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AN EVALUATION OF ALTERNATIVES IN DOWNHOLE STEAM GENERATION

Work Performed for the Department of Energy
Under Purchase Order No. 79-SF-10879

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Commercialization Insights
Tampa, Florida

U. S. DEPARTMENT OF ENERGY

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ABSTRACT

Studies have been made of two developing technologies. One is downhole steam generation, as such, being developed by Sandia Laboratories, in which the steam is injected into the formation, with or without the combustion gases. The other is downhole oil treatment, being developed by World Energy Systems and Aerospace Research Corporation, in which steam is also generated downhole, but from hydrogen and oxygen, usually employing an excess of one or the other. The excess hydrogen is envisioned as possibly dissolving in the oil in place, reducing its viscosity and thereby making it more producible, or chemically reacting with it with the same result. Excess oxygen would permit reactions similar to those taking place in in situ combustion, providing heat, pressure, and, possibly, chemically reactive sites for subsequent hydrogenation.

Representatives from six oil companies were interviewed to obtain their views on one or both of these technologies. Their comments are included in the report but not identified by individual or company.

The interest in downhole steam generation was almost exclusively centered on the high pressure version, which is the one employing injection of combustion gases into the formation. This interest was based upon the hope that this approach would either reduce or postpone air pollution problems. Considerably less importance was attached to the possibility that it would reduce heat losses. Insulation was thought to be an effective alternative. A number of suggestions were made regarding future field tests.

The economic evaluations of downhole steam generation that were previously done by Sandia were extended to include the effects of rate of return on investment (ROI), higher-than-predicted capital cost, and various fuel oil and crude oil prices. The results were expressed as the

barrels of crude that would have been produced per million btu released downhole in order for the specified return on investment to be realized. Among the results, it was found that 1.2 bbl/10^6 btu, or more, would result in a 40% ROI even if the required capital investment was 50% greater than predicted, fuel oil cost $25/bbl, and the crude price was $25/bbl. The above oil yield corresponds to the use of 5.3 bbl steam/bbl oil or less. For higher crude (and fuel oil) prices the production required to achieve this return is less.

Downhole oil treatment is not so well defined as downhole steam generation. The hardware for generating hydrogen/steam and oxygen/steam mixtures has been developed. There is a need, however, for computer simulation supported by laboratory data to explore the technical capabilities of the technology.

The energy required by the production of oxygen and hydrogen is not excessive. Using reasonable operating parameters, it was estimated that 1/3 to 1/2 of the produced oil would be needed to supply material and energy for production of those two components.

Because the proposed technology is a considerable departure from current practice, the economic analysis was made assuming that the operator who would consider using it would be looking for a high benefit to risk ratio. That ratio, as used in this report, is the total revenue over a three-year period discounted by the required ROI divided by the total cost of the test. The oil yields which would be required to obtain benefit/risk ratios of 5.0 were estimated to be 2.0 to 4.0 bbl/10^6 btu with an oil price of $25.00/bbl. The low values are for a wet oxidation process while the higher ones are for hydrogen treatment or dissolution; intermediate values apply to straight steaming. These results reflect the fact that hydrogen costs are much greater than oxygen costs.

The required oil yields indicated above are higher than any indicated to be required for economically-attractive downhole steam generation. These are not competitive technologies. Nevertheless, it is possible to achieve the required oil yields, although the techniques for using the available hydrogen, steam and oxygen rates to do so have not been studied yet. The best targets for downhole oil treatment are very tight formations, oil shale and tar sands - resources which are, at best, difficult to produce.

AN EVALUATION OF ALTERNATIVES IN DOWNHOLE STEAM GENERATION

I. OBJECTIVE

To evaluate two alternative approaches, taken by Sandia and World Energy Systems in their development of downhole steam generators, in terms of the requirements for commercialization and the technical and economic goals which each one must reach in order to satisfy those requirements.

II. CONCLUSIONS

1. The high-pressure downhole steam generator being developed by Sandia has potential for commercialization for production of heavy oil in the next few years.

2. The critical performance parameter is oil yield and can be expressed in terms of bbl oil/million btu of steam generated; the yield which is required for clear economic attractiveness of the high-pressure generator is 1.2 bbl/10^6 btu which corresponds to 5.3 bbl steam/bbl oil.

3. The downhole hydrogen/oxygen burner being developed by World Energy Systems has potential for commercialization for production of resources which are now unproducible or uneconomical.

4. The critical performance parameter is oil yield and the minimum value required for economic attractiveness is about 2.0 bbl/10^6 btu.

5. The thermal requirements of oxygen, hydrogen, and steam production have been estimated to be about 1/3 to 1/2 of the oil produced by downhole oil treatment under commercially attractive conditions.

III. INTRODUCTION

This report covers two distinct studies. The first one is concerned with downhole steam generation but covers only the generators being developed by Sandia. The second study shows that the technology under development by World Energy Systems is not steam generation as such. It is an in situ treatment of oil with the purpose of making that oil more producible. This means that production would be cheaper compared with alternatives or it would be feasible where there are no other means available except possibly mining. Throughout this report, this technology will be referred to as Downhole Oil Treatment.

This study included the solicitation of comments from representatives of oil companies which have expressed an interest in either Downhole Steam Generation (DSG) or Downhole Oil Treatment (DOT). Comments on these two technologies were obtained from representatives of the producing departments and production research departments, respectively. This breakdown was made because DSG seems to be much closer to commercialization than DOT and more familiar to the production people who will eventually make commercialization decisions.

The oil companies which were visited are listed below. Some of them were contacted only with regard to DSG, others regarding DOT and still others, both.

Chevron	Phillips
Gulf	Shell
Mobil	Texaco

The positions of the people who contributed to this study are listed below in random order:

Senior Production Consultant
Manager of Operations
General Manager
Production Engineering Consultant
Supervisor
Chief Engineer
Reservoir Engineering Consultant
Senior Research Chemical Engineer
Manager of Exploration and Production Research Laboratory
Senior Engineering Associate
Senior Staff Research Engineer (Retired)

All of the information in this report was obtained in face-to-face discussions with these representatives in their companies' offices. For the DSG discussions, the companies had previously shown some interest in the technology under development. For DOT, all of the contributors were from companies which had already made their own attempts to develop some kind of treatment technology. As a result, they were aware of the problems and opportunities.

The discussions were conducted with the understanding that none of the comments which were made would be attributed to a company or an individual. They were frank and cordial with an apparently genuine effort to supply the guidance which was sought.

In addition to the discussions which are mentioned above, interviews were held with representatives of two companies which plan to commercialize DSG in the relatively near future, perhaps 1980. In those meetings, it was understood that the information furnished for this study

would be attributed to the individuals and companies involved, and this has been done.

IV. SUMMARY

The primary industrial interest in downhole steam generation is based upon its need to reduce air pollution problems associated with surface steam generation. The high pressure generator, which is operated with injection of combustion gases into the formation, has potential for meeting this need. Among the industry views regarding the outlook for this technology was one that saw coal-fired steam generation as a more promising approach. Two companies are prepared to offer downhole steam generation and top-of-the-hole steam generation in 1980. The latter technique is based upon the developer's field data that shows the most significant heat loss to be in surface lines from the generator to the production well.

The scope of the economic evaluations previously done by Sandia were extended to include 20% and 40% return on investment (ROI), capital costs which are 50% higher than they had estimated and interrelated fuel and produced-crude prices at three levels: $25.00, $32.50, and $40.00/bbl. The results showed that at $25/bbl, 40% ROI, and the higher capital cost, an oil yield of 1.2 bbl of crude/10^6 btu released downhole would be required. This is equivalent to the use of 5.3 or less bbl steam/bbl oil, which is considered to be realizable. The product of oil yield, X, and price, P, is a performance factor which takes both of these variable into account; lower values are more attractive (easier to achieve). Over the ranges of the above variables, XP varied from 15 to 30; none of them had a dramatic effect on the economics.

The industry consensus regarding downhole oil treatment is that there are a lot of unknowns and the technology needs work. Computer

simulation supported by laboratory data of the effects of hydrogen/steam/oxygen mixtures at reservoir conditions is recommended. Because of the high cost of hydrogen, there is a need to establish some preliminary relationships between hydrogen pressure and (potential) incremental crude production. There was disagreement about the effects on the formation. The parallel between this technology and in situ combustion suggests that the latter be closely examined as a guide to useful approaches.

Material and energy balances indicate that there is no serious problem regarding energy efficiency. Under conditions which are potentially achievable, about 1/3 to 1/2 of the produced crude will be needed to provide energy and material for the production of oxygen and hydrogen.

The cost of a three-month field test of downhole oil treatment has been roughly estimated to be about $500,000 if the gas generation (hydrogen/steam/oxygen) becomes available as a service. The oil yields which would be required at various benefit/risk ratios have been calculated. To achieve a discounted cash flow over a three-year period of $2.5 - 3.0 MM, a 5 - 6 to 1 benefit/risk ratio, would require XP values of 50 to 100 depending upon which stimulation technique proved to be effective. (Wet oxidation is much cheaper than hydrogen injection.) These values are higher than those for downhole steam generation because of the higher operating costs. Nevertheless, for P = $25/bbl, X values of 2.0 to 4.0 would result in good economics and these might be achieved. The high benefit/risk ratios which are cited above are needed to offset the initially high technical risk. Values of XP greater than 30 are required to obtain any benefit at all.

The above results confirm that downhole oil treatment is not a competitor of downhole steam generation. Its targets are resources which are not producible by other means including, but not limited to, very tight formations, oil shale, and tar sands.

V. DOWNHOLE STEAM GENERATOR DEVELOPMENT

The downhole steam generator program at Sandia has two parts. One is developing a low pressure generator in which the combustion products will be returned to the surface. The other is developing a high pressure generator in which the combustion products will be injected into the formation. These are presented in turn below, after a general introduction.

A. The Concept

The application of this technology is to situations in which steam drive is technically attractive but the economics are unsatisfactory. If the economics can be made attractive by reducing the heat losses in the wellbore, downhole steam generation may be desirable. Since the combustion takes place near the oil zone, the heat losses that normally occur will be essentially eliminated. The savings in heat must provide a good return on the additional hardware investment and the increased difficulty of operation and do so at the level of risk which it represents. Its competition is surface generation of steam with insulation.

B. Low Pressure Generator

The key characteristics of this system which distinguish it from the high pressure generator are:

1. return of combustion products to the surface where they must be cleaned up.

2. smallest well in which the generator can be placed is 10" in diameter.

Since the combustion products will be contained, the problems of cleanup may be about the same as in the surface generation of steam. Still, a major concern is how to make sure that the system will be environmentally safe.

In many cases, steam will be the primary method of stimulation. Then there will be no problem in drilling and completing a 10" well with casing. In doing this, the generator would be combined with the casing to provide a good seal.

C. High Pressure Generator

The distinguishing characteristics of this generator are:

1. combustion products are put into the formation and will eventually reach the producing well.

2. the generator can be installed in a 7-inch diameter well.

Because of (1), there are many factors to be considered regarding the effect of the combustion gases on the formation, to what extent the gases will be absorbed or cleaned up by the formation, and what the clean up job will be if they are not environmentally safe when produced. Injection of (acid) combustion gases will not be satisfactory for carbonate/limestone reservoirs but in the United States most heavy oil occurs in sandstone.

Because of (2), the technology can be applied to existing wells.

In the region nearest the wellbore, the formation will be exposed to particulates, high pressure and high temperature. The particulates are ash and unburned carbon. The generator which is being used in a field test

(see below) has been evaluated by using it to generate particles, putting them on a core and flow testing the core. Experimenters at Sandia generated various kinds of particles, characterized them, and looked at the effect of water- and wall-quench. (Wall-quench is a flame retardation phenomenon which occurs when the flame contacts an uninsulated surface whose temperature is lower than the adiabatic flame temperature because of heat losses to the surroundings; this produces an actual flame temperature which is lower than the adiabatic one which results in incomplete combustion and increased soot formation.) It was found that the particles are in the 500A^{o} range, a size which is too small to cause significant plugging. They will study the effect of washing them out, perhaps once a year. Deep reservoirs are in compacted to consolidated zones with permeabilities ranging from 50 to 500 mD. They will try to characterize the technology in terms of the range of permeabilities in which it is acceptable.

The region farther away from the wellbore will feel the effects of high pressure, lower temperature, and the acid combustion gases, SO_2, SO_3 (strong acids), and CO_2 (a weak acid). Will their effects be good or bad? Will they open up the reservoir or simply dissolve material, transport it in the direction of the producing well, and then deposit it still farther from the injection well, thereby plugging the formation? In addition, the changes in pH will cause changes in (oil/water) interfacial tension which could cause emulsions.

At regions far from the injection well, analyses that have been made indicate that fingering may take place. Qualitatively, the fluid flow will be less stable because of the presence of combustion gases, but it is not known how much.

The CO_2 that is injected into the formation will have a beneficial effect. Some will dissolve in the oil in place and reduce its

viscosity, thus making the oil more easily produced. A theoretical analysis was made based upon vapor-liquid equilibrium and the estimate of the effect of CO_2 solubility at reservoir conditions on the viscosity of the mixture. The analysis indicated perhaps a two-fold increase in the rate of production because of this effect. There may be an advantage to using oxygen instead of air as the oxidizer since it will greatly increase the partial pressure of CO_2, its solubility, and, therefore, the extent of viscosity reduction.

The presence of inerts can have beneficial effects. The acids may form emulsions as described above. The gases can have a stabilizing effect on the emulsions, forming foams which could effectively block thief zones. In addition, they will reduce the thermal conductivity of the bed. They will tend to pass over the oil-saturated zone and thereby reduce the heat loss to the overburden. One of the questions to be answered by the planned field test is whether the combustion gases which are pollutants will reach the production wells as gases, dissolved in liquids, or not at all.

Three field tests are planned. The first one is being done by Chevron at Bakersfield using an 800 ft. well which was previously in steam drive. The pressure is 300 - 400 psi, and the response to steam drive is known. The test will run for six months at which time a decision will be made regarding continuation. The test will be a simulation of downhole steam generation. The steam will be generated at the surface and it and the combustion products will be injected into the formation as if they were generated downhole. The response data which they will obtain include the loss to the overburden, flow stability measured by means of radioactive tracers, and emulsions in produced fluids. The last item will not be obtained in the six-month test but will come from either the continuation of the test or after the subsequent return to steam drive. The second test is tentatively planned for FY81. Originally there was to be one each on low

and high pressure but money will probably only be available for one. The last test is to be a pilot in FY83.[1]

In summary, high pressure downhole steam generation may be environmentally safe and applicable to shallow reservoirs. There is an opportunity to choose the steam quality and to tailor the gas composition.

D. Comments from Industry Representatives

There was a broad consensus expressed by representatives of the three companies visited regarding the opportunities and problems for downhole steam generation. The degree of optimism regarding its commercial future, however, varied considerably: apparent enthusiasm, wait-and-see, and a lack of interest were all represented. That is, the descriptions of what might be done were similar, but the expectations regarding results and the predictions of what they would mean differed considerably.

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[1] Note added in proof:

By August 1980, the initial test described in the text had been successfully completed. There was apparently no degradation of the reservoir. Combustion gases were produced but with significant reductions in sulfur and nitrogen oxides. The breakthrough of gas was accompanied by a transient increase in production which subsequently returned to prior levels. New tests are being planned for FY81 which will compare the use of air and oxygen, and the effect of dissolved CO_2 on performance. The test with air will utilize downhole steam generation and the one with oxygen will simulate downhole operation with surface generation and injection of combustion gases.

The discussions dealt almost exclusively with high pressure steam generation because of its potential environmental advantages over its low pressure counterpart. The latter was dismissed primarily because it has the added complications of larger wellbores and additional tubing strings to return the waste to the surface.

The high pressure downhole steam generation has a number of pros and cons. They are discussed below under the following topics:

1. environment
2. economics
3. operations
4. strategic factors

Environmental Factors

The environmental situation in California was discussed in some detail. Environmental problems are so bad that one operator is about to be shut in by the California Air Resources Board (CARB). SO_2 is being removed by stack gas scrubbers; a lot of these are being installed now with many more later; NO_x is also a target. EPA is not pushing NO_x so hard, but CARB sets tolerances that are unachievable in order to "force technology to advance." One strategy has been to extend the time-till-compliance. CARB seems to be almost capricious. The San Joaquin Valley is approaching EPA NO_x standards, and EPA may relax requirements with trade-offs. Time is critical since industry is approaching the NO_x limit. Industry is striving to buy some time until the NO_x control technology is developed, and, at the moment, the downhole steam generation is the only way to reduce emissions and buy time. With new source review retroactive on NO_x one company will only be able to install one generator out of four that are already permitted over the next five years. They would install more than ten times that many with the proper permits, and the loss is 25-30,000 bbl/day of incremental

production. They cannot meet CARB's requirements with the best available technology (BAT): ammonia injection, which costs $700,000 per installation, will do only 60-70% of the job that is required. New resource review rules require that resources be made retroactive to December, 1976, and therefore, they would need a large number of approvals prior to that date for trade-offs. (This is no longer true.[1]) They see downhole steam generation as a method of deferring pollution, helping them with their permitting problems and, below 2,500 ft. depths, providing them enough efficiency to get 80% steam quality.

It seems certain that the combustion gases will break through to the producing well and, thereby, reduce the value of the downhole steam generation. These will include, perhaps, SO_2, NO_x, CO_2, and even CO; there are 100 volumes of flue gas (measured at reservoir conditions) per volume of oil recovered. This could happen in 30 days. When this happens in fire flooding, the gas is produced and caustic scrubbing is used with catalytic after-burning to control pollution. Getty was forced to clean up gases from well casings. It is hard to talk about a permitting operation because the targets keep changing. It is not possible to predict what will have to be done in the field in order to comply, so it is very difficult to cope with it. Nevertheless, some things are standard. The production end is supposed to be a closed system and in practice one operator felt that in industry, in general, and they, in particular, approach it. Hydrogen sulfide gas is always captured, for example; these wells are environmentally more acceptable. Finally, if industry can get early permits, it will commercialize new technology.

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1 In Chemical Engineering 87 No. 7, 54, April 7, 1980, it is reported that CARB "rolled forward the baseline date for NO_x controls to September 12, 1979."

Economics

The two potential economic advantages to downhole steam generation that were discussed are:

1. reduced cost of compliance with environmental regulations.

2. fuel savings due to higher thermal efficiency.

These are discussed below, along with some negative economic considerations.

The economic advantage is derived primarily from the reduced cost of clean-up. In a typical steaming application, the generator costs $350,000 and the scrubber $250,000. The cost of scrubbing could be substantially reduced or eliminated with downhole steam generation. In addition, with full scale scrubbing, there is trouble burying the wastes.

There were different views on the economics of increased thermal efficiency. In one case it was observed that they lose about 12-18% of the heat out of the stack, and downhole generation will increase the thermal efficiency. On the other hand, it is believed that, because of the shallow depths, all that is required is the addition of a little extra heat in order to overcome the heat losses. Furthermore, heat losses can be reduced by insulation. In one application, the heat loss at 600 feet could not pay out a packer. In addition, the cost of the fuel used to drive compressors will be greater than the savings in heat. Future economic analyses should keep in mind one representative's comment: Foster Miller report contains an error in compression horsepower requirements.

One view that was strongly voiced is that the use of coal will greatly improve the economics of steam generation despite the environmental considerations. Coal delivered costs $25/ton, whereas the oil price is about that per barrel; as a result, there is a considerable amount of money available for coal handling and environmental cleanup.

Three other economic factors were mentioned: Workovers and fail-safe controls entail costs which must be included in the analysis. One representative thought that the economics did not warrant all the effort (hidden costs) which would be required to commercialize downhole steam generation.

Operations

A number of operating problems were discussed. None of them was judged to be insurmountable and a few were thought to be manageable, but most of them will require careful consideration. They are:

1. breakthrough of gases resulting in low production

2. corrosion

3. effect of combustion gases and particulates on products and formation

4. pressure limits in the formation

5. explosions

6. maintenance and reliability

7. difficulty of using it for huff and puff

When the combustion gas is put into the formation, the effect of the nitrogen is unknown. One possible problem is that there will be gravity override, or gaseous breakthrough sooner. If produced gases are environmentally acceptable, the technique probably will be too. If not, perhaps they can be tied up with foam. In that way, they will be prevented from coming through. In addition, the foam is expected to produce a better vertical profile. Foam drive at ambient temperature works: Union Oil has done it, and Shell is getting patents now. However, foam stability with steam is a problem. The basic idea is to "heal" an area with foam, either an override or thief zone. With conventional steam, all vapors are condensible; a noncondensing gas is needed in order to get foam.

Corrosion is a problem. It will be necessary to protect the tubing and use stainless steel fittings. In cyclic operation, temperature stress and sulfide embrittlement are potential problems.

The combustion products can react with the oil in place and modify it. Sulfonates can be produced which can form emulsions with the hot water. The nature of the products themselves is expected to be similar to that of the products of in situ combustion, and they are acceptable because they can be blended off with other material. The emulsions are thought to be manageable.

Solids will be put into the formation. As far as particulates from combustion are concerned, heavy oil is in unconsolidated sand, therefore, the problems are not great. Originally, at one company, when they put steam into the formation, they made sure it was very clean. Now they throw everything, that is, all of the solids which are in the water, into the formation. Water with oil and solids is recycled into the formation and eventually it does plug it, even in unconsolidated sands. These solids will probably partially plug up streams of high permeability and improve things.

The consensus was that the combustion products probably do not degrade the formation.

The pressure which will be generated creates both an opportunity and a problem. In some cases it will be necessary to use high pressure in order to energize the low pressure reservoirs in which heavy oil is found. However, there is a pressure limitation. The pressures that are being proposed are close to those which create fractures, roughly 0.8 psi/ft depth. There are cases in which fractures have been created, by Shell in Venezuela, for example. In general however, companies do not want to admit that they have done so; it is not good practice. In Canada, horizontal fractures have been made in shallow wells.

Although one representative said that they can live with an occasional downhole explosion, he and the others expressed concern about safety and reliabiilty. Explosion hazards must be contained and the system must be designed to be at least as safe as a home furnace. The advice was to use a knowledgeable burner manufacturer to design the system. Burner tips have melted and casings have too. People do not realize what can happen when surface controllers malfunction. If there is no operator in attendance, it probably would be necessary to put in a fail-safe mechanism. When one company lost a compressor, it burned up the well.

Using downhole steam generation, it will be necessary to pull everything out of the hole to get a pump in, and that is alien. Normally, they leave the pump in the hole after primary production. The practice is to use the tubing rod annulus, which is used to put steam down the hole, and not to use mechanical packers but rather an inert gas. This keeps the downhole equipment simple. There is a flexibility problem with downhole steam generation. What can you do with downhole steam generation? Not much. How do you kill the well when you are trying to pull it out?

Strategic Factors

The strategic factors are:

1. applications
2. how to proceed towards commercialization
3. general considerations

At the present time, it seems that surface generation of steam with insulated tubing and insulating fluids is effective down to depths of 4000 ft. Most of the oil of interest is shallow. Therefore, eliminating heat losses is not the main idea. It may not be generally applicable but, instead, limited to special situations; it is not a threat to surface generation. Oil patch people like to use existing technology, and downhole steam generation is a maverick. In a comparison between fireflooding and downhole steam generation, the latter is applicable to shallow, viscous reservoirs. Fireflooding is suitable for a deeper (lighter gravity) reservoir, and it works in a thin reservoir because there is heat to throw away. At 4000 ft. with a thick pay, you would not use downhole steam generation because it might need as much as 10,000 barrels of steam per day.

Belridge and Getty, who have the industry successes, believe in heating up the entire formation when a thick reservoir is present. Getty says they get 50% oil recovery. Their strategy is to heat up the whole formation and handle the water economically: 500,000 barrels of water/day producing 50,000 barrels of oil/day. In direct drive, 1½ barrels steam/day are required per acre-ft of reservoir. In a typical 2½ acre area, 100 ft. thick pay zone, the requirement is for 375 barrels of steam per day or 5500 lbs/hr. For huff and puff operations, there still will be a need for a great deal of steam. In addition, there will be a requirement for considerable turndown to cover the required range. Eventually many fields will go to direct drive. So there are applications.

Downhole steam generation needs to be thoroughly field tested. One representative stated that at least three or four successful tests over a period of three to four years would be necessary before he could recommend it. Another spoke in terms of 9-18 months required for a single test.

There is a need for careful planning of field tests. The immediate objectives of such a test would be to determine:

1. Whether the equipment works
2. The effect on produced gases
3. The effect on produced fluids
4. The effect on oil recovery rate
5. Corrosion rates
6. Effect on formation fluids and solids.

As far as the gases are concerned, are they environmentally acceptable? As far as fluids are concerned, are there emulsions formed that would prevent movement of the fluids? An improvement in oil recovery rate of 25% was suggested as a desirable result but not as a fixed goal. If a breakthrough were to occur before any increase in production rate occurred, it would be considered to be a negative result. Nevertheless, some perseverance may be required; steam cycle took 4-5 years to get going. In summary, an adequate test will be concerned with balancing steam and inerts while worrying about gravity override, heat, gas, corrosion, steam quality at the sand face, reliability, maintenance, packers, possible loss of a well, and the effect of combustion gases on produced gases and fluids and formation fluids and solids. A complete test will isolate as many of these variables as possible using as many measurements as practical.

One company has been looking at downhole steam generation regularly for twenty years and has always found it wanting. Another looked at it very carefully as recently as five years ago and found that high

pressure operation, which they judged to be essential, was uneconomical. Although there is a general agreement as to the problems to be solved, there is none on the likelihood of early commercialization.

E. Economics

The economics that were previously prepared by Sandia Labs were reexamined from a cash flow viewpoint. A sample calculation is shown in Appendix B.

The results of case studies done on rate of return, capital investment, and crude oil price, P, are shown in Table 1 on the following page. The dependent variable is X, the required oil yield expressed in bbl/10^6 btu in 85% quality steam. Also shown are the corresponding values of the steam/oil ratio at the required oil yield. In order for these results to be on a comparable basis with the Downhole Oil Treatment results, XP is also shown. The cost of fuel for steam generation was taken to be the crude oil price. If a premium must be paid for the fuel (middle distillate, for example, as chosen for Sandia's original costs analysis), the results in Table 1 may be easily modified. For each 20% increase in fuel price over the crude oil price, increase X by 0.07, and calculate a new value of XP. For example, for 20% ROI, $1,105,000 capital investment, $25/bbl of crude oil produced and $30/bbl of fuel for steam generation (20% premium), x = 0.84 + 0.07 = 0.91 and XP = 25 x 0.91 = 22.75.

Table 1

Required Oil Yield for Representative Economic Factors

ROI /DCF	Capital Required	Crude Oil Price P	Required Oil Yield, X	Steam/Oil Ratio	XP
%	$1,000	$/bbl	bbl/10^6 btu	bbl/bbl	$/$10^6$ btu
20	1,105	25.00	0.84	7.6	21.0
20	1,105	32.50	0.72	8.8	23.4
20	1,105	40.00	0.65	9.8	26.0
20	1,657	25.00	0.93	6.8	23.25
20	1,657	32.50	0.80	7.9	26.0
20	1,657	40.00	0.72	8.8	28.8
40	1,105	25.00	1.00	6.3	25.0
40	1,105	32.50	0.85	7.5	27.6
40	1,105	40.00	0.76	8.4	30.4
40	1,657	25.00	1.19	5.3	29.8
40	1,657	32.50	1.00	6.3	32.5
40	1,657	40.00	0.88	7.2	35.2

All the results are favorable. The required oil yield ranges from 0.65 to 1.19 bbl crude/10^6 btu with the highest requirement for the case where the ROI is 40% after taxes, the capital investment if 50% more than the estimate, and the crude oil price is $25/bbl, the low end of the expected range. The 0.65 - 1.19 values seem to be technically feasible since it has been estimated that Getty gets 0.5 - 1.35 bbl/10^6 btu.

It is also important that these favorable economics are not sensitive to any one factor or combinations of factors. This means that even if the economic factors prove to lie outside of the ranges selected, there probably will not be an unusually large effect on the performance required.

In addition to the sample calculation, Appendix B also contains the general formula for calculating X when the various economic variables are specified. It may be used to calcualte the required performance for any set of values for the economic factors.

F. Chemical Oil Recovery Company (CORCO)
P. O. Box 9666
Bakersfield, CA 93309

Their brochure states that "CORCO was formed to assist in solving the problems of EOR by providing design, equipment, products, engineering, laboratory and experienced service personnel to the petroleum industry." CORCO was founded in 1973. They are a licensee of Phillips Petroleum Company for their U. S. patent no. 3456721, July 22, 1969, assigned by R. V. Smith. The patent covers a downhole steam generator that was developed at Phillips from their combustion research program. Mr. Smith, who is now retired from Phillips, consults for CORCO. The latter has a five-year exclusive agreement for the application of this technology in the United States.

I was shown the drawings of the generator and the generator itself in the CORCO office. They have bench-tested the concept of a downhole steam generator with success. The generator is 6" in diameter and 6' long. All controls will be standard catalogue items. They feel that they have taken a practical approach and have designed a generator for rugged duty. Portable generators are not rugged enough for general application. The first real test is scheduled to begin in six weeks with manual control. It will take place in a Kern River field in cooperation with an oil producer. It will be in a low pressure reservoir at a depth in excess of 1,500 feet. It will be carried out with a minimum of publicity and attendance, although there will be oil industry representatives present. The test will be run using crude as fuel and they will measure the response of the well and the unit. An area of CORCO expertise is in oil field production measurements, and the test will be conducted with the appropriate measurements. The well itself has a long production history and since it is in cyclic operation, the response to the steam generation test will be relatively rapid. When the test is over, the generator will be examined and then used for further bench-testing.

Their generator concept is a departure from others currently being used. In their oil field measurement work, they have found that at a central steam generator the quality may be 82%, at the well head 37%, and at the sand face 31%. The CORCO generator will sit at the top of the well and deliver steam with 50°F superheat which will result in 90% quality steam at the sand face after the heat losses in the well. Water will be introduced directly into the flame front and the products will be exhausted into a tubing string. All the combustion gases will be put into the formation. They recognize that these gases will appear at the producing well, but in view of the fact that these wells must have vapor recovery equipment now, they think that this is not a problem. They agree that they might need technology to remove sulfur dioxide and nitrogen oxide and that it may require new technology to get these pollutants out of a cold system. They are working on environmental solutions and measurements.

They plan to sell either hardware or service as a field service organization. They are shooting for the end of the summer for their initial marketing effort. They plan to start providing the service at the start of the fourth quarter. In addition to the service itself, they will offer courses on the generator and basic controls to educate field people, emphasizing the principles involved: how it works, why, and how to fix it.

G. M.C.R. Oil Recovery International, Inc.
9025 Wilshire Boulevard, Suite 215
Beverly Hills, CA 90211

This company ran the following advertisement in the December 3, 1979, issue of Oil & Gas Journal:

DOWNHOLE
STEAM GENERATOR
AVAILABLE FOR
HEAVY OIL
RECOVERY

Research and development oil company has developed proprietary product for downhole steam generation. Equipment availabe for field use.

COMPANY SEEKS JOINT VENTURE
PROPOSALS FROM:

I. Natural resource corporation with heavy oil reserves

II. Oilfield service companies that seek to expand present field services to a new division for field steam service

DOWNHOLE STEAM GENERATOR CAPABILITIES:

1. Maximum depth 5,000 feet
2. Steam output 1,000 bbl./day
3. 75% steam quality
4. Maximum Steam temperature 750°
5. 15 million Btu maximum
6. Minimum bottomhole diameter 7"
7. Gravity of oil 8.5 - 15
8. Field service cyclic steam or steamflood

Additional information appears in Appendix A, copied from materials given out during the interview. Additional information obtained during the interview with Mr. Craig Rhoades and Dr. Martin J. Gould, is presented below.

The technology is based upon a unique design (not described) which has been bench tested and is the basis of a patent application. They feel that their approach is very practical, geared to existing oil field practice; for example, their design conforms with state-of-the-art packer technology. They have taken this approach in order to get the technology commercialized faster.

They believe that in shallow fields their technology is competitive with conventional steaming operating up to 2,000 ft. depths. They are thinking in terms of 2,500 ft. - 5,000 ft. depths as well. They believe that their computerized analysis predicts the heat delivered to the formation in btu/hr. to within $\pm$ 1-2%. In a typical application, the heat is carried by 70% quality steam, delivering 10 - 15 MM btu/hr at the oil face at 550°F at a steam pressure of 1,200 psig. Alternatively, pressures may range from 250 to 2,000 psig. The fuel is No. 1 or No. 2 diesel. The costs

shown in Appendix A are without an air compressor. The total cost may be in the $500,000 - 800,000 range.

We discussed environmental problems briefly. It is possible to either put the combustion products into the formation or use a low-contaminant emission system. They believe that environmental standards will be relaxed when there is an energy crunch.

A copy of a letter from the two people who were interviewed appears in Appendix A.

VI. DOWNHOLE OIL TREATMENT

The work on downhole oil treatment is a joint project of the U. S. Department of Energy and

World Energy Systems 2120 Ridgar Blvd. Fort Worth, TX 76116	Aerospace Research Corp. 5454 Jae Valley Road Roanoke, VA 24014

It is being done at Aerospace Research in Roanoke.

A. The Concept

The idea behind this project is that it is possible to carry out the viscosity reduction of oil in place by chemical means. High temperature alone will do it, and these high temperatures can be achieved by partial oxidation of the oil. This can be thought of as either thermal cracking or vis breaking or a process akin to in situ combustion. The viscosity reduction can also be achieved by hydrocracking, which, in the absence of a catalyst, requires high temperature and high hydrogen pressure. These two techniques are combined with straight steaming which is used to heat up the

formation. Thus, the concept is to utilize technology which is otherwise known - downhole steaming (controlled), downhole in situ combustion, and surface visbreaking/thermal hydrogenation--to bring about viscosity production in order to produce oil. The viscosity reduction will be necessary in the refinery in order to produce finished products, and here it can be carried out as a step toward increased production.

As will be discussed further under Operating Philosophy, the flexibility which the hardware offers makes it possible to think in terms of downhole refining. As will be discussed under Comments from Industry Representatives, others have considered downhole chemical reactions, and in situ combustion is just that, but without a substantial degree of control. If this technology makes it possible to propagate and control chemical reations, it is possible that downhole refining will find siginificant application. Fifty years ago, the control of chemical reactions which are so commonplace in a refinery today, was in its infancy. It remains to be seen whether downhole chemical reations assume a place of comparable importance in oil production, and whether the hardware that is being developed in this project plays a significant role.

B. Hardware

The design requirements for the hardware are the ability to produce 20 MM btu/hr as steam at about 600°F. The 6" well is accepted as a constraint. It is also necessary to be able to turn down either the oxygen or the hydrogen so that a mixture of steam and hydrogen or steam and oxygen is delivered to the formation.

It is believed that control is very important because past failures have been due to system design problems. At the startup of such a generator, high pressures will be required, and then it will be necessary to reduce the pressure in order to avoid choking and fingering. Therefore, a

large turndown ratio is needed. If the pressure drop in the formation is too high, the flow will go around the tight regions. If the pressure drop is low, the sweep efficiency will be high. It is planned to monitor the well pressure and, when it increases, to reduce the flow in order to keep the pressure constant or reduced.

A ten-stage process is envisioned, although six stages may be sufficient. Each stage is a burner with water quench and is about 6" long. At the top of the series of stages there is a special section called a pilot in which the combustion chamber reaches a temperature of 2,000^{o}F. In the stages themselves, the temperature will be 1,600^{o}F, and when the steam-gas mixture emerges from the last stage, it will be approximately 600°F. A packer is used in this last stage.

The burner operation is as follows: based on the total flow which is desired, the total hydrogen is fixed. Then the individual oxygen flow rates are controlled by uphole controllers and individual feed lines. Water to each stage actually controls the temperature to 1,600^{o}F. The total heat delivered to the pay zone is as steam. The total flow can be changed by cutting out stages.

Because of the use of hydrogen and oxygen, safety is an important part of the system design. Hydrogen production will be sited more than 1,000 feet away from the well head. The controls are based upon 1,000 foot lines and the corresponding lags. The project management has high explosive and rocket fuel development safety know-how and feels confident of its design.

The hydrogen production is via steam reforming of LPG followed by shift conversion of the CO and H_2 or partial oxidation of produced crude.

Field oxygen is available in truck-mounted modular units capable of producing 4 MM btu/hr.

Downhole there will be nothing electrical. Control is achieved with 49 pneumatic valves capable of 10^6 cycles.

The range of application is formations with depths in the 1,000 - 3,000 ft. range, and therefore they are using 3,000 psi materials.

C. Operating Philosophy

The present view of operations anticipates the use of the three modes of operation previously mentioned. Initially, the generator would be used to produce steam only, to heat up the formation. When it reached an appropriate temperature, the hydrogen flow would be reduced, and steam and oxygen would be used to achieve controlled in situ combustion. This is expected to result in temperatures sufficient to achieve vis breaking via wet oxidation. The third mode of operation would use a steam-hydrogen mixture to carry out thermal cracking and hydrogenation to reduce cracked products.

Production would be via side wells or cyclic operation. Side wells might be used to produce hydrocarbon vapor which resulted from the cracking. Heat recovery would be employed; it might even be economical to use that heat to obtain a preliminary fractionation of the products. As an alternative to the use of producing wells, it might be appropriate to produce the oil via a process analogous to steam cycle. With a 6" well it would be necessary to pull the generator, but with a larger well, a separate tubing string might be used.

If oxygen is produced on-site via distillation of air, there is another means for helping production. The oxygen generator could be

operated as a nitrogen generator (which would leave some nitrogen in the oxygen). While the nitrogen is still liquid, it might be pressured to a desirable level, and nitrogen vapor put into the formation to energize it. How this might be done needs to be worked out.

The best way to produce still needs to be determined. It is a major problem partially because of the use of a new technology.

D. Target Resources

The targets are not the resources in which steam drive or cyclic steam is economical. Any resource present at depths less than 2,500 ft., which is not amenable to conventional production via primary, secondary, or tertiary means is a potential target. These are, in order of potential:

1. Heavy oil in consolidated sandstone
2. The material with the next lower hydrogen-to-carbon ratio, perhaps tar sands
3. Oil shale
4. Coal
5. Abandoned wells in light oil reservoirs
6. Lignite

The validity depends, of course, on economics. The principle competition for producing these target resources is mining. To produce liquid fuels from some of these resources will require synthetic fuel technology, which is projected to be expensive, perhaps $40/barrel, or more. It is believed that

there are appropriate target resources in the first category in Arkansas, Louisiana, and East Texas.

E. Comments from Industry Representatives

Comments were obtained from representatives of four of the oil companies listed in the introduction to this report. At least three of the four have experience in downhole chemical reations as indicated by their reports of experimental work, their issued patents, or both. At least one of them has such experience in downhole hydrogenation, another in partial oxidation of oil in place other than in situ combustion, and the other in variants of in situ combustion. Their representatives were informative regarding the problems and opportunities in downhole chemical reaction. In the presentation, below, of the results of the discussions with these people, the material is organized topically. Not every point was covered during each company visit, so that the report does not represent a consensus of all those interviewed. There was much overlap, however, and so the comments can be interpreted as representing substantial agreement. Where different views were expressed, they are presented separately within the same topical discussion. The material is grouped as follows: Opportunities, Conceptual Issues, Potential Operating Problems, and Suggestions for Future Work.

Opportunities

The best opportunities lie in the areas of unproducible, or very hard to produce, fields. There are "dry holes" in which sample cores are extractable with the normal amount of oil in place. It is heavy oil bearing rock in which the combination of low permeability and high viscosity prevents the oil from being produced. If such a finding is made, it will be declared a dry hole because there is no existing technology to produce it. There are hundreds of millions of barrels of oil in place of this type. However, at 5,000 ft. - 5,500 ft, you get to the critical pressure of water

and there is no latent heat. There is no application of steaming down there, although in situ combustion is all right. Nevertheless, most of the tight formations are shallow, at depths not exceeding 2,000 ft. After stating that hard-to-produce areas are prevalent, one representative questioned how much potential they have. Another possibility is in areas which are too deep to steam, and which are too thin to steam, meaning that there is too much of a heat loss. Eventually, tar sands will be a good target. Finally, hydrogenation and high temperatures might be used to work a fracture; steam stimulation is not effective in the tight formations.

Appropriate targets probably are:

1. oil shale
2. tar sands
3. coal
4. lignite

In oil shale, either hydrogen or oxygen might offer a solution to the problem of extracting oil from the kerogen matrix. Oil shale formations are massive, continuous, very slightly fractured, and have zero permeability. Some people think that 1,500 - 1,800^{o}F steam will do it because it will condense and will be separated easily, however, there is a clear pressure limit. The other three targets also have the same pressure limitation. Deep coal is "amenable" to hydrogenation; however, it is not well defined. One ton of coal will yield two barrels of liquid fuel of lower heating value.

This technology has at least two environmental advantages. One of them is the ability to produce steam without pollution and the other is the use of oil-in-place as a fuel.

Another advantage is based on the fact that in steaming piping expansion causes pipe to pop out and rupture cement bonds. In this application, only the bottom section will be thermally expanded, and this is

a valuable advantage. Steam generation in the well bore near the surface does not solve this problem.

Most representatives thought that 8×10^6 btu/hour is a satisfactory rate of heat delivery. One stated that the minimum heat delivery is 15×10^6 btu/hour.

There would be no objection to using a field service to generate steam (buying the steam in the field).

Conceptual Issues

One of the chief concerns was with the energy efficiency. At the time that the interviews were conducted, the results of the energy balance, which appear elsewhere in this report, were not available. In hydrogen generation, the energy efficiency may not be satisfactory. In addition, the raw materials necessary for that generation will not be plentiful in the fields where the hydrogen is needed. Do an energy balance and look at the hydrogen take-up requirements, as well as the thermodynamic equilibrium. This technology makes hydrogen by the reverse of the same reaction which will take place downhole. Efficacy of hydrogenation downhole is very low because it is nonselective. The efficiency of the use of the energy that is released in the hole is low compared with the energy used to produce the hydrogen and oxygen. Good refinery management requires selective hydrogenation, which is achieved by segregating stocks according to market requirements. In addition, it may be that the use of a premium energy source, such as methane or propane, will not be acceptable. Oxygen is not much better than air for the production of steam.

Another important issue was how this technology will compare with its competition: in situ combustion, in situ steam reforming and

steaming. Wet combustion is a good alternative or good competitor to this technology. The auto-ignition temperature is somewhere above 175°F. Obviously, this uses heavy oil (in place) as the fuel. Some distillation takes place and, therefore, some selection of fuel material. The wet combustion process will thermally crack the oil in place and drive it ahead. Coke and asphalt are left behind. The biggest problem is getting communication between injection and production wells. This is very difficult in tight formation, and it is the reason why it is done there. Reverse combustion was developed to handle this problem. With a little gas transmissability, you can drive the gas into the formation near the production well and start the burning at the production well. This will produce combustion gases and cracked oil near the production well. The burn will be from the production well to the injection well. If the proposed downhole oil treatment is any good, one could just add hydrogen to in situ combustion.

Hydrogenation is one of the few processes with some promise of in situ capabilities. In situ gasification, or partial oxidation, can take place producing carbon monoxide and hydrogen. In hydrogenation, the order of reactivity is mercaptan (RSH), sulfide (RSR), and nitrogen compounds. In steam soaks in California at 2000 psig, H_2S and $(NH_4)_2S$ have appeared in the casing. It is suspected that the steam reforming of methane was taking place forming carbon dioxide and hydrogen. The hydrogen reacted with mercaptans to form hydrogen sulfide, which in turn could react with ammonia to form the ammonium sulfide. In this operation higher API gravity oil was produced, which could have resulted from hydrotreating. It is better to do steam reforming in place, as suggested by the above observations, and produce $H^{\cdot}$. Perhaps iron would be a catalyst for hydrocracking and could be carried in the water.

Steaming is a strong competitor. Only 20% of the cost is in capital equipment, and 80% is in fuel. The total cost of scrubbing is $1.00/barrel of oil produced.

There was considerable discussion of thermal hydrogenation. When this technology is used to produce excess of hydrogen, it is supposed that thermal hydrogenation might take place. Hydrogen will migrate upward. The maximum pressure may be calculated from the rule of thumb of 0.7 - 1.0 psi/ft. depth. (At 2000 ft., the maximum pressure is 2000 psi.) No significant hydrogenation would take place at 1000 psi and 600 - 700°F. There are grave limitations on the extent to which hydrogenation will take place, although thermal cracking is reasonable. It does not have to have fluid injection schemes which are proposed. Hydrogen donor cracking does not suppress coking, it only saturates light ends. With reference to the hydrogen donor cracking, it is judged that the proposed technology probably would not suppress coking, either.

It is possible to get steam cracking at 2000°F. In the steam-only version of this process, steam cracking could take place but it is available in a standard combustion process.

The mass of rock in a formation is so great relative to the oil that one company's calculations have shown that it is not reasonable to expect that the exothermic reaction will maintain the desired temperature level and, therefore, the technology must include intermittent or continuous heating of the formation. (The previous statement seems to be based upon the amount of hydrogen that can reasonably be used downhole, the amount of reaction that will take place using that hydrogen, and the amount of heat that will generate.) On the other hand, when this technology is successful, it will produce an enormous amount of hot rock. It will be possible to put in water which will be converted to steam, and use that to convert the hot rock to pressure. Economics suggest the use of lower temperatures. Heat release in <u>in situ</u> combustion must make up heat losses to the cap rock and base rock. Air must be fed to the formation at a specified rate to make up for these losses. If you were to depend on hydrogenation, there would be a much smaller heat of reaction to work with. Steam and oxygen in <u>in situ</u>

combustion lower the temperature and, therefore, the heat loss. This is good for economics. The lower temperatures are around 700 - 800°F. Furthermore, since the energy left in the rock is also high, in situ combustion uses steam to pick up the heat and carry it to the combustion front. There was one additional concern expressed: Will this technology provide sufficient sensible heat away from the injection well?

Discussion of interaction of the products of this technology with the rock produced divergent views. There was agreement that there would be clay swelling but not on its effect. The system in which this technology will be applied will have low permeability, and constitutent water will be trapped. Montmorillonite clays will swell from the action of the combustion water and will form impermeable layers. This is not necessarily bad in that the fresh water which produces these changes in the clays as it displaces salt water might improve conformance of the formation. One view was that the theoretical chance of success in light of the clay swelling problem is not good and difficult to predict. Even if you can rehydrate the clay and open up fractures, it will be necessary to deal with the concomitant plugging. The alternative view was that clay swelling will not be a problem at elevated temperatures, just at reservoir temperatures.

Shale with trapped water will explode when exposed to extreme degrees of heat.

In applying this technology for oil production, where will the driving force come from? It will be necessary to apply pressure; push/pull (huff and puff) will not work on 0 - 15°API oil. How will it be pressurized? There will be an increase in the number of moles of gas as a result of cracking and hydrocracking; how can this be used?

All of the above issues, except perhaps the energy efficiency, are aspects of economic considerations. The technology must be profitable commensurate with the level of risk which a potential user sees.

Potential Operating Problems

As far as the gas generation technology is concerned, oxygen and steam mixtures may cause serious metallurgy problems. There is a question as to whether the burner can be kept cool enough and whether there is a sufficient cross section of area for the heat flux. It should be born in mind that quartz fusion takes place at 1200°F and the hydrogen-oxygen flame is much hotter than that.

This technology is potentially dangerous and the explosive conditions which will be created downhole may be a limiting factor. Production people will be greatly concerned about safety. Safety issues have killed the use of oxygen. One company has looked at and found that it was not worth it. Hydrogen is scary because it is explosive. Oxygen is scary because it is explosive. In addition, these will break through to the production well.

As a general consideration, if a field test is carried out, it would be desirable to test the produced oil to see if anything chemical happened. In particular, it may make hydrogen sulfide.

There is a problem in equipping a well for high temperature. An example from one company's experience is that they injected air for a month into thick pay, and used thermocouples to look for hot spots. Nevertheless, despite their precautions, oxygen diffused, undetected, upward through the formation and burned a hole in the casing.

Additional concerns are: the Safe Drinking Water Act, and the need for extra caution in creating pollution problems away from the well.

Suggestions for Future Work

The work of one company was described and the benefits that were obtained from computer simulation of the downhole reactions were emphasized. The representative felt that for this technology there will be no need for reservoir simulation. This view was widely shared. A good, orderly development of this technology requires computer simulation of it. In order for that computer simulation to be reliable, it will require laboratory simulation to develop empirical coefficients, and perhaps boundary conditions that are required for the computer simulation. The laboratory and computer work should be the next two steps in the development. Do not go to the field: see what it will do in the laboratory. Try it at the Bartlesville Energy Technology Center or the Laramie Energy Technology Center or in private production laboratories. The chemistry is not difficult; just establish effective flow rates.

Finally some suggestions were made for field tests and operations. It will be important to test for transmissability of non-condensibles, and then use a kind of reverse combustion. Alternatively, huff and puff could be used. Do an ordinary steam soak just to get a cavity using an ordinary field heater, which is cheap and trailer-mounted, and then pump the oil out. Run it for a few weeks, and if you don't produce oil, you are in the wrong place.

F. Energy and Economics

An approximate energy balance has been calculated, and the development and results are shown in Appendix C. The basic balance is as follows:

In

Propane required for fuel and feedstock to make hydrogen

Hydrogen required to make propane from produced crude or equivalent

Crude to make propane

Electricity to make oxygen

Out

Produced crude minus refinery losses

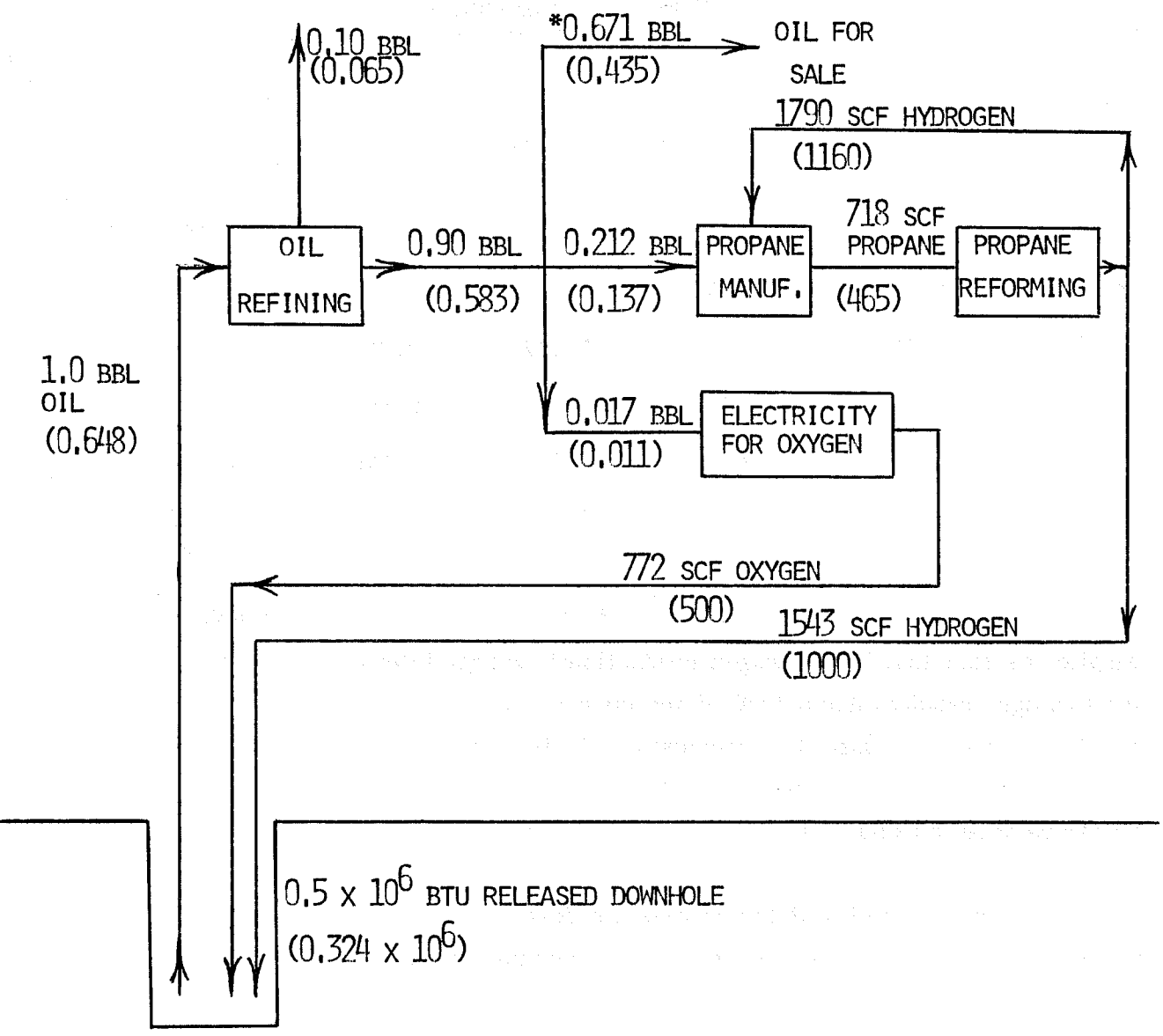
That is, for each barrel of crude produced there is a need for energy and materials to produce the oxygen and hydrogen by which it was produced. The hydrogen is assumed to be derived from steam reforming of propane. The propane can be thought of as coming from the crude after hydrogenation of a fraction of it. This requires some of the hydrogen produced from the propane reforming. (The rest of the hydrogen comes from the crude and the steam.) This is shown schematically in Figure 1. The principal set of figures is based upon 1.0 bbl of oil produced, and it shows the yield distribution. The figures in parenthesis are based upon 1,000 SCF of hydrogen which is the basis for the calculations in Appendix C where the details are given.

The results shown in Figure 1 are for the particular case in which the oil production, X, is 2.0 bbls/10^6 btu released downhole and the refinery yield loss, Y, is 10%. In that case, the net oil yield is 0.671 bbls of oil produced; the result is identified by (*). Net oil yields have been calculated for other values of X and Y. The results are summarized in Table 2.

This analysis is often made without regard to the refinery yield. In that case the production which is calculated to produce as much energy as it consumes is 0.456 bbl/10^6 btu released. When production reaches twice that level, 0.91 bbl/10^6 btu, the net crude production, in excess of the material and energy requirements, is 50% of the total.

FIGURE 1

Schematic Diagram for Balanced Downhole Oil Treatment



Bases: 1 bbl of oil produced at the wellhead

(Alternative basis: 1000 SCF hydrogen released downhole; results shown in parentheses.)

Stoichiometric oxygen

Oil production: 2 bbls crude/10^6 btu released

Refinery yield loss: 10% including oil required to provide energy for refining

TABLE 2

Net Yield of Crude Available for Sale

X, Oil Produced, bbl oil/ 10^6 btu released downhole	Table entries are bbl oil available for sale/bbl produced				
	Y, Refinery Yield Loss				
	0.0	0.05	0.10	0.15	0.20
0.5	0.088	0.038			
0.75	0.392	0.342	0.292	0.242	0.192
1.0	0.544	0.494	0.444	0.394	0.344
1.5	0.696	0.646	0.596	0.546	0.496
2.0	0.772	0.722	0.672	0.622	0.572

It is clear that net energy production is potentially achievable despite the fact that the hydrogen production is energy intensive. Because the hydrogen requires about 95% of the energy and oxygen only 5%, if not all the hydrogen is used for combustion, it is necessary to maintain a constant ratio of crude produced to hydrogen consumed in order for the energy balance to remain as good as is shown in the table.

The economics of the process are developed in Appendix D. The business concept is that the people who will commercialize the process will offer it as a service to production companies. Therefore, it is necessary to separate the service company's economics from those of their customers, and this has been done.

The first step was to establish a rental fee for the service company to charge its customers. It must be borne in mind that this has been done NOT to establish that fee itself but to determine under what circumstances the technology will be attractive to the petroleum industry. At this point, there is considerable uncertainty in the figures, but the direction for the business and for future experimental work seems clear.

The first attempt to determine the rental fee was based upon purchase of small hydrogen and oxygen units. The total capital for this approach came to $2,300,000 (see Appendix D) and the rental which would produce 20% return on investment by discounted cash flow (ROI-DCF) was $3,878/day. It was apparent that the oxygen plant required a relatively large cash flow ($1,427/day) while the oxygen capacity requirements could be met by purchases of bulk oxygen at $90/ton for $1,170/day. It is cheaper to buy it than make it. Similarly, the hydrogen plant cash flow requirements are $1,203/day plus $2,066/day for propane purchases, or a total of $3,818/day. Considering bulk hydrogen purchases at $8.50/1,000 SCF, it was found that 75% of the hydrogen capacity requirements could be met. Since the unit would be operated at less than full hydrogen flow for much of the time, it is cheaper to buy hydrogen than to make it. The system, then, consists of water treatment facilities, incidental captial investments, working capital, and operating costs. The calculated rental is $1,248/day. The customer buys his own hydrogen and oxygen.

The user's economics are based upon that rental. The method of analysis consists of determining the upside potential of the process and comparing it with the downside potential. The idea is that in any new situation the user must run a test which would have the following costs:

1. additional workover of well (if needed)
2. rental of gas generator
3. hydrogen

4. oxygen
5. operating costs

An equation is given in Appendix D which expresses these costs as well as revenues. The equation permits one to calculate the costs of the test, the cost of continued operation, the revenues for that operation, and the ratio, R, of upside potential (expressed as total net dollars received discounted to date of completion of test) to downside potential, which is the cost of the test. The critical parameters are X, bbl oil produced/10^6 btu released downhole; P, price received for the produced crude, \$/bbl; Z'_o, the fractional oxygen use during production (relative to the rated capacity of 300,000 SCF/day) and Z'_h, the fractional hydrogen use during production (relative to the rated capacity of 600,000 SCF/day).

A sample problem is calculated in Appendix D, and the results are shown in Figure 2. In addition to the economic parameters previously cited - \$1,248/day rental, \$90/ton of oxygen, \$8.50/1,000 SCF hydrogen--the following are used: \$25,000 workover cost, operating cost of \$562/day, a test period of 90 days, and a production period of three years. During the test period, the average oxygen utilization factor, Z'_o, is 0.50 and the same is true for Z_h, the test period hydrogen utilization factor. The total cost of the test has been estimated to be \$470,000.

Three operating strategies have been evaluated economically with the results shown in Table 3 and Figure 2. Cases 1 - 3 utilize full oxygen capacity, $Z'_o = 1.0$, and a reduced hydrogen requirement, $Z'_h = 0.25$. It is assumed that the excess oxygen is consumed by <u>in situ</u> combustion. Cases 4 and 5 correspond to straight steaming and are included here only for comparison purposes; it is not expected that downhole oil treatment will compete with any form of steaming. Case 6 is for hydrogen pressure with steam. This result is difficult to interpret since the oil yield is based upon the heat released and no credit is given for the incremental oil produced as

a result of the hydrogen dissolution or treatment. The oil yield would have to double as a result of hydrogen dissolution or treatment in order for it to be as economically attractive as steaming. The oil yield must increase three-fold to compete with wet oxidation.

In the calculations, the cost of a test has been treated as an investment and the indicated rates of return on investment have been used to account for the time value of money. The benefit/risk ratio, R, has been calculated after discounting the return at the indicated rate. If the returns had not been discounted, the benefit/risk ratios would have been higher.

TABLE 3

Downhole Oil Treatment

Benefit/Risk Ratios for Representative Cases

Case No.	Description	Fraction of oxygen capacity used	Fraction of hydrogen capacity used	XP	P $/bbl	X	R
1	Wet oxidation	1.00	0.25	60	30	2.0	6.2-8.0
2	Wet oxidation	1.00	0.25	45	30	1.5	3.5-4.5
3	Wet oxidation	1.00	0.25	40	25	1.6	2.2-3.0
4	Stoichiometric combustion	0.5	0.5	80	40	2.0	3.8-5.0
5	Stoichiometric combustion	0.5	0.5	80	30	2.7	3.8-5.0
6	Excess hydrogen	0.5	0.25	110	30	3.7	1.0-1.5

What do these economics mean? A reasonable price for produced crude may be \$30/bbl. A potential ratio of 5.0 is also in the general region of interest - \$2.3 MM return in 3 years on a \$470,000 test. For Getty Oil, X is apparently 0.5 to 1.35 depending on whether you assume 85% steam quality or 30%. The latter figure, which is certainly within the possible range (see Section V, Chemical Oil Recovery Company, in which they claim a reduction from 82% at the generator to 31% steam quality at the sand face for unidentified clients), suggests that X = 2.0 is possible and attractive. What production level is implied? As shown in Appendix D,

$$\text{total production} = X\,(132Z'_o + 62.4Z'_h)$$

For $X = 2.0$, $Z'_o = 1.00$, and $Z'_h = 0.25$

$$\text{total production} = 295 \text{ bbl/day}$$

For $X = 2.0$, $Z'_o = 0.50$, and $Z'_h = 0.50$

$$\text{total production} = 194 \text{ bbl/day}$$

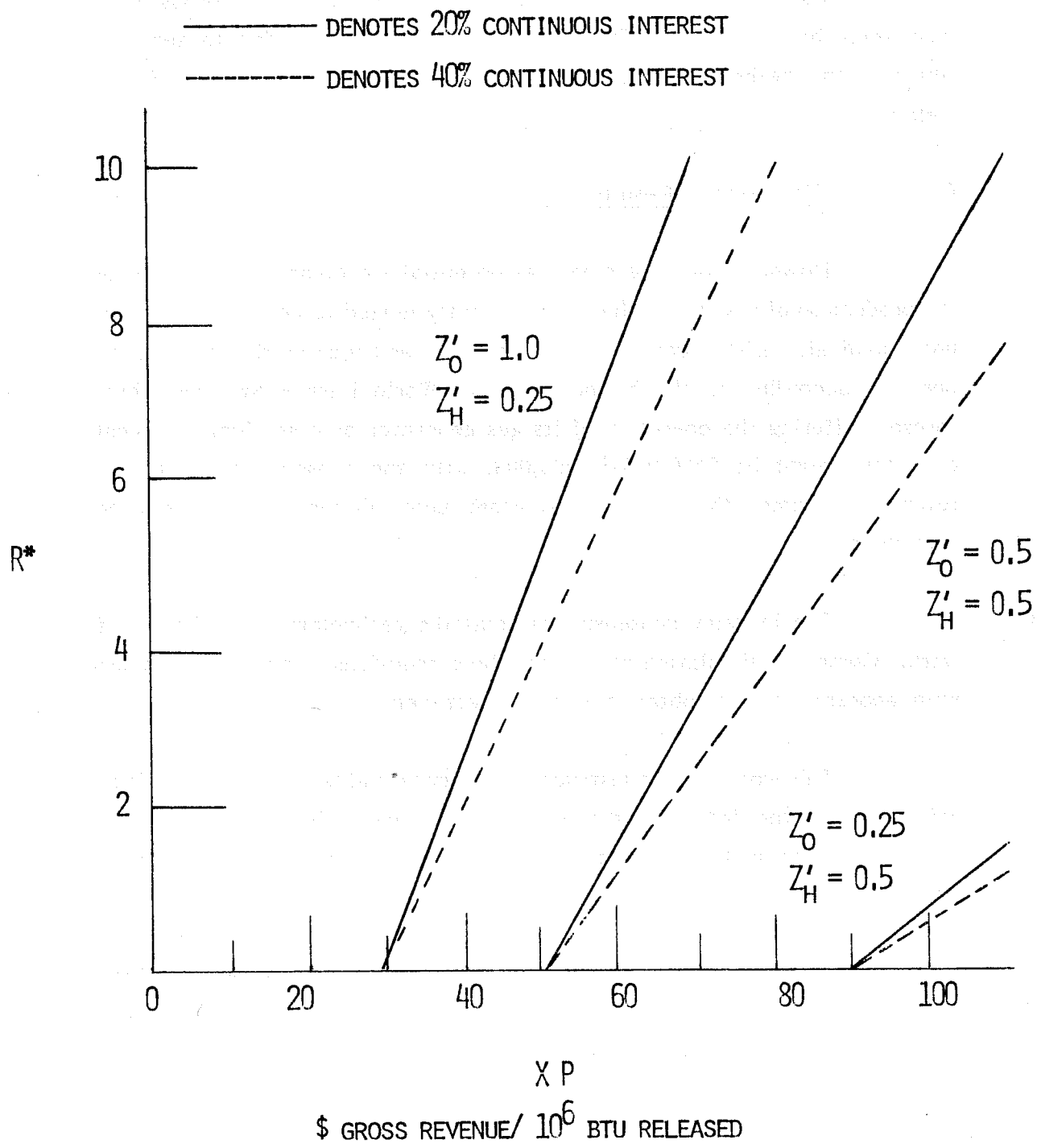
These are the production levels required to generate the cash flows that make this attractive.

The sensitivity of these results to the numerical values of the parameters is of interest. At R = 5.0, the sensitivity of practical importance is probably about 1.0 which is a change of $\pm$ 20%. This is equivalent to a change in costs of 0.20 (470,000) = 94,000. Therefore, if the initial cost of installation went as high as \$120,000 (from the \$25,000 allocated for workovers), R would be reduced to 4.

For the first case, $Z'_o = 1.0$ and $Z'_h = 0.25$, the sensitivity to oxygen and hydrogen costs is about the same. An increase in cost in either one of about 40% will decrease R from 5.0 to 4.0. It would take a 50% increase in rental or a 100% increase in operating costs to produce the same effect. The major difference in the second case, in which $Z'_o = 0.5$ and $Z'_h = 0.5$, is an increase in sensitivity to hydrogen cost: an increase of 20% will

FIGURE 2

Economic Attractiveness of Downhole Oil Treatment



*R IS THE UPSIDE POTENTIAL RELATIVE TO THE DOWNSIDE RISK, $ REVENUE FROM 3 YEAR TEST/$ TEST COST

change R from 5.0 to 4.0. In general, there is no extraordinary sensitivity of the results to the economic parameters.

Using the equation for R given in Appendix D, numerous other cases may be evaluated. The above examples are intended to serve to illustrate the method, and the results are presented to set targets for future field work.

G. Discussion of Results

Downhole oil treatment has potential for commercialization for the production of resources which are currently judged to be unproducible or uneconomical. Little capital investment is required on the part of an operator according to the business plan of World Energy Systems which foresees offering the operation of its gas generator as a service. The cost of a test might be $500,000-$1,000,000, with the prospect of getting a return of 5 times that in 3 years, based upon oil yields which may be attainable.

The industry consensus was that the technology needed a lot of work. Computer simulation of the downhole reactions is needed combined with laboratory data to obtain empirical coefficients for the simulation.

This work may be justified by the potential which the technology offers and by the fact that the potential and the technology are largely unexplored. Part of the potential lies in the area of 'unproducible' resources where means of achieving production might be devised for this new technique. Since it offers ranges of temperature, pressure, and hydrogen/steam/oxygen ratios there is considerable flexibility which might be utilized for the creation of some downhole technical/economic advantage.

One of the bases for commercial interest on the part of an operator could be the opportunity to lease 'unproducible' resources. For crude-short companies, this might be attractive.

APPENDIX A

LITERATURE RECEIVED FROM

MCR OIL RECOVERY INTERNATIONAL INC.

M.C.R. / DSG-33-1

MCR Steam Generator Component Configuration

A. Down Hole Equipment:
   1. Burner and Combustion Chamber, approximately 5½ inches in diameter by 6 to 8 feet long.
   2. Remote spark ignition system
   3. Water cooled burner

B. Steam Generator Components:
   1. 5½ O.D. by 20 to 30 feet long
   2. Metering and control sensors
   3. Remote control steam packer

C. Up Hole Transfer Lines:
   1. For ease of installation and removal, flexible hoses to be reeled into the well at one-third of conventional installation time, 3,000 to 5,000 feet
   2. Hoses; Water, air and fuel, and oxygen
   3. Anchor line
   4. Data cable

D. Surface Assisted Equipment
   1. Twin air compressors; 350/450 psi at 1,200 to 2,400 cfm
   2. Water pump 3,000 psi capacity
   3. Control, panel
   4. Hose reels and winch
   5. Water tank - 500 barrel capacity
   6. Fuel tank - 500 barrel capacity
   7. Mobile field office control room

E. M.C.R. Steam Generator Operating Specifications:
   1. Burner flame temp; 3,000 degrees
   2. Steam temp; range 300-700 degrees
   3. Steam generator capacity 15 to 30 gallons per minute
   4. Barrels of water for 24 hours 500 barrels water to 1,000 barrels
   5. Steam generator fuel #2 Diesel or natural gas
   6. B.T.U.'s per hour 7 million B.T.U.'s per hour to 14 million B.T.U.'s

M.C.R. OIL RECOVERY · INTERNATIONAL INC.

CONVENTIONAL AND DOWN HOLE STEAM GENERATING DIAGRAM

PROCESS A

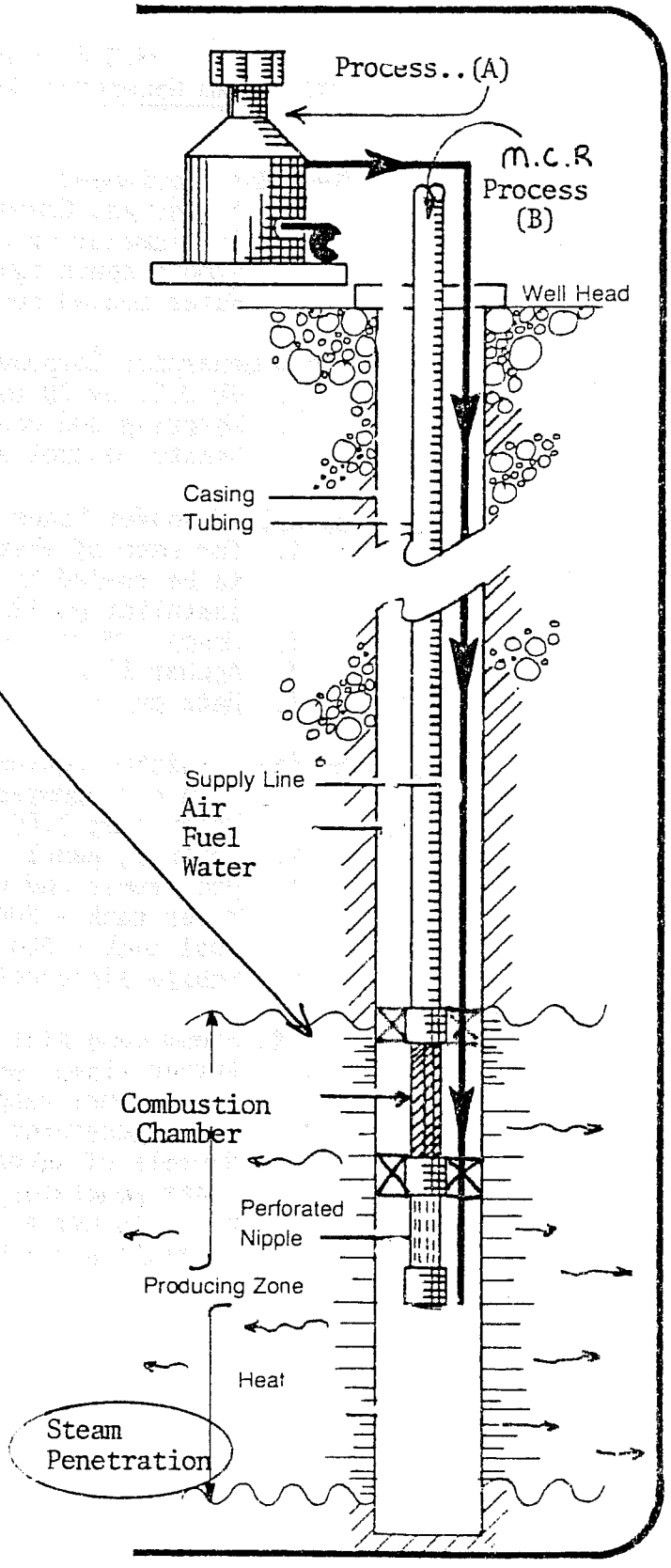
This system is a surface steam generator, single-well capacity, that supplies steam injected directly at the well head, which is a standard process of the cyclic or "Huff and Puff" system.

PROCESS B

MCR Down Hole Steam Generator, (Model Number M.C.R./DSG 333).

This system produces steam at the bottom of the production zone with down hole burner. Supply line has both air, fuel and water transfer lines. Maximum diameter of down hole burner is 6 inches and about 8-12 feet long. The unit is fully automatic.

*Controls: Pressure relief valve; fluid inlet and outlet temperature gauges; limit switches to shut off gas for low fluid pressure, low flow rate, or high fluid outlet temperature; gas regulator and modulating (or on-off) burner valve controlled by fluid discharge temperature and flame monitor, plus automatic ignition unit. All units have 1 second fast response shutdown system with additional high fast pressure safety switch.



Surface Operation Layout for Support Equipment

Portable or Stationary Water and Fuel Tanks

Portable Compressor

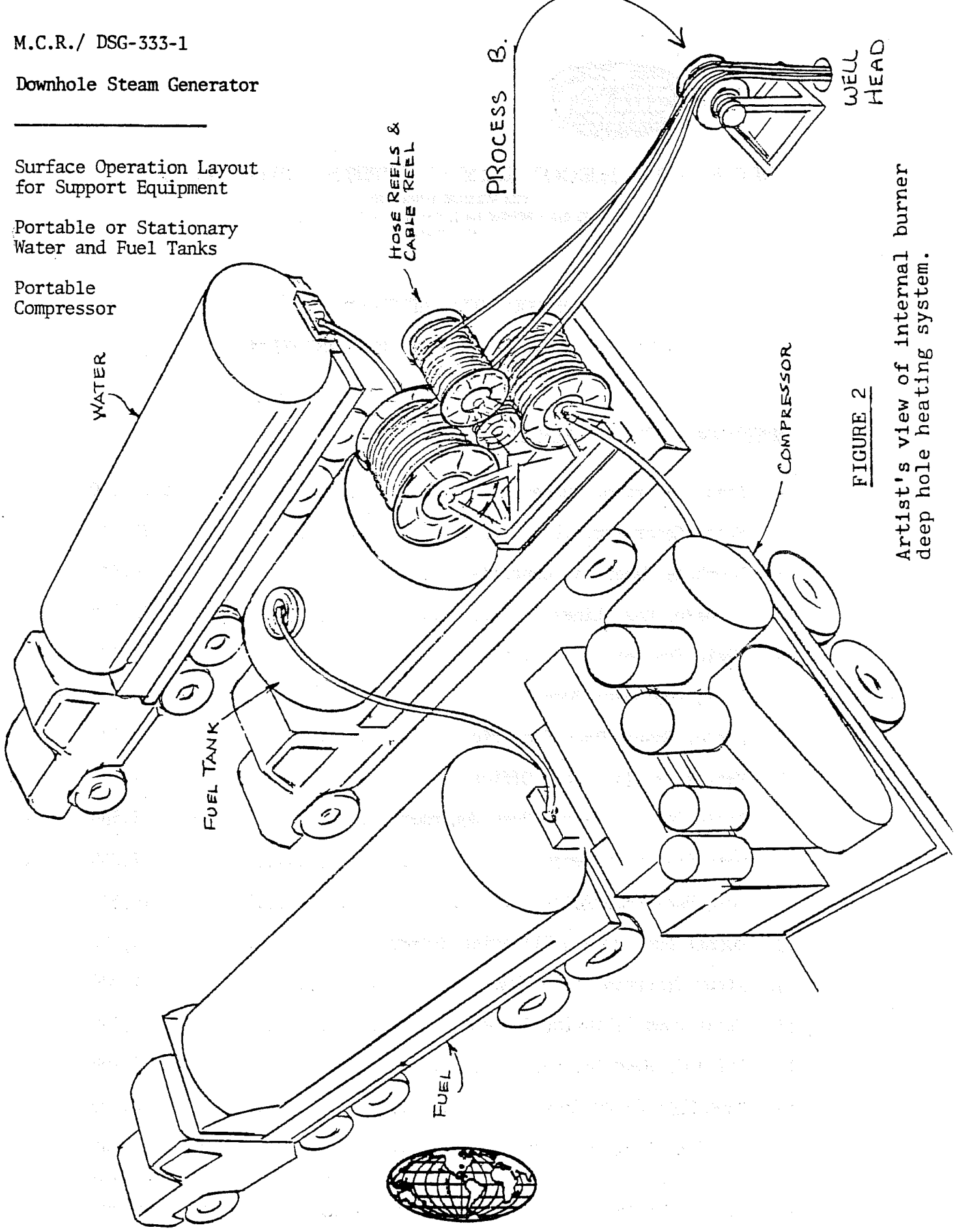


FIGURE 2

Artist's view of internal burner deep hole heating system.

M.C.R. OIL RECOVERY · INTERNATIONAL INC.
9025 WILSHIRE BOULEVARD
SUITE 215 • BEVERLY HILLS, CALIFORNIA 90211 • U.S.A.
(213) 271-4557

DOWNHOLE STEAM GENERATOR

AUXILIARY SUPPORT EQUIPMENT PURCHASE QUOTE

I. Approximate Cost of Equipment

1.	Steam Generator Burner.....	$ 12,500
2.	Steam Generator.....	23,000
3.	Downhole Generator Controls.....	6,500
4.	Transfer Hose Lines.....	55,000
5.	Field Trailer.....	7,500
6.	Field Equipment Boom.....	10,500
7.	Diesel Power Plant Electric.....	7,500
8.	Mobile Trailer Field Office.....	8,500
9.	Field Office Control Room Equipment.....	5,500
10.	Metering Instruments.....	7,200
11.	Hose Reel Drum Hoist.....	10,500
12.	Burner Fuel Pump & Filtering System.....	6,500
13.	Steam Generator Water Pump.....	21,000
14.	Water Pump Filtering System.....	2,200
15.	Oil Well Head Adaptor.....	3,500
16.	Down Hole Steam Packer.....	2,500
17.	Oil Tool Equipment Truck.....	10,100
18.	.....Capital Equipment Expenditure Total.....	$200,000.

Sullair PetroSteam, Inc.
550 W. Patrice Place, Unit F
Gardena, CA 90248
(213) 327-7130

February 5, 1980

Commercial Insights
Attn: Dr. Charles H. Ware
33 Sandi Drive
Poughkeepsie, New York, 12603

Dear Dr, Ware:

Thank you for the opportunity to discuss our down-hole steam generator and how we view the DOE programs for secondary recovery of heavy crude oil.

The most important criteria for secondary recovery of heavy crude oil is immediacy of cost-effective and energy-effective field operations. Systems requiring long-range research and development program will not be available in time for the high priority role visualized for secondary recovery of heavy crude. That role is the achievement of significant oil production during the period 1980 to 1983. In the long range, more sophistocated systems will also play a role, but the priority for such developments is lower, being comparable with the priority for solar, geothermal, oil shale and other programs.

The MCR Down-hole Steam generator will be operating in the field by May 1980 with capability of putting 24 systems in the field during the first year 48 more systems the second year and 96 more systems the third year. Assuming cyclic (huff and puff) operations of 500 barrels (50% Capacity) of high quality steam for 10 days per well, 2 wells per system per month (2/3 Capacity) and 2.5 barrels of crude oil recovery per barrel of stream injected, the crude oil produced is projected at:

500 x 10 x 2 x 2.5 x 12 x 24 = 7,200,000 barrels. Summarizing, the production for the first three years:

7,200,000	barrels the first year
21,600,000	barrels the second year
50,400,000	barrels the third year
79,200,000	barrels over the 3-year period, or 79,200,000.

An average of 216,986 BOPD, an important contribution to the immediate energy program.

The estimated capital investment is approximately $168,000,000.

The total energy recovered over the 3-year period is approximately 7.92×10^6 bbls x 5.22×10^6 BTU/bbl = 41.3×10^{12} BTU.

The total energy used to recover this energy is approximately:

246 systems x 2 jobs/month/system (50% Utilization) x 10 days/job x 7.5×10^6 BTU/hour (50% Capacity) x 24 hours/day x 1.75 (support equipment energy factor.) = 1.66×10^{12} BTU obtained from combustion of fuel (Diessel No.2)

The energy recovery effectiveness is:

$$\frac{\text{Energy Obtained}}{\text{Energy Used}} = \frac{41.3 \times 10^{12}}{1.66 \times 10^{12}} = 24.9$$

The second important criterion for secondary recovery of heavy crude is the ability to operate within the oil well casing size limitation of a large number of wells. The MGR/DSG can presently operate in a 7" casing.
The DOE funded contractors at present require a 9 3/4" casing. Approximately, 90% of the heavy crude oil wells in California have 7" or greater casing diameter and 10% have 9 3/4" Casing diameter or greater.

The third important criterion for secondary recovery of heavy crude is the ability to stimulate production for depths of wells greater than 2500 feet. This appear to be the exclusive province of the down-hole class of steam generators.

Finally, if the oil industry can become convinced that the economies are sound, they will become much more active in this area and increase the previous projections significantly. However, in order to produce reliable economic data, the results of secondary recovery field operations should be evaluated over at least 1-year period. Because of the potential risk of adverse economics the use of government subsidies to encourage 1-year pilot operations is recommended.

An added thought not discussed with you concerns the role of DOE-sponsored laboratories. Sandia Laboratories, technical arm of DOE, has sponsored the development of various down-hole steam generators and has developed a capability to provide extensive mobile instrumentation facilities to support the testing of these down-hole steam generators being developed by their contractors. An important service could be rendered to privately sponsored down-hole steam generator developments, if the services of the Sandia mobile instrumentation facility could be made available to these private developments to test their capabilities and environmental acceptability, without loss of proprietary advantage.

Sincerely yours,

Craig A. Rhoades

Craig A. Rhoades
President

Martin J. Gould

Dr. Martin J. Gould
Vice-President

APPENDIX B

DOWNHOLE STEAM GENERATOR ECONOMICS

These calculations are an extension of Sandia Laboratories' previously-developed economics. The extensions are:

1. Crude price is a variable

2. Oil yield, bbl/10^6 btu, is a variable

3. Economics are based upon cash flow and time value of money

4. Required return on investment is a variable

A summary of Sandia's economic results which were used in these calculations is given below:

System: No. 3, Air/Fuel Oil-Direct (High Pressure Generator)

Sandia Capital Investment	
Uphole	$ 932,120
Downhole	172,676
	$1,105,000
Sandia Operating Costs	
Fuel	$ 450,000
Water	7,000
Maintenance	58,000
Spares	20,000
	$ 535,000

In addition, the following costs were included:

Cost of Power to Drive the Air Compressor

For combustion of diesel fuel, the theoretical air requirement is 7.45 lb/10,000 Btu.[1] For the 20 million Btu/hr, it will be 14,900 lb/hr or 4.14 lb/sec.

For 3 stage compression the theoretical power requirement is:

$$W = \frac{nkp_1V_1}{k-1}\left[(p_2/p_1)^{\frac{k-1}{nk}} - 1\right] \div 550$$

$n = 3$

$k = 1.395$

$p_1 = 1.47 \times 144 = 2{,}116.8 \text{ lb/ft}^2$

$V_1 = 4.14 \text{ lb/sec} \times 13.41 \text{ cf/lb} = 55.5 \text{ cf/sec}$

$p_2 = 14.7$

$W = 1{,}232$ Horsepower = 919 kW

At 80% efficiency

$W = 1{,}149$kW

At $0.035/kWh,

Cost= $40.22/hr x 24 hrs/day x 365 days= $352,000/year

Incremental Labor

It is possible that no additional men will be required for a pilot or isolated production operation. Alternatively, this project would have the same labor

---

1 Chemical Engineers Handbook, Robert H. Perry and Cecil H. Chilton, McGraw-Hill, 1973 p. 9-17

requirements as Downhole Oil Treatment (see Appendix D, page 73) which is estimated to cost $205,000/year. Approximate the incremental labor cost to be $140,000.

Total annual operating costs	
Sandia estimate	$ 535,000
Compression power cost	352,000
Incremental labor	140,000
	$1,027,000

1,500 bbl/day of water converted to steam

Fuel price $15/bbl middle distillate

For an assumed value of return on investment (ROI), calculate the cash flows. Assume a 10-year service life for depreciation purposes but a 5-year project life for recovery of capital. Using double declining balance for depreciation, calculate the book value at the end of the project life and credit the project with that amount, discounted according to the ROI. Use 50% tax rate.

Sample Calculation ROI = 20%

Depreciation on $1,105,000

	Depreciation Factor	Depreciation ($1,000)	Discount Factor	Cash Flow ($1,000)
	0.2	221.0	0.906	200.
	0.16	176.8	0.742	131.
	0.128	141.4	0.608	86.
	0.1024	113.1	0.497	56.
	0.08192	90.4	0.407	37.
Total	0.67232	742.7	3.160	510.
Salvage	0.32768	362.3	.0368	133.

Operating Cost

The sum of the discount factors for 5 years = 3.16

Discounted cash flow for 5 years = $1,027 x 3.16 = $3,245

Working capital = 50

Discount factor at 5 years = 0.368

Cash flow recovery of working capital = 50 x 0.368 = 18

To achieve the required ROI, the following equation must be satisfied:

Annual Revenue (1 - Tax Rate) (Discount Factor) - Cash Flow for Operating Costs (1 - Tax Rate) - Construction Costs - Working Capital + Cash Flow for Depreciation (Tax Rate) + Cash Flow for Salvage + Cash Flow for Recovery of Working Capital = 0

In the above example, the only unknown is the annual revenue; for constant revenue, its discount factor is 3.16. Substituting the appropriate values into this equation:

Annual Revenue (1 - 0.5) (3.16) - 3,245 (1 - 0.5) - 1105 - 50 + 510 (0.5) + 133 + 18 = 0

Required Annual Revenue	=	1,501
	=	$1,501,000/yr
Actual Annual Revenue	=	365 XPSH x 10^{-6}
where X	=	oil produced, bbl/10^6 btu released downhole
P	=	oil price, $/bbl
S	=	steam rate, lb/day
H	=	enthalpy of vaporization at the assumed quality level, btu/lb

The design is based upon 525,000 lb/day of steam (1,500 bbl/day). At 1,500 psi injection pressure and 85% quality, H = 450 btu/lb. Since the middle distillate price is specified as \$15/bbl, the value of P is at most this. For the actual revenue to be equal to the required revenue:

$$365 \times PSH \times 10^{-6} = 1{,}501{,}000$$

$$X = 1{,}501{,}000/(365 \times 15 \times 525{,}000 \times 450 \times 10^{-6})$$

$$X = 1.16 \text{ bbl}/10^{6} \text{ btu}$$

To consider other oil prices, separate operating costs into fuel for steam generation and other: 30P + 577. Then the cash flow equation becomes:

$$86XP\,(1 - 0.5)\,(3.16) - (30P + 577)\,(1 - 0.5)\,(3.16) - 1{,}105 - 50 + 510\,(0.5) + 133 + 18 = 0$$

$$136XP - 47.4P - 883.3 = 0$$

$$X = \frac{47.4P + 1661.}{136P}$$

$$= 0.35 + 12.2/P$$

To obtain the results shown in the text, the cash flow relationship was generalized slightly to allow for different capital investments, C, and different discount factors, D_i, reflecting various rates of return. The resultant equation is given below.

$$43XPD_1 - 15PD_1 - 288.5D_1 - C - 50 + 0.5CD_2 + 0.328CD_3 + 50D_3 = 0$$

D_1 = discount factor for continuous cash flow for 5 years

= 3.16 at 20% ROI

= 2.16 at 40% ROI

D_2 = discount factor for doubling declining balance depreciation and continuous one-year cash flows

= 0.461 for 20% ROI

= 0.339 for 40% ROI

D_3 = discount factor for cash flow at an instant in time 5 years hence

= 0.368 for 20% ROI

= 0.135 for 40% ROI

The 50% tax rate has already been applied to obtain the coefficients 43, 15, and 42.5.

$$X = 0.35 + \frac{288.5D_1 + 50(1 - D_3) + C(1 - 0.5D_2 - 0.328D_3)}{43PD_1}$$

This equation was used to generate Table 1.

APPENDIX C

ENERGY BALANCE FOR DOWNHOLE OIL TREATMENT

Energy Balance for Generating Hydrogen and Oxygen to Produce Oil

Hydrogen Production

Basis: 1,000 SCF Hydrogen

Production of 1,000 SCF requires 215 SCF propane for fuel and feedstock and produces 10 lb of export steam.

Energy in: 215 SCF x 2,516 btu/SCF	=	541,000	btu
Energy out: 10 lb steam x 1,100 btu/lb	=	11,000	
		530,000	
Additional Power: 1.4 kW x $\frac{\text{8,800 btu cons.}}{\text{kW produced}}$	=	12,300	
TOTAL	=	542,300	btu

Oxygen Production

Basis: 500 SCF oxygen

Production of 500 tons/day of oxygen requires 6900 kW

$$6{,}900 \ \frac{\text{KW-hr}}{\text{hr}} \times \frac{\text{24 hr}}{\text{day}} \times \frac{\text{day}}{\text{500T}} \times \frac{\text{Ton}}{\text{2,000 lb}} \times \frac{\text{32 lb}}{\text{lb-mole}} \times \frac{\text{lb-mole}}{\text{379 SCF}} \times \text{500 SCF } O_2$$

$$\times \ \frac{\text{8,800 btu of energy to power plant}}{\text{kW-hr produced}} = \text{61,500 btu}$$

Total power in 542,300 + 61,500 = 604,000 btu

The energy that will be consumed will be for the total production of hydrogen. Some of that hydrogen must be used to upgrade the oil that is

produced to propane. It will be assumed that the produced oil will have a 1:1 H/C ratio. The approximate chemical equation is:

$$3\ CH + 2.5\ H_2 \rightarrow C_3H_8$$

The chemical hydrogen requirement for the production of propane is:

$$215 \text{ SCF propane} \times \frac{2.5 \text{ SCF } H_2}{\text{SCF Propane}} = 537.5 \text{ SCF } H_2$$

That is, for every 1,000 SCF of H_2 produced in the generator, 537 SCF H_2 must be returned to the hydrogenation of crude. The net hydrogen production must be:

$$1000 - 537.5 = 462.5\ H_2 \text{ available/1,000 SCF produced}$$

Revise the basis of the calculations:

$$61{,}500 + \frac{542{,}000 \text{ btu}}{1{,}000 \text{ SCF } H_2 \text{ produced}} \times \frac{1{,}000 \text{ SCF } H_2 \text{ produced}}{462.5\ H_2 \text{ available}} =$$

$$1.233 \times 10^6 \text{ btu required for 1000 SCF } H_2 \text{ available}$$

Production

Let X = oil production expressed as bbls oil/10^6 btu. 1,000 SCF H_2 available will release 0.324×10^6 btu. Oil production will be 0.324X bbl/1,000 SCF H_2 available. Not all of this oil will be available for sale.

The propane requirement is 215 SCF/1,000 SCF produced or

$$\frac{215 \text{ SCF Propane}}{1{,}000 \text{ SCF } H_2 \text{ Produced}} \times \frac{H_2 \text{ Produced}}{0.4625 \ H_2 \text{ available}} = 465 \text{ SCF}$$

Express this requirement in terms of oil. From the chemical equation shown previously, 3 moles of CH (mol. wt. = 13) are required to make one mole of propane:

$$\frac{465 \text{ SCF Propane}}{1{,}000 \text{ SCF } H_2 \text{ available}} \times \frac{\text{lb-mole}}{379 \text{ SCF}} \times \frac{3 \text{ lb-mole CH}}{\text{lb-mole}} \times \frac{13 \text{ lb CH}}{\text{lb-mole}} =$$

$$\frac{48 \text{ lb oil}}{1{,}000 \text{ SCF } H_2 \text{ available}}$$

For 10° API gravity oil, the weight is 350 lb/bbl. Therefore, the produced crude that will be required to make the propane is

$$\frac{48 \text{ lb oil}}{1{,}000 \text{ SCF } H_2 \text{ available}} \times \frac{\text{bbl oil}}{350 \text{ lb oil}} = \frac{0.137 \text{ bbl}}{1{,}000 \text{ SCF } H_2 \text{ available}}$$

Denote the refinery loses by Y bbls/bbl of oil produced. Then 1 - Y = bbls for sale/bbl produced. The net yield of salable oil is

$0.324X\ (1 - Y) - 0.137$ bbls of oil/1,000 SCF H_2 available

The heat of combustion for crude is assumed to be 16,000 btu/lb x 350 lb/bbl = 5.6×10^6 btu/bbl. The heat available is

$\{0.324X\ (1 - Y) - 0.137\} \times 5.6 \times 10^6$ btu available/1,000 SCF H_2 available

The energy balance becomes:

-In + Out = Net available

$-0.061 \times 10^6 + \{0.324X\ (1 - Y) - 0.137\} \times 5.6 \times 10^6$ = Net btu/1,000 SCF H_2 available

The energy break-even point is where there is no net production. Find the oil yield, in bbl/10^6 btu, for hypothetical refinery yields.

Y Refinery yield, %	X_{MIN} Oil production required for energy break-even bbl oil/10^6 btu released downhole
0	0.457
5	0.481
10	0.507
15	0.537
20	0.571

Because of the requirements for propane, largely hydrogen plus some additional energy, for energy to make oxygen, for propane manufacture feedstock (produced crude must be dedicated to meet that requirement) and for refinery fuel, the energy yield from this process is reduced. In the absence of these requirements,

$$X_{MIN} = 1 \times 10^6/5.6 \times 10^6 = 0.18$$

Depending upon the refinery yield, the actual break-even production level is 6 to 8 times higher than the theoretical quantity, based only on the downhole heat released.

In the energy balance, no specific account was taken of hydrogen or energy requirements for propane. It is tacitly assumed that the oil not used for propane production is untreated or treated with a yield loss Y which includes material required for the energy for the treating.

Yields of Produced Crude after Correcting for Process Energy Requirements.

Net energy available $= -0.061 \times 10^6 + \{ 0.324X (1 - Y) - 0.137 \} \times 5.6 \times 10^6$ btu per 1,000 SCF H_2 available.

Express that as crude available by $\div 5.6 \times 10^6$ btu/bbl

Net crude available $= 0.324X (1 - Y) - 0.148$ bbl/1,000 SCF H_2 available

Oil produced will be 0.324X bbl/1,000 SCF H_2 available

Yield = Net crude available/Crude produced $= 1 - Y - \frac{0.456}{X}$

Results

	Y				
X	0	0.05	0.10	0.15	0.20
0.5	0.088	0.038	---	---	---
0.75	0.392	0.342	0.292	0.242	0.192
1.0	0.544	0.494	0.444	0.394	0.344
1.5	0.696	0.646	0.596	0.546	0.496
2.0	0.772	0.722	0.672	0.622	0.572

APPENDIX D

ECONOMICS FOR DOWNHOLE OIL TREATMENT

ECONOMICS

Express the results on a daily basis.

The design requirement is 8×10^6 btu/hr. The heat of combustion for H_2 is 0.324×10^6 btu/SCF.

The hydrogen requirement is

$$8 \times 10^6 \div 0.324 \times 10^6 = 25{,}000 \text{ SCF } H_2$$
$$= 600{,}000 \text{ SCF } H_2/\text{day}$$

The oxygen requirement is 300,000 SCF/day.

$$\frac{300{,}000 \text{ SCF}}{\text{day}} \times \frac{\text{lb-mole}}{379} \times \frac{32 \text{ lb}}{\text{lb-mole}} \times \frac{\text{ton}}{2000 \text{ lb}} = 12.66 \text{ tons } O_2/\text{day}$$

Capital Requirements

600,000 SCF H_2/day plant (quote scaled to 1980)	$ 800,000
13 tons/day oxygen plant (quote)	950,000
Water treatment (estimate)	80,000
Installation, piping, clearing space, etc. (uphole)	100,000
Modifications to well (downhole)	50,000
Burner, computer, van	100,000
	$ 2,080,000
10% contingency	208,000
	$ 2,300,000

Calculation of Rental Charge Needed to Achieve 20% ROI by DCF

Total capital = $2,300,000

Project life = 5 years

Recovery of capital after 5 years = book value

Direct labor (1/shift) 4 @ $20,000 =	$ 80,000/yr
Overhead and administration (Including payroll expense, supervision, accounting, purchasing, selling expense)	80,000
Maintenance @ 2% of purchased materials (Including contractor fees)	44,000
Moving costs	10,000
TOTAL ANNUAL COSTS	$ 214,000

Tax Rate = 50%

Operating Time = 300 days/yr (Allows for moving, startup and downtime)

The factor used below, 0.4104, takes into account depreciation, taxes, and the time value of money. For 20% ROI, it converts an investment cost into a uniform annual cash flow for the five-year project life.

Capital investment figures include 10% contingency.

COST SUMMARY

H_2 Plant $880,000 x 0.4104 = $361,000 =	$ 1,203/day
O_2 Plant 1,045,000 x 0.4104 = 428,000 =	1,427
Other 367,000 x 0.4104 = 150,000 =	502
Operating costs 214,000 =	713
Interest on working capital 10,000 =	33
	$ 3,878/day

Cash flow required to produce oxygen is $1,427/day.

Cash flow required to buy 13 tons of O_2/day at $90/ton is

13 x 90 = $1,170/day.

It is cheaper to buy oxygen than to make it.

Cash flow required to produce hydrogen is

Capital	$ 1,203/day
Propane @ $.50/gal	1,634/day
	$ 2,837/day

The cash flow required to buy 600,000 SCF H_2 per day @ $8.50/1000 SCF = $5,100.

With $2,837/day, 56% of the hydrogen capacity can be met. Since the long-term average use of hydrogen is supposed to be less than 56%, it is cheaper to buy than to make it. For higher returns on investment, a greater portion of the hydrogen capacity can be met through purchases.

REVISED COST SUMMARY

Other	$ 502/day
Operating Costs	713
Interest	33
	$ 1,248/day

Customer buys his own oxygen and hydrogen.

Let X = oil production, bbl oil/10^6 btu

P = price obtained for produced oil, $/bbl

XP = $ revenue/10^6 btu released downhole

Z'_h = Hydrogen consumption in fractional rated capacity (actual consumption ÷ 600,000 SCF/day), 0.25

Z'_o = oxygen consumption in fractional rated capacity (actual consumption ÷ 300,000 SCF/day), 1.00

Assume 194.4×10^6 btu released by 600,000 SCF H_2.

For excess O_2, assume that it reacts with oil-in-place with a heat of combustion of 16,000 btu/lb. Assume crude has the formula -CH-. Then

$$\frac{16{,}000 \text{ btu}}{\text{lb}} \times \frac{13 \text{ lb}}{\text{lb-mole CH}} \times \frac{4 \text{ moles CH}}{5 \text{ moles } O_2} \times \frac{\text{lb-mole}}{379 \text{ SCF}} =$$

0.22×10^6 btu/500 SCF O_2

Excess O_2 is $Z'_o \times 300{,}000 - 0.5Z'_h \times 600{,}000$.

$$\text{Heat Release} = \frac{0.22 \times 10^6}{500} \times 300{,}000\,(Z'_o - Z'_h)$$

$$= 132\,(Z'_o - Z'_h) \times 10^6$$

Oil production from excess O_2 = $132X\,(Z'_o - Z'_h)$

Total oil production = $X\,\{194.4 \times Z'_h + 132\,(Z'_o - Z'_h)\}$

$= X\,\{132Z'_o + 62.4Z'_h\}$

For $Z'_o \geq Z'_h$

Total oil production = $194.4XZ'_o$ for $Z'_o < Z'_h$

Let C_r = rental cost \$/day, \$1248/day

C_{O_2} = cost of oxygen, \$90/ton

C_{H_2} = cost of hydrogen, \$8.50/ton

T' = production period, days, 1095

D = discount factor for income in the future,

0.752 for 20% ROI

0.659 for 30% ROI

0.582 for 40% ROI

C_w = cost of workover, \$25,000

Z_o = fractional oxygen capacity used during test, 0.5

Z_h = fractional hydrogen capacity used during test, 0.5

T = test period, days, 90

C_{op} = operating cost other than O_2 and H_2

R = ratio of revenues over a three year production period (discounted to time zero) to cost of test

Operating Costs

5 men @ \$20,000/yr =	\$ 100,000/yr
Salary overhead and administration =	90,000
Supervision (shared) =	15,000
	\$ 205,000/yr

$$C_{op} = \$205{,}000 \div 365 \text{ days/yr} = \$562/\text{day}$$

$$\text{Net revenue} = (XP\{132Z'_o + 62.4\,Z'_h\} - \{C_r + 13C_oZ'_o + 600\,C_hZ'_h + C_{op}\})\,T'D$$

$$\text{Test cost} = C_w + \{C_r + 13C_oZ'_o + 600\,C_hZ_h\}T$$

$$R = \frac{\text{Net Revenue}}{\text{Test Cost}} \text{ or } \frac{\text{Upside Potential}}{\text{Downside Risk}}$$

SAMPLE CALCULATION

Use values given with definition of terms

$$R = \frac{\{14.7.6XP - 1,248 - 1,170 - 1,275 - 562\} \ (1,095)\,(0.752)}{25,000 + (1,248 + 585 + 2,550 + 562)\ 90}$$

$$R = 0.00175\ \{147.6XP - 4,255\}$$

When XP = 28.8, R = 0.0; XP = 67.54, R = 10.0

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