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Consider using hydrogen plants to cogenerate power needs

Many forces are reshaping the worldwide hydrogen market; refiners have several options to receive steam and electrical power from a hydrogen plant

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The worldwide market for hydrogen and carbon monoxide (HyCO) in the refining and petrochemical/chemical industry has been particularly vibrant in the 1990s. In the refining sector, more stringent environmental regulations—governing emissions of NO_x and SO_x in Europe and the U.S. and heavy sour crude development in Venezuela and Canada—are driving hydrogen demand. In the petrochemical/chemical sector, continued economic development has been the primary impetus for hydrogen, carbon monoxide and synthesis gas. At the same time, the electrical power industry is being deregulated and economic issues are becoming increasingly important in the generation sector. Furthermore, outsourcing goods and services that are not core to a manufacturer's production expertise is a growing trend. These changes provide new opportunities for sourcing hydrogen (H_2), steam and electrical power.

The supply of H_2, steam and electrical power by third-party specialists can be particularly valuable when these requirements are large enough to justify the development of an independent supply infrastructure to serve multiple customers. By outsourcing industrial gas and utility needs to a single supplier, a refinery can focus capital and human resources on core business. In several case histories, the varying scenarios that simultaneously produce H_2, steam, and electrical power from a single-production plant are discussed. The integration of a steam-methane reformer (SMR) with various power generation technologies such as a topping turbine gas turbine and condensing turbine are explored.

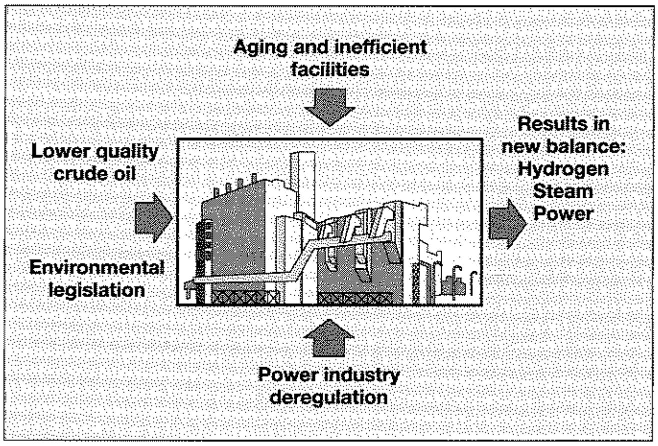

Fig. 1. Forces affecting refiners.

Delegating plant functions. The trend to outsource noncore activities is impacting almost every manufacturing sector on a worldwide basis. Initially, outsourcing was selectively used by smaller companies as a way to get necessary expertise without making a large investment. In the 1990s, the outsourcing philosophy is being embraced by the largest multinationals as a means of becoming more cost competitive. There is a growing recognition to concentrate on core competencies in which a company can attain world-class status. Activities that fall outside this realm are more advantageously outsourced. Examples of outsourcing range from plant security, landscaping and cafeteria services to plant engineering, design, construction and maintenance.

Outsourcing has been successfully applied in developed economies, where major corporations have increasingly outsourced activities that are not core to the manufacturing process. This arrangement benefits both the supplier and customer due to increased economy of scale, greater focus, improved efficiency and reduced capital requirements. In developing countries, where numerous grassroots petrochemical/chemical and refining complexes are being built, the outsourcing concept is expected to be particularly valuable. In situations where infrastructure is generally weak and capital is scarce, the need for low-cost, reliable utilities is particularly acute. Once this outsourcing philosophy is

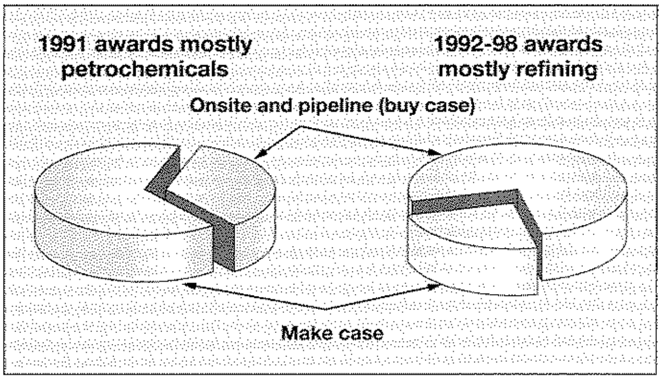

Fig. 2. The paradigm is shifting for hydrogen market.

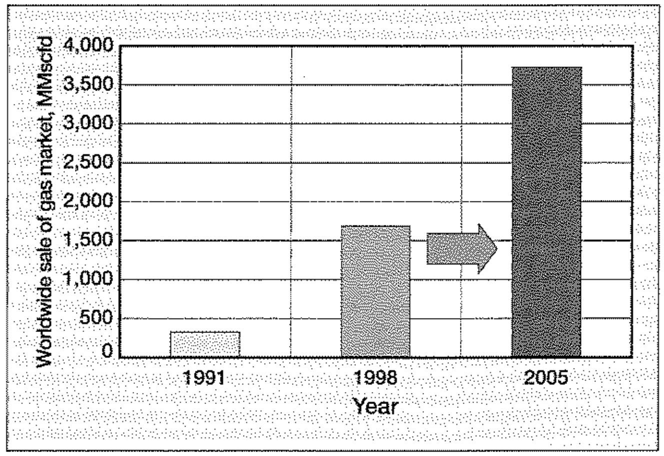

Fig. 3. HyCO onsite/pipeline market is growing rapidly.

adopted by manufacturers, recognized by government authorities and supported by financial institutions, a driving force will be established that creates the infrastructure for further economic growth.

In the chemical and petroleum refining industry, the supply of industrial gases and utilities is increasingly being outsourced to third-party specialists to improved efficiency and reliability. This paper will review the technology and economics of producing H_2, steam and electrical power from a single production plant. Such a "utility island" can provide many benefits—reduced cost, improved environmental performance, and enhanced reliability,—that will ultimately improve the refiner's profitability.

Market trends. Demand for H_2, steam and power is expected to increase at both U.S. and European refineries over the next several years. The main factors driving this demand are shown in Fig.1.

Lower quality crude oil. In the last decade, the refining industry has been impacted by several trends that have increased H_2 demand. First, in the aggregate, crude oil is getting heavier and sourer. This situation has led to higher H_2 consumption for upgrading the crude oil and removing sulfur. This long-term trend, which is impacting the worldwide refining industry, is expected to continue.

Environmental legislation. Since 1990, the U.S. refining industry has been impacted by stricter environmental regulations. Federal Clean Air Act Amendments (CAAA) and state requirements such as the California Air Resources Board (CARB) regulations have redefined the composition of transportation fuels, such as gasoline and diesel, to reduce air emissions. These regulations include lower limits on aromatics, olefins and sulfur content. To comply with these regulations, many refiners have had to adopt these practices:

- Reduce the operating severity of catalytic reformers[1] to produce fewer aromatics from naphtha
- Increase the degree of hydrotreating of refinery products.

Reducing the severity of catalytic reformers *reduces the byproduct H_2 supply* at a refinery, while greater hydrotreating *increases H_2 demand.* Similar regulations are already being considered in Canada, Mexico, South America, Europe and Asia.

Power industry deregulation. The retail electricity market has continued to evolve in the U.S. since the passage of the National Electricity Policy Act in 1992, although restructuring has proceeded at a slower pace than most electricity-intensive industries would like. Through the end of 1998, 13 states had approved final legislative restructuring statutes. Three states have bills pending final approval and another 20 states had either task forces or transitional legislation in place to deal with the issue.

Generally, deregulation will result in a dismantling of the vertically integrated structure of the electric utility industry. It will create a competitive generation market while retaining a regulated transmission and distribution industry. Included in the competitive market will be generation services such as spinning reserve, nonspinning reserve, black-start capability, automatic load control, voltage support and backup, and maintenance power. The cost for these services is likely to be lower than the regulated, tariff-based rates presently in effect. We believe some of these charges could be as little as ⅓ to ½ the current rates.

The ability to purchase and supply electricity in the competitive marketplace provides a significant opportunity for energy-intensive industries that can use cogeneration to produce steam and electricity in a highly cost-effective manner. The market price for power generation will be set by the hourly market. The average market price will move around the cost of new baseload generation. The components of electricity cost are capacity, energy and operations and maintenance expenses. During periods of capacity surplus, the market price will decrease toward average marginal operating costs that is primarily the cost of fuel with less than full recovery for invested capital. This cost is determined by the heat rate of the unit (Btu/kWh) and the cost of the fuel ($/MMBtu). The generated cost is directly proportional to the heat rate. During periods of capacity shortage, the price will increase. For the foreseeable future, the cost of new base-load generation in the U.S. will be based upon a large central station natural gas combined-cycle plant. While combined-cycle power plants are highly efficient, cogeneration plants have significantly better heat rates than the best of these units. Furthermore, as natural gas prices rise, cogeneration facilities with low heat rates provide a natural hedge with an increasing margin on fuel costs.

An integrated HyCO-cogeneration configuration provides a fuel chargeable to power heat rate superior to

Table 1. Congenerate electricity from hydrogen plants

	H_2, MMscfd	Power, MW	Turbine configuration
Mobil—Torrance, California	90	37	Gas/topping
Air Products–Wilmington, California	80	30	Topping/condensing
Air Products–Pernis Netherlands	80	35	Topping (3)
Texaco–Wilmington, California	15	21	Topping/condensing
Air Products–New Orleans, Louisiana	60	35	Topping/condensing/gas

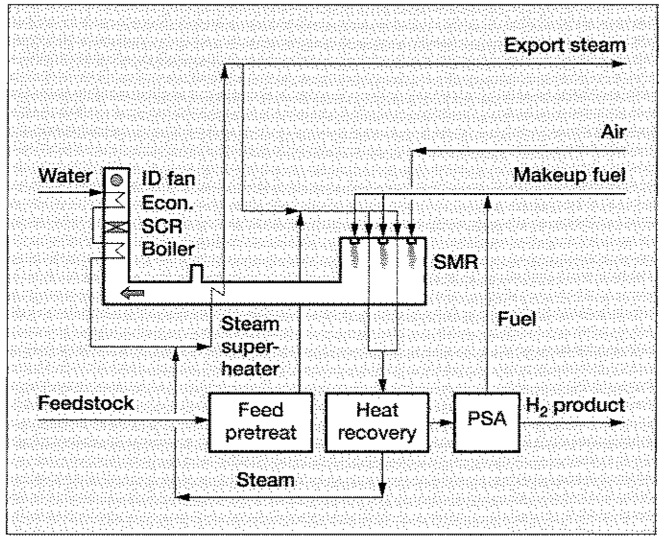

Fig. 4. Process flow diagram of a stand-alone H_2 facility.

most cogeneration options while the incremental capital investment is competitive to much larger generation facilities. Thus, production costs for the on-site supply of power are generally superior. In addition, onsite power has the advantage of transmission and distribution cost avoidance. This may provide an additional 0.5 ¢/kWh price advantage.

Aging and inefficient facilities. Many refiners have to expand or replace existing H_2 plants, steam boilers and power plants because of poor efficiency or environmental performance. In many instances, when a refinery is being expanded, the need for additional H_2, steam and electrical power occurs concurrently. In other instances, the refinery may have to shut down old boiler capacity to reduce operations and maintenance expenses, avoid capital expenditures from environmental compliance rules, improve operating efficiency or create emissions allowances. These situations provide an opportunity to reassess the entire H_2, steam and power balance and improve the total cost structure.

Market impact. The combined effect of these trends is that a typical refinery is becoming significantly short on H_2. These factors have created additional H_2 demand that will more than double by the turn of the century. In the U.S., these factors have created supply/demand imbalances of up to 90 MMscfd at some locations. These requirements are supplied by some of the largest and most sophisticated H_2 plants. They require substantial capital investment and technical know-how to achieve the high degree of plant reliability that is critical to a refinery. Also, these large requirements present many opportunities for utility integration.

Another important driving force that is shaping the industry is a shift in the buying habits of refiners. This effect is depicted in Fig. 2. Increasingly, refiners are choosing to buy H_2, steam and power instead of making it themselves. Until the 1990s, a majority of the new H_2 demand was supplied by the "make case," wherein the end user bought a H_2 plant and operated it themselves. Also, most of the new H_2 demand was in the petrochemical sector. In 1992, this paradigm was broken with the startup of the first large onsite H_2 supply. This project was a large SMR for Tosco Refining Co., located in Martinez, California. Over the last five years, two things have changed. First, a majority of the H_2 has been supplied from onsite and pipeline H_2 systems owned and operated by industrial gas companies. Second, most of the new requirements have been in the refining industry as acceptance for third-party supply of H_2 has grown.

The worldwide market for HyCO has been particularly vibrant in the 1990s. From 1991 through 1997, the worldwide sale-of-gas (SOG) market grew fivefold from 325 to 1,700 MMscfd. The next wave of growth in the worldwide HyCO SOG market is expected to add approximately 2,000 MMscfd of capacity by the year 2005. This trend is shown graphically in Fig. 3.

Besides the growth in H_2, the deregulation of electricity has created opportunities for integrated power production. Recent examples of H_2 plants integrated with power are presented in Table 1.

Increasingly, refiners are outsourcing H_2 requirements to third-party specialists with proven safety and reliability track records. Thus, a refiner may refocus capital and manpower resources on core businesses. This approach can be particularly valuable in the context of a large, high-conversion oil refinery, whose H_2 requirements are becoming large enough to justify the development of an independent, third-party supply infrastructure to supply multiple industrial gases and utilities with a variety of process needs.

Hydrogen is generally the largest product that is outsourced in terms of volume and value for a typical refinery. Consequently, the entire project will usually be structured around H_2 in terms of timing, location and economic viability.

Hydrogen, steam and power integration. SMR, which is principally designed to for the production of H_2, can also economically produce steam and electric power. Technically, SMR is an endothermic reaction. However, for acceptable kinetics, the temperature has to be above 1,450°F in the radiant section of the reformer furnace. Thus, waste heat is usually available. Normally, waste heat is used to make export steam for other process uses.

It may be noted that a SMR also consumes power

Table 2. Process and economics for power generation

	Base	Case 1 Topping turbine	Case 2 Gas turbine	Case 3 Cond. turbine	Case 4 Topping/gas
H_2, MMscfd	80	80	80	80	80
Export steam, lb/hr	350,000	350,000	350,000	0	350,000
Export power, kW	-	13	28	49	41
Effective heat rate, Btu/kWh	-	4,500	5,700	12,000	5,300
Capital costs, MM $	-	11	17	25	28
$/kW	-	860	620	500	700

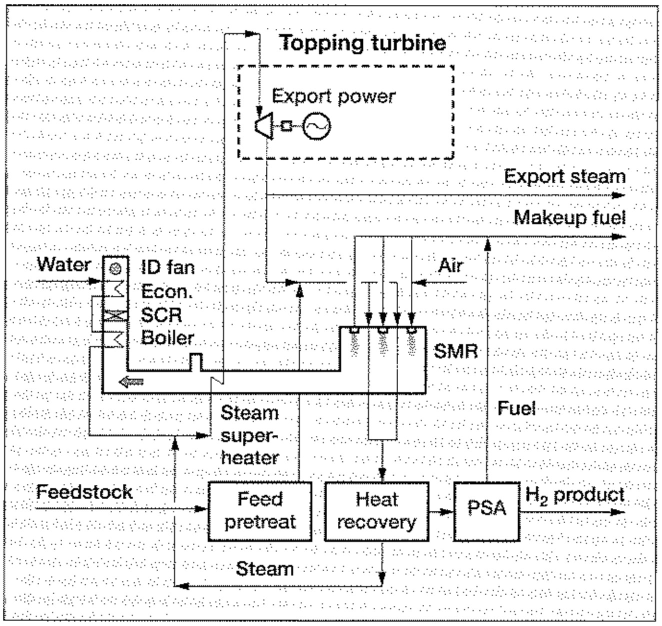

Fig. 5. Process flow diagram of a H_2 plant with a topping turbine.

for fans, compressors and pumps. In many cases, sufficient power can be produced to meet not only the H_2 plant's own internal needs, but also export some to the host refinery and local electrical grid. The technology is proven and cost-effective. Fundamentally, electrical power generation can represent a higher value end use of steam. Once H_2 and steam requirements have been established, the amount of power produced can be set by incorporating the appropriate power-generation technology, which will be integrated into the overall plant design.

Benefits of integration. The simultaneous supply of H_2, steam and power from a single package provides several distinct advantages:

- ▶ Integrated project execution
- ▶ Economy of scale
- ▶ Improved energy efficiency
- ▶ Enhanced reliability
- ▶ Improved environmental performance
- ▶ Operations and maintenance synergy
- ▶ Simplified contract management.

Integrated project execution. It is simpler and less expensive to build a single integrated plant that produces H_2, steam and power compared to several stand-alone facilities. A single project provides engineering design and construction cost savings. Furthermore, some redundant equipment can be eliminated. For example, the reformer convection section, which is similar to a cogeneration plant's heat recovery steam generator (HRSG) can be shared between the SMR and gas turbine. Many utilities such as boiler feed-water, firewater, condensate return and wastewater disposal can be shared. Likewise, the electrical substation, cooling tower, control room, air pollution control, maintenance and supplies warehouse can be combined.

An integrated HyCO-cogeneration configuration reduces plant space requirements by about 20% compared to the nonintegrated design, by eliminating redundant equipment and buildings.

Economy of scale. The production of H_2, steam and power is highly capital intensive. Capital-related costs, including operations and maintenance (O&M), typically represent 30%–50% of the total unit cost for H_2, with the remainder being fuel. Likewise, for power generation, the capital cost component can be as high as 60%. It is well known that the capital costs of chemical process equipment scales by the "rule of 0.6," while fuel consumption scales linearly with size. This means that the cost of a plant increases by 52% as its capacity is doubled, providing economies of scale. Thus, it is possible to reduce unit capital costs by building a larger plant. This can be achieved by satisfying the needs of multiple users with multiple products such as H_2, steam and power.

Improved energy efficiency. For a given product slate of H_2, steam and electrical power, the integrated SMR cogeneration configuration is more energy efficient than stand-alone SMR and cogeneration facilities. The energy consumption for power can be ~20% less compared to a similarly sized stand-alone cogeneration facility. Overall, the net thermal efficiency—which includes the energy content of the H_2 product, improves by over 3% compared to a nonintegrated package. In a gas turbine, energy efficiency is improved by introducing the gas turbine exhaust into the radiant section of the SMR, thereby reducing stack heat losses. Additionally, secondary benefits include reduced total radiation losses, improved back-end heat recovery and reduced cooling water flow. Also, using a topping or partially condensing turbine and increasing the steam generation pressure within the SMR provides additional efficiency benefits.

Enhanced reliability. To a typical refiner, the reliability of H_2, steam and power is as important as cost, because these products are essential to operating the refinery. If these utilities are unavailable, then the refiner cannot operate hydrocracking or hydrotreating facilities. Consequently, gasoline and diesel fuel production, which are the main revenue sources the refiner, is compromised. An industrial gas company that specializes in H_2 and power production can design features into the plant, which guarantee superior reliability.

Improved reliability is achieved by incorporating appropriate design features in the plant and having a dedicated workforce that is focused on H_2 and power technology, operation and maintenance. Additionally, the experience gained by operating numerous plants all over the world is translated back into the engineering and operations function so that continuous improvements can be made.

Environmental performance. An integrated design results in reduced CO_2, CO, NO_x and VOCs emissions due to more efficient fuel utilization compared to stand-alone HyCO and cogeneration plants. This is achieved without additional on-purpose pollution-reduction devices. For example, NO_x emissions may be reduced by up to 50%. CO emissions are also drastically reduced by using the reformer burners to destroy nearly all of the CO generated in the gas turbine.

Operations and maintenance synergy. A single team can operate and maintain all plant equipment from one control room. The skill sets in power generation and steam methane reforming are similar since both are high-temperature processes with rotating equipment and highly automated controls. Combining these functions reduces total manpower needs.

Simplified contract management. Using a single point of contact to manage the entire scope of an integrated HyCO and power generation package through design, procurement and construction simplifies the customer's contract and production management process. It enables the customer to deal with a single party rather than multiple organizations in the definition of project scope, design and project construction management. Also, once the plant is operational, the single point of contact remains in place.

As noted previously, the need for H_2 is the primary driver to construct an SMR. Once that decision has been made, the cost of H_2 can be reduced by also producing steam and power. In this manner, capital and operating costs of the facility can be spread over a larger number of products, thereby reducing the costs for each. The feasibility and economics of steam and power production must be carefully conducted.

The amount and method of power production from the SMR will be governed by the size of the unit and the quantity and pressure of the export steam. Increasing steam production may not increase O&M costs and may actually reduce capital cost of the SMR. However, integrating power production into the design requires additional equipment, changes to the SMR's operating conditions, and additional O&M expenses. These costs must be properly allocated to power generation and a detailed economic evaluation needs to be completed.

Table 3. Economics for a topping turbine

Dimensions		Economics	M$/yr
H_2, MMscfd	80	Capital charges	2,318
Export steam, lb/hr	350,000	Natural gas ($2.5/MMBtu)	1,204
Export power, MW	13	**Total**	3,522
Heat rate, Btu/kWh	4,500	Unit cost, $/kWh	0.032
Capital, $/kW	860		

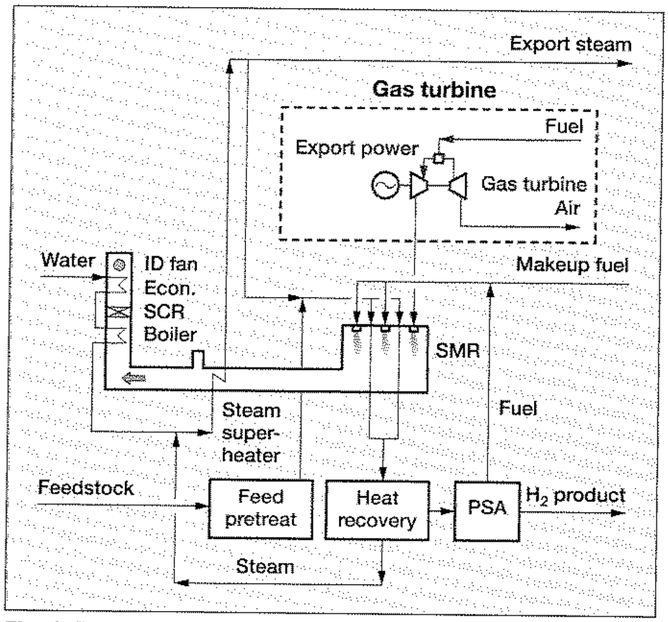

Fig. 6. Process flow diagram of a H_2 plant with a gas turbine.

Process and plant design. From an engineering viewpoint, the main processing steps in H_2 production are feed compression, feed purification, steam reforming, shift conversion, steam generation, purification by pressure swing adsorption (PSA) and product compression. A simplified process flow diagram of a typical steam-methane reformer, based on natural gas, is presented in Fig. 4.

Feed gas is compressed, preheated and desulfurized before it can be fed to the reformer furnace. Desulfurization of the feed gas, which is most economically done with a zinc oxide catalyst, is needed since sulfur can poison the reformer catalyst. Hydrocarbon feedstock with up to several hundred ppm sulfur can be handled by using an appropriate desulfurization process in a properly designed H_2 plant.

After purification, the feed gas is mixed with process steam at a steam-to-carbon mole ratio of ~3.0. This "mixed feed" is preheated by reformer flue gas in the mixed feed preheat coil in the convection section of the reformer furnace before entering the reformer. The primary reformer contains tubes filled with nickel reforming catalyst. The catalyst converts the feed gas to an equilibrium mixture of H_2, methane and carbon oxides. Most of the CO in the reformer product is converted to CO_2 and additional H_2 in the shift reactor.

The shift product is cooled and fed to a PSA unit for purification. Typically, a PSA produces H_2 at 99.9%. The adsorbent, which is a mixture of activated carbon and zeolites, removes all contaminants from the H_2 product in a single step. Each adsorption vessel in the PSA follows a cycle of adsorption, stepwise depressurizing, purging and stepwise repressurizing. The system maximizes H_2 recovery by effectively using residual H_2 in an adsorber vessel at the end of its cycle to repressurize the other vessels and H_2 for purging.

Waste heat is available from two sources in a typical steam reformer. The first is the heat in the reformer furnace flue gases, while the second is the heat in the process gases exiting from the reformer. The heat from the reformer furnace can be used to generate steam, superheat steam, preheat air and preheat the

Table 4. Economics for a gas turbine			
Dimensions		**Economics**	**M$/yr**
H_2, MMscfd	80	Capital charges	3,930
Export steam, lb/hr	350,000	Natural gas ($2.5/MMBtu)	3,253
Export power, MW	28	**Total**	7,183
Heat rate, Btu/kWh	5,700	Unit cost, $/kWh	0.031
Capital, $/kW	620		

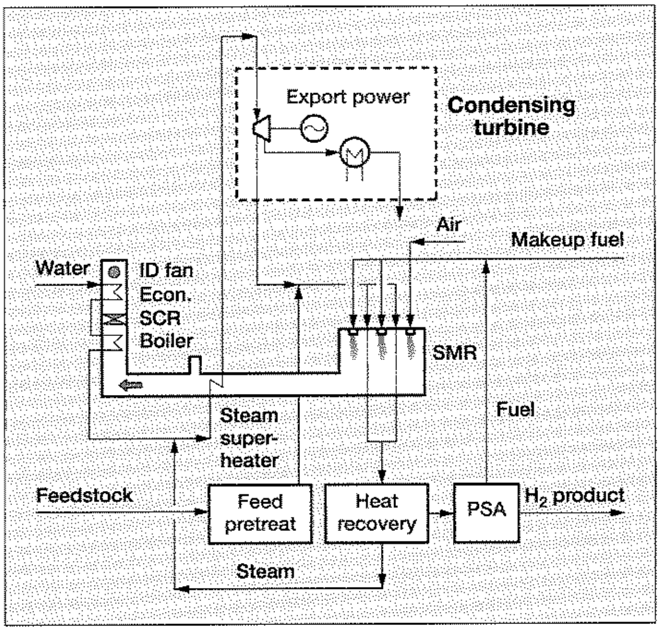

Fig. 7. Process flow diagram of a H_2 plant with a condensing topping.

feed/steam mixture. Heat from the process gas is used in preheating the feed to the desulfurizer, generating steam in a process-gas boiler, heating boiler feedwater, heating condensate, providing deaeration steam, and supplying heat to the makeup water. As more heat is recovered, fuel efficiency is improved, and cooling water requirements are reduced. However, additional heat integration results in higher capital costs.

Power generation options. Several options for power generation can be integrated into an SMR. Simple process flow diagrams that depict the various options are presented in Figs. 5–7. The basic process and economic parameters for the following five cases are:

- Base Maximum steam SMR
- Case 1 Topping turbine
- Case 2 Integrated gas turbine
- Case 3 Condensing turbine
- Case 4 Topping turbine + gas turbine.

The SMR will normally be baseloaded and run in a near steadystate condition for H_2 production. Demands for H_2 will dictate the operational "dispatch" of the plant. Hence, the ability to independently vary steam or power output is limited. Thus, the preferred mode of SMR operation for steam and power would be "base load," and other process boilers would have to handle swings in demand for either of these products.

A limited amount of steam demand variation can be incorporated if a condensing turbine is incorporated in the plant design. However, the incremental power produced from swings in steam demand would probably have a reduced value if its availability cannot be guaranteed.

Economics. The technical viability of cogenerating power in H_2 plants has been unequivocally established in several commercially operating plants. Several examples will be discussed. Ultimately, in a competitive and cost-driven marketplace, a technical concept will be adopted *only* if it is economically attractive. While economics for such large, complex process schemes are always site-specific analyses and generalizations are difficult, we have evaluated several cases in detail.

The baseline in each case is an 80-MMscfd H_2 plant that produces approximately 350,000 lb/hr of steam as shown in Fig. 4. Such a plant represents a "high steam" export configuration[2] and includes very little heat integration within the reformer circuit. In each cogeneration case, all additional costs—including capital, fuel, power, labor and maintenance—are allocated to the cost of producing power. As a result, the cost of H_2 and steam is held constant and a true incremental cost can be determined. In assessing the economics presented, it is useful to keep the following benchmarks in mind. A similarly sized stand-alone, natural gas-fired cogeneration plant producing about 40 MW of power would have a capital cost in the range of $800/kW and a fuel chargeable to power heat rate about of 6,500 Btu/kWh. The cost of producing electricity in such a configuration is $0.038/kWh when natural gas is $2.50/MMBtu. The presented cases should be compared against this benchmark.

Case 1: Topping turbine (Export power = 13 MW). In this configuration, the steam system in the H_2 plant is upgraded from 650 psig to 1,500 psig. All of the steam is produced at the higher pressure. By throttling the steam down from 1,500 psig to 650 psig, ~14.5 MW of power is produced. Approximately 1.5 MW is consumed for plant needs, while the remaining 13 MW is available for export to the refinery or local grid. Fig. 5 is a simple schematic of this configuration.

The capital cost for this option is estimated to be $11 million. This translates into $860/kW, which compares favorably with the benchmark given the relatively small capacity of this unit. Additional natural gas translates into a heat rate of 4,500 Btu/kWh, which compares very favorably with the benchmark. Consequently, the net cost of power in such a process scheme is $0.032/kWh. Table 3 summarizes the economics for this case.

A topping turbine is even more cost-effective when the steam can be throttled down to a lower pressure. By reducing the pressure from 1,500 psig to 300 psig, it is possible to significantly increase the amount of power that is produced from a topping turbine.

Case 2: Gas turbine (Export power = 28 MW). A simplified flowsheet, depicted in Fig. 6, shows how the exhaust from a gas turbine enters the radiant section of the reformer. At 1,000°F, this gas still contains 13% oxygen and serves as combustion air to the reformer. Since this stream is hot, reformer fuel consumption is decreased. The convection section replaces the heat recovery steam generator (HRSG) in a cogeneration design. Once heat is recovered, the cooled gas enters an induced-draft fan and leaves via the stack. Steam raised in the convection section can be put through either a topping or condensing turbine for power generation. In this configuration, the steam system in the H_2 plant does not have to be upgraded from 650 psig. Instead, natural gas is fired in a gas turbine. Approximately 28 MW of power is produced out of which ~0.2 MW is consumed for plant needs, while the remaining is available for export to the refinery or local grid.

The system can be designed such that production of H_2 can continue in the event of loss of the power generation units through the incorporation of fresh air inlets into the SMR. This permits outages of the gas turbine for maintenance and repair of the turbine generator. Separately, a gas turbine exhaust bypass system allows the gas turbine to be decoupled from the reformer. In the event of a reformer trip, the gas turbine can operate and continue to produce electricity.

For this configuration, the capital cost is estimated to be $17 million. This translates into $620/kW, which compares very favorably with the benchmark. The additional natural gas translates into a heat rate of 5,700 Btu/kWh, which also compares very favorably with the benchmark. As a result, the net cost of power in such a process scheme is $0.031/kWh. The economics are summarized in Table 4.

Case 3: Condensing turbine (Export power = 49 MW). In this configuration, the steam system in the H_2 plant is upgraded from 650 psig to 1,500 psig. All of the steam is produced at the higher pressure. By condensing the export steam, it is possible to convert the sensible and latent heat in steam to ~52 MW of power. Approximately 3 MW is consumed for plant needs, while the remaining 49 MW is available for export to the refinery or local grid. This configuration results in zero export steam. Fig. 7 is a simple schematic of this design.

The capital cost for this option is estimated to be $25 million. This translates into $500/kW that is relatively low compared to the benchmark. The additional natural gas consumption translates into a heat rate of 12,000 Btu/kWh, which is very high compared with the benchmark. Factoring in the lost steam revenues, the net cost of power in such a process scheme is $0.042/kWh. While the economics are not compelling, this scheme may be valuable in situations where there is no "home" for the export steam or where reliable, on-site, electric power supply is desired. This option becomes relatively more attractive at lower natural gas prices since the heat rate is high. The economics are summarized in Table 5.

Table 5. Economics for condensing turbine

Dimensions		Economics	M$/yr
H_2, MMscfd	80	Capital charges	4,735
Export steam, lb/hr	0	Natural gas ($2.5/MMBtu)	12,221
Export power, MW	49	**Total**	16,956
Heat rate, Btu/kWh	12,000	Unit cost, $/kWh	0.042
Capital, $/kW	500		

Table 6. Economics for topping turbine/gas turbine combination

Dimensions		Economics	M$/yr
H_2, MMscfd	80	Capital charges	6,119
Export steam, lb/hr	350,000	Natural gas ($2.5/MMBtu)	4,474
Export power, MW	41	**Total**	10,593
Heat rate, Btu/kWh	5,300	Unit cost, $/kWh	0.031
Capital, $/kW	700		

It may be noted that a condensing turbine affords the opportunity of condensing varying amounts of steam. Consequently, steam production can be decoupled from power generation to meet specific customer needs.

Case 4: Topping turbine/gas turbine (Export power = 41 MW). This configuration is a combination of topping turbine (Case 1) and gas turbine (Case 2). Basically, power production and economics are obtained as a combination of cases 1 and 2. We believe this is more advantageous than a condensing turbine for most cases when 40–50 MW are needed. The steam system in the H_2 plant is upgraded from 650 psig to 1,500 psig. All of the steam is produced at the higher pressure. The topping turbine produces 15 MW and the gas turbine produces 28 MW. Approximately 2 MW is used for plant load, leaving 41 MW for export.

The capital cost for this change is estimated to be $28 million. This translates into $700/kW, which compares very favorably with the benchmark. The additional natural gas consumption translates into a heat rate of 5,300 Btu/kWh, which also compares very favorably with the benchmark. Thus, the net cost of power in such a process scheme is $0.031/kWh. Table 6 lists the economics for this case. In this configuration, appropriate bypasses can be incorporated into the plant design to decouple H_2 production from power production.

It can be seen that electricity can be generated in an H_2 plant at approximately $0.03/kWh at $2.50/MMBtu for natural gas, which is very competitive with either on-site stand-alone cogeneration or the price of retail-purchased power in a deregulated market. In general, power generation from an H_2 plant is most cost-effective when a large steam requirement exists. If steam production must be minimized, the reformer becomes more expensive, and the turbine system suffers from the lack of economy of scale. From a practical standpoint, the price of power generated in an integrated H_2 plant is competitive. As a result, total need for power should really determine whether and how much power should be produced. Therefore, it is essential to carry out a detailed analysis and optimize H_2, steam and power requirements to minimize total cost.

Case studies. Overviews of three projects that comprise H_2, steam and power generation are shown:

Los Angeles basin. In 1995, a large SMR with power generation capability was started up in the Los Angeles basin to serve the local refining industry (Fig. 8). This plant produces and exports H_2, steam and power.

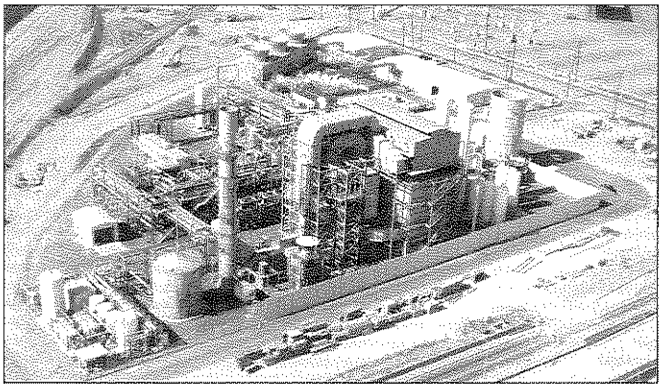

Fig. 8. Los Angeles basin hydrogen facility.

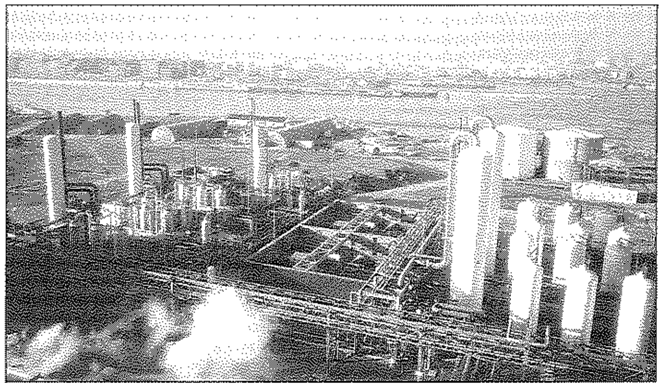

Fig. 9. The Pernis hydrogen facility at Rotterdam, The Netherlands.

A steam topping/condensing turbine and generator was selected to increase the export power capability. A surface condenser was added, as well as a substantially larger cooling tower designed to handle the cooling water requirements of the surface condenser. Under normal operating conditions, the topping turbine generates all power required for the H_2 plant. In addition, ~8 MW of power was available for export. Some details on the steam generator are presented:

Type	Multivalve, double auto-extraction
Generator	Synchronous
Frequency	60 Hz
Speed	3600 rpm
Voltage	13.8 KV
Output	32 MW (Generator rating)

Rotterdam, The Netherlands. To illustrate how individual components truly create a beneficial infrastructure for petrochemical/chemical manufacturers, it is interesting to examine the Rotterdam area, a leading chemical center. At this location, some of the largest and most sophisticated gas production equipment are operated by a third-party operator. The total system includes air separation, H_2, CO and steam and electricity production. A dozen customers are served by over 200 km of pipeline on long-term contracts. If the customers had

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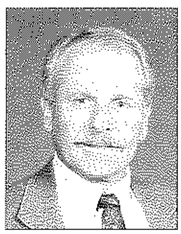

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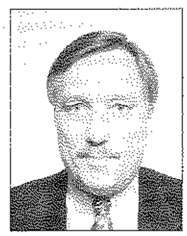

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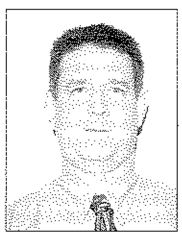

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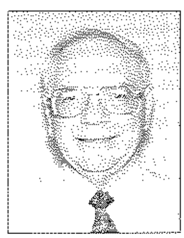

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built their own individual gas and utility plants, then the total energy, capital and manpower would have been much higher. Nearby, at a second site in Rotterdam/Botlek, a major H_2 and CO unit feeds the pipeline system. The hydrogen plant is located in Pernis, near Rotterdam, The Netherlands, and is shown in Fig. 9.

West Coast refiner. At a major West Coast refinery, the integration of gas turbine exhaust (GTE) with the reformer in a H_2 plant was successfully implemented. This is an efficient way to increase steam production for the refinery while generating electric power for internal consumption at very attractive rates. Using GTE improves waste-heat recovery in the reformer convection section due to higher flue gas temperatures and rates. A portion of the GTE is consumed as preheated air for firing. The remainder is routed to the convection section for waste-heat recovery and steam generation. The gas turbine, itself produces, ~16 MW, while a steam turbine produces an additional 20 MW from high pressure steam raised in the waste-heat recovery section of the reformer convection section. The H_2 plant at this refinery has been in operation for 11 years and has consistently achieved operating rates in excess of its nameplate capacity.

Hydrogen options. A SMR plant can be designed to produce steam and power in addition to H_2. This enables a refiner to outsource all three products. The integration of a SMR with various power generation technologies—such as a topping turbine, condensing turbine, and gas turbine—has been commercially demonstrated. Integrated power production in a H_2 plant becomes more economic as the cost of energy increases due to the superior heat rate of a topping and gas turbine compared to a stand-alone cogeneration plant. These options are particularly valuable in developing economies, where infrastructure is weak and capital is scarce. We expect integrated utility supply schemes to gain greater acceptance as the refining industry continues to streamline operations and reduce costs.

ACKNOWLEDGMENT

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NOTES

[1] It may be noted that a catalytic reformer is the only major source of by-product hydrogen in a refinery.

[2] For a discussion of varying steam production in a steam-methane reformer, see literature cited.

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