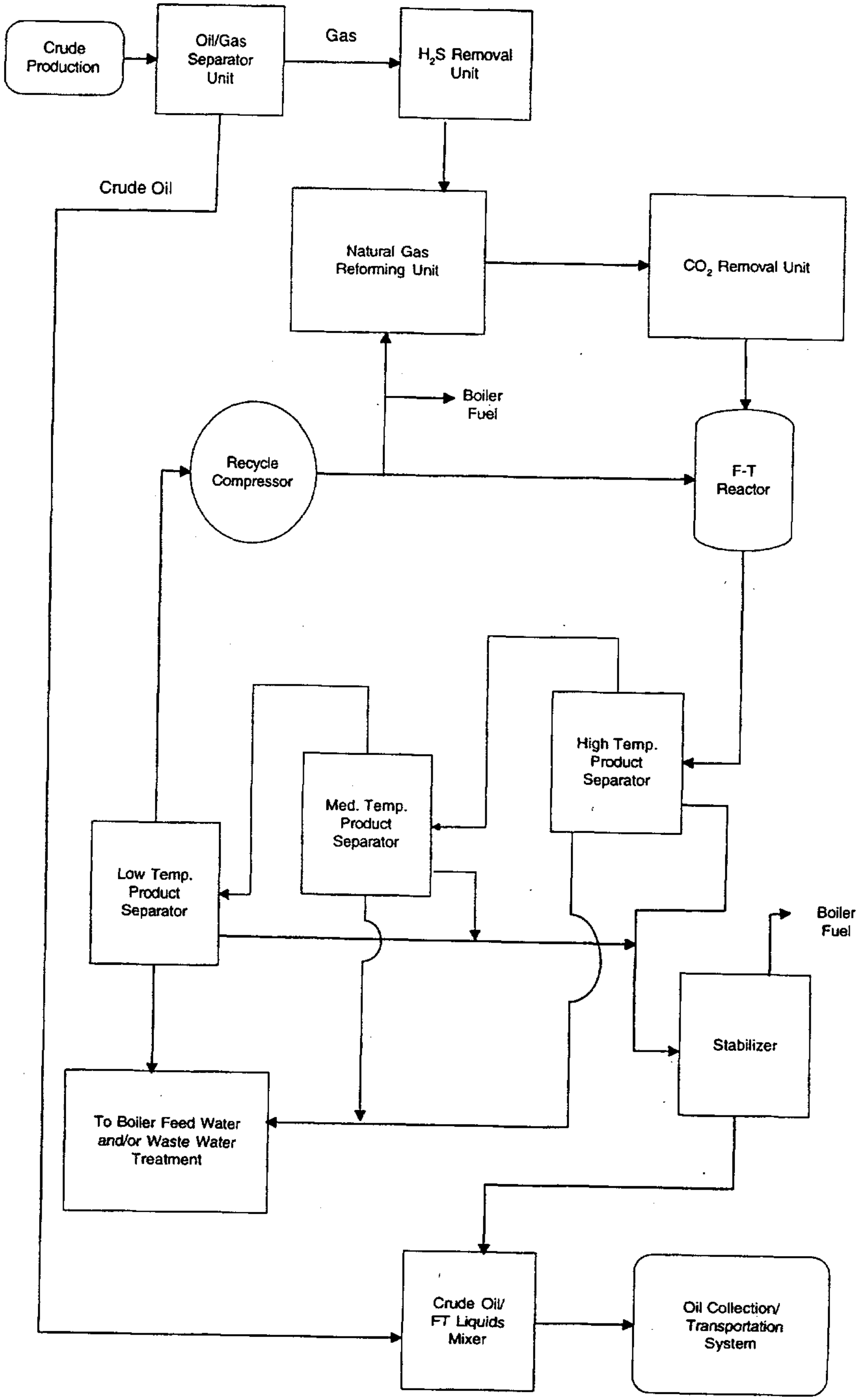
Figure 1

FISCHER-TROPSCH SYNTHESIS PROCESS

Figure 2

OFFSHORE FISCHER TROPSCH PLANT

ASSOCIATED GAS TO HYDROCARBON LIQUIDS



3. Steam Reforming

The purified associated gas stream is converted to synthesis gas in a steam reforming unit. The conversion of hydrocarbons into synthesis gas takes place with steam in a tubular furnace. The exit gas contains primarily H_2, CO, and CO_2.

4. Carbon Dioxide Removal

The CO_2 formed in the reforming unit is removed by a standard CO_2 removal system. Some of the CO_2 removed may be recycled back to the reformer to utilize its carbon value and help suppress CO_2 production. The remainder of the CO_2 is vented to the atmosphere. The treated synthesis gas contains primarily H_2 and CO.

5. F-T Synthesis and Liquids Recovery

The CO_2 free synthesis gas is then fed to the F-T synthesis unit where it is combined with gas recycled from the F-T liquids recovery system. Reaction heat is removed from the reactors by circulating pressurized boiler feed water which is then flashed to make steam.

The F-T reactor effluent is cooled in stages with water and brine. The oil-water mixture from each stage of cooling is decanted, with the oil sent to stabilization. The water phase contains alcohols and acids formed in the F-T reactor which are removed in the waste water treatment unit and burned as boiler fuel.

The unreacted gas from the separator system is compressed and recycled to the F-T reactor where it is mixed with fresh feed gas. A purge stream is taken from the recycle loop to help control the synthesis gas composition and remove inerts from the system. Most of the purge gas is used as boiler fuel. Some of the purge gas may be recycled back to the steam reforming unit.

6. Liquids Stabilization

The oil collected from cooling and separation is decanted from the water phase and sent to a stabilizer. The stabilizer distills enough light hydrocarbons from the liquids so that the vapor pressure of the liquids is reduced to an acceptable level. The vapor overhead from the stabilizer is used as boiler fuel.

7. Produced Oil and F-T Liquids Blend

If desired, the stabilized liquids are blended with the produced degassed crude off in a high efficiency in-line mixer. This blended product is sent to the oil collection system for transport to shore. Otherwise, the stabilized liquid is stored separately, and then transported to shore.

8. Waste Water and Boiler Water Treatment and Utilities

The water from the F-T reactor effluent contains alcohols and acids. This waste water is sent to a treatment system which removes residual oil, alcohols, acids and other contaminants. This waste material is burned in the boiler. The recovered water is further treated for use as boiler feed water and used as steam in the reforming unit and rotating equipment drives. Any excess water would be clean enough to discharge to the sea or to re-inject into the producing formation.

High pressure steam is generated in the reformer waste heat boilers and low pressure steam is generated in the F-T reactors. A separate high pressure boiler is used for start up and to make up any deficiencies.

Raw sea water is used for cooling purposes.

X. FFTP VESSEL TYPE

Field development predicated on use of the FFTP will likely first be appropriate to production of reservoirs in 7,000 to 10,000 ft. This is the water depth range in which a driller/producer team has just announced definitive plans to acquire an exploration/field delineation capability, a drillship, at a cost of $320,000,000 (this is a field development tool expense that approximates that projected for the FFTP, an indication of the level of costs which major offshore companies will make in order to produce deep water finds). It is a water depth where competing production capability does not currently exist, and which may be quite distant from useful tie-back structures. It is a water depth where pipe laying is not yet practiced, at least routinely. And viewing deep water exploration and production from the perspective of the owner of the foregoing , very expensive field development drillship, it is extremely unlikely that he will want to be restricted as to where he explores, finds and produces, by considerations and limits imposed on him by distance from pipeline infrastructure, i.e., by considerations for tie-back pipeline cost, the availability on his schedule of a suitable lay barge, etc. This is a strong argument for the field development independence given by use of an FFTP production system.

The foregoing being true, alternative scenarios for field development by FFTP may include:

Configuration A_ - a mini -TLP to support production controls and provide well workover capability; moored nearby, a vessel of only that size necessary to house the FFTP and to support the FFTP mooring and multiple production risers; and tandemly moored to the FFTP, a storage/off-loading vessel (FSO) which receives via separate lines, produced crude and Fischer-Tropsch liquids, and at intervals discharges these to a shuttle tanker having segregated cargo tanks.

Configuration B - a mini-TLP to support production controls and provide well workover; moored nearby, a vessel large enough to house the FTP and to provide significant segregated storage for produced crude and the Fischer-Tropsch liquids. This FFTP/FSO would at intervals discharge to a calling shuttle tanker.

Configuration C - an FFTP/FPSO (Floating Fischer-Tropsch Plant/Floating Production, Storage and Offloading vessel - see Section II - Revised Concept) which provides all the services of the three vessels of A, likewise, the services of the two vessels of B, except the well workover capability of the TLP. It is presumed that in a majority of deep water field developments that wells will be so widely dispersed to obtain high production rates that it will be common practice that well workover are provided on an 'as required' basis by leased semi-submersible or drillship.

In light of the cost of a single mooring system and that of any single deep water production vessel, be it TLP, FSO or FPSO, little argument can be made for the Configuration A system which entails use of three vessels, two of which are bottom moored. The third vessel, the FSO, would use a substantial DP system to minimize the strain the FSO places on the FFTP tandem moor and, through the tandem moor, the added load placed on the FFTP bottom moor.

As to Configuration B, this arrangement would be most appropriate in development of relatively small to medium size fields where, one, multiple wells from a single drill template will substantially drain the field, workover being performed from the TLP moored over the template. It is anticipated that in a few short years both the TLP and the FFTP/FSO would be moved to another field much like the first.

Configuration C is that recommended as the basis for evaluation of the FFTP concept. A multiple use vessel it will have greatest utility for the money spent, i.e., provide best production efficiency as measured by Production System Cost/BOE Exported. Appendix C postulates a variant of this Configuration C wherein wells are not so widely dispersed as to preclude workovers and completions from an upgraded FFTP/FPSO to be designated a FFTP/FPDSO.

XI. FISCHER-TROPSCH FLOATING PRODUCTION, STORAGE AND OFFLOADING VESSEL (FPSO) COST

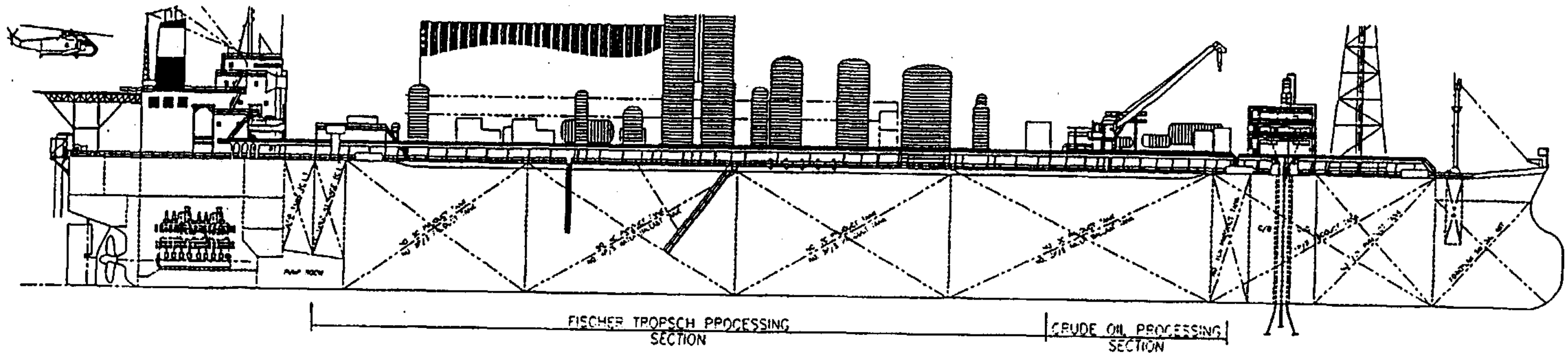
A. Vessel Design

Deep water province development will always focus on obtaining a high crude oil production rate because a strong desire will exist to recover quickly the cost of field development. A first consequence of this is that the FFTP/FPSO (hereinafter referred to as the FFTP) must have large storage capacity to permit large and relatively infrequent offtake operations. A converted tanker will have the needed storage capacity and will usually be less costly than a purpose built vessel. Our inital study was done assuming conversion of a Suezmax tanker. Discussion of these initial results with firms who potentially would use the FFTP approach indicated that they were interested in a plant that would process more gas than initially envisioned. Since a Suezmax tanker couldn't accomodate such a large plant, a design and cost estimate for a plant mounted on a Very Large Crude Carrier (VLCC) was developed.

For the initial study, the EI equipment list and purpose built barge layout was used and two Slurry Column Bubble Reactors were substituted for the original six Fixed Bed Reactors, fitting all the equipment aboard a Suezmax tanker. The layout is shown on Figures 3 and 4. The FTP is fitted aboard from approximately 30% aft of the forward perpendicular to 85% aft of this perpendicular. Just forward of the FTP a crude oil processing, gas and produced water separation facility has been installed. All are nominally correctly sized for an EI specified Fischer-Tropsch plant capable of handling 56,000,000 cf/d of associated gas derived from 22,400 bbl/d of crude, a GOR of 2,500.

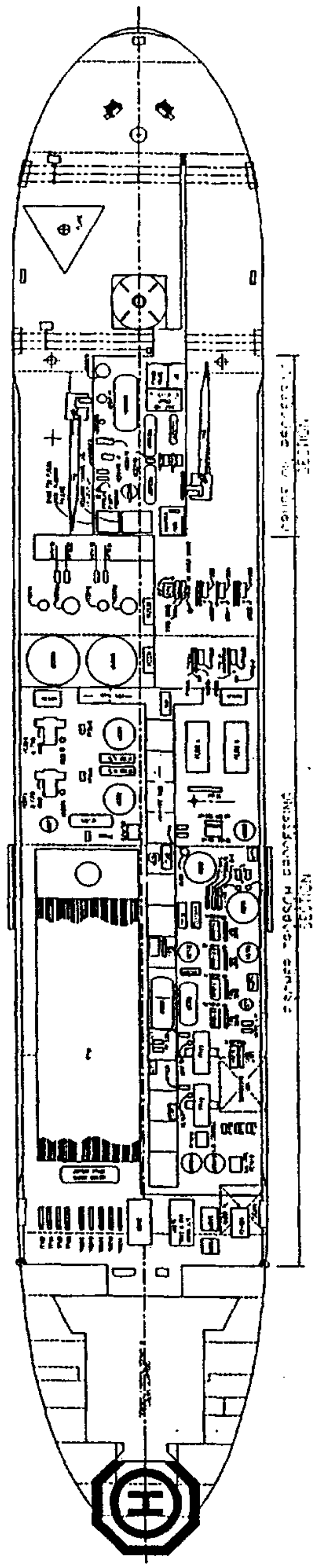
Forward of the crude processing facility is the internal turret through which is obtained well product; the turret also mounts at its bottom a spider to which the vessel mooring lines are made fast. On the port side just forward of the turret a flare tower is provided to routinely handle those gases not processed to Fischer-Tropsch products nor consumed as fuel; these gases include any CO_2 to be dispersed. The flare capacity is designed by the gas flow which must be handled in the event of a plant emergency shutdown; until this is better specified it is assumed to be the 56 MMCF/d rate of the FTP feed. Crew accommodations and plant offices are aft as is a newly installed helicopter pad for resupply and for crew rotations.

Figure 5 illustrates the field deployment of the FFTP as currently envisioned. Two alternate mooring concepts were evaluated, the conventional chain and wire catenary and the evolving, advanced, deep water taut line synthetic mooring which is shown in Figure 5. Also shown is the offloading shuttle tanker tandem moored to the stern of the FFTP. A floating product transfer hose runs from a manifold at the stern of the FFTP to a midships manifold on the shuttle. The shuttle shows DP thrusters; these would only be present if dedicated shuttle tankers are used. It is not anticipated that this will be required; standard equipped tankers routinely offload VLCC's and ULCC's in the U.S. Gulf, these tanker types being of too great a size to be accommodated in any U.S. port.



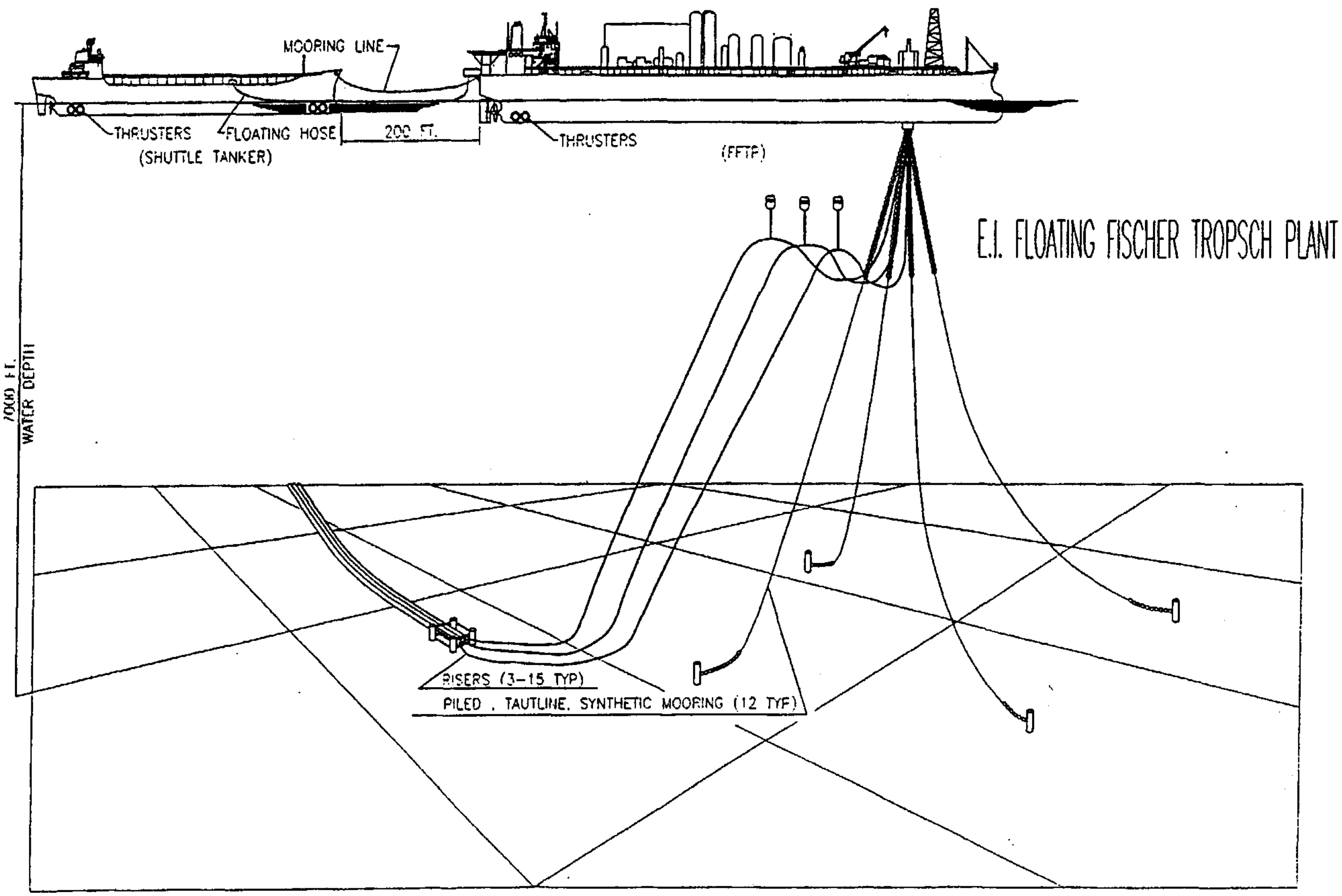
E.I. FLOATING FISCHER TROPSCH PLANT

Figure 3



E.I. FLOATING FISCHER TROPSCH PLANT

Figure 4



FFTP FIELD DEPLOYMENT

Figure 5

B. Vessel Cost Estimate

There are a large number of Suezmax tankers operating and nearing the end of their useful life, i.e., they will soon require major rehabilitation to realize useful life extension. Also, they will soon no longer be allowed to operate as tankers due to OP-90 requirements for double hulls. An FPSO is not required to have a double hull. A 135,000 DWT tanker recently changed ownership for $7.25 million; it was built in 1977. A 20-yr life extension would see it operating with a 40-yr hull; this is old but not out of the question. For comparison, the 210,000 DWT FPSO Tazerka was built in 1968 and has been in FPSO service in 460 ft of water off Tunisia since 1982.

Criteria and design for life extension have both been much enhanced by the American Bureau of Shipping over the past decade. If a vessel built in 1987 were to be chosen for use as an FFTP hull cost would more than double with no assurance that less extensive modifications would be required to obtain a 20-yr extension of useful life. Twenty years has been assumed as the planned for useful life of the FTP. Life extension is largely a matter of steel replacement to recover lost structural strength, coatings renewal to preserve structural strength, and the taking of necessary corrosion control measures to avoid material loss.

Accommodations aboard the Suezmax tanker will be insufficient to meet FFTP needs. An earlier EI study specified an FTP operating shift as comprised of 11 persons. However, the plantship crew also includes marine operating personnel, plant and ship maintenance persons, a steward's department to feed and housekeep for the crew, oil and gas production control persons (perhaps optional depending on the field produced) and clerical types. In total, the crew may number as many as 65. There will, accordingly, be major change to the existing ship's accommodation package.

Major structure will be added as foundations for the FTP equipment, many of which are of substantial weight. These loads must be distributed for stability considerations and carried efficiently into the hull for strength considerations.

Vessel systems must be rehabilitated and in some instances significantly augmented, e.g., the fire water and emergency deluge systems, because of the new vessel role as host to the FTP. Affected systems include:

- Electrical
- Product transfer and discharge (crude and FTP)
- Ballast system (add tank nitrogen blanket for corrosion wastage suppression)
- Fuel oil (diesel) fill and transfer
- Lube oil
- Ship's service air
- Fire water and deluge
- Deck and Machinery area drains
- Potable water
- Sewage
- Product tank inert gas system
- CO_2 distribution

- Hydraulic
- Steam
- Life saving systems (add larger enclosed lifeboats and associated davits)

The earlier EI FTP design quite adequately handled vessel requirements for power generation, compressor and pump drives (steam), and provision of circulated sea water for steam condensing. In addition, product offloading pumps were provided -- these duplicate those already aboard the Suezmax tanker and will be eliminated at a future date. Similarly, the 1500 KW generator needs to be reviewed. Until a new electric load analysis is completed it is not possible to know if this generator is excess or inadequate; the ship itself carries three 800 KW generators. With addition of the electric drive DP thrusters, however, and the expanded conditioned accommodation space it is probable that additional generation will be required.

Finally, it is necessary to address the crude processing plant and flare additions. In each of three instances of design and installation of these facilities on three FPSO's in the past five years, the budget for these items was virtually the same; about $6,000,000. None, however, had to handle so much gas, 30 MMCF/d being the largest; account is made for this in the FFTP cost estimate which follows:

For the VLCC case for handling 200 MM SCFD of natural gas feed, the design was revised as needed, and the costs adjusted using appropriate scaling factors. Particulars of the Suezmax and VLCC FFTP's are as follows:

FFTP Particulars	**Suezmax**	**VLCC**
Length, Overall	908'-9"	1030
Length, Between Perpendiculars	876'-0"	-
Breadth, Moulded	145'-8"	175
Design Draft	79'-0"	85
Draft, Summer Loadline	55'-0"	-
Liquid Cargo Capacity, bbl	1,063,700	1,500,000
Crude Production, bbl/d	22,400	75,000
FTP Production, bbl/d	5,600	20,000
Offload Frequency, Maximum	38 days	-
Displacement, DWT	135,000	200,000

COST ESTIMATE: TANKER CONVERSION AS HOST TO FTP, M$

Element		Suezmax	VLCC
Vessel acquisition		7,250	15,000
Mobilization to conversion yard		500	600
Life extension measures			
Steel replacement		2,000	2,720
Coatings removal/renewal		3,500	4,760
Corrosion inhibition;	anodes	200	272
	active system	50	68
Engineered systems and structures installations			
FTP foundations and structure upgrades		12,000	24,000
New/upgraded ship's systems, and equip.		8,000	10,000
Accommodations upgrade		500	500
Mooring/Internal Turret (taut line, synthetic)		37,000	65,000
Crude processing and flare tower		7,000	16,240
Naval architecture, marine engineering and constr. supervision; owner's rep.		1,750	2,940
TOTAL		71,250	142,100

XII. FFTP STATION KEEPING

Three options exist for keeping a vessel on site to receive well product, to field inject produced water, and to export 'dry', stabilized, crude (dewatered/desalted/degassed/Reid Vapor Pressure adjusted) and produced FTP; these are dynamic positioning, mooring via attachment to the sea floor, and a combination of these.

Dynamic positioning (DP) entails a decision to incur greater operating expense (opex) to avoid acceptance of greater capital expense (capex). At the level of the current investigation, because it is focused on operation of a fixed floating platform in water depths not heretofore attempted, it is not possible to assess rigorously nor to discriminate accurately between the systems on the basis of their respective operating and capital costs. The capex of each is significant (e.g., one DP shuttle tanker operating in the North Sea to offload floating storage units (FSU's) uses four 3.5 megawatt dynamic positioning thrusters). Dynamic positioning of the FFTP, a larger vessel with a tight watch circle, would require at least as much DP power and a control system of significantly greater sophistication and automatic positioning capability; capex would not be inconsequential. On the other hand, technology advances are reducing deep water mooring capital expense.

Capability to moor in deeper waters with lines of increased buoyancy (thus reducing platform loads, and hence, required waterplane area/structure and cost) and reduced line cost (sheathed polypropylene rather than chains and wire cable) will favor production via floaters at ever greater distance from pipeline infrastructure. Recent improvements in mooring line deployment patterns have reduced mooring costs while facilitating bringing of more product risers, hence more product, to the floating production vessel. The realized increased field drainage rate improves project internal rate of return, which is very important to field development decisions. Adoption of a newly developed internal mooring/product receiving turret design has reduced mooring strains on the vessel and thus the tons of vessel structure necessary to manage these loads. Like the arrival of synthetic mooring lines, the improved mooring line deployment patterns and the internal turret will hasten use of floating production systems in the deep water Gulf.

The system recommended for the FFTP is mooring lines supplemented by a DP assist system. Reliability of station keeping was the criterion most determinant of the system recommended. Certainty of fixing the FFTP on site is best given by the selected system. Reliance on DP alone would entail the accepting of two unacceptable risks, power loss and control failure. Each, when occurring, requires, at minimum, instant shut-in of the wells and shutdown of the processing plant; in the extreme, each threatens severance of production risers and well control umbilicals with attendant, potentially major, adverse consequences for the environment. Power loss puts the FFTP at the mercy of the forces of nature; control failure manifests itself in "drive-off" respecting the position to be kept. Neither is an acceptable risk in an initial deployment of an FFTP. There are several reasons why it is recommended that mooring lines be complemented by DP assist.

First, on those occasions of coincidence of wind, wave and current forces, or on the occurrence of 50-yr or 100-yr storm forces, loads on the mooring can be eased by the DP thrusters. Second, in periods of offloading (frequent on high production rate fields, every 10 to 15 days, less frequent on medium to low producing fields, every 30 to 60 days) the DP thrusters make conducting of operations to interface the shuttle tanker, its approach, its presence, and departure, more safe, particularly in periods of poor weather and of unaligned wind, current and wave forces.

Two cost estimates are presented here for recommended station keeping systems, for the Suezmax case. One is for using conventional mooring lines in catenary deployment; the second using synthetic lines in taut line deployment.

CATENARY MOORING, CONVENTIONAL SYSTEM (STEEL LINES)

Element	**Cost, $**
Internal turret and swivel stack	10,000,000
Hull modification to accept turret casing and mooring loads	3,000,000
Mooring piles/anchors	3,000,000
Chain	20,000,000
Wire (for chain-wire-chain system)	4,000,000
Thrusters/electric motor drives and controls	2,000,000
Subcontractor Design and Test, ABS Certification	2,000,000
Installation (including attachment of risers)	7,000,000
TOTAL	$51,000,000

TAUT LINE MOORING, ALTERNATIVE SYSTEM (SYNTHETIC LINES)

Element	**Cost, $**
Internal turret and swivel stack	9,000,000
Hull modification to accept turret casing and mooring loads	2,000,000
Mooring piles/anchors	2,000,000
Chain	4,000,000
Wire	-0-
Synthetic lines	10,000,000
Thrusters/electric motor drives and controls	2,000,000
Subcontractor Design and Test, ABS Certification	2,000,000
Installation (including attachment of risers)	6,000,000
TOTAL	$37,000,000

XIII. FISCHER-TROPSCH PLANT AND FFTP COST

A base process design and estimate was prepared for a barge mounted Fischer-Tropsch plant producing 6,000 Bbl/d of liquid fuel product A sized and priced equipment list was prepared. This estimate was then scaled to a 20,000 Bbl/d plant. Costs are based on end of year 1996 prices. Details of the estimate and plant design are given in Appendix A.

For the 20,000 Bbl/d plant the total capital cost, including catalyst and chemical inventories, is estimated at $420 MM, and the operating cost, including catalyst and chemical, labor, and feed costs, at $72 MM/year. Natural gas feed cost is assumed to be $ 0.50/MM BTU.

The total capital cost for the FFTP, including the above Fischer-Tropsch plant cost and the FPSO cost is estimated to be $562 MM. Operating cost for the FPSO has not been addressed. This is dependent on the details of the crude oil production being done in parallel with FTP.

XIV. FFTP/FPSO COST AND FINANCING

Section 13 and Appendix A present a $562 million estimate of FFTP/FPSO system cost, an FPSO plus mooring cost of $142 million and an FTP cost of $420 million. At a production rate of 25,000 bbl/d of F-T liquids the per unit capital cost of production is $22,500/bpd. This compares favorably to the $24,000/bpd unit capital cost of production quoted by Exxon (Houston Chronicle, 10/31/96) for a $1.2 billion 50,000 bbl/d Fischer-Tropsch plant which is the subject of discussion between Exxon and Qatar. The EI plant would obtain 25,000 bbls from 200 mmscf of gas (8 mcf/bbl); the Exxon plant would obtain 50,000 bbls from 500 mmcf (10 mcf/bbl). It should be noted that the EI plant addresses "wet" gas; were it to address "dry" gas the yield would be 20,000 bbls from 200 mmcf of gas, precisely the 10 mcf/bbl advertised by Exxon.

The foregoing is presented to validate, before proceeding further, the EI FFTP/FPSO system cost and productivity estimates.

Lease Rates for Offshore Deepwater Production Rigs - A major operator of producing offshore leases noted to EI in the course of this study that operators frequently elect to lease rather than to own drilling and production platforms. In Table I are cited representative instances of such leases; the capital cost of equipment leased and the effective daily lease rate are noted.

Table 1 - Representative Offshore Production Vessel Lease Rates

1. BP has contracted from Reading and Bates (Offshore, 11/95) a $300 million drill rig at $220,000/day; contract duration is 5 years (Offshore, 12/96 states the rate to be $200,000/day.

2. Conoco has contracted from Reading and Bates a drillship and drill rig of combined value $320 million. The 6-year contract will generate total revenues of $350 million, an effective day rate of $160,000 assuming full time availability and utilization.

3. Pride has purchased from Noble Affiliates multiple jack-up rigs for a combined sum of $265 million. Pride states these will generate revenues of $120 million/year, an effective day rate of $329,000 for this fleet of rigs. (It is unstated that the rigs will be upgraded to earn the premium day rates that these figures imply; upgrading costs must be added to the acquisition cost before premium rates can be earned).

4. PGS has placed a $200 million vessel on a 7-year contract which will see revenues totaling $350 million generated, an effective day rate of $137,000.

5. Noble Affiliates will convert eight 300 ft water depth capable submersibles into eight 3000 to 6000 ft water depth capable semisubmersible drill rigs at an average cost of $80 million/rig; anticipated day rates are $105,000 to $120,000. An initial unit, the EVA-4000, is contracted to Shell for a term of 4-years plus an option year (Offshore, 1/97).

6. Sedco Forex (Offshore, 2/97) projects new build deepwater semisubmersible drill rigs to cost $250 million and to command day rates of $180,000. Current rig upgrades can cost as much as $155 million and earn a day rate of $140,000.

7. Rowan Cos. Inc. (Oil and Gas Journal, 11/25/96) will deliver out of the yard in June 1998 the Gorilla V an enhanced design 400 ft water depth capable jack-up at a construction cost of $175 million; a day rate of $170,000 is expected when a contract for use is committed. The company will build on spec Gorilla VI and VII at an additional total cost of $380 million.

In the above cited examples of equipment leases contract periods are in the range of 4 to 7 years and day rates per million of construction/acquisition/upgrade costs are as follows:

	Example	*Day Rate/Capital Expense*	*Extension, $/mm$*
1.	BP	$210,000/$300 million	700
2.	Conoco	$160,000/$320 million	500
3.	Pride	$329,000/$265 million	1240
4.	PGS	$137,000/$200 million	685
5.	Noble Affiliates	$105,000/$80 million	1310
6.	Sedco Forex	$180,000/$250 million	720
7.	Sedco Forex	$140,000/$155 million	900
8.	Rowan	$170,000/$175 million	970

The foregoing has been developed to test the validity of a projected lease rate for the FFTP/FPSO when that has been developed later in this section. Before proceeding to determination of this 'appropriate' lease rate for the $562 million FFTP/FPSO, however, time is taken here to cite one more example of a vessel deployment which strongly supports the economic viability of the EI FFTP/FPSO.

In the February 1997 issue of Offshore it is reported that Norsk Hydro has contracted Umoe Haugesund to deliver a production semisubmersible 'floater' for start-up in September 1999. Construction cost is $590 million; the vessel will generate daily revenues of $2,500,000 (exporting 125,000 bbls/d at an assumed $20/bbl). In comparison, the EI FFTP/FPSO of Appendix A processes 200 mmcf/d into 25,000 bbls of F-T liquids and exports this plus 150,000 bbls/d of processed crude; it will generate daily revenues of $3,625,000 (25,000 bbls/d X $25/bbl + 150,000 bbls/d X $20/bbl). The productivity of the Norsk Hydro vessel as measured by its annual revenue dollar per dollar of construction cost (365 X 2,500,000/590,000,000) is 1.55; the productivity of the EI FFTP/FPSO is 2.52 (365 X 3,625,000/525,000,000). Were it permissible that the FFTP/FPSO have as low a productivity as the Norsk Hydro vessel then the FFTP/FPSO could have a construction cost as high as $854 million (365 X 3,625,000/1.55).

<u>Determination of Lease Rate to Cover FFTP/FPSO Construction and Operating Costs</u> - The Rowan Gorilla V was built with U.S. Maritime Administration (MARAD) Title XI mortgage guarantee financing. Twenty-five year financing can be obtained under a MARAD loan guarantee; this guarantee allowed Rowan to find financing at an interest rate of 6.1 percent. It is permissible

to finance as much as 87.5 percent of qualifying construction costs. Presumably the balance, 12.5 percent, is equity invested in the project. In the offshore industry equity can frequently be attracted to a project at an internal rate of return (IRR) on equity as low as 15 percent. Respecting the EI FFTP/FPSO the foregoing results in the following:

Total Construction Cost	$525,000,000
Equity Amount at 12.5 Percent	66,000,000
Mortgaged Amount at 87.5 Percent	429,000,000
Annual Mortgage Payment, 25-yr at 6.1 Percent	36,250,000
Annual Return to Equity at 15 Percent IRR	13,750,000
Annual Operating Cost*	35,000,000
Total Annual Costs	$ 85,000,000

*Derived from reference to U.S. Department of Transportation, Federal Highway Administration, Final Report METHANOL PLANTSHIP PROJECT, Contract No. FHWA-RD-93-091, June 30, 1993. Includes costs for Management and Administration, Operators and Operator's Fee, Insurance, Maintenance and Repairs, Inspections and Certifications (Plant, Machinery and Hull), and Accruals for Catalyst Replacement, Periodic Turn-Arounds and 16th Year FFTP/FPSO in Drydock Overhaul (assumes field lease holder supplies feedstock and export shuttle tanker service).

If one assumes 96 percent utilization (350 d/yr), the minimum required FFTP/FPSO day rate equals $85,000,000/350 days = $243,000/day.

At the foregoing computed required day rate the day rate/million of construction cost is $463. This compares very favorably with the rates developed in Table 1 which are in the range $500 to $1300. Striking the two highest from the eight examples given (they appear too lucrative and apply more to upgraded existing vessels rather than to new construction of enhanced capability vessels) the average for the remaining six examples is $746. If this figure can be obtained for the FFTP/FPSO a lease period contract in the 4 to 7 year range might permit vessel financing to be obtained; if only the computed $463 is attainable an operating contract for the life of the mortgage might be required to obtain construction financing. Further, it should be recognized that if a day rate/million of construction costs somewhere near the mid-point between $463 and $746, e.g., $600, can be realized then relief can be found on financing terms and a greater IRR can be used to attract equity investors.

Finally, it should be noted that the offshore operator who suggested that leasing be considered then went on to say that if a lease rate in the order of $250,000/day could be offered then leasing interest in the FFTP/FPSO would be found among offshore operators; the foregoing would indicate that the EI FFTP/FPSO is within real striking distance of this goal and the opportunity it represents to the nation's energy users, the deepwater operator and the entrepreneur, alike.

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