Evaluation of the St. Lucia Geothermal Resource

Engineering Investigation and Cost Estimate

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EVALUATION OF THE ST. LUCIA GEOTHERMAL RESOURCE ENGINEERING INVESTIGATION AND COST ESTIMATE

by

**J. H. Altseimer, F. J. Edeskuty
W. B. Taylor, and K. D. Williamson, Jr.**

ABSTRACT

An engineering and economic study of the development of geothermal energy in St. Lucia has given cost estimates for electricity and process heat produced from the geothermal energy, identified additional industries that are worthy of further examination, and developed methods for examining the economic impact of this new energy source. Costs have been estimated for electricity produced from geothermal energy, by diesel engines used only during peak power demand, by diesel engines producing the total electricity requirement, by an oil-fired steam-power plant, and by a coal-fired steam-power plant. Costs have also been estimated for thermal energy to be used for industrial process heat under various conditions of transport distances, capacity factors, and temperature requirements. Several industries that may be attracted to St. Lucia by the development of geothermal energy have been identified.

I. INTRODUCTION

The encouraging results of the geothermal investigation of the Qualibou Caldera led to questions concerning the cost of this energy and its impact upon the economy of St. Lucia. For this reason, an engineering evaluation of the use

of geothermal energy (GTE) in St. Lucia was carried out. First, it was necessary to make a preliminary design of a conceptual system to give an idea of the type of equipment needed as well as the relative amounts of electrical and thermal energy that might be made available. Next, a reasonable scenario for the drilling of geothermal wells and the installation of electric generators was established. From this scenario followed a schedule of construction and operating costs which was used to compute the levelized life cycle cost (LLCC) for the electrical and thermal energy that would be produced. These costs were then used as a basis for identifying various industries that might be of interest to St. Lucia, and the energy requirements for a number of industries were subjected to a preliminary examination.

II. ELECTRIC-SYSTEM DESCRIPTION

A representative power-generation system design was developed in sufficient detail to allow component and busbar cost estimates to be made. The base-case design is conservative with regard to the reservoir's temperature, pressure, depth, and wellhead flow rate as well as possible drilling difficulties. The reservoir is assumed to be large enough to easily sustain power-generation rates well over the 30 MWe case studied and the geothermal fluid is assumed to be neither excessively saline nor corrosive. Also, because the previous geothermal studies^{1,2} have now been upgraded by intensive measurement efforts by Los Alamos, it is assumed that the average success ratio will be one of every two wells drilled.

The geothermal surface facilities that are described below are "best estimates" of what might be installed on St. Lucia, given present data. Other more complex designs that might have higher technical performances but not necessarily better near-term cost effectiveness can be considered as actual data on well costs, flow rates, and fluid conditions are obtained. Therefore, it is recommended that more detailed cost-optimization studies be conducted after the reservoir is penetrated and more data on the resource are available. However, the information and data given below provide the background for a conservative estimate of the cost of electric power produced in the Qualibou Caldera. Also, the information will be of assistance in the planning and initiation of the development program.

Presented below are discussions of well-field components, geothermal power-generation systems, and peaking power-generation systems. A summary is first

presented for the reader not interested in the more detailed technical discussions.

A. Summary

The concept of the electricity-generation system is simple, has good performance, and is compatible with a high-temperature water or brine resource. A low-pressure turbine is driven by steam generated in a single-flash, steam-liquid separator. A steam condenser is used to provide the desired low pressure at the turbine discharge. Noncondensable gases, hydrogen sulfide, and mineral particulate removal subsystems are included in the design. The major features and operating parameters for the base-case design are given in Table I.

The first 10 MWe of generation capacity can be provided by four wellhead generator modules. This number can be decreased accordingly if the well flows and/or temperatures used for the performance estimates are exceeded. This approach will provide power to the grid at the earliest possible date while concurrently providing measurements of the reservoir capabilities. If all goes well and the power demand increases as expected, it might be preferable that a more centralized facility be constructed. This will include geothermal-fluid piping to interconnect both the wellheads and the centralized generators.

It is recommended that a reinjection system for the residual fluids be installed at the earliest possible time in order to prevent adverse environmental effects.

The logical, initial sources of peaking power are diesel generators, because such units are already available, and they also satisfy the requirement of having low initial capital costs. There are other types of peaking power systems that could be considered in the future that use geothermal power in such a way as to eliminate the use of diesel fuel.

B. The Well Field

Based on the Los Alamos analysis of the geologic structure of the Qualibou Caldera, initial well sites have been recommended. The initial well designs will be based upon experience in other geothermal fields. It is anticipated that a rapid learning experience will take place once drilling commences, and progressively better drilling techniques and well designs will evolve. Furthermore, a continuous monitoring and analysis of downhole samples will greatly improve the chances of successful selections of follow-on sites.

Typical well-drilling problems and designs are described by Carson, et al.,³ for eight different geothermal areas in the U.S. The total cost per

TABLE I

BASE-CASE ASSUMPTIONS AND OPERATING CHARACTERISTICS

• Well depth	: 1000 to 2000 m
• Reservoir-fluid temperature	: 250 °C (482 °F)
• Fluid-saturation pressure	: 4.0 MPa (580 lb/in ² abs.)
• Pumping is by flash-boiling action in the well.	
• Steam-separator pressure	: 0.62 MPa (90 lb/in ² abs.)
• Steam-separator temperature	: 160°C (320°F)
• Residual water	: 98 600 kg/h (217 400 lb/h)
• Total steam generated	: 24 267 kg/h (53 510 lb/h)
• Steam through turbine	: 23 040 kg/h (50 800 lb/h)
• Turbine inlet pressure	: 0.52 MPa (75 lb/in ² abs.)
• Turbine efficiency	: 0.80
• Steam-condensation temperature	: 46°C (115°F)
• Steam-condensation pressure	: 10 kPa (1.5 lb/in ² abs.)
• Surface condenser cooled by ocean water is assumed.	
• Coolant temperature into condenser	: 15.6°C (60°F)
• Coolant temperature out of condenser	: 43.3°C (110°F)
• Coolant-flow rate	: 474 000 kg (1 045 000 lb/h)
• Gross power	: 2865 kWe
• Net power	: 2500 kWe

well is a good measure of the drilling and casing problems encountered. Table II shows typical costs as derived by Carson. The first three areas are perhaps most representative of the type of wells that will be required at St. Lucia. They are characterized by lost circulation (i.e., the drilling mud is lost in badly fractured formations), corrosion of metal drilling components due to the use of air drilling techniques, and "crooked" holes. The Imperial Valley wells are in a sedimentary basin that is much easier to drill, and well costs are relatively low.

Because the well designs for The Geysers, Baca, and Roosevelt wells will probably be similar to those in St. Lucia, a description of the wells from the

TABLE II

TYPICAL GEOTHERMAL WELL COSTS IN THE U.S.

[Thousands of \$US (1983)]

Geothermal Area	Depth		
	1000 m	1500 m	2000 m
The Geysers, California	640	820	1200
Baca, New Mexico	740	900	1400
Roosevelt Hot Springs, Utah	570	910	1100
Average of 5 Imperial Valley, California, sites	340	470	630

Source: Reference 3.

above three areas should provide some advance information as to what might be expected in St. Lucia. A typical well may start with a section of 1.07-m (42-in) diameter hole followed successively by 0.66-, 0.44-, 0.31-, and 0.22-m (26-, 17-1/2-, 12-1/4-, and 8-3/4-in) diameters. There would be four nested casings of 0.76-, 0.51-, 0.34-, and 0.27-m (30-, 20-, 13-3/8-, and 10-3/4-in) diameters starting at the wellhead but all extending to different depths. These are called the conductor, surface, intermediate, and tieback casings, respectively. Depending upon the nature of the formation in the lower part of the borehole, either the hole is left uncased or a slotted liner (or perforated casing) is installed to preclude hole-collapse problems at a later date.

The surface terrain at The Geysers is very similar to that in St. Lucia: very rugged with few flat areas. As a result, many of the wells are directionally drilled from a common drill site. Later in the St. Lucia program, after the various drilling cost components become better known, a directional-drilling technique might also be used.

It should be noted that "slim holes" are sometimes used for exploratory drilling. Slim holes are about 1/2 the diameter of the wells described above and about 1/2 the cost. They would be too small for power production but might be suitable for production of process heat. No attempt was made in this study to develop a scenario containing a combination of slim and full-sized holes. If

difficulties are encountered in locating the primary reservoir, the consideration of slim holes might be worthwhile.

In the projected development scenario (see Sec. IV), the initial program would require the drilling of eight wells to find four wells capable of producing enough steam to generate 10 MWe. This number can be decreased accordingly if the well flows and/or temperatures used for performance estimates are exceeded. It may develop that some of the generator modules may have to be somewhat displaced from the producing wellheads and require piping of the geothermal fluid. This need not cause any serious problems because the required piping and its associated components are readily available. Such piping would probably be 0.3 to 0.6 m (1 to 2 ft) in diameter and aboveground. Also, the piping system would require a moderate thickness of insulation around the pipes, expansion or contraction capabilities, water and dirt traps with blow-off valves, drain and bypass flow valves, and sound mufflers where fluid is allowed to vent to the atmosphere.

An advantage of a multiwell arrangement for each generator module would be that the availability of geothermal fluid is improved because one well can flow while another is temporarily shut down for maintenance or tests.

A system of reinjection piping will also be required. These pipes will be uninsulated and considerably smaller than the lines discussed above. Reinjection will avoid air pollution and contamination of surface waters, and it is recommended that the reinjection system be installed as early as possible so as to minimize the discharge of geothermal fluid into the environment around exploratory wells.

A properly designed reinjection system will also avoid the reinjection of the cooled residual fluid at a location where it can mix with and cool reservoir fluid that is close to a production well. Such a situation could cause a degradation of the production temperature with subsequent loss of power-generating capability. Surface subsidence is not expected to be a problem in St. Lucia but the probability of its occurrence will be reduced by reinjecting the residual fluids.

C. The Power-Generation Plant

Preliminary engineering estimates have been made of the design and performance characteristics of a representative generating system that would use well established technology.⁴ An objective was to select the simplest technical approach consistent with reasonable generation efficiency, reliability, and

minimum environmental impacts. The selection was guided by numerous conversations with industrial experts in the field.*

Figure 1 is an artist's sketch of the general layout of the development that could occur by about the year 2000. The well field will be located within the Qualibou Caldera. A centralized power-generation facility will be built in a location selected as most economical from standpoints of reservoir size and location, geothermal fluid gathering, process-heat transport, land availability, power plant accessibility, and cooling water availability. The sketch arbitrarily shows the power plant in the northern or northwestern part of the caldera. An ocean water cooling system is shown. The cold water pumping station is located near the shoreline south of Soufriere. The cold water line would extend to the depth required to reach the desired low temperature. The warm water in the return line would flow by gravity to a discharge location not far offshore.

A separate water flow loop is used to transport heat from the power plant, or directly from a well, to industrial plants that require heat in the geothermal temperature range. Several heat transport loops are shown on the sketch. One loop extends from the power plant site to southern cities such as Choiseul or Vieux Fort. Another loop extends to industrial plants in Soufriere. Enough low temperature heat at about 66°C (150°F) would be available to take care of any new hotel development to the north of Soufriere as well as other potential uses in town such as restaurants or laundries.

The electric power is assumed to be connected to the main grid on the island.

In order to make preliminary performance calculations, a power-generating system design was selected. The major components are illustrated in Fig. 2. As the liquid rises in the well, there will be a level where the pressure will be less than the fluid saturation pressure of 4.0 MPa (580 lb/in² abs). As the fluid continues to rise, it will flash increasingly to steam; the fluid column will be less dense than if it were liquid, and the buoyancy effect plus any excess reservoir pressure will pump the fluid out of the well. There will be flow-control valves at the wellhead to provide for shutdown, vent to atmosphere,

*Personal conversations with industrial experts to determine the latest state of the art, e.g., at the Geothermal Resources Council 1983 Annual Meeting, "Geothermal Resources: Energy on Tap!", Portland, Oregon (October 1983).

Fig. 1. Artist's conception of future geothermal power and heat production systems in St. Lucia.

or flow to the plant. Noise mufflers would be used at any vent location in the system.

A single-flash steam generator and separator system is used. The steam will contain hydrogen sulfide and probably particulate matter. To avoid turbine damage, it is assumed that such contaminants will be removed before the steam enters the turbine. A small fraction of the steam is bled off for jet-pumping the noncondensable gases that will accumulate in the steam condenser. The primary steam flow will drive the turbo-generator and then be condensed in a water-cooled condenser. The cooling water will be pumped from the ocean to flow through a simple surface condenser. The design options for the condenser and cooling components are numerous.

It was considered conservative to assume that the net power output would be 2500 kWe. To obtain this power, the geothermal-fluid flow rate for the base

Fig. 2. Basic power-generation components.

case is estimated as 122,800 kg/h (270 900 lb/h) of 250°C (482°F) temperature liquid. The total steam rate is 24 267 kg/h (53 510 lb/h) with 23 040 kg/h (50 800 lb/h) of steam flowing through the turbine.

The above flow rates are not high compared to other high temperature fields around the world.^{5,6} For example, Ref. 5 shows data for 230° to 300°C water or brine wells. All except one of the flow rates range from 230 000 kg/h (507 000 lb/h) to 400 000 kg/h (880 000 lb/h). The exception was a New Zealand well flow of 150 000 kg/h (331 000 lb/h).

The steam condenser adds complexity to the system. However, without it, the required steam flow rate to match the base-case output would be approximately double, and valuable geothermal energy would be wasted. It would be possible to operate without a condenser and with the turbine exhausting to the atmosphere during the very early stages of the project. The noise, hydrogen sulfide, and steam plume may be tolerable if only one or two wells are flowing. However, for the long term it is recommended that a condensing system be installed.

Assuming that a condenser will be used, it is desirable to operate at as low a condensing pressure as possible. The minimum feasible pressure will depend on the quantity of noncondensable gases in the geothermal fluid, the coolant temperature, and the heat-exchanger efficiency. Figure 3 illustrates the sensitivity of the base case system to the condenser back pressure and temperature. The base case is 10 kPa (1.5 lb/in² abs) and 46°C (115°F) and should be easily attainable if cold water, i.e., ocean water, is available. If even colder conditions and a 7 kPa (1.0 lb/in² abs) pressure are achievable then the power output would increase 8%. If less efficient cooling systems must be used, the performance losses might easily be of the order of 10 to 15%.

The major parasitic power loads in a geothermal plant are usually caused by the cooling system. Cooling can be by air flowing in a forced draft tower, but in the warm St. Lucia climate the parasitic load would be significant. The use of local water would be best if adequate supplies are readily available. However, it is believed that such is not the case. Therefore, the use of cold ocean water may be the most viable option for the ultimate centralized plant. In the near term, the wellhead modules will probably have to be operated with more conventional cooling systems.

The base case does assume cooling with ocean water. It was estimated that the water temperature is 13°C (56°F) at 400 m depth and that a 1600-m long pipe

Fig. 3. Effects of condenser conditions on gross power output.

is required to reach the 400-m depth. These estimates were based on data for Keahole Point, Hawaii, and Punta Tuna, Puerto Rico.⁷ Allowing for a temperature rise from inlet to plant, the plant inlet temperature of 15.6°C (60°F) was estimated. An onshore pipe length of 1600 m was used including a 122-m elevation rise. The warm return line was also 1600 m in length onshore plus 400 m offshore. The above elevation rise would be similar to a plant location at Cresslands. Other potential sites might be at Sulfur springs, Belfond, or Etangs where the elevation might be at least 300 m. When more information is available, the design could be re-evaluated and the various options compared. Nevertheless, it is felt that the parasitic losses calculated for the present base-case design are reasonable and representative of a final design.

Table I summarizes the assumptions that make up the base-case generating system and the results of the operating characteristics calculations.

D. Peaking Power Generators

Peaking units typically have low capacity factors (average load ÷ maximum capacity). Consequently, low initial capital costs are necessary in order to

keep the unit production costs down. Diesel generators (D-G) meet the capital cost requirements and are already available in St. Lucia. On the other hand, the high capital costs of the geothermal system preclude its use as an economically viable peaking system. Therefore, it is logical that D-G be used in concert with the new geothermal-power generators. The problem with D-G, however, is that diesel fuel is used and must be imported at the world market price.

The use of an alternative peaking system would be desirable. Several concepts were evaluated but only in a cursory manner because of time and funding limitations. The one that appears promising for this application would combine conventional hydro, pumped hydro storage, and the use of sea water in the power plant condensers. When the geothermal development is well underway, this concept (Fig. 4) might be considered as a future development item. Near the power plant, a water reservoir would be built that would be large enough to meet the requirements for at least one day of peaking power. The reservoir would be filled from three sources. First, the power-plant condenser would use cold sea water as the coolant and it would discharge into the reservoir. Another pumping system would pump sea water from a shallow ocean-inlet point to the reservoir. Its temperature is not important. The pumps would be driven by power from the geothermal plant.

The third water source would be from surface drainage. No detailed investigation of the potential for a water reservoir was made. It was learned that a 33 kWe hydro plant did exist at one time above Soufriere. Certainly the rainfall would be sufficient to provide some natural storage. Whatever water could be trapped by the reservoir would help reduce the annual cost of generating power, but the concept does not depend on this source.

To meet peaking power demands, water would be allowed to flow from the high elevation to sea level through hydraulic turbo-generators. When the system is properly tuned to the daily demands, the geothermal plant will operate very nearly as a true base-load system. This situation would result in the highest possible geothermal capacity factor and minimum geothermal-power costs.

The costs of the hydro power will depend upon the geothermal power costs, the distance from the shore, the elevation rise of the geothermal-power plant, the cost of the sea water piping and pumping system, the capacity factor for the hydro units, the size and costs of the reservoir, and the quantity of surface water that flows into the reservoir.

Fig. 4. Hydro-energy storage and peaking concept.

Preliminary calculations indicate that the cost of this type of peaking hydro power could be less than D-G power costs. Even if these costs were equal, there would be economic benefits to St. Lucia because of the reduction in diesel fuel importation.

III. THERMAL-SYSTEM DESCRIPTION

Although the primary objectives of the St. Lucia geothermal project are to produce reasonably priced electric power and reduce diesel fuel imports, an enormous quantity of low- and intermediate-temperature heat will also become available for other applications. This section describes how the heat might be transported from the field to industrial users. Design concepts were established to estimate the costs of major components such as piping, pumps, and heat exchangers. These costs are input data for the levelized life cycle cost analyses discussed in Sec. V. The designs that have been studied represent only the first phase of a design optimization study and were selected to bracket the range of costs. Therefore, recommendations are also given for a more advanced version of the heat-supply system.

A. Summary

All systems studied consisted of a heat exchanger (HX_1) at the power plant or well, a closed water loop to carry the heat from HX_1 to another heat

exchanger (HX_2) at a factory, and the necessary electric pumps and controls (Fig. 5).

The closed water loop is recommended because it minimizes corrosion and contamination problems in the plumbing. The hot and cold lines of the loop can be installed either below or aboveground.

The geothermal fluid from which heat is extracted will be reinjected underground to prevent environmental problems. It is recommended that it not be used directly in a factory. The process working fluid would be heated in HX_2 and its flow would be controlled by the factory.

Three system designs were studied, two of which make use of residual heat, defined as the heat remaining in the geothermal fluid after steam is extracted and used for power production. The third design delivers primary heat, defined as heat taken directly from the wellhead with no intermediate heat utilization for other purposes.

Using the base-case, power-generator design, the residual heat is at 160°C (320°F). After transport over 2.4 km (1-1/2 mi) to HX_2 inside a factory, the maximum delivered temperature could be about 140°C (285°F). This factory might be near or in Soufriere. For a factory in the Vieux Fort industrial park, the estimated distance is 21 km (13 mi) and the factory-side temperature is about

Fig. 5. Residual-heat system.

132°C (270°F). The corresponding maximum rates for delivery of heat from one 2500 kWe power plant are 47 000 and 43 900 MJ/h (44.6 and 41.6 million Btu/h).

In the primary-heat system, the fluid is fed into HX_1 in a liquid condition and at the full 250°C (482°F) temperature. The factory-side temperature in a 2.4 km distant factory could be 223°C (433°F). The maximum rate at which primary heat can be delivered from one base-case well is 100 000 MJ/h (95.6 million Btu/h), assuming a factory working fluid temperature range of 80° to 433°F. However, the cost of this heat is higher than the residual heat, because costs include both the production and reinjection wells in addition to a submerged pump in the borehole.

A more practical and useful design could be a compromise between the above residual and primary-heat systems. For example, the steam generator could be operated to provide a 204°C (400°F) residual temperature instead of the 160°C (320°F) base-case temperature. This could deliver a factory-side temperature of 177°C (350°F) over a 21-km distance. This would be a very useful temperature for many water or steam applications. Once a list of potential new industries is established, the most optimum heat-supply system can be determined.

B. Residual Heat Supply For Soufriere

New industrial or commercial applications of geothermal heat in Soufriere are worth considering because of its close proximity to the source. To bracket the range of heat costs, both residual and primary-heat supply systems were analyzed. This section is limited to the discussion of residual heat, defined as the heat remaining in the geothermal fluid after steam is extracted from it and used for power production. The estimated distance between the power generation site and the potential factories in Soufriere is 2.4 km (1-1/2 mi).

Figure 5 illustrates the basic design concept for the residual-heat system plus important operating parameters consistent with the base-case, power-generation system discussed in Sec. II. The average temperature differences across the heat exchangers are for high performance heat exchangers. Increasing the temperature differences decreases their size and cost. No attempt was made to arrive at an economic optimum except to use engineering judgment as to what might be close to optimum.

The heat is transferred from the power-plant site to the factory by means of a water loop connecting heat exchangers HX_1 and HX_2 . The water in the loop is chemically controlled to prevent corrosion in the piping, pumps, and heat

exchangers. Heat exchanger HX_1 is made of alloy steel to resist corrosion by the geothermal fluid. HX_2 is made of carbon steel.

There are four pumps. Pump P_1 augments the pressure in the geothermal fluid to drive the fluid through the hot side of HX_1 . Pumps P_2 and P_3 overcome the resistances to flow in the loop and heat exchangers. Even though there is an elevation difference between the power plant and the factory, the hydraulic heads in the two legs of the loop balance one another. The elevation head cannot be ignored, however, because it contributes to the design pressures in the loop. An elevation head of 107 m (350 ft) was assumed.

Pump P_4 and 30 m (100 ft) of insulated piping are included as parts of the heat-supply system in the factory. The pump is used to drive water (or other working fluid) through HX_2 . A pressurized-liquid heat exchanger was assumed, although it might also have been one with hot water on one side and steam on the other. This depends on the factory's requirement.

Table III gives a summary of the component costs for the case of 100% of all residual heat from one base-case power generator being delivered to Soufriere.

TABLE III

COST SUMMARY

100% of the Residual Heat to Soufriere From One Power Generator
[Thousands of \$EC (\$US)(1983)]

<u>Component</u>	<u>Best Estimate Including 25% Contingencies</u>		<u>Spares Over 20-yr Life</u>	
HX_1	1174	(435.0)	294	(109.0)
HX_2	702	(260.0)	175	(65.0)
Pumps	174	(64.3)	87.2	(32.3)
Return piping	200	(74.1)	20.0	(7.4)
Outbound piping	667	(247.0)	66.7	(24.7)
Factory piping	10.3	(3.8)	1.1	(0.4)
TOTALS	2927.3	(1024.2)	644.0	(238.8)

As is shown in the table, the best estimates are increased by 25% to take care of contingencies. Estimates for purchases of spare parts are also listed.

The operating availability was estimated as 94% using the following rationale: The availability of the hot geothermal fluid can be as high as 95% by using redundant piping between several sources of the hot fluid. Redundant arrangements can also be incorporated in the heat exchangers by using modular designs that can be repaired while the remaining modules continue to operate. Components like pumps and valves can be redundant and/or quickly replaceable by spares. A 1% availability loss is estimated for piping and electric-power-line repairs. The net availability factor is 94%.

Capacity factors are estimated by using the factory operating conditions and the above 0.94 availability factor for the heat-supply system. Another parameter is the operating-power requirement. For the Soufriere system, 97 kWe is required to run the system at full output. It is also assumed that the system will run in an idle mode even if all factories are shut down. The power requirement during idle is estimated as 5 kWe.

Table IV summarizes the capacity factors and the annual power consumption.

TABLE IV
CAPACITY FACTORS AND POWER CONSUMPTION

100% Residual Heat to Soufriere From One Power Generator

Factory Operation (days/wk, h/day)	Working Hours Per Week	Capacity Factor = $h/wk \times 0.94$ $\div 168$	Annual Electric Power Consumption ^a (kWh/yr)
7, 24	168	0.94	801 000
5, 24	120	0.67	583 000
7, 16	112	0.63	551 000
5, 16	80	0.45	406 000
5, 8	40	0.22	221 000

^aUsed for water circulation.

The data in Table III and IV are all for the case of using 100% of the residual heat that could be delivered from one 2500 kWe generator. At the present time, there are not enough factories to use the available heat from one well. Therefore, a hypothetical design was established for the delivery of only 10% of the maximum available heat from a base-case plant. Data for the 10% case are shown in Tables V and VI. The maximum heat rate for this case is 4.5 million Btu/h.

C. Residual Heat Supply For Vieux Fort

Vieux Fort has been designated by St. Lucia as the location of an industrial park development. The distance from the possible source of residual heat to the park was estimated as 21 km (13 mi) and 17 km (10-1/2 mi) for sources being located at Cresslands and Etangs, respectively. The 21 km distance was used for cost estimation.

The basic system concept is the same as that previously discussed and shown in Fig. 5. The most important additional consideration is that the heat losses are greater than before because of the much longer pipes. It is estimated that the delivered temperature in the Vieux Fort factory is 132°C (270°F). In this case, the maximum delivery rate from one generator is estimated as 43 900 MJ/h (41.6 million Btu/h).

TABLE V

COST SUMMARY

10% of the Residual Heat to Soufriere From One Power Generator

[Thousands of \$EC (\$US) (1983)]

<u>Component</u>	<u>Best Estimate Including 25% For Contingencies</u>	<u>Spares Over 20-yr Life</u>
HX ₁	117.4 (43.5)	29.4 (10.9)
HX ₂	70.2 (26.0)	17.5 (6.5)
Pumps	22.4 (8.3)	11.2 (4.15)
Return piping	133.4 (49.4)	13.3 (4.94)
Outbound piping	533.2 (197.5)	53.3 (19.75)
Factory piping	6.7 (2.5)	0.7 (0.25)
TOTALS	883.3 (327.2)	125.4 (46.49)

TABLE VI

CAPACITY FACTORS AND POWER CONSUMPTION

10% of Residual Heat From One Power Generator to Soufriere

<u>Factory Operation (days/wk, h/day)</u>	<u>Annual Power Consumption (kWh/yr)</u>
7, 24	97 000
5, 24	70 000
5, 16	49 000
5, 8	26 000

The summary of the costs of the major subsystems are shown in Table VII for the case in which 100% of the residual heat from one power generator is delivered to Vieux Fort.

Table VIII summarizes the annual electric-energy consumption. The power required for full capacity operation is 211 kWe.

D. Primary Heat Supply to Soufriere

For the assumed reservoir temperature of 250°C (482°F), the water saturation pressure is 4.0 MPa ($580\text{ lb/in}^2\text{ abs}$). As the hot fluid rises in a well, the hydraulic-head pressure decreases and flashing occurs. As the pressure continues to decrease, so does the saturation temperature. The result is that the temperature of the liquid-steam mixture is less than the original 250°C in the reservoir. This phenomenon can be avoided by keeping the liquid at or above the original pressure by using pumps submerged in the wellbore at a depth of about 460 m (1500 ft). This is a concept that has been studied intensively in the U.S. and is a technically sound one. In the U.S. the prospects for its use are primarily in very saline fields like those in the Imperial Valley, California, or in low-temperature fields where organic Rankine Cycle systems are used. As discussed below, the concept was incorporated in the design used for estimating the cost of primary heat.

Figure 6 shows the system design for delivering primary heat to Soufriere. The pump would be driven either mechanically or electrically. The fluid flows into a heat exchanger, HX_1 , at 250°C (482°F) and exits at 48°C (119°F). Pump P_2

TABLE VII

COST SUMMARY

100% Residual Heat to Vieux Fort From One Power Generator
Over a 21 km Distance

[Thousands of \$EC (\$US) (1983)]

<u>Component</u>	<u>Best Estimate Including 25% For Contingencies</u>	<u>Spares Over 20-yr Life</u>
HX ₁	1 550 (574)	392 (143)
HX ₂	589 (218)	146 (54)
Pumps	381 (141)	192 (71)
Return piping	1 739 (644)	173 (64)
Outbound piping	6 950 (2574)	694 (257)
Valves, controls, etc.	<u>338 (125)</u>	<u>170 (63)</u>
TOTALS	11 547 (4276)	1767 (652)

TABLE VIII

CAPACITY FACTORS AND CONSUMPTION ELECTRICITY

100% of Residual Heat to Vieux Fort From One Power Generator

<u>Factory Operation (days/wk, h/day)</u>	<u>Annual Electricity Consumption (kWh/yr)</u>
7, 24	1 742 000
7, 16	1 196 000
5, 16	879 000
5, 8	474 000

Fig. 6. Primary-heat system.

then is used to reinject the fluid into the reservoir. The reinjection well is assumed to be at a distance of 1.6 km (1.0 mi) from HX_1 .

A heat transmission loop similar to that used for the residual heat system is used. Because of the high temperature, both HX_1 and HX_2 are constructed of alloy steel. The estimated temperature deliverable to the factory working fluid is 223°C (433°F). The maximum rate of heat delivery is 100 000 MJ/h (95 million Btu/h), based on a geothermal-fluid flow rate of 123 000 kg/h (270,900 lb/h) corresponding to that in the 2500 kWe base-case power generator.

Table IX shows the estimated costs of the primary-heat system. Note that this system includes three expensive components that are not necessary in the residual heat system: the two wells and the submerged pump.

Table X shows the annual electricity consumption. The power required for full-power operation is 486 kWe.

As was the case for the residual-heat system, the heat rate from the above system is much greater than can be used in St. Lucia. Therefore, a design to supply 10% of the above heat was analyzed.

TABLE IX

COST SUMMARY

100% of the Primary Heat to Soufriere From One Production Well

[Thousands of \$EC (\$US) (1983)]

<u>Component</u>	<u>Best Estimate Including 25% For Contingencies</u>	<u>Spares Over 20-yr Life</u>
Production well	6 750 (2500)	540 (200) ^a
Reinjection well	6 750 (2500)	---
Downhole pump	776 (287)	621 (230)
HX ₁	2 717 (1006)	543 (201)
HX ₂	2 079 (770)	416 (154)
Other pumps	445 (165)	178 (66)
Return piping	199 (74)	16 (6)
Outbound piping	780 (296)	65 (24)
Factory piping	10 (4)	---
Reinjection surface piping	135 (50)	11 (4)
Valves and controls	<u>337 (125)</u>	<u>135 (50)</u>
TOTALS	20 978 (7777)	2525 (935)

^aFor hookup to alternative wells.

For convenience, it was assumed that the submerged pump would be used to supply both the electric power and the heat-production systems. This means that the electric-power generator could deviate from the base-case design, but this deviation was not considered important for calculating heat costs. The 123 000 kg/h (270 900 lb/h) value for geothermal fluid flow out of the well was retained, and 10% of that was assumed to be available for primary heat. Ninety per cent of the costs of components common to both power and heat systems were charged to electric power and 10% to heat production. Table XI summarizes the costs for the 10% system. Table XII shows the power-consumption data. The power required for full-power operation is 52.5 kWe.

TABLE X

CAPACITY FACTORS AND POWER CONSUMPTION

100% of Primary Heat to Soufriere From One Production Well

<u>Factory Operation (days/wk, h/day)</u>	<u>Annual Power Consumption (kWh/yr)</u>
7, 24	4 014 000
7, 16	2 759 000
5, 16	2 031 000
5, 8	982 000

TABLE XI

COST SUMMARY

10% Primary Heat to Soufriere Using One Base-Case Production Well

[Thousands of \$EC (\$US) (1983)]

<u>Component</u>	<u>Best Estimate Including 25% For Contingencies</u>	<u>Spares Over 20-yr Life</u>
Production well	675 (250)	---
Reinjection well	675 (250)	---
Downhole pump	78 (29)	78 (29)
HX ₁	273 (101)	67 (25)
HX ₂	208 (77)	51 (19)
Other pumps	236 (87)	119 (44)
Return piping	135 (50)	13 (5)
Outbound piping	535 (198)	54 (20)
Factory piping	8 (3)	---
Reinjection piping	13 (5)	3 (1)
Valves and controls	111 (41)	57 (21)
TOTALS	3126 (1157)	442 (164)

TABLE XII

CAPACITY FACTORS AND POWER CONSUMPTION

10% Primary Heat to Soufriere Using One Base-Case Production Well

<u>Factory Operation (days/wk, h/day)</u>	<u>Annual Power Consumption (kWh/yr)</u>
7, 24	433 000
5, 24	312 000
5, 16	213 000
5, 8	113 000

E. Recommendations For Further Studies

The residual-heat system shown in Fig. 5 is simple and should result in the lowest cost for process heat. However, the delivered temperatures are only 140°C (285°F) and 132°C (270°F) in Soufriere and Vieux Fort, respectively.

The primary-heat system of Fig. 6 delivers 223°C (433°F) but includes a downhole pump and is more complex. It is recommended that a system be considered for further study that delivers a temperature intermediate to the above two values and without a downhole pump. For lack of time, this was not studied in any detail, but preliminary performance estimates for such a system are given below. Much of what can be done will depend upon the actual well characteristics.

The estimates for the base-case power generator indicated that the steam generator should be designed to operate at 0.62 MPa (90 lb/in² abs) pressure and 160°C (320°F) temperature. A compromise can be made between power and heat-production requirements. For example, the steam generator could be designed to operate at 1.7 MPa (247 lb/in² abs) and 204°C (400°F). With this residual temperature, it should be possible to deliver a temperature of 177°C (350°F) to a factory in the Vieux Fort area. This corresponds to a heat-delivery rate of 70 000 MJ/h (66.1 million Btu/h). This would be a very good temperature level for many industrial processes. If a process must have a temperature that is somewhat higher, additional heat could be added in the factory by other means such as burning diesel oil. The additional costs would probably not be significant because most of the process heat would already have been supplied by the geothermal system.

The above system assumes that the well will satisfactorily pump its fluid to the surface at a reasonable flow rate without a downhole pump. It is felt that this will be verified when the production wells are completed.

Compared with the base-case power generator, the above concept will generate less power. If the wellhead flow rate is still 270,900 lb/h, then the new net power will be approximately 1800 kWe. This number might be increased if all of the residual heat is not used in the factories but a fraction is used in a power cycle compatible with the lower temperatures. The above combination of power plus heat-production systems would need to be optimized to meet future St. Lucia development plans.

IV. SCENARIO FOR THE INTRODUCTION OF GEOTHERMAL ELECTRICITY

The actual scenario for the introduction of geothermal electricity in St. Lucia will depend upon a number of factors, including funding schedules, and will be greatly influenced by actual well drilling costs, the geothermal-fluid conditions, and the well productivities that are encountered. Furthermore, the final decision on the actual schedule will be made by the government of St. Lucia. Nevertheless, in order to make a cost estimate it is necessary to have a schedule of expenditures for the construction period as well as for the operation period.

An additional constraint arises from the economic advantage that accrues by having the geothermal-power production units operate with the highest practical capacity factor (ratio of power produced to the maximum power that could be produced). Preliminary calculations have shown the cost of geothermal electricity to be in the neighborhood of \$0.17 EC/kWh (\$0.06 US/kWh), whereas electricity generated by diesel units is closer to \$0.27 EC/kWh (\$0.10 US/kWh). However, the major portion of the cost of the geothermal electricity arises from the initial investment, whereas with the diesel production most of the cost is due to the cost of the fuel. Consequently, the cost per unit of geothermal electricity rises as the capacity factor decreases, but the cost per unit of electricity produced by diesel engines is relatively insensitive to capacity factor. Thus, the lowest charge for the geothermal electricity would result if these units were to be operated so that they are always base loaded. However, for the geothermal units to contribute the greatest saving, it is more advantageous to introduce additional units until the last unit added will have a

capacity factor less than the maximum possible but still high enough that the cost of its electricity does not exceed that of a diesel unit.

At present there are two independent electric power grids in St. Lucia. As stated in data supplied to Los Alamos, St. Lucia Electric Services Ltd., LUCELEC, has projected an annual increase in electric-power demand of 4% in the southern grid and 5% in the northern grid. The use of this projection leads to the electric-power demand shown in Fig. 7, which shows the expected average and peak power demand curves until 2016. The uppermost smooth curve shows the projection of the total installed capacity so that the 43% reserve compared with

Fig. 7. A senario for the introduction of geothermal electric power in St. Lucia.

maximum demand which existed in 1983 is maintained until a total of 5 MW occurs, and then that value is maintained.

Data were not available to determine the minimum power demand as a function of time. Therefore, it was assumed that the minimum power demand curve will lie as far below the average power demand as the peak power demand is above the average power demand. Also, a linear relationship between capacity factor and power demand was assumed. With these assumptions, it is possible to compute the capacity factor for each additional geothermal unit added to the power-production system. For this calculation, a 2.5 MW unit was used. Because the cost of the geothermal electricity is essentially inversely proportional to the capacity factor, it is possible to add 2.5 MW geothermal units until the capacity factor has decreased to the point where the cost of the power produced by the last unit added approaches, but is still just less than, the fuel cost of a competing diesel unit (about 90% of the total cost of electricity generated by diesels). This calculation was made for each of the years shown in Fig. 7 with the total of the resulting geothermal capacity being shown as the lower cross-hatched section.

The additional production capacity needed for peaking and for standby power must then be provided by another method. For this study, it was assumed that this additional capacity would be provided by the existing diesel engines, replacing them as necessary during the duration of the study period. The upper cross-hatched area in Fig. 7 represents the diesel peaking and reserve capacity. An additional study should be made when sufficient data become available to evaluate the possibility of other methods of providing peaking power, including peak shaving methods such as pumped hydro.

For this study, a period of 30 yrs was assumed. This period is not a limitation of the geothermal reservoir lifetime but is long enough to cover the lifetime of the longest lived equipment to be installed and will result in a cost that reflects the cost of continuous operation past that time. Table XIII gives some of the pertinent data concerning the operation of the electric-power system with geothermal base units supplemented by peaking diesel engines. The smaller production from geothermal units in 1987 is due to the fact that the third and fourth geothermal units will not be in service until late in the year. This schedule is based upon the assumptions that 90 days will be allowed for the drilling of each well; that one out of two wells will be sufficiently

TABLE XIII
ELECTRIC-POWER-SYSTEM PARAMETERS

Year	Number of Geothermal Units	Geothermal Power (kWh x 10 ³)	Number of Diesel Units	Diesel Power (kWh x 10 ³)
1987	4	52 509	5	29 179
1988	4	69 292	5	15 268
1989	4	70 168	5	18 448
1990	4	70 956	5	21 917
1991	4	71 832	5	25 500
1992	4	72 708	5	29 328
1993	5	86 396	5	20 511
1994	5	87 600	5	24 405
1995	5	89 024	5	28 334
1996	5	90 338	5	32 617
1997	6	105 250	5	23 575
1998	6	106 430	5	28 553
1999	6	107 485	5	33 935
2000	7	122 180	5	26 000
2001	7	123 407	5	31 838
2002	7	124 633	6	38 012
2003	8	139 634	6	30 606
2004	8	141 036	6	37 514
2005	8	142 613	6	44 457
2006	9	159 651	6	36 354
2007	9	160 242	7	45 118
2008	9	160 834	7	54 316
2009	10	176 076	7	49 394
2010	11	191 275	7	44 915
2011	11	193 684	7	53 776
2012	12	209 714	7	49 556
2013	12	212 868	8	58 782
2014	12	216 284	9	68 329
2015	12	219 964	10	78 236
2016	12	220 226	10	92 254

productive; that drilling will begin near the end of 1984; and that after the drilling of a successful well, a period of one year will be used in testing well quality, establishing geothermal-fluid conditions, and installing the generating equipment.

V. COST ESTIMATES

The cost estimates were made with the use of a levelized life cycle computer code called BICYCLE.⁸ The levelized life cycle cost (LLCC) is set so

as to make the total revenue from sales equal to the total cost of building and operating the plant over its lifetime. Input requirements of this code include plant capacity, fraction of borrowed funds, interest rate, inflation rate, capacity factor for each year of operation, expenditures by year during plant construction, and operating expenditures by year. The LLCC is given both in constant and current dollars; however, only constant dollars (1983) are given here.

In making the cost estimates, all costs have been included in 1983 dollars, and a currency exchange rate of \$2.7 EC = \$1.0 US was used for conversion of US dollars to EC dollars. A study period of 30 yrs was used, which corresponds to the longest lifetime for any of the installed equipment.

A. Cost of Electricity

The cost of electricity was estimated for several different methods of production. These methods were the following: production from geothermal energy with all borrowed funds, production from geothermal energy with UN funding for the first three wells, diesel-engine production for peaking power, total power production by diesel engines, production by an oil-fired steam plant, and production by a coal-fired steam plant.

The electricity costs estimated herein do not include the cost of the integration of the two distribution grids, nor are any losses in the grid included. Thus, the costs given here are busbar costs.

1. Geothermal Electricity. The geothermal electric-power system studied was one which can produce a maximum of 30 MWe with the use of twelve 2.5 MW units and in which the rate of introduction of these units is according to the schedule shown in Fig. 7. With the assumptions of the initiation of drilling in late 1984, a 90-day drilling period for each well, one of each two wells being capable of producing a net electrical output of 2.5 MW, and a period of 1 yr for well testing and for the installation of the generation equipment, the first geothermal electricity can be expected to be on line in late 1986. Also, these assumptions lead to the expectation of 10 MW of geothermal electricity being available by the end of 1987. After that, a period of 5 yrs will elapse before another 2.5 MW geothermal unit will be required. Subsequently, increasingly shorter periods occur between additions of geothermal units as the slope of the demand curve gradually increases. The schedule assumed here results in a capacity factor that varies from about 77% up to a maximum of 85%, which is assumed to be the maximum availability of the system.

Tables XIV, XV, and XVI give expected costs during the respective construction years of 1984, 1985, and 1986. Table XVII indicates the recurring costs during the operation years from 1987 through 2016; however, many of the actual costs are not given in this table because of their variation, which depends upon the requirement for well drilling, either for new wells or for the replacement of existing wells, and for generator installation.

It was assumed that the wells would be drilled to a depth of 2000 m, that they would have a useful lifetime of 20 yrs, and that the drilling costs would be \$2M US for each well. These assumptions are felt to be conservative for several reasons. The nature of the reservoir might easily be such that a 2000 m depth will not be required. However, for this depth the assumed cost is approximately twice the expected cost for similar wells drilled in other locations in the USA, and in addition, the same 25% contingency factor that has been applied to all other expenses was also applied to this well cost. The assumption of a 2.5 MWe output per well is also felt to be conservative.

The electric-power-producing equipment was assumed to cost \$1000 US per kW (installed), and this includes the equipment for the removal of H₂S and particulates. This equipment was assumed to have a useful lifetime of 30 yrs.

Other costs were also included for items such as labor, maintenance, shelters, shops, and for the reinjection of the spent geothermal fluid back into the geothermal reservoir. ReInjection is recommended both to assist in maintaining the productivity of the geothermal field as well as to avoid adverse environmental effects. It was assumed that one or more of the nonproductive wells can be reworked for this purpose, or if a different well location is needed, the cost is contained in the allowance made for nonproductive wells.

TABLE XIV
GEOTHERMAL-PLANT CONSTRUCTION COSTS - 1984

<u>Item</u>	<u>Cost (k\$ US)</u>
Site preparation	300
Move drilling rig	100
Drill one well	2 000
SUBTOTAL	<u>2 400</u>
Contingency (25%)	600
TOTAL	<u>3 000</u>

TABLE XV

GEOTHERMAL-PLANT CONSTRUCTION COSTS - 1985

<u>Item</u>	<u>Cost (k\$ US)</u>
Generator building	100
Site staff	100
Site preparation	200
Warehouse and shop	100
Four wells	8 000
SUBTOTAL	8 500
Contingency (25%)	2 125
TOTAL	10 625

TABLE XVI

GEOTHERMAL-PLANT CONSTRUCTION COSTS - 1986

<u>Item</u>	<u>Cost (k\$ US)</u>
Generator building	300
Site staff	100
Site preparation	200
Injection systems	400
Three wells	6 000
Four generator sets	10 000
Well maintenance	100
Generator maintenance	25
SUBTOTAL	17 125
Contingency (25%)	4 281
TOTAL	21 406

TABLE XVII

GEOTHERMAL-PLANT OPERATING COSTS

Well maintenance	=	10% of initial cost
Generator maintenance	=	2% of initial cost
Site staff	=	\$200k per year
Well drilling (as needed)	---	
Generator addition (as needed)	---	
Contingency	=	25%

Additionally it was assumed that all funds would be borrowed at a 10.5% interest rate (except for the case in which the U.N. would fund the drilling of the first three wells) and that inflation would remain at 5% throughout the course of the study. For the case involving the U.N. funding, it was assumed that the UN repayment schedule of 5% of the sales price (presently \$0.19 US/kWh) would be used for all geothermal electricity produced for the first 15 yrs of plant operation. An insurance charge of 2% of the investment was also included.

2. Diesel-Generated Electricity. For estimating the cost of electricity generated by diesel engines, the following values were used: cost of a 2.6 MWe unit = \$939,000 US (price given by LUCELEC, amounts to \$361 US/kW); cost of diesel oil = \$3.39 EC per imperial gallon; a generation efficiency of 17.24 kWh/imperial gallon; and the same values as above were used for inflation, interest, and insurance.

For the generation of electricity by diesel engines, two cases were considered: first, the diesels were considered as providing the peaking power only, and second, as providing the entire power demand. As can be seen from the relative costs as given in Table XVIII and shown in Fig. 8, the cost per kWh is a little less for the diesel generated electricity carrying the total load as compared with the diesel generated electricity used for peaking only. This is due to the considerably lower capacity factor that results in the peaking operation.

3. Electricity From Oil-Fired and Coal-Fired Steam Plants. For comparison cost, estimates were also made for electricity generated by oil-fired and coal-fired steam-power plants. For the oil-fired plants, the following values were used: fuel cost (No. 6 fuel oil)=\$28 (42 gallon) per barrel, plant cost = \$1642 US/kW.

For the coal-fired plant, the following values were used: coal (delivered in St. Lucia) = \$50/US ton; plant cost = \$2422 US/kW.

The cost estimates for each of the above methods of producing electricity in St. Lucia are given in Table XVIII and shown graphically in Fig. 8, where it can be seen that the electricity generated from the geothermal field is expected to be the least expensive. It should also be mentioned that in the case of the oil-fired and coal-fired steam plants the inconvenience and possible interruption of imported supplies was not considered. In addition, no consideration was

TABLE XVIII

COST COMPARISON--ELECTRICITY FROM GEOTHERMAL ENERGY
AND FROM ALTERNATIVE TECHNOLOGIES

System	LLCC (\$EC/kWh)	LLCC (\$US/kWh)	Savings ^a (\$M EC)	Remarks
1. Geothermal	0.170	0.063	253	No U.N. funds
2. Geothermal	0.167	0.062	264	U.N. funds three wells
3. Diesel (peaking)	0.275	0.102	---	Add on to base-load system
4. Diesel (total)	0.243	0.090	0	Continuation of present system
5. Oil-fired steam	0.233	0.086	5	
6. Coal-fired system	0.192	0.071	167	

^aSavings represent difference in total expenditures between continued diesel generation and using diesels for peaking only, plus geothermal systems for base-load for 30-yr period.

Fig. 8. Levelized life cycle busbar costs for electricity generated in St. Lucia.

given to the fact that these plants must be introduced in much larger increments, which will make it difficult for them to maintain the 80% capacity factor that was assumed in calculating their costs.

B. Cost of Process Heat

Thermal energy can be made available in two ways if GTE is developed in St. Lucia: first, from the residual heat that remains in the GTE fluid after the production of the electricity; and second, by the diversion of some of the heat directly from the well instead of using this portion of the heat to produce electricity. We refer respectively to these two types of heat energy as residual and primary. In addition to the actual geothermal fluid condition of temperature and flow rate, the amount and temperature level of residual heat available will depend upon the specific process used for the production of the electricity. For the cost calculations here, we have chosen a relatively simple single-flash system. Thus, for a well with a discharge temperature of 250°C (482°F) and producing 2.5 MW of electricity, a residual stream with a temperature of 160°C (320°F) and a thermal-energy flow of about 47 000 MJ/h (45 million Btu/h) would be available if the entire stream energy could be utilized down to a temperature of 27°C (80°F). For a well dedicated to the production of process heat, the usable wellhead temperature would approach 250°C (482°F), and up to 100 000 MJ/h (95 million Btu/h) could be made available. The maximum temperatures that can be delivered to a factory 2.4 km distant (Soufriere) were estimated to be 140°C (285°F) and 233°C (433°F) for the residual and primary type systems, respectively.

The same cost calculation methods as those used for the electrical energy costs were also used to estimate thermal-energy costs. Because of the many factors influencing the cost of the thermal energy, the results cover a very wide range. The costs are a very strong function of the capacity factor of a given system, the quantity of heat delivered, the distance over which the heat is to be transported (both Soufriere and Vieux Fort were considered as use sites), and whether residual or primary heat is desired. If we consider a system availability of 94%, this will be the capacity factor for a plant working three shifts per day, 7 days per week. However, a factory working one 8-h shift per day for 5 days per week will have a capacity factor of 22%. Figure 9 gives some costs of residual process heat delivered to Soufriere as a function of capacity factor and also shows the effect upon cost of limiting the lower end of

Fig. 9. Cost of residual heat from a geothermal-power generator and delivered into a factory over a 2.4 km distance and at a 140°C (285°F) maximum delivered temperature.

the useful energy range to 65°C (150°F) as compared with allowing the heat to be used down to 27°C (80°F). Also illustrated is the effect of the cost of the electricity required for pumping the heat-transfer fluid from the well site to the factory. Figures 10 and 11 show similar costs for the use of primary process heat transported to Soufriere and for residual heat transported to Vieux Fort, respectively.

From Figs. 9, 10, and 11, it can be seen that the cost of process heat increases greatly as the capacity factor decreases, thus emphasizing the economic advantage of using this heat as continuously as possible. If the capacity factor can be kept reasonably high, e.g., 67%, which corresponds to three-shift operation, 5 days per week, the process heat can be low enough to

Fig. 10. Cost of primary heat from a wellhead and delivered into a factory over a 2.4 km distance and at a 223°C (433°F) maximum delivered temperature.

attract industries needing this type of heat. Figure 12 shows the costs of process heat for three-shift operation for 5 and 7 day per week operation. Two sizes of system are represented, which amount to total heat from either primary or residual heat from a well or to 10% of the total system capability. The 2.4 and 21 km distance refer to heat delivered to Soufriere or Vieux Fort, respectively. The 222°C temperature is from primary heat and the 140°C refers to residual heat. Also shown are the costs of process heat from natural gas and oil in the U.S. and the cost now being paid for process heat from bunker C oil in St. Lucia. From Fig. 12 it can be seen that, with proper planning, the cost of process heat can be made low enough to make it very attractive to new industries for St. Lucia.

Fig. 11. Cost of residual heat from a geothermal-power generator and delivered into a factory over a 21 km distance and at a 132°C (270°F) maximum delivered temperature.

VI. INDUSTRIAL APPLICATIONS

The geothermal development may provide opportunities to develop new industries in St. Lucia. Both electric- and heat-intensive industries were considered. The study results are described below following a summary discussion.

Fig. 12. Summary of process heat costs.

A. Summary

Two electric-intensive industries were studied: ammonia and aluminum production. These would both be large industries, but neither one appears feasible based on the predicted costs for geothermal power.

The potential development of heat-intensive industries was much more encouraging. Ten different applications were studied:

1. Coconut-oil production
2. Timber drying
3. Concrete-block production

4. Beer production
5. Alcohol/gasohol from sugarcane
6. Dry-ice production
7. Banana-chip production
8. Tourist and other commercial hot-water applications
9. Fresh water from geothermal steam
10. Alumina production

The first nine of the above applications are the most promising for the near-term. However, use of the geothermal heat will only be economic if the users are grouped together and the different required flow rates and temperatures are coordinated.

One geothermal well system can easily supply all of the heat for the first nine applications.

The alumina application is interesting because the production process requires large quantities of steam and thermal energy. Whether or not the size of an economically viable alumina plant can be compatible with the St. Lucia geothermal resource is not clear at this time.

B. Electric-Intensive

1. Ammonia Production. Ammonia is one of the foremost chemicals in the world, ranking high in total tonnage produced as well as value of production. Its value to St. Lucia could be both as an agricultural fertilizer and as an export product. The competitive sources of ammonia are those plants that use cheap natural gas as the feedstock. For example, such a competitive facility is in nearby Trinidad.

In the reaction to produce ammonia, nitrogen and hydrogen are combined in a process requiring relatively high temperature ($\sim 500^{\circ}\text{C}$) and high pressures (~ 200 atm). The nitrogen can be obtained directly from the atmosphere. The hydrogen is most commonly and economically obtained by reforming natural gas, a resource not available on St. Lucia. However, hydrogen could be produced by using geothermal electricity to electrolyze water.

For the electrolytic hydrogen to be competitive with the hydrogen obtained from natural gas, the cost of electricity would have to be approximately \$0.03 EC (\$0.01 US) per kWh. However, the projected cost of electricity is \$0.17 EC (\$0.063 US) per kWh. At best, these costs might be halved, but would still be

three times those required for competitive ammonia production. We conclude that this industry does not appear to be feasible in St. Lucia.

2. Aluminum Production. The production of aluminum requires electric power plus carbon, cryolite ($3 \text{ NaF} \cdot \text{AlF}_3$) and alumina ($\text{Al}_2\text{O}_3 \cdot 3\text{H}_2\text{O}$). The alumina is produced from bauxite ore. St. Lucia would have to import the carbon, cryolite, and bauxite and could have no competitive edge in that regard. The price of electricity in St. Lucia would have to be on the order of 3 cents (US) per kWh to match those of competitors, e.g., in the U.S. Considering the predicted power costs in St. Lucia and the need to import feedstocks, this application does not appear promising at this time.

C. Heat-Intensive Applications

1. Coconut-Oil Production. Coconut oil refining is already a viable industry in St. Lucia and one requiring process heat at temperatures compatible with the geothermal-energy development. Indeed, the Copra Manufacturers, Ltd., plant in Soufriere is a prospective user of the nearby geothermal heat.

A tour of the Copra Plant and follow-up telephone inquiries were made. The plant employs about 100 people and works a three-shift, 5-days-per-week schedule. The copra throughput is currently about 4500 metric tons (5000 U.S. tons) per year, which is less than before Hurricane Allen in 1980. The plant has the capacity to produce $15 \text{ m}^3/\text{day}$ ($3300 \text{ Imp. gal./day}$) of refined oil. During the tour, processing temperatures up to of 116°C (240°F) were noted, but a need for steam temperatures greater than 200°C (392°F) was expressed later by the plant manager.

The process heat is obtained by burning 36 to 45 metric tons/yr (80 000 to 100 000 Imp. gal./yr) of bunker C fuel. This fuel cost is slightly over \$1.00 (US) per Imp. gal. Using a high-heating value of 60 kJ/m^3 (150 000 Btu/US gal.), $450 \text{ m}^3/\text{yr}$ (100 000 Imp. gal./yr), 240 work days/yr, and a boiler efficiency of 85%, the plant's average heat-consumption rate is 2800 MJ/m^3 (2.66 million Btu/h).

The systems described in Sec. III for providing heat to Soufriere can provide up to 47 000 and 100 000 MJ/h (44.6 and 95.6 million Btu/h) of residual and primary heat, respectively. The Copra Plant's rate is then 6% (of residual) or 3% (of primary) of the heat available from one base-case power plant or well.

2. Timber Drying. St. Lucia's Central Forest Reserve totalled 6600 hectares (16 400 acres) in 1982, and an additional 40 000 hectares (100 000 acres) were forested, with the total representing 76.4% of the island's land area. From

these forests, 77 700 board feet of undressed lumber and 36 030 board feet of dressed lumber were purchased in 1982.⁹

Energy consumption in timber drying comprises 60 to 70% of the total energy used in manufacturing most wood products. Drying energy varies from 1266 to 6858 MJ (1.2 to 6.5 million Btu) per thousand board feet of lumber, depending on the green-wood moisture content and whether it is softwood or hardwood. Kiln drying temperatures vary from 38°C (100°F) to 93°C (200°F),¹⁰ and drying times vary from a few days to a few weeks. This compares with the many months required to dry lumber naturally in the open air. Kiln drying the 113 730 board feet of lumber (undressed and dressed) purchased in St. Lucia in 1982 would have required 144 000 to 780 000 MJ (136.5 million to 739.2 million Btu).

A typical drying kiln has interior dimensions of 3 m (10 ft) high, 4 m (12 ft) wide, and 6 m (20 ft) long and can dry approximately 15 000 board feet of palletized lumber during each drying cycle, which can vary from a few days to as much as 3 months.¹¹ Such a kiln would require 7.6 loads per year to cure 113 730 board feet of lumber.

Assuming an average of 20 days curing per load and a 50% efficiency for the kiln,¹¹ 422 MJ/h (400 000 Btu/h) would be required as input to the kiln system.

3. Concrete Block Production. During a Los Alamos fact-finding trip in August 1984, Mr. Rae Atkinson of the Ministry of Finance and Planning for the Government of St. Lucia stated that the demand for concrete blocks in St. Lucia is substantial. He also reported the import of 50 000 bags of cement of 42 kg each (94 lb) per month. He described pumice deposits in the southern, western, and central parts of the island. However, because there is no evidence of large surface deposits of limestone on the island, the manufacture of cement from local raw materials does not seem feasible. However, the other materials for concrete block manufacture should be available.

Mr. Cromwell R. Goodridge of the St. Lucia National Development Corporation reported clay deposits at Choiseul, between Soufriere and Vieux Fort, which could form the basis of a tile or building-block manufacturing facility.

Reports from the National Concrete Masonry Association (NCMA)^{12,13,14} indicate that:

- The production rates of a typical concrete-block forming machine is between 2000 and 3000 "8-in equivalent" 20 cm x 20 cm x 40 cm or 8 in x 8 in x 16 in wet, newly formed concrete blocks/hour.

The capacity of a kiln to cure concrete blocks in a 16-h cycle (required for reasonable efficiency of the block machine) should be two to three times the block machine's production rate, i.e., 4000 to 9000 blocks. A typical kiln is a 5.5 m (18-ft) wide, 12 m (40-ft) long, and 3 m (10-ft) high concrete structure with a steam-distribution system and doors adequate to accommodate a forklift truck carrying pallets of concrete blocks.

- Low-pressure (i.e., atmospheric) steam curing requires roughly from one-half to one pound of steam/hour/block of kiln capacity, depending on the maximum design temperature, either 55° or 88°C (130° or 190°F), and the design rate of temperature rise of 22°C/h or 33°C/h (40°F/h or 60°F/h).
- A typical plant of four 88°C kilns producing 5200 blocks/day consumes steam at rates of 1050 kg/h (2300 lb/h) maximum, 320 kg/h (700 kg/h) minimum, with an average of 635 kg/h (1440 lb/h).

It is estimated that a small home would require 1000 blocks and an industrial or commercial building, 10 000 blocks. There is probably a demand for at least 400 homes and 25 larger buildings per year. This would add up to 650 000 blocks/year.

From the above 650 000 blocks/year as a hypothetical production rate and the NCMA data, the required flow rates of steam would range from a maximum of 545 kg/h (1200 lb/h) to a minimum of 164 kg/h (360 lb/h) and an average of 330 kg/h (730 lb/h).

4. Beer Production. The Windward and Leeward Brewery, Ltd., in Vieux Fort, is the largest industry in St. Lucia, on the basis of value of annual production, which was EC\$14,110,200 in 1980, and growing. The brewery employs 109 persons and can produce 12 000 bottles of beer per day. It can produce three products: Heineken beer, a stout, and a nonalcoholic drink called Malta. The brewery is currently operating at approximately one half of its full capacity.

The brewery consumes 22 700 liters (5 000 Imp. gal) of bunker C fuel oil per month for generation of process heat in the form of steam at 10 atm (150 psi) and 179°C (322°F). The fuel's heat content totals 939 000 MJ (890 million Btu) per month, or an average of 5800 MJ/h (5.57 million Btu/h) if operated on a one-shift, 5-day per week basis. Assuming a boiler efficiency of 85%,¹⁵ the heat delivered to the brewing processes is approximately 5000 MJ/h (4.7 million Btu/h).

5. Alcohol/Gasohol From Sugar Cane. St. Lucia imported 18 million liters (4 823 000 gal) of gasoline for automotive fuel in 1982.¹⁰ Gasoline imports could be reduced by 10% with negligible effect on vehicle performance by adding 1 part of alcohol to each 9 parts of gasoline to produce "gasohol." The amount of alcohol required per year would thus be approximately 1.8 million liters (482 300 gal), which could replace an equal amount of pure gasoline.

Data published by the U.S. Department of Energy indicate that 57 liters (15 gals) of alcohol can be produced by standard milling, fermentation and distillation processes from 900 kg (1 ton) of sugar cane.¹⁶ Thus, St. Lucia would require 29 000 metric tons (32 153 tons) of sugar cane per year to produce the alcohol required to replace their gasoline with gasohol.

Data published by the U.S. Department of Agriculture indicate that a sugar cane crop yield of 50 metric tons per hectare is average in the Eastern Caribbean islands, with Barbados producing 50.4 in 1982/83 and 65.6 projected for 1983/84.¹⁷ At 50 metric tons/hectare (22.3 tons/acre), St. Lucia would require 584 hectares (1442 acres) of sugar cane to produce the alcohol needed.

A modern sugar mill in Hawaii processes 1 100 000 metric tons of sugar cane per year, generating 2500 kW and 77 000 kg/h (170 000 lbs/h) of steam at 10.9 atm (160 psig) and 218°C (425°F) in a 150 000 kg/h (330 000 lbs/h) boiler fueled by oil (45%) and bagasse (>55%) pressed from the sugar cane.¹⁸ Scaling down to the sugar cane required for St. Lucian gasohol, a small mill in St. Lucia would require approximately 4700 MJ/h (4.5 million Btu/h) of 218°C steam, and the plant's bagasse could meet about half of this steam requirement.

Commercial alcohol distilleries consume approximately 44 MJ (42 000 Btu) for each gallon of alcohol produced.¹⁹ Assuming a one-shift, 5-days/week operation, a distillery, to produce the alcohol required for St. Lucian gasohol, would require process heat at a rate of 10 000 MJ/h (9.76 million Btu/h).

Therefore, working a three-shift, 5-days/week schedule, a combined sugar mill and alcohol distillery sized to 483 200 gals of industrial-grade alcohol per year would require process heat totalling 4.0 million Btu/h at a maximum temperature of 425°F.

6. Dry-Ice Production. Carbon dioxide (CO₂) is almost always present in geothermal fluids, and CO₂ is already known to be present in significant quantities in the St. Lucia geothermal fluid. The CO₂ is undesirable in a turbine generator system because it does not condense at the condenser temperatures

resulting in a higher back pressure. A parasitic power loss occurs because of the need to pump the noncondensable gases (mostly CO_2) out of the condenser.

The presence of the CO_2 may be changed from a detriment to an advantage if CO_2 is captured and solidified into "dry ice." Dry ice could provide an easily transportable source of refrigeration amounting to 132 000 J/kg at 78°C (275 Btu/lb at -110°F) and lead to the development of a larger fishing industry. The refrigeration systems could be mechanically simple and easy to use. Uses could include:

- Fish storage aboard fishing boats, to give fishermen more time at sea.
- Land-based storage facilities.
- Refrigerated trucks for fish hauling in St. Lucia.
- Insulated containers for ocean transport to overseas markets.

The key to the success of a dry-ice industry is the availability of CO_2 . Typically, geothermal steam contains about 1% CO_2 by weight. If the base-case power system has that level of CO_2 content, 1270 metric tons/yr (1400 tons/yr) of CO_2 could be recovered from each 2.5 MWe well. This represents enough refrigeration capacity to cool and freeze 1.6 million kg (3.5 million lb) of fish from 29°C (85°F) to -18°C (0°F).

In addition, a major dry-ice production requirement is steam at the rate of 9100 kg (20 000 lb) of steam per ton of dry ice. The steam is used to drive compressors raising the CO_2 pressure to 75 atm (1100 lb/in^2). The only other resource required is labor at eight man hours per ton of dry ice.

A check on the price of dry ice in Los Alamos showed a consumer cost of \$486 EC (\$180 US) per US ton.

The technique for recovering the CO_2 from the noncondensable gases in the turbine condenser would have to be developed because it is believed that no previous geothermal system has had the requirement. Detailed studies of CO_2 recovery techniques can be made once the fluid properties become known.

Assume that a dry-ice plant works three shifts and five days per week or 250 days/yr. The steam-consumption rate would be 2135 kg/h (4700 lb/h), and to convert water from 27°C (80°F) to steam at 177°C (350°F) at this rate would require 5800 MJ/h (5.5 million Btu/h).

7. Banana-Chip Production. Through telephone discussions with Dr. Belice, a technical person with the United Fruit Co., it was learned that St. Lucia produces about 4.3 million stems/yr of bananas at 18 kg (40 lb) per stem. Forty per cent of the stem weight is skin, leaving 47 million kg (103 million lb) per

year of banana fruit. According to Dr. Belice, 10% of the crop normally cannot be sold as whole fruit because of blemishes. This fruit is available for other purposes such as making banana chips.

According to New Mexico State Extension agents, bananas can be dehydrated slowly at 66°C (150°F). However, the approach favored by United Fruit is to fry banana slices at 149° to 177°C (300° to 350°F) in oil for a period of several minutes. Peanut oil is considered best but cottonseed, sunflower, or coconut oils can be used. Coconut oil would be excellent except for its cost. There are two kinds of fried chips--"sweet" chips made from ripe fruit and "salty" chips made from unripe fruit. The equipment for this kind of frying operation is commercially available.

A hypothetical heat-exchange arrangement was established in order to arrive at a process-heat delivery rate. Reference 20 shows that banana fruit contains 75% water. If 10% of the St. Lucia banana crop is used, the water content would be 3.52 million kg/yr (7.74 million lb/yr). Working three shifts, 5 days per week, the average water to be cooked out of the fruit is 586 kg/h (1290 lb/h). If the fruit temperature in the oil bath increases from 27°C (80°F) to 177°C (350°F) and the heat exchange efficiency is 70%, the average heating rate equals 2200 MJ/h (2.1 million Btu/h). The temperature range of the water flowing through heating coils immersed in the oil bath is estimated as 177°C (350°F) to 66°C (150°F). The 66°C (150°F) water flowing out of the fryer might be used for low temperature processing, for example, to more slowly dehydrate banana chips to produce a different product.

The strength of the market for banana chips is not clear, and a market analysis is needed. St. Lucia will probably have to enter into a marketing agreement with a large banana-distribution company before initiating this project.

8. Tourist and Other Commercial Hot-Water Applications. Many industrial processes can use hot water at 66°C (150°F) to 177°C (350°F). The remaining heat in the water can be used for other applications such as luxury tourist hotels or commercial establishments like restaurants or laundries. The tourist hotels on St. Lucia are in direct competition with those on other islands, and any improvement in their comparative energy-consumption efficiency should be worthwhile.

Energy data were obtained for several luxury hotels operating in a somewhat similar climate to that of St. Lucia. The two most applicable cases were a

Holiday Inn in the Bahamas and the Hilton Inn in San Diego, California, using thermal energy at the rate of 17 000 MJ (16.5 million Btu) and 59 000 MJ (55.9 million Btu) per room year, respectively.

The Holiday Inn data were used to estimate heat-delivery rates. A hypothetical case was assumed for a 256-room hotel. This is similar in size to the Halcyon Days Hotel (currently closed) in Vieux Fort. The hypothetical hotel might also be located near Soufriere (see Fig. 1). If the annual-capacity factor, which depends upon occupancy rate, for the delivered heat is 0.67, and the typical usage is similar to the Holiday Inn in the Bahamas, the average rate for the hotel is 399 MJ/h (321 700 Btu/h).

The Hilton Hotel consumption rate is over three times as great, so that the range of the estimates is between 316 to 1160 MJ/h (0.3 to 1.1 million Btu/h) for one large hotel.

9. Fresh-Water Production. Clean and cheap water in ample supply is always important to both the general welfare and industrial development of a nation. Two water-production techniques were evaluated. The first is the use of geothermal heat to desalinate sea water. The second is the capture and condensation of steam that is or can be generated by the geothermal fluid.

In the sea water desalination study, six known techniques were evaluated and none appears economically attractive. The lowest possible production cost is about \$11 EC (\$4 US)/1000 gal (US), even if the heat cost is zero. On St. Lucia, other water sources such as rain reservoirs and wells should be cheaper than the above.

For the geothermal-steam-recovery technique for producing water, assume that a system like the base-case power generator described in Sec. II is used. The steam through the turbine equals 23 000 kg/h (50 800 lb/h). The residual geothermal fluid being discharged from the steam separator is at 6.1 atm (90 lb/in²) abs pressure and 160°C (320°F) temperature. If this fluid is flashed in another steam separator at 1.36 atm (20 lb/in²) abs pressure and 109°C (228°F), 9800 kg/h (21 600 lb/h) of additional steam could be produced and condensed. The total condensate would be 32 900 liter/h (8680 gal/h) from one 2.5 MWe base-case system.

If the above steam-recovery system has an operating availability factor of at least 0.80, potential fresh-water production would be 230 million liters (60.8 million gal) per year. If 12 well systems are operating in the future and

the population is 150 000, the per capita production rate would be equivalent to 50 liters (13.3 gal) per day.

The water being produced might be used for domestic or industrial purposes. With the cheaper geothermal power being available, it should be feasible to pump the water to any location on the island.

10. Alumina Production. The production of dry alumina hydrate ($\text{Al}_2\text{O}_3 \cdot 3\text{H}_2\text{O}$) from bauxite ore is an intermediate step in the aluminum production process and could be an industry by itself. In the U.S., the cost of producing alumina is approximately equally divided among feed stocks (bauxite, sodium hydroxide, and water), process steam, and labor. The power cost is secondary, especially since the plants are located where power is cheap.

In St. Lucia, bauxite and sodium hydroxide would be imported, and it may not be possible to do much about reducing their costs. However, St. Lucia might be able to take advantage of lower shipping costs for bauxite compared with those for competitors in Europe or the U.S. Nearby bauxite sources are in Brazil, Guyana, Suriname, and Jamaica.

It may be possible to reduce the other major cost items. Labor costs are low, and the water, steam, and power costs depend upon the outcome of the geothermal development. The latter three might decrease if:

1. Water is producible from turbine condensate or from steam extracted from the residual hot water.
2. The alumina plant is close to the geothermal-heat source and operates at a high capacity factor.
3. The geothermal reservoir is more favorable than has been assumed in this study.

It is concluded that the production of alumina may be viable in the future, depending on the geothermal development and the plant size.

The practicality of an alumina plant in St. Lucia may depend on a scale effect which is not known to this study. For an indication of the way heat quantity per well relates to plant production capability, assume that the plant is sized to use all of the 70 000 MJ/h (66.1 million Btu/h) of heat from the system described in Sec. III-E. If the steam is superheated to 177°C (350°F), 26 000 kg/h (57 200 lb/h) of steam can be generated using the heat from one well system. Working three shifts, 7 days/week and with a capacity factor of 0.94, 28 500 metric tons of alumina per year could be produced. This production rate may be too small to be economically viable. Information from the Kaiser

Aluminum & Chemical Co. indicates that for economic feasibility a production rate of at least 600 000 metric tons per year is required. However, a more detailed study is needed that uses the conditions that are unique to St. Lucia.

D. Heat-Production Capacity of St. Lucia Wells

The conversion of geothermal energy to electric power is a low-efficiency process, and the flow of heat through the power system is very large. In contrast, the direct use of the thermal energy for industrial processing is a very efficient process. The net effect of these considerations is that we need 12 producing wells to generate 30 000 kWe and only one well to provide enough process heat for a significant number of factories.

Table XIX shows the energy requirements for the 10 process-heat applications described in Sec. VI.C above. The required delivery rate for the first nine applications totals 17 300 to 19 000 MJ/h (16.4 to 18.0 million Btu/h). The maximum capacity of a system that delivers heat to Vieux Fort at a 177°C (350°F) temperature (see Sec. III-E) is 70 000 MJ/h (66 million Btu/h). Therefore, the first nine applications above would only require about 25% of the capacity of one well.

TABLE XIX
TYPICAL PROCESS-HEAT DELIVERY RATES

Activity	Work Schedule (8-h shifts/ days/wk)	Production	Average Heat Consumption (million Btu/h)
1. Coconut-oil production	3/5	3300 Imp. gal/day	2.7
2. Timber drying	3/7	15 000 brd. ft./ 20 days	0.4
3. Concrete-block production	2/5	650 000 blks/yr	0.4 to 1.2
4. Beer production	3/7	6 000 bottles/day	1.0
5. Alcohol/gasohol from sugar cane	3/5	482 300 US gal/yr	4.0
6. Dry-ice production	3/5	1 270 metric tons/yr	5.5
7. Banana-chips production	3/5	10.3 million lb/yr	2.1
8. Tourist & other commercial hot-water applications	3/7	2/3 of 256 room hotel's annual needs	0.3 to 1.1
9. Fresh-water production	3/7	61 million US gal/ well year	---
10. Alumina production	3/7	28 500 metric tons/yr	66

The alumina production application, the 10th item in Table XIX, has the potential to use all of the heat-delivery capacity from one well and probably many more. The inclusion of a large heat consumer such as an alumina plant would result in a favorable cost of delivered heat for all uses serviced by a common system. This is because the system's physical characteristics such as pipe sizes, pressure drops, heat losses, and higher delivery temperatures all improve compared to systems supplying much lower heat rates.

VII. CONSEQUENCES OF THE DEVELOPMENT OF GEOTHERMAL ENERGY IN ST. LUCIA

Even though conservative assumptions were used in estimating the costs of the geothermal electricity, it still turned out to be the least expensive of the methods studied and represents more than a 35% cost reduction from the present method of electricity generation by diesel engines. However, the continued use of the diesel engines can provide a method of generating peak electricity by a proven technology during the accumulation of geothermal capacity and experience. Even if diesel engines are used for the entire 30-yr period of the study, a comparison of the relative costs of operating the geothermal plus diesel systems with a total diesel system for the generation of electricity results in a saving of \$253M EC (\$94M US) that can be made over the 30-yr period studied. Also, during this period there will be a savings in diesel oil import of 1.05×10^9 liters (231 million Imp. gal).

Because of the conservatism in the cost estimate for geothermal electricity, a considerably lower price for the busbar cost for electricity generated from the geothermal resource may be possible. Thus, additional cost estimates made at a later date with actual well costs, geothermal-fluid conditions, and well productivity could lead to a more favorable conclusion about moving electricity intensive industries to St. Lucia. However, with present knowledge it does not seem possible that the expected price of electricity will attract any new electricity-intensive industry to locate in St. Lucia.

On the other hand, the cost of industrial process heat can be made attractive to additional industries for St. Lucia. Existing industries in St. Lucia, such as coconut-oil refining, can benefit immediately from low-cost process heat. Other industries such as dry ice and alumina production will require development.

As soon as the first wells are drilled, the data that will then be available will permit optimization of electricity production as well as thermal-energy production. However, this optimization process must consider both types of energy requirements, which also requires the long-term planning of industries that can use process heat.

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