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HEAVY OIL RECOVERY PROCESS

CONCEPTUAL ENGINEERING OF A DOWNHOLE METHANATOR AND PRELIMINARY ESTIMATE OF FACILITIES COST FOR APPLICATION TO NORTH SLOPE ALASKA

Contract: DE-FG 01-89 CE 15446

FOURTH QUARTERLY REPORT

ABSTRACT:

Tasks No.8 and 9 have now been completed. The Final Report (Task No.10) is under preparation. The entire project will thus be completed on schedule and within budget. The project results are the subject of a forthcoming SPE paper, submitted for presentation at the International Arctic Technology Conference, in Anchorage, Alaska May 29-31, 1991. The paper will be co-authored by Dr. Michael Gondouin, S-Cal Research Corp. and by Mr. Joseph M. Fox, Bechtel Group, Inc.

Results of Task No.8:

The costs of materials and of manufacturing the Downhole Methanator, including those of the upper cross-over section, the valve section, the connection joint, the lower cross-over section, the reactor head and the reactor hanger have been estimated, based on the design and specifications developed in Tasks No.5 and 6, on price information from vendors, estimated machining man-hours, estimated detailed engineering and testing man-hours, overhead, royalties and profits.

The cost of drilling and completing the large-diameter vertical cased well and the twin horizontal drainholes in the West Sak reservoir was determined on the basis of current costs of materials delivered on the North Slope of Alaska, current rates for drilling rigs on that location, estimated rig times based on the experience of the drilling department of a North Slope major oil operator, and on the prevailing costs of oil service companies for this area. The well specifications are those obtained as a result of Task No.6

To take into account the technical risk related to the novelty of the Downhole Methanator and to the fact that no horizontal wells have yet been drilled in the West Sak reservoir (although many have been drilled on the North Slope into other reservoirs by this experienced operator), a contingency factor of 50% was applied to both the cost of the Downhole Methanator assembly and to that of the cased well and drainholes. This brings the total cost of each well equipped with a Downhole Methanator and two horizontal drainholes to 11 Million Dollars at present value (including contingency).

Results of Task No.9:

The preliminary design of surface facilities presented in Fig.4 and the specifications given in Table 4 served as a basis for a partial optimisation of the process. This was done using a computer program of the Bechtel Group, Inc. to establish the material balance, the heat balance and the steam balance of this basic process flow diagram for various feed conditions. Two different natural gas feed

compositions were considered, corresponding respectively to that of the separator off-gas from the Prudhoe Bay field and that of the residue gas from the Prudhoe Bay NGL extraction plant.

It was found that, for either feed composition, the steam reformer furnace heating duty corresponding to that of one train of the New Zealand GTG plant could supply at least two Downhole Methanators of the capacity and design specifications established in Tasks No. 1, 3, 5 and 7.

An important parameter in the design of steam reformers is the steam/carbon ratio required to prevent coking of the catalyst, by the Boudouard reaction. It was found that, when using the leaner feed gas, a carbon/steam ratio of 2.0, which is acceptable for most commercial steam reforming catalysts, 226 MMSCF/D of Methanator feed (1 CO, 3.5 H₂) containing 6 % of unconverted Methane, could be produced from a single train of proven design. This amount of Syngas could be handled by two Downhole Methanators of length, and capacity only 6.25 % greater than those of the basic design. The corresponding oil production rates of the associated drainholes would then average 16,250 B/D.

The required auxiliary facilities, including electrical power generation, inert gas generation, flare and Ammonia synthesis unit were considered, in addition to the major process equipment shown on Fig. 4.

For increased reliability, electrically-driven auxiliaries (BFW pump, CO₂ recycle compressor, etc...) powered by an independent gas turbine-driven generator and a turbine exhaust waste heat auxiliary start-up boiler were selected as start-up and emergency facilities.

In view of the relatively small volume of Ammonia required to stabilize the swelling clays of the West Sak formation, and of the need for a liquid Nitrogen plant as inert gas generator, the preparation and compression of the Ammonia Synthesis gas mixture was simplified and the Casale process was preferred to the Haber process. In this process, the electrically-heated synthesis reactor and compact heat exchanger lend themselves to modular construction used on the North Slope of Alaska.

Because these surface facilities exclusively use proven technology, with comparable units already built and operating elsewhere, the only remaining technical risk is that of packaging the equipment into a set of transportable Arctic modules, according to the usual practice on the North Slope. In view of Bechtel's experience in this domain, a contingency factor of only 25% was applied to the cost estimates. These were derived from recent engineering and cost estimating work done by Bechtel, partially funded by the California Energy Commission.

On this basis, the over-all capital cost required, per barrel of daily oil production by the novel process is compared to that which was actually spent to bring on stream various marginal offshore fields, including one in the North Sea and the Endicott field, the only offshore producing field in the Beaufort sea. The additional expense of building two artificial islands and a causeway made the Endicott a marginally-attractive project, at a time when North Slope oil prices were about 15 \$/B. At currently higher oil prices, the allowable capital cost could be correspondingly increased without jeopardizing the project viability.

The cost of the surface facilities is much greater than that of the wells and of subsurface equipment. Any savings resulting from further optimization of the design of surface facilities will dwarf savings

achievable by an improved design of the downhole Methanator assembly.

This is a favorable situation because surface facilities are based on well-known, proven technology for which experienced engineering contractors, such as Bechtel, have repeatedly demonstrated that large savings may be obtained by systematic engineering optimization.

In the case of the Endicott field, large savings were achieved by the use of mini-modules, transported via the TAPS haul road. Another approach which appears promising is to build the entire train on the deck of a single barge, at a location where labor costs are lower than on the North Slope of Alaska. This would eliminate a large portion of the labor cost associated with unloading, transporting and connecting modules on the North Slope. It would also reduce the need for gravel pads and piling supports. Another approach would be to consider the use of autothermal steam reformers and/or partial oxidation reactors to take full advantage of the availability of gas at a higher pressure than 400 psig. These are only a few of many options to be evaluated in an engineering optimization, to be done in Phase 2.

To reduce the technical risk associated with the detailed design, construction and operation of the downhole reactor assembly, a test program of the various elements should also be done in Phase 2.

Finally, a pilot field test in a heavy oil field located in a region where construction costs are lower than in the Alaskan Arctic must be conducted over a sufficient length of time to acquire operating experience with the novel process, prior to its application to the more hostile and costly environment of the West Sak field.

In the previous economic analysis for the West Sak, no cost was attributed to the natural gas consumed in the Syngas plant, because this gas has no market in the foreseeable future. This gas being used for additional oil production by an Enhanced Oil Recovery process, it was also assumed that it would be exempt from Alaskan royalties and severance taxes. This appears to be a pre-requisite to the application of any steam injection method to the development of North Slope heavy oil, unless oil prices remain above 30 \$/B (in 1990 Dollars) throughout the fields life. This being unlikely, the subject of exempting natural gas used for EOR and field operations should be addressed by the State of Alaska Department of Natural Resources to cover not only in-field use but also the use of gas imported from an adjacent field.

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9. Task No.8:PRELIMINARY COST ESTIMATE OF SUBSURFACE FACILITIES

9.1-DRILLING AND COMPLETION COSTS OF VERTICAL WELL AND DRAINHOLES

Because the depth of the West Sak reservoir varies greatly (2,000-4,500 ft according to the latest published information of Ref.46) the well cost will vary throughout the field. For cost estimating purposes, the depth of the average vertical well was taken as 3,000 ft, with two horizontal drainholes of 300 ft radius of curvature and each with 3,000 ft horizontal reach.

The vertical well is designed to be completed with a 24.5 in. OD casing, as specified in Table 3 (see 3rd quarter report). Drilling is assumed to proceed with an existing rig currently available on the North Slope (Nabors 18-E) for which current rates were provided by a major Alaskan Oil Company. Estimated drilling times are based on the experience acquired by that company's drilling department when drilling deeper wells through the same formations in the general area of the West Sak. A list of the required sequence of operations is given in Table 5. The casing includes connection joints of the type described on Fig. 28. Two to four such joints will be installed to

connections to ultimately as many as eight drainholes, of which only two will be drilled initially. The other drainhole pairs may be drilled at a later date into the reservoir zones which are not adequately drained by the first two drainholes. Consequently, the injection time fraction of each "huff and puff" cycle initially starts at a value of 50% and declines later to 12.5%, as the heated zone increases in size.

The well work-over corresponding to the addition of the second pair of drainholes may be scheduled at the same time that a catalyst change is required (about 2 years after start-up). The work-over cost and periodic catalyst replacements are deferred expenses which were not included in the initial well cost, but which are part of the Field Operating and Maintenance costs factors applied in the economic analysis. Although four major sands were identified as suitable candidates for steam injection in the West Sak, in many areas of the field, fewer than eight drainholes may be sufficient, with at least two being connected to the Downhole Reactor Assembly, under the "huff and puff" mode of operation considered in Section No. 5. Some of the drainholes may ultimately be dedicated to a single mode of operation, if a steam flood is implemented to replace the cyclic injection. Because of the relatively low permeability of the West Sak reservoir, this change in the mode of operation is likely to occur in the latter part of the field's life. Such changes, and the costs associated with them, are generally included in the operating expenses.

9.2-COST ESTIMATE OF DOWNHOLE EQUIPMENT:

The Downhole equipment consists of the Downhole Reactor Assembly, located at and below the reactor head/hanger, and the Reactor Overhead Assembly, located above it. These two assemblies are run-in and

installed respectively before and after drilling and completion of the first pair of drainholes.

Costs of the major materials listed in Table 6 for the Downhole Reactor Assembly were obtained from vendors.

Design, fabrication and testing costs were obtained from estimated man-hours and labor rates for the Gulf Coast.

The costs of major materials and of the valves, instrumentation and controls for the Reactor Overhead Assembly were derived from vendor quotes on the West Coast. They are listed in Table 7.

From a comparison of Tables 5, 6 and 7, it appears that the total cost of the Downhole Equipment is about twice that of the well and drainholes. Even with a 50% contingency factor, the total cost of the well and its complete equipment is only about 11 million Dollars. Gravel costs have not been estimated, because it is assumed that the roads and unloading facilities of the Kuparuk unit (Fig. 32) would be used for the West Sak, at a nominal cost, since the West Sak development would take place more than 10 years after the start of the Kuparuk field, i.e. long after these facilities have been depreciated. It is likely that, to reduce the environmental impact, the State of Alaska would not grant permits for any significant extension of existing roads and facilities even if the oil operators of the West Sak could not come to an agreement with the owners of the underlying Kuparuk.

10.-Task No.9:PRELIMINARY ENGINEERING AND COST ESTIMATE OF THE SURFACE FACILITIES:

10.1-PRELIMINARY SIZING OF THE STEAM REFORMER FURNACE:

As part of the New Zealand GTG project, Bechtel has designed and

built large steam reformer trains, which are currently operating to convert a CO₂-rich natural gas into Syngas, as a first step of Methanol synthesis. The heating duty of these existing steam reformer furnaces was taken as the main parameter to determine the size of each train to be used for the West Sak. The main difference between the Syngas required for Methanol synthesis and that required the Downhole Methanators is that the H₂/CO ratios are different: 2/1 for Methanol vs. 3.5/1 in the present case. In order to achieve a 3.5/1 H₂/CO ratio, it is necessary to increase the CO₂ content of the steam reformer feed by means of a CO₂ recycle stream (see Fig. 4), taken from the effluent of the CO₂ removal unit (such a unit is unnecessary for Methanol synthesis).

10.2-PRELIMINARY PROCESS OPTIMIZATION:

The most abundant source of natural gas on the North Slope is the Prudhoe Bay field, where presently more than 5 BCF/D of gas are re-compressed and re-injected into the Prudhoe Bay gas cap. Two main sources of gas are available: 1) the separator off-gas, and

2) the residue gas from the existing NGL/EOR plant, with a present capacity of about 3.5 BCF/D.

A major concern in the design of steam reformer plants is to prevent coke deposition on the catalyst surface. For this purpose, a large excess of steam is used in the reformer tubes feed mixture. The allowable steam/Carbon ratio for most commercially-available catalysts ranges from 2 to 4. The excess steam, which acts as diluent, re-appears in the tubes effluent and must be re-condensed. This increases the size of the waste heat boiler and of all the auxiliaries required to prepare and to handle the boiler feed water (BFW). Quantitative

guidelines about the selection of steam reformers operating parameters have been derived from Ref.46.

A Bechtel proprietary process simulator was used to begin this process optimization. Table 8 shows the heat and material balances obtained when the steam reformer feed is the Prudhoe Bay separator off-gas, with a steam/carbon ratio of 3. The heat rate in the steam reformer furnace required to supply two Downhole Methanators of the capacity presented in Table 2 (see 2nd Quarter report) corresponds to 98.7 % of that of one train of the New Zealand GTG plant. The power required for the CO₂ recycle compressor is then 3,268 BHP and the CO₂ removal unit extracts 3200 lb.mol/h from the cooled effluent from the tubes.

Using the residue gas from the NGL/EOR plant as feed, with a steam/Carbon ratio of 2 allows to produce 6.25 % more Methane-free Syngas as shown in Table 9, for the same heat rate as in the GTG train. It also reduces the CO₂ recycle compressor to 2,089 BHP, and the CO₂ removal unit only has to extract 2,045 lb.mol/h of CO₂. The increase in Syngas throughput, coupled with about 36% reduction in the capacity of the CO₂-handling facilities illustrates the large potential for cost savings which would result from a systematic optimization of the surface facilities, even though all of them only use proven technology.

10.3-PRELIMINARY OPTIMIZATION OF THE AMMONIA SYNTHESIS UNIT:

In order to prevent the degradation of the West Sak reservoir permeability, it is necessary to stabilize the swelling clays present in the reservoir rock, to avoid clay swelling when in contact with steam condensate. This is accomplished by adding to the injected

mixture a relatively small concentration of Ammonia (about 0.4 mole %) which, when dissolved in the condensed steam, provides enough NH_4 cations to serve as counter-ions on the clay surface, thus preventing it from swelling.

Despite its small concentration, the total volume of Ammonia required is sufficient to justify its fabrication locally, using a slip stream from the Syngas feed. Other auxiliary units, such as those required for start-up, for inerting facilities during any shut down, and for safe operation (flares, etc...) have also been considered in Bechtel's design review of the surface facilities. For economies of scale, these auxiliary units may be shared by several Syngas trains. It was determined that four such trains could use one set of such auxiliary units. The cost estimates basis was therefore a four train plant, which, fed with residue gas from the Prudhoe Bay NGL/EOR plant and operated according to the conditions of Table 9. It could supply 8 Downhole Methanators of the basic design, operating at 106.25 % of design capacity. The corresponding estimated oil production is 65,000 B/D.

The Ammonia synthesis unit, with a throughput of about 60 T/D remains much smaller than a world-scale plant. It is however possible to make low-cost Ammonia on that scale if the cost of the $\text{N}_2 + 3 \text{H}_2$ feed to the Ammonia synthesis reactor is very low. This is achieved by using the inert gas unit (a small liquid Nitrogen plant) as a source of high pressure Nitrogen for the feed gas mixture. Conversely, the Hydrogen required is obtained, also at high pressure, by membrane extraction of a Hydrogen slip-stream from the compressed Syngas stream, in a Prism membrane separator. Finally, by considering that the Ammonia synthesis unit operates on an interruptible basis, the stand-by

electrical generator, required for plant safety, may also supply during the periods of non-emergency the electric heat required to maintain the synthesis reactor of the Casale Ammonia synthesis process at its operating temperature. The corresponding process diagram is shown on Fig. 33, which supersedes that of Fig. 4b (2nd Quarter Report), based on the conventional Haber process. The liquid Nitrogen vaporizer provides cooling of the reactor effluent to separate Ammonia from the recycle stream. This use of auxiliary facilities, required in any case, greatly simplifies the small Ammonia unit while using a proven process better adapted to small-scale units and better suited to modularization. This is another example of the large potential savings obtainable from the engineering optimization of surface facilities.

10.4-MULTI-PURPOSE AUXILIARY FACILITIES:

The emergency electrical generator is driven by a gas turbine. The exhaust heat from the turbine is used to generate the steam required for start-up of the reformer unit. This process steam, at 400 psig, is fed to the catalyst-filled tubes while the furnace temperature is gradually raised to 1616 F, at which time the natural gas is gradually added to the steam in the tube feed, until the desired steam/Carbon ratio of 2/1 is reached. The furnace waste heat boiler is also heated gradually, while the BFW pump driven by an electric motor is still powered by the emergency generator. As more steam is raised, the Syngas compressor, driven by the back-pressure steam turbine, can then be started-up. The same large steam turbine also drives the main electric generator, which can then be switched on, while the gas-turbine driven emergency generator power shuts down. It may, however, re-start if the the main generator becomes overloaded as a result of the power

load required for start-up of the Ammonia Synthesis reactor and for driving the liquid Nitrogen plant.

A reverse sequence is used for shut-down of the entire unit, while maintaining emergency electric power generation and a reduced supply of process steam.

10.5-COST ESTIMATE OF SURFACE FACILITIES:

Bechtel's estimate of the cost of surface facilities is based on:

- 1) equipment cost data for the Methanol units in the New Zealand GTG 1983 project, in which Bechtel was one of the engineering contractors. Escalation of these costs from 1983 to 1990 was taken as 19%.
- 2) North Slope cost factors developed for a similar Methanol plant, assumed to be built at Prudhoe Bay. This California Methanol Fuel study, also by Bechtel, was funded in part by the California Energy Commission. It benefited from Bechtel's extensive experience in designing and constructing a large number of modularized oil production facilities for the Alaskan oil fields. These Arctic modules, weighing as much as 2,500 t each, consist of a steel platform and structure for enclosing the process equipment in a heated, lighted and ventilated housing protecting the operators and the equipment from the Arctic climate. These self-supporting modules, built on the West Coast, are then loaded on barges which transport them to the North Slope during the summer months, when open sea conditions prevail for a few weeks. The modules are unloaded from the barges at their destination pier and transported on tracked crawlers to the building site, where they are installed on top of steel pilings, pre-set in a thick gravel pad. This method of construction was adopted for most of the facilities built on the North Slope. The bulk materials required for

this modularization of the process facilities, and the man-hours of construction labor greatly add to the cost of the process facilities. Interconnecting the various modules into an entire plant in the Arctic is another direct cost item (Off-plot), see Table 10. Added to these direct costs are the indirect costs, which include the sealift and module movement, the catalysts and chemicals, the construction camp and catering costs and various indirect costs, taxes, duties and freight incurred by the Contractor. To this field cost are added the Engineering fee, charged by the Contractor under a cost plus fee contract, and the owner costs, incurred for supervising the Contractor. Finally, a 25% contingency factor is applied to the total.

The total estimate cost of surface facilities (including contingency) for a plant serving 8 Downhole reactors is 1,415 \$MM (in mid 1990 Dollars). This cost dwarfs that of all the subsurface facilities, by a factor of more than 16/1, which shows that any effort to further optimize the design of surface facilities will be very rewarding. Bechtel's estimate of the equipment cost of the steam reformer section may be compared with that of a unit of 50% capacity, given in Ref. 47. This comparison is shown on Table 11. Another indication that this estimate may be conservative is the average cost per module of Bechtel's 16 module train. This average module cost is somewhat higher than historical costs of large conventional Arctic 2,500 t modules. Lighter modules, used extensively for the production facilities of the Endicott field have shown to be considerably less expensive. These "mini modules" are transported to the site via the TAPS haul road, thus eliminating the sea-lift and reducing North Slope labor costs.

The application of this new mode of construction to the required

West Sak surface facilities should be investigated in Phase 2.

10.6-OUTLINE OF PHASE 2 ENGINEERING OPTIMIZATION:

Among the other options worth investigating during a Phase 2 engineering optimization are:

- the possibility of building each complete train on the deck of a single barge, which would be sunk in a shallow pool dug into the shore, and later protected from the sea and ice forces by a gravel dyke. This construction technique, which greatly reduces Arctic labor costs, was successfully used for the Prudhoe Bay sea water treating plant for this large waterflood (capacity 2 MM B/D).
- the possibility of using another process (autothermal steam reforming or non-catalytic partial oxidation), alone or in combination, to make full use of the availability of the Natural Gas feed at a much higher pressure than that allowable for a steam reformer tubular furnace. This would reduce the Syngas compressor size.
- the possibility of transferring downhole some of the Syngas feed preparation process, to further reduce heat losses and modularization costs.

10.7-SIMPLIFIED ECONOMIC ANALYSIS:

A complete economic analysis would be based on the comparison between: 1) the net present value of the discounted cash flow from oil production, over the life of the field, after royalties and taxes, and

2) the net present cost of production, including depreciation of facilities, operating costs, work-over costs, oil finding costs, on the same discounted basis,

3) the resulting discounted net profit, after tax, and the

IROR attributable to the project.

This is beyond the scope of the present contract and would require additional information, including a reservoir engineering forecast of the field production versus time, an estimate of inflation and a forecast of well head oil prices as a function of time, over the life of the field. Finally, the IROR threshold, which determines the economic viability of a project varies for different oil companies, depending upon their resources, their tax rate and their alternative investment opportunities.

Instead of a complete economic analysis, simple yardsticks are often used to determine the viability of a project. One of them is the investment cost per daily barrel of oil produced in the same geographical area, where royalties, taxes and political risk are comparable, and for a comparable period. For instance, in Ref. 48, BP's development of the first offshore field in the Beaufort sea, the Endicott, is described. This field came on stream in 1987, at a time when Alaskan oil prices (G.C.) were about 15 \$/B. It produces about 100,000 B/D of oil from facilities initially budgeted at 2 Billion Dollars. This corresponds to 20,000 \$/B/D of oil production. Further engineering optimization (mini-modules) and lower equipment costs in a period of low oil development activity have brought the final cost closer to 10,000 \$/B/D. Such a low level may not be achievable for the West Sak, but, with oil prices now about 30 \$/B, a target of 20,000 \$/B/D may presently be economically attractive. This is apparent in the recent announcement by Shell (Ref. 49) to spend 6 Billion Dollars over the next 5 years in additional field development to increase its Nigerian oil production by 300,000 B/D (this corresponds to a hurdle rate of 20,000 \$/B/D). Table 12, taken from Ref. 39, shows the main

economic results of a marginal North Sea oil field development begun at a time when oil prices were 18 \$/B. The required investment is 23,067 \$/B/D, resulting in a 12% real rate of return. In the same paper, the BP authors point that, in most heavy oil development projects, the capital expenditure is less front-loaded than that for lighter oil fields. This is also illustrated in Table 12, which shows the economics of a typical heavy oil development for comparison with that of a marginal North Sea field. The longer production plateau (Fig. 34) and the effect of spreading a significant part of the capital expenditures over the life of the heavy oil field largely contribute to its much higher real rate of return (26%). In the Arctic, the latter effect is less pronounced, because of the higher cost of initial surface facilities, in proportion to those incurred during the field's life.

The investment cost per barrel of daily production, derived from the previous West Sak cost estimates and from the forecast of average production rate (65,000 B/D) for this four train plant and its eight associated wells equipped with Downhole Methanators is: 23,123 \$/B/D. This is comparable to that indicated by BP for a marginal North Sea field in Table 12.

A pro-forma economic analysis is presented in Table 13, based on the following assumptions:

- Arabian light oil prices remain at 30 \$/B (in constant dollars) throughout the 32 years life of the project. The corresponding price for heavy oil produced in California, or landed on the West Coast is 25 \$/B.
- After deduction of the marine transportation cost and the TAPS tariff, assumed constant, the net present value of each barrel of oil produced from the West Sak is estimated at 17 \$/B at the well head.

- Tax rates assumed are shown on Table 12. The income taxes reduce the Net Present Costs (NPC), but a 7% interest rate is applied to all capital expenditures from year 1. These factors, applied to a 2 year construction period are shown in Table 13.
- Operating & Maintenance costs versus time are also shown on Table 12, together with their discount factor, corresponding to the previously assumed 7% continuous discount rate.
- The net present value of the produced oil (after income taxes) also reflects the effect of the 7% discount rate (hurdle rate).
- The average production period is 355 days/year.
- The total income tax rate (State & Federal) is assumed to be 48% of the taxable income.
- For determining the Pay Out time, depreciation is based on NPC (i.e. after tax), rather than on actual capital expenditures.

The economic forecast of Table 13 shows that the NPV, after taxes, minus the NPC, also after taxes, leaves a discounted Net Profit, after tax, of 1,148 \$MM for the project taken as a basis in Bechtel's cost estimate.

The Real Rate of Return, after tax, is about 12%, which again is comparable to that of the marginal North Sea project presented in Table 12. Pay Out occurs 5 years after the start of production, in year 7, corresponding to an Accelerated Cost Recovery System for calculating depreciation.

Despite the conservative nature of Bechtel's cost estimate and despite the large contingency factor applied to the costs of wells and subsurface facilities, it appears that this novel process may be economically viable at current oil prices. With further optimization of the surface facilities, it should become very attractive.

An illustration of the potential economic improvement achievable by

engineering optimization is given by the case history of the Endicott field development, where the cost of facilities was reduced by nearly 50%, from the original budget of \$2 Billion, by the use of lighter modules, transported via the TAPS haul road, instead of the sea-lifted heavy modules taken as a basis for Bechtel's cost estimate. Table 14 shows the pro-forma economic analysis resulting from a 30% reduction in the cost of surface facilities, a realistic target considering that Bechtel's cost estimate already includes a 25% contingency factor. The real rate of return, based on the same assumptions as for Table 13, increases to 19%, while the pay-out time decreases to 4 years.

Implied in the successful application of this novel process to the West Sak is the assumption that the Prudhoe Bay NGL/EOR plant residue gas would be available at a negligible cost and that it would not be burdened by State royalties and taxes. This appears to be an essential condition for maintaining the West Sak operating cost at a level comparable with that of the other North Slope fields. The large amount of gas used as fuel in each of those fields is exempt from royalties and taxes as long as it comes from the same unitized reservoir. It would be in the State's interest to also exempt reservoirs in this geographic area, which contain insufficient quantities of indigenous gas for their exploitation and which must import some gas produced from other units, as long as there is no other use for such gas.

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- 47) "Syngas production by reforming", by S.P. Goff, S.I. Wang, Chem. Eng. Progress, Aug. 1987, p. 46

48) "Endicott, the oil field that might not have been", BP Scene, Summer 1990, p.10

49) "Industry and Profession", J. Pet. Tech. Aug. 1990, p.1007

39)-see 2nd Quarter Report-"Development of Heavy Oil Reservoirs", by P.J. Briggs, R.P. Baron, R.J. Fullylove, M.S. Wright, J. Pet. Tech., Feb. 1988, p. 206

TABLE 5

DRILLING AND COMPLETION SEQUENCE AND PRELIMINARY COST ESTIMATE

OPERATION	COST (1,000 \$)
1) Auger 42 in.hole & install 80 ft of 36 in.conductor pipe.....	25
2) Mobilize/demob.rig (Nabors 18-E) @ 20/day for 12 days.....	200
3) Drill 30 in.hole to 3,000 ft (3 days @ 40/day).....	120
4) Run 24 in.casing to 3,000 ft @ 150 \$/ft	450
5) Cost of 4 connector joints in casing string.....	40
6) Cement 24 in. casing (5,500 cu.ft).....	100
7) Hang Downhole Reactor Assembly (1 day).....	20
8) Drill 2 horizontal drainholes 8.5 in.,3,000 ft long(12 days)..	600
9) Complete 2 horizontal holes (5.5 in.slotted liners + 2 days)...	95
10) Run 13 3/8 in.tubing,cross-overs,connector/valve assembly ...	140
11) Run 11 3/4 in.tubing (36 \$/ft + 1 day).....	128
12) Run 9 5/8 in.tubing (31 \$/ft + 1 day).....	112
13) Wellhead (w/metal/metal seals).....	160
14) Christmas tree.....	110
	Total..... 2,300
Costs include:mud,drilling tools & bits,cement,tubulars,all freight	
15) Contingency factor (50 %)	1,150
	Total,incl.contingency.....3.450

Table 6

COST ESTIMATE OF DOWNHOLE REACTOR ASSEMBLY

RAW MATERIALS:		Cost(Gulf Coast)
Item	Material	(1,000 \$)
21 in.Reactor shell (250 ft)	Hastelloy C-22 @ 9.95 \$/#.....	243
2 3/8 Water tubing (250 ft)	Hastelloy C-22 @ 153.5 \$/ft.	38
3 1/2 Gas tubing (250 ft)	Hastelloy C-22 @ 233.5 \$/ft.....	58
5 1/2 Steam-water Sep.(250 ft)	Croloy TF 321 H @ 64.7 \$/ft.....	16
7 in.Injectant tubing (250 ft)	Hastelloy C-22 @ 595 \$/ft.....	149
5/8 in.Water tubes (25,000 ft)	Croloy TP 321 H @ 3.25 \$/ft.....	81
Threaded reactor hanger/head	Hastelloy C-22 @ 10 \$/#	41
14 reactor unit head/base	Hastelloy C-22 @ 10 \$/#	388
Reactor base	Hastelloy C-22 @ 10 \$/#	20
Methanation Catalyst		1,000
	Subtotal Materials	2,034
DESIGN,FABRICATION AND TESTING.....		2,000
Warehousing and Freight		200
	TOTAL DIRECT COST	4,234
CONTINGENCY (50%).....		2,117
	TOTAL (incl.contingency).....	6,351

TABLE 7

 COST ESTIMATE OF REACTOR OVERHEAD ASSEMBLY
 INCLUDING CROSS-OVERS, CONNECTORS AND DOWNHOLE VALVE SECTION

RAW MATERIALS:

Item	Material	Cost (1,000 \$)
18 in. OD Outer shell (0.4" wall)	Hastelloy C-22 @ 9.95 \$/#	25
Lower Cross-Over Section	Hastelloy C-22 @ 10 \$/#	10
Twin Connectors Section (7" OD)	Stainless 321 H @	10
Valve Section (90 ft, 5.5" OD)	Stainless 321 H @	20
Upper Cross-Over Section	Hastelloy C-22 @ 10 \$/#	10
1/4" Hydraulic Lines (9,000 ft)	Stainless 304 @ 1 \$/ft.	9
300 tubing clamps	Stainless 304 @ 20 ea.	6

 Subtotal raw materials..... 90

DESIGN, FABRICATION AND TESTING: 500

VALVES, INSTRUMENTATION AND CONTROLS:

2 Downhole Valves		45
1 Syngas Feed Control Valve		5
4 Temperature Controllers		10
4 Water Level Controllers		20
1 Reactor Control Computer		20
Assembly and Testing		100

 Subtotal Instruments & Controls... 200.

Warehousing and Freight: 50

CONTINGENCY FACTOR (50%) 420

TOTAL (Incl. Contingency) 1,260

TABLE 8 (Prudhoe Bay Separator-Off Gas Feed)

A	B	C	D	E	F	G	H	I	J	K	L	M
1												
2												
3												
4	Feed Gas	1	2	3	4	5	6	6	6	7	8	9
5	Stream Name	Feed Gas	CO2 Recycle	Steam	Comb Feed	Effl		Gas Out	Gas Out	Cooled Gas	Water	CO2 Free Gas
6	Properties			Reformer								
7	Composition											
8	CH4 - MPH	74.607	4448.1	0.0	4448.1	700.1	700.1	700.1	700.1	700.1	0.0	700.1
9	C2H6	6.426	383.1	0.0	383.1		700.1	0.0	0.0	0.0	0.0	0.0
10	C3H8	3.772	224.9	0.0	224.9		1.62E-16	0.0	0.0	0.0	0.0	0.0
11	C4H10	1.603	95.6	0.0	95.6		0.0	0.0	0.0	0.0	0.0	0.0
12	C5H12	0.830	49.5	0.0	49.5		0.0	0.0	0.0	0.0	0.0	0.0
13	CO2	12.156	724.7	1767.0	2491.7	3430.1	3430.1	3430.1	3430.1	3430.1	0.0	230.0
14	N2	0.606	36.1	0.0	36.1	36.1	3430.1	36.1	36.1	36.1	0.0	36.1
15	O2		0.0	0.0	0.0	0.0	2.65E-16	0.0	0.0	0.0	0.0	0.0
16	CO		0.0	0.0	0.0	0.0	4880.3	4880.3	4880.3	4880.3	0.0	4823.3
17	H2		0.0	0.0	0.0	0.0	17076.6	17076.6	17076.6	17076.6	0.0	17076.6
18	H2O		0.0	0.0	21730.2	14973.3		14973.3	14973.3	73.1	14900.2	73.1
19	Total - MPH	100	5962.0	1767.0	29459.2	41096.4		41096.4	41096.4	26196.3	14900.2	22996.2
20	C atoms		7243.4	1767.0	0.0	9010.4		9010.4	9010.4	5010.4	0.0	5810.3
21	H atoms		23439.3	0.0	43460.5	66900.1		66900.1	66900.1	37099.7	29800.4	37099.7
22	O atoms		1449.5	3534.0	21730.2	26713.7		26713.7	26713.7	11813.5	14900.2	5413.3
23	N atoms		72.3	0.0	0.0	72.3		72.3	72.3	72.3	0.0	72.3
24	Total - #/hr		134824.6	77765.7	391492.0	604082.2		604082.2	604082.2	335640.4	268441.8	194803.8
25	Conditions											
26	Temp - Deg F		200.0	323.8	448.0	1616.0		1000.0	318.0	100.0	100.0	100.0
27	Press - Atm			28.57	28.24	24.84		24.00	24.00	23.14	23.14	21.43
28	MM Btu/hr		-242.16	-287.59	-2074.98	-1694.06		-1914.62	-2141.59	-744.73	-1745.18	-216.99
29	Delta H				-2604.73	186.96		723.71	-220.56	1396.86	-348.32	0.00
30	oxygen/carbon				0.00							
31	steam/carbon				3.00							
32	H2/CO					3.50		3.50	3.50	3.50		3.50
33	(H2-CO2)/(CO+CO2)					1.64		1.64	1.64	1.64		3.30
34	Boudouard Ratio					-0.04563		0.050332	0.050332	0.033276		0.031536
35	O2=0 air=1			0								
36	Delta T SMR - Deg F					15.0 H2O mol fraction				0.002791		
37	Eq. Temp - Deg K					1144.8 CO2 mol fraction						0.01
38	Delta T WGS - Deg F					0.0						
39	Eq. Temp - Deg K					1153.2						
40	Equilibrium Constants											
41	K - WGS					0.801569						
42	K - SM					842.5523						
43	K - Boudouard					0.035042						

TABLE 8 (Continued)

N	O	P	Q	R	S	T	U	V	W	X	Y	Z
1												
2												
3												
4												
5	Stream Name											
6	Properties											
7	Composition											
8	C ₁ H ₄ - MPH											
9	C ₂ H ₆											
10	C ₃ H ₈											
11	C ₄ H ₁₀											
12	C ₅ H ₁₂											
13	CO ₂											
14	N ₂											
15	O ₂											
16	CO											
17	H ₂											
18	H ₂ O											
19	Total - MPH											
20	C atoms											
21	H atoms											
22	O atoms											
23	N atoms											
24	Total - #/hr											
25	Conditions											
26	Temp - Deg F											
27	Press - Atm											
28	MM Btu/hr											
29	Delta H											
30	oxygen/carbon											
31	steam/carbon											
32	H ₂ /CO											
33	(H ₂ -CO ₂)/(CO+CO ₂)											
34	Boudouard Ratio											
35	Comp Eff											
36	H ₂ O mol fraction											
37	CO ₂ mol fraction											
38	Heat Cap - molar											
39	k											
40	(n-1)/n											
41	Comp. Ratio											
42	Head - ft											
43	HP											

TABLE 9 (Prudhoe Bay NGL/EOR residue Gas Feed)

A	B	C	D	E	F	G	H	I	J	K	L	M
1												
2												
3												
4	Feed Gas	1	2	3	4	5		6	6	7	8	9
5	Stream Name	Feed Gas	CO2 Recycle	Reformer	Comb Feed	Effl	per Reformer	Gas Out	Gas Out	Cooled Gas	Water	CO2 Free
6	Properties	Md %		Steam						H2O Free		Gas
7	Composition											
8	C14 - MPH	79.7	6124.1	0.0	0.0	6124.1	1533.2	1533.2	1533.2	1533.2	0.0	1533.2
9	C2H6	5	384.2	0.0	0.0	384.2	1533.2	0.0	0.0	0.0	0.0	0.0
10	C3H8	2	153.7	0.0	0.0	153.7	4.45E-16	0.0	0.0	0.0	0.0	0.0
11	C4H10	0.3	23.1	0.0	0.0	23.1		0.0	0.0	0.0	0.0	0.0
12	C5H12	0.000	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0
13	CO2	12	922.1	550.0	0.0	1472.1	2293.4	2293.4	2293.4	2293.4	0.0	248.2
14	N2	1	76.8	0.0	0.0	76.8	2293.4	76.8	76.8	76.8	0.0	76.8
15	O2		0.0	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0
16	CO		0.0	0.0	0.0	0.0		5091.3	5091.3	5091.3	0.0	5091.3
17	H2		0.0	0.0	0.0	0.0		17798.4	17798.4	17798.4	0.0	17798.4
18	H2O		0.0	0.0	0.0	16735.8	10001.9	10001.9	10001.9	75.0	9926.9	75.0
19	Total - MPH	100	7684.0	550.0	0.0	24969.8	36795.0	36795.0	36795.0	26868.1	9926.9	24823.0
20	C atoms		8367.9	550.0	0.0	8917.9	8917.9	8917.9	8917.9	8917.9	0.0	6872.7
21	H atoms		28261.8	0.0	33471.5	61733.3	61733.3	61733.3	61733.3	41879.5	19853.7	41879.5
22	O atoms		1844.2	1100.0	16735.8	19679.9	19679.9	19679.9	19679.9	9753.0	9926.9	5662.8
23	N atoms		153.7	0.0	0.0	153.7		153.7	153.7	153.7	0.0	153.7
24	Total - #/hr		150645.7	24205.5	301511.3	486362.5	486362.5	486362.5	486362.5	307519.9	178842.5	217513.8
25	Conditions											
26	Temp - Deg F		200.0	323.8	448.0	1000.0	1616.0	1600.0	1000.0	100.0	100.0	100.0
27	Press - Atm			28.57	28.24	24.84		24.00	24.00	23.14	23.14	21.43
28	MM Btu/hr		-307.60	-89.51	-1598.07	-1829.30	-1105.23	-1110.41	-1299.64	-584.27	-1162.68	-247.01
29	Delta H				-1995.18	165.89	724.07	-5.19	-189.22	715.36	-447.32	0.00
30	oxygen/carbon				0.00							
31	steam/carbon				2.00							
32	H2/CO					3.50		3.50	3.50	3.50		3.50
33	(H2-CO2)/(CO+CO2)					2.10		2.10	2.10	2.10		3.29
34	Boudouard Ratio					0.131053		0.09068	0.09068	0.068676		0.068499
35	O2-air=1			0								
36	Delta T SMR - Deg F					15.0	H2O mol fraction			0.002791		
37	Eq. Temp - Deg K					1144.8	CO2 mol fraction					0.01
38	Delta T WGS - Deg F					0.0						
39	Eq. Temp - Deg K					1153.2						
40	Equilibrium Constants											
41	K - WGS					0.801569						
42	K - SM					842.5523						
43	K - Boudouard					0.035042						

TABLE 9 (Continued)

N	O	P	Q	R	S	T	U	V	W	X	Y	Z
1												
2												
3												
4												
5	Stream Name	CO2 Compr	Stage 1	Stage 2	CO2 Product	Stage 1	CO2 Free	Stage 1	Stage 2	Stage 2	Stage 3	Total H2O
6	Properties	Inlet	Outlet	Outlet	Outlet	Inlet		Outlet	Inlet	Outlet	Outlet	Produced
7	Composition											
8	CH4 - MPH	0.0	0.0	0.0	0.0	1533.2	1533.2	1533.2	1533.2	1533.2	1533.2	0
9	C2H6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
10	C3H8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
11	C4H10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
12	C5H12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
13	CO2	2045.1	2045.1	2045.1	2045.1	248.2	248.2	248.2	248.2	248.2	248.2	0
14	N2	0.0	0.0	0.0	0.0	76.8	76.8	76.8	76.8	76.8	76.8	0
15	O2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
16	CO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
17	H2	0.0	0.0	0.0	0.0	5091.3	5091.3	5091.3	5091.3	5091.3	5091.3	0
18	H2O	0.0	0.0	0.0	0.0	75.0	75.0	75.0	36.0	16.9	16.9	9984.956
19	Total - MPH	2045.1	2045.1	2045.1	2045.1	17798.4	17798.4	17798.4	17798.4	17798.4	17798.4	0
20	C atoms	2045.1	2045.1	2045.1	2045.1	6872.7	6872.7	6872.7	6872.7	6872.7	6872.7	0
21	H atoms	0.0	0.0	0.0	0.0	41879.5	41879.5	41879.5	41801.4	41763.3	41763.3	19969.9
22	O atoms	4090.3	4090.3	4090.3	4090.3	5662.8	5662.8	5662.8	5623.7	5604.7	5604.7	9985.0
23	N atoms	0.0	0.0	0.0	0.0	153.7	153.7	153.7	153.7	153.7	153.7	0
24	Total - #/hr	90006.2	90006.2	90006.2	90006.2	217513.8	217513.8	217513.8	216810.6	216467.3	216467.3	179889.0
25	Conditions											
26	Temp - Deg F	100.0	323.8	323.8	323.8	100.0	238.8	237.8	100.0	237.8	237.8	100.0
27	Press - Atm	1.60	7.28	28.57	28.57	21.43	91.43	46.51	44.51	96.59	205.26	23.14
28	MM Btu/hr	-337.27	-332.85	-332.85	-332.85	-247.01	-222.53	-222.72	-243.17	-218.92	-217.06	-1169.48
29	Delta H		4.41	4.41	4.41	-133.07	24.48	24.29	20.45	24.25	24.23	
30	oxygen/carbon							23.91		23.87	23.85	
31	steam/carbon											
32	H2/CO					3.50			3.50		3.50	
33	(H2-CO2)/(CO+CO2)					3.29			3.29		3.29	
34	Boudouard Ratio					0.068499			0.015176		0.007136	
35	Comp Eff		0.77	0.77	0.77			0.77	0.77		0.77	
36	H2O mol fraction								0.001451		0.000683	
37	CO2 mol fraction											
38	Heat Cap - molar		9.64	9.64	9.64	0.01	7.10	7.10	7.10		7.10	
39	k		1.2061	1.2061	1.2061		1.2797	1.2797	1.2798		1.2798	
40	(n-1)/n		0.2219	0.2219	0.2219		0.2839	0.2839	0.2839		0.2839	
41	Comp. Ratio		4.55	4.55	4.55		2.17	2.17	2.17		2.17	
42	Head - ft		35382	35382	35382		85503	85503	85547		85718	
43	BFP		2089	2089	2089		12199	12199	12180		12170	

TABLE 10

INTERIM COST ESTIMATE OF SURFACE FACILITIES SERVING
EIGHT DOWNHOLE REACTORS
(\$MM)

Basis: Bechtel Cost Data (mid 1990); 2,500 T modules, sea-lifted

	Major Equipment	Bulks	Labor	Total
Reformer Section	154.7	126.8		
Compressor Section	28.0	23.2		
CO2 Removal	21.1	11.5		
Desalination	13.5	10.8		
Crude Separation	2.8	2.0		
 Total On Plot	 220.1	 174.3	 107.1	 501.5
Off Plot	76.8	80.8	21.2	178.8
Contractor Indirects				135.2
Catalysts & Chemicals				8.0
Tax, Duties, Freight				7.6
Camp & Catering				10.0
Sealift & Module Movement				95.6
 Total Field Cost				 936.7
Eng'ng, HO and Fee				83.2
 Total Contractor's Cost				 1,019.9
Owner Costs				112.1
Contingency at 25%				283.0
 Total Project				 1,415.0

Number of Modules: 16 / train x 4 trains = 64 modules
Average cost / Module: 22.1 \$MM

TABLE 11

COMPARISON OF STEAM REFORMER COST ESTIMATES BY BECHTEL GROUP, INC. AND
BY AIR PRODUCTS CO. (Ref. 47)

	BECHTEL	AIR PRODUCTS
Steam Reformer Capacity (Nb. of Downhole Methanators / Train)	2	1
Cost Estimate (\$ MM) mid 1990 Dollars		
Basic Equipment + labor On Plot	75.2	
Contractor Indirects (19.9%)	15.0	
Tax, Duties and Freight (2%)	1.5	
Catalysts and Chemicals	2.0	
Total Field Cost	93.7	
Engineering, HO and Fee (8.9%)	8.3	
Total Contractor's Cost	102.0	
Contingency (25%)	25.5	
Total (Gulf Coast Price)	127.5 (1990)	
		74 (1987)
		81.4 (1990)
Capacity Exponent: 0.6		
Capacity Adjusted Cost:	127.5	123.3

TABLE 12 - COMPARATIVE PROJECT COSTS

	<u>Marginal North Sea Development</u>	<u>Typical Heavy-Oil Development</u>
Total recovery, 10^6 STB	75	64
Plateau rate, 10^3 B/D	30	7
Initial capex, U.S. \$1 million	692	85
Annual capex, U.S. \$1 million	—	19
Annual opex, U.S. \$1 million	35	13
Cost of oil, \$/bbl	15	13
1986 oil price, \$/bbl	18	14
Margin, \$/bbl	3	1
NPV at 8%, U.S. \$1 million	60	100
Real rate of return, %	12	26

TABLE 13
PRO-FORMA ECONOMIC ANALYSIS OF THE BASIC PROJECT

Assumed: 12.5% royalty and 10% sev. tax on WH price
48 % of income for State & Federal taxes
17 \$/B WH price in constant dollars
355 D/y production at 65,000 B/D constant rate for 30 years
7% p.a. interest rate from year 1 to year 32

Year	Capital Cost(\$MM)	Disc.fact. (aft.I.Tax)	Capex (\$MM)	O. & M. Cost(\$MM)
------	-----------------------	---------------------------	-----------------	-----------------------

1	(751)	0.670	(503)	0
2	(752)	0.635	(477)	0

TOTAL: (1,503) TOTAL NPC: (980)

	Depr. ACRS	O. & M. Cost(\$MM)	disc.fact. (aft.I.T.)	Opex (\$MM)	disc.Gross (-Roy., S.T.)	Taxable (disc.)	NPV (aft.I.T)
3	(196)	(45)	0.49	(22)	256	38	20
4	(218)	(53)	0.43	(23)	241	0	0
5	(208)	(45)	0.38	(17)	225	0	0
6	(193)	(53)	0.33	(17)	210	0	0
7	(165)	(45)	0.29	(13)	194	16	8 P.O
8	0	(61) (W.O.)	0.26	(16)	182	166	86
9	0	(45)	0.23	(10)	170	160	83
10	0	(53)	0.20	(10)	157	147	76
11	0	(45)	0.18	(8)	148	140	73
12	0	(61) (W.O.)	0.16	(10)	139	129	67
13	0	(45)	0.14	(6)	130	124	64
14	0	(53)	0.12	(6)	120	114	59
15	0	(45)	0.11	(5)	111	106	55
16	0	(61) (W.O.)	0.09	(5)	105	100	52
17	0	(45)	0.08	(4)	96	92	48
18	0	(53)	0.07	(4)	90	86	45
19	0	(45)	0.06	(3)	83	80	42
20	0	(53)	0.05	(3)	77	74	38
21	0	(45)	0.04	(2)	74	72	37
22	0	(53)	0.03	(2)	68	66	34
23	0	(45)	0.03	(1)	65	64	33
24	0	(53)	0.02	(1)	59	58	30
25	0	(45)	0.02	(1)	56	55	29
26	0	(53)	0.01	(1)	52	51	27
27	0	(45)	0.01	(1)	50	49	25
28	0	(53)	0.006	(0.3)	48	48	25
29	0	(45)	0.005	(0.2)	47	47	24
30	0	(53)	0.004	(0.2)	46	46	24
31	0	(45)	0.003	(0.1)	45	45	23
32	0	(53)	0.002	(0.1)	44	43	22

REAL RATE OF RETURN = 12%

TOTAL NPV = 1,148 \$MM
(after tax)

TABLE 14
PRO-FORMA ECONOMIC ANALYSIS AFTER 30% REDUCTION OF SURFACE FACILITIES
COST BY ENGINEERING OPTIMIZATION, WITH SAME ASSUMPTIONS AS IN TABLE 13

Year	Rev.Capital Cost(\$MM)	Disc.fact. (aft.I.Tax)	Capex (\$MM)	O. & M. Cost(\$MM)			
1	(526)	0.670	(352)	0			
2	(526)	0.635	(334)	0			

TOTAL:(1,052)		TOTAL NPC:		(686)			
	Depr. ACRS	O. & M. Cost(\$MM)	disc.fact. (aft.I.T.)	Opex (\$MM)	disc.Gross (-Roy.,S.T.)	Taxable (disc.)	NPV (aft.I.T.)
3	(137)	(45)	0.49	(22)	256	97	50
4	(218)	(53)	0.43	(23)	241	0	0
5	(167)	(45)	0.38	(17)	225	41	21
6	(110)	(53)	0.33	(17)	210	83	43 P.O.
7	(54)	(45)	0.29	(13)	194	127	66
8	0	(61) (W.O.)	0.26	(16)	182	166	86
9	0	(45)	0.23	(10)	170	160	83
10	0	(53)	0.20	(10)	157	147	76
11	0	(45)	0.18	(8)	148	140	73
12	0	(61) (W.O.)	0.16	(10)	139	129	67
13	0	(45)	0.14	(6)	130	124	64
14	0	(53)	0.12	(6)	120	114	59
15	0	(45)	0.11	(5)	111	106	55
16	0	(61) (W.O.)	0.09	(5)	105	100	52
17	0	(45)	0.08	(4)	96	92	48
18	0	(53)	0.07	(4)	90	86	45
19	0	(45)	0.06	(3)	83	80	42
20	0	(53)	0.05	(3)	77	74	38
21	0	(45)	0.04	(2)	74	72	37
22	0	(53)	0.03	(2)	68	66	34
23	0	(45)	0.03	(1)	65	64	33
24	0	(53)	0.02	(1)	59	58	30
25	0	(45)	0.02	(1)	56	55	29
26	0	(53)	0.01	(1)	52	51	27
27	0	(45)	0.01	(1)	50	49	25
28	0	(53)	0.006	(0.3)	48	48	25
29	0	(45)	0.005	(0.2)	47	47	24
30	0	(53)	0.004	(0.2)	46	46	24
31	0	(45)	0.003	(0.1)	45	45	23
32	0	(53)	0.002	(0.1)	44	43	22
TOTAL NPV =						1,300 \$MM	
(after tax)							

REAL RATE OF RETURN = 19%

[illegible]

LIQUID N₂ UNIT

NH₃ SYNTHESIS

EMERGENCY POWER

FIG. 33 - MULTI-PURPOSE AUXILIARY FACILITIES/NH₃ PLANT

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END

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