Can gas-to-liquids technology get traction?

The plunge of U.S. natural gas prices since 2010 has undermined the coal industry, roused the nation's petrochemical companies and begun transforming the power-generation business.

But could low prices also jump-start a niche industry — called gas to liquids, or GTL — that for nearly a century has struggled to establish a foothold in the world of fossil fuels?

Last year a massive GTL plant opened in Qatar. Another plant is under construction in Nigeria. An Uzbekistan project is in the early stages of development. A major chemical company is studying the feasibility of GTL projects in Louisiana and Canada. Brazil's national petroleum company is testing compact GTL for offshore platforms.

The idea of a gas-to-liquids solution for Alaska's North Slope stranded gas occasionally arises but has failed to get momentum.

Despite the buzz of activity and interest, progress has been stymied by the astronomical cost of building GTL plants — and the career risk facing CEOs who undertake such investments — as well as by oil prices that have swung between rock bottom and sky high.

Gas-to-liquids is a technology that turns methane, the primary component of natural gas, into such products as cleaner-burning diesel for trucks, kerosene for jet fuel, naphtha for high-octane gasoline or petrochemical feedstock, even waxes for candles or cardboard waterproofing.

The gas-to-liquids process was born, and has been largely sustained, out of a primal force that has inspired many innovations: fear. Fear that a region is falling behind in industrial competitiveness for lack of liquid fuels. Fear that the world might be running short of crude oil.

Source: Shell

Storage tanks for liquids made at Shell's Pearl GTL plant in Qatar.

For short periods of the 20th century, the outcome of this fear abetted forces of evil, with the technology helping fuel the Nazi war machine and lubricating South Africa through apartheid embargoes.

But mostly GTL has languished, outmaneuvered in the marketplace by products made more cheaply from refined crude oil.

In recent years, the impetus behind GTL has turned to another primal force: The desire to transform otherwise stranded or flared natural gas into money.

Quadrillions of Btu waft into the atmosphere each year from natural gas flaring or venting at oil production wells. The gas has just a fraction of oil's value, and often there's no profit in moving the gas to market. If only GTL technology could be refined and its cost reduced so that gas could be converted into marketable products instead, one scientist recently mused. The environmental impact would be as if every car in the United States was retrofitted as a hybrid vehicle.

ONLY A TOEHOLD GAINED

There's nothing new about transforming a fossil fuel into other products. Apply a bit of chemical engineering muscle and money and ... presto.

The components of natural gas today get divvied up and sent to their separate markets. Methane goes to furnaces to make heat and power plants to make electricity. Ethane heads to the petrochemical industry as feedstock. Propane to your barbecue grill. Butane to cigarette lighters.

Crude oil gets refined into gasoline, diesel, jet fuel, heating oil and other products.

These fossil fuels are largely clusters of hydrogen atoms and carbon atoms in varying numbers. That's why they're called hydrocarbons.

Break apart the atoms and recombine them in different ways to make different products that also are comprised of hydrogen and carbon atoms.

Coal also can be transformed this way.

A National Energy Technology Laboratory database

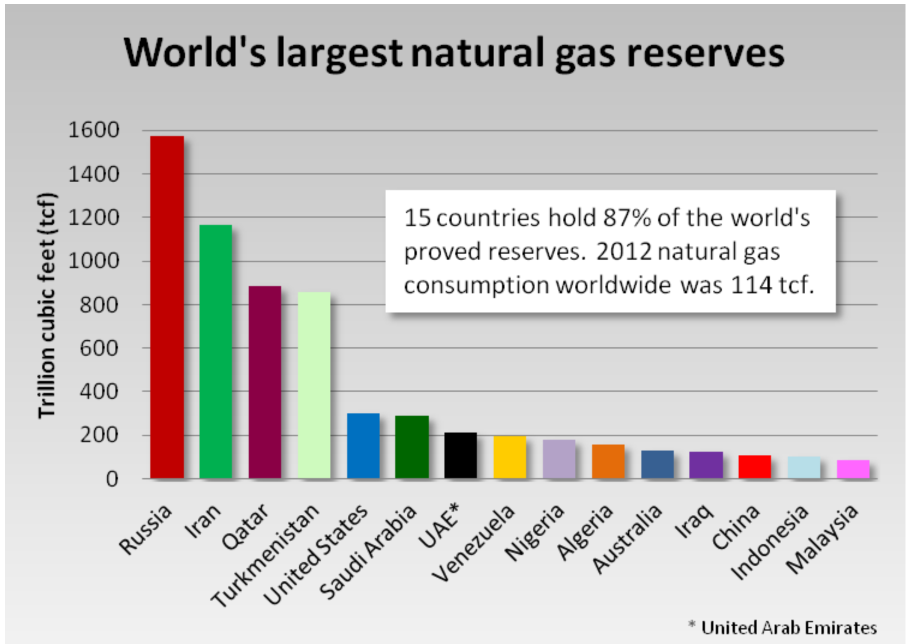
GTL plants worldwide

Pearl	
Location	Qatar
Owners	Qatar and Shell
Natural gas input	1.6 bcf a day
Products	Gasoil, kerosene, naphtha, paraffin, lubricants
Liquids capacity	140,000 barrels a day
Year opened	2011
Oryx	
Location	Qatar
Owners	Qatar and Sasol
Products	Diesel, naphtha
Liquids capacity	34,000 barrels a day
Year opened	2007
Bintulu	
Location	Malaysia
Owners	Shell, Mitsubishi, Petronas, Sarawak state government
Products	Naphtha, kerosene, gasoil, paraffins, solvents, lubricants, waxes
Liquids capacity	14,700 barrels a day
Year opened	1993
Mossel Bay	
Location	South Africa
Owner	PetroSA
Products	Chemicals, gasoline, kerosene, diesel, lubricants, waxes
Liquids capacity	36,000 barrels a day
Year opened	1992

of gasification plants lists 191 sites operating or under development worldwide. The plants primarily use coal and primarily make chemicals, ammonia and methanol. So industry has been in the fuel-transformation game for many decades.

But only a few GTL plants operate commercially today — in Malaysia, South Africa and Qatar. All were started up in the last 20 years — two of them in the past five years.

Most of the world's big oil companies have dabbled in gas-to-liquids R&D.



Source: 2012 BP Statistical Review of World Energy

BP ran a 300-barrel-a-day demo plant in Nikiski, Alaska, from 2003 to 2009. ConocoPhillips built a 400-barrel-a-day plant in Oklahoma. ExxonMobil put its test plant in Louisiana. The Japan National Oil Corp. has dipped its toe in GTL research. China's Sinopec acquired a GTL technology that a small U.S. start-up developed but never commercialized. Some demo plants have made as little as one barrel of product a day. Rarely has the R&D gotten past the demo-plant stage.

Big announcements sometimes get made about grandiose GTL plans.

Nearly a decade ago ConocoPhillips and ExxonMobil separately announced plans to build massive GTL plants in Qatar, home to the world's largest natural gas field. Both shifted instead to liquefied natural gas projects that recently began production.

Sasol, a South African chemicals company that operates GTL and coal-to-liquids plants, has said for years it wants to enlarge its 34,000-barrel-a-day Qatar GTL plant. Shell has made similar noise about its 14,700-barrel-a-day Malaysia plant.

Construction started a couple of years ago on a GTL plant in Trinidad and Tobago before the project sank into a swamp of lawsuits between the partners.

Restraining GTL from growing more broadly has been the enormous cost of building the plants and making products. Complicating the cost has been the wild swings in the price of oil, which can make the same products. GTL developers — and the banks that lend them money — face the risk that oil prices will drop so low that their products get priced out of the market.

Dane A. Boysen, U.S. Department of Energy director of advanced energy research projects, recently identified interlocking risks a GTL project developer faces, including volatile prices for GTL products, volatile feed-gas prices, cost overruns and unpredictable costs of catalysts used in GTL operations.

A University of Houston chemical engineering professor, Michael J. Economides, in 2005 found that both GTL and LNG can work financially for shipping stranded gas to far-away markets — GTL competing with crude oil in the transportation-fuels market and LNG used to generate electricity. But oil prices must be high and natural gas prices low to make either work. GTL can be more attractive than LNG at very low gas prices, he found.

"Availability of large volumes of low-priced natural gas feedstock is critical to the economics of GTL plants," Economides concluded.

HOW GTL WORKS

Making gas-to-liquids products is crazy expensive because a GTL plant involves three steps, each of which is costly all by itself.

Think of a GTL plant as three distinct factories linked into a single assembly line: A gas processing plant, a chemical plant and a refinery.

Here's the basic program:

First, a product called syngas, or synthetic gas, gets made. The feedstock is methane purified of gas liquids and such contaminants as sulfur and metals. If the methane hasn't been purified before arriving at the GTL plant, the cleansing occurs there. Separately, air also is processed to remove nitrogen and other elements to leave pure oxygen. Then the oxygen and methane are combined under ferocious heat and pressure to generate syngas — two atoms of hydrogen plus one each of oxygen and carbon, or H2 plus CO in chemistry lingo. The process binds the atoms together to create the syngas.

It sounds simple, but it's not. In fact the syngas stage comprises perhaps 50 percent or more of the GTL manufacturing cost. Air is superchilled (minus 292 degrees) to separate out oxygen. Methane and oxygen are combined under superheat (2,000 degrees) and superpressure (perhaps 1,000 pounds per square inch). It takes a fantastic amount of energy to make gases that cold and that hot. Just think of your air-conditioner bill during a heat wave or furnace bill during a cold snap, then multiply by a "super" number.

(Syngas also can be made from coal or biomass rather than methane.)

The second step flows syngas into a reactor that makes synthetic crude, or syncrude. A process called Fischer-Tropsch does this conversion. (More later on Fischer and Tropsch's role in history.) A variety of Fischer-Tropsch processes exist. Shell licenses one variation. Sasol another.

Essentially, Fischer-Tropsch forces the syngas under heat to react to a catalyst that accelerates the conversion into a liquid hydrocarbon. Typically cobalt is the catalyst, but sometimes others get used, especially iron, which is cheaper but less durable.

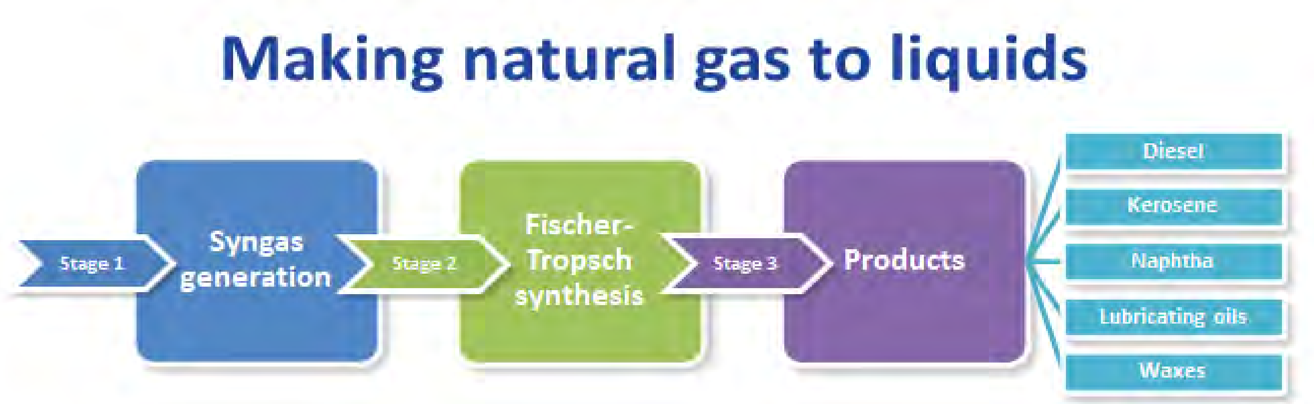
At Shell's gargantuan Pearl plant in Qatar — the world's newest GTL plant — cobalt is the catalyst. It's distributed throughout tens of thousands of tubes — each with microscopic inner channels — packed inside two 1,200-ton reactors. The surface of the cobalt is so vast that if it were spread out horizontally it would encompass an area almost 18 times greater than Qatar itself, Shell says.

The Fischer-Tropsch step typically consumes 25 percent or more of the total GTL capital cost. The end result is that syncrude is made, sometimes called GTL wax or long-chain hydrocarbons.

This product then flows to step three. Essentially a refinery makes the finished products. This step can total 15 to 25 percent of the cost.

As was said, the Fischer-Tropsch output is long-chain hydrocarbons — an example would be 100 atoms of carbon — C100 — plus associated hydrogen atoms.

The refinery cracks apart these chains into such



Source: Shell

Aerial photo of Shell's Pearl GTL plant in Qatar .

products as naphtha (C4 to C10, plus associated hydrogen atoms), kerosene (C10 to C13), diesel (C14 to C20) and so on.

This three-step processing adds a painful cost: Up to 40 percent of the methane that enters at step one burns up by the time GTL products exit after step three. By contrast, a liquefied natural gas plant might consume about 15 percent of the gas during production.

GTL operators can recoup some of this cost by using the waste heat to power the plant, or sell waste carbon dioxide or sulfur pellets, if they can find buyers.

But the short lesson is that gas-to-liquids manufacturing is spectacularly expensive.

Some champions of the industry say an entire plant can be built for roughly $30,000 to $50,000 per barrel of output per day (a 35,000 barrel-a-day plant then would cost about $1 billion).

That hasn't been the reality. Construction delays are chronic. Costs escalate as the giant projects create their own economic weather for engineering, labor, steel, shipping and other services.

Shell's Pearl development cost an estimated $18 billion, or over $100,000 per barrel of daily output. The spending included costs for offshore platforms, wells and pipes as well as gas liquids processing.

Chevron's Escravos plant in Nigeria is years behind schedule, and at the new estimate of $8.4 billion will cost over $200,000 per barrel of daily output.

By comparison, a rule of thumb is that building a typical LNG plant costs about $45,000 per barrel equivalent of daily output, according to global energy consultants Wood Mackenzie.

HIGH COST, HIGH RISK

The spectacular and unpredictable cost helps explain why so few GTL plants exist. It's the kind of cost and risk that only a few companies in the world will take on.

The economics of GTL work best when natural gas prices are low and oil prices are high. That creates an enviable competitive position: Feedstock is cheap and substitute products are expensive. That same dynamic let plastic trump paper at the supermarket checkout.

When the reverse is true — gas is expensive and oil is cheap — GTL can be a disastrous investment. That partly explains why, despite the world's abundance of natural gas, few GTL plants have opened.

Qatar is a special case. Two GTL plants started-up there in the past five years. Qatar holds modest oil reserves for a Persian Gulf nation but is spectacularly endowed with natural gas. The North Field, the world's largest natural gas field, lies offshore Qatar. It holds about 900 trillion cubic feet of natural gas, nearly 40 times the size of Prudhoe Bay, Alaska's natural gas crown jewel.

The two new plants are part of the Qatar government's bid to turn its natural gas bounty into long-term wealth. The government is majority owner of both plants, partnering with Shell for one and Sasol for the other. Qatar provides the gas cheaply to ensure the plants make money.

Source: Shell

Air separation towers at Shell's Pearl GTL plant in Qatar.

Nigeria GTL is another special case that, as in Qatar, is an attempt to convert stranded gas reserves into cash. (Nigeria also started LNG exports in the past decade to monetize its natural gas resources.)

But the Nigeria plant under construction also reflects a modern sentiment that is driving some contemporary talk about the need for more GTL production. For years Chevron has disposed of natural gas that rises up its oil wells by flaring it or venting it into the atmosphere. In part to deflect condemnation of this practice — and government edicts to stop — the company is pursuing a GTL option. But construction is years behind schedule and billions over budget.

Among Chevron's many woes in completing the Escravos plant in Nigeria: The project has been plagued by marauding kidnappers.

A DARK HISTORY

Turning an idle resource into money was not the original idea behind gas-to-liquids science, or that of its older brother coal-to-liquids.

Fear was.

In the early 1900s, coal was losing steam as the fuel of choice. The automobile and airplane were showing that crude oil, which mainly had been refined into kerosene, could be used as a transportation fuel and in other new ways. Discovery of giant fields in Texas, Azerbaijan, Indonesia and elsewhere spurred along the switch to oil. It also didn't hurt that oil packed more energy than coal and burned cleaner.

Some countries well-endowed with oil, such as the United States, were well-positioned for an industrialized future fueled by oil.

But German leaders were worried. Their country had plenty of coal but little oil. Necessity focused the mind of German scientists.

In 1913, just before World War I, a gifted chemist named Friedrich Bergius developed a technique for liquefying coal under high pressure. Bergius was awarded a Nobel Prize in 1931. (Bergius later turned his research toward obtaining sugar from wood cellulose. He died in Argentina after World War II.)

After Bergius' breakthrough, coal-to-liquids fever seized German chemists. In 1923 Franz Fischer and Hans Tropsch devised the alternate technique that bears their name.

German industry then advanced and commercialized coal-to-liquids technology, helping allow Germany's menacing territorial expansion and the madness of World War II that followed.

Coal-to-liquids plants provided well over half of Germany's wartime fuel needs for its navy, army and air force. Germany built 12 plants based on Bergius' breakthrough by the end of the war, and nine based on Fischer-Tropsch. (The chemical cartel IG Farben had a plant under construction at the Auschwitz concentration camp at war's end.)

The two technologies complemented each other. Bergius' hydrogenation made aviation fuel and gasoline, and it was the more abundant approach. Fischer-Tropsch synthesis made diesel, lubricating oil, waxes and lower-grade gasoline.

Japan's war machine got into the coal-to-liquids game, too. During the 1930s and 1940s, Japan's quest for industrial natural resources led to invasions of China and Southeast Asia. With more raw materials in hand, Japan chemists tried to perfect coal-to-liquids manufacture, but their efforts flopped.

Japan "did excellent laboratory research on the coal hydrogenation (Bergius) and Fischer-Tropsch conversion processes, but in their haste to construct large synthetic fuel plants they bypassed the intermediate pilot-plant stage and failed to make a successful transition from small to large-scale production," according to a history of Japan's effort.

As occurred in Germany and Japan, leaders in South Africa during the 1930s recognized that their nation was vulnerable to being left behind in an industrialized world. The country had no domestic oil reserves, but lots of coal.

That decade, South Africa flirted with oil-shale production, but produced little oil that way. After World War II ended in 1945, the government turned to coal-to-liquids conversion. Newly formed Sasol opened the first plant in Coalbrook — now called Sasolburg — in 1955.

Around the same time, a consortium led by Texaco ran a small plant in Brownsville, Texas, using the Fischer-Tropsch process to make liquids from natural gas this time, not coal. The consortium closed the plant in 1953 when natural gas prices started rising.

Except for in South Africa, coal- and gas-to-liquids essentially went into hibernation until the oil-price spikes of the 1970s. Then, the U.S. Department of Energy poured funding into research. But those efforts faded when oil prices crashed in the mid-1980s.

Meanwhile in South Africa, the coal-to-liquids industry kept the country energized when international embargoes limited oil imports during the 1970s and 1980s due to the nation's apartheid policy of racial segregation. South African industry diversified into gas-to-liquids after finding offshore natural gas fields in the 1980s. PetroSA, South Africa's national oil company, opened a gas-to-liquids plant at Mossel Bay in 1992. That plant is the oldest of today's GTL plants.

GTL FOR THE FUTURE?

With low North American natural gas prices and high oil prices worldwide, Sasol is giving GTL a fresh look.

The South African fuel maker has two feasibility studies under way. One is considering a roughly $10 billion, 96,000-barrel-a-day plant in Louisiana using plentiful U.S. natural gas. The other would involve a similar plant in western Canada, tapping shale-gas fields there. (A Canadian partner recently bailed out of the Canada study.) The studies are expected next year.

Last year Sasol also signed an agreement with the government of Uzbekistan to develop a GTL plant that would use that land-locked Central Asia nation's ample gas reserves to lessen its oil imports.

What about GTL for Alaska's 35 trillion cubic feet of stranded gas reserves at its North Slope oil fields?

That idea has been looked at but never has obtained much traction. ExxonMobil, the largest gas leaseholder on the North Slope, considered GTL in the 1980s and 1990s. But now the company and its fellow North Slope producers are looking at the possibility of piping the gas to a Southcentral Alaska liquefaction plant for LNG export.

BP's demonstration plant at Nikiski from 2003 to 2009 was aimed at testing a GTL production technique that could be applied elsewhere in the world, not specifically at Prudhoe Bay.

An energy industry veteran named Richard Peterson has been touting a North Slope GTL option without success since the late 1990s. He believes the GTL process can be tweaked so that the plant would specialize in supplying jet fuel for the state's international airports and military bases.

Last year, a study commissioned by the Alaska Gasline Development Corp., a state agency, concluded that such a plant taking gas delivered by a smaller-diameter pipeline from Prudhoe Bay probably wouldn't make enough money to attract investors.

Hatch, a global engineering consultant based in

Canada, looked at locating a GTL plant either near Anchorage or Fairbanks that would make diesel, jet fuel and naphtha for in-state use and export.

Neither site would work, the study concluded, even if the plant could sell excess energy into the local electrical-power grid and waste carbon dioxide to produce more crude from Cook Inlet-area oil fields in Southcentral Alaska.

The plant would cost perhaps $3 billion to build and almost $1 billion a year to operate. The feedstock gas would have to be almost free to make the plant's economics work, Hatch concluded in its report for the state agency.

For more information, please visit our website: www.arcticgas.gov

Contact information:
Bill White, Researcher/Writer for the OFC
(907) 271-5246
bwhite@arcticgas.gov

General Questions:
info@arcticgas.gov

Locations:
OFC Washington, DC
1101 Pennsylvania Ave. NW, 7th Floor
Washington, DC 20004
(202) 756-0179

OFC Alaska
188 W. Northern Lights Blvd., Suite 600
Anchorage, AK 99503
(907) 271-5209