LNG Trade Set to Correct High Prices and Rigid Terms

Expanding the Use of LNG

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Introduction

A growing number of people, particularly government officials, have been advocating a shift to greater use of natural gas (LNG) in Japan. Indeed, at an IEEJ-sponsored symposium preceding the “Producer-Consumer Dialogue” held in Osaka in September 2002, Mr. Hiranuma, Minister for Economy, Trade and Industry, predicted that natural gas would be responsible for “20% of Japan’s primary energy (in 2020).” Were his remarks a reflection of the high expectations held for natural gas as a means to meet GHG reduction targets under the Kyoto Protocol?

Entering the 1990s, however, Japan’s LNG demand continued to grow but at a slower pace. This downturn was largely attributed to a slowing of demand for gas in electrical generation and city gas use. However, an increasing number of electricity and city gas utilities have claimed in recent years that high-priced and inflexible LNG sales contracts were to blame and that these needed to be reviewed if sales were to be stimulated.

Amid such a climate, the media reported that low cost LNG would be supplied to China and that Japanese buyers have taken every opportunity to negotiate favorable terms, notably when renewing their contracts, and have successfully won concessions from suppliers on price and flexibility of supply.

This paper seeks to clarify the factors behind these changes in LNG trading.
1. High-priced and Inflexible Sales Contracts

LNG Projects Initiated by Buyers Willing to Take Risks

LNG supplied to Japan has been priced much higher than that bound for the United States and Europe. Taking figures for the year 2000 as an example, the CIF price for Europe-bound LNG averaged $3.1/MMBTU and the U.S.-bound price averaged $3.39, compared with Japan-bound LNG priced at $4.73, representing an increase of 53% and 40%, respectively. This may be based on differences in actual conditions, including the availability of domestically produced natural gas and other energy resources, transport distances, and the presence of rival pipelines; however, these price variations are too large to be explained based on these differences alone.

It is a well-known fact that LNG pricing is linked to crude oil pricing. The pricing formula applicable to Japan, and also employed by Korea and Taiwan, is as follows:

\[ P = aX + b + S \text{ curve} \]

Here, \( P \) is the price, “a” and “b” are constants, and \( X \) represents the crude oil price (Japan Crude Cocktail = average CIF price of all-Japan crude oil imports). The \( S \) curve is a means to moderate the price curve when it is above (or below) a certain price zone. The constant “a” is set in a way so as to price LNG at around 80% of the fluctuating crude oil price. Thus, it is designed to keep the LNG price less volatile in the event of oil-price spikes. When crude oil stays within a low price zone, this formula works to help sellers stabilize their operations by smoothing out price increases, as compared to cases when LNG price follows fluctuations in crude oil with 100% correspondence. On the other hand, when crude oil prices are on the rise, this formula benefits buyers by easing price decreases. The \( S \) curve works to prevent LNG prices from rising to a higher level or falling to a lower level, and during the last few years, as crude oil prices have remained very high, this formula has helped electric and gas utilities stabilize their fuel and feedstock costs.

However, as previously cited, the problem is high price levels and the magnitude of “price risk” these involve.
Moreover, due to large project scales and huge investments, LNG contracts involve a large contract volume and a long contract term, in addition to a take-or-pay clause that creates “quantitative risk.”

Since the introduction of LNG, Japanese LNG buyers have consistently and faithfully accepted these price risks and quantitative risks.

Electric and gas utilities, which are direct LNG consumers, had few choices but to take such risks, as they were in great need of the benefits of clean-burning natural gas. In 1969, when LNG shipments to Tokyo Electric Power and Tokyo Gas began, Japan suffered from a different kind of environmental problem from that faced now: namely, serious air pollution caused by sulfur/nitrogen oxides. The use of LNG was seen as the answer. Also important is the fact that natural gas-fired power plants feature outstanding generation efficiency, which can offset the costs of LNG compared with alternative fuels.

In addition, these public utilities were allowed considerable monopolistic control of power and gas supplies, which meant they could absorb the price risk by passing on the extra costs to the consumer in the form of power and gas rates; because they could capture all demand within their service areas automatically and monopolistically, the quantitative risk was annulled insofar as it remained within the range of demand available in their service areas.

2. Changes in Both Supply and Demand

During the 1990s, LNG players both on the demand and supply sides, as well as the environment in which they operated, underwent a variety of changes.

Since LNG was first introduced in 1969, the shift to LNG from alternative power sources has been so popular that LNG buyers should have had few difficulties throughout the 1980s in consuming the LNG supplies specified in their contracts. However, along with the shrinking demand for new LNG applications that became noticeable from the early 1990s, LNG trading terms themselves came into question, particularly
by the electricity sector. By that time, the shift to LNG had advanced to the extent that LNG-fired power
accounted for 22 – 23% of the total generated output by electric utilities. From such aspects of the best mix,
the role of LNG has been changing—from a baseload to a middle and middle-peak load source (primarily
due to the take-or-pay clause); this process has eroded operation-based flexibility.

It was around this time that electric utilities, the largest LNG consumers, began voicing concerns about
the take-or-pay clause (hereinafter referred to as “TOP”). While conceding the significance of TOP as a
necessary means of effecting LNG projects, the electric utilities expressed their hope that projects subject to
TOP should not be 100%, but should represent a portion of contract volumes 70 – 80%, for example.

Changing Environment on the Supply Side

On the supply side, many natural-gas-rich countries began unveiling their plans for new and additional
LNG projects.

In Asia, existing LNG-exporting countries began to hammer out new projects, including capacity
expansion. In 1995, Malaysia began Malaysia DUA (II) to serve Japan, Korea, and Taiwan and
simultaneously disclosed that Project TIGA (III) was being planned. NWS of Australia announced a plan to
expand the fourth train (liquefaction unit), and Indonesia, the largest LNG exporter, carried out the
construction of additional trains at the Bongtang terminal. A large number of new projects were announced,
including Sakhalin I and II and the Tangguh project in Indonesia, as well as a new project in Myanmar.

In the Middle East, ADGAS of Abu Dhabi, the pioneer in this region, constructed additional trains and
expanded its exports to 4.30 million tons from 1994. Qatar, keenly engaged in project marketing since the
1980s, and was the first after Abu Dhabi to reach an agreement with a Chubu Electric Power-led consortium
of Japanese buyers. Oman, Yemen, and Iran followed suit by adding their names to the list of would-be LNG
sellers. While its first project was under construction Qatar continued aggressive marketing and financing
efforts for Project II (Ras Rafan) with its initial shipments slated for 1999.
Not all of these projects will see plant construction in the 1990s, which means their supply capacities still remain as potential ones. Yet, regardless of their real or potential capabilities, supply capacities for the Asian market are growing remarkably in response to the consumer requirements of Asia.

LNG supply costs were also drastically reduced. This was a result of technological innovation, increasing plant size (typically by introducing giant liquefaction units), and price competition intensified by a rapidly expanding number of new suppliers. The per-ton LNG plant construction cost has been constantly declining, from the 1970s through the 1990s. For example, the per-ton construction cost of an Oman project, on-stream in 2000, is estimated to be 50% of that of a Brunei project that began supply in 1972.

Due to the ultra-low temperature of LNG (−162°C), transporting it is far more expensive than transporting crude oil or LPG. During the early 1990s in particular, the cost of constructing a 130,000 m³ LNG tanker, the standard capacity at that time, rose above ¥20 billion and then spiked to nearly ¥25 billion, two to three times higher than a VLCC or a crude oil tanker of the same size.

The spike was attributed primarily to a long list of new tanker construction orders, including eight tankers to serve North West Shelf (NWS), Australia, which started shipments in 1989, and two to serve Alaskan projects. Another reason for the price spikes was that Japanese shipbuilders constructed all LNG tankers built since the mid-1980s. In short, the price spike reflected a tightening of supply and demand. Later, however, a number of shipyards affiliated with Korean conglomerates started LNG tanker construction, which triggered a fierce struggle for orders and sent the price plunging to as low as around ¥15 billion. In addition, the introduction of larger tankers greatly contributed to reducing the cost per DWT.

Emerging Signs of a Changing Financial Situation

While all these changes were taking place, the finance system was changing as well. Of the seven projects from which Japan received LNG before 1997, when supplies from Qatar Gas were not available, all but the Alaskan project were funded with participatory loans by the Export–Import Bank of Japan. The most popular finance system for Japan’s LNG projects had so far been the so-called “purchase-and-finance
package system.” This system was arranged by trading companies who served as the intermediary between
Japanese government-affiliated banks and Japanese LNG customers. The customers agreed to purchase
100% of the volume. This package system was employed even in the Malaysia DUA (II) project, which
shipped 4.25 million tons to Korea and Taiwan out of total contract volumes of 7.45 million tons.

Qatar Gas, the newest project built to serve Japan, was successfully funded with the conventional
“purchase-and-finance package system,” though the specific methods of financing the project reportedly
involved lengthy and heated discussions, with the major point of debate being how to handle political risks in
the Middle East. The package system has been adopted by none of the subsequent LNG projects, principally
because no Japanese buyers participated in either the Ras Gas or Omani projects at the financing stage.

At that time, the generally accepted view in Japan was that an LNG project involved such huge capital
outlays that it could only be financed by the “purchase-and-finance package system,” a Japanese invention.
Some even boasted that “no project could be financed without the participation by of a Japanese firm as the
buyer.” The cost reduction described previously represented a crucial factor in the defeat of this sort of
arrogant thinking. Moreover, this cost reduction even permitted projects to be initiated without securing
commitments from potential buyers to purchase 100% of output. The Asia/Pacific region is therefore set to
see the emergence of actual production capacity as opposed to potential production capacity.

Public Utilities Feel the Limit of Risk Taking

A major change also occurred on the demand side; namely, the shrinking growth of LNG demand, down
from an average 8.0% during the 1980s to 4.1% in the 1990s.

This was primarily because the shift to LNG was basically completed by the early 1990s in the electricity
sector and by the mid-1990s in the city gas sector. Entering the 1990s, in the electricity sector, LNG-fired
power accounted for 22% of output generated by electric utilities. The Electricity Utility Industry Council, an
advisory body to the Minister of MITI, unveiled a policy stipulating that to increase the share of LNG-fired
power further would be undesirable, meaning that further growth of LNG consumption should depend on
electricity demand. The problem however, is that since the beginning of the 1990s, electricity demand growth itself plunged by half, from an average 4.4% per year during the 1980s to 2.2% in the 1990s (in terms of output generated by electric utilities). Naturally, the LNG demand growth is destined to shrink further.

In the city gas sector, entering the 1990s, Tokyo Gas, Osaka Gas, and Toho Gas completed shifts to natural gas one after another. As a result, the share of LNG/natural gas in city gas jumped from 76% in 1990 to 87% by 2000. This means that as with electricity, further growth in LNG demand in the city gas sector can be expected only within the range of city gas sales growth. (Despite signs of changes noted at this time, LNG is not the only city gas feedstock fuel; LPG is also utilized to adjust heat quantities. Given the shrinking growth of city gas sales, from 5.1% in the 1980s to 4.1% in the 1990s, the rate of LNG demand growth should be expected to fall as a matter of course.

However, the situation in place after the 1990s has proven quite different from that sketched out in the recommendations of the Electricity Utility Industry Council.

As previously mentioned, during the 1990s electricity demand grew by 2.2%. LNG demand for electricity generation, which was supposed to increase correspondingly, actually grew 3.4%, with LNG’s share of the electric utilities’ power mix rising from 22% to 26%. This outcome was related to the presence of TOP, as electric utilities had to take the volumes specified under TOP at the expense of what they believed to be the best mix. LNG use was increased by greatly overrunning adequate limits in terms of both national energy security and the best power mix, and this obviously hinders the elastic operation of not merely LNG but also of other power sources. This is the primary reason for the vocal demands of electric utilities for TOP revision. Simply put, they have confessed to having reached the limit in terms of quantitative risk.

At the same time, electric and gas utilities have been subject to extensive deregulation since the mid-1990s. The principle of competition was introduced into the power and gas businesses under the Electric Utility Industry Law and the Gas Utility Industry Law as amended in 1995. These two industry laws were further amended in 1999: electricity retailing was deregulated and the scope of city gas liberalization was broadened. As a result, about 30% of the sales amount in the power and gas industries were deregulated or
subject to competition from rival suppliers and/or alternative fuels, and the government is currently considering ways of widening the scope of this liberalization even further.

Electric and gas utilities alike must obviously seek the least expensive LNG. To assume all of the price risk would threaten their very survival. Given the mounting uncertainties of power and gas demand in the future, taking the “quantitative risk” becomes ever more difficult.

Amid this changing environment, customers’ concept of LNG procurement has also changed. As they put the highest priority on the security of supply, they believed long term contracts to be unavoidable; economics and contract flexibility were therefore given secondary priority, and TOP and prices higher than those in the West were accepted. While the importance of supply security remains unchanged, customers now place a higher priority on economics and contract flexibility.

A simple explanation of the present situation can be described briefly as follows. Those on the supply side have a growing surplus capacity. Since they wish to sell as much capacity as capacity to as possible, they are willing to start up projects even if LNG prices are low. Those on the demand side want the lowest price possible, but do not want to commit to purchasing a fixed amount, particularly in large quantities. This suggests a point of agreement at least in regard to redistribution of price risk, if not from in terms of quantitative risk.

3. Cheap China-bound LNG Surfaces

On August 12, 2002, an Australian LNG consortium managed to secure a supply agreement signed by China’s first LNG receiving terminal in Guangdong. Its contract term is 25 years, from 2005 – 2006 onward. One-third of these imports will be supplied to Hong Kong for power generation and residential/commercial uses. Also, with equity participation of 25%, CNOOC (China National Offshore Oil Corporation) is reported to be about to establish a joint venture with the Australian NWS project to supply LNG to the Guangdong terminal.
On September 26, another industry player, the Indonesian Tangguh project, won a contract to supply LNG to a terminal to be built in Fujian; under this agreement 2.60 million tons will be supplied per annum for 25 years. Construction of the receiving terminal will start in 2004, with operation slated for 2007. The terminal will supply LNG to two gas-fired power plants and five neighboring cities.

According to BP, a leading member of the Tangguh project, a partner in the Fujian terminal construction and a one-sixth shareholder in the Australian NWS project, the two LNG terminals will play a vital role in China’s natural gas policy, which aims at quadrupling natural gas demand by 2010.

What is most surprising about the LNG projects in China, which have progressed rapidly in a short period, is the low price of the LNG. As mentioned above, Guangdong awarded its contract to the Australian NWS project, but only after price bidding by a handful of selected and promising projects. According to HSBC, a UK-based bank, the prices tendered were $1.80/MMBTU by Tangguh and $2.05 by NSW. Even the highest bidding price, offered by Ras Gas, remained at $2.35 (CEDIGAZ NEWS REPORT, August 19 issue; though not specified, these should be FOB prices.) Some press reports put these bidding prices at an estimated $3 ex-ship (ex-ship contract basis) in terms of current crude oil prices.

In comparison, reflecting the high crude oil price level, LNG delivered in Japan was priced at an average of $229.26/ton in FY2001, or about $4.4/MMBtu. Given the difference between ex-ship and free-on-board contracts and such unknown factors as the crude oil price level, on which China’s bidding prices were based, a simple comparison is difficult, and yet the prices offered to China seem extraordinarily inexpensive.

Outside China, on August 22, after a yearlong negotiation, Petronet Project of India reached an agreement with Ras Gas of Qatar on the price offered to the Dahej LNG terminal. This project, to receive 5.00 million tons of LNG yearly, has various devices to curb the impact of crude oil price volatility. For instance, it puts the benchmark price of crude oil at $18/bbl. When the crude oil price stays at this level throughout a year, Petronet will pay $1 billion to Ras Gas, translating into $200/ton.* (*Note by author: This represents a figure of $3.85/MMBTU and this appears somewhat questionable.) While the LNG price is determined by linking it to JCC, it is reported that, with the ceiling and floor prices fixed, the price fluctuates.
within a range between $2.03/MMBTU (when crude oil was priced at $16/bbl) and $3.04 (when is was priced at $24/bbl). (Figures from “Arab Oil & Gas;” September 1 issue.) This price, which is under an ex-ship contract, appears very cheap even when taking into account the distance between Qatar and India’s West Coast.

Meanwhile, the October 1 issue of “Arab Oil & Gas” reported that the ceiling of crude oil prices was narrowed to $21 – 22, from the previous level of $16 – 24; this shows that the Indian negotiators are tough enough to renegotiate a previously settled agreement.

4. Risk Redistribution Set to Move Toward Further Expansion of LNG Use

Electric and gas utilities in Japan, the first Asian country to have introduced LNG and still the world’s largest LNG importer, have shown irritation whenever other countries have introduced LNG and are ready to receive LNG supplies. This irritation is a reaction to projects originally designed to supply Japan now taking advantage of their surplus capacities by serving new LNG markets.

Additional explanation may be needed here. To start up an LNG project involves astronomical investment (the Australian NSW project, for example, which started shipments in 1989, reportedly required approximately ¥1 trillion in investments). To finance such a project through investments, not merely the sellers but also the buyers (namely, the Japanese customers), are required to share appropriate risks. These risks are in such forms as commitments to securing massive amounts of demand, long-term contracts lasting 20 to 25 years, take-or-pay clauses (quantitative risk), and higher prices than those paid by Western customers (price risk). The projects they brought into existence by taking such formidable risks are now providing their surplus production under spot or short-term contracts to new LNG markets and Western consumers, who take no risks. This fact just vexes and is a source of frustration to the Japanese customers.

The agreement recently concluded with China shocked Japanese customers in a different way and to a much different degree, largely because of the unbelievably cheap contract price (although just how cheap is unknown to those outside the deal, as we are) As we have seen, the startup costs of LNG projects have been
drastically reduced in the past ten years or so, as the prices tendered for the Guangdong project prove. Simultaneously, it appears reasonable to assume that the risks involved in such projects have also decreased, and it is quite natural for Japanese customers to demand that the degree to which they are involved in risk taking be reviewed accordingly.

A New Risk Distribution Model to Incorporate Price Cuts and Flexibility

Under these circumstances, the contracts of the Malaysian SATU (I) project were renewed in March this year.

Since 1983 this project has supplied 4.80 million tons a year to Tokyo Electric Power (TEPCO) and 2.60 million tons to Tokyo Gas (TG), all ex-ship (contracts under which the seller delivers LNG to the terminals designated by buyers). As a result of renewals, part of the contract term was set as short as four years (during which TEPCO would take 700,000 tons and TG 500,000 tons). The long-term portion was also shortened to 15 years, down from the previously agreed 20 years. Concurrently, TEPCO and TG alike would buy 1.20 million tons and 600,000 tons, respectively, under FOB (free-on-board) contracts, which would be transported by their LNG tankers. On this occasion the Japanese customers managed to increase the flexibility of the contracted amount. DQT/UQT (allowance of quantitative downs/ups) reportedly increased to around 20%, up from the conventional level of around 10%. Thus, the impact of TOP was effectively reduced.

Some press reports indicated that an agreement was reached on a price cut of around 5%, and these contract renewals can be seen as successfully redistributing the price and quantitative risks.

However, the latest contract renewals did not end in one-sided risk-relief for buyers. As a result of the FOB contract-based volumes introduced, buyers now share transportation risk, which was previously assumed in full by the sellers. This additional risk-taking is, of course, expected to yield returns. This arrangement should be seen as furnishing both sellers and buyers with a starting point from which they can move toward a new risk distribution model.
TEPCO and TG have negotiated the Australian Darwin project, scheduled to start up in 2006, in parallel with the contract renewals with Malaysia SATU. Almost concurrently with the signing of the SATU project renewal, the two companies announced their participation in the Darwin project and outlined its scope. Needless to say, the project succeeded in producing a new risk distribution model. The project, from which TEPCO and TG will take 2.00 million tons and 1.00 million tons a year each, involves a contract term of 17 years and FOB contracts under which the whole contract volumes will be shipped by LNG tankers arranged by the two companies. What is of particular interest is that both TEPCO and TG invested in Darwin LNG Co. This means that TEPCO and TG are the sellers, transporters, and buyers. In the capacity of sellers, they take part of the price risk in anticipation of returns. In the capacity of transporters, they take the transportation risk while trying to slash transportation costs. On the other hand, in the capacity of buyers, they ease both the quantitative and price risks. Thus, by participating in the whole of the LNG chain, the buyers work toward optimization of LNG procurement in return for the assumption of risk.

This is seen as an evolution of the new risk distribution model constructed for Malaysia’s SATU.

**Toward Further Expansion of the Use of Natural Gas**

From early 2003, Japanese customers will start a series of price negotiations with Australian NSW, Brunei, and Malaysia DUA (II). TEPCO and TG officials have commented that, “No doubt the price will be down, given today’s supply and demand, the presence of fully depreciated projects, and the falling costs of LNG plants and tankers.” They added that, “Among others, the LNG spot prices payable by Western customers, pricing currently employed by the new start-up projects in Southeast Asia, the purchase prices offered to China, and the bidding should all have a vital impact on Japan. In the years to come, LNG prices are likely to converge into an international price level” Top officials of major industry players, or the principal suppliers, also appear to be conceding that a price cut is inevitable.

Putting the special attention paid to the two Chinese projects and India’s Petronet into perspective, the Japanese buyers are ready for the opening of the second and third rounds of negotiations. They are
determined to incrementally advance the new risk distribution model first unveiled during the Malaysian SATU renewal talks. To what extent will risks be redistributed and how will a new risk distribution model be formed? Further, what impact will the new model have on LNG trade in the Asia/Pacific region, particularly on Japan? Evolution of this new risk distribution model is promising in many ways. It makes it easier to trim generating cost and to realize the best power mix, which ultimately leads to greater electricity demand. It helps gas utilities improve their competitiveness against rival fuels and enables them to promote natural gas use in the industrial sector, where gas consumption remains limited at present, and thus take a step forward from the city gas framework toward new fields of demand. As a result, we can fully expect an increased use of natural gas and LNG demand in Japan.

Conclusions

However, many challenges remain.

How should the quantitative risk redistributed from the buyer to the seller be treated? How can production capacity, reportedly already considerably in surplus, be put to effective use? Fostering sound spot markets may represent one viable option. It is probably impossible to deny the importance of spot markets from the aspect of embedding flexibility in LNG trade, and yet realizing a sound spot market is by no means easy.

Also, the degree of TOP taken as a mortgage by financial institutions when financing could be subject to a new risk distribution model. Isn’t there room to lower the TOP levels? Turning our attention to resource-rich countries responsible for natural gas production, what risks have gas-producing governments and their national corporations shared so far? Are there any risks that should be redistributed among such governments and their state-run enterprises? Are there any risk-sharing mechanisms suitable for facilitating upstream investments?

The list of challenges is long. If, as it has been said, greater LNG use benefits not merely sellers and buyers but also the national economies of LNG-exporting and importing countries, all stakeholders should
spare no effort in entering into constructive discussions designed to solve the great many challenges that lie ahead.

IEEJ intends to continue to observe the situation and provide opportunities for such discussions.

(References)

Concepts helpful in considering new pricing formula

- PETRONAS (Muri Mohammed, Vice President for Gas):
  Oriented toward a crude oil price-free mechanism; talks are under way with customers on fixed pricing.
  (Stated at SPEC 2002)

- Osaka Gas Co. (Yoshikazu Koyama, Managing Director):
  The following formula is proposed as an option.
  Linkage to crude oil should be limited to the “natural gas price” at wells, with liquefaction and transportation to be charged in a lump sum (cost + fee) system. Namely, the formula can be expressed as follows:
  “LNG price = Natural gas price at wells (linked to crude oil) + the lump sum incurred in gas processing and liquefaction + the lump sum incurred in transportation.” (As stated at the World Gas Congress 2000)

- Petronet Project of India:
  Though JCC-linked, the price is designed to fluctuate within a range of $2.03 (when crude oil is priced at $16) and $3.04 (when oil is at $24). Petronet have already reached an agreement with Ras Gas (According to “Arab Oil & Gas”)

- Guangdong Project of China:
  Given that “a” in P = aX + b is set much lower than that in the pricing formula applicable to Japan, its resultant price is expected to fluctuate within a very narrow range. (Unconfirmed information)

- Europe (Continental): LNG prices are linked to heating oil, heavy fuel oil, coal, etc., (at levels competitive to rival fuels in burner tip price terms).

- The United States: The price is determined by linking LNG to NYMEX futures and Henry Hub.

New pricing formulas under consideration

- To lower the ratio of crude oil-linked portion by increasing the ratio of fixed elements (Koyama type
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proposal = In search of price cuts and stabilization

- To set “a” in \( P = aX + b \) low enough to achieve the resultant price nearing a fixed price (China/India type = In search of price cuts and stabilization)
- To employ the coal price, the coal/heavy fuel oil/crude oil basket price, the electricity retail price, etc., as price indicators (Continental Europe type, to make LNG competitive to rival fuels used in electricity generation)
- To employ petroleum products, such as heavy fuel oil and kerosene, as price indicators (Continental Europe type, to make LNG competitive to rival fuels used in town gas production)
- To link LNG to NYMEX/IPE futures and the like (How can price volatility be curbed?)

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