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POTENTIALS FOR FUEL CELLS IN REFINERIES AND CHLOR-ALKALI PLANTS

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ABSTRACT

The market potentials for fuel cell cogeneration systems in petroleum refineries and chlor-alkali plants were evaluated. Costs of the total energy consumed (power plus steam) were calculated and compared with those for more conventional cogeneration systems. Questionnaires were sent to major plants in both industries to determine technical requirements and data required for the assessment of the market potential.

The most promising application appears to be in chlor-alkali plants where the production process is electricity intensive. Future anticipated changes in the production process are favorable to the use of fuel cells. The energy use in refineries is steam intensive with the required steam pressures ranging from approximately 15 to 650 psig. The near-term use of fuel cell cogeneration in refineries is not as attractive as in chlor-alkali plants. The phosphoric acid fuel cell is the most developed and the most cost competitive, but its use is limited by its being able to produce only low-pressure steam. Over the longer term, the molten carbonate and the solid oxide fuel cell, both of which operate at significantly higher temperatures, are technically very attractive. However, they do not appear to be cost competitive with conventional systems.

I. INTRODUCTION

Under the sponsorship of the Department of Energy (DOE) Advanced Energy Conversion Program Office, Los Alamos National Laboratory has been analyzing and assessing potential applications of fuel cells in the period 1990 to 2000. In FY83, Los Alamos completed a literature review of fuel cell applications[1] and one of the conclusions was that attractive applications for fuel cells may be for industrial cogeneration. Subsequently, the use of fuel cells for cogeneration in the chlor-alkali industry and in petroleum refineries were studied. A Los Alamos report on the chlor-alkali study has been published[2] and a report on petroleum refinery applications will be published in the near future.

In 1983, a nonprofit corporation was formed that is called the Industrial Fuel Cell Association (IFCA). Membership includes a broad spectrum of corporations interested in utilizing fuel cell technologies for their energy needs. The IFCA goal is to facilitate the development of fuel cells by serving as a vehicle for better communication between all interested parties, by helping identify industrial markets, and by determining the features needed in fuel cell systems for each application. The IFCA assisted in the conduct of the Los Alamos studies, and Joseph M. Anderson, IFCA Executive Director, coordinated the IFCA input.

These studies addressed the following questions:

- Are there any technical, economic, or institutional impediments?
- Is this industry promising for the use of fuel cells?
- What is the market potential?

To provide answers, the different process requirements of the industries were characterized and energy requirements determined. The competitive cogeneration systems were also characterized. To assist in the technical characterizations, a questionnaire was sent to planning personnel in all of the major plants in each industry in the US. The objective was to determine the present and projected energy requirements for each plant and the potential use of fuel cell systems.

Using a Los Alamos computer code,[3] levelized energy costs were calculated for the different competitive systems to determine their economic competitiveness. Other economic factors were also evaluated that might have a bearing on the choice of a cogeneration system.

II. The CHLOR-ALKALI INDUSTRY

A. Overview

The chlor-alkali industry in the US is generally tied to the resource--underground salt deposits. A large segment of the industry is located along the Gulf Coast in the states of Texas and Louisiana. Fig. 1 shows the location of existing US chlor-alkali plants. The industry is extremely competitive and is characterized by small profit margins. Energy costs are often a large portion (greater than 50% of overall manufacturing costs). In Texas and Louisiana, electricity prices are expected to increase rather substantially over the next few years as a result of the deregulation of natural gas and renegotiation of gas contracts. Electric utilities now enjoy relatively inexpensive gas prices that were negotiated at a time when supplies were abundant. Natural gas price increases are more uncertain.

Demand growth for this industry's products--chlorine and caustic soda--has dropped steadily through the 1970s as a result of environmental, toxicological, and end-use change impacts.[4] The production levels of 1979 are not expected again until the early to mid 1990s.

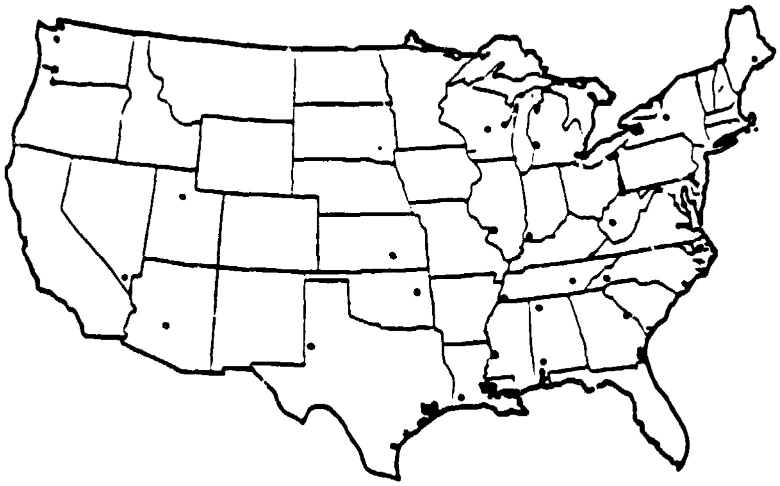

Fig. 1. Location of chlor-alkali plants in the US.

There is intense price competition within the chlor-alkali industry and producers strive to achieve the lowest manufacturing costs. To reduce manufacturing costs, producers with sufficient investment capital may install new energy-efficient membrane cell technology as older electrolytic cells need to be replaced. Another important investment option will be to install energy efficient cogeneration systems to help lower energy costs. Any gain in energy efficiency will translate into important profit gains in this very competitive industry.

Production is expected to increase at a rate of about 3% per year to a level of 12 million tons of chlorine per year by the early 1990s (one metric ton of caustic is produced for every short ton of chlorine). This growth includes the closing of some noncompetitive plants. By the early 1990s, chlor-alkali plants should be producing once again at 90% capacity.

B. Processes and Steam Requirements

Chlorine can be obtained by several chemical techniques, but the one used for large-quantity commercial production is the electrolysis of aqueous NaCl. The basic processes are

Anode: $2Cl^- \rightarrow Cl_2 + 2e^-$

Cathode: $2H_2O + 2e^- \rightarrow H_2 + 2OH^-$

In what are called diaphragm cells, the brine flows continuously from the anode to the cathode compartment and the Na^+ in the solution combines with the OH^- ions. The solution is gradually converted from aqueous NaCl to aqueous NaOH (caustic soda). The product is relatively dilute and is contaminated with NaCl. By means of chemical treatments, solid NaCl precipitate-removal techniques, and an evaporaative process, the resultant cathodic liquor is converted into commercial-grade caustic soda.

The above diaphragm cells represent today's state of the art. Most of the plants designed in the late 1960s and early 1970s, when most of today's capacity was established, used the diaphragm process. The anodes can be made of graphite or metallic materials. The cathodes are made of iron and are separated from the anodes by asbestos diaphragms. The flow rate through the diaphragm is controlled to minimize the diffusion of the OH^- ions away from the cathode.

Another cell type, called the mercury-cathode cell, has also been used and actually is still being used in a number of small plants around the country. The cathode consists of an inclined trough of mild steel down which mercury flows. Gaseous chlorine is produced at the anode and the Na^+ at the cathode amalgamates with the mercury. The sodium-amalgam flows or is pumped to a separate decomposition vessel. Here the amalgam is mixed with water in the presence of graphite acting as a depolarizer. The galvanic reaction that occurs results in Na^+, Hg, H_2, and OH^- being produced. Final products are aqueous NaOH (very pure and at a high ~50% concentration), Hg (almost free of Na), and H_2. The Hg is recovered and recirculated.

The major problems with the mercury-cathode cells are economic and environmental. The latter problem is caused by mercury losses, is especially severe, and is causing mercury-cathode cells to be phased out of the industry.[4]

A third cell technology is now being incorporated in new installations. Instead of a porous diaphragm separation of the electrodes, a permionic membrane is used that only Na^+ ions can pass through. The resulting product at the cathode is gaseous H_2 and a high (~35%) concentration of NaOH. Evaporators used to concentrate the 35% NaOH solution only require steam at 50 to 100 psig instead of up to the 250 psig used in diaphragm plants. The presence of NaCl in the NaOH solution is negligible.

Because the brine in the anode side of the membrane cell is being continually diluted, it needs to be resaturated. To do this requires a supply of solid NaCl or, in many cases, the dilute brine is recycled into underground salt deposits. The above need for saturated brine is causing some plants to use the precipitated NaCl by-product of diaphragm plants to feed membrane cell systems. The membrane cells are therefore being added in increments to diaphragm plants rather than being installed in large full-scale membrane plants . This is making the shift to membrane cells a relatively gradual process.

The chlorine/caustic (chlor-alkali) industry is a very large user of both electricity and steam in the US. Typically the industry has produced 10 million short tons of chlorine and 11 million short tons of caustic soda per year, and some 27,000 megawatt-hours of electricity and 80 x 10^{12} Btu's of thermal energy were used. Energy use has decreased significantly over the past 15 years, and as the industry moves from the diaphragm to membrane technology, further drops can be expected.

C. The Chlor-Alkali Industry Questionnaire

1. Introduction - The IFCA has assisted Los Alamos by developing a questionnaire that was sent to chlor-alkali plants. The questions were selected to provide answers in the following areas of interest:

- Likely size of fuel cell installations
- Probable size of the market
- Characteristics of the processing systems used
- Steam requirements
- Institutional factors that could encourage fuel cell use

Questionnaires were sent to companies operating 45 separate chlor-alkali plants, and replies were received from 19 of these plants. The replies cover somewhat over 50% of total US chlor-alkali production today. A summary of the responses is given below.

2. Summary of Responses

a. Electric demands. The average power-to-heat ratio for chlor-alkali plants is high and appears to be increasing as new technology is installed. The respondents showed that their present electrical demand per plant is distributed as follows: (1) less than 50 MW - 58%; (2) 50 to 100 MW - 21%; (3) 100 to 200 MW - 21%; (4) 200 to 400 MW - 0%; and (5) 400 to 800 MW - 0%. [Note: The total connected demand in the U.S. is approximately 3700 MWe.]

b. Fuels used - Many plants already use the by-product hydrogen as a fuel today, and more indicate that they would increase hydrogen use if fuel prices increase. Thus, for many chlorine producers, their by-product is valued at its fuel value. Many of the plants use two or more fuels. The fuels and the percent of respondents using each fuel are: (1) natural gas 95%; (2) fuel oil 42%; (3) coal 5%; and (4) hydrogen 37%.
If the plants had to switch fuels, 47% would switch to coal, 26% to fuel oil and 27% felt that they had no viable alternative and would just have to maximize their use of hydrogen.

c. Steam Demands - An indication of the average total steam demand per plant is given below: (1) less than 100,000 lb/h 37%; (2) 100 to 150,000 lb/h 26% (3) 250 to 500,000 lb/h 26%; and (4) 500 to 1,000,000 lb/h 11%.

The required steam pressures are: (1) less than 50 psig 14%; (2) 50 to 99 psig 21%; (3) 100 to 199 psig 0%; (4) 150 to 199 psig 29%; and (5) 200 to 250 psig 36%.

d. Importance of Energy Costs Unless a chlor-alkali producer has access to inexpensive hydroelectric power, their energy costs are more than half of their total manufacturing costs. Eleven percent indicated costs greater than 60%.

e. Present Energy Sources - Most of the plants (63%) indicated that they purchase electricity from a public utility and produce their steam with a conventional boiler. The larger plants are installing gas turbine combined cycle systems.

f. Fuel Cell System Requirements - All the respondents indicated that if they decided to install fuel cell systems, the first units would have capacities less than 10 MWe. Thereafter, individual fuel cell installations will be divided about equally between units of less than 10 MW and those in the 10- to 25-MW capacity range.

Most chlor-alkali producers would use fuel cells as a supplementary direct-current power source for their chlorine circuits. Thus, the fuel cell systems should be designed to supply high amperage direct current electricity at 1,000 volts or less.

g. Potential Market - The respondents predicted that by the year 2000 fuel cell capacity in their plants could reach 24% to 40% of existing electrical demand. This would translate into 900 to 1,500 MW for the entire chlor-alkali industry as it exists today.

D. Candidate Cogeneration Systems

Four fuel cell technologies were considered as candidates for this application--the phosphoric acid fuel cell (PAFC), the Occidental Chemical Corporation (OXY) alkaline or acid fuel cell, the molten carbonate fuel cell (MCFC), and the solid oxide fuel cell (SOFC). The PAFC was selected because it is now well along in its development as a utility power generator and could be available for use in the 1990s.

The MCFC and the SOFC both operate at relatively high temperatures--1,100 to 1,300 F and 1,800 F, respectively and have the potential to satisfy many more process heat requirements than does the PAFC. However, both of these types are not as well developed as is the PAFC. Better cost estimates were available for the MCFC than for the SOFC; therefore the MCFC was selected to represent both of these high-temperature-type cells.

The OXY fuel cell is not a true cogenerator but has been included because it may be the first fuel cell system installed by the chlor-alkali industry. Also, Occidental Chemical's predictions for the basic stack costs are very favorable. The concept is that the fuel cell would use a by-product hydrogen stream as its fuel.

The conventional gas turbine combined cycle (GTCC) technology was included in the analysis because it is the most likely system against which the fuel cells will compete in the coming decade. It is a mature technology that produces electricity and steam at very competitive rates and is the technology being installed in the chlor-alkali industry today.

For all four of the above power generating systems we "normalized" to a 50-megawatt electrical (MWe) output. Such an output is very approximately an average value for US plants. This assumption is favorable to the GTCC because its cost has a significant scale-effect, the capital costs becoming considerably less attractive at lower power outputs. Fuel cell modules are being designed at approximately 10 MWe and are much more compatible with the concept of adding small power increments. This fact should be considered if a plant is not interested in a large power increment because of limited funds for capital investments.

Table I shows our assumptions for the operating and performance characteristics of the candidate cogeneration systems. Assumptions for a steam boiler system are also shown because they were used to estimate the value of steam in a chlor-alkali plant.

E. Economic Analysis

Table II provides a summary of the electrical generation costs for the "base case" cogeneration systems for a typical plant today with a P/H ratio of 1.14. Also included in Table II are the principal performance and cost assumptions used to derive the levelized annual electricity costs. Two different cost derivations are given: one reflecting a system where full credit is given for steam generation but no charge is assessed for steam shortfalls and electricity costs are computed therefrom; and other that reflects a charge to each system for the steam shortfalls.

The net generating cost (¢/kWh) values presented in row 2 of Table II assume todays average process requirement in the chlor-alkali industry, a P/H of 1.14. If the newer diaphragm and tomorrow's membrane process technologies and their respective P/H requirements of 1.52 and 3.86 are assumed, the net generating costs (¢/kWh) for fuel cell cogeneration costs decrease. The following matrix presents the net generating costs in cents per kilowatt-hour for those comparisons when steam charges are made for any steam deficiencies. Other assumptions are the same as listed in Table II. These estimates show an increasingly favorable comparison of PAFC and OXY systems to the GTCC as the chlor-alkali technology improves.

	Type of Cogeneration System (¢/kWh)			
P/H Requirement	GTCC	PAFC	OXY	MCFC
1.14	5.7	6.1	7.4	11.6
1.52	5.7	5.6	6.9	10.6
3.86	5.7	5.5	5.8	10.6

Except for the conventional system of choice today, the performance and cost assumptions are based principally on paper studies and educated estimates. Therefore, the base-case condition for each system do not necessarily represent equivalent levels of accuracy. A more realistic economic comparison is presented in Fig. 2 where net electric generating costs (¢/kWh) are plotted against capital costs ($/kW). All base-case performance and cost parameters, except the capital cost, are held constant for this particular comparison. The horizontal line at 5.7 ¢/kWh, the net generating costs for the GTCC base-line system, provides a ready benchmark against which to judge cost competitiveness of other systems.

TABLE I

OPERATING AND PERFORMANCE CHARACTERISTICS ASSUMED FOR POWER AND STEAM GENERATING SYSTEMS IN CHLOR-ALKALI PLANTS

System Parameters	System				
	Phosphoric Acid Fuel Cells	Molten Carbonate Fuel Cells	Occidental Alkaline Fuel Cells	Gas Turbine Combined Cycle	Steam Boiler
Fuel	Natural gas or hydrogen*	Natural Gas	Hydrogen**	Natural Gas	Natural Gas
Fuel Heat Input (10^6Btu/hr)	379	322	316	523	203
Electricity (MWe)	50	50	50	50	0
Steam (lb/hr)	100,000	80,000	0	150,000	150,000
Efficiencies:					
Electrical (%)	45	53	54	33	0
Heat Extraction (%)	30	27	0	32	85
Overall (%)	75	80	54	65	85
System power to heat	1.50	1.86	00	1.03	0

*If available at a competitive cost.

**By-product in chlor-alkali plant

TABLE II

BASE-CASE SYSTEM PERFORMANCE AND COST CHARACTERISTICS:
CHLOR-ALKALI INDUSTRY APPLICATION

Characteristics	System			
	Gas Turbine Combined Cycle	Phosphoric Acid Fuel Cell	Molton Carbonate Fuel Cell	Occidental Alkaline Fuel Cell
Levelized Annual Electricity Costs	5.7	5.5	10.6	5.2
(¢kWh)--				
With Steam Charge	5.7	6.3	11.6	7.5
Capital Cost (CC)	560	515	1,300	250
($/kW)				
O&M Cost[a] (% of CC)				
Fixed	2	9	4	14
Variable	5	5	10	10
Capital Replacement[b] (% of CC)	-	6	11	10
Total O&M[c] (% of CC)	7	20	24	35
Steam Credit[d] (% of CC)	113	76	61	-
Additional Steam Requirements[e]	0	24	39	100
(% of needs)				
Overall Efficiency (%)	65	75	80	54
Electrical Efficiency (%)	33	45	53	54
Steam Efficiency (%)	32	30	27	-
Btu Steam Output/kWh	3,300	2,275	1,745	-
Btu Input/kWh	10,460	7,585	6,450	6,320
Steam Credit or Charge Value	7.21	7.21	7.21	7.21

[a]Actual percentages based upon best available data. Fixed variable definitions dependent upon source of data.

[b]Capital replacement is based upon present thinking for fuel cell (stack) replacement.

[c]This figure was used for purposes of modeling and reflects total annual operating expenses.

[d]Assumes a P/H of 1.14. The figure reported represents that portion of today's typical chlor-alkali steam requirements that can be met by the cogeneration system in question.

[e]See footnote d above. The percentage figure represents additional steam requirements to meet the needs of today's typical chlor-alkali process. It is this figure upon which the steam charge is based for computation of the levelized annual electricity costs presented in Row 2.

Several observations can be made about Fig. 2. First, two different plots have been made for each of the four cogeneration technologies. One assumes that no additional steam is needed or charged to the overall system costs ("o" designation). The other plots assume that a steam charge is made to bring total output from the cogeneration system to the desired P/H operating requirement of 1.14 for today's typical/average plant operation ("1" prefix).

Second, one can read the break-even capital costs directly from the figure itself. For example, the OXY technology at $320/kW (without steam charge) provides the same levelized annual electricity costs as the conventional gas-turbine combined-cycle technology. This can be interpreted as the greatest cost at which the OXY technology will be favorably compared to the system of choice today and in the near future. However, with a steam charge, the OXY fuel cell break-even capital cost drops to less than $50/kW.

Third, for cogeneration systems much smaller than the 50-MWe-sized units for which base-case conditions were derived, cost/capital cost relationships were not plotted. However, a simplistic comparison can be envisioned by assuming a 10-MWe system where capital costs for the conventional gas turbine combined-cycle technology is priced at $840/kW (approximately equal to actual quotes today for similarly sized units), resulting in a generation cost of 6.9 ¢/kWh. At this levelized annual electricity cost, the break-even capital cost for the fuel cell technologies also increases. For example, the dollars-per-kilowatt figure for the MCFC (without steam charge) technology increases from $800 to $910 at this now higher electricity cost. The relative improvements for the PAFC and OXY system are greater than for the MCFC.

Fourth, the OXY fuel cell technology will have to meet or exceed its cost goals if it is to effectively compete when the value of steam is taken into

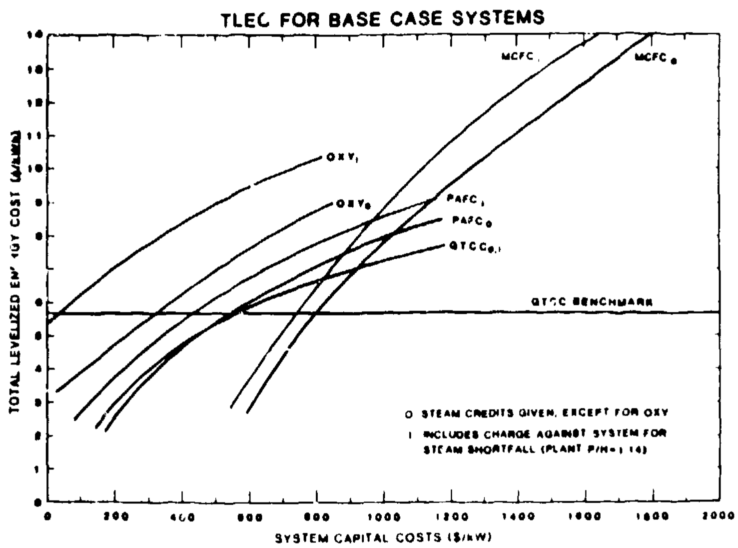

Fig. 2. Comparisons of base-case cogeneration technologies (¢/kWh vs $/kW).

consideration. For the 10-MWe power level, it appears that costs at or below $200/kW would be needed for competitive consideration of this technology vis-a-vis the conventional GTCC technology.

F. Market Potential

The market for fuel cell cogeneration systems in the chlor-alkali industry will break down into four categories: (1) replacement of cogeneration systems, (2) installation of fuel cells in plants that have no existing cogeneration system, (3) installation of fuel cells as plants expand production capacity, and (4) installation of fuel cells to supplement existing power generating systems. Many plants installed natural gas-fired cogeneration systems in the mid-1970s when the entire chlor-alkali industry underwent a period of capacity expansion. many of the systems will need to be replaced by the early 1990s, and fuel cell systems will be one of the options available at that time.

In the second category are plants that choose not to install conventional cogeneration systems in the next 8 to 10 years. The conventional systems (for example, the GTCC) are typically large and, therefore, expensive. The number of plants in this category will be affected by the availability of investment capital, the rate of increase in electricity and fuel costs, and the competition from other energy conservation alternatives.

With regard to the third category--unless demand for chlorine increases far more than currently forecasted, new chlor-alkali plants are not likely to be built in the early to mid 1990s. Instead, plants will want to expand capacity incrementally, and fuel cells can be installed in membrane cells. The membrane technology is compatible with the idea of using the NaCl by-product from the diaphragm cells, and both types can be used in the same plant. Also, the power-to-heat ratio of membrane cell energy requirements is well matched to fuel cells. The above reasons indicate that these plants should be an excellent potential market for fuel cells in the 1990s.

The results of our industry survey suggest that the market potential of fuel cells may be greatest in the last category. Respondents indicated that if fuel cell systems were installed by their companies, the first unit would most likely be less than 10 MWe. They further indicated that subsequent units would be either less than 10 MWe or in the range of 10 to 25 MWe.

The survey responses highlighted other factors that could affect the market potential of fuel cells. Most of the respondents indicated that their steam requirements are in the 150- to 250-psig range. Thus, if fuel cells could operate at temperatures high enough to generate 250 psig of steam, they could achieve a larger technical market potential. The PAFC can easily meet a 100 psig requirement and can probably meet the 150 psig also. Two factors tend to mitigate the severity of the 250 psig requirement. One is that the newer membrane technology does not need it. The second is that if fuel cells are used for supplemental power, then it should not be difficult to find applications for both fuel cell low-pressure steam and the conventional high-pressure steam in the same plant.

The price of energy, especially that of purchased electricity, makes up a large portion of a typical chlor-alkali plant's manufacturing (operating) and total costs. That portion can range to 60% or more. In a recent article[5] comparing the costs of alternative process technologies, the assumed price of electricity is 4¢/kWh. At this assumed price, electricity represents anywhere from 49% to 54% of manufacturing costs and 37% to 42% of total costs (includes a charge for capital), depending upon the technology under investigation. Thus, if less expensive,alternatives will likely be exercised. Such a substitution pattern in the chlor-alkali industry has been observed in the past and continues to be observed today.

Although the price of electricity is not known for any specific plant, we have constructed some estimates of possible maximum prices paid today and potential rates of price increase for a selected number of plants in Texas and Louisiana.

Figure 2 presented the net generating costs of the cogeneration technologies at differing costs of capital. If we now superimpose the current electric rates a 4.0- to 5.2-¢/kWh range paid by industrial customers today the competitive position of each technology can be quickly evaluated. Base-line capital costs for the fuel cell technologies result in net generating costs that exceed these current electric rates. However, relatively small decreases (10% to 25%) in the OXY or PAFC technology costs (without a steam charge) do bring them to a position of economic competitiveness. A large decrease will be necessary for the MCFC technology to enjoy a similar position.

Electric rates are increasing across the country, and in some regions, substantially so. For the states of Texas and Louisiana (approximately 60% of US chlor-alkali capacity), a projected 23% increase (in real terms) in industrial electrical rates was forecast by DOE for the span of 1983 to 1995. If we now add this 23% on to today's current range of rates, more favorable results to the fuel cell cogeneration technologies are obtained-- although the CFC base-line/capital costs are still measurably above this projected range.

Several of the major utilities have acknowledged that consumer electric rates could easily rise 20% to 25% in their service areas (Texas and Louisiana) in the next few years and that they could rise an additional 25% to 50% or more by the mid to late 1990s. If we add 1.5¢ to 2.0¢ on top of the 23% average regional price forecast, a better picture of economic competitiveness emerges. Break-even capital costs can now be somewhat higher for two of the three fuel cell technologies and yet allow net generating costs to remain less than the purchased electricity price.

These increases in electricity prices, although absolute levels are uncertain, could improve market potential for cogeneration technologies in the future. Fuel cells should compete fairly well with purchased electricity if increased rates materialize. However, we have emphasized that these rates are most likely higher than large industrial customers are able to negotiate with utilities. Furthermore, in spite of the fuel cells' attractive attributes such as modularity and capital costs that are fairly linear with size of installation, the GTCC may remain in a better economic position vis-a-vis the fuel cell technologies for many years to come, simply because it is a mature technology and enjoys widespread use in the chlor-alkali industry today.

III. PETROLEUM REFINERIES

A. Overview

Major refinery products include gasoline, diesel and jet fuels, and various grades of heating oils all of which are produced in large quantities. The basic design of a refinery is generally dictated by the processes needed to produce the large-quantity products. However, crude oil consists of a very large number of hydrocarbons that can be converted into many useful products. The US petroleum industry produces well over 2300 products with 17 different product categories. Such potential diversity in plant output results in each refinery being somewhat different from any other and also different in thermal (steam and direct heat) requirements. In addition, other factors affect the plant design such as the purchased power and fuel costs at a plant's location, its age and size, and the crude oil available as feedstock.

The largest fraction of a refinery's thermal requirement is in the direct heat form. For example, approximately 60 to 70% of the total can be direct heat. Direct heat is obtained from by product fuel gases and oils plus purchased natural gas. The temperature of the[5] direct heat is in the approximate 750 to 1000°F range.* A quantity of process heat equal to roughly one-third of the direct heat is embodied in the steam and is used for a variety of purposes. Steam is a convenient heat-transport medium and is also a necessary reactant in some of the chemical processes. Steam pressures range from approximately 15 to 650 psig and even up to 1500 psig. The latter high pressure is not necessary for the processes but is sometimes used to generate power with back-pressure turbines, with the back pressures being about 600 to 700 psig.

Relative to the energy used for direct heat and steam, the energy used for electric power generation is low. For example, previous studies showed that the average power-to-steam heat ratio in US refineries is about 0.13.[2] If both steam and direct heat is included, the power-to-heat ratio is only approximately 0.03.**

The 1985 annual refinery survey compiled by the Oil and Gas Journal lists 191 refineries in the US.[8] This compares with 274, 225, and 220 in 1982, 1983, and 1984, respectively.[9-11] Recent decreases in crude oil prices and increasing overseas competition are creating economic difficulties for US refineries and many small refineries have shut down. The largest US refinery is Exxon's 494,000 barrel per day Baytown plant in Texas. As of January 1982, there were 18 plants above 225,000 Bbl/D, 38 in the 100,000 to 225,000 Bbl/D size range, 42 at 50,000 to 100,000 Bbl/D and 176 below 50,000 Bbl/D. Figure 3

*Temperatures are reported in °F as this is standard industry practice.

**The above ratios are based on the use of 3413 Btu/kWh and not the 10,000 to 11,000 Btu/kWh which would have to be used if the power were generated internally.

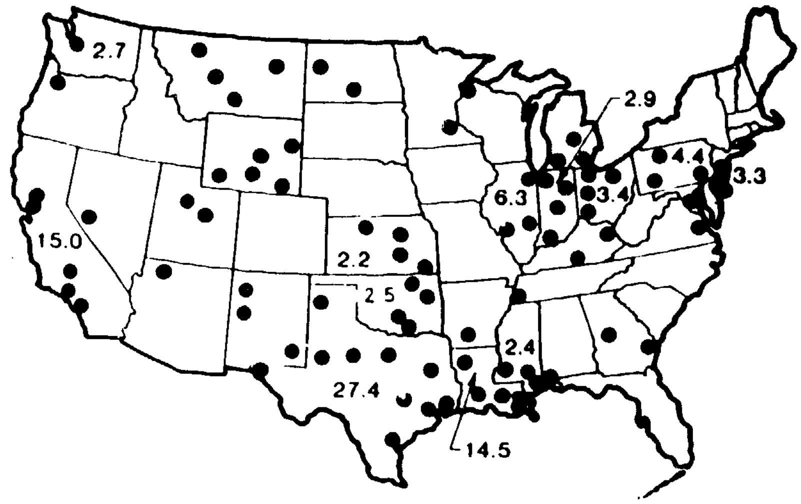

Fig. 3. Refinery locations and percent U.S. capacity as of January 1, 1985.

shows the approximate locations and existing capacities of refineries in the US.

B. Processes and Steam Requirements

Highly detailed discussions of the major refinery processes are given in Refs. 7 and 12. A large integrated refinery may incorporate most of these processes but not necessarily all. No attempt will be made in this short paper to describe the processes in detail.

Steam requirements vary from plant to plant for a given process. Reasons for this divergence can include (1) process efficiency improvements, (2) old vs new plants, (3) internal processing differences to produce the same product, (4) possible plant capacity differences, (5) process emphasis on a different product but using the basic process nomenclature, and (6) combinations of the previous reasons. A similar situation is observed for the fuel and electricity requirements for the various refining processes. Under these circumstances, an energy description for a "typical" refinery becomes a difficult task. Nevertheless, a model refinery was constructed and energy requirements determined. This was done in collaboration with Mr. J.M. Anderson, Executive Director of IFCA.

The selected capacity of the above mentioned model refinery is 150,000 Bbl/D, consisting of 100,000 Bbl of West Texas Intermediate (sweet) crude and 50,000 Bbl of Alaskan North Slope (sour) crude. This is about the ratio of sweet to sour crudes that refineries are being built to handle today. The 150,000 Bbl/D capacity is large enough to allow all the needed processing units to be installed in an economically efficient size and is the size refinery expected to compete in future fuels markets.

Figure 4 is a block flow diagram of this refinery. It contains the processing units to produce the higher valued products demanded by the American market: unleaded gasoline, jet fuel, domestic heating oil, and LPG. Petroleum coke and sulfur are produced as by-products. The capacity of each processing unit is shown in its respective block. Table III provides the throughput data and product output for the facility. Table IV shows the steam balance for the refinery. The steam consumptions are generally lower than those reported by the 24 actual refineries responding to the questionnaires (Sec. III.c). Four reasons may partially account for this difference. The units in the model are all designed for energy efficiencies commensurate with present day fuel costs, which would lower steam consumption by 10 to 20% over older refineries. Secondly, all the units in the model are sized to exactly match; there is no excess capacity in any part of the refinery operating inefficiently. All actual refineries have been added to over the years, and there are inevitable mismatches in unit capacities. Thirdly, the model refinery numbers are for full operating rate on a crude slate that exactly matches its design. This never occurs in real life. Lastly, the mechanical drive turbines are designed to be full condensing. If they had been designed to operate as back pressure units, exhausting at 150 psig, the required 600 psig steam would be twice that shown in the model.

This plant requires 50 MWe of electric power which is the actual consumption at 100% capacity, giving a value of 8 kWh/Bbl of crude. Total connected load is probably a third higher, or around 65 MW. The power requirement and the high pressure steam requirement will vary inversely from one refinery to another, depending on how many turbine drives they use on their centrifugal compressors and large pumps. The trend is toward large electric motor

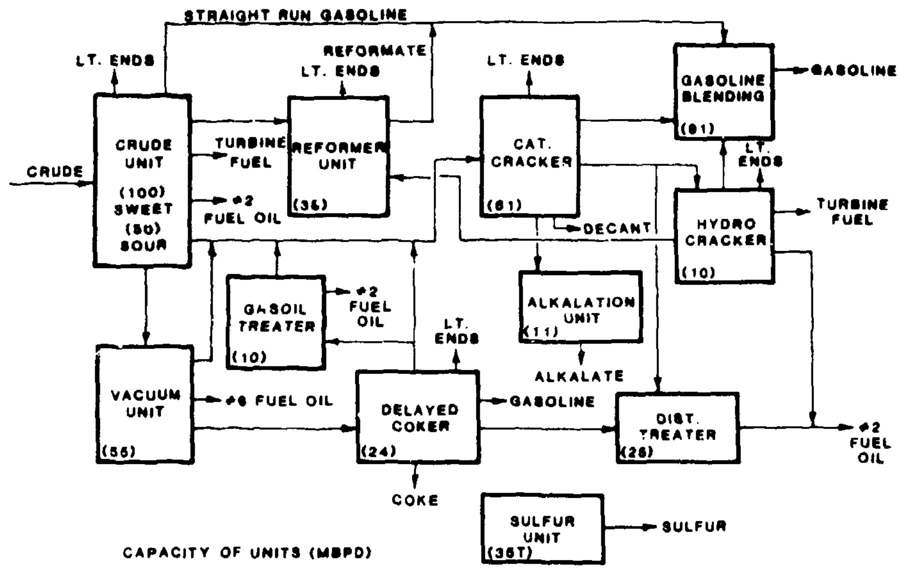

Fig. 4. Flow diagram of a typical refinery 100,000 BPD sweet crude plus 50,000 BPD sour crude.

TABLE III

REFINERY THROUGHPUT DATA

Feed

100 MBbl/D West Texas intermediate crude (sweet)
50 MBbl/D Alaskan North Slope crude (sour)

Products	MBbl/D
Gasoline (87 AKI clear)	91
Turbine fuel (jet fuel)	15
Distillate fuel (#2 fuel oil)	30
Heavy Fuel (#6 fuel oil)	1
LPG	6
Coke	920 TPD
Total Liquid Recovery	143
95.7% of Feed	

drives, because they are more efficient than turbine drives.

From a fuel-balance analysis for this refinery, it was estimated that the fuel consumption is 479 MMBtu/MBbl crude. This is typical of a fully integrated refinery designed to handle some sour crudes, and to produce the higher valued products demanded by the American market. A simple fuels refinery producing less gasoline, and #6 fuel oil instead of coke would probably consume around 380 MMBtu/MBbl crude.

The total energy consumption (on a per barrel basis) of the model refinery is:

	MBtu/Bbl
Fuel consumed	479
Fuel equivalent of power consumed	80
Total Energy Consumption	559

By way of comparison, the average energy consumption of US refineries in 1983 was 580 MBtu/Bbl.

C. The Petroleum Refinery Questionnaire

1. Introduction - The IFCA has assisted Los Alamos in this project by collecting data on the energy consumption in refineries, the characteristics of the steam supply system, and the possible sources of fuel for the fuel cells. The Association has also provided consulting help on the interpretation of the data collected.

Over the period of April through September 1985, the IFCA sent out a questionnaire to the major refiners as part of its data collection efforts, and received replies on 24 specific refineries ranging in size from 26-50 Mbbl/D to above 300 Mbbl/D. Because the answers were received from refiners who are maintaining their competitive posture, the replies should be typical of current refinery operations. In addition to this, the Association and Los Alamos jointly interviewed five major refining companies who operate a total of 28 refineries. The remarks of these refining experts helped greatly in identifying the trends in the industry and the reasons for the range of answers to some of the items in the questionnaire. A summary of the responses to the questionnaire is given below.

TABLE IV

REFINERY STEAM BALANCE
(1000 lb/h)

Unit	600 psig Steam Prod.	600 psig Steam Used	600 psig Steam Net	150 psig Steam Prod.	150 psig Steam Used	150 psig Steam Net	50 psig Steam Prod.	50 psig Steam Used	50 psig Steam Net
Crude distillation					135	(135)	30	15	15
Vacuum distillation				22	28	(6)			
Delayed coking				12	14	(2)	7		7
Reforming (process)				76	27	49	11		11
Reforming (mechanical)		30	(30)						
Catalytic cracking (process)				305	363	(58)	61	18	43
Catalytic cracking (mechanical)		156	(156)						
Alkylation (process)					83	(83)	21	46	(25)
Alkylation (mechanical)		82	(82)						
Hydrocracking					45	(45)	4	1	3
Distillate treating					25	(25)			
Gasoil treating					10	(10)			
Sulfur recovery				11	7	4			
Product, gasoil blending					9	(9)		18	(18)
Subtotals			(268)	426	746	(320)	134	98	36
General plant					33	(33)		20	(20)
Power house	302	34	268	386	33	353	17	33	(16)
Total Consumption	302			386				151	
Total Consumption, lb/Bbl	48			62				24	

2. Summary of responses

a. Electric demands - The total electrical demand per refinery ranged from less than 10 MWe to between 100 and 200 MWe with 29% at 11 to 25 MWe and 36% at 51 to 100 MWe. An average electrical demand of 10.8 kWh/bbl of capacity was indicated. The answers probably reflect peak demand, therefore the actual electrical consumption per barrel is probably slightly less than this value. However, one modern refinery reported an electrical consumption of 12.3 kWh.bbl. Purchased electricity represented 10-20% of the operating cost for 28% of the refineries. The rest said that it was less than 10%.

There appears to be a strong interest in selling excess power. All respondents said that if they could generate more power than they could consume then they would sell the excess to the local utility.

b. Steam demands and supplies - The respondents all indicated three levels of steam pressure were distributed in their refineries. The following data are typical of the system reported:

Steam System	Pressure psig	Consumption lb/bbl
Low Pressure	25	26
Medium Pressure	150	91
High Pressure	600	134

36% of the respondents indicated that they could use more medium pressure steam from a phosphoric acid fuel cell system if that system could meet the 125-150 psig pressure needed. The steam requirement in these refineries averaged 215 Mlb/h.

All respondents indicated that they could use 600 psig steam from a molton carbonate or solid oxide fuel cell installation. This requirement averaged 450 Mlb/h.

Many of the refinery processes require direct heating at high temperatures, e.g. 700 to 1000 F. Some of this heat is recoverable and can be used to generate steam useful for lower temperature processes and in turbines to drive machinery and to generate electric power. Additional power and energy sources are needed and some refineries have more than one type of alternative source in operation. The different types that are now being used are tabulated below and fuel cells, if used, would have to be competitive with these types. Sources of refinery energy today include: (1) Purchased electricity and a boiler, 50%; (2) Combined cycle system, 46%; (3) Coke- or coal-fired boiler and turbogenerator, 17%; and (4) Oil- or gas-fired boiler and turbogenerator, 13%. [Responses total more than 100% due to more than one energy source within a refinery.] The cogeneration concept is widely used with 54% of the refineries using cogeneration systems to produce steam and part of the electricity they require.

c. Available fuels - Most refineries buy extra fuel, but the amount varies from none, up to 35% of the refinery's total requirements. There appeared to be no correlation between the % of purchased fuel and the size of the refinery.

When asked about gasoline reformer off-gas, 38% have off-gas available. Amounts range from 1 to 50 MMCF/D. 21% have off-gas in amounts ranging from 8 to 50 MMCF/D, and averaging 25 MMCF/D. Percent H_2 varied from 30-90% and the typical hydrogen content was 80%. Those who have this off-gas available, value it at 100% of natural gas fuel value. Those who had no excess off-gas valued it typically at 150% of natural gas.

With regard to the hydrotreater off-gas, 46% of the respondents have hydrotreater gas available. Hydrogen content varies from 30-80%, with 56% average H_2 content. This steam was valued at 100-130% of natural gas fuel value, with most indicating 100% of natural gas. Amount of off-gas available

TABLE VI

BASE-CASE SYSTEM PERFORMANCE AND COST CHARACTERISTICS:
PETROLEUM REFINERY APPLICATION

Parameters	System						
	Gas Turbine Combined Cycle (1)	Gas Turbine Combined Cycle (2)	Phosphoric Acid Fuel Cell (1)	Phosphoric Acid Fuel Cell (2)	Molten Carbonate Fuel Cell	Solid Oxide Fuel Cell	Coke Fluidized Bed Boiler
Levelized annual electricity costs (¢/kWh)	4.5	5.1	5.3	5.1	9.9	9.6	7.3
Capital cost (CC) ($/kW)	560	560	515	515	1300	1300	500
O&M cost[a] (% of CC)							
Fixed	2	2	9	9	4	4	4
Variable	5	5	5	5	10	10	8
Capital replacement[b] (% of CC)	---	---	6	6	11	11	4
Total O&M[c] (% of CC)	7	7	20	20	24	24	16
Overall efficiency (%)	80	75	80	75	75	75	85
Electrical efficiency (%)	45	35	42	45	52	54	5
Steam efficiency (%)	35	40	38	30	23	21	80
Btu steam output/kWh	2655	3900	3090	2275	1510	1325	55 070[d]
Btu input/kWh	1585	9750	8125	7585	6565	6320	68 260[d]
Steam credit ($/$10^6$ Btu)	4.80	4.80	4.80	4.80	4.80	4.80	4.80

[a]Actual percentages based upon best available data. Fixed and variable definitions dependent upon source of data.

[b]Capital replacement is based upon present thinking for fuel cell (stack) replacement.

[c]This figure was used for purposes of modeling and reflects total annual operating expenses.

[d]These values are really misleading due to the method of computation and the small quantity of electricity generated with respect to total steam output and fuel inputs.

varied from 2-25 MMCF/D, with 29% of the respondents indicating they had 10 MMCF/D or more available.

Typically the refineries needed more hydrogen than they had available in high concentration streams and 21% had a steam-methane reformer for additional hydrogen. Available hydrogen from this source ranged from 10-100 MMCF/D, with most reporting 25 MMCF/D or more. Hydrogen content was 95% or better. This steam was valued at 140-170% of natural gas dollar value with 150% being typical.

When asked if there were any sources of CO and H_2 mixtures (such as excess capacity in a steam-methane reformer, or a coke gasifier) that might be used in MCFC or SOFCs, 4% had a low Btu gas steam available, containing 10% H_2 and 20% CO. This was valued at 110% of natural gas. 20 MMCF/D of gas was available.

d. Potential market for fuel cells - Considering that fuel cell systems are modular, the respondents estimated that the initial facility would probably be no larger than 5 MW. Subsequent units would probably be in the 6-20 MW range, with only 22% as small as 5 MW. The respondents also estimated that fuel cells could make significant inroads as an energy source by the year 2000, depending on the level of savings such systems could offer. The estimates are based on a total industry electrical capacity of about 4000 MWe: (1) 50% lower energy costs, 3280; 30% lower energy costs, 2080; and (3) 10% lower energy costs, 320.

D. Candidate Cogeneration System

In addition to the three fuel cell technologies considered for petroleum refinery applications, the gas turbine combined cycle (GTCC), and coke fluidized bed boiler (CFBB) options were included in the overall analysis. The three fuel cell technologies were basically equivalent in design to 3 of the 4 considered for chlor-alkali application: phosphoric acid (PAFC), molten carbonate (MCFC), and solid oxide (SOFC). The conventional GTCC technology was included in the analysis because it is the most likely competitive cogeneration system in the coming decade. The CFBB cogeneration technology was included because several refineries have plans to install this system in the near future to make use of available coke fuel or refinery product.

For all but the CFBB cogeneration technologies, we "normalized" to a 50,000 lb/hr steam output. A 300,000 lb/hr steam output was selected for the CFBB based on current prototypes. Electrical generation capacities from each cogeneration technology were based on typical design characteristics of each. Table V shows our assumptions for the operating and performance characteristics of the candidate cogeneration systems. Assumptions for a steam boiler are also shown because they were used to estimate the value of steam in a petroleum refinery.

E. Economic Analysis

Table VI provides a summary of the electrical generation costs for the "base case" cogeneration systems for a typical refinery today. Also included in Table VI are the principal performance and cost assumptions used to derive the levelized annual electricity costs.

Except for possibly the conventional system of choice today, the performance and cost assumptions are based principally on paper studies and educated estimates (as was also true for the chlor-alkali industry). Therefore, the base-case conditions for each system do not necessarily represent equivalent levels of accuracy. A more realistic economic comparison is presented in Fig. 5 (similar assumptions as employed in Fig. 2) where net electric generating costs (¢/kWh) are plotted against capital costs (¢/kW). The horizontal lines at 4.5 and 5.1¢/kWh, the net generating costs for the GTCC base-line system--80% (case 1) and 75% (case 2) overall efficiencies respectively, provide ready benchmarks against which to judge cost competitiveness of other systems.

As for Fig. 2, one can read break-even capital costs directly from the figure itself. For example, the PAFC technology (case 2) at $510/kW and $450/kW provides the same levelized annual electricity costs as the conventional gas turbine combined cycle technology, case 2 and case 1, respectively. However, the MCFC is similarly comparable at $760 and $720 per kilowatt respectively.

We have not plotted the second PAFC case, case 1, option for the difference in results is fairly small. The case 1 PAFC plot would be approximately 5 percent greater than that for the PAFC case 1 in Fig. 8, or 5.3¢/kWh vs 5.1¢kWh at the base case capital costs of $515/kW. Interpretation of results along the plots would be similar: at any given capital cost the resultant generating costs would be approximately 5 percent higher; or, for any given generation costs the capital costs would have to be approximately 5 percent lower to be equivalent to case 2

The CFBB technology results in significantly higher generation costs than the fuel cell technologies at capital costs below $1500/kW. However, if the coke refinery fuel is priced lower ($1.50/$10^6$ Btu assumption used in baseline computation) then the plot for CFBB will fall commensurately. It may even be the case that the coke be-product could be priced at a value less than zero for its disposal costs may exceed its heating value. (e.g. $2.00/$10^6$ Btu equivalency disposed costs less $1.50/$10^6$ Btu fuel value gives rise to a negative $0.50/$10^6$ Btu fuel "charge" in the cost computations.) The CFBB is also a steam generator, with electricity only a secondary product.

F. Market Potential

As stated earlier, petroleum refineries in the US have decreased in both number and capacity during the past 5-8 years. Today, there are fewer than 190 operating refineries and additional closings are likely. Product imports to the US are on the rise; and world-wide refining capacity continues to increase as more producers enter the downstream market. The price of oil has fallen recently; the market mix of products continues to shift away from

TABLE V

OPERATING AND PERFORMANCE CHARACTERISTICS ASSUMED FOR POWER AND STEAM GENERATING SYSTEMS IN PETROLEUM REFINERIES

System Parameters	PAFC Case 1	PAFC Case 2	MCFC	SOFC	GTCC Case 1	GTCC Case 2	Purchased Power Plus Boiler	Coke Fluidized Bed Boiler
Fuel Type	N.G.	N.G.	N.G.*	N.G.*	N.G.	N.G.	N.G.	Refinery Coke
Fuel Heat Input (10^6 Btu/hr)	149×10^6	167×10^6	252×10^6	276×10^6	161×10^6	145×10^6	409×10^6	506×10^6
Electricity (MWe)	18.3	22.0	38.4	43.7	21.3	14.9	0	7.5
Steam (lb/hr)	50×10^3	50×10^3	50×10^3	50×10^3	50×10^3	50×10^3	300×10^3	300×10^3
(psig)	15-125	15-125	125-400	400-600	15-50	125-400	~600	~650
Efficiencies:								
Electrical (%)	42	45	52	54	45	35	-	~5
Heat Extraction (%)	38	30	23	21	35	40	85	~80
Overall (%)	80	75	75	75	80	75	85	~85

N.G. - Natural Gas
*Other fossil fuels can also be used.

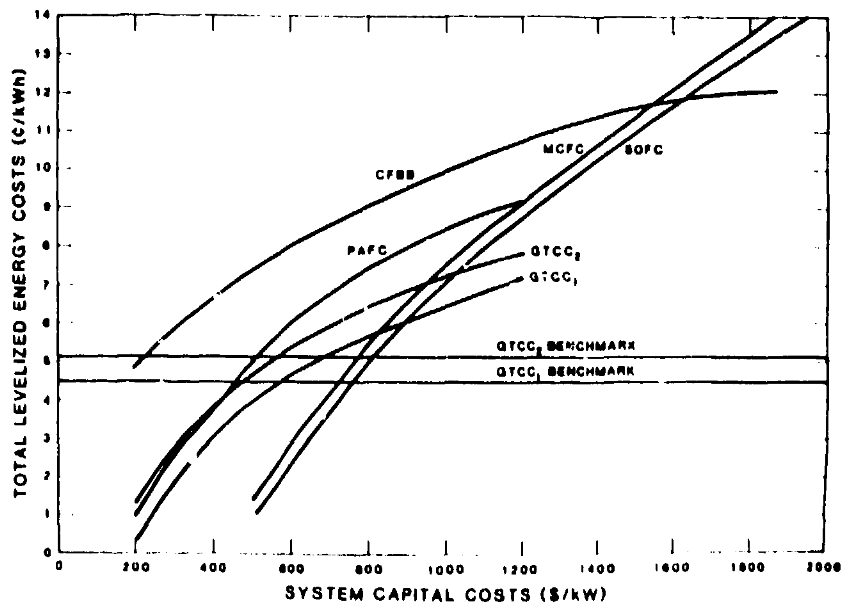

Fig. 5. TLEC for refinery base case systems.

"heavies" to "lights;" the quality of crude processed by refineries, on average, is lower today than in the past; and profits and profit margins are relatively low in contrast to petroleum's earlier years and today's industrial averages--all of which indicates that even further pressure on US refining capacity could easily result in more reductions. New investment in plant and equipment, althrough necessary to upgrade some older refineries and to increase throughput of marketable products (lights), will be delayed further.

The overall prognosis for petroleum refining in the US is not good. However, expansion of refinery capacity in certain product catogories will occur as demand continues to shift and even as total capacity decreases. This incremental capacity expansion may offer fuel cells an opportunity because fuel cells can easily be installed in incremented units.

The results of our industry survey suggest that the market potential of fuel cells may be greatest as a supplemental energy source to existing power and steam generating systems. Respondents indicated that if fuel cell systems were installed by their companies, the first unit would be 4MWe or less. Subsequent units would also be fairly small, 10 to 20 MWe. Sizing of fuel cell installations at these size increments support the supplement energy market segment for fuel cell application in petroleum refineries.

The survey responses also highlighted several other factors that could effect the market potential of fuel cells. First, the cost difference between fuel cell net generating cost and present or conventional system costs would have to be above the 15 to 20 percent range for large scale purchases. The PAFC technology could achieve that goal in the next decade if system prices are lowered as much as some have forecast or believe--a factor of 2 or more separates those capital cost figures today. However, the PAFC technology will only have a limited application because of its relatively low steam pressure and temperature operating levels (although there are significant low pressure and temperature requirements in a refinery). Second, because of the higher pressure and temperature requirements of a refinery there was strong indication that the MCFC and SOFC technologies would be better long-term candidates for adoption. Both of these technologies have received increased attention in the R&D community of late. Third, these two technologies could potentially make use of a variety of fuel sources available in the refinery such as off-gases and coke. The PAFC technology requires natural gas or hydrogen, a fuel that has grown in value that far exceeds that of natural gas itself.

The price of energy, especially that of purchased electricity, is important to the petroleum refining industry (although less than the chlor-alkali industry). Cogeneration is not new to the industry, moreover, generation of excess electricity from cogeneration systems and subsequent sole to utilities is taking place today at several refineries. Questionnaire responses also indicated a strong willingness to consider sales of electricity to utilities from an on site cogeneration system if steam generation costs were competitive with today's costs (on a net energy cost basis).

The price of electricity paid by major petroleum refineries cannot be known for any given plant. However, we have constructed estimates of prices from published rate structures. Figure 6 portrays the range of these estimated prices by state. Also included in Fig. 6 is additional information on the number of operating refineries and their collective capacity as of early 1985. States with large capacity and relatively high industrial electrical rates would appear to be potentially attractive markets for fuel cells.

The state of California, Louisiana, and Texas comprise nearly 60% of US refining capacity and in two of the three have relatively high electric rates. Electric rates are forecast to dramatically increase in the third, and all face higher prices in the future due to new plant expansion coming on line, nuclear rate shocks, and higher natural gas prices--especially true for Texas and Louisiana where much of existing electric capacity is gas-fired. Texas and California are considered two of the more supportive states--both institutionally and rate structure wise--for cogeneration. By examining again Fig. 5, and considering that electricity prices could easily be 2 to 3¢/kWh higher than the "base-line GTCC reference lines, then fuel cells look more promising even at higher capital costs. However, the GTCC technology appears to be a difficult competitor and will likely remain so for a number of years.

IV. SUMMARY

Although there is much that can be said about fuel cell applications, economic competitiveness, and market potential in both the chlor-alkali and petroleum refinery industries, the following brief statements serve to summarize principal findings and key conclusions.

A. The Chlor-Alkali Industry

- The chlor-alkali industry is an attractive application for fuel cell cogeneration systems.

- The PAFC appears to be the most promising fuel cell type for this application.

- If by-product H_2 is readily available at low cost, the OXY fuel cell could supply supplemental power.

- The chlor-alkali industry has many attractive characteristics that are favorable to fuel cells:

  - Cogeneration is already used extensively
  - Natural gas is primary fuel of choice (easily reformed fuel)
  - By-product H_2 is of high quality and used as fuel
  - Plant P/H ratios of 1.14 to 3.86 are favorable to fuel cells
  - Incremental installation of fuel cells matches planned plant expansions
  - High amperage direct current requirements matches output of fuel cells

- The GTCC technology will be a difficult competitor well into the 1990's and even into the next century.

B. The Petroleum Refining Inudstry

- The petroleum refining industry is only a marginally attractive application for fuel cell cogeneration systems.

- The MCFC and SOFC appear to be more technically attractive fuel cell technologies because of their much higher pressure/temperature regimes.

- A limited role is foreseen for the PAFC due to its relative low operating pressures and temperatures.

- Attractive characteristics of the petroleum refining industry that are favorable to fuel cells:

  - Cogeneration is a commonly used concept
  - There is a strong interest in selling excess electric power.
  - Supplemental energy supplies are viewed positively.

- However, there are also unfavorable characteristics:

  - Plant power-to-heat ratios are low.
  - H_2 for fuel cell use is not readily available.

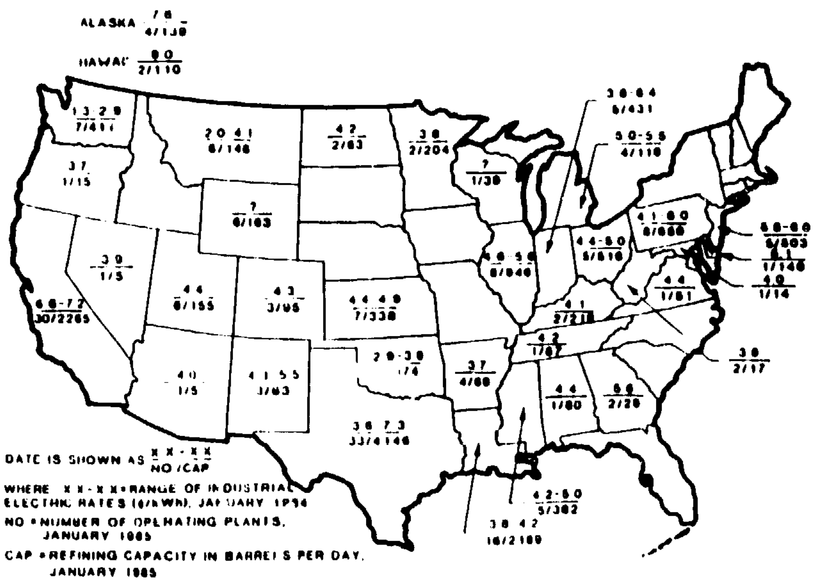

Fig. 6. Typical electric rates, number of plants and refining capacity.

- Large direct heat requirements exist in most refineries.

- Steam or gas turbines give the user a choice of P/H and steam quality. The GTCC technology is and will remain a very tough competitor for fuel cell cogeneration systems.

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