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Quarterly Report

OCEAN THERMAL ENERGY

at The Johns Hopkins University Applied Physics Laboratory

JANUARY – MARCH 1982

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THE JOHNS HOPKINS UNIVERSITY ■ APPLIED PHYSICS LABORATORY

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AI01-77ET20342

THE JOHNS HOPKINS UNIVERSITY ■ APPLIED PHYSICS LABORATORY
Johns Hopkins Road, Laurel, Maryland 20707

FOREWORD

The Applied Physics Laboratory issues the *Quarterly Report* series to provide the defense establishment and the scientific community with current awareness of selected APL activities. At present, the *Quarterly* consists of the following volumes:

Programs	Report Designators
Department of Defense Programs	
Research and Development	RQR
Exploratory Development for Missile Propulsion	DQR
Civil Programs	
Ocean Thermal Energy	OQR
Biomedical Research, Development, and Engineering (Annual Report)	MQR

The nomenclature for the APL *Quarterly Report* is as follows. The designation for *Quarterly Report*, "QR," is preceded in each case by a letter that indicates the volume's program area. After the "QR," a virgule is followed by a year indicator (e.g., "82-") and a number from 1 to 4 to specify the calendar quarter.

The format is designed so that most technical articles can be presented on a single sheet of paper. Each article is given a section number (e.g., §24), which applies to the current *Quarterly* only. Each article is keyed to its major program area (e.g., Research and Exploratory Development), its technical instruction (e.g., Amorphous Semiconductors), its budget code (e.g., A3), the Laboratory Group or Groups that performed the work (e.g., BBE), and the agency that supported it (e.g., SEA-62R).

Certain Laboratory programs, including some that report a portion of their activities through the *Quarterly Report*, use document series other than the *Quarterly* to report the bulk of their activities. Those series are available only to individuals and organizations that are directly concerned with the specific programs involved.

Requests for *Quarterly Reports* should be directed to: Supervisor, Technical Publications Group, Applied Physics Laboratory, Johns Hopkins Road, Laurel, Maryland 20707.

PREFACE

The Johns Hopkins University Applied Physics Laboratory, under a contract with the U.S. Department of Energy's Division of Ocean Energy Technology (DOE/DOET), is engaged in developing Ocean Thermal Energy Conversion (OTEC) systems that will provide synthetic fuels (e.g., methanol), energy-intensive products such as ammonia (for fertilizers and chemicals), and aluminum. The work also includes assessment and design concepts for hybrid plants, such as geothermal-OTEC (GEOTEC) plants. APL has been designated the Lead Laboratory in these areas by DOE/DOET. Another effort that began this spring is a technical advisory role to DOE with respect to their management of the conceptual design activity of the two industry teams that are designing offshore OTEC pilot plants that could deliver power to Oahu, Hawaii. In addition, the Laboratory is now taking part in a program in which tests of a different kind of ocean-energy device, a turbine that is air-driven as a result of wave action in a chamber, are being planned. This *Quarterly Report* summarizes the work on the various tasks as of 31 March 1982.

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OCEAN THERMAL ENERGY CONVERSION §1
OTEC Pilot Plant Program Management
Technical Advisory Laboratory Support ZY3COE
Support: DOE/DOET
D. Richards January-March 1982

OTEC PILOT PLANT CONCEPTUAL DESIGN REVIEW

The Division of Ocean Energy Technology of the Department of Energy (DOE/DOET) has announced the award of two contracts for conceptual designs of OTEC 40 MW pilot plants (Ref. 1) at Kahe Point, Hawaii and has set up an OTEC Pilot Plant Program Management Office with Carmine Castellano as Program Manager. The Energy Technology Engineering Center (ETEC) of Rockwell International has been named Technical Support Contractor to provide management and coordination support. APL has been designated as a Technical Advisory Laboratory as have the National Oceanic and Atmospheric Administration (NOAA), Lawrence Berkeley Laboratory (LBL), and Argonne National Laboratory (ANL). A working group has been formed by DOE/DOET to monitor progress on the two contracts; APL is participating as a member of the group.

BACKGROUND

The OTEC Pilot Plant Program was stipulated to be a multiphase program: Phase I-Conceptual Design; Phase II-Preliminary Design; Phase III-Detail Design; Phase IV-Construction, Deployment, and Acceptance Test; Phase V-Joint Operational Test and Evaluation; and Phase VI-Transfer of Ownership and Contractor Operation. The Program Opportunity Notice mechanism by which proposals were solicited anticipated the award of five to eight fixed-price ($900,000) preliminary design contracts in which the contractors were expected to cost-share in the range of 15 to 40%. Of the nine proposals received, one was withdrawn and eight were evaluated from the cost-sharing criterion and from six technical evaluation criteria ratings.

The winning proposals are listed below; the discussions are based on Ref. 1.

General Electric (GE). GE would act as systems integrator and Brown & Root, Hawaiian Dredging, and Gibbs and Hill as subcontractors. GE proposes to build a 40 MWe net power plant on a shelf-mounted fixed tower that is sized to accommodate a 100 MWe power system. The tower will be located in 328 ft of water approximately one mile offshore from Kahe Point, Oahu, Hawaii and will be based on offshore oil rig technology. The condensers will be located 150 ft below the surface, and the evaporators will be 280 ft deep. The steel cold water pipe (CWP) is 33 ft in diameter and 9800 ft long. The heat exchangers are a flat plate design of aluminum construction. The turbines are single-stage axial flow units coupled directly to 14,000 kVA generators. The working fluid is to be Freon R-22. The surface of the heat exchangers will be enhanced to increase heat transfer coefficients. The electrical cable will be trenched and buried in the sea floor.

Ocean Thermal Corporation. TRW would act as systems integrator and TRW, Hawaiian Dredging, Burns & Row, R. J. Brown Associates, and Science Applications, Inc. as subcontractors. This consortium proposed a 40 MWe plant that would be constructed on an artificial island in 28 ft of water approximately 600 ft off Kahe Point, Oahu, Hawaii. The plant is to be connected to the cooling water discharge of the Hawaiian Electric Company's 600 MWe fossil fuel power plant, thereby increasing the thermal gradient. The power system has four 10 MWe modules (each with two condensers and two evaporators) and one 10 MWe four-stage axial turbine. The heat exchangers are of the horizontal tube and shell design and are made with titanium tubing. The CWP is 30 ft in diameter and is made of reinforced lightweight concrete. The deployment technique requires the pipe to be held in place on the sea floor with a combination of flotation tanks and anchors. The pipe is 18,700 ft long and will be installed on a sloping bottom of 26°.

The six other proposals are listed below (Ref. 1):

Virgin Islands Water and Power Authority (VIWPA). EBASCO would act as systems integrator and J. R. McDermott and TRW as subcontractors. This proposal offers to design and construct a 12.5 MWe plant on a shelf-mounted tower about 5000 ft off the coast of St. Croix, Virgin Islands. About 2.5 MWe will be used to produce 50 million gallons of fresh water daily. A portion of the cold water will be used for mariculture experiments. The platform will be mounted in shallow water and fixed to a 39° sloping bottom. The condensers and evaporators would be mounted on the tower below the wave action level. The heat exchangers would be made of titanium and would be cleaned through open top tubes and by low level chlorination. The CWP is 15 ft in diameter, 4500 ft long, and constructed of fiberglass-reinforced plastic.

Commonwealth of Northern Marianas. Science Applications, Inc. would act as systems integrator and Dillingham/Hawaiian Dredging, Burns & Roe, and Global Marine Development Inc. as subcontractors. This proposal would result in a plant with a net output of 10 MWe. The equipment would be located on a concrete barge that would be flooded and installed in shallow water on a prepositioned foundation. The barge would be placed in approximately 23 ft of water about 328 ft offshore of Saipan. The power system would generate 14 MWe gross output and use ammonia as the working fluid. Pumps would be vertically submerged, axial-flow, multistage, high-capacity pumps. Heat exchangers would be constructed from titanium using the Alfa Laval design. Biofouling would be controlled by a hypochlorite injection system with removal for scrubbing if required. The CWP is 5244 ft long and 16 ft in diameter. The upper 984 ft section is made of concrete and much of it would be trenched and buried. The last 4260 ft would be constructed of fiberglass-reinforced plastic and installed in lengths of approximately 500 ft onto sea bottom mounted piers. The cold water plume would be designed so that some of the cold water could be redirected for experiments in desalination and mariculture at some time in the future.

Solaramco. Lockheed would act as systems integrator and ABAM, Owens-Corning Co., and M. W. Kellogg Corp. as subcontractors. Solaramco proposes to build a floating plantship that would graze in the equatorial North Pacific and would use OTEC-derived electricity to operate an ammonia production plant. This proposal would yield an energy intensive product, ammonia. The platform suggested is a concrete hulled ship that uses current shipbuilding techniques. The equipment is all located above board, thus facilitating inspection, maintenance, and repair. The ammonia manufacturing techniques are those used by industry and should be adaptable to the plantship environment. The platform would keep station with four electric thrusters of 2500 hp each. The required power for the thrusters is to be provided from OTEC-generated electricity. The CWP is 23 ft in diameter, 3280 ft long, and constructed of fiberglass-reinforced plastic.

Puerto Rico Electric Power Authority. Brown & Root would act as systems integrator and Westinghouse, United Engineers and Constructors, and Raytheon as subcontractors. A 40 MWe system would be built on a tower platform placed in 225 ft of water near Punta Tuna, Puerto Rico. The baseline design uses the oil rig platform design and shell and tube titanium heat exchangers. The consortium has an identified user in the prime contractor. The submarine cable to deliver the electricity is within the state of the art. Hurricane frequency is less than one in eight years.

Florida Ocean Thermal Energy Consortium. The Florida Solar Energy Center would act as systems integrator and TRW, Stone & Webster, and Sante Fe International as subcontractors. The baseline design proposed by FOTEC uses a steel-hull ship-shaped barge with a single point moor located 30 miles off Key West in the Florida Straits. The plant would generate electricity that would be transferred to the shore electrical grid through a riser cable. This concept relies on the existence of a current from a constant direction for mooring and for warm water intake and the flow of discharge water. The CWP is to be 30 ft in diameter and 2600 ft long with a gimbal attachment to the platform. It would be fairly buoyant, made of fiberglass-reinforced plastic with a balsa wood or foam core. The power cycle would use ammonia as the working fluid. The proposed heat exchangers are tube and shell titanium with enhanced surfaces. Cleaning would be accomplished with Amertap balls and chlorination. Components have been identified for the turbine and the pumps. Mooring would be accomplished via 30 ft solid bar sections that are screwed together like drill pipes. The 9000 ft long moor would be held in place by pile anchors at the bottom and a surface spar buoy. The riser cable would be buoy supported near the platform and buried near shore. The total cable length would be approximately 30 miles.

Ocean Solar Energy Associates. Sea Solar Power, Inc. would act as systems integrator and General Dynamics and the Center for Energy and Environmental Research of the University Puerto Rico as the subcontractors. This offeror proposed to design and build a 24,000 ton semisubmersible structure made of steel. The platform would be dynamically positioned by louvered jets discharging the water from the heat exchangers. The plant would be located off the coast of Puerto Rico and would provide electricity to shore through a riser cable. The CWP is a patented "stockade" design, constructed of a circle of individual steel, aluminum, or drill pipes joined together in a 30 ft diameter cylinder constructed in 60 ft long sections. The power system would use turbine driven seawater pumps to move the warm and cold water through the heat exchangers. The heat exchangers would be made of aluminum or copper-nickel, would use a multistaged, compact design, and would employ Freon R-22 as the working fluid for the Rankine cycle. The design of the heat exchanger allows reverse flow for cleaning with the addition of abrasive slurries or cleaning chemicals. Details on the proposed electrical cable were not provided.

DISCUSSION

Selection of the winning proposals was based in part on experience and professional program management skills. "Candidate concepts most likely to succeed should be selected. It is desirable to have a minimum of design conditions which push the state-of-the-art and involve unnecessary risks" (Ref. 1). In this latter consideration, the designs selected eliminate the requirement for suspended, flexibly connected CWP of floating plants and the moorings and flexible deep-water electric cables required for moored-floating plants.

The scope statement from the OTEC Pilot Plant Program Management Office (Ref. 2) states, "The main thrust of the work is to perform a technical review of the formalized deliverable documents specified in the contracts to the design teams. The objective of the review is to apply the knowledge and experience gained as first hand researchers in the OTEC technology to assure DOE that the concepts developed are reasonable and practical and that the risks, schedules, and costs presented form a sound basis for continued government support.

"Additional objectives include providing technical assistance to the contractors to assure access to the publicly owned OTEC data base to avoid known hazards; to assist DOE in its administrative reporting responsibilities; to protect proprietary information from unauthorized disclosure and to disseminate non-proprietary information to the maximum advantage of OTEC program participants."

The APL Statement of Work includes:

1. Design Review - Work packages produced by the design consortia will be provided, and a formalized review activity will be implemented. The Technical Support Contractor will assign the schedule for completion, receive the results, and coordinate the output with concerned parties. The work to be reviewed will be assigned in accordance with the areas of responsibility previously carried out as an OTEC program participant as follows: overview of OTEC system design approaches, including power systems

Table 1

Responsibility matrix.

Area of Responsibility: Description	Delivery[1]	Responsible Body: ETEC In-house	ETEC NA/ME	LBL	NOAA	ANL	DOE HQ	APL
Conceptual design, OTEC concept[2]		L	A	A	A	A	A	A
Interim report	6							
Draft final report	9							
Final report	12							
Design and operational data sets[2]		A	A	L	A	A	A	A
Initial set	2							
Interim report	5							
Draft final report	6							
Final report	12							
Site specific EA		I	A	L	A	I	I	I
Initial draft	3							
Interim report	5							
Final report	6							
Plan site/design specified EIS		I	A	L	A	I	I	I
Interim report	7							
Draft final report	9							
Final report	12							
Required permits and licenses[3]		I	A[4]	A[5]	A	I	L	I
Initial plan to obtain	3							
Final permits and licenses	As applicable							
Preliminary safety analysis report		L	A	A	A	A	A	A
Interim report	3							
Final report	9							
Site description		A	A	L	A	I	I	I
Initial report	1							
Interim report	6							
Draft final report	9							
Final report	12							
Risk analysis[2]		A	A	A	A	A	L	A
Interim report	6							
Draft final report	9							
Final report	12							
Cost assessment		L	A	A	A	A	A	A
Initial report	2							
Interim report	6							
Draft final report	9							
Final report	12							
Physical model test plan		L	A	I or A depending on what is proposed				A
Interim report	7							
Draft final report	9							
Final report	12							
Operation and maintenance plan		A	L	I	A	A	I	A
Initial report	3							
Interim report	6							
Draft final report	9							
Final report	12							
Commercialization plan[2]		A	A	I	A	A	L	A
Initial report	3							
Interim report	6							
Draft final report	9							
Final report	12							
Prelim. test plan and long-lead items		L	A	I	A	A	A	A
Interim report	6							
Draft final report	9							
Final report	12							
Technology transfer plan		L	A	A	A	A	A	A
Initial report	10							
Final report	12							
Prelim. system interface criteria		L	A	I	I	A	A	A
Initial report	2							
Interim report	6							
Draft final report	9							
Final report	12							

[1] Months from start of contract.
[2] All parties will review.
[3] Under Public Law 96-320.
[4] NA/ME = Naval Architect/Marine Engineer: U.S. Coast Guard, American Bureau of Shipping.
[5] LBL: EPA, NPDES, NOAA.

L = Lead
A = Advisory
I = Information
EA = Environmental assessment
EIS = Environmental Impact Statement

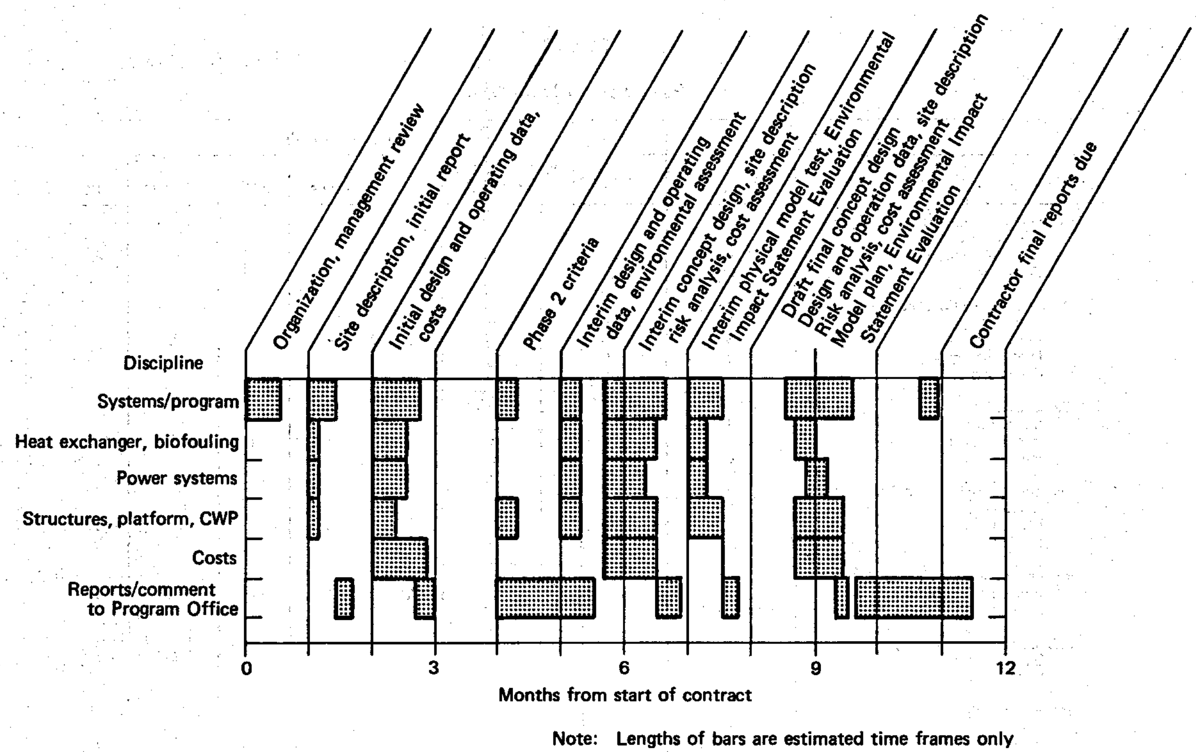

Fig. 1 Planning schedule for OTEC Pilot Plant Program management support at APL. (82-1/29)

and OTEC heat exchangers, seawater systems, energy-intensive product applications, systems integration aspects, and commercialization plans. Reviews include design approaches, performance analyses, materials, constructability, operation, and maintenance.

2. Program Assistance - Assistance to the DOE Program Office staff will include ad hoc studies, evaluations, and recommendations; participation in meetings and conferences; and programmatic planning and budgeting activities. Assistance to the design contractors will be provided, including presentations of prior work and dissemination of data in the public domain. Assistance to the Technical Support Contractor will include attendance at review meetings; planning/budgeting activities; preparation and review of subsequent phase technical requirement documents; and ad hoc studies, evaluations, and reports.

An initial Program Management "kick-off" meeting held at DOE on March 18, 1982, developed a responsibility matrix (Table 1). The preliminary APL planning schedule (Fig. 1) is based on this table.

REFERENCES

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OCEAN THERMAL ENERGY CONVERSION §2
OTEC Energy Products ZY3COE
Support: DOE/DOET
W. H. Avery and D. Richards
January-March 1982

OTEC METHANOL

The use of OTEC plantships to produce synfuels and energy-intensive products makes the tropical oceans an unlimited resource for world energy needs. The present program is part of a broad effort to identify and prioritize the OTEC products and processes that can have a significant effect on United States oil imports and electric power requirements, beginning before 1990. OTEC methanol is a particularly attractive candidate fuel because it can replace gasoline as a motor fuel and is the preferred fuel for high-efficiency fuel cells for power generation. In both applications, preliminary analysis indicates that costs will be below those projected for alternative sources.

SUMMARY

The background and status of the OTEC-methanol R&D were summarized in the first issue (Oct-Dec 1981) of this new report series. Work during the present quarter has concentrated on details of the process and system components that will determine overall yield and cost. Under direction of DOE, all work on OTEC energy products is to be completed under the first increment of FY 82 funding received. Efforts are being redirected to complete the planned programs in a way that will provide a worthwhile base to transfer the technology to the private sector and will facilitate further development if funds become available.

BACKGROUND AND DISCUSSION

An examination of the schemes that have been proposed for the production of methanol from coal shows that the principal uncertainties affecting the OTEC-methanol process will be in the design of the gasifier. (In the conventional process, there also are problems in the design of the shift conversion subsystem, but this step is eliminated in the proposed OTEC-methanol process.) The problems in gasification arise from three characteristics of coal: (a) it is a solid of widely varying composition, (b) its reactivity (time to burn completely) depends on the physical form of the coal and its method of preparation as well as the composition, and (c) the coal, on heating, evolves gases and liquids, along with residual solids that may be converted to liquid (molten slag), fly ash, or solids (clinkers), depending on the rate of heating and the temperature regime. This combination of factors has led combustion engineers to try many combustor arrangements, coal preparation methods, and operating temperatures that form the basis for the variety of synfuel proposals that have been submitted to the Synfuels Corp. In concluding the energy product program, APL is trying to select the best choice for the OTEC-methanol gasifier among synfuel projects that appear likely to succeed.

In late February, discussions were held with Conoco representatives who conducted a detailed design and cost evaluation of a plant to produce 240 million ft^3/day of synthetic natural gas (98% CH_4) plus secondary products from 17,000 tons/day of bituminous coal (Illinois No. 6). The Conoco gasifier would use crushed coal (2 by 1/4 in.) as feed to a fixed bed combustor designed by British Gas/Lurgi. This combustor operates at 450 psi at a temperature above the liquefaction temperature of the slag (2000°F) so that liquid slag is produced and drained from the bottom of the combustor. Oxygen and steam are introduced along with coal and limestone to fluidize the slag.

The total cost of the plant was estimated to be $920M in early 1978 dollars, or $1113M in 1980 dollars (conversion factor is based on the *Chemical Plant Index*). Scaled to 1340 tons/day with a scaling factor of 0.6, the OTEC gasifier cost would be estimated at $26M. The prorated cost of the gasifier for the full-scale plant, including off-site and indexed costs, is $120M. A parallel study of coal to methanol to gasoline plant costs was conducted for DOE by Mobil Corp. and gave a total cost of $1.7 to $1.9B for plants that have an input of 27,300 tons/day of coal. These plants are also designed to use a fixed bed gasifier of the Lurgi type. The prorated cost of the gasification section for these plants is $317M. Scaled to 1340 tons/day, the cost would be $68M in 1978 dollars or $83M in 1980 dollars.

Costs scaled to 1340 tons/day for the appropriate gasification sections of the 192 tons/day TVA ammonia from a coal pilot plant at Muscle Shoals, Ala. (Texaco gasifier) would result in a cost of $104M; however, since this is an R&D project, realistic adjustment might result in costs of $70 to 80M.

A cost breakdown for the Tennessee Synfuels Assoc. coal to gasoline (via methanol) plant lists coal handling and gasification at $224M (mid 1981 dollars). Adjusted to 1980 dollars and scaled to 1340 tons/day, the estimated cost would be $95M.

Disparity among the cost estimates reflects differences in the process features, as well as estimating difficulties. A more thorough design review will be necessary to refine the estimates

OTEC METHANOL PROCESSES

Studies of the gasification-process steps and the requirements to carry out such operations on board an OTEC plantship led to the conceptual OTEC-methanol process (Fig. 1). As previously reported, the proposed

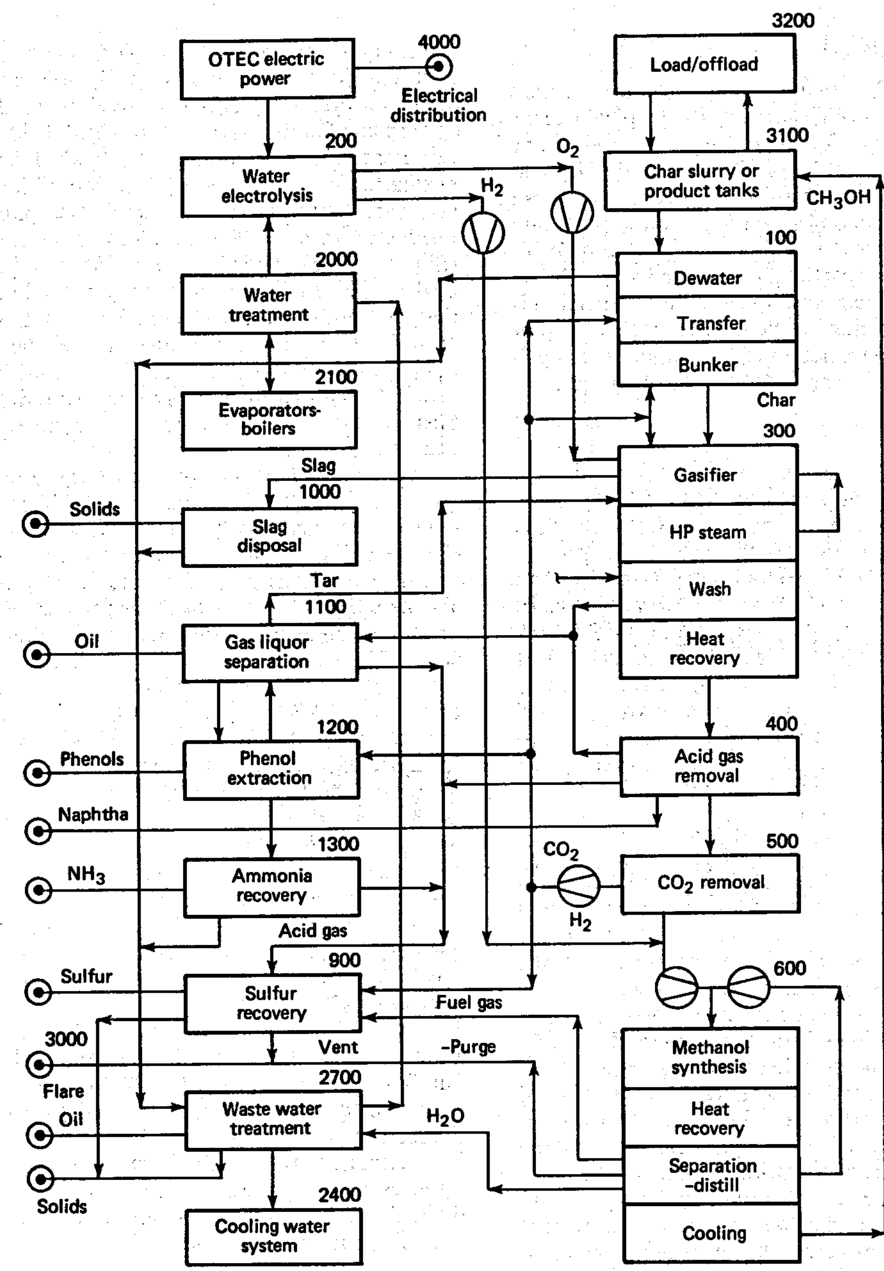

Fig. 1 Schematic of conceptual onboard OTEC-methanol process plant. (82-1/28)

carbon source is a pyrolized char transported as a slurry, but as was discussed later it may also be coal slurry or solids.

Designs for at-sea plants to make methanol from associated gas or marginal natural gas fields (Refs. 1 and 2) including tests for the effect of column motion (Ref. 3) are in progress in both Europe and Japan. The onboard processes for OTEC methanol via coal or coke gasification will require development, although portions of existing coal to synproduct designs and the aforementioned at-sea plants may be directly applicable.

Alternative commercial designs are available for each process requirement shown in Fig. 1; selection of particular processes for the OTEC system will depend on detailed design of a plantship and economic studies.

The char (or coal) water slurry is pumped aboard via a hard pipeline connection (Section 3200 in Fig. 1) from the transport tanker with simultaneous off-loading of the methanol product. Designs for hardline cargo transfer under similar dynamic conditions are being developed (Ref. 4). The slurry and product quantities may be nearly equal (68 to 82 kt for a 30-day cycle), and the same holding tanks may be used (sequentially) for each, including separated water. Delivery procedures and transfer times must also take into account ballasting and trim distribution needs for each vessel. Materials handling and transfer systems for other process chemicals and plantship liquid and bulk supplies as well as liquid and solid by-products and wastes will need to be addressed.

It is feasible to burn by-product oils, phenols, naphthol, and even NH_3 to generate additional process heat or power requirements if that is more economical than transshipment and sale, but sulfur and hazardous solids and liquids will need to be collected for disposal either by approved methods at sea or by transport for disposal ashore at a disposal site. (Sulfur can be sold for credit.) Waste water treatment in particular will differ from the usual land-based settling/clarification-digester systems and will probably include pressure filtering and digester systems.

Char-slurry handling, dewatering, and transfer systems (Section 100 in Fig. 1) are expected to be standard equipment with dust and inerting (gas) control. The separated water is recycled to meet process and makeup needs, supplemented by waste-heat seawater evaporators where necessary.

Several gasifier systems appear to be adaptable for OTEC operation, depending on whether it is carbon feed-lump (sized) coal, ground slurry, or ground-air blown, and on the bed design. Pressure operation (400 to 600 psi) is desirable to minimize subsequent syngas compression, and higher temperatures ($\approx 1800°F$) to minimize CO_2 formation. In all designs, the gasifier is water-jacketed, and high-pressure steam is generated for the process. The exit gas flows through a wash cooler where tars, heavier compounds, and dusts are removed and recycled via Section 1100. The cooled gas passes through a low-pressure steam generator and coolers before further processing. A typical crude gas composition based on the COED char gasification process (Ref. 5), modified for OTEC-O_2 oxidation, might be:

	H_2O	CO_2	CO	H_2	CH_4	H_2S	Total
Vol. (%)	0.84	1.7	63.2	33.6	0.7	0.02	100
Wt. (%)	0.78	4.02	91.0	3.6	0.6	0.03	100

Before the gases can be fed to methanol synthesis sections, all traces of sulfur and acid gases must be removed by further cooling in refrigerated exchangers and cold methanol washing in Section 400, where water, naphtha, and some CO_2 are also removed. Separation of the absorbed compounds including some recycled CO, H_2, and CH_x is effected in several steps. The purified wash methanol is then cooled and recycled.

CO_2 is removed in Section 500, typically by absorption in a potassium carbonate solution in a countercurrent packed column. The CO_2 content of the exit gas is adjusted, after addition of OTEC-H_2, to a methanol synthesis feed range of $(H_2 - CO_2)/(CO + CO_2) = 2.05$ to 2.8 by volume (Ref. 6). The rich absorber solution is then flashed first to recover syngas, which is recycled, and again to recover CO_2, which is compressed and used for inert-gas needs. The solution is then further stripped by regeneration before it is recycled for absorption. The OTEC hydrogen is mixed with the final syngas stream before admission to the methanol synthesis section where the main reaction, $CO + 2H_2 = CH_3OH$, and the following reaction, $CO_2 + 3H_2 = CH_3OH + H_2O$, occur over a copper catalyst at approximately 260°C. The exothermic reactions are controlled by recycle gas compression and cooling exchangers where water is removed and the methanol is condensed and transferred to the storage tanks. The degree to which water and other constituents, including higher alcohols, may be present in the product is not addressed, but since it is fuel-grade methanol it is assumed that further refining on board the plantship is not necessary.

This simplified description has omitted several intermediate process steps, subsidiary process recovery cycles, and what are normally termed "off-sites," but it represents the OTEC systems required. Estimates of weight and area requirements, and feedstock-product/by-product analyses are yet to be made, but a brief inspection indicates that the process equipment and storage tanks could be integrated with the OTEC plantship power systems to meet both safety and environmental requirements.

The methanol synthesis section can be one of several relatively standard available designs, e.g., the I.C.I. low-pressure, multibed, quenched process, the Lurgi tubular-packed, water-jacketed process, or the Wentworth high-pressure process.

In addition to the Conoco discussions noted above (the Fig. 1 process descriptions are largely adapted from their design for an equivalent (coal) tonnage gasifier pilot plant), similar discussions relating to the conceptual OTEC process were held with Babcock and Wilcox Research Laboratories and with R. Essenhigh at Ohio State University in February. From these discussions, the slurry-transport concept would appear to be feasible although some development in regard to ship transport stability would be required. Ongoing studies on slurry transport and combustion by both Babcock and Wilcox and Prof. Essenhigh as well as research supported by the Electric Power Research Institute and in the literature would indicate that a 30 to 50% water slurry can be combusted in boilers. The optimum water limit for the OTEC process requirement as well as gasifier constraints is a key issue. The KBW fluidized bed gasifier limit may be 5% water whereas the Texaco gasifier (TVA project) is $\geq 30\%$.

In later discussion with the Synthetic Fuels Corp., the slurry concept was questioned, particularly in regard to the water cleanup problem and dual-use tankage.

FUTURE PLANS

Small concept study contracts initiated upon receipt of the first increment of FY 82 funding will identify and resolve the key gasifier issues as noted and develop and verify the onboard proven requirements, including physical characteristics. Some additional effort will be given to the questions of feedstock handling and water and product cleanup requirements.

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REVIEW OF ELECTROLYZER DEVELOPMENT PROGRAMS AND REQUIREMENTS

Over 99% of the ocean area in the tropics suitable for OTEC is too far from utility outlets on land to be used economically for direct transmission of electric power from offshore OTEC plants. However, the ocean resource can be used efficiently if the electric energy produced on the OTEC ship is stored as chemical energy, which may then be transferred ashore by conventional tankers or ships. Water electrolysis provides a highly efficient way of storing electrical energy because 80 to 90% of the electrical energy is converted to the chemical energy of the hydrogen.

$$\frac{\text{high heating value of hydrogen}}{\text{kWh of electrical energy input}} \geq 80\% .$$

The hydrogen may be combined with other products (e.g. ammonia, methanol) in equilibrium reactions of high efficiency for convenient transport to shore. The program being conducted under this heading is concerned with coordination of the design requirements for electrolyzer units of suitable size for economical OTEC use. The required electrolyzer efficiency is currently available in the United States only in units of tenths of megawatts rather than in the multimegawatt sizes desired for efficient packaging and production.

SUMMARY

In 1981, APL began a detailed investigation of the status of water electrolysis development programs and development needs to meet projected manufacturing requirements for OTEC energy products. The results of these investigations, including discussions with electrolyzer manufacturers, assessment of energy product plantship requirements, and possible OTEC development funding, were summarized last quarter.

During this quarter, discussions continued with U.S. manufacturers, and comments were received from them on our assessments. Meetings were held with DOE/DOET program managers and with Brookhaven National Laboratory Chemical/Hydrogen Energy Systems Program personnel on the planning and application of anticipated funding for OTEC electrolyzer development. Specific development actions at several funding levels were reviewed with General Electric Co. (GE) and Teledyne Energy Systems, Inc. (TES).

With the DOE management decision to discontinue funding of OTEC energy product work, electrolyzer development for OTEC is being terminated. However, the work reported here (including specific expanded discussion and comment on U.S. electrolyzer manufacturer developments and prospects and the interim recommendations for development funding applications) will have relevance for commercial OTEC development and other hydrogen needs and will provide a basis for possible further government support.

BACKGROUND AND DISCUSSION

OTEC energy products such as ammonia (NH_3), methanol (CH_3OH), and liquid hydrogen (LH_2) require the generation of hydrogen; methanol production requires oxygen and a carbon source. Hydrogen and oxygen are produced on board the plantship by the electrolysis of desalinized seawater. Prior assessments of these OTEC products (including production rates per plantship, capital costs, space and weight requirements for installation on a plantship, and overall economic evaluations) have been made on the assumption of the availability of high-efficiency, 2 to 5 MWe electrolyzer modules. Such modules are available from European and Canadian firms and are being improved (Ref. 1), but the efficiencies and current densities (A/ft^2) of present versions are lower than desired, making them large, heavy, and unattractive for OTEC uses.

The DOE Office of Advanced Conservation Technologies, Thermal and Chemical Storage Branch (DOE/TCSB), the Electric Power Research Institute, and the Niagara Mohawk Power Corp., among others, have funded electrolyzer development, with the major portion invested in the GE solid polymer electrolyte design. Electrolyzer capacities, costs, and efficiencies projected by GE have been used in OTEC plantship projections by APL. The reduced funding and interest in the fuels and load-leveling applications (Refs. 2 and 3), reductions in the proposed module capacity and in effort at GE by DOE/TCSB (and cutback in funding), together with extended development time frames, led to DOE/DOET recognition that an OTEC-oriented electrolysis program was needed. APL was asked to direct it.

The requirements were keyed to the 40 MWe OTEC-ammonia pilot/demonstration plantship baseline design (Ref. 4) where a conceptual ammonia product plant design used the then-proposed 5 MWe (nominal input) GE-SPE, 10 ft^2 cell electrolyzers at 524 V DC ($\pm$262 V), 1000 A/ft^2, and a module efficiency η_{oe} of 83% (Ref. 5). On the basis of cost, control, and OTEC-power-generator-set matching, power to the electrolyzers was supplied via a 10 MWe (nominal), 20,000 A step-down transformer with DC rectifier systems, each supporting two electrolyzers.

The aim of the OTEC pilot/demonstration plan is to confirm the viability and economics for larger commercial plants in which electrolyzer efficiency, reliability, and life will significantly affect product costs and for which electrolysis system module capacities up to OTEC turbine-generator sizes of 30 MWe (net) may be desired. In the pilot/demonstration baseline design (Ref. 4), the electrolysis system represented 8% of the overall plantship capital cost and was assumed to have an overall electrolysis system efficiency (η_{os}) near 80%. For later commercial plantships, an η_{os} in the 85 to 90% range is projected. This includes transformer-rectifier efficiency and current, shunt, and support equipment losses. For an OTEC electrolyzer development program, comparative performance measurements must be based on product rate and total kilowatt-hour input. Figure 1 is a schematic representation of a typical electrolyzer system; the various losses are identified. The electrolysis η_{oe} is the key element, but the total cell stack voltage (number of cells per module) will bear on the transformer-rectifier efficiency and costs owing to ampere ratings (at equal kVA ratings).

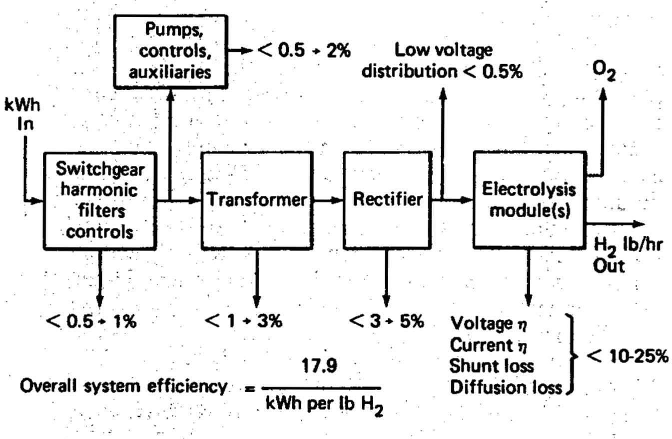

Fig. 1 Electrolysis system losses. (81-4/31)

EVALUATION OF PRESENT STATUS

We judge that each of three U.S. companies – GE, TES, and Life Systems, Inc. (LSI) – could meet the requirements for OTEC commercial plants with implementation of designs and performance demonstrated in small scale equipment. Private funding to demonstrate large scale performance and production capability will not be provided in the absence of U.S. interest in the potential large scale use of electrolytic hydrogen, as is recognized by the Canadian government. Continuing discussions with GE, TES, LSI, DOE, and Brookhaven National Laboratory (BNL) were aimed at obtaining specific program objectives and cost proposals. Specific development goals and demonstration requirements of the three designs are discussed below.

General Electric. The GE design uses a solid polymer electrolyte, Nafion, a sulphonate-group-doped fluoropolymer film. The technology stems from a 1975 design study for BNL, with the aim of high-efficiency hydrogen generation at high current density (1000 A/ft^2) to reduce cell area requirements and costs (Ref. 5). The cell stack configuration and scale-up to OTEC requirements are indicated in Fig. 2. The design of the 10 ft^2 carbon collectors, the most critical fabrication element (Fig. 2), is reported to be completed, and no fundamental technical barriers to this scale are foreseen, although difficulties at smaller scales have indicated that there may be an engineering problem. Costs for delivered systems are uncertain.

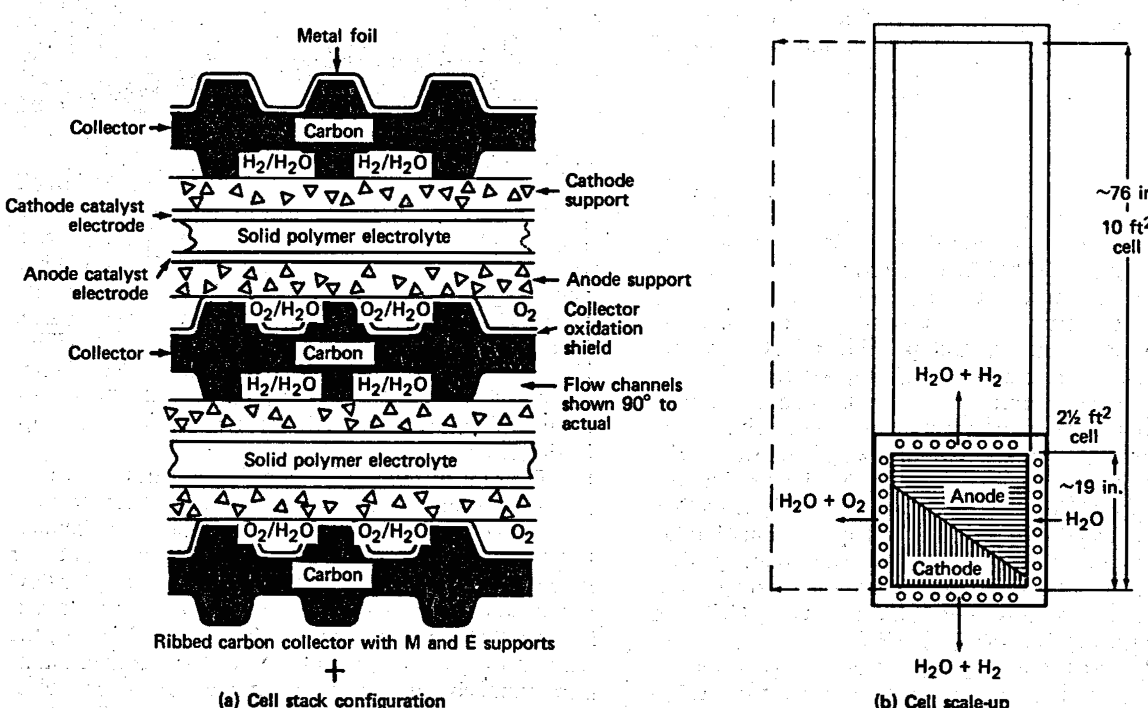

Fig. 2 General Electric Co., solid polymer electrolyte electrolyzer. (81-4/33)

Several areas of improvement have been reported; the binding agent (power coating) in the molded carbon current-collector/cell separator was changed from a phenolic resin (said to contaminate the electrodes) to a fluoropolymer. Better control of material properties has resulted in higher density, reducing the ohmic loss by approximately 60% ($\approx$70 mV) and reducing gas leakage. The desired configuration of the water flow channels has been difficult to attain because the carbon collector and titanium foil collector oxidation shield do not exactly conform when they are integrally pressed. Dry-out blistering and peroxide buildup were reported. Preforming of the titanium shield is claimed to eliminate the problem. Similarly, the 1-mil-thick perforated titanium foil anode support deflected into the water flow field; it was changed to an 8-mil-thick porous titanium plate. These supports also act in full-face electrode-current transfer and hence must maintain electrode contact.

A proprietary anode catalyst, designated WE-3, has resulted in improved performance. The anode and cathode use noble metals, and the present loading is given as 3 to 4 mg/cm^2 (at $\approx$\$120/ft^2, including both electrodes). It is claimed that equal performance will be attained at 0.5 to 2 mg/cm^2, but this has not been demonstrated on full-scale cells. Projected costs are stated to be based on catalyst cost at \$30/ft^2.

The Nafion film is supplied by DuPont at a reported cost of \$35 to 40/ft^2. A gain of 63 mV is projected for a reduction of film thickness from 10 to 7 mils but is partially offset by increased hydrogen diffusion. This loss is said to be represented as a current efficiency, $\eta_I = (\text{A/ft}^2 - 13.5)/\text{A/ft}^2$ (for 7 mils, 240°F, 100 psi), which is 0.987 at 1000 A/ft^2 decreasing to 0.949 at 250 A/ft^2. GE claims zero shunt current losses, but contact resistance losses are evident from the cell construction. Water purity is essential (<1.0 MΩ-cm). Cathode contamination by amines, not seen in resistivity measurements, was reported during development but was eliminated by adding a cation bed after the deionizer.

Water pumped through the anode flow channels is the major temperature control, and flow rates are well in excess of that consumed. Oxygen gas from the anode leaves the cell with the excess water. Hydrogen ions and water (stated as about eight times stoichiometric) pass through the electrolyte by protonic pumping, and hydrogen evolves at the cathode, where it flows with the water in flow channels (90° to the O_2-H_2O channels) to the adjacent sides of the cell from the oxygen/water manifolds. Following gas separation, the hydrogen-side water is cooled and returned to the supply tanks, while the oxygen-side water plus makeup is cooled and returned to the system by the circulating water pump. Good water flow distribution is vital and has been improved by the configuration of the collector. Scale-up to the 10 ft^2 cell maintains the same anode flow but increases the length (cathode flow) by four times (Fig. 2). The ability to meet tolerance requirements is yet to be demonstrated.

Originally it was thought that gasketless construction between the Nafion film and the carbon collector-oxidation shield would be possible; however, the achievable flatness and thickness tolerances have required the use of sealing ridges and Teflon tape. They have solved the leakage problems by compensating for cell stack tolerances. The cell stacks are pneumatically loaded at each end. Collector flexibility may limit the number of cells in a stack that can be sealed reliably. From an original 140 cell stack concept (each side), GE now states a probable stack limit of 70 on each side, thus halving the original 10 ft^2 electrolyzer module capacity, so that twice as many are required, increasing floor space requirements and costs. Operation at 100 psi of hydrogen (50 psi of oxygen) has been demonstrated continuously in all sizes to date.

GE performance predictions for future production systems are based on amine removal (80 mV reduction) and a higher operating temperature (42 mV reduction) of 240°F (115°C), with further reduction of carbon collector and separator losses noted above. Catalyst improvements are projected. With all these improvements, 1.7 V performance would be attained at 1000 A/ft^2 (Ref. 6). While small scale tests have been run at 240°F (to 5000 h), life-reliability trade-off considerations may result in the acceptance of lower operating temperatures. It is not clear that all of the development objectives and requirements could be attained for a pilot/demonstration plant by 1986, but they possibly could be met by 1988-90 for a commercial OTEC plantship.

Teledyne Energy Systems. The TES electrolyzer is composed of pressed-board, asbestos-fiber separators, proprietary electrodes, metallic flow screens-supports, and a nickel or nickel-plated bipolar plate cell divider (Fig. 3). The electrolyte is a 25% by weight KOH solution circulated by anolyte and catholyte pumps via individual gas separators and coolers. TES markets a packaged system with 110 cells, each 0.8 ft^2, and has developed a 1.4 ft^2 cell. Limited tests have been made on an 8.5 ft^2, four-cell system, but little information is given. TES proposes scale-up to 15 ft^2 cells for OTEC, based on 4 by 4 ft material for cell construction. Overall efficiencies near 80% at 100°C have been demonstrated, with higher efficiencies depending on higher operating temperatures (Refs. 7 and 8).

TES has been cautious in projected performance and life at higher temperatures, but improvements attained at lower temperatures should not be life-limited if European filter-press electrolyzer operation data are indicative. Development efforts include a search for alternative separator materials, reduction of the present chrysolite asbestos separator thickness to 0.3 mm to reduce resistive losses, and improved electrodes. Separator materials that have been evaluated include polybenzimidazole, a porous polytetrafluoroethylene (PTFE) impregnated with potassium titanate, and polysulfone. TES says the asbestos separator life is 5 years at 100°C, but French researchers claim extended life at 125°C with a silicate additive. Continuing temperature-life tests would be very desirable. No problems are anticipated in meeting OSHA requirements while handling asbestos.

Electrode developments have included PTFE-bonded nickel powders, nickel powders sintered on nickel wire screens, and catalyst-coated wire screen electrodes. A projected performance of 1.65 V at 125°C at 500 mA/cm^2 is reported with a British Petroleum

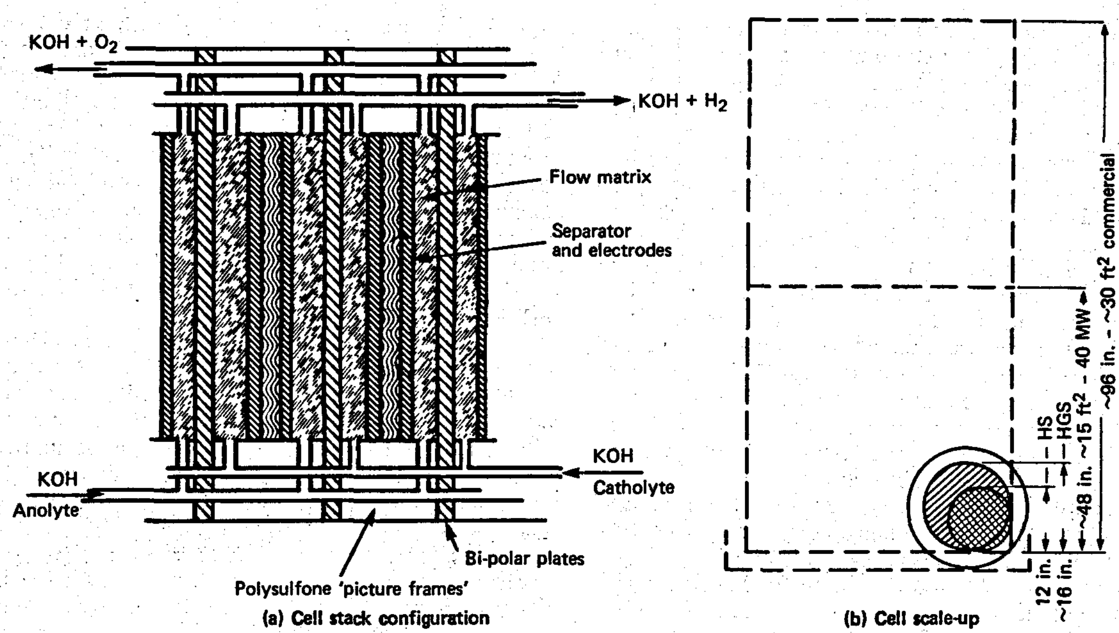

Fig. 3 The Teledyne Energy Systems' alkaline "filter press" electrolyzer (25% KOH) (Ref. 7). (81-4/34)

Research Centre cathode catalyst designated C-AN (a nickel-molybdenum compound) and an anode catalyst designated A-380. However, long term stability above 75°C has not been demonstrated.

Stable life tests to ≈1500 h at 500 mA/cm^2 (464 A/ft^2) are reported. It would appear that performance improvement beyond that currently claimed by TES is possible, the major constraint being operation at temperatures >100°C. Scale-up of separator-electrode structures to 15 or 30 ft^2 would not appear to be a significant problem, but demonstration is needed.

The flow screens (electrode supports must provide for current transfer and collection-channeling of the evolved gas) may be the most difficult design problem for operation at high A/ft^2 and high electrolyte flow rates. Electrolyte-gas port sizes are critical in the limitation of electrical bypass-shunt losses. The bipolar cell separation plate is now 10 to 30 mil solid nickel. In the larger sizes, TES anticipates using a nickel-plated or clad-carbon steel, possibly with integrally mounted flow screens; again, size should not be a problem except for handling.

Specific development goals are: demonstrated life and reliability at 125°C with an improved separator, improved electrocatalysts, a scale-up capability, and reduced ohmic and shunt loss.

Life Systems, Inc. The LSI design (Fig. 4) is a variation of the basic alkaline cell in that the electrolyte (25% KOH) is immobile. Water is fed as a vapor from a separate matrix. LSI calls the design a "static feed electrolyzer," but they propose to combine the feed and the coolant. It has been demonstrated (1150 h test with simulated seawater) that feedwater impurities can be tolerated with this concept (Refs. 9 and 10). Module (10 cells) tests have extended to 10,000 h at a 0.23 ft^2 cell size. Hardware for a 1 ft^2 cell has been scaled from the 0.1 ft^2 size for a regenerative fuel cell/alkaline electrolyzer system and has been tested under a BNL/DOE funded program (Refs. 11 and 12). An 800 h test was completed with a 1.0 ft^2 single cell, including 400 h at 400 to 1000 A/ft^2. The voltage efficiency of about 1.65 V at 500 mA/cm^2 fell within the expected performance of comparable smaller cells demonstrating successful scale-up.

The design utilizes polysulfone cell frames, asbestos separators, and proprietary electrodes: anode Super (WAB6) and cathode Advanced (WCB2). Electrode supports and water vapor and gas flow screens abut the electrodes. High voltage efficiencies have been demonstrated without current losses (no shunt loss). The interelectrode current collectors eliminate voltage loss through the intermediate components. The absence of circulating electrolytes through the cell and the isolation of all water feed and electrolyte manifolding and ports from current-carrying cell parts are said to eliminate shunt losses. The simple cell configuration and the absence of circulating fluids avoid problems in scale-up and product gas/liquid separation/masking at high current densities. The water feed matrix and feed compartment are added components.

LSI says that the cell is initially filled with KOH solution and then drained, leaving only KOH-saturated asbestos. Shutdown or loss of power does not require this operation to be repeated on new start-up. On scale-up to a 10 ft^2 size, the water feed with KOH in the feed compartment and the assembly tolerance build-up may be questionable, although the electrode-support/flow-field members have some "spring capacity." Cooling should not be a problem since either a separator coolant or the feed water is circulated adjacent to the anode

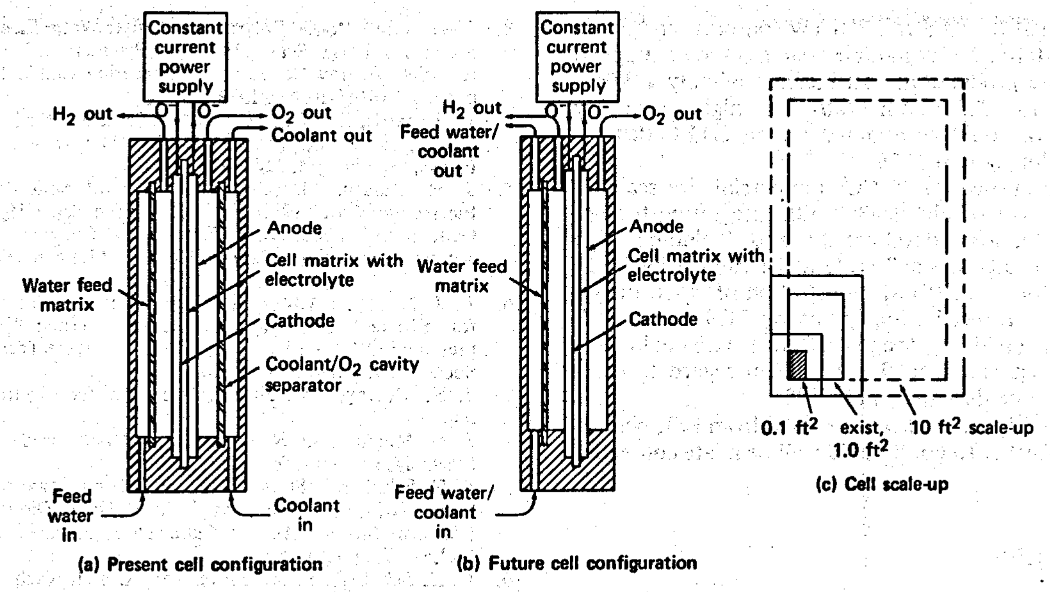

Fig. 4 Life Systems Inc. "static feed" alkaline cell (25% KOH). (81-4/35)

current collector (highest waste heat source). LSI has made a mock-up of a 60-cell module and projects an OTEC module stack of 230 cells. In LSI's response, the company proposed going directly to a 10 ft^2 cell in a funded program, with the possiblity of a multicell stack by 1986.

The apparent improvement in efficiency and water impurities tolerance makes this design very attractive. Scale-up to 10 ft^2 will present some new engineering challenges and risks. Comments made on design improvement are similar to those by TES – the asbestos separator temperature limitation has led them to look for alternate materials compatible with KOH. Cell operation at 150°C and electrode development is continuing, particularly for anode voltage reduction.

OTEC CONSIDERATIONS

Long life and minimal maintenance are prime considerations for a large electrolyzer plate at sea. Full capacity must be maintained to match OTEC power output. Evaluation of any specific electrolyzer design must include probable plant availability, maintenance and repair considerations, and spare capacity requirements. Trade-offs among system cost, operating A/ft^2, and resulting product costs will require more complete data for each design than are now available.

Foreign companies have reported R&D for more efficient electrocatalysts; separator materials for operation at higher temperatures and technical developments could be licensed or sold to United States manufacturers. The competitive and proprietary aspects of ongoing electrolyzer development and the manufacturers' reluctance for detailed process and cost disclosures (if at all possible at this point) make it difficult to assess probable electrolyzer cost ranges without more detailed investigations.

Facility requirements for scaled-up electrolyzers and their manufacture, including material supply, were not discussed in detail, nor was the necessary development test equipment, including electric power supplies. Significant cost items that may affect manufacturer market decisions and the OTEC program must be addressed. For the present, a tentative identification of specific goals for each manufacturer is as follows:

1. General Electric – demonstrated life and reliability at 115°C, reduction of ohmic losses, reduced platinum catalyst loading, and tolerance and leakage control with scale-up to 10 ft^2.
2. Teledyne Energy Systems – demonstrated life and reliability at 125°C with improved separator, improved electrocatalysts, scale-up capability, and reduced ohmic and shunt losses.
3. Life Systems, Inc. – scale-up capability beyond 1.0 ft^2, validataion of "static feed" concept for cells >1.0 ft^2, demonstrated life and reliability at temperatures >90°C and pressures ≥ 200 psi, and reduced ohmic loss.

RECOMMENDATIONS

For the three U.S. manufacturers, at least two years of continued development-demonstration effort would appear necessary. The GE electrolyzer developments are the most advanced, and the limited OTEC funding that appeared possible would do little to further development to commercial OTEC scale except for the purchase of tooling (collector molds). Existing GE funding (Niagara Mohawk, the Empire State Energy Research Corp., and GE IR&D) in 1982, and anticipated 1983 funds, will permit continued development tests and demonstration of the 2.5 ft^2 cells with anticipated performance and life data for six-cell, 50 kW units by September 1982. GE has proposed that four 2.5 ft^2, 500 kW (output) modules in place of a 10 ft^2, 2 MW module system could be supplied at a (mature production) cost increase of only $43/kW ($293 versus $250/kW); thus, a high efficiency demonstrator could be attained for an OTEC demonstration/pilot plant by 1986.

TES proposed an OTEC commercial size scale-up effort at a cost of about $300,000, integrating the advanced technology development and including high temperature tests at small scale to be funded by BNL. Assuming the successful demonstration of performance and life of advanced components by TES under BNL support and a scale-up design ($\geq 10\ ft^2$), TES could be in a position equivalent to that of GE in regard to commercial scale-up development by 1983.

No specific proposal was received from LSI; while it may have further to go, it could well be a late contender for OTEC.

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FINANCIAL AND LEGAL CONSIDERATIONS IN OTEC IMPLEMENTATION

Technical development and engineering design studies in recent years have concluded that commercial OTEC plants and plantships will produce electric power and energy products at costs competitive with or lower than those for plants based on fossil fuel or nuclear power. However, suitable financial structures and legal and institutional mechanisms must be developed before industry will be able to proceed with construction and operation of OTEC systems. The work being done in this part of the APL program has the objective of defining the economic requirements for OTEC commercialization and indicating procedures that will facilitate early growth of U.S. industrial capability to produce OTEC plants and plantships in numbers large enough to make significant contributions to U.S. energy needs in the 1990's.

SUMMARY

Work during this period has been concentrated on evaluation of the potential financial return from a 60 MWe (nominal) OTEC plant designed for operation off Puerto Rico, with consideration of the incentives provided by current tax laws, loan guarantees, and depreciation rules.

Example results are presented from cost sensitivity analyses for a moored OTEC vessel that would supply an average of 51.4 MWe of power to the Puerto Rico Electric Power Authority grid at a 90% operating factor. The results indicate that an OTEC proof-of-concept vessel of moderately large scale could be a profitable private venture even with substantial cost overruns. The final section of the article presents a preliminary discussion of perceptions that such a venture is high risk and suggests the exploration of an avenue of risk amelioration that may facilitate raising equity capital.

BACKGROUND AND DISCUSSION

The estimated costs of acquiring, constructing, and deploying OTEC proof-of-concept/experimental and larger vessels, developed during the preliminary engineering design work that was led and coordinated by APL from 1979 through 1981, were published in Ref. 1. The estimated costs are summarized in Table 1. For the basic case used in this Quarterly Report, the second column of costs under the headings "Puerto Rico Site," "Average ΔT = 40.3°F," "Nominal Size 60 MWe," and "Power Delivered to Shore 51.4 MWe" has been used. The input assumptions for this base case are listed in Table 2.

The case studies run using the 57-input pro forma profit and loss and cash flow computer program developed at APL in 1980 and 1981 are reported in Ref. 2. The case used as the basic case is conservative in that there are very substantial component replacements, over and above the normal annual allowance for maintenance materials, in the tenth, fifteenth, and twentieth years of the 25-year calculated life of an OTEC vessel. A nominal case, without major component replacements, would have a greater return to investors than the cases cited. It is not yet clear when such replacements will be necessary, if at all, during the 25-year life of an OTEC vessel.

In the example results, the financial management rate of return (FMRR), is used as the primary indicator of cost sensitivity. (For a discussion of FMRR, see Ref. 3). FMRR is a reasonably comprehensive indicator in general corporate use among company treasurers and comptrollers who would advise management regarding the relative attractiveness of OTEC as an investment compared to other options. The FMRR compensates for inherent shortcomings in the internal rate of return (IRR) when used in evaluating unconventional investments. In our cases, IRR's are very high for the first proof-of-concept OTEC vessels since special incentives in the law provide for low equity capital requirements and for large positive cash flow in the first years of operations because of very large depreciation relative to the cash requirements during construction.

Sensitivity to Hull Cost. The estimated cost of the 60-MWe (nominal) hull structure was extrapolated from the cost developed during the baseline preliminary engineering design study of a 40-MWe (nominal) offshore moored and cabled barge-type hull (Ref. 1). A factor of 1.48 was used to arrive at the estimated cost at 60-MWe scale. The resulting cost is $34.8 million (all costs are in 1980 dollars unless otherwise specified) or 15% of the total vessel construction cost of $227.3 million. Costs have been calculated in detail, based on the quantities of concrete, steel reinforcing bar, labor-hours, and other items, by a company that had completed the engineering and participated in the construction of a concrete vessel of comparable dimensions. These costs were verified later by an independent industrial estimate. Therefore, possible increases in hull costs or cost overruns of 25 to 50% are considered to be reasonable, based upon a different construction site or different companies. These increases cause the calculated FMRR, assuming both short- and long-term reinvestment rates of 15%, to drop from 31.8% after taxes to only 31.5 and 31.3%, respectively (Fig. 1a).

Sensitivity to Cold Water Pipe (CWP) and Deployment Services Costs. The estimated costs of the 30-ft

Table 1

Estimated costs for acquisition, construction, and deployment of OTEC proof-of-concept/experimental and larger vessels.

	Puerto Rico Site, Average ΔT = 40.3°F			Atlantic Ocean Site, Average ΔT = 43°F		
Nominal size (MWe)	40	60	120	40	60	120
Power delivered to shore or process (MWe)	34.3	51.4	98.1	40.3	60.5	120.9
	Costs ($M*)			Costs ($M*)		
Platform system	69.6	100.1	158.7	47.3	64.2	109.7
Hull structure	23.5	34.8		20.4	30.2	
Position control system	24.2	35.1		7.6	8.4	
Other equipment	21.9	30.2		19.3	25.6	
Cold water pipe system	9.5	9.5	18.8	9.4	9.4	18.8
Pipe system	6.7			6.6		
Screen	0.1			0.1		
CWP/hull transition	2.7			2.7		
Power systems	42.0	60.9	114.3	42.0	60.9	114.3
Evaporator and condenser systems	28.3	42.4		28.3	42.4	
Power generation, working fluid, controls, etc.	13.7	18.5		13.7	18.5	
Energy transfer system	23.1	24.2	25.4	25.5	35.8	64.0
Acceptance testing	0.9	1.1	1.4	0.9	1.1	1.8
Deployment services	20.7	26.9	41.6	11.6	12.8	22.6
Platform deployment	0.9			1.3		
Power system deployment	0.7			1.1		
CWP deployment	9.4			9.2		
Discharge pipe deployment	1.7			—		
Electric cable deployment	8.0			—		
Industrial facilities			Treated separately			
Engineering and detail design	3.8	4.6	5.4	3.8	4.6	5.4
Total	169.6	227.3	365.5	140.5	188.8	336.6
$/kWe on board	4945	4422	3726	3486	3121	2784

*Estimated costs in mid-FY 1980 dollars; no allowance for overall profit or contingency.

(9.1-m) diameter, 3000-ft (915-m) long, lightweight concrete CWP system for the 40-MWe baseline OTEC vessel of $9.5 million would be the same at 60 MWe (nominal), since the same pipe could be used. The costs for deployment of the OTEC platform, power system, CWP, water discharge pipes, and electric cable of $20.7 million for the 40-MWe vessel were increased by 30% in extrapolating to the 60-MWe size. The resultant CWP and deployment costs are $26.9 plus $9.5 or $36.4 million, 16% of total construction costs. The items have not been manufactured or deployed in the tropical oceans before. However, their cost estimates were developed by firms familiar with the type of fabrication and deployment problems involved. Because of the first-of-a-kind nature of many of the engineering solutions, we assumed that higher increases or cost overruns should be considered. FMRR's for 100 and 200% increases in CWP and deployment costs fall only to 30.8 and 29.7%, respectively (Fig. 1b).

Sensitivity to Cable (Energy Transfer) System Cost. The estimated cost of the submerged electric power cable from the OTEC vessel to shore, obtained from work by the Simplex Wire and Cable Co. on a cable rated at a capacity of 100 MWe, was $23.1 million. This cost was multiplied by a factor of 1.05 for an estimate of $24.2 million or 11% of total cost for the 60 MWe application. The 5% increase in estimated cost is for additional capacity in the on-board transformers and in the substation ashore, not in the cable itself. Because the cable is a new item not previously manufactured for the size and conditions of OTEC operation, we again considered increases of 100 and 200%, which caused the FMRR's to fall to 31.1 and 30.4%, respectively (Fig. 1c), from the base case 31.8%.

Sensitivity to Mooring (Position Control) System Cost. The estimated costs used by APL for the mooring (position control) system of the 40-MWe (nominal) baseline OTEC floating barge, taken from work by the

Lockheed Missile and Space Corp. (LMSC), amounted to $24.2 million. For a 60-MWe (nominal) OTEC plant, the costs were extrapolated upward, using a factor of 1.45, to $35.1 million or 15% of the total vessel cost. Experience with mooring a large vessel in such deep water has been limited, the mooring of the OTEC-1 off Hawaii in 1980 being the most similar. However, the OTEC-1 mooring design used a single anchor and mooring line and the ship could be detached from the mooring to ride out a storm using the ship's propulsion. The LMSC design calls for a more extensive and complex eight-point mooring system with some ability to maintain a heading into a storm while remaining moored. It is likely that modifications will be made during the detailed design phase as the characteristics of the site selected are more thoroughly equated with the mooring options. Because of the first-of-a-kind nature of the 60-MWe (nominal) OTEC mooring, 100 and 200% increases or cost overruns were considered, which caused FMRR reductions to 30.8 and 29.8%, respectively (Fig. 1d).

Sensitivity to Equipment Costs. The estimated costs of the OTEC platform system, other equipment, power systems, acceptance testing, and engineering design for the 40-MWe (nominal) vessel were extrapolated to 60 MWe by various factors, depending on equipment use and relationship to hull size, crew size, and increase in volume handled. The resultant $96.8 million is 43% of the 60 MWe total construction cost. The costs were developed primarily by estimates from established suppliers and construction engineers who deal regularly in the manufacture or supply of component modules, equipment, and services of comparable scope and use, including cost estimates prepared by The Trane Co. for the folded-tube modular aluminum heat exchanger design and for Trane's rectangular modular aluminum heat exchanger design. OTEC researchers at APL considered that reasonable increases in costs or cost overruns for this equipment would not exceed 25 and 50% above the estimates. These increases cause the FMRR to fall from 31.8% after taxes to only 31.1 and 30.4%, respectively (Fig. 1e).

Sensitivity to O&M Costs. Operations and maintenance (O&M) costs are calculated by the computer program using the input data from Table 2 for crew costs and size, logistics and supply ship costs, auxiliary fuel costs for periods when the OTEC plant may not be operating, maintenance materials costs, etc. However, the completeness of the coverage of operations and maintenance requirements is uncertain because (a) the final crew size will be known only after the U.S. Coast Guard review is completed, (b) maintenance costs of work done by others (such as mooring and cable systems) may change as development progresses and detailed design modifications are incorporated, and (c) possible additional environmental monitoring or sampling requirements may be made known during the OTEC licensing process. Because of the extent of these uncertainties, 50 and 100% cost increases for O&M were considered; the FMRR's dropped to 30.7 and 29.4%, respectively (Fig. 1f).

Table 2

Input assumptions, OTEC-utility venture.

Construction costs (M$)	227.3
Power selling price (mills/kWh)	77.993
Annual production (MWh)	407,367
Average cost per crew member ($)	40,610
Transportation and distribution costs (mills/kWh)	0
Customer bill and collection (mills/kWh)	0
Supply boat charter costs ($)	365,000
Boat stevedore costs ($)	10,000
Ships chandler costs ($)	25,000
Land transportation costs ($)	25,000
Miscellaneous costs ($)	25,000
Cost per inspector ($)	60,000
Auxiliary fuel costs ($)	30,000
Cost per manager ($)	60,000
Miscellaneous logistics costs ($)	50,000
Crew air travel costs ($)	0
Stores costs ($)	140,000
NOAA Application fee ($)	250,000
Annual legal fees during construction ($)	500,000
Members of crew	30
Number of crews	1
Number of inspectors	0
Number of managers	5
Number of years for construction	3
Number of years to depreciate	5
Depreciation rate, declining balance	1.75
Years to pay back debt	25
Days of working capital	120
Year of operations start	1985
Final year of cost projections	2010
Year of cost inputs	1980
Insurance (% of plant investment)	0.5
Maintenance materials costs (% of plant investment)	1.0
Training cost factor (% of crew cost)	5.0
Annual inflation rate (%)	9.0
Real price escalation rate (%)	0
Interest rate on debt (%)	13.0
Interest rate on bank loans (%)	N/A
Contingency on construction cost (%)	10.0
Profit added to construction and contingency costs (%)	10.0
Tax credits, net effect (%)	22.5
Construction cost in year 1 (%)	10.0
Construction cost in year 2 (%)	40.0
Tax rate on earnings (%)	46.0
First year production realized (% of rated)	65.0
Private debt portion of construction cost (%)	87.5
Government subsidy (%)	0
Brokerage fees (%)	0.8
Title XI investigation fee (%)	0.125
Stock brokerage fee (%)	2.0
Tax package sale rate (%)	100.0
During construction, Title XI fee (%)	0.375
Operating, Title XI fee (%)	0.75
General manager fee (% of plant investment)	4.0
General manager fee (% of revenues)	1.0
Government subsidy (M$)	0
No. of years of government subsidy	0

Costs are in 1980 dollars.

Sensitivity to Inflation Rate. The foregoing analyses were done for an assumed average inflation rate of 9%/yr for revenues and variable costs. Recently, the inflation rate has varied sharply between 12% and a

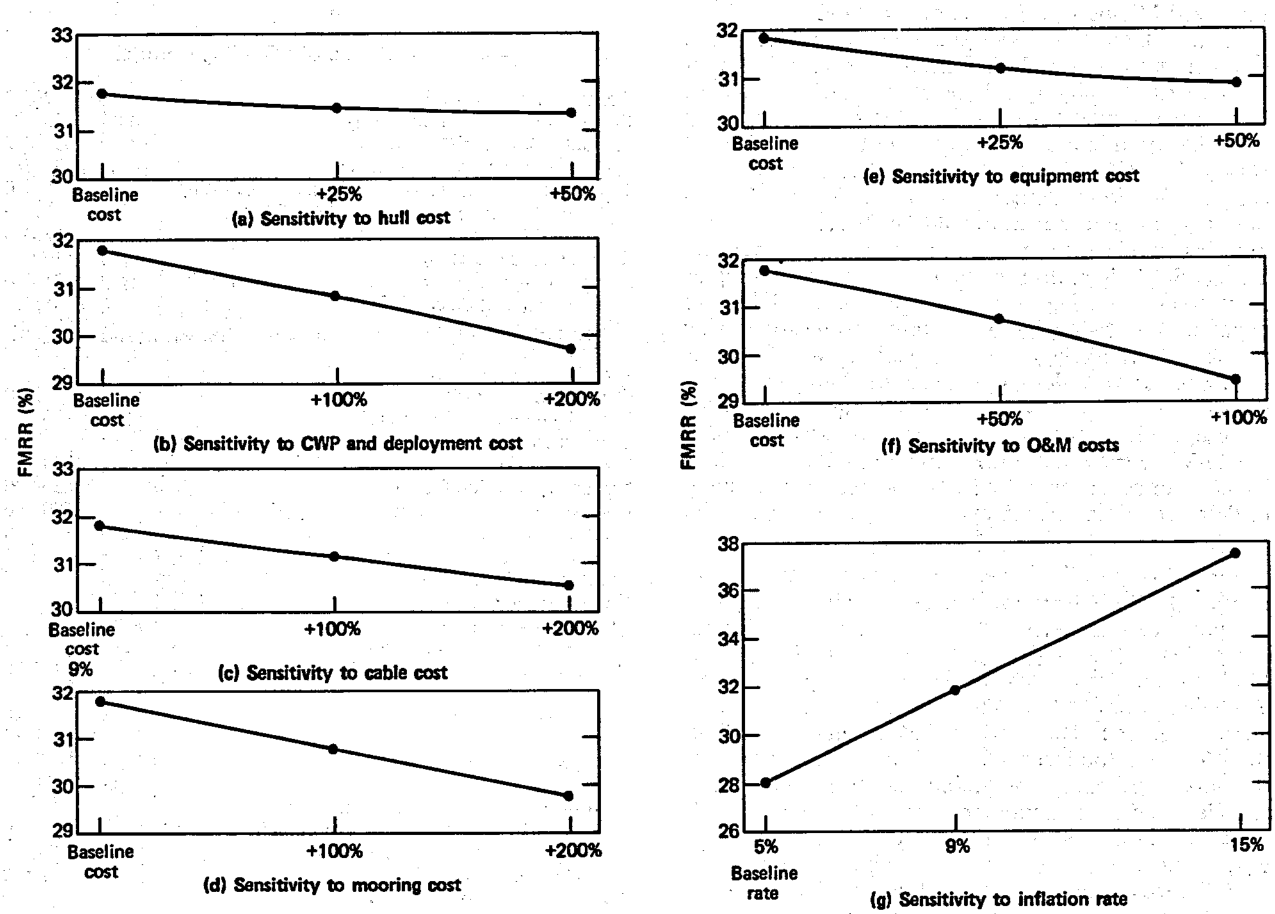

Fig. 1 Cost sensitivities in terms of financial management rate of return (FMRR) at 15% short- and long-term reinvestment rates for a moored plant at Puerto Rico with a nominal capacity of 60 MWe and a delivery capacity of 51.4 MWe. (82-1/30)

currently projected low of 5%/yr. Since revenues can be expected to exceed variable costs in all or most operating years, depending on other input assumptions, the net effect of a higher inflation rate would be expected to be a higher FMRR. We judge that rates of 5, 9, and 15%/yr should bound the reasonably possible rates. Once chosen as the input, the same rate is applied by the program through the five or more years from 1980 through construction and the 25 years of projected operations. The resulting FMRR's are 28.0% for 5% inflation, 31.8% for the 9% base case, and 37.4% for 15% inflation (Fig. 1g).

These resulting FMRR's require additional discussion. For the 9% base case, safe short- and long-term reinvestment rates of 15% for both were used, which may be conservative in the current investment climate at 6% above inflation. If so, reinvestment rates of 15% for both at 15% inflation would be overly conservative or unrealistic. The 13% interest rate for Title XI bonds would also be unrealistic. At 5% inflation, the 15% safe short-term and 15% long-term reinvestment rates are 10% above inflation and may be optimistic. For 5% inflation, the 13% Title XI bond interest may be high. Case inputs are a matter of judgment and will be influenced by the rates actually being obtained by corporations faced with an OTEC investment decision. If we assume reinvestment rates and bond interest proportional to those assumed for the 9% inflation case, we would use rates of 8.3% for both and bond interest of 7.2% for a 5% inflation case, and 25% for both and bond interest of 21.7% for a 15% inflation case. These assumptions should result in more pronounced changes in the FMRR's because positive cash flow is achieved early and occurs most years for both boundary cases.

PERCEPTION OF RISK

There is a general perception that the construction, operation, and ownership of an OTEC vessel is a high-risk undertaking. The basic reasons for this perception are believed to be:

1. A 60-MWe (nominal) OTEC vessel as described above is estimated to cost, with allowances for an overall profit of 10% and contingencies of 10%,

about $275 million. The general partner or prime contractor for the vessel sees himself as "at risk" for the total sum, even if he can pass some of the risk along to others through private or public offerings of stock, contracts with suppliers that include warranted performance, insurance, or other means. The limited partner equity owner sees himself as "at risk" for the amount of his investment but considers that the risk is generated by factors beyond his technical capabilities (i.e., in first-of-a-kind work on other areas of the overall OTEC vessel system), and thus he is, prudently, at high risk.

2. The CWP is quite large; for those not familiar with at-sea deployment of large structures (e.g., jack-down or tilt-up oil drilling rigs), it is perceived to be high risk. Most OTEC-knowledgeable companies doubt that it will be possible to obtain fixed cost, warranted construction for this component.
3. Aluminum heat exchangers, although modular, will be large and represent a substantial percentage of the vessel cost (19%). Further, there is relatively limited experience (6 months continuously) with samples of the aluminum in seawater under simulated operating conditions. These facts lead to an assumption of high risk. Titanium heat exchangers are much more costly and may have similar risks, although they should have better corrosion resistance.
4. The mooring and positioning system, at a depth of 3280 ft (1000 m) or more, situated on a sloping seabed and in an area where hurricanes, though infrequent, could occur, is beyond the state-of-practice for maritime structures. While it is the opinion of technical teams who are familiar with the problem that a satisfactory position control system could be designed and built, it is considered to be a risk.
5. The undersea cable to shore is also considered to be a risk, even after consideration of the extensive design work done by Simplex Wire and Cable Co. (Ref. 4) and the careful fatigue and properties tests carried out by the High Voltage Laboratory of the Institut de Recherche de l'Hydro, Quebec, in salt water with DOE funding (Ref. 5).

Using the financial analysis computer program and a general-partner/limited-partners form of funding, as discussed last quarter (Ref. 6), the total cost of the base case 60-MWe (nominal) vessel is $406 million. The equity requirements for construction payments during the three-year period assumed for construction total $50 million (average November 1984 dollars). At least three companies are actively pursuing OTEC projects as prime contractors or general managers: General Electric Co., Ocean Thermal Corp. (subsidiary of Basic Resources, Inc.), and Bethlehem Steel Co. There are also a number of likely investors and limited partners being discussed by the prime contractors and general managers, major OTEC suppliers, brokerage houses (which could sell stock to their corporate investors lists), insurance companies (which also sell tax syndications to customers), and legal firms. For the present, only the instance of a major OTEC supplier as limited partner is discussed.

Assuming that a heat exchanger manufacturer is a limited-equity partner, the potential new sale of aluminum heat exchangers for a 60-MWe OTEC vessel is 19% of the basic vessel cost (not including overall profit, contingency allowances, and capitalization fees) or $76 million in average November 1984 dollars. We assume equity funding of about $3 million in "up-front" preprospectus costs (government license, Title XI investigation, 25-year "take-or-pay" contract, etc.) and about $50 million in construction equity. Companies that could supply OTEC heat exchangers include The Trane Co. for the Trane design, Brown & Root, Inc.'s Allied Industries, General Dynamics' North Carolina facility, or a large shipyard's pipe shop (e.g., Avondale shipyards, Bethlehem Steel's Sparrows Point shipyard) for the folded aluminum tube design. Assuming that equity funding would be made available as needed, a 19% share of equity "up front" and for construction payments would be: $570,000 in 1982, $850,000 in 1983, $3,700,000 in 1984, and $5,000,000 in 1985 for a total of $10,120,000. Lesser amounts would probably accomplish the objective of indicating that several strong companies are involved with an equity position in the project—an indication that would make the remaining equity easier for a brokerage house to place.

The question is whether, considering the perceived risk, substantial equity investment would be taken by a major OTEC supplier to help establish the first sale of $76 million and the much larger follow-on new heat exchangers market, should OTEC be demonstrated at large scale to be a potentially attractive new energy industry. It would be expected that a company interested in finding a major new market for its product would be a logical equity partner since nearly all new product lines require some up-front investment in design, samples/fabrication, sales force, display areas, shipment costs, etc. The investment would be in two stages: preprospectus, $570,000, and postprospectus, $9,550,000.

Government officials and others familiar with the controls and safeguards inherent in the first OTEC vessels may consider that even the first OTEC vessel, except for the preprospectus stage, is not a significant risk in view of the special OTEC provisions of Public Laws 96-320 and 96-223 and the structuring of an OTEC project. Certainly, if an effective job is done during the process of reviews and decision making, controls and safeguards will be created, including:

1. NOAA coordination of reviews by many government agencies and the American Bureau of Shipping of the technical, environmental, safety, and other features of the OTEC project as part of the one-stop licensing process.
2. MarAd review of the technical and commercial elements of the project as part of the Title XI government loan guarantee investigation.
3. Review of the technical, financial, and guarantee provisions of the project by the Hawaiian Electric Co. or the Puerto Rico Electric Power Authority before agreement to add OTEC power to the power

grid on either an ownership or "take-or-pay" contract basis.

4. Review by the brokerage house offering equity participation, as part of its "due diligence" process to protect itself and potential investors. This review would be expected to include the extent to which a guarantee is provided that the project will be completed and operated over some specified period of time.

The main argument that the structure of the OTEC project would preclude noncompletion of construction as well as a possible "belly-up" situation in the early years of operation is that, after the extensive government approvals and guarantees are obtained, a large United States corporation would not be willing to assume the negative image that would accrue from failure to complete such a highly visible project.

Despite the above argument, current indications are that potential suppliers of major OTEC components perceive that there is high risk, particularly in the components for which they do not have substantial direct technical capabilities. An example frequently cited to support this contention is the approximately $300 million insurance payment made by Lloyds of London to El Paso Natural Gas Co. when the insulation split on the first liquid natural gas (LNG) tanker built by Avondale Shipyards, rendering the vessel inoperable for that purpose. In this case, a number of prior LNG ships had been successfully built and used. Further, the vessels could still be used as bulk cargo carriers, should the LNG tanks be taken out. OTEC has few if any such alternate uses, only the prospect of similar use at an alternate site. Thus, the OTEC case is said to be a much higher risk.

An exploration of the possibility that one or several corporations could undertake to guarantee all or a part of the risk is recommended. The exploration should include the possibilities that the OTEC vessel would not be completed and deployed, that circumstances may arise during the early years of operation of the vessel that would lead to shutdown of operations, and that the government would recapture all or a part of the tax credits allowed. Such a guaranteeing corporation might be a large insurance company (or several to spread the risk), the prime contractor or general partner, or some combination.

Table 3 is a summary of the total equity capital contributions needed for a total OTEC base case project and the amounts at risk for each year.

Table 3

Summary of total equity capital contributions needed for a total OTEC base case project and amounts at risk for each year.

		At Risk of			
		Noncompletion, Cumulative		Tax Credits Recapture, Cumulative	
Year	Equity Needed	%	Cost	%	Cost
1982	$3,000,000	100	$3,000,000		—
1983	4,450,000	100	7,450,000	100	$8,200,000
1984	19,400,000	100	26,900,000	100	43,400,000
1985	26,400,000	100	53,300,000	100	91,350,000
1986	—		—	100	91,350,000
1987	—		—	80	73,100,000
1988	—		—	60	54,800,000
1989	—		—	40	36,500,000
1990	—		—	20	18,300,000
1991	—		—	—	—

CONCLUSIONS

An OTEC project could have substantial cost overruns in individual components and still provide an attractive financial return. Basic assumptions, such as the inflation rate over the next 25 years, could also change substantially, with the OTEC project still providing an attractive profit opportunity. However, the perception that an OTEC project is a high risk undertaking indicates that an investigation should be made to determine if the burden of risks – that the project will not be completed or that the government will recapture the tax credits – could be guaranteed by one or several corporations.

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5. D. Richards, "Visit to High Voltage Laboratory of Institut de Recherche de L'Hydro, Quebec, Canada, Jan. 15-16, 1981."
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OCEAN THERMAL ENERGY CONVERSION §5
OTEC Hybrid Plants ZY3AEO
Support: DOE/DOET
J. A. Whelan (NWC) and G. L. Dugger
January-March 1982

POTENTIAL NAVY SITES FOR GEOTEC SYSTEMS

The technology developed in the OTEC program for power generation from warm and cold water sources offers new possibilities for efficient utilization of geothermal warm water. Specifically, the use of geothermal water at 140 to 250°C in combination with cold water drawn from the ocean nearby might be called Geothermal-Enhanced OTEC or GEOTEC. Such hybrid GEOTEC plants could prove attractive for electric power production at many sites worldwide. In cooperation with the U.S. Navy, APL is investigating the potential of GEOTEC for supplying power at island or coastal military bases that are now dependent on oil.

SUMMARY

The existing information about U.S. Navy and U.S. Air Force installations known to have some potential for GEOTEC plants has been reviewed, and the results are summarized herein. Taking into account the political and economic apects as well as the geothermal resource potential for the 11 sites considered, it is concluded that the best candidate for GEOTEC implementation is Adak Island in the Aleutian chain and the next best candidate is Lualualei, Oahu, Hawaii. The information on Adak is presented in some detail, including recommendations for futher exploration of the geothermal resource on the northern half of the island that is controlled by the Navy.

BACKGROUND AND DISCUSSION

During 1981, APL, together with the Naval Civil Engineering Laboratory (NCEL), Port Hueneme, Calif. and the Geothermal Utilization Division, Public Works Department, Naval Weapons Center (NWC), China Lake, Calif., developed the generic GEOTEC concept and developed plans to evaluate its application at Navy and Air Force installations as well as at potential civil sites near shorelines (see companion report, "Hybrid Geothermal-OTEC Power Plants: Single-Cycle Performance Estimates"). The basic concept and preliminary parametric cycle analyses were published in Refs. 1 and 2 and in previous progress reports (Refs. 3 and 4). Adak Island, Alaska, was known to have promise as a Navy application based on prior geological and geophysical work, and several other Navy and Air Force sites were known to have geothermal potential. Accordingly, an outline of a resource assessment plan for a Navy GEOTEC plant using Adak as an illustrative case (Ref. 5) was distributed among APL, NCEL, NWC, NAVFAC, and selected geologists. In August 1981, J. A. Whelan of the University of Utah, a geology consultant to NWC, B. Marsh, a geologist at The Johns Hopkins University, and others visited Adak.

On 2 and 3 September 1981, a meeting of DOE, APL, NCEL, and NWC representatives was held at NCEL to discuss results of the trip to Adak, program plans, and tasks. An NWC task was to evaluate the following sites with respect to GEOTEC potential:

Continental U.S.	Puget Sound Naval Shipyard
Alaska	Naval Air Station, Adak Island
Hawaii	Marine Corps Air Station, Kaneohe
	Bellows Air Force Base
	Naval Magazine, Lualualei
Philippines	Subic Bay Navy Complex
Azores	Lajes Air Force Base
Italy	Naval Air Facility, Sicily
	Naval Facility, Naples
Iceland	Naval Facility, Keflavik
Diego Garcia	Naval Facility

This report synopsizes Ref. 6 by Prof. Whelan, with some added comments by APL and some information from Prof. Marsh (Ref. 7).

PUGET SOUND NAVAL SHIPYARD

There is a potential area for prospecting, but there are no indications of a resource at the site.

NAVAL AIR STATION, ADAK ISLAND, ALASKA

Data on Adak are taken from Ref. 8 except for new data on water geochemistry and the discussion of possible future work.

Area Description and Geology. Adak Island (Fig. 1) is near the center of the Aleutian Islands chain. The development of a GEOTEC plant could be of significant benefit to the Navy. There are approximately 5000 people at the Naval Air Station. The present source for all electrical generation and space heating on Adak is imported JP-5 fuel; approximately 9 million gallons are used annually (Ref. 9).

Over 60 major volcanic centers of Quaternary age occur along the northern edge of the Aleutian arc, at least 40 of which have been active in the past 200 years (Ref. 10). The volcanism appears to be the northward subduction of the Pacific plate beneath the North American plate, with magma being generated along the Benioff seismic zone, which lies some 100 to 125 km beneath Adak Island. The northern part of Adak Island contains three of these volcanic centers: Mt. Moffett, Andrew Bay, and Mt. Adagdak (Ref. 11). Most of Adak Island is underlain by the Finger Bay volcanics, a thick (at least 1500 m) series of predominately pyroclastic rocks and lava flows. The unit is moderately deformed and intensively altered and is considered to be early Tertiary in age. The Finger Bay volcanics are overlain by the Andrew Lake Formation, a sequence of marine sedimentary rocks more than 850 m thick, composed chiefly of tuffaceous sandstone, siltstone, and siliceous shale interbedded with mafic flows. The formation is middle or late Eocene in age.

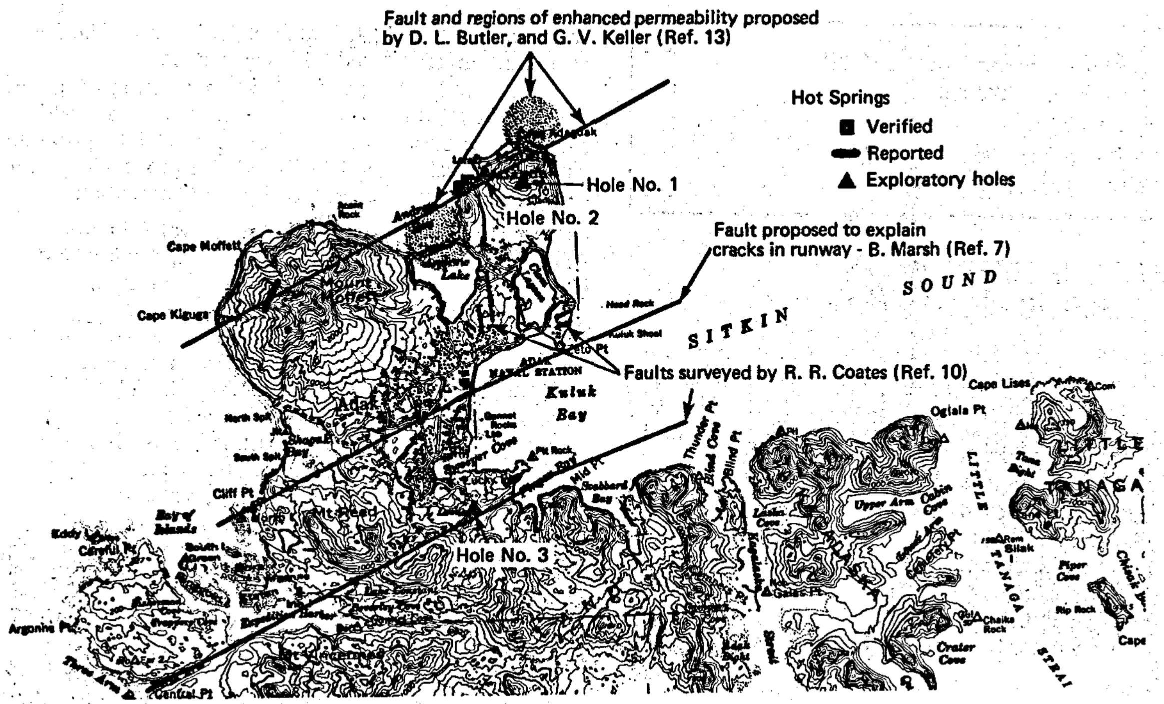

Fig. 1 Locations of selected faults, thermal springs, and test holes, Adak, Alaska. (82-1/31)

Figure 1 illustrates the deduced fault lines through the Mt. Moffett/Andrew Bay/Mt. Adagdak region and the Finger Bay region, and a third possible fault line between those two that was hypothesized by Marsh because of reports of cracking in the airfield runways; however, on his 1981 visit, Prof. Marsh did not find any clear surface evidence to support this hypothesis (Ref. 7).

Both the Andrew Lake Formation and the Finger Bay volcanics are intruded by hornblende andesite that outcrops as several small glaciated domes in the vicinity of Kaluk Bay. Volcanic and volcaniclastic rocks associated with Mt. Moffett, Andrew Bay, and Mt. Adagdak volcanoes unconformably overlie the Andrew Bay Formation. Mt. Moffett appears to be a typical andesitic stratocone some 10 km in diameter, composed of intercalated flows and tuffs. The Andrew Bay and Mt. Adagdak volcanoes are dominated by large andesitic to dioritic domes emplaced in central vents of andesitic stratocones. On the basis of potassium-argon age determinations, Miller and Smith (Ref. 11) feel that the Mt. Adagdak and Andrew Bay volcanoes were active approximately 200,000 and 800,000 years ago, respectively.

Water Geochemistry. Analyses of waters from the hot springs on the beach below Mt. Adagdak (Table 1, columns 1 and 2) yielded calculated quartz temperatures of 186 and 184°C (Refs. 11 and 12). The concordance of these two temperatures, together with the low sea-surface temperatures (0°C in February and 10°C in August), indicates a resource attractive for GEOTEC power production. On 31 July 1981, Moore sampled the Adagdak springs and seawater at that locality and noted the similarity between the two (Ref. 12). With the various chemical geothermometers, Adagdak waters give reservoir temperatures from 142 to 198°C; seawater is 123 to 185°C. The first author concurs with Moore that the Adagdak spring waters are probably contaminated seawater.

Moore found another 160°C spring on the beach 1 mile south of Cape Kiguga (51°54+'N,176°47'30"W) that consisted of fractured volcanics from which warm water and CO_2 were escaping (column 4 in Table 1). The fractures were vertical and oriented parallel with the beach in ±S45°E direction. Marine vegetation was absent from the immediate spring area. Basic exposure above the beach consisted of glacial drift (till). The spring water is relatively clean (total dissolved solids, 1939 ppm) yet it gives geothermometer temperatures of 20 to 195°C. The lower temperatures are from silica geothermometers that are easily invalidated by silica precipitation from the samples prior to analysis. This water, by ionic ratios, is closer in composition to seawater than the Adagdak waters. Since seawater is low in silica, the spring waters, if contaminated by seawater, would have higher temperatures than indicated by the analyses. There is also the possibility that at Adagdak the thermal waters consist solely of seawater slightly altered by water-rock reactions. An additional hot or warm spring was reported north of Cape Moffett (Ref. 12). All things considered, a minimum reservoir temperature of 180 to 190°C is probable.

Geophysics and Gradient Drilling. Under Navy contracts, Butler and Keller (Ref. 13) and Hoover (Ref. 14) evaluated the geothermal potential of Adak. Seismic,

Table 1

Chemical characteristics of Adak thermal waters and seawater (Ref. 6).

Characteristics	Data from Ref. 11		Data from Ref. 12		
	1	2	3	4	5
Sample number	76AMm220	76AMm221	881-8613	881-8615	881-8617
Sample description	Adagdak	Adagdak	Adagdak	Cape Kiguga	Seawater
Laboratory	USGS	USGS	CECI[2]	CECI	CECI
Na-K (°C)	149	142	164	160	123
Na-K (modified) (°C)	186	180	198	195	164
Na-K-Ca (°C)	183	182	194	195	185
Na-K/Ca/Mg (°C)	163	133	48	–	–
Na-K-Ca-CO_3 (°C)	189	181	166	195	–
SiO_2 quartz conductive (°C)	186	184	177	54	–
SiO_2 chalcedony conductive (°C)	165	164	155	20	–
SiO_2 quartz steam flushing (°C)	174	173	167	62	–
Specific conductance (mho)	–	–	710,000	3,900	710,000
pH	7.4	7.5	5.5	4.5	–
Mean temperature (°C)	63	71	68	16	–
CaH (mg/l)	1,500	1,300	1,300	21	290
MgH (mg/l)	70	110	460	38	340
Na (mg/l)	6,800	6,100	5,800	500	6,800
K (mg/l)	460	380	460	38	340
Fe (mg/l)	–	–	3.8	0.87	0.20
B (mg/l)	87	70	89	0.39	3.5
NH_3^+ (N) (mg/l)	–	–	1.5	3.1	0.22
NH_3^+ ( ) (mg/l)	–	–	1.9	4.0	0.26
Cl^- (mg/l)	13,500	12,000	14,000	1,100	15,000
SO_4	120	330	350	200	2,300
SiO_2	218	215	192	15.4	–
F	0.49	0.55	0.60	0.26	0.85
HCO_3, 1/2	420	430	512	36	–
Total calculated dissolved solids[1]	22,962	20,720	22,885	1,939	25,075
CO_2	–	–	668	870	–
Cation equivalent (%)					
Na+K	79.2	78.8	72.0	84.5	89.8
Mg	1.5	2.6	10.3	11.6	8.0
Ca	19.3	18.6	17.7	3.2	4.2
Anion equivalent (%)					
Cl	97.6	96.1	96.2	86.8	89.8
SO_4	0.6	1.9	1.8	11.6	10.2
HCO_3 + CO_3	1.8	2.0	2.0	1.6	0.0

[1] Calculated by Whelan (Ref. 6).
[2] California Energy Corp.

aeromagnetic, gravity, and electrical studies generally indicated the region south of Adagdak volcano to be favorable. Audio-magnetotelluric tests showed very low electrical resistivities at depths of 602 and 574 m, which may indicate the presence of geothermal brine. Two thermal gradient holes were drilled during the summer and fall of 1977 to depths of 323 and 624 m. The geothermal gradients were 126°C/km (measured to a depth of 84 m) and 82°C/km, respectively, values sufficient to warrant further exploration. Instead of the expected basalt and andesites, volcanic ash altered to montmorillonite was encountered to total depth in both holes, and it was extremely difficult to keep the small-diameter gradient holes open. Therefore, for deeper tests, drilling should be done using oil-field-type drilling rigs and techniques for drilling into swelling-unconsolidated material. The method might include using the casing as the drill stem (Ref. 3).

HAWAII

Marine Corps Air Station, Kaneohe. This site was initially considered to have geothermal potential (Ref. 8), but additional studies by the Hawaii Institute of Geophysics (HIG) (Ref. 15), partially funded by NWC, indicate the potential to be low.

Bellows Air Force Base. Originally thought to have good potential (Ref. 16), this site was also considered by HIG. Its geothermal potential is now considered to be low.

Naval Magazine, Lualualei, Oahu. This Navy facility may have geothermal potential as indicated by low subsurface electrical resistivity and shallow temperature-measurement holes (Ref. 17). Additional geochemical and alteration studies by HIG (Ref. 18) support the favorable conclusions of Ref. 17, which is an excellent summary of the geology of Oahu.

SUBIC BAY NAVY COMPLEX, LUZON ISLAND, PHILIPPINES

There is no clear indication of anomalous heat in the vicinity of Subic Bay (Ref. 8); thus, the geothermal potential may be inadequate for GEOTEC. Subic Bay is underlain by serpentinized periodotites of the Zambales batholith that are bounded by low-angle thrust faults along which there is no apparent deep fluid circulation. However, further studies are recommended.

LAJES AIR FORCE BASE, TERCEIRA ISLAND, AZORES

Several islands in the Azores Archipelago have significant geothermal potential; potential power of many hundreds of megawatts has been estimated (Ref. 16). Ranking the islands in order of potential, the most important resources are on San Miguel, Terceira, Graciosa, Fayal, and Pico. The potential on San Jorge, Flores, Santa Maria, and Crovo is unknown at this time, but the latter two are reported to be devoid of fumarolic activity or hot springs (Ref. 19). Lajes AFB (also a NATO base) is on the northeastern portion of Terceira Island, 4.8 km east of the city of Praia do Victoria. Terceira has two large calderas in the eastern and central parts of the island. The volcanoes are aligned on a west-northwest trend. A graben strikes northwest in the northeastern portion. The oldest rocks are ankaramites, succeeded by relatively young basalts, trachytes, and olivine basalts. Although no hot springs are known to exist on Terceira, the central volcano, Caldeira de Guilherme, has water vapor present (90°C). Considerable CO_2 and H_2S and sulfur deposits are present. The rocks are considerably decomposed, probably indicating severe hydrothermal alteration.

ITALY

Naval Air Facility, Sicily. The island of Sicily appears to have good geothermal potential (Refs. 20 and 21). Bedrock in the area consists of the basalts of Mt. Etna, which last erupted in 1977. Hot springs exhibit temperatures >300°C and are controlled by the northwest-trending fractures. Unfortunately, water quality data are not available. The only negative indication was found in Ref. 20, which placed Sicily in an area of low heat flow, less than 1 HFU; however, low heat flow on an island with numerous hot springs and an active volcano appears suspect. There is very little geologic literature published in English about the island; the best summary is that in Ref. 21.

Naval Facility, Naples. The area surrounding Naples has very good potential (Ref. 22); temperatures near 300°C have been measured at 1800 m depth. Technical difficulties, mainly low permeability of the reservoir rocks and hypersaline waters, have hindered development. It is considered doubtful, however, that the U.S. Navy could obtain geothermal rights in Italy. The recommended course of action is to monitor and encourage geothermal development in the area by local private and goverment agencies.

NAVAL FACILITY, KEFLAVIK, ICELAND

Geothermal resources have been used to heat Iceland's capital, Reykjavik, for 50 years. The United States is committed by a 1974 Memorandum of Understanding to join with the Icelanders in developing geothermal heat sources. Sudurmes Regional Heating Corp. (SRHC), a local entity, is developing geothermal wells and a distribution line to towns near Keflavik. Distribution lines now connect the Svartsengi plant area with towns on the Reykjanes Peninsula; connection of Icelandic buildings is well advanced. In FY 80, a military construction project started conversion to geothermal energy by providing connection charges to SRHC. Some Navy buildings were connected to heating mains in FY 80. Most of the conversion of Navy boiler room and heating systems is programmed in FY 81. The total budget for connection and conversion is $35 million.

DIEGO GARCIA ISLAND

The writers have no knowledge of the geology of Diego Garcia in the Indian Ocean, but it is on the edge of an oceanic plate (*World Semismicity 1961-69*, NIEC Map 3005, National Earthquake Information Center, Coastal Geodetic Survey, Washington, D. C.) in a seismically active area and thus might have some geothermal potential.

CONCLUSIONS, RECOMMENDATIONS, AND NEAR-TERM PLANS

The ranking of possible sites as to the probability of having a geothermal resource is:

1. Known resource: Keflavik and Naples
2. High probability: Lajes and Sicily
3. Good probability: Adak and Lualualei
4. Unknown potential: Subic Bay, Puget Sound, and Diego Garcia
5. Low potential: Kaneohe and Bellows AFB

Considering the political, economic, social, and institutional aspects, the prospects for a successful U.S. GEOTEC installation at a military station are ranked as follows: Adak, Lualualei, Puget Sound, Bellows AFB, Kaneohe, Subic Bay, Diego Garcia, Sicily, Naples, Lajes, and Keflavik.

Adak, which is remote, isolated, and entirely Navy controlled, presents the least problems for possible development; Lualualei is next. Bellows and Kaneohe present severe social and environmental problems. All foreign locations present legal and institutional problems. The State Department would have to obtain permission for development. Permission probably would be easiest to obtain from the Philippines, followed by Britain (Diego Garcia). In Italy, it would appear to be easier to have a development at Sicily than at Naples. It is unlikely that Iceland would allow development in competition with their own. Meidav (Ref. 23) notes that geothermal development in the Azores is being delayed by infighting between the local government and the central government of Portugal.

Another factor to be considered is sea surface temperature – the lower it is, the more efficient the plant. The approximate sea surface temperatures in Table 2 were taken from charts in Ref. 24.

Table 2

Sea surface temperatures (°C).

Location	Feb	Aug	Av.
Adak	0	10	5
Iceland	5	7	6
Puget Sound	9	16	12.5
Azores	14	20	17
Italy	12.5	25	18.8
Diego Garcia	24	25	24.5
Hawaii	22	28	25

Considering the above factors, Adak is the logical choice for an initial GEOTEC system at a U.S. military station. Originally, Ref. 8 recommended drilling with oil-field-type rigs, which made the project very expensive (Ref. 9). Per Ref. 6, the present NWC recommendations for drilling, which will have to be done with Navy funds, are as follows. Experience in observation hole drilling at Fallon has indicated that a truck-mounted drilling rig would be satisfactory for drilling 600 to 900 m observation holes. The cost of a 600 m hole in the continental United States ranges from $47,000 (Navy at Fallon) to $80,000 (Phillips Petroleum budget planning costs). Using a cost factor of 3 for Adak, a 600 m observation hole would cost $250,000; a 900 m hole, $400,000. Because of the location of Andrew Lake in relation to the favorable geothermal indications, the accessibility of the site for power plant construction, and the availability of seawater for cooling, at least one hole, possibly more, should be drilled in the Andrew Lake area. Siting of other holes will be determined after the 1982 field work has been completed and the availability of funds is known. The 1982 field work will include relogging of the two existing holes on Mt. Adagdak, preparation of fracture maps, resampling of the hot springs, magnetics work, reexamination of all available seismic data, and other details yet to be established.

In relation to these NWC recommendations, APL suggests that the following points be kept in mind: (a) the best way to install a GEOTEC plant at Adak probably would be to build the plant on a barge at a U.S. shipyard and tow it to Adak for installation at a shoreline, and (b) a 10 MWe plant is estimated to require 3 to 12 production wells (for geofluid wellhead temperatures in the 140 to 200°C range) and possibly some reinjection wells. For these reasons, it might prove more cost effective to drill more exploration holes to shallower depths to define better the boundaries of the geothermal field near the shorelines in the Andrew Bay/Andrew Lake area. Further surface explorations are being planned; NWC expects to send Prof. Whelan and other geologists and geophysicists to Adak, probably in late July 1982. In connection with that period of exploration and other possible work prior to deep drilling, Prof. Marsh (Ref. 7) offered the following comments:

"In evaluating the potential for geothermal energy on northern Adak, which consists entirely of volcanic vents and their products, it is obviously important to know very well the locations of hot springs. These hot springs may be the result of enhanced circulation of water along faults or reflect the late intrusion of a dike or plug near the water table. Up-to-date aerial photographs should be studied and the entire volcano should be geologically mapped in detail. Helicopter support is essential in such a study. The weather is generally very poor, precluding work at elevations above about 1500 feet. When good weather appears, whatever time is available can be used effectively.

"Areas of known hot springs should be carefully investigated to understand the origin and geologic setting of the spring itself. Holes can be dug or short, inexpensive, drill holes (similar to those used in mining and quarrying) can be sunk to understand the immediate thermal regime of the springs. (The usual geochemical tests for a possible high temperature source should always, as a matter of course, be made.)

"Since it is important that not only hot water, but an abundance of hot water be found, areas of possible major faults should be investigated. Because these faults are approximately parallel to the island arc and because subduction is oblique to the arc, some slip is to be expected in this NE-SW direction. The slip rate is apt to be small (mm per 1-10 yr), but such movement can be detected by examining offsets of strata in the young (5000-7000 yr) volcanic ash that mantles the entire island to a depth of about a meter or so. Digging with a back hoe is a useful tool in revealing suspected offsets. Damage by earthquakes to buildings, etc. may be useful in locating possible fault zones. And the in situ strain measurements (perhaps still going on) made by NOAA on Adak may also be useful in locating faults."

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OCEAN THERMAL ENERGY CONVERSION §6
OTEC Hybrid Plants ZY3AEO
Support: DOE/DOET
G. L. Dugger and L. L. Perini
January-March 1982

HYBRID GEOTHERMAL-OTEC POWER PLANTS: SINGLE-CYCLE PERFORMANCE ESTIMATES

For locations far from the equator where conventional Ocean Thermal Energy Conversion (OTEC) cannot be used (no warm surface water) but where a moderate-quality (120 to 200°C) geothermal water resource exists near a shoreline, there could be advantages in combining OTEC and geothermal binary cycle technologies. Such hybrid GEOTEC plants could be particularly attractive for remote military bases having a modest power demand (10 to 40 MWe) now satisfied by an oil-fired plant, such as the Naval Air Station at Adak, Alaska. This report addresses plants using a single closed cycle; the companion report, "Potential Navy Sites for GEOTEC Systems," addresses some of the sites of interest for such plants.

SUMMARY

The analysis of performance of single-cycle GEOTEC plants has been extended to show the effects of several parameters on the geofluid and seawater flow rates and the heat exchanger areas needed to generate 10 MWe of net power. Results are presented for cases for which ammonia is the working fluid. Two particularly important parameters are the geofluid temperature and the drawdown depth in the geofluid production wells. For 140°C and 250 m drawdown, the geofluid flow would have to be more than twice that for 180°C and 30 m drawdown. Another important parameter is the cooling water (seawater) temperature; an increase from a 5°C annual average value, typical of Adak Island, Alaska, to 15°C, achievable at 300 m seawater depth at Lualualei, Oahu, Hawaii would require a one-third increase in geofluid flow.

PARAMETRIC PERFORMANCE INVESTIGATION

As geofluid is withdrawn by downhole pumps, it is replaced by water from other places in the reservoir. Since the permeability and recharge mechanism cannot be generalized easily, we treat well drawdown as a parameter and assume herein that the geofluid will be reinjected for environmental reasons and to stabilize the well drawdown with time. We assume that, for each two production wells, there is a reinjection well located far enough from the production wells to avoid thermal breakthrough during the economic life of the system. However, for some sites it may be feasible to discharge the used geofluid into the ocean, possibly after also using it in a heating application. Such cases will be addressed next quarter.

We have developed a simple computer program for a single-cycle GEOTEC plant (Fig. 1) that uses ammonia, isobutane, or some other working fluid. (We are also considering dual-binary cycles (Ref. 1) that will be addressed again in future reports.) Because the major capital cost items for a GEOTEC plant will be the geofluid production and the reinjection wells, our approach is aimed at minimizing the geofluid flow rate, $\dot{w}_{GW}$, needed to develop the required net power. The independent parameters are the net power output (a refinement from the prior gross output basis), the geofluid temperature, T_{GW} (140 to 200°C), the cooling seawater temperature, T_{SW} (assumed here to be 5 or 15°C), the working fluid pump and turbine efficiencies ($\eta_{PA} = \eta_{TA} = 0.8$ is assumed here), the reinjection temperature, T_{inj} (60 to 80°C), the "pinch" temperature difference, ΔT_p (the minimum ΔT allowed between the two fluids in any heat exchanger, assumed here to be 5.6°C), the pressure or saturation temperature in the condenser, T_{CA} (assumed here to be 15 or 25°C), and the well drawdown depth, Z_d (30 to 250 m).

The geofluid exit temperature from the evaporator is equal to T_{inj}. The turbine inlet pressure is equal to the evaporator pressure, p_{EA}, which is also set by T_{inj}, since the saturation temperature in the evaporator is $T_{EA} = T_{inj} - \Delta T_p$ and $p_{EA} = f(T_{EA})$ and is determined from the thermodynamic properties of the working fluid. The required $\dot{w}_{GW}$ is equal to $\dot{w}_A \Delta h_{EA} / \Delta h_{GW}$, where Δh_{EA} is the enthalpy change of the working fluid in the evaporator including liquid heatup to T_{EA}, Δh_{GW} is the enthalpy drop of the geofluid,

$$\Delta h_{GW} = c_{p_{GW}} (T_{GW} - T_{inj}) , \qquad (1)$$

and $\dot{w}_A$ is the working fluid flow rate determined from $\dot{w}_A = P_g / \eta_{TA} \Delta h_{TA}$, where Δh_{TA} is the turbine Δh.

The net power, P_n, is given to a first approximation by

$$P_n = P_g - P_F - P_{SW} - P_{GW} - P_{inj} , \qquad (2)$$

where P_g is the gross power output and P_F, P_{SW}, P_{GW}, and P_{inj} are the pumping power requirements for the working fluid, seawater, geofluid delivery to the cycle, and geofluid reinjection, respectively.

The well and reinjection pumping power requirements are based on three kinds of pumps. First, a deep-hole well pump will bring the geofluid to the surface. We assume a combined pump and motor efficiency of 40% for drawdown depths (Z_d) in the 150 to 250 m range, and

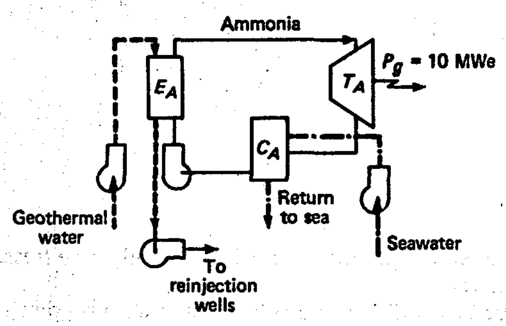

Fig. 1 Simplified diagram of GEOTEC binary cycle using ammonia loop. (82-1/32)

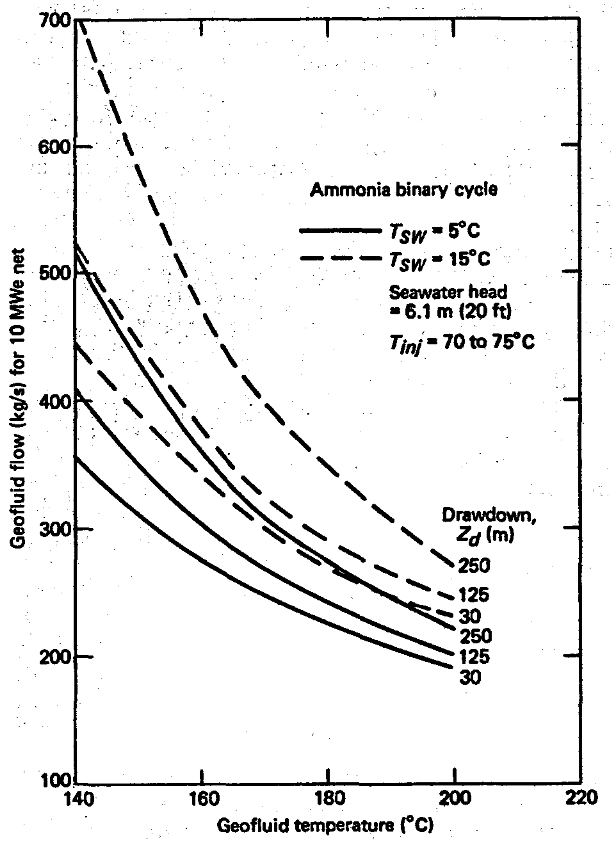

Fig. 2 Geofluid flow needed for 10 MWe net power versus geofluid temperature for three drawdown depths and two seawater temperatures. (82-1/33)

70% efficiency for $Z_d \leq 30$ m. A linear fit is used between 30 and 150 m, $\eta_{GWP} = 0.775 - 0.0025Z_d$. To prevent geofluid flashing, the geofluid pressure must be kept above the saturation pressure. Therefore, for each wellhead temperature, a head (based on the saturation pressure of steam) is required that is supplied by a surface pump-motor set with 70% efficiency. For wellhead temperatures of 200, 180, 160, and 140°C, the required heads to prevent flashing are 183, 115, 70, and 40 m, respectively. Reinjection to the drawdown depth is assumed, based on a 70% efficient pump-motor set. As it leaves the power plant, the geofluid has a substantial head, and only the additional head needed to reinject to a depth equal to the drawdown depth is assumed to be supplied (at 70% efficiency) by the reinjection pump. In some cases with high T_{GW} and small Z_d, there is sufficient head to reinject without using a pump.

Figure 2 shows the effects of geofluid temperature, seawater temperature, and drawdown depth on the geofluid flow required to produce 10 MWe net power for a plant using ammonia as the working fluid. At Adak, which has an annual average seawater temperature near 5°C, the flow required for 250 m drawdown and 140°C would be more than double that for 30 m drawdown and 180°C. The dashed curves show the greater requirements for a site such as Oahu, where 15°C seawater could be attained by pumping from 300 m depth offshore.

Figure 3 shows effects of the aforementioned parameters on the gross power output, P_g, needed to yield 10 MWe net. For small drawdown depths, P_g increases slightly as the geofluid temperature increases because of the higher pressure (hence greater pumping power) needed to avoid flashing before the geofluid enters the heat exchangers. However, for large drawdown depths, the parasitic power would be much greater at the lower geofluid temperatures than at the higher ones.

Figure 4 shows the effects of the same parameters on the size of the required heat exchangers. The condenser area, A_C, is large because large seawater flows are used (see Table 1) as part of the strategy to minimize geofluid flows. The condenser size varies with drawdown in the same way the gross power requirement does for those cases. The evaporator area, A_E, is much smaller, but its size is more strongly affected by geofluid temperature.

Table 1 lists most of the results and shows the effect of the reinjection temperature, T_{inj}, and the combined number of production plus reinjection wells. Parts A-C of Table 1 are for 5°C seawater, and part D is for 15° seawater. The best results are found at T_{inj} between 70 and 80°C with the assumptions we are using in the strategy to minimize the geofluid flow requirement. The T_{inj} effect was also displayed with respect to gross power output in Ref. 2.

DISCUSSION

The companion report indicates that the expected resource temperature at Adak Island, Alaska, is in the 180 to 190°C range. The results presented here for the ammonia binary cycle are indeed encouraging if wellhead temperatures near 180°C can be attained with adequate flow rates and with drawdown depths of the order of 100 m or less.

As indicated in a prior report (Ref. 2), the effect on the geofluid flow requirement of using a working fluid other than ammonia (e.g., isobutane or a freon) would be relatively small. Other fluids would require larger heat exchangers (and turbines), but if working fluid pressures are smaller, the cost differential may be modest in rela-

Table 1

Results for binary cycle with ammonia developing 10 MWe net power; seawater head = 6.1 m

T_{GW} (°C)	T_{inj} (°C)	$\dot{w}_{GW}$ (kg/s)	$\dot{w}_{SW}$ (kg/s)	A_E[1] (m^2)	A_C[1] (m^2)	P_g (MWe)	No. of wells[2]
A. T_{SW} = 5°C, T_C = 15°C, 30 m drawdown							
140	60	376	5930	497	4710	11.1	9
	70	357	4790	476	3900	11.0	9
	80	378	4270	505	3410	11.1	9
160	60	303	5960	382	4740	11.2	8
	70	279	4810	356	3830	11.1	8
	80	284	4290	363	3430	11.1	8
180	60	254	6020	307	4780	11.3	8
	70	229	4850	280	3800	11.2	6
	80	229	4310	279	3450	11.2	6
200	60	221	6100	256	4840	11.4	6
	70	197	4900	230	3900	11.3	6
	80	192	4360	225	3480	11.3	6
B. T_{SW} = 5°C, T_C = 15°C, 125 m drawdown							
140	60	431	6790	553	2907	12.7	11
	70	405	5450	528	4340	12.5	11
	80	432	4900	560	3910	12.7	11
160	60	332	6540	411	5200	12.3	9
	70	303	5240	380	4170	12.1	8
	80	310	4680	387	3740	12.1	8
180	60	271	6390	323	5080	12.0	8
	70	243	5120	293	4080	11.8	6
	80	241	4560	291	3640	11.8	6
200	60	233	6410	267	5090	12.0	6
	70	205	5120	238	4080	11.8	6
	80	201	4550	233	3640	11.8	6
C. T_{SW} = 5°C, T_C = 15°C, 250 m drawdown							
140	60	557	8780	681	6970	16.4	14
	70	515	6920	638	5510	15.9	14
	80	559	6330	683	5060	16.4	14
160	60	403	7930	481	6300	14.9	11
	70	361	6230	437	4960	14.3	9
	80	370	5580	446	4460	14.5	9
180	60	315	7450	366	5910	14.0	8
	70	278	5860	327	4670	13.5	8
	80	276	5210	324	4170	13.5	8
200	60	259	7140	291	5670	13.4	8
	70	226	5630	257	4480	13.0	6
	80	220	4990	251	3990	12.9	6
D. T_{SW} = 15°C, T_C = 25°C, 125 m drawdown							
140	60	606	9820	725	7400	13.7	15
	70	519	7170	636	5420	13.1	14
	80	532	6190	652	4700	13.2	14
160	60	460	9320	534	7030	13.0	12
	70	384	6830	457	5160	12.5	10
	80	378	5860	450	4440	12.5	9
180	60	371	9030	417	6800	12.6	9
	70	305	6620	351	5010	12.1	8
	80	292	5670	337	4300	12.1	8
200	60	319	9050	346	6820	12.6	8
	70	258	6630	286	5010	12.1	7
	80	243	5660	270	4290	12.0	6

[1] A_E , area of evaporation; A_C , area of condenser

[2] Includes one reinjection well for every two production wells; assumed geofluid flow rate is 65 kg/s (1000 gpm) per production well.

tion to total plant cost. The alternative use of a dual-binary cycle would decrease the geofluid requirement. Reference 1 presented gross power results for such a system using isobutane and ammonia loops and indicated that the geofluid flows for a given gross power output could be reduced by 20 to 30% compared to the single cycle.

Small additional parasitic power requirements associated with the plumbing and control valves for a plant will be taken into account when a preliminary plant layout concept is developed. Pipe friction losses can be quite small if well spacing is not too great (e.g., ≤0.5 km) and the seawater intake and discharge pipes from the assumed shoreline, barge-mounted plant are also of modest length (e.g., 0.3 km). The 6.1 m (20 ft) seawater head assumed here may prove to be a bit low. These factors will all be involved in the economic trade-off analyses that will be done as the plant layout concept evolves.

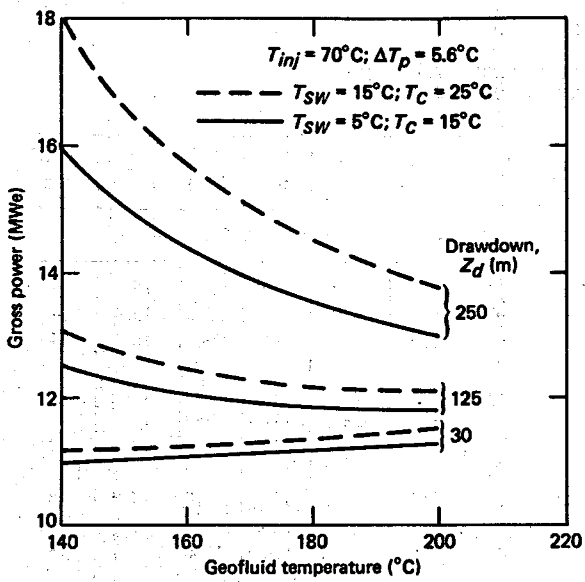

Fig. 3 Effects of geofluid temperature, well drawdown, and seawater temperature on the gross power required to produce 10 MWe net power for binary cycle with ammonia. (82-1/34)

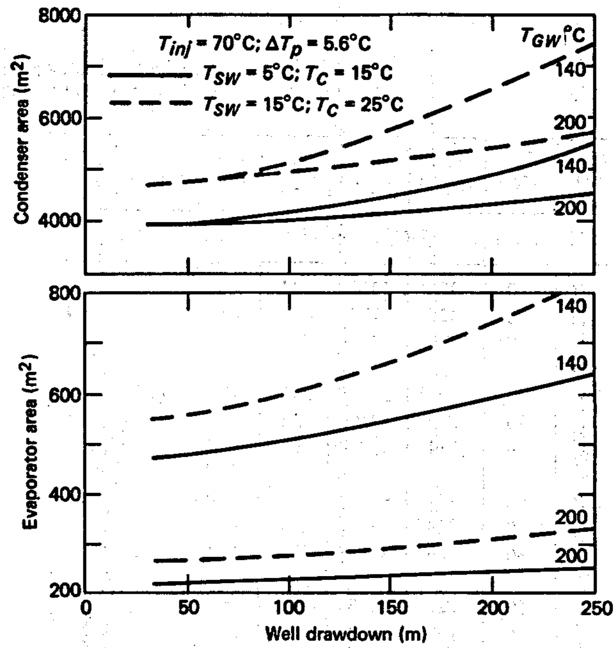

Fig. 4 Effects of well drawdown, geofluid temperature, and seawater temperature on heat exchanger areas for binary cycle yielding 10 MWe net power with ammonia. (82-1/35)

FUTURE PLANS

The plans for developing preliminary plant layout concepts and cost estimates during the next quarter remain as outlined in Refs. 1 and 2. More work will be done on dual-binary cycles, including a look at one with steam and ammonia, which might prove to be an economically attractive system for the higher geothermal water temperatures (e.g., >160°C).

REFERENCES

1. Section 6, Quarterly Report, Oct–Dec 1981, JHU/APL OQR/81-4.
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D. Richards
January-March 1982

SUPERVISION OF TESTING OF PNEUMATIC WAVE ENERGY CONVERSION SYSTEM

The use of ocean waves to produce power has often been proposed in the search for renewable energy sources. Although many technically feasible systems have been devised, economically attractive systems of general applicability have not been demonstrated. The present investigation concerns the use of the novel concept of M. McCormick – counter rotating turbines that are coupled to a wave compressed air supply in a fashion that produces unidirectional rotation of an electric generator. Wave tank tests of the system by McCormick have demonstrated the principle in accord with predictions. Estimated construction costs indicate that power costs will be attractive.

SUMMARY

DOE/DOET has supported work on the design, construction, test, and modeling of a wave-energy-extraction system with an oscillating water column. The system features a novel bidirectional pneumatic turbine. A pneumatic turbine power system has been constructed and has undergone mechanical and electrical testing to determine rotary inertias, torques, and resistances. At-sea tests at the Naval Civil Engineering Laboratory (NCEL), Port Hueneme, Calif., have been proposed, and APL has been asked to oversee this testing program as part of its technical assistance effort for DOE.

BACKGROUND

A wave-energy converter scientific feasibility model of an oscillating water column powering a bidirectional pneumatic turbine through an air chamber was demonstrated by Prof. McCormick in a wave tank at the U.S. Naval Academy in Annapolis, Md. The key principles demonstrated in this experiment were that:

- The kinetic and potential energy of ocean waves could be converted into compressed air energy in an appropriately designed captive chamber.
- The work of compression and expansion could be converted into mechanical shaft work in a valveless, bidirectional pneumatic turbine where the direction of rotation remains unchanged with the change in airflow direction driven by the water column oscillation (Fig. 1).

In April 1978, DOE signed an international agreement with the International Energy Agency (IEA) and several countries to study pneumatic forms of wave-energy conversion. The IEA program goal was to develop and evaluate contending prototype models that were to be tested on the barge-like vessel, *Kaimei*, in the Sea of Japan. The United States, Japan, and the United Kingdom were to design, construct, and deliver 125 kWe turbogenerators that convert wave-excited air in the multiported wave-air chambers on the *Kaimei* into useful electricity. Data obtained from each system were to be analyzed to compare the different systems. The U.S. turbine was not available for the *Kaimei* tests, but pneumatic chamber data were obtained using an orifice.

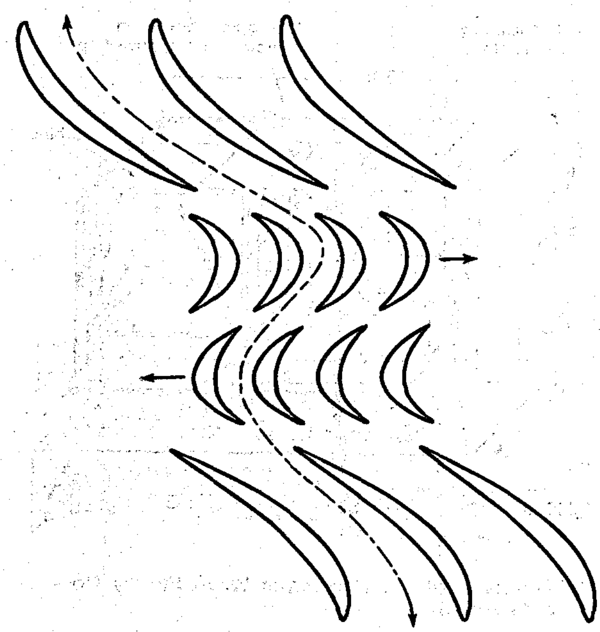

Fig. 1 Typical cross section of the McCormick turbine rotor/stator profiles showing probable airflow path. (82-1/36)

In 1979, Robert Latham (Ref. 1) and L. H. Smith, Jr., refined McCormick's earlier conceptual design (Ref. 2) for the bidirectional turbine, and the Naval Ship Research and Development Center, under the leadership of J. I. Schwartz, completed the designs and coordinated the manufacturing and fabrication of the prototype system. The prototype Pneumatic Wave Energy Converter (PWEC) consists of four separate subsystems on a single base (Fig. 2): a multiple turbine set that converts the cyclic air pressure change into rotary motion, a combining gearbox that transmits the torque generated by the two turbines to a single output shaft, a 125 kWe gen-

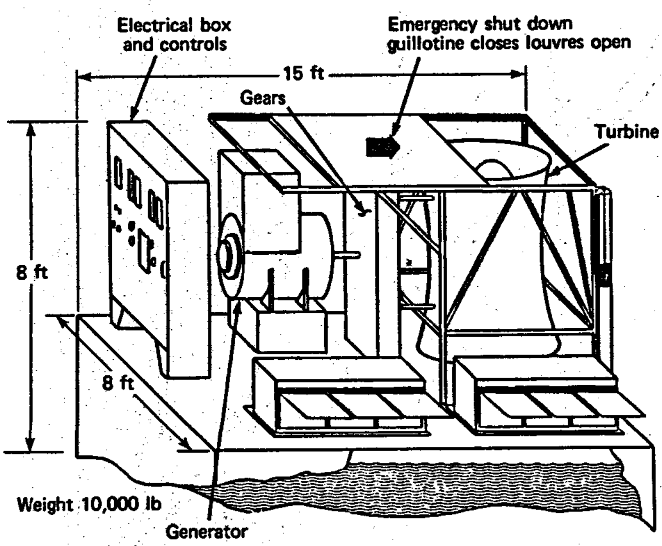

Fig. 2 Prototype of the Pneumatic Wave Energy Converter. (82-1/37)

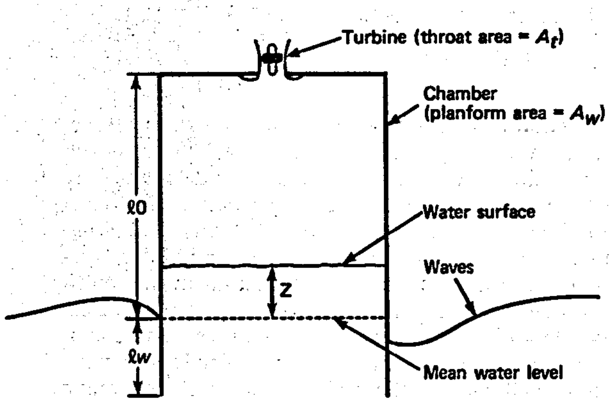

Fig. 3 Schematic of air chamber. (82-1/38)

erator that converts mechanical power to electrical power, and a control system that regulates speed and voltage.

The Solar Energy Research Institute (SERI), Golden, Colo., was directed by DOE to model the system (Ref. 3) and develop test plans for the evaluation and optimization of the turbine-system oscillating water column design (Fig. 3). Thermodynamic and hydrodynamic modeling (Refs. 3 and 4) indicates that, considering specific wave heights and periods, a design turbine-throat-area/water-column-area ratio of the oscillating water-column pneumatic turbine can be selected and the air column height "tuned" for optimum chamber volume, corresponding to the length ℓ_0 in Fig. 3.

At this time, only the mechanical test including the coast-down tests noted earlier have been conducted. The wind tunnel tests and possible wave-channel hydrodynamic tests planned by SERI to determine turbine operational characteristics have been dropped. DOE has requested that the prototype system be shipped from SERI to an NCEL test site after platform-site selection.

FUTURE PLANS

Preliminary discussions have taken place with DOE, NCEL, and McCormick on probable test requirements, equipment, and costs. At this time, a tentative concept for the at-sea tests is an air chamber that is a 20-ft-high, 22-ft-diameter tank with an open bottom and submerged flotation tanks with the PWEC mounted on top, tension-moored with draft adjustment capability. Planning meetings are scheduled for April to discuss test concepts, platforms, test requirements, costs, and data acquisition and analyses. An initial funded feasibility study will be made by NCEL. Depending on that study, it is anticipated that a complete design study might be available by June 30 and a complete system ready for operational tests by August 1982.

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