Evaluating Natural Gas Import Options for the State of Hawaii

Prepared for
The Hawaii Energy Policy Forum
The Hawaii Natural Energy Institute
&
The Office of Hawaiian Affairs

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Honolulu, Hawaii
A Member of the FACTS Global Energy Group of Companies

April 2007
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FACTS
List of Abbreviations

AAGR average annual growth rate
ANWR Arctic National Wildlife Refuge
ANS Alaska North Slope
b/d barrels per day
bcf/d billion cubic feet per day
bscf/d billion standard cubic feet per day
BTU British thermal unit
cf/d cubic feet per day
cm³ cubic meters
DBEDT Department of Business Economic Development and Tourism
EIA Energy Information Administration
GW gigawatts
GWh gigawatt hours
HECO Hawaiian Electric Company, Inc.
IGCC integrated gasification combined cycle
IEA International Energy Agency
IPP independent power producers
IRP Integrated Resource Plan
kb/d thousand barrels per day
km kilometers
ktoe thousand tonnes of oil equivalent
KWh kilowatt hours
LNG liquefied natural gas
LPG liquefied petroleum gas
LSFO low sulfur fuel oil
MECO Maui Electric Company, Inc.
mmb/d million barrels per day
MMBtu million British thermal units
mmmscf/d million standard cubic feet per day
mmtoe million tonnes of oil equivalent
mmtoe/d million tonnes of oil equivalent per day
mtpa million tonnes per annum
MW megawatts
scf standard cubic feet
toe tonnes of oil equivalent
tcf trillion cubic feet
tscf trillion standard cubic feet
TWh terawatt hours
USWC United States West Coast
Acknowledgments

The FACTS team for this study was led by Mr. Shahriar Fesharaki who worked in conjunction with Dr. Jeff Brown, Dr. David Isaak, Dr. Kang Wu, Mr. Robert Smith, and Bulganmurun Tsevegjav. The project was supervised by Dr. Fereidun Fesharaki, Chairman and CEO of FACTS Global Energy.

During the course of completing this study, FACTS Inc. conducted numerous interviews with contacts in Hawaii, on the mainland US, and in the Asia-Pacific region. There is a long list of individuals that we owe a debt of gratitude and would like to thank them for their assistance which proved invaluable. We would also like to thank Terry Surles and Sharon Miyashiro of the University of Hawaii, and Mark Glick and Yuko Chiba of the Office of Hawaiian Affairs for their financial contributions and inputs into the study. In addition, special thanks go out to Paul Britton at EnerSea Transport L.L.C., Rob Bryngelson at Excelerate Energy L.L.C., and John Tantlinger and Steve Alber of DBEDT for providing valuable data which was used extensively throughout the report. Overall, we trust that this study will yield useful insights as to the future prospects of LNG in the State of Hawaii.
Introduction and Overview of Findings

The prospect of bringing natural gas, particularly liquefied natural gas (LNG), to Hawaii has been discussed at various times in the past, but has been largely dismissed due to high costs. However, a decline in costs in key parts of the LNG chain—such as liquefaction and shipping—has made LNG more affordable. In recent years, the LNG market has undergone a dramatic transformation. From the end of the 1990s to 2005, fierce competition among suppliers to secure markets led to dramatic changes such as lower crude oil linkages and more flexibility in Asian LNG contracts and pricing formulas. However, with the sharp increase in oil prices over the last few years and the tightening of the global LNG market due to strong demand for natural gas, sellers are now trying to recapture some of their lost gains. Even with the change to a “sellers’ market” LNG can be competitive with oil products in Hawaii’s power sector and clearly deserves a close look as Hawaii considers its future energy strategy.

This report provides an update on the state of the regional LNG market and to examine the advantages/disadvantages of bringing LNG to Hawaii in the context of recent market developments. In a new angle to the 2004 study, we also look at the possibility of compressed natural gas (CNG) imports into Hawaii. This section provides a brief introduction to the LNG market and a general overview of the findings of this study.

LNG: Characteristics and Background

- LNG is natural gas that has been cooled to -256 °F, at which point it liquefies and occupies 1/600th the volume that it does in its gaseous state.
- LNG is not pressurized or flammable in its liquefied state.
- The first LNG trade in the Asia-Pacific region was between Alaska and Japan, beginning in 1969.
- The major suppliers in the Asia-Pacific region are Australia, Brunei, Indonesia, and Malaysia. Russia (Siberia) is expected to join this group in late 2008.
- Approximately 2/3 of the 158 million tonnes per annum (mtpa) LNG market is in the Asia-Pacific region, but both the US and European markets are set to grow quickly over the coming decade.
LNG: Possible Hawaii Demand Scenarios

- As reflected in the figure below, power would likely dominate LNG use. According to our estimates, if all of the major oil fired power plants on Oahu were to be converted to gas, Hawaii would require approximately 1.40 million tonnes (mt) of LNG in 2013 (a hypothetical date for first imports) for use in power generation. This would grow to 1.48 mt by 2020.

- In comparison to consumption in the power sector, the Oahu utility gas market is likely to be quite small (an estimated 66,734 tonnes in 2013). However, there is certainly a lot of room for growth as the price of utility gas may be reduced with LNG imports.

- Over time, there is the possibility that other uses may emerge, including compressed natural gas (CNG) for vehicles, neighbor island use, and reforming natural gas into hydrogen for fuel cells.

![Likely and Possible LNG Demand 2010-2020](image)

Source: Calculations based on information provided by DBEDT

- While LNG supply is tight in the current market, it should be noted that this tightness is not reflective of overall reserves and is more of a reflection of increased demand and a squeezed contractors markets. There is a large amount of “stranded” gas in the Asia-Pacific region which could supply Hawaii, including domestic gas from Alaska. If Hawaii chooses to sign a long-term contract, it is essentially claiming proven gas reserves for its own use for 20-30
years, which is the typical time frame for a long-term contract. The figure below shows that Hawaii’s reserve requirements (approximately 1.8 trillion cubic feet over the life of a 20-year contract) are relatively small when compared to the proven reserves of major potential suppliers.

**Proven Gas Reserves for Selected Countries as of January 1, 2007**

- Indonesia
- Australia
- Malaysia
- Alaska
- Timor Sea
- Russia (Sakhalin)
- Brunei
- Peru
- Hawaii

Hawaii needs approximately 1.8 tcf to support demand of 1.4 mtpa + demand growth for 20 years.

Source: BP Statistics

**Compressed Natural Gas (CNG):**

- Compressed natural gas (CNG) technology offers an alternative to transporting natural gas instead of using pipelines and LNG. Unlike LNG, where the main costs are in the liquefaction process, the actual transportation of CNG is capital intensive and accounts for about 85% of the total capital costs with the remaining 15% being split between compression and loading at the point of origin and unloading at the final destination. Due to the high costs of the ships, CNG works best in regional markets, i.e., where the buyer and seller are within 2,500 miles or less. Alaska would be a prime candidate for supplying CNG to Hawaii, assuming one could get an exemption for the Jones Act.
While no commercial large-scale trade currently exists, the technology is well known and has substantially less requirements for facilities and infrastructure compared to LNG. It has a lower cost of production and storage compared to LNG, as it does not require an extensive cooling process and cryogenic tanks. Moreover, CNG is geared to satisfying small demand markets and monetizing smaller scale gas reserves.

Transporting CNG to neighbor islands is much more workable than delivering LNG due to the substantially lower infrastructure costs. In addition, if natural gas were to be delivered in the form of CNG into the State, a larger percentage of the transport market could be captured compared to LNG imports as there would be no added costs of converting LNG into CNG.

Advantages of Natural Gas for Hawaii

There are a number of clear advantages to pursuing natural gas imports into Hawaii:

Energy Security

- As illustrated below, natural gas offers the opportunity for substantial diversification away from oil within a decade. Currently, oil is the source of close to 90% of Hawaii's energy consumption.
- If Hawaii chooses to pursue gas imports, it could reduce oil’s share of the primary energy mix by approximately 20% within 4-7 years of a decision to move forward.
- Natural gas may be sourced from stable supply sources, such as Australia or domestic sources such as Alaska.
- HECO could retain the ability to consume fuel oil in the event of an LNG supply disruption, thereby further enhancing energy security.
Environment

- Natural gas is the cleanest of all fossil fuels, compared to coal and oil, which are composed of much more complex molecules and have a higher carbon ratio and higher nitrogen and sulfur content. The combustion of natural gas releases very small amounts of sulfur dioxide and nitrogen oxides, virtually no ash or particulate matter, and lower levels of carbon dioxide, carbon monoxide, and other reactive hydrocarbons.
Using LNG instead of maintaining current fuel plans would reduce the global warming potential of Oahu’s power generation by approximately 25% in 2013 and roughly by an average of 23.5% per annum through 2020. It should be noted, however, that LNG production and transport consumes more energy than oil production and transport, so the true reduction is closer to 15% in 2013 when the entire production chain is taken into account.

Source: Calculations based on information provided by DBEDT
A Potential Bridge to a Hydrogen Economy?

- Title 8 of the 2005 Energy Policy Act coupled with Advanced Energy Initiative and the President’s Hydrogen Fuel Initiative has helped to reduce many of the costs associated with hydrogen production, though a further cost reduction is still necessary for hydrogen to be cost competitive with existing fuel sources.

- Hawaii is arguably among the best sites in the US to explore this technology—electricity generated via geothermal, solar, and wind power has long been viewed as the ideal, albeit currently expensive, emissions free means of producing hydrogen for fuel cells (via electrolysis of water).

- In spite of its promise, the high cost of producing hydrogen and developing a hydrogen infrastructure is a considerable roadblock along the path towards an emissions-free hydrogen economy. There is, however, a possible solution in bridging the gap towards a Hawaii hydrogen economy—natural gas.

- Natural gas is currently the least expensive feedstock for producing hydrogen. However, it should be pointed out that natural gas is not viewed as a viable long-term feedstock for hydrogen production because it is not emissions free, it is not a renewable resource, its price is volatile, and there are competing demands for supply in other sectors (power, residential, commercial, and industrial). Eventually the hope would be to move away from a dependence on natural gas and to produce hydrogen using electricity that is generated from renewable sources.
Competitive Price

- The recent increase in crude prices coupled with tightening of the global LNG market has given suppliers a new sense of bravado with respect to LNG pricing. However, we do see the market easing up a bit around the middle half of the next decade, as substantial new amounts of liquefaction capacity comes onstream.
- Hawaii has some clear advantages over alternative markets. First, Hawaii has a well developed legal structure and a very dependable major buyer in HECO. It is also unlikely to see large-scale deregulation and other potential turmoil which threatens some market players in Asia. Second, the State’s potential demand is relatively stable, and does not see the dramatic seasonal swings which limits the need for storage and allows producers to more fully utilize their capacity throughout the year. Finally, Hawaii’s location between Asia and the emerging market of Mexico and possibly the US West Coast offers potential synergies that were not in existence even a few years ago.
- Among the main disadvantages of Hawaii as an LNG market is that it is a relatively small market with limited growth potential and it may be both expensive and difficult to establish a receiving terminal.
- The following figure illustrates the range of potential costs to supply LNG to Hawaii versus other fuels. We have included the latest LNG prices agreed upon in 2006/07 and assumed delivery to Hawaii. In addition we have included our vision of future prices in the Asia-Pacific region and our forecast of HECO’s LSFO and diesel costs through 2020.
• The high prices achieved through the NWS allocation process and the diversion of Qatari volumes to Korea in 2006/07 has become the new price benchmark in the Asia-Pacific region if one is looking to procure LNG in the next couple of years. The free on board (FOB) prices for the Australian and Qatari deals were approximately $7.10/MMBtu and $9.20/MMBtu, respectively. If we add estimated shipping costs from these two supply sources to Hawaii in addition to our estimated cost of $0.53-0.79/MMBtu for onshore regasification, port costs, and other capital costs we get a delivered ex-ship (DES) LNG price in the range of $9.20-$12.40/MMBtu, with an average price $10.80/MMBtu.

• Our mid-term Asian LNG FOB price forecast for new long-term contracts is around $6-10/MMBtu as we see the market easing a bit from its current high. If we add an average $2.00/MMBtu for shipping and onshore regasification costs to Hawaii we would get a DES LNG price in the range of $8.00-$12.00/MMBtu, with an average price of $10.00/MMBtu. We forecast HECO’s LSFO and diesel costs to average approximately $11 and $14/MMBtu (2007 dollars), respectively, from 2010-2020. The figure above clearly shows that LNG prices to Hawaii can compete with HECO’s LSFO and diesel costs if the receiving terminal is built onshore.

• With respect to an offshore terminal we can take our earlier assumption that the mid-term Asian LNG FOB price for long-term supply will be around $6-10/MMBtu and apply Excelerate Energy costs assumptions for supply from Australia, Alaska, and Russia. The DES price of LNG from Australia would be on the order of $9.70-$13.70/MMBtu, while that from Alaska and Russia would be around $8.94-12.94/MMBtu. Under this scenario, the gains in savings from fuel costs compared to LSFO are marginal if gas is sourced from Alaska or Russia and non-existent if the gas is sourced from Australia.

• With respect to the CNG offshore terminal, EnerSea Transport has provided an estimated transport tariff of $4.00/MMBtu from an Alaskan supply source, which is essentially all-inclusive and accounts for the capital costs of all the ships, the transport of the gas from the point of origin to the final destination, and the construction and operation of the offshore storage facility. In order to compete with future LSFO costs, the FOB price of Alaskan gas would have to be somewhere on the order of $5.00-6.00/MMBtu. Given, that CNG requires no liquefaction and hence no cryogenic technology, a price of $5.00-6.00/MMBtu
for Alaskan gas seems within reach as the compression process is relatively straightforward and not a major expense in the overall supply chain.

Economic Impact of the Introduction of Natural Gas to Hawaii

- Hawaii by far and away pays on average the most of any state in the union for electricity and gasoline. If Hawaii were able to secure an LNG contract that was capped at a delivered price of around $9-10/MMBtu, the fuel savings to consumers would be substantial, on the order of tens of millions of dollars per year as the price of gas to the power plants would be on average about $1-2/MMBtu less than the price forecast for LSFO. The savings in the transport sector could be even larger as the retail price for gasoline is currently around $24/MMBtu.

- Constructing an LNG terminal typically takes approximately 3 years. One source estimates that about $100 million would be spent in local communities, but this obviously varies depending on the type of terminal that is selected. For example, if an offshore terminal is selected the number of jobs created would be less.

- At the peak of construction approximately 400 direct contract construction workers would be employed. If you include direct, indirect, and induced jobs (i.e., the employment multiplier—jobs created as a result of the initial job. For example, an employee at the LNG terminal could buy a new house, thereby creating construction jobs.), approximately 891 jobs could be created over the course of the construction period.

- An LNG terminal would have approximately 45 direct full-time employees once it is in operation. Because it is not an established industry in the State, it is not clear what the employment multiplier is for LNG, but if the employment multiplier for the power industry (3.10) and the job multiplier for the petroleum industry (4.63) are taken as guidelines, between 140 and 208 jobs would be created in the overall economy.¹

- With respect to investment, end-use activities are likely the best area in the chain for locally-based investment opportunities. The primary sectors for end-use are power, industrial, residential/commercial, and transportation. Investment in the transport sector is the most

¹ Source: Eugene Tian, DBEDT
intriguing as there will be a need for businesses that can be contracted to convert vehicles and to maintain and service vehicles running on natural gas. Such businesses will also need to cover refueling, which means increasing the number of service stations or piggybacking on existing ones.

The Potential Impact of Natural Gas on the Refineries

• The main disadvantage of natural gas is that it would be disruptive to the existing energy infrastructure. In some ways, this is acceptable because one of the primary goals of the State is to diversify away from its existing dependence on oil. There could, however, be some negative consequences which must be weighed against the advantages.

• Fuel oil comprises a large share of the production of both the Chevron and Tesoro refineries. The refineries could respond in a number of ways if a large portion of the fuel oil market is displaced by natural gas, including changing their crude slate, upgrading to produce higher value products, and exporting to other markets. While it is possible that one refinery may shutdown it is by no means a guarantee.

• Whether natural gas comes to Hawaii or not in the longer term, both refineries face challenges in terms of changing environmental specifications (sulfur standards continue to tighten everywhere and the refiners have limited ability to cope with these), scale (the refineries are on the small side), and high operating costs (industrial business in Hawaii is difficult). These challenges remain irrespective of natural gas entering Hawaii.

Summary

• If Hawaii was developing its energy infrastructure from scratch, natural gas whether in the form of LNG or CNG would be an ideal fuel, especially given the available options. It would allow the State to limit its dependence on oil, it is clean burning, and it could serve as a useful ‘bridge’ fuel as the State looks to develop other technologies, such as fuel cells. On top of this, natural gas is price competitive with alternative fuels that are currently being consumed in the power and transport sectors.

• Of course, Hawaii is not developing it energy infrastructure from scratch. Natural gas would displace existing fuels, and as a result its introduction could be disruptive to the existing infrastructure, including the possible closure of a refinery although the refineries face
challenges even in the current environment.

- To conclude, Hawaii missed the boat on procuring “cheap” natural gas in the form of LNG, as the market has recently switched in favor of the sellers. However, given the current prices paid by HECO and our price forecasts for LSFO and diesel, we believe natural gas in the form of LNG can be competitive if the terminal is built onshore. An offshore LNG terminal using the Excelerate Energy’s business model is cost prohibitive given the current market. The best solution in terms of economics, security of supply, and possible use for the neighbor islands would be to import CNG from Alaska via EnerSea Transport’s V-ships.
Chapter 1
Why Natural Gas?

This section of the study lays the framework insofar as why Hawaii would consider importing natural gas. The chapter begins by looking at Hawaii’s current primary energy mix and then goes into a brief description of natural gas and a discussion on why natural gas has become a fuel of choice in the last decade or so. The latter half of the chapter discusses FACTS’ long-term oil forecast and how future oil prices will impact natural gas prices in the US.

Hawaii’s Primary Energy Mix

By almost any measure, it is evident that the State of Hawaii is hugely oil dependent, relying on oil for almost 89% of its primary energy in 2004 as illustrated in the figure below. Coal, another hydrocarbon-based fuel, accounts for about 6% of Hawaii’s primary energy, while renewable fuels satisfy approximately 5% of the State’s primary energy demand.

![State of Hawaii Primary Energy Fuel Mix: 2004](image-url)

*Note: Solar includes wind and solar heated water. Source: DBEDT preliminary data for 2004.*
Oil has always been a dominant fuel in Hawaii’s energy mix. Over the last 45 years oil has accounted for a minimum of 81% (1962) and as much as 92% (1989) of the primary energy mix. Why has this ratio stayed relatively stable over the last half century? Essentially, the answer lies in the versatility, accessibility, and price of oil when compared to competing products. While the State has seen some penetration in the power sector by other fuels, such as coal and geothermal, the transport sector still essentially remains fully dependent on gasoline and diesel as there are currently no economically viable, large-scale alternatives.

Given the State’s physically remote location and its dependence on oil for approximately 89% of its primary energy needs, it is no wonder that Hawaii’s policy makers (as well as their constituents) have long called for diversification and the development of non-traditional fuels to drive the State’s economy. While oil will likely continue to play a substantial role in Hawaii’s energy mix for the coming years, its share can be reduced through the continued introduction of new fuels, particularly in the power sector, where there are viable substitution choices. Fuel diversification is a standard energy policy of many industrialized consuming nations, particularly those that are heavily dependent on imported energy sources such as Hawaii. For example, Japan has seen its dependency on oil products drop from 75% in 1975 to around 47% in 2006, mainly in response to the first oil shock in the early 1970s, when prices doubled. Japan has been able to decrease its reliance on oil by increasing consumption of other fuels namely coal, nuclear, natural gas, and to a lesser extent renewables.

One way in which the State can reduce its dependence on oil and the corresponding volatility in prices is to look at large scale substitution in the power sector. On Oahu alone, approximately 79% of the power generated in 2005 was oil based (fuel oil and diesel) with the balance going to coal (17%) and renewables (4%). If Oahu were to substitute all the oil products used in the power sector for another fuel, the contribution of oil to the State’s energy mix would drop substantially, under 70%. Natural gas is well placed to help reduce Hawaii’s dependence on fuel oil and diesel in the power sector, particularly on Oahu. In the US mainland, the majority of powerplants built in the last decade have been gas fired due to the environmental benefits when weighed against other hydrocarbons and also the increased efficiency from gas-fired combined cycle turbines.
Natural Gas: A Brief Description

When energy analysts use the term “natural gas,” they are often referring to pipeline-quality gas: a combustible mixture of hydrocarbon gases. While natural gas is formed primarily of methane, it can also include ethane, propane, butane, and pentane. In contrast, LNG is comprised of almost pure methane and as a result, the heat content of LNG is generally a little lower than pipeline gas. The table below outlines the typical makeup of pipeline natural gas.

<table>
<thead>
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<th>Typical Composition of Natural Gas</th>
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<td>Methane</td>
</tr>
<tr>
<td>Ethane</td>
</tr>
<tr>
<td>Propane</td>
</tr>
<tr>
<td>Butane</td>
</tr>
<tr>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>Oxygen</td>
</tr>
<tr>
<td>Nitrogen</td>
</tr>
<tr>
<td>Hydrogen Sulfide</td>
</tr>
<tr>
<td>Rare Gases</td>
</tr>
</tbody>
</table>

Why Natural Gas?

For a number of reasons, natural gas use has increased substantially in recent decades and this trend is forecast to continue, if not accelerate, in the near future (see figure below).
First of all, liquefied natural gas (LNG) is allowing gas to penetrate markets that were in the past inaccessible because of distance barriers. Developments in both liquefaction facilities and LNG tankers over the past thirty years have led to declining unit costs, thereby increasing the competitiveness of LNG versus other fossil fuels, such as oil and coal. Secondly, governments are looking to reduce their dependence on Middle East oil imports and diversify their national energy supply mix and natural gas often allows them to do this. This is particularly relevant to Hawaii, as we are dependent on oil for approximately 90% of our energy mix, making the State very susceptible to turmoil in the world oil markets. A strike in Nigeria or a war in the Middle East has a direct effect on the price we pay for gasoline, power, and other goods and services. Diversifying our energy sources could help alleviate some of these price fluctuations. Finally, in the power sector, higher efficiencies, lower investment, and operating costs have made natural gas a popular alternative to other fuels, despite its higher fuel cost when compared to coal. This, coupled with the environmental benefits of burning natural gas, makes it an attractive fuel.
Environmental Benefits

Natural gas is the cleanest of all fossil fuels, compared to coal and oil, which are composed of much more complex molecules and have a higher carbon ratio and higher nitrogen and sulfur content. This means that when combusted, coal and oil release higher levels of harmful emissions, including a higher ratio of carbon emissions, nitrogen oxides (NOx), and sulfur dioxide (SO2). Coal and fuel oil also release ash particles into the environment, substances that do not burn but instead are carried into the atmosphere and contribute to pollution. The combustion of natural gas, on the other hand, releases very small amounts of sulfur dioxide and nitrogen oxides, virtually no ash or particulate matter, and lower levels of carbon dioxide, carbon monoxide, and other reactive hydrocarbons.¹

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Natural Gas</th>
<th>Oil</th>
<th>Coal</th>
</tr>
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<tr>
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<td>164,000</td>
<td>208,000</td>
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<tr>
<td>Carbon Monoxide</td>
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<td>Nitrogen Oxides</td>
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<td>Particulates</td>
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<tr>
<td>Mercury</td>
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<td>0.007</td>
<td>0.016</td>
</tr>
</tbody>
</table>

Source: EIA - Natural Gas Issues and Trends 1998

Future Oil Prices and Its Affect on the Natural Gas Market

FACTS’ Long-Term Oil Price Forecast

Oil prices in nominal terms have continued to trend upward over the past few years, reaching historical highs not seen in the past three decades, and exceeding record levels of the late 1970s. However, in real terms, prices are still well below the peak that was reached in 4Q 1979 (see figure below) and the world’s economy seems to grow relatively unscathed. Many had seen this as unsurprising, since oil is a lesser part of the world’s GDP now than in the 1970s. Nonetheless, high prices have been seen to impact negatively on the oil demand growth of some developing countries, especially those which reduced or eliminated product subsidies, and their economies may also slow to some extent due to their high dependency on oil.

¹ [www.naturalgas.org](http://www.naturalgas.org)
Many factors have contributed to the current high oil prices, but the key fundamental factors are: 1) persistent demand growth despite high prices, and 2) the perception of tighter supply and rising costs in the future. In the last few years leading to the current high prices, the unexpected high demand for products led to a sudden reduction in spare refining capacity worldwide. This drove up product prices, bringing with them increases in crude prices.

Apart from fundamental factors, many in the market believe that the crude price has been significantly elevated because of the fear premium. The fear premium is prompted by geopolitical uncertainties in various major producing countries (particularly major exporters) and a lack of supply flexibility due to low excess capacity. There are also allegations that speculative hedge funds inflate prices above what the fundamentals would indicate. The bullish sentiment of the energy market has led to a rise in fund activity in the futures markets, possibly contributing to higher oil price levels.

Recent oil prices have weakened due to a sudden strengthening in non-OPEC oil production, arising as a result of several new projects coming onstream in a relatively short time (compounded by the absence of the widely-expected hurricane disruptions to US production) and weaker growth in demand. The demand weakness is partly due to unseasonably warm weather in the Northern Hemisphere. Furthermore, the fear premium diminished considerably over the past months as
geopolitical tensions in various major producing countries eased and there was an increase in excess capacity, implying greater supply flexibility.

The question on many minds today is whether the recent downward price trend will continue. We feel that prices may move slightly lower in 2007, due in part to a short-lived boost by non-OPEC supply and modest additional OPEC spare capacity. However, going forward, if demand continues to rise, it will be more difficult for supply to meet it. The problem is not so much that the oil is not there, but that it will be more difficult to deliver the oil to the market. Only limited areas can increase production, most notably OPEC countries that are not open to foreign investment. Additionally, some governments that had been open to development have recently restricted access.

Technological limitations, lack of availability of drilling equipment, and shortages of skilled specialized labor will also inhibit supply growth in the near term. As a result, we expect prices to trend upward in the medium term. However, the truth is that we cannot predict with certainty what prices will be in the future. What we can do is project price scenarios and show likely implications.

We present our base-, low-, and high-case scenarios for crude oil prices in the following figure. The base case is the price path we think “equilibrium” prices will tend to gravitate to in the long run. As such, the high- and low-cases should not necessarily be interpreted as separate price paths; instead, they bound the range within which we expect average prices to fluctuate.
Our base-case price forecast for crude oil indicates our current perception of the global oil market. Due to the tightness of supply, we believe that in the long run oil prices must increase to a level that curbs demand growth. The question is what is that price? We feel that real prices have to rise by anywhere from 50% to 100% on the back of moderate economic growth before demand is curbed by much more efficient use and new technologies that will reduce dependency on oil. Of course, we cannot be too sure of the timing, but we think this will happen some time in the middle of the next decade or about ten years from now. After a significant downward correction we expect prices to recover as the underlying oil supply problems have not gone away. Beyond that we see these prices as a long-term equilibrium.

Natural Gas Price Forecasts in the US and the UK

In order to forecast natural gas prices in the US (where gas is traded as a commodity) FACTS has examined the historical trend of natural gas spot prices at Henry Hub (HH) in the US, as compared to WTI marker crude and product prices (gasoil and fuel oil), and developed a method of forecasting spot prices using price forecasts of gasoil and fuel oil. The following graph illustrates the historical evolution of HH, gasoil, and fuel oil prices.
During the last 15 years, natural gas prices at Henry Hub have generally been fluctuating between gasoil and fuel oil prices. This suggests a relatively strong relationship between these prices and indicates that the two product prices can be used to project HH prices. The price ratio of natural gas (HH) to the average of gasoil and fuel oil prices in the US market seems to be mostly stable from 1990 to 2006, and it has been found that a polynomial time trend of the order of two can be used to estimate this ratio. However, it should not be a surprise that in some years this method may not fare well, especially when exceptional weather conditions (like the unusual mild temperatures and weak hurricane season experienced in 2006) resulting in HH prices going well below fuel oil prices or well above gasoil prices. HH prices are likely to trend slightly more towards fuel oil prices, with fuel oil likely to be more of a factor over the next few years, as a result of higher switching with natural gas.

The same method is also applied to the projection of the National Balancing Point (NBP) prices in the United Kingdom (UK). Contrary to the US market, NBP prices in the UK market are likely to trend gradually towards gasoil prices, with fuel oil likely to be less of a factor over the next few years,
as a result of lower switching with natural gas. The following figure illustrates the accuracy of the dual product price method for forecasting natural gas prices, using historical data.

This analysis is aimed to provide an insight into the long-term trends affecting the gas prices in the US and UK markets. Although, the relation between HH prices, gasoil, and fuel oil may at times vary significantly from the historical trend, as was the case in 2006, our vision of the future is that HH prices in real 2007 dollars should hover around the $8/MMBtu level in the next few years, while NBP prices are expected to be close to HH prices, before trending a little higher in 2010. Beyond 2010, we believe that the price ratio of natural gas prices (both HH and NBP) to the average of gasoil and fuel oil prices will decline slowly over time due to competition from other sources, such as coal, etc. This competition will evolve over time with sustained high gas prices. After which, with the oil prices projected to ease from 2015 through 2020, we expect the price ratio of natural gas to gasoil and fuel oil to stabilize. However, prices may rise and fall with oil prices. Due to unseasonably warm weather in the Northern Hemisphere, we expect both the HH and NBP price ratios (with respect to the average of gasoil and fuel oil prices) to be lower in 2007 than the long-term trend and therefore chose a lower ratio for both. Our long-term price forecasts of both HH and NBP are presented in the following figure.
Price Forecasts for Natural Gas ($/MMBtu)

- U.S. Henry Hub
- U.K. NBP

*Actual up to 2006, and forecasts thereafter in $2007.
Chapter 2
Background and Market Familiarization

Natural Gas in the Primary Energy Mix
Historically, natural gas has been viewed by the energy industry as an “ugly duckling,” compared to its more versatile brother, oil. In fact, a number of oil producers simply treated natural gas as a byproduct and flared it, as the cost of processing the gas was greater than its value. Often the negative value of the gas was due to the long distance from demand centers, thereby making it uneconomic to transport via pipeline. Technological innovations, such as liquefied natural gas (LNG), have enabled producers to utilize these previously stranded gas fields, and have contributed to the rise in the international trade of this hydrocarbon. More recently, tightening environmental standards throughout the world have increased the popularity of natural gas, especially in the power sector.

World Primary Energy Consumption, 2005

In 1970, worldwide natural gas consumption was 36 trillion cubic feet (tcf), or about 17% of primary energy consumption (PEC). By 2005, natural gas consumption had jumped to 97 tcf, accounting for 23% of PEC (see figure above). Pipeline gas accounted for 93% of natural gas supply in 2005.

whereas LNG accounted for 7%, making it a relatively small force in overall supply. However, LNG is expected to play a much larger role in the natural gas market, as a number of new and expansion projects are coming online in the next decade, as discussed in subsequent sections.

**Gas Reserves**

Since the mid-1970s, world natural gas reserves have generally increased every year. As of January 1, 2007, proven world natural gas reserves were 6,183 tcf as reported by the *Oil & Gas Journal*. Worldwide, the reserves-to-production ratio (RP ratio) is estimated at 65 years, with higher RP ratios in regions with substantial reserves and low consumption, such as Africa and the Middle East. Please note that these are proven reserves and do not count possible and potential reserves, which would significantly increase the reserve figures. The figure below illustrates the regional distribution of proven worldwide natural gas reserves.

![Proven World Gas Reserves by Region as of January 1, 2007](chart)

The Middle East and Former Soviet Union (FSU) along with Eastern Europe (EE) dominate world gas reserves with a 74% share. The Asia-Pacific region is a substantial consumer, yet holds only 7% of proven gas reserves and these reserves are spread out across the region, hence the popularity of LNG. In North America the situation is somewhat unstable, with depleting reserves (4% of the world total) and the largest consumption in the world. Traditionally, US’ gas consumption has been served by domestic production, along with substantial piped imports via Canada, thereby negating
the need for the more expensive LNG. However, with the production of North American suppliers stagnating, prices have increased from the historical range of $2-3/MMBtu to the $7-12/MMBtu range that we have seen over the last two years. This has influenced the re-emergence of LNG on the domestic gas scene, as LNG is seen as economically viable at US gas prices of $3.50/MMBtu and higher.

A key question in the context of this study is: if Hawaii were to source LNG from the Asia-Pacific region, would there be enough gas available for export considering the region has only 8% of the world’s gas reserves? The answer is a resounding yes. Gas demand in Asia is strong and reserves are comparatively limited on a worldwide scale, yet they are still substantial, especially when looking to export to a small market such as Hawaii. The figure below looks at likely possible suppliers of LNG to the State and compares proven reserves with Hawaii’s current potential demand of approximately 1.4 million tonnes per annum (mtpa).² The figure clearly shows that there are ample reserves available among the possible candidates in Asia (also Peru and Chile) and that exporters should have no problem supplying the gas from their specific projects. The more important factor on assessing the potential of LNG imports into Hawaii rests with the price, not supply availability. This will be addressed in detail in Chapter 5.

Proven Gas Reserves for Selected Countries as of January 1, 2007

Hawaii needs approximately 1.8 tcf to support demand of 1.4 mtpa + demand growth for 20 years.

World LNG Trade

In 2006, worldwide LNG trade grew by 15.3 million tonnes (mt), or nearly 11%, from 2005 levels. The Asia Pacific market accounted for 65% of worldwide LNG trade, or 102 mt. The amount of LNG imports into Asia increased by 11%, mainly because of stronger than expected demand in Japan, Korean growth, and the development of Indian LNG imports that started in 2004. Japanese LNG imports grew by 7% in 2006, or 4 mt, due to Chubu’s Electric nuclear problems and a strong demand for LNG in the industrial sector. By 2020, LNG demand in the region is expected to reach 185 mt. Given its location in the middle of the Pacific, it is important that Hawaii understands the likely direction of the Asia Pacific market as it considers future LNG options.
The figure above illustrates that Europe accounted for about 27% of world LNG trade in 2006, with the major consumers being France and Spain. Europe, with 15% growth in 2006 was a solid contributor to the overall increase in global LNG demand, although the autumn and winter 2006/2007 was exceptionally warm. LNG imports to Spain increased by 3% and reached 18.4 mt (the country is currently the third largest LNG importer in the world), while LNG imports in France, UK, and Belgium grew by 4.5 mt.

The Americas (US, Puerto Rico, Mexico, and the Dominican Republic) accounted for the remaining 8% of LNG demand in 2006. Of this, 12 mt were consumed in the US, while the remaining 1.4 mt were consumed in the other regional markets. In 2006, LNG demand in the US was 7.6% lower than the previous year. The decrease can be attributed to a number of one-off factors, such as the unusual warm weather in 2006, the very mild hurricane season, and therefore the absence of any domestic supply disruption linked to hurricane damages.

The high percentage of LNG trade in Asia can be traced to the distance between demand centers, such as Japan and South Korea, and supply centers in the Middle East, Southeast Asia, and Australia. On the other hand, Europe and the US have always imported less LNG because of adequate domestic reserves or close proximity to supply centers. Economics dictate that the estimated cost of moving gas from the wellhead to the market is cheaper for onshore pipelines, compared to LNG imports, up to a distance of 3,600 km. If the gas pipeline is offshore, then this distance marker decreases to approximately 1,800 km. In the case of the US and Europe, onshore imports were readily available from neighboring countries. However this situation is now starting to change as
domestic production in Europe (the biggest gas market), and in the US declines, and imports from neighboring countries—especially Canada—begin to stagnate. Rising concerns on security of supply in Europe are also pushing for a greater diversification of supply sources for natural gas. The result will be an increase in LNG imports and the race is on to build new terminals.

Although Hawaii’s potential LNG demand is relatively small, increased gas demand in the US (particularly the USWC), as well as in Asia, puts Hawaii in a unique position as it is well placed between the two regional demand centers. Multiple suppliers in Southeast Asia and Australia have signed memorandum of understandings (MOUs) with potential receiving terminals on the USWC and in Baja, California. Having Hawaii as a supply option may also allow potential suppliers to better optimize shipping, thereby lowering costs. There is also the possibility of Hawaii acting as a midway point between the two regions and receiving LNG either on the way to the USWC or during the backhaul.

**Key Players**

As mentioned earlier, LNG demand is poised to increase drastically during the next couple of decades. The industry has responded with a plethora of projects, some expansion projects, and some new, or “greenfield” projects. As recently as 1997, there were only eight LNG exporters worldwide, namely Abu Dhabi, Algeria, Australia, Brunei, Indonesia, Libya, Malaysia, and the US (Alaska). The last nine years have witnessed five other entrants into the market, Qatar in 1998, Trinidad and Tobago and Nigeria in 1999, Oman in 2000, and Egypt in 2005, thereby increasing the number of LNG exporters to thirteen. Eight of the thirteen aforementioned exporters have long-term contracts with Asian customers through to at least 2009, signifying the importance of the Asian market. Currently, Qatar has the largest amount of liquefaction capacity followed by Indonesia, Malaysia, and Australia, etc.

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3 The Sempra receiving terminal dubbed Energia Costa Azul is under construction and expected to come online in 2008.
The table above illustrates a substantial amount of production capacity expected to come online in the next decade. In the Asia-Pacific region alone 104 mtpa will be operating by 2010 (currently operating plus under construction) with the majority of the projects targeting the Asia Pacific market. Indonesia, Malaysia, Australia, and Russia (Sakhalin) have all expressed interest in supplying the USWC markets, thereby making them potential suppliers to Hawaii.

It should be noted that although a substantial amount of capacity is coming online in the Middle East (especially in Qatar and Iran, which share the largest gas field in the world), the primary target of this added capacity is Europe and the Gulf/East Coast of the US. As a consequence, the Middle East is not particularly relevant as a potential supplier from Hawaii’s perspective. In general, Middle Eastern suppliers have shifted their focus away from their traditional markets in Asia and towards
Europe and the Gulf/East Coast of the US because of strong future demand growth in these regions and a desire to balance their export portfolio.

Before proceeding with a more detailed examination of the challenges of bringing LNG to Hawaii, as presented in the following sections, it should be pointed out that LNG would likely be delivered to Hawaii under one of three scenarios. (1) A supplier in Asia, or even Latin America, would deliver LNG cargoes from a single supply source that are solely destined for Hawaii (this is the traditional model). (2) A supplier in Asia/Latin America would deliver LNG cargoes from multiple supply sources to Hawaii (this is the new trend, as it optimizes shipping). (3) A supplier from Asia would deliver to the USWC and drop off some cargo along the way or as backhaul. Each of these scenarios is plausible, according to the companies we have spoken to with equity in LNG projects in Asia and Latin America. However, 1 and 2 are viewed as the most likely scenarios.
Chapter 3

Developments in the LNG Supply Chain

This section of the study provides an overview of the technology that is employed along the LNG chain. While the final stages of the chain are of primary interest to Hawaii, there have been a number of technological developments that have triggered costs savings and have also opened up new possibilities for consumers. In addition, the end of the chapter explores the possibility of compressed natural gas (CNG) imports into the State which could provide a more cost effective solution than LNG imports.

Liquefaction

Natural gas is delivered to the liquefaction plant after initial processing at the well-head, where water is removed and condensate separation normally takes place. The figure below shows a simplified schematic of the liquefaction process. The gas is first treated to remove any remaining water, condensates, and contaminants such as carbon dioxide and hydrogen sulfide, which would freeze out in the liquefaction process and stop it from working. Any traces of mercury in the gas also have to be removed, since mercury will corrode the aluminum, which is used extensively in LNG plants. Liquefaction takes place in the heat exchanger, where the temperature of the feedgas is reduced to negative 161°C, the temperature at which its main constituent (methane) turns into a liquid. The liquefied gas is stored in tanks, until it can be loaded onto an LNG ship for export. After the initial liquefaction, normally, no further refrigeration takes place. This is because storage facilities along the supply chain: from the liquefaction plant, to LNG ships, to the regasification terminal, are adequately insulated.

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1 This chapter draws on FACTS database and sources; CNG: An Alternative Transport for Natural Gas Instead of LNG, Asim Deshpande and Michael J. Economides, University of Houston, Enersea Transport L.L.C. Presentation, Economics of CNG vs LNG Transport, Asia Gas Partnership Summit, Feb 20, 2006.
The basic process used to liquefy the gas is the same as that used in a domestic refrigerator. A refrigerant gas is cooled by compression and released through a valve, which lowers its temperature (called the Joules-Thompson effect). The refrigerant gas is then used to cool the feedgas in the heat exchanger.

There are a number of different processes that are used to apply this principle to the liquefaction of natural gas. The most widely used liquefaction technology is the Multi-Component Refrigerant (MCR) process, originally developed by Air Products and Chemicals, Inc. (APCI). Other companies are now offering processes using a mixed refrigerant. These include Shell’s dual mixed refrigerant (DMR) process and the Axen’s process developed by the Institute Francais des Petroles.

The main alternative to the MCR process is the Phillips Cascade process, first used when the Kenai plant in Alaska came online in 1969. An updated version—the Phillips Optimized Cascade process—was first used in the Atlantic LNG plant in Trinidad and is now being applied in the Darwin project in Australia, the Egyptian LNG project at Idku, and the Equatorial Guinea LNG plant.
Other less widely utilized liquefaction processes include a process developed by the Pritchard Corporation, now a subsidiary of Black & Veatch; this process is used mainly for small-scale peak-shaving plants. Statoil and Linde have also developed their own process, which uses mixed refrigerants and is being installed in the Snohvit project in Norway. Two processes that are no longer available are the Technip process, which was used in the world’s first LNG plant at Arzew in Algeria and the TEALARC process developed by Teal (a joint venture between Technip and Air Liquide), used at the Skikda plant.

**LNG Train Size**

The following figure shows the evolution of LNG train sizes since 1964, when the first commercial LNG plant came into operation at Arzew in Algeria. The three trains each had a capacity of 0.3 mtpa. Train sizes increased as the technology improved and projects took advantage of the economies of scale that could be achieved with larger trains. By the early 1980s, trains had reached 2 mtpa capacity, as APCI designed ever larger heat exchangers, and use was made of frame 5 gas turbines rather than steam turbines.

The next step change was in the mid-1990s, as the use of frame 7 gas turbines enabled Malaysia’s second plant to install 2.5 mtpa trains. By the end of the decade, the size had risen again to over 3 mtpa and the last few years have seen further advances. The largest train in operation as of January 2007 was the recently commissioned Train 4 of the Atlantic LNG project in Trinidad and Tobago with a design capacity of 5.2 mtpa. However, the Qatargas II project is expected to come online in 2008 and will have a single train with the capacity of 7.8 mtpa. This high design capacity will be achieved through the use of frame 9 gas turbines and an AP-X heat exchanger. This single Qatargas II train will have a larger capacity than the original Qatargas three-train plant, which was commissioned as recently as the end of 1996.
Most of the increases in size have come from plants using the APCI process. However, Train 4 in Trinidad employs the Phillips Cascade process and has a capacity of 5.2 mtpa, demonstrating that other liquefaction technologies can also be scaled-up.

It is impossible to say how long 7.8 mtpa will remain the maximum size of LNG trains. It represents a significant step-up in size, a 50% increase over the current largest (Trinidad Train 4) and more than double the size of the trains commissioned just over 5 years ago. However, extensive experience with such large trains will probably be needed before there is a further major step-up in capacity. Qatar is planning at least six trains of 7.8 mtpa and Nigeria LNG has also indicated that its seventh and eighth trains will be of a similar size. A potential problem with trains of this size is the need to find markets for a large volume of LNG over a short period of time. Smaller trains may offer the marketers more flexibility to meet the demands of the market.
Liquefaction Plant Costs

Reducing the capital cost is a central concern for investors in any LNG project, since it typically makes up over 80% of the total cost of liquefaction (with the other 20% being operating costs). Considerable success in keeping capital cost low was achieved between 1995 and 2004. However, the last 2 years have seen a reversal of the downward trend in capital costs. A number of factors have combined to send costs on an upward trend, with some sources suggesting that costs may have increased by as much as 100%.

The level of activity in the LNG industry is clearly one reason for the cost increase. There is more new liquefaction capacity under construction today than any other time in the past and it is not just in LNG where activity is at a record level. Other parts of the hydrocarbons industry, including petrochemicals, are also experiencing a high level of activity. Contractors’ order books are full and in this environment costs inevitably rise as the demand for scarce resources (experienced people, specialized equipment, raw materials) increases beyond the capacity of the industry to respond. The lead times for key items of equipment have also grown, extending the period needed to construct a new LNG plant from an estimated 36 to 39 months to 45 to 48 months. Extended construction periods also add to capital investment costs.

It is difficult to produce consistent data to show how capital costs have been changing. The costs quoted for a project may be based on just the contractor’s costs or they may include owners’ costs (the cost of managing construction), design costs, and/or finance costs.

The following figure is an attempt to establish cost trends in liquefaction plants over the past 40 years. The capital expenditure of each LNG plant has been estimated from published data and the costs have, as far as possible, been put on to a common basis. In each case, they represent the cost of the liquefaction plant including storage tanks, export jetty, and berth. They include the cost of the EPC (engineer, procure, and construct) contract and the owner’s costs but excludes finance costs.
The costs have been averaged over 5-year periods based on the commencement of production. This allows trends to be identified and also avoids breaching the confidentiality of data on some individual plants. The costs are shown in terms of US dollars per tonne per annum (tpa) of production capacity. For example, a 3 mtpa costing $900 million would have a cost per tonne of annual production capacity of $300. All the costs are in real 2006 US dollars. For the period 1995 to 2010 a range of costs is shown as the hatched area on the chart.

The figure illustrates that the capital expenditure per tonne per annum of installed capacity per year ($/tpa) came down from over $500/tpa in the earliest plants to around $350/tpa by the early 1980s, as trains sizes increased and technology improved. The second half of the 1980s saw costs leap, largely because the main investment over that period was the Australian Northwest Shelf plant, which was widely acknowledged to be the world’s most expensive LNG facility in terms of the cost per tonne of installed capacity until recently. The location of the plant in a remote area of north-western Australia, the use of local rather than imported labor, and the timing of the development all contributed to the high costs. Average costs remained high in the first half of the 1990s but, with low oil and natural gas prices in the 1990s, capital investment cost reduction became a key success factor for LNG projects.
The industry responded well to the cost challenge and plants built in the second half of the 1990s cost between $200 and $300/tpa—as much as 50% lower as in the previous five-year period. Further reductions in costs were achieved between 2001 and 2005, with some plants being built for under $200/tonne. However, the buildup of cost pressures resulted in costs for plants now under construction of between $250 and $500/tpa. The very large trains under construction in Qatar are at the low end of the range, while some of the new greenfield plants are at the top end of the range. There are reports that the initial cost estimates for some of the plants currently at the planning stage are significantly above $500/tpa, causing the sponsors to delay a final investment decision (FID) as they review ways of reducing the costs.

The increase in the size of LNG trains was a major factor in the reduction in costs in the late 1990s and the early part of the 2000s. Increased competition between contractors and project licensors also put downward pressure on costs. Technological developments, improved practices in engineering contracting, and changes in design also contributed to the reduction in costs. There have been many claims and counterclaims by process licensors that they can offer lower costs than the competition. However, the available evidence suggests that the choice of technology has not had as great an impact on reducing costs as the competition between the technology providers.

The step change in LNG train size to close to 8 mtpa was, at least in part, an attempt to maintain the downward trend in costs, while the economies of scale are still having an impact, they have been insufficient to overcome the upward pressure on costs from full order books, escalating raw material costs, and a shortage of experienced personnel.

The operating costs of an LNG plant depend on such factors as location, staff levels, and maintenance needs, varying considerably between projects. However, experience suggests that, on an annual basis, they range between 3% and 5% of the initial capital cost of the facility.

Translating capital costs per unit of capacity into production costs requires assumptions to be made regarding such factors as the rate of return required by the investor, the phasing of the capital investment, tax rates, and the period over which the investment is amortized. Approximately $0.30/MMBtu is required to earn a real rate of return of around 12% for each $100/tpa of capital investment. Operating costs average around $0.20 to $0.30/MMBtu. Based on these approximate
estimates, the unit production cost for an LNG plant costing $200/tpa of capacity is around $0.80 to $0.90/MMBtu, but at a capital cost of $500/tpa the unit costs are $1.80 to $1.90/MMBtu. More definitive estimates would require detailed information on individual projects.

**LNG Transportation**

LNG ships are a key part of the LNG chain, providing the vital link between the liquefaction plant and the market. These ships are specially designed to carry LNG, which is kept cold by insulation and the effect of some of the LNG continually boiling-off. The tanks are not pressurized and only one ship in operation has facilities to reliquefy the boil-off gas. The relatively high cost of LNG ships has meant that most have been built to transport LNG on behalf of the sellers or buyers of a designated project. Before 2000, a few LNG ships were ordered by ship owners on a speculative basis, and those that were lost money for their owners as the ships had to be laid-up because of lack of demand.

The increased level of activity in the LNG business, since 2000 has resulted in a major expansion of LNG shipping capacity and the emergence, for the first time in 20 years, of speculative orders. The world fleet stood at 218 ships as of the end of 2006, with a further 134 on order for delivery by 2010. The new ships will increase the capacity of the global LNG fleet by approximately 90%.

Two basic designs of LNG ships (Kvaerner-Moss and Membrane) account for all but six of the LNG ships in operation. All of the ships on order are of one of these two basic designs.

**The Kvaerner-Moss Design**

Ships of this type carry their cargo in spherical tanks constructed from aluminum alloy (two of the early ships had tanks made from 9% nickel steel). The tanks are supported around the equator by a cylindrical skirt, welded to the ship’s hull, with the upper part of the sphere protruding above the deck, giving the ships a distinctive profile. The figure below shows a photograph of the North-West Shearwater (a Kvaerner-Moss ship with a capacity of 127,500 m³), which came into service in 1991 and operates between Australia and Japan. Most of the Kvaerner-Moss ships in operation and on order have between four and six tanks.
The Membrane Designs

Two different Membrane systems are employed in LNG ships in operation, the Gaztransport and the Technigaz. In both, the tanks are built into the hull of the ship with the cryogenic lining of the membrane tank bearing the cargo load and transmitting it to the vessel’s hull. Initially, these two designs were in competition with each other but the companies promoting them merged in 1994 to become Gaztransport & Technigaz (GTT). Both technologies are still available to ship owners. Recently, GTT has developed a new membrane design, which is being used in three ships being built for Gaz de France by the Chantiers D’Atlantique shipyard in France. This new design reduces the thickness of the support and insulation, thereby enhancing the cargo capacity of the ships without increasing its external dimensions.

The following figure is a photograph of the Excalibur, a membrane ship built by the Daewoo yard in Korea that came into service in 2002. It has a capacity of 138,200 m$^3$ and was one of the first ships ordered on a speculative basis in the new wave of interest in LNG that commenced around 2000. Its owner, the Belgian company Exmar, chartered the ship to Enron after the ship-building order was placed, but the latter company’s demise left the ship uncommitted until Suez LNG chartered it.
for 2 years at the end of 2002. The ship is currently on short-term charter to Excelerate Energy, a US company that is using the ship to trade LNG.

**Design of Ships in Operation in 2006**

Fifty five percent (120 ships) of the ships in operation as of the end of 2006 were Membrane ships and 42% (92 ships) were Kvaerner-Moss ships. The remaining 3% (6 ships) were of alternative designs. Four were built in the early days of the industry, using self-supporting aluminum tanks, a design that is no longer available. Two are more modern, having been brought into service in 1993 to operate from Alaska to Japan—self-supporting prismatic (SPB) tanks designed by the Japanese company, Ishikawajima Harima Industries (IHI). Although, the ships have operated reliably over the last ten years, no further orders for this design of ship have been placed, mainly due to the uncompetitive prices offered by the yard.

**Kvaerner-Moss versus Membrane**

In terms of ship operability, and (often) cost, there has been little to choose between the two main designs. The decision rests on the preferences of the ship owner and charterer. However, the recent trend has been towards Membrane ships. One reason is that the Korean yards have been the most successful in securing new orders and these yards now only have a license to build Membrane
ships (Hyundai had a license to build Kvaerner-Moss ships, but now only offers Membrane ships). Membrane ships are seen by some owners as being more suitable for the growing short-term LNG trade. They can be cooled-down faster than a Kvaerner-Moss ship, as happens more frequently in the short-term business, all the LNG is unloaded and the ship’s cargo tanks are allowed to warm-up. When LNG ships are employed on a full-time basis on a fixed trade route, some LNG is left onboard (known as the ‘heel’) to keep the tanks cold and ensure that LNG can be loaded immediately on return to the liquefaction plant without needing to spend time cooling them down. The tanks are normally only allowed to warm-up when the ship goes into dry-dock.

Suez Canal transit fees are lower for a Membrane ship than for a Kvaerner-Moss ship with the same capacity, an important consideration as the trade from the Middle East to Europe and the US increases. The savings are equivalent to around US$0.04 per MMBtu for a roundtrip through the Canal at current transit fees for LNG ships.

**Steam versus Diesel Engines**

The majority of the LNG ships in operation and most of those on order are powered by steam turbines. This differentiates them from most other types of ship that are almost exclusively powered by gas turbines. There have been concerns in some quarters that the industry could be faced with a shortage of marine engineers with experience in steam turbines. Steam turbines are well suited to burn boil-off gas and are very reliable technically, an important consideration in the past, when most ships were employed in delivering LNG under a long-term contract and there were few uncommitted ships available to replace them in the event of a technical problem.

Boil-off gas typically represents around 40% to 50% of the fuel consumption of the ships, with heavy fuel oil providing the remainder. Diesel engines are more efficient, but are considered by some companies to be less reliable. Furthermore, boil-off gas has to be reliquefied or the engine modified to allow it to burn gas rather than diesel oil. However, the industry appears to be moving towards the use of diesel engines. Only two ships with diesel engines were ordered prior to 2004, but 69 diesel powered ships were ordered between January 2005 and January 2007. The 36 ships of over 200,000 m³ ordered for the Qatari projects will all use slow speed diesel engines, which cannot burn boil-off gas. These ships will have reliquifiers on board to deal with the boil-off gas. The other diesel ships on order will use duel-fuel diesel engines that can burn boil-off gas.
LNG Ship Operations
The typical LNG ship coming into service today has an average service speed of 19 to 19.5 knots but can achieve speeds of up to around 21 knots if required to make up for delays due to, for example, bad weather or having to wait for a berth. LNG ships can be loaded and unloaded in 12 hours or less. After adding time for berthing, preparing to load or unload, disconnecting, and returning to sea, they normally spend up to 24 hours in port at both the liquefaction plant and the receiving terminal. The ships are dry-docked for about two weeks every 30 to 36 months. When the ships are dedicated to a project, the dry-docking is, whenever possible, scheduled to coincide with the shutdown of LNG trains for maintenance to minimize the disruption to trade. The early LNG ships were designed for a 20-year life, but they have proved to be much more durable in service. As of the end of 2006, 36 ships had been in operation for over 30 years and the oldest was over 40 years old.

The first LNG ships had a capacity of 27,400 m³, but the size has steadily increased over time. The first 125,000 m³ ship came into service in 1975. The largest ship in operation has a capacity of 154,500 m³ and the largest on order 270,000 m³.

LNG Ship Prices
The prices of LNG ships have varied considerably over time, driven to a large extent by competition for orders amongst the shipyards. The following figure shows the average cost of new ships of between 125,000 m³ and 145,000 m³ capacity, ordered over the last 34 years, and compares it with movements in the cost of very large crude oil carriers (VLCCs). VLCCs are often built in the same construction docks as LNG ships, so the demand for this type of vessel can influence the price of LNG carriers. The prices are the estimated average price of ships ordered in the given year in nominal US dollars.

In the late 1980s and early 1990s, the cost of a 135,000 m³ ship (the largest ships in operation at that time) reached over $250 million. Costs fell steadily during the 1990s and by 2003, the cost of a 145,000 m³ ship (typical of the size of ships being ordered at that time) was between $150 and $160 million. However, price has risen again since, partly as a result of the increasing price of steel and other equipment. In 2006, the shipyards are reporting prices of around $220 million for a 155,000 m³ ship. The prices of the ships over 200,000 m³ ordered for the Qatargas and RasGas projects in
Qatar are reported to range from $230 million for the orders for ships around 210,000 m³ placed in 2004 to $290 million for the most recent 270,000 m³ ships.

Competitive pressures and the price of steel and other raw materials will determine whether ship prices will continue their upward trend or whether we have seen the last of the increases. The level of activity in the LNG industry will continue to exert upward pressure, but the entry of new shipyards, including China, which is currently building its first LNG ships and possibly India in the longer term, should moderate that pressure. It may even result in a downturn, as happened from the late 1990s, when Korean yards began to compete with Japanese yards for international orders.

**Operating Costs**

There are two main elements in the operating costs of an LNG ship: fixed costs, which are incurred irrespective of the employment of the ship, and voyage costs. The fixed costs include crew, maintenance, administration, and insurance, while the voyage costs include fuel used (bunkers and boil-off), port charges, and, where necessary, Suez Canal costs.
The fixed costs vary considerably between operators. Crew costs make up a large proportion of the fixed costs and the way in which the ship is crewed (including the nationality of the officers and deck crew) has a major influence. Operators have been under intense pressure by projects and buyers to reduce the fixed costs, but there is a limit to how much can be achieved without compromising the safety and reliability of operations. The shortage of experienced people is becoming a major concern as the LNG fleet expands at an unprecedented rate and operators compete to find experienced crews for their ships. Fears that LNG ships could become the target of terrorists have increased both the cost of providing security and insurance premiums. The one area where costs savings have been achieved is in administration with larger fleets allowing costs to be spread over several vessels, but the effect is marginal since administration make up only a small part of the overall costs. The cost of operating an LNG ship is estimated between $9,000 and $16,000/day. The challenge is to keep them at this level against the continuing upward pressures.

Fuel costs depend on the round voyage distance. Boil-off gas typically provides around 50% of the fuel needs of steam-engine ships, with the remaining fuel being bunker fuel oil. The FOB buyer pays for the volume of LNG that is loaded onto the ship, which includes the LNG that will boil-off during the voyage, so there is a clear value for the boil-off gas. For the CIF or DES seller, the question arises as to whether the boil-off should be valued at the price of the LNG in the market, the marginal cost of production, or some value in between. Bunker fuel oil costs are determined by the price of fuel oil in world markets. The entire fuel costs of the Qatari ships, over 200,000 m³, will come from the burning of diesel oil in the ship’s engines.

Port costs cover the use of tugs and pilots, and payment to the Port Authority. They vary considerably between ports from as little as $25,000 per visit to a maximum of $300,000. Suez Canal charges are based on the registered tonnage of the vessel. Regular users of the Canal have negotiated discounts that amount to over 40% of the full fee if over 2 mt of LNG is transported through the Canal in a 12-month period. This can reduce the fees by around $0.13/MMBtu for a roundtrip (loaded and in ballast) for a Membrane ship. The higher registered tonnage of a Kvaerner-Moss ship results in its costs being around $0.04/MMBtu higher.
LNG Ship Charter Rates

The number of ships in the LNG fleet is a small fraction of the number, for example, of crude oil carriers. Most of the LNG ships in operation are committed to a project or to an LNG buyer. The result is that there are too few charters (short-, medium-, or long-term) arranged for a market index of LNG charter rates to have been developed, in the same way as it happened for the charter of VLCCs. Information on LNG charter rates comes largely from the few deals where the details are made public or from unpublished information exchanged within the industry.

The available information suggests that LNG charter rates came under downward pressure in 2004 and the early part of 2005, as a record number of ships were delivered into service. The owner of a ship of between 135,000 m³ and 145,000 m³, costing $200 to $220 million is estimated to require a payment of between $45,000/day and $55,000/day to cover the capital cost of the vessel (interest payments, repayment of capital, and return on the equity part of the total capital cost), with the actual rate depending on such factors as interest rates, the share of the investment in the ship covered by loans, and the period over which the cost of the ship is amortized. Adding the $9,000/day to $16,000/day needed to cover fixed operating costs, gives a total charter rate of between $54,000/day and $71,000/day.

In 2003, 20-year charters for new vessels are reported to be fixed at around $65,000/day, but the rate in 2005 appeared to have fallen to just under $60,000/day, partly as a result of increased competition between ship owners and partly because interest rates on loans have declined. Short-term charters (from a single voyage up to a period of two years) tend to be more volatile than long-term charters. When ships were in short supply in 2001, the charter rate for short-term fixings rose to $150,000/day. In 2005, short-term charter rates are reported to have fallen to $30,000/day or less. However, in late 2005 and early 2006, the increase in LNG production, as new liquefaction trains came into operation and the commitment of a number of ships to the 2-month round voyage from the Atlantic Basin to Asia, rates recovered to over $80,000/day. In mid-2006, the rate for short-term charters settled to around $60,000/day and is expected to stay around that level over the winter months as the delivery of ten new ships in the last five months of 2006 covers the additional production expected over that period.
LNG Regasification

Onshore LNG Terminal

Currently, there are over 50 regasification terminals in the world, of which nearly half are located in Japan. The US has five terminals in operation and a handful more that are under construction or in the permitting phase. The main facilities at an onshore receiving terminal include a jetty to berth and unload ships, storage tanks, regasification facilities or vaporizers, and a connection to a pipeline grid or powerplant. There are numerous types of storage tanks in use throughout the world, ranging from single containment, to double containment, to full containment. The tanks are generally constructed of nickel steel to withstand the extremely low temperature of LNG. Full containment tanks offer the maximum protection against failure, which allows tanks to be placed much closer together but costs are substantially increased. If land space is not an issue, it makes economic sense to spread single containment tanks throughout the site. In the case of Hawaii, adequate land space is an issue and thus the more expensive full containment tanks would almost certainly be required.

There are a host of difficulties in building an onshore receiving terminal on Oahu, not the least being that the only suitable site would be Barber’s Point Harbor. Substantial modifications would be needed at the port, as the basin is too small and the depth is inadequate. One way to get around the basin depth is to employ smaller LNG tankers (70,000 m³) whose draft is around 35 feet although this would require a higher number of vessels to be employed to deliver the gas. Currently, most LNG tankers have a draft of around 40 feet and require an extra 6 feet or so of clearance to minimize the risk of the ship running aground. Therefore, the basin would have to be at least 46 feet to receive a typical size LNG tanker, whereas the current depth is 38 feet. There are plans to increase the basin depth to 45 feet at an estimated cost of $55 million, but this will not fully solve the problem as the basin is too small for a typical LNG tanker to maneuver freely. Moreover, even if the port were modified specifically, so that it could receive an LNG tanker, the port authority and the Coast Guard would require a safety zone that could seriously impede any activities in the harbor while the ship is unloading. This would likely disrupt exiting operations within the harbor.

While building an onshore receiving terminal at Barber’s Point faces many obstacles, it should be noted that it is not impossible. The costs of onshore receiving terminals are site specific and a Front End Engineering Design (FEED) study is needed to get a true cost estimate. However, one can
come up with a generic terminal cost by first beginning with the storage tanks. The cost for a 160,000 m³ full containment tank (equal to a bit more than a standard size LNG cargo, which is 145,000 m³ or 60,000 tonnes) is around $80 million. In our discussion with industry contacts, storage typically represents 40%-50% of terminal costs. Therefore, based on two tanks, that would imply a total cost of somewhere in the region of $320 to $400 million for a 2 mtpa terminal. It may be possible that Hawaii could get away with the construction of one storage tank, thereby bringing down the capital cost to $240 to $320 million. However, this does not take into account the substantial costs that would go along with the port modifications, which could range from $55 to $100 million. For comparison purposes, Jamaica recently completed a FEED study in the fall of 2006 for the construction of an onshore receiving terminal with capacity of 1.15 mtpa. The cost estimate had increased to $300 to 400 million from $250 million because of the need for more dredging than originally anticipated and rising labor and material costs.

Offshore LNG Terminal—‘Energy Bridge’

Another option the State of Hawaii could explore is offshore terminals that have recently been introduced in the LNG industry. The world’s first offshore LNG terminal came into service in March 2005. It involves the use of purpose built ‘regas’ vessels that have vaporizers onboard to regasify the cargo. The ships also have a specially designed system to transfer LNG from the ship into a pipeline to shore. When the ship arrives to unload, a connector is dropped through the ship and attaches to a buoy floating about 100 feet below the surface. The buoy, which is connected to a pipeline to shore, is pulled into the ship and the regasified LNG is transferred using a turret system, which has been successfully employed for the transfer of oil in harsh conditions of the North Sea.

The following figure shows an artist’s impression of the Energy Bridge with an LNG ship on station unloading its cargo. In locations where a continual flow of gas is required, two buoys will be provided so a second ship can connect, while the first is completing unloading. The first system of this type has been installed in the Gulf of Mexico, 116 miles offshore the coast of Louisiana.
The cost of the mooring buoy system, the connector, and the regasifiers are around $50 million. Add to that the cost of the ship ($220 million for a conventional LNG ship) and the cost of the pipeline to shore and you are looking at total capital costs somewhere on the order of $300 million. The advantage of a system such as this, is that it would reduce NIMBY (not in my backyard concerns), there would be no need for dredging at the harbor, one could avoid further congestion in the harbor, there are costs savings compared to a land based terminal, and fast implementation. The major disadvantage of such a system in the context of Hawaii is that the offtake would need to be used directly, as there is no suitable natural gas storage mechanism in the State.\(^2\) With Hawaii’s small market, it is unlikely that these ships will be able to unload a full cargo very quickly, unlike major demand centers on the Gulf/East Coast. This would obviously add to costs as an expensive tanker would sit idle for days. Additionally, because of a lack of storage facilities in the State, any delays in deliverability could have profound affects on Hawaii consumers. However, this risk could be mitigated by having diesel oil or naphtha as back-up fuels, as is the case in the small-scale LNG receiving terminal in Puerto Rico.

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\(^2\) In the continental US, natural gas is stored in underground salt caverns or depleted gas fields.
Use of an LNG Ship as Floating Storage

An alternative to the Energy Bridge concept is to moor a conventional LNG ship permanently and install regasifiers onboard. LNG would be transported from the liquefaction plant by a second ship and the LNG would be transferred to the moored ship, which will ‘weathervane’ around the mooring system and effectively act as the LNG receiving terminal, providing storage and vaporization facilities. Plans are at an advanced stage to install this type of system in the Mediterranean Sea, offshore Livorno in northeast Italy.

As with the Energy Bridge concept, the technical feasibility of using such a system will depend on the sea conditions, since transfer of the LNG between the ships would have to be halted in rough seas. The delivery of cargoes will also have to be carefully managed, since the volume of storage in the moored vessel will be the same, or similar, to that of the ship bringing the LNG from the liquefaction plant. Without careful scheduling, there is a risk of insufficient storage to unload the ship or the powerplant running short of gas supply if the vessel is delayed in transit. Capital costs for the scheme are likely to be of a similar order of magnitude as those for the Energy Bridge concept.

The advantages of this type of system are similar to those outlined above for the regasification vessel. Additionally, the moored terminal would have onboard storage, thereby eliminating the offtake problem. The main disadvantages include having a ship permanently moored off of the coast, requiring around the clock security, potential disruption to offshore activities such as fishing/diving, possible eyesore to local residents, and implementing a system that deals with the waves and currents of the coast.

CNG: An Alternative to LNG

Compressed natural gas (CNG) technology offers an alternative to transporting natural gas instead of using pipelines and LNG. One of the leading providers of CNG technology is Enersea Transport LLC based out of Houston, Texas. Their “VOTRANS” technology compresses and cools the gas, which reduces the volume compared to compressing the gas in ambient temperatures. The compressed gas is then placed in specially designed ships that have a containment system made of stacked horizontal or vertical pipes to transport the gas. The technology can be divided into three
parts namely compression, refrigeration, and transportation. Transportation includes the loading, the voyage using the CNG carriers, and unloading.³

Unlike LNG, where the main costs are in the liquefaction process, the actual transportation of CNG is capital intensive and accounts for about 85% of the total capital costs with the remaining 15% being split between compression and loading at the point of origin and unloading at the final destination.⁴ Due to the high costs of the ships, CNG works best in regional markets, i.e., where the buyer and seller are within 2,500 miles or less.

While no commercial trade currently exists, the technology is well known and has substantially less requirements for facilities and infrastructure compared to LNG. It has a lower cost of production and storage compared to LNG, as it does not require an extensive cooling process and cryogenic tanks. Moreover, CNG is geared to satisfying small demand markets and monetizing smaller scale gas reserves.

Given security of supply issues, adequate gas reserves and distance from Hawaii, the most likely economic gas source to supply Hawaii via CNG ships would be Alaska, assuming Hawaii could get an exemption from the Jones Act. Given current possible LNG demand of 1.35 mt (details to be discussed later) the State would require at least 4 ships to move the gas between Kenai, Alaska and Hawaii with a ship coming to port every 4th or 5th day. Unfortunately, as is the case with the LNG option, Barber’s Point is too small to accommodate the CNG ships that would be needed to bring the gas from Alaska, which leaves an offshore option. Under this scenario, five ships would be needed with one ship being permanently moored offshore.

**LNG/CNG for the Neighbor Islands**

Most of the discussions on the possibility of bringing LNG to Hawaii focus on the Oahu market, but it is certainly, technically feasible to bring LNG to the neighbor islands as well. Delivering LNG to the neighbor islands would certainly offer unique challenges, as the markets are obviously substantially smaller than Oahu and it would not make economic sense to build full-scale receiving

³ CNG: An Alternative Transport for Natural Gas Instead of LNG, Asim Deshpande and Michael J. Economides, University of Houston.
terminals on all of the outer islands. However, there is the possibility of using barges to carry LNG from Oahu to various destinations, as is done in Japan, albeit at a high cost.

Perhaps a more workable option would be to deliver natural gas via CNG to the neighbor islands as the infrastructure costs are much lower. EnerSea Transport promotes a barge-based CNG delivery system, based on the same VOTRANS technology and principles used in its ship-based system. The Volume-Optimized CNG barge system (VO-BargeTM) provides solutions for gas delivery needs in the range of <10 mmscf/d to over 50 mmscf/d over transit distances ranging from 50 nautical miles to 500+ nautical miles.
Chapter 4

This section of the study provides an overview of the main terms of an LNG contract. Of course, Hawaii could develop a contract structure that fits its individual needs and priorities, but this is the general framework that most contracts follow. The important thing to remember is that developing an LNG contract is analogous to developing a relationship. Both sides need to signal steadily deepening levels of commitment for things to move forward, and investment to progress.

Main Terms in a Typical LNG Contract

A typical LNG contract, or sales and purchase agreement (SPA), is a definitive contract between a seller and buyer for the sale and purchase of a quantity of LNG for delivery during a specified period at a specified price. Prior to finalizing the full details of an SPA, a letter of intent (LOI), memorandum of understanding (MOU), or heads of agreement (HOA) is typically signed, used as a broad outline to develop the terms for the sale and purchase of LNG. Although LOIs, MOUs, or HOAs outline the broad principles of the agreement, they do not include the details of certain aspects, including pricing mechanism. In most LOIs, MOUs, or HOAs there is likely to be a provision for either the sellers or the buyers to withdraw if an agreement cannot be reached on the details of the SPA.

LNG contracts/SPAs define details and clauses covering specific issues such as those listed below:

- Duration
- Volume
- Free on board (FOB) versus cargo, insurance, and price (CIF)/ex-ship
- Take-or-pay flexibility
- Price
- Force majeure
Other relevant procedures

Duration
Long-term LNG contracts have typically been for durations of 20 years, although some have been for only 15 years and still others have been for 25 years or even longer. Sellers required contracts of this duration to ensure the cash flows needed to remunerate the investment in the facilities and to pay any loans that were raised. Long-term contracts were especially important in the past when there were very few buyers and the seller needed the assurance that there was a long-term commitment to the purchase of LNG. On their part, buyers were prepared to enter into contracts of this duration since they had to pay for their receiving terminals, power plants, and/or gas distribution networks. Additionally, with a limited number of LNG plants in operation, they wanted to be sure of the long-term availability of supplies to meet their customers’ needs.

The last decade has seen an increase in the use of medium- (around 3 to 10 years) and short-term (less than two year) contracts. In part, this reflects the increasing size and flexibility of LNG supply as more liquefaction plants come into service. Furthermore, buyers are finding that their natural gas requirements grow more uncertain as markets are liberalized and there is increased competition in the gas and power markets. As a result, LNG buyers are now often using a mix of contract durations to help manage their demand uncertainty.

Despite the increased use of short- and medium-term contracts, the traditional long-term (20 or more year) contracts continue to dominate the business. Especially, in the case of new greenfield developments, where the investors in the facilities and their financiers still want the assurance of long-term cash flows to pay-back the investment. Although the volume of LNG bought and sold on a spot or short-term basis is increasing, it has not yet reached the level at which sellers can be confident of marketing the output from a new project without some long-term commitments from buyers. However, the increasing size of the short-term market has resulted in some projects going ahead with only a part of the planned production committed on a long-term basis.
Volume

In most SPAs there is a “build-up” period before buyers take the annual contracted volumes. Some buyers need a slower build-up period to meet market growth. For sellers, rapid build-up is important, as build-up volumes provide the early cash flow to remunerate investment.

A contract also provides the buyer with “upward flexibility” and “downward quantity tolerance.” Upward flexibility provides the buyer with the right to receive additional volumes that the seller has the ability to supply. Meanwhile, downward quantity tolerance is the volume the buyer can elect “not to take” without triggering a take-or-pay obligation. Typically the quantity tolerance on older contracts is quite narrow, while some of the newer contracts and extensions have adopted wider quantity tolerances.

FOB versus CIF/ex-ship

In an FOB contract the buyer lifts the LNG from the liquefaction plant and is responsible for transporting the LNG to the receiving terminal. The buyer is responsible for the shipping, either owning the LNG ships or chartering them from a shipowner. Transferring ownership of the LNG occurs as it passes through the flange connecting the ship to the loading arms at the seller’s liquefaction plant.

Under a CIF contract, the seller is responsible for transportation and insures the cargo on behalf of the buyer. Ownership of the LNG transfers from the seller to the buyer at an agreed point on the voyage from the seller’s liquefaction plant to the buyer’s receiving terminal. The cost of transportation and insurance of the cargo is paid by the seller and is taken into account in the price of the LNG.

Under a delivered ex-ship (DES), more common than CIF, the seller is responsible for transporting the LNG to the buyer’s receiving terminal. However in this case, ownership transfers as the LNG passes through the flange connecting the ship to the unloading arm in the buyer’s receiving terminal. The cost of transportation is taken into account in the price of the LNG.
In both FOB and CIF/ex-ship deals, the contract must delineate shipping related issues, including the obligation of a responsible party to provide sufficient LNG tankers to lift the contracted volume and relevant operating procedures.

**Take-or-Pay and Destination Clauses**

A take-or-pay clause is the volume of LNG that the buyer agrees to take and pay for each year. This clause provides sellers with a secure stream of revenue, as it ensures that the buyer does not fail to take its contractually required quantities. The take-or-pay level is typically at least 90% of the contracted quantity in most existing contracts, but some sellers are softening take-or-pay terms in recent contracts. If the buyer does pay for LNG that it has not taken then a make-up right is generated. The buyer is able to lift an equivalent volume of LNG at a later date provided that (1) it has taken the annual contract quantity (ACQ) for the year and (2) the seller has the capacity to produce and, in the case of a DES or CIF contract, deliver the LNG. When make-up LNG is taken, the price is normally the prevailing price at that time it is lifted. If the price has increased in the meantime, the buyer pays the difference between the amount paid as take-or-pay and the value of the cargo when it was actually taken. If the price has gone down the buyer receives a refund from the seller.

Take-or-pay levels are normally one of the most contentious issues in the negotiation of an LNG contract. No buyer wants to have the obligation to pay for LNG that it does not need, but for the seller, take-or-pay guarantees the volumes of LNG that will be paid for each year. The removal of the volume risk can be very important in the financing of the investment in an LNG project.

Although take-or-pay levels are a major negotiating issue for most contracts, it is a provision that is rarely invoked. Indeed, in the last 20 years there is only one reported case where a buyer has paid for LNG that it could not take. There have been other examples where buyers have taken less than the minimum bill, but on these occasions buyers and sellers have been able to negotiate a solution to the problem. For example, after the Asian economic crisis of the late 1990s, Korea Gas saw its downstream customers’ demand for gas drop sharply and, as a result, it could not take all the LNG that it had contracted from Malaysia and Indonesia. It agreed that, for each cargo below the take-or-pay level it did not take, it would lift two cargoes in the future. The Korean economy then made a
rapid recovery and within 3 years Korea Gas had taken both the make-up LNG and the additional cargoes.

Insofar as destination clauses are concerned, most existing contracts limit the buyer’s ability to transfer cargoes to other buyers. Under destinations clauses, some contracts even limit the buyer’s ability to take cargoes to alternate terminals owned by the buyer. Buyers are already requesting more flexible destination clauses and contracts like ConocoPhillips’ Bayu-Undan agreement with Tokyo Gas and Tokyo Electric Power Co. (TEPCO)—where the seller gets a share from certain redirected/retraded cargoes—which will likely increase in the future, as discussed later in this chapter.

**Price**
LNG pricing formulas are discussed in detail in Chapter 5. In this context it should be noted that in addition to the base-price formula, the contract also states procedures for price renegotiation under “a sudden change of circumstances.” Some buyers have a “side agreement” under their long-term contracts (namely the Japanese buyers), which allows for regular price reviews, usually every 4-5 years.

**Force Majeure**
Force majeure is defined as “any circumstance which is beyond the reasonable control of the party affected and prevents or hinders due performance of obligations under the contract and which cannot be overcome by due diligence.” Examples of the events that could trigger the declaration of force majeure include natural disasters, war, actions by governments, and damage to facilities not due to negligence. The full list is normally much longer. Declaration of force majeure allows the party concerned to suspend its performance and obligations under the contract until the problem is solved. Consequently, force majeure is a critical part of the SPA. Each side will typically want as many eventualities to be covered by the force majeure clause and, at the same time, try to minimize the circumstances under which the other party can declare force majeure. A common issue is the extent to which problems downstream of the receiving terminal or upstream of the liquefaction plant can be claimed as force majeure.
The force majeure clauses also define the actions required by the affected party to remedy the force majeure event and the rights of the unaffected party to buy or sell LNG from or to a third party and eventually to terminate the contract if the force majeure is prolonged.

**Other Relevant Procedures**

In addition to these main terms discussed above, the contract includes other relevant procedures and details, such as quality of LNG, measurement and testing of LNG when it is loaded or discharged, invoicing and payment, and the applicable law.

**Recent Trends in LNG Contracts**

From the end of the 1990s to 2005, fierce competition among suppliers to secure markets led to dramatic changes in the Asian LNG contracts and pricing formulas. However, with the sharp increase in oil prices and the tightening of the global LNG market, sellers are now trying to recapture some of their lost gains. The year 2005 constitutes a sort of turning point between the buyers’ market of the previous years and the change turn to a sellers’ market. This leads to the emergence of two phases in “new-style” contracts, in contrast with more traditional “orthodox” contracts below.

**“Orthodox” Contracts vs. “New-Style” Contracts**

“Orthodox” Asian LNG contracts of the past have typically been long-term and on an ex-ship basis, with a price formula that generally exhibits an 85% linkage to the price of crude oil. The crude oil price marker is generally JCC, with the exception of the existing Indonesian contracts with Japanese buyers, which are priced off of ICP (Indonesian Crude Price).

Selected components of the “orthodox” contracts are listed below:

- Prevalence of CIF/ex-ship contracts
- 20 years or greater contract durations
- 90% or greater take-or-pay
- Strict destination clauses
- Minimal seasonal offtake flexibility
- Formula pricing with approximately an 85% crude oil linkage
In contrast, selected components of the “new-style” contracts are detailed below.

**FOB Contracts**

Many of the new contracts are signed on an FOB basis, which gives buyers more control over cargoes and the potential to manage variations in demand. Buyers are able to trade LNG during low demand periods if their contracts give them a resell option.

Due to the uncertainty surrounding market deregulation, it is clear that many Japanese buyers increasingly favor FOB contracts. For example, TEPCO—Japan’s largest LNG importer, which accounts for more than 33% of the country’s total imports—has started using some of its own vessels for transportation, thereby allowing it more control over shipping. The first vessel was operational in October 2003 and the second vessel, dedicated to the Darwin project, started operation at the beginning of 2006. Other Japanese buyers are preparing themselves for FOB contracts as well. In 2007, Osaka Gas has four operational vessels and intends to increase their LNG fleet to six vessels by 2010. Tokyo Gas has 4 vessels and plans to increase the company’s fleet to seven ships by 2011.

**A Combination of Long-Term/Short-Term Contracts**

Trends towards market deregulation and weak demand growth forecasts, particularly in Japan, have driven the buyers’ desire for a combination of long-term and short-term/spot contracts. Additionally, many of the current LNG exporters have amortized their investments and are not required by the financial institutions to solely offer inflexible 15-25 year contracts. Finally, with the start of new receiving terminals on the west coast of North America, Asia Pacific sellers will have access to an alternative market.

**Relaxed Take-or-Pay Levels**

Over time, take-or-pay terms have been relaxed from the traditional 90-95%. Older projects have been able to creatively relax take-or-pay levels by transferring portions of renewed contracts to a short-term basis. Some expansion projects offer a mixture of long-term and short-term volumes to create greater offtake flexibility, effectively lowering take-or-pay requirements on a de facto level. However, take-or-pay terms for greenfield projects, with the exception of internally funded projects, will likely remain high as this is often necessary to finance a project. Examples of contracts with
relaxed take-or-pay levels include MLNG Satu with Tokyo Gas and TEPCO, and MLNG Tiga with a Japanese buyers’ consortium.

Relaxed Destination Clauses
Most existing contracts limit a buyer’s ability to transfer cargoes to other buyers. Buyers are increasingly requesting more flexible destination clauses and contracts like ConocoPhillips’ Bayu-Undan (Darwin LNG) agreement with Tokyo Gas and TEPCO—where the seller gets a share of certain redirected cargoes. Relaxed destination clauses will likely become more commonplace in the future.

Seasonal Offtake Flexibility
Although sellers are generally reluctant to offer seasonal volumes, Korea Gas Corp. (KOGAS) has secured medium-term contracts with MLNG Tiga and NWS that give KOGAS seasonal offtake flexibility. This is an extremely important concession, considering Korea consumes about 70% of its LNG during the October-March period.

Formula Pricing with Lower Crude Oil Linkages
Compared to Asia’s “orthodox” pricing formula, which has an 85% linkage to the price of crude oil, contracts (both new and renewals) agreed at the turn of the new millennium have lower crude oil linkages, especially when oil prices are high. In some cases buyers have achieved a ceiling at prices as low as $25/b. The Guangdong contract is an example of this trend. A contract between India’s Petronet and RasGas carries this trend to the extreme, with a fixed price for the first five years of the contract. However, with the return of a sellers’ market, we have seen sellers negotiating a higher oil indexation, especially in the case of existing plants, while greenfield projects, like Gorgon or Pluto in Australia, accepted a lower linkage at high oil prices in order to make their projects more attractive. The following figure illustrates the trend towards a declining relationship with oil prices for greenfield projects and an increasing linkage for existing plants in recent LNG contracts. It is also worth mentioning that the RasGas to India contractual fixed price is only valid for the first five years of the agreement. It will be followed, after a five-year transition period, by a 75.5% relationship to crude oil.
Selected Details of “New-Style” Contracts

Details of selected “new-style” contracts, which are changing Asia’s marketing traditions and setting innovative precedents, are discussed below.

Phase 1: Contracts in a Buyers’ Market

MLNG Satu to Japan: Under a contract renewal (supplies began in April 2003), MLNG Satu gave TEPCO and Tokyo Gas significant flexibility as compared to the previous 20-year contract on an ex-ship basis. The renewed contract has a combination of long-term (15 years with a provision for a 5-year extension) and short-term (4-year base) volumes as shown in the following table. The two Japanese buyers will use their own vessels to deliver part of the volumes on an FOB basis. The renewed contract includes a regular price review every four years and is believed to have a different price for each category (long-term, short-term, ex-ship, and FOB).
MLNG Satu to TEPCO and Tokyo Gas

<table>
<thead>
<tr>
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<tbody>
<tr>
<td></td>
<td>Long-Term (15 years)*</td>
<td>Short-Term (4-year-base)**</td>
</tr>
<tr>
<td>Ex-Ship</td>
<td>3.2 mtpa</td>
<td>0.4 mtpa</td>
</tr>
<tr>
<td>FOB</td>
<td>0.9 mtpa</td>
<td>0.3 mtpa</td>
</tr>
<tr>
<td>Total</td>
<td>4.1 mtpa</td>
<td>0.7 mtpa</td>
</tr>
<tr>
<td>Grand Total</td>
<td>4.8 mtpa maximum</td>
<td>4.8 mtpa maximum</td>
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</tbody>
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<tbody>
<tr>
<td></td>
<td>Long-Term (15 years)*</td>
<td>Short-Term (4-year-base)**</td>
</tr>
<tr>
<td>Ex-Ship</td>
<td>1.7 mtpa</td>
<td>0.3 mtpa</td>
</tr>
<tr>
<td>FOB</td>
<td>0.4 mtpa</td>
<td>0.2 mtpa</td>
</tr>
<tr>
<td>Total</td>
<td>2.1 mtpa</td>
<td>0.5 mtpa</td>
</tr>
<tr>
<td>Grand Total</td>
<td>2.6 mtpa maximum</td>
<td>2.6 mtpa maximum</td>
</tr>
</tbody>
</table>

*With provision for a 5-year extension. **Review after every 4 years.

MLNG Tiga to Japan: In the face of strong competition in Asian LNG markets, MLNG Tiga departed from their traditional contract structure to secure buyers. In February 2002, Osaka Gas, Toho Gas, and Tokyo Gas signed an SPA with MLNG Tiga that contained a mixture of long-term and short-term volumes for a maximum offtake of 1.6 mtpa for 20 years from 2004 (see table below). Under the agreement, 680,000 tpa (ex-ship) will be delivered under take-or-pay conditions over 20 years. Additionally, the buyers’ consortium takes 480,000 tpa (FOB) under a renewable one-year contract and has the option of taking another 440,000 tpa during the contract period (20 years). The optional quantities (of up to 440,000 tpa) depend upon both the buyers’ needs and the sellers’ availability.

MLNG Tiga to Japan Gas Consortium

<table>
<thead>
<tr>
<th>Japan Gas Consortium</th>
<th>MLNG Tiga (04-2004)</th>
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<tbody>
<tr>
<td></td>
<td>Long-Term (20 years)</td>
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<tr>
<td>Ex-Ship</td>
<td>0.68 mtpa</td>
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<tr>
<td>FOB</td>
<td></td>
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<tr>
<td>Sub Total</td>
<td>1.16 mtpa</td>
</tr>
<tr>
<td>Optional Volume</td>
<td>0.44 mtpa</td>
</tr>
<tr>
<td>Grand Total</td>
<td>1.6 mtpa maximum</td>
</tr>
</tbody>
</table>

*Renewable for up to 20 years.
Bayu-Undan to Japan: ConocoPhillips has an established relationship with Japanese buyers through its Alaska Kenai project, which many believe gave both sides room to easily negotiate a flexible contract for the new Bayu-Undan project. TEPCO and Tokyo Gas are also participating in the Bayu-Undan project, in which they hold a 10.1% share. The two Japanese utilities will receive a maximum of 3 mtpa (2 mtpa for TEPCO and 1 mtpa for Tokyo Gas) on a FOB basis for 17 years starting in 2006.

The contract includes a price formula, which has a lower crude oil price linkage and a portion of it has a fixed price. The contract also permits sales within Japan without informing the supplier, however, sales outside of Japan require the seller’s permission and a 50/50 split on any additional revenue. TEPCO and Tokyo Gas will use their own vessels for transportation, thereby enabling them to resell their LNG.

NWS and MLNG Tiga to Korea: In their 2003 supply agreements, both NWS and MLNG Tiga gave seasonal offtake flexibility to KOGAS in order to satisfy Korea’s increasing seasonal shortfalls. KOGAS is contracted to buy 500,000 tpa (ex-ship) from the NWS project for seven years, starting in late 2003. 100% of the contracted volume will be supplied in Korea’s winter season (generally understood to be October-March). KOGAS’ contract with MLNG Tiga allows it to buy 1.5 mtpa (with the option to buy an additional 500,000 tpa) on an ex-ship basis for 7 years, beginning in May 2003. 80% of the contracted volumes will be supplied in the winter months (October-March) to meet the seasonal increase in demand and the remaining 20% in the summer.

NWS to China Guangdong: The Chinese focused their negotiation efforts on the pricing formula, while keeping an “orthodox” contract duration of 25 years. The contract allowed the Chinese to achieve a lower overall price as well as reduced price volatility through a more limited crude oil price linkage. The Chinese contracted to buy 3.7 mtpa of LNG from NWS beginning in mid-2006 (there is a build-up period). Initially, the LNG will be supplied on a ex-ship basis, and then transferred to an FOB basis once the Chinese have constructed their own LNG vessels.

Phase 2: The Turn Towards a Sellers’ Market During 2005

The market has clearly tightened in the last couple of years and sellers now have the upper hand. This phenomenon, however, has been a gradual progression and the end result is a mix of still...
competitive deals, renegotiations of some deals agreed during the buyers’ market area, and new trends.

**Tangguh to CNOOC:** The FOB contract is for 2.6 mtpa beginning in 2007 for 25 years. However, the startup date will be delayed—perhaps to 2009. The original contract price was even cheaper than Guangdong, as Tangguh at the time was very eager to secure an anchor customer. However, Tangguh, under intense pressure from the Indonesian regulator, BP Migas, succeeded in renegotiating the contract price in May 2006. Indonesia used a clause in the original contract that obligates CNOOC to complete the construction of the receiving terminal by 2007. The terminal was delayed because Tangguh was delayed, but CNOOC by not adhering to the ‘conditions precedent’ gave Indonesia an excuse to raise the price. The outcome of the negotiation is that the LNG ceiling price is $0.70/MMBtu higher than the original agreement, a substantial escalation from the earlier agreed upon level.

**NIOC LNG to India:** The contract between Iran’s NIOC LNG and the Indian consortium of ONGC/IOC/GAIL is for a base volume of 5 mtpa, with an option for an additional 2.5 mtpa, beginning in December 2009 over a period of 25 years. The FOB price is capped at $3.22/MMBtu. A couple of noteworthy features are that the price is fixed for three years and that there is a Brent crude oil linkage instead of JCC. Some buyers and sellers like the option of linking Brent to their LNG price as it allows them to hedge on the futures market and diversify their risk. However, as the deal has not been approved by the NIOC Board of Directors and the High Economic Council, the contract is now considered ineffective by the Iranian government. As such, NIOC does not feel concerned about the $150 million penalty payable to India 12 months after the SPA (late summer of 2006) nor about the deliver-or-pay penalties and wants to renegotiate the price. While India was looking for a discount for the remaining 2.5 mtpa, Iran is now looking for prices of some $6-7/MMBtu on an FOB basis.

**Gorgon to Japan:** Marketing of LNG sales for this 10 mtpa project was done independently by the shareholders of Chevron (50%), ExxonMobil, and Shell (25% each). While ExxonMobil is still marketing its share, Shell has declared that they would deliver their share to North America, where they have receiving terminal capacity. Chevron agreed in December 2005 to sell 4.2 mtpa for 25 years to Chubu Electric, Osaka Gas, and Tokyo Gas. It seems that Chevron wanted to rapidly secure a market for its share and was able to secure sales through a low-price strategy. The FOB
price is bit over $4/MMBtu at current oil prices, which is a substantial discount compared to most recent deals.

**Northwest Shelf Allocation Process:** Instead of carrying out negotiations with other buyers, NWS adopted a tougher stance for the remaining volumes of Trains 1-3, 4, and 5. The venture invited its remaining long-term buyers to submit requests for volumes of LNG at a non-negotiable price, equivalent to $7.90/MMBtu (DES) at JCC of $60/b. The process closed on April 21 and was finalized at the end of May 2006. All the original buyers participated. A total of 4 mtpa of LNG was proposed to the participants. KOGAS was given their original 0.5 million tonnes for 7 years with an option for an additional 8 years (SPA signed in January 2007), whereas the Japanese buyers (except Toho and Chugoku) received the remaining 3.5 mtpa.

**Qatar diversions to KOGAS:** In March 2007, KOGAS signed an SPA with RasGas for the supply of 2.1 mtpa for 20 years starting in 2007. The volumes will be diverted from their initially targeted western markets. The contractual price agreed is reported to be slightly higher than the KOGAS legacy price with Qatar and is around $10.50/MMBtu at $60/b JCC price.


As can be seen above, sellers have taken a tougher stand in the last year or so with respect to contract terms and pricing. We are now seeing sellers asking for contracts of shorter durations, as they feel more comfortable with the the direction of the gas market and being able to recuperate their investments without committing their supply for a full 20 years and missing out on some potential upside. That being said, sellers will continue to seek long-term deals as they offer a stream of revenue that will ensure that their projects are “bankable.” Sellers’ strategy will be a mix of long- and short-term deals and FOB and DES terms in order to maximize their portfolios. Additionally, take-or-pay levels are expected to remain relatively high for financing new projects, but internally financed projects may be more flexible.
Chapter 5
LNG Pricing\(^1\)

Regional LNG Prices
If Hawaii is to import LNG, among the many decisions that will have to be made is how to price the
LNG. Hawaii is located between two major markets that have very different pricing mechanisms
and the State may wish to adopt one of these mechanisms or it may wish to adopt an entirely new
system. Whatever the decision, it will have long-term implications for the State in terms of price
level and volatility. This chapter presents an overview of likely options for the State. Please keep in
mind that this list is not meant to be exhaustive, but is a good outline of the options that may be
considered.

Natural gas is not yet a globally traded commodity, so prices can vary substantially from region to
region. Currently, Europe, Asia, and the US each have their own unique pricing mechanisms (see
the following figure). In the US, a competitive gas market is firmly ensconced and prices are
generally linked to the market price at Henry Hub (a physical point in Louisiana where numerous
gas pipelines intersect), thereby creating a competitive reference point. The price of gas at various
points in the continental US is derived from differentials (+/−) from Henry Hub. The differentials
are based on demand patterns and distance from end-users. LNG sales into the US, whether they
are spot sales or long-term trades, are linked to Henry Hub prices because LNG is competing with
pipeline gas. It is interesting to note that the high volumes at Henry Hub allow for a transparent
marker, enabling a futures market to develop on the NYMEX. This futures market allows sellers
and buyers to hedge their sales and purchases, thereby securing future prices.

\(^1\) This chapter draws on FACTS database and sources, BP Statistical Review 2006, World Gas Intelligence (various
issues), as well as presentation material provided by Andy Flower @ Pacific Gas Insiders, December 2006.
In the past, price volatility and low prices in comparison to the other major gas markets deterred LNG suppliers from targeting the US market. However, recent prices of $7-12/MMBtu and a projected decline in domestic production and pipeline imports from Canada have added to the appeal of bringing LNG into the US.

In Europe, the liberalization of the natural gas market has led to the emergence of spot market locations, mostly in Northwest Europe (mainly the UK, Belgium, and the Netherlands). For example, natural gas prices in the United Kingdom are set on the National Balancing Point (a notional point in the transportation system) by the law of supply and demand. In Belgium, natural gas similarly is traded on the Zeebrugge hub. In these countries and the nearby region, LNG is also indexed on these spot market prices, since it competes with pipeline gas. However, this pricing system is quite recent, and the rest of continental Europe, in the absence of a reliable and liquid enough spot market, natural gas prices are set to compete with oil products, namely gasoil and fuel oil.

In Asia, LNG prices are generally linked to crude oil prices, specifically the Japan Custom Cleared or Japan Crude Cocktail (JCC) price. JCC is the average price of crudes imported into Japan every month and is published every ten days. Because of the linkage between crude prices and LNG, the price of LNG goes up or down with the price of JCC. The extent to which the two prices are linked has changed in recent contracts, which will be explored further in a subsequent section.
The following figure illustrates crude and gas prices from 1975-2005. It shows that until recently, Europe and the US typically had lower gas prices than Asia because of competition from gas pipelines. In the US, gas is produced domestically and is also imported from Canada and Mexico. In Europe, gas is piped from Algeria, the Netherlands, the North Sea, and Russia.

We can also see from the figure that the price of LNG in Asia is roughly in line with the price of crude oil, demonstrating the relationship between the two. In the early years, LNG was generally priced at a discount to crude oil, and then from the mid-1980s until 2003 it was generally priced at a slight premium to crude. Now with the escalation of crude prices, the price of LNG is again at a discount to crude in part due to ‘S’-curves and price ceilings. The evolution of pricing in the Asian LNG market will be discussed in the following section.
Evolution of LNG Prices in Asia

In 1969, the first LNG cargoes were shipped from Kenai, Alaska to Japan at a fixed price of $0.52/MMBtu. This was a substantial premium to crude oil, as the crude price averaged $0.33/MMBtu in equivalent terms.\(^2\) Then in 1973, the Arab-Israeli war led to the 1973-74 Arab Oil Embargo and a rapid increase in oil prices. Prices skyrocketed from an average of $2.83/b in 1973 to $10.41/b or $1.79/MMBtu in 1974. The LNG suppliers wanted to capture the benefits of the higher oil prices and the Japanese accommodated their request, agreeing to a crude oil linkage.

The basic formula and crude oil linkage remained the same until 1986, when prices crashed with OPEC’s decision to abandon the use of official government selling prices (OGSP), and to allow prices to be set by supply and demand in the world oil markets. The oil price crash in 1986 put the suppliers in a bind and they again asked for the help and cooperation of the Japanese. The Japanese accommodated and agreed to an ‘S’-curve based pricing formula. As depicted in detail in the next section, the ‘S’-curve retained a crude oil linkage, but reduced the volatility implicit in the old formula.

In recent years we have witnessed wide discussions of new pricing indices. Some have suggested linking a portion of the LNG price to inflation and some have advocated a return to fixed prices. Others have pushed for a linkage to coal prices, as it is a major competing fuel in many markets. During the period of 2000-2005, the LNG market turned to the advantage of the buyers, with plenty of supply available and costs reductions, driving prices down. We have seen buyers tendering for supply, a reduction of the oil linkage, and floor and ceiling prices emerge in some contracts. Even more recently, with the return of a sellers’ market in late 2005, we have witnessed a new increase in the crude oil linkage, the removal of the ‘S’-curve formula towards a straight line formula, and new pricing methods. The following table illustrates the evolution of LNG prices in Asia.

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\(^2\) In order to compare various fuels, one has to calculate a heating value, which is measured in millions of British thermal units (MMBtu). In the case of crude oil, each barrel contains approximately 5.8/MMBtu. This enables one to compare heating values of hydrocarbons such as oil and natural gas, which have different physical and chemical compositions.
### Evolution of LNG Pricing in Asia

<table>
<thead>
<tr>
<th>Year</th>
<th>Event Description</th>
<th>Pricing Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>1969</td>
<td>Start of Asian LNG trade (Alaska to Japan)</td>
<td>Fixed pricing-$0.52/MMBtu</td>
</tr>
<tr>
<td>1973-74</td>
<td>First oil crisis (High oil prices) ($10.41/b or $1.79/MMBtu)</td>
<td>Change to crude oil index to capture higher oil price</td>
</tr>
<tr>
<td>1986</td>
<td>Oil price crash</td>
<td>Provisional pricing</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Introduction of S-Curve</td>
</tr>
<tr>
<td>Late 90s</td>
<td>Market changes, supply to new market, tendering process</td>
<td>Introduction of ceilings and floors Fixed prices</td>
</tr>
<tr>
<td>2005-</td>
<td>Tight supply, emergence of a sellers’ market</td>
<td>New price indices and mechanisms emerging</td>
</tr>
</tbody>
</table>

### Traditional LNG Price Formula in Asia

The current Asian LNG price formula revolves around a crude oil linkage. The traditional formula breaks down in the following manner: \( P_{LNG} = A \times P_{Crude\ Oil} + B \). The variables are defined below:

- \( P_{LNG} \) = price of LNG in US$/MMBtu
- \( A \) = slope of line (shows crude linkage)
- \( P_{Crude\ Oil} \) = price of crude oil in $/b
- \( B \) = a constant in US$/MMBtu

Most LNG sold in Asia uses this formula, where typically \( A=0.1485 \) and \( B=70-90\text{¢} \). The slope is critical because it shows the linkage between LNG prices and crude oil prices. A slope of 0.1485 has about an 85% crude oil linkage, meaning that if the price of crude increases by 10%, the price of LNG will increase by 8.5%.\(^3\) In the past, the slope generally remained the same for all Asian LNG contracts and the point of negotiation usually focused on the constant.

Although never announced as a formal policy, in the past, Japanese buyers were prepared to offer newer projects a higher constant (and hence, a higher price) than projects that had been in operation for many years. The rationale was that the older projects had already paid off most, if not all, of their capital costs, but the newer projects needed higher prices to remunerate the capital investment. The projects with the highest constants (given a slope (A) of 0.1485) are Australia (commissioned in

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\(^3\) The 85% crude oil linkage is calculated by dividing 0.1485 by 0.172.
1989), Abu Dhabi (new train commissioned in 1994), and Qatargas (commissioned in 1997). The constant (B) for those projects is around 87.5¢. At the other end of the scale are the Alaskan (commissioned in 1969) and Brunei projects (commissioned in 1972) with a constant (B) of around 60¢.

The following figure outlines the concept of the basic formula and illustrates how suppliers are able to achieve a premium over crude oil parity at low oil prices, and how the buyers are able to achieve a premium at higher oil prices.

With the introduction of an ‘S’-curve in the mid-1980s, subsequent negotiations in the mid-1990s resulted in all of the projects supplying Japan, except those in Indonesia, to modify their pricing formulas by adopting the ‘S’-shaped pricing curve illustrated in the following figure. The price formula in the mid-oil price range (typically $16.50/b to $23.50/b) was retained in the form shown above, with a slope (A) of around 0.1485 and a constant (B) in the range of 70¢ to 90¢. At oil prices below $16.50/b, the slope of the pricing curve was reduced, giving the seller an increased premium over the oil-price parity. At oil prices above $23.50/b, the relationship with oil prices was similarly reduced to help the buyers in a high price environment.
It should be noted that South Korea and Taiwan have only relatively recently moved to incorporate ‘S’-curves in some new and/or renegotiated contracts. In spite of this, with the recent high oil prices, the lack of an ‘S’-curve in most of their contracts is opening an increasing gap between Japanese, Korean, and Taiwanese LNG prices. An additional factor that favors the Japanese buyers in a high oil price environment is that most of the Japanese price formulas have an ‘applicable’ range, typically $11 to $29/b. Outside of that range, the parties agree to meet and discuss prices. JCC prices have exceeded $30/b since December 2003, and have stayed above that level, averaging $50/b in 2005, and reaching $72/b in September 2006. With JCC well above the upper end of the range, the “meet and discuss” provision has now been triggered and discussions are ongoing about what should be done. In the case of legacy Australian contracts, for example, it appears that $29/b has become another “kink point” above which the linkage to crude oil has been further reduced.

In contrast to most other contracts, Indonesian price formulas do not have an applicable range, so the LNG price has continued upwards with the oil price. For example, in August 2006, Taiwan and Korea paid, respectively, an average of $12.95/MMBtu and $12.02/MMBtu for Indonesian LNG. In 2004, after some very acrimonious negotiations, a dispute between Pertamina and the Western Japanese buyers was settled by the introduction of an ‘S’-curve into the contracts, with a reduced
slope of approximately 7.5 above $35/b. However, no limit was placed on the application of the upper part of the ‘S’-curve, which has resulted in Indonesia’s prices to Japan being higher than those of other projects in the current high oil price environment. Thus, the average price of Japan’s Indonesian imports was $8.37/MMBtu against an average Japanese import price of $7.25/MMBtu.

**Recent Trends in LNG Pricing in Asia**

The recent increase in crude prices coupled with tightening of the global LNG market has given suppliers a new sense of bravado with respect to LNG pricing. This new found confidence has led suppliers to abolish ‘S’-curves in favor of straight line formulas, do away with price ceilings, increase the linkage to crude oil, and adopt a tendering process thereby increasing competition amongst buyers. The following figure illustrates the various stages in the move to a sellers’ market and shows how sellers rapidly increased their price expectations from October 2005 to December 2006 (date of signature of the agreements). Gorgon and Pluto price formulas remain very competitive at high oil prices, compared with legacy contracts. Both projects have included price review clauses every five and three years, respectively, starting from the signature of the HOAs. Faced with sharp increases of project costs, these greenfield projects are likely to renegotiate their contractual prices before signing any final agreement.
Future LNG Pricing in Asia

The price of LNG in Asia has in the past evolved with current market conditions and this trend is expected to continue in the future. As discussed earlier, 2005 was seen as a turning point in LNG prices, with the growing evidence of a switch from a buyers’ market to a sellers’ market. We have seen the abolition of ‘S’-curves, new price indexation, and sellers adopting near tendering processes, increasing the competition between buyers. The result is an increase in prices, especially at high oil prices. Both buyers and sellers now seem convinced that crude oil prices will remain high for the foreseeable future and the latter are determined to benefit from it. However, it is a recent change and the extent to which this logic will be pushed and for how long by the sellers, remains to be seen.

We believe that new buyers will have difficulty securing new LNG supplies if they don’t increase their price expectations. As such, even new LNG contracts from Gorgon or Pluto can no longer be used as a yardstick. On the other hand, sellers need to acknowledge the fact that long-term prices in the range of $8-10/MMBtu are not acceptable to countries such as China and India and they run the risk of seeing these countries move to alternative fuels, as they are not yet addicted to natural gas. However, with the increasing tightness of the market, it can be said with some confidence that sellers will not be prepared to offer better terms than the current market situation in the next few years.

Whereas historically, LNG prices to Japan and Korea were priced near parity to crude oil prices (and even above crude oil price parity after the oil crash in 1986) they are now at an all-time discount of more than $4/MMBtu for Japan and $2/MMBtu for Korea in 2006. The belief that LNG will be priced at a long-term discount to oil prices, at high oil prices, paradoxically generates a demand pull for LNG in the actual high oil price environment.

We believe that sellers will continue to regain some value and increase the oil indexation in LNG price formulas. As a consequence, the prices obtained by the Japanese buyers in recent deals constitute a new floor and those prices in the range of the Northwest Shelf supply tender or the most recent Qatari contracts with Korea will become the new benchmark if one is looking for supply over the next couple of years.
We also expect the global LNG market to remain tight until the start of greenfield projects in Australia and the Atlantic Basin around 2012/13, but some of them could be delayed. In these circumstances, sellers are likely to maintain their high price expectations until the start of these new projects. However, the start of the new Qatari trains from late 2008 could generate a small surplus of supply in the following couple of years if demand does not rise as fast as supply. We believe that once LNG begins flowing from the new Qatari trains and has to move west, price expectations will lower, with HH and NBP likely to become the new benchmark. The understanding of this situation has led Qatar to insist on signing long-term agreements, which fetch them higher prices, realizing that its advantageous negotiating position may soon become a thing of the past.

How to Price LNG in Hawaii

This chapter has discussed how LNG is priced throughout the world, and specifically how LNG prices have evolved in the Asia-Pacific region. In the context of Hawaii, there are numerous options available and the goal of this section is not to recommend a specific pricing mechanism, but rather to layout the possible options. The general goal of most pricing systems is to protect the buyer and seller from volatility, and also to minimize the incentive for default on the part of either side.

In our 2004 study, *Evaluating Liquefied Natural Gas (LNG) Options for the State of Hawaii*, we summarized in the table below potential LNG pricing options for Hawaii during the buyers’ market, and the pros and cons of each strategy. We had identified eight potential pricing mechanisms ranging from the traditional Asian price formula to a combination of a Henry Hub, LSFO, and fixed prices.
### Potential LNG Pricing Options for Hawaii: 2000-2005

<table>
<thead>
<tr>
<th>Pricing Options</th>
<th>Pros</th>
<th>Cons</th>
</tr>
</thead>
<tbody>
<tr>
<td>1) Traditional Asian Formula</td>
<td>Established pricing mechanism that suppliers are comfortable with</td>
<td>Fuel price still closely linked to oil market</td>
</tr>
<tr>
<td>5% linked to crude, 15% fixed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2) Asian Price Formula with ‘S’-Curve</td>
<td>Reduces volatility and increased protection for buyers at high oil prices</td>
<td>While not as closely linked to oil prices as option #1, fuel prices are still subject to oil price volatility</td>
</tr>
<tr>
<td>30% linked to crude, 70% fixed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3) Chinese LNG Price Formula</td>
<td>Even less price volatility as 70% is fixed</td>
<td>Some oil price volatility</td>
</tr>
<tr>
<td>30% linked to crude, 70% fixed</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4) 100% fixed price</td>
<td>No volatility and can accurately budget fuel costs</td>
<td>Can't capture benefits of lower oil prices</td>
</tr>
<tr>
<td>5) Linkage to oil but not JCC</td>
<td>Linkage to LSFO fuel price is a concept that HECO is familiar with and LSFO prices tend to vary less than oil prices</td>
<td>Uncommon in Asia and US mainland; LSFO prices are correlated with oil prices</td>
</tr>
<tr>
<td>e.g., Could link to LSFO price in Singapore</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6) 100% linkage to Henry Hub Prices</td>
<td>LNG prices linked to a transparent marker that consumers could easily follow</td>
<td>Prices fluctuate daily and Hawaii would be exposed to market conditions of US mainland</td>
</tr>
<tr>
<td>7) Price floor and a price ceiling</td>
<td>Limits volatility and gives the buyer a range of what the price will be</td>
<td>Can't capture benefits of lower oil prices</td>
</tr>
<tr>
<td>e.g., Recent contract in India</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8) Combo of Henry Hub, LSFO, fixed prices</td>
<td>Spreads risk through diversification of price markers</td>
<td>May be confusing to consumers</td>
</tr>
<tr>
<td>e.g., Price is 1/3 linked to Henry Hub, 1/3 to LSFO and 1/3 is fixed</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

At the time, the buyers had the upper hand and were able to negotiate deals that were similar or on the order of those illustrated above. Unfortunately for Hawaii, that window of opportunity has closed and now the market has clearly tightened. It is highly unlikely that a supplier will agree to most of the above scenarios. In order for Hawaii to procure LNG, it has to compete with the alternative market(s). In the case of supply stemming from the Asia Pacific and/or Alaska, the alternative markets are typically the Asian importers and the US market. Therefore, in order for Hawaii to attract suppliers away from these markets, Hawaii will likely have to price LNG with a crude oil linkage (JCC), a Henry Hub linkage, or a combination of both. The pros and cons of these three options are described below.

### Potential LNG Pricing Options for Hawaii: 2007

<table>
<thead>
<tr>
<th>Pricing Options</th>
<th>Pros</th>
<th>Cons</th>
</tr>
</thead>
<tbody>
<tr>
<td>1) Traditional Asian Formula</td>
<td>Established pricing mechanism that suppliers are comfortable with</td>
<td>Fuel price still closely linked to oil market</td>
</tr>
<tr>
<td>JCC linkage</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2) 100% linkage to Henry Hub Prices</td>
<td>LNG prices linked to a transparent marker that consumers could easily follow</td>
<td>Prices fluctuate daily and Hawaii would be exposed to market conditions of US mainland</td>
</tr>
<tr>
<td>or Southern California Based</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3) Combo of Henry Hub and JCC</td>
<td>Spreads risk through diversification of price markers</td>
<td>May be confusing to consumers</td>
</tr>
<tr>
<td>e.g., Price is 1/2 linked to Henry Hub, 1/2 to JCC</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Option 1 focuses on adopting the traditional Asian formula that has a JCC linkage. As discussed in Chapter 4, the most recent contracts have seen an increased relationship with crude oil, although it is not out of the question to have a lower crude oil linkage and a higher fixed percentage as long as the final price is competitive with the international market. Among the benefits of this formula is that it is an established pricing mechanism that suppliers have experience with and, perhaps more importantly, are comfortable with. One of the negative aspects of this formula is that if there is a high crude oil linkage, the final price is closely linked to the oil market and therefore it would not reduce the State’s exposure to the volatility of oil prices, which is one of the main reasons to introduce LNG in the first place.

Option 2 focuses on linking the price of LNG to Henry Hub prices as is the case in the continental US. The benefit of a Henry Hub linkage is that LNG prices are linked to a transparent marker that consumers could easily follow and understand. Of course the delivered fuel price would include transportation charges plus the terminal cost plus the buyer’s margin. Once these prices are broken down, the consumer could check daily on the internet and verify the price of Henry Hub plus the additional charges to see their daily fuel costs. The main drawback of this pricing mechanism is that not only do prices fluctuate daily, but more importantly consumers in the State would be exposed to the market conditions of the US mainland. Therefore, a rupture in a pipeline or a cold winter in the Northeast would cause a spike in prices and would hurt consumers in the State because of issues that are beyond their immediate control.

Additionally, one could link the price of LNG to Southern California (Socal) gas prices, which are also based off of Henry Hub. Socal prices are chosen as a reference point, since a large portion of the LNG that is targeting the west coast of North America will be looking to penetrate the southern California market. Interestingly, Socal gas prices have traded at a discount to Henry Hub for the much of the last few years due to local market conditions. The same pros and cons that apply for Henry Hub apply for a Socal based pricing marker.

Option 3 proposes a pricing mechanism that combines Henry Hub price and JCC. For example, the price of LNG into Hawaii could be 50% linked to Henry Hub and 50% linked to a traditional Asian price formula. The above is an example of equal weight distributed among the two options, although in theory any combination could be used, depending on the needs and perceptions of the
buyer. The benefit of this pricing mechanism is that risk is spread through the diversification of various price markers. The main drawback of this combined pricing option is that it may be confusing to customers who want to know how their fuel costs are calculated.

It is important to note that while the three options presented above covers an array of possible pricing alternatives, it is obviously not an exhaustive list. What is included here is what we believe sellers will be willing to accommodate in the current market; not unrealistic pricing scenarios such as fixed prices and/or prices with ‘S’-curves and price ceilings that were being implemented only a few years ago. Sellers have in the past signaled a willingness to accommodate variations on traditional pricing options, although currently they will likely be less flexible given their market power.

The option that should be pursued depends on one’s perception as to the future direction of related markets, risk tolerance, and the direction of government policy. FACTS cannot comment on the risk tolerance of relevant stakeholders and future government priorities. However, we do feel that it is unlikely that the price of oil will drop below $40/b for a sustained duration in the future. As a consequence, securing as low a crude oil linkage would appear to fit the State’s need for low price volatility. Moreover, the market could change by the time the State decides to implement an LNG receiving terminal and if conditions warrant we would also advocate implementing ‘S’-curves and price ceilings in any LNG contact.
Chapter 6
Environmental and Safety Concerns

Introduction
Of course, we all have an interest in maintaining our State’s pristine surroundings. The environment has added importance in Hawaii because it is the bread and butter of our economy, as it draws tourists from all around the world. As a consequence, it is critical to examine the impact that LNG could have on our environment in terms of emissions and possible spills. Obviously, safety concerns are important as well. Each of these issues is discussed in turn in this chapter.

Overall, we believe it is fair to say that in comparison to other fuels, LNG has numerous advantages. Compared to other hydrocarbon fuels, it is environmentally friendly and has an excellent safety record: LNG is not explosive, toxic, or carcinogenic. A key point is that LNG is not pressurized and it dissipates quickly and thus the risk of explosion is very low, especially when compared to some fuels already in use in Hawaii, such as LPG.

Environmental Concerns

Emissions
Liquefied natural gas (LNG) consists almost entirely of methane, and it is the cleanest burning of all fossil fuels. The main byproducts of combustion of natural gas are carbon dioxide and water vapor. At the other end of the spectrum, coal and fuel oil both emit relatively high quantities of pollutants, including nitrogen oxides (NOₓ) and sulfur dioxides (SO₂). Combustion of these fuels may also release particulate matter into the environment. The following figure illustrates the varying levels of emissions from natural gas, coal, and oil. Natural gas emits the lowest levels of carbon dioxide and negligible amounts of SO₂, particulates, and mercury.

---

Spills

It is well known that an oil spill can have catastrophic consequences, both environmental and economic. After the Exxon Valdez incident in 1989, the State funded a study to determine the potential damage to the economy if an oil spill were to occur in Hawaiian waters. The study found that, in addition to the environmental damage, the monetary loss could be staggering. Cleanup costs were estimated at $210 to $305 million and if oil washed onto Oahu’s shores it could translate into a 32% reduction in tourism or a $3.06 billion loss in tourism revenue.

Whether spilled in water or on land, when LNG is released into the atmosphere it begins to evaporate, causing a visible vapor cloud. The likelihood of this vapor cloud igniting is very slim, as LNG vapor is lighter than air, which causes it to dissipate rapidly (as discussed later in this chapter). Hawaii’s trade winds would accelerate dissipation, acting as a natural safety measure. Unlike oil, an LNG spill leaves no residue and thus there is no environmental cleanup.

LNG Safety Issues/Concerns

Since the inaugural shipment in 1959, LNG has been transported in oceangoing vessels for nearly 50 years, making more than 40,000 voyages without a significant incident involving loss of cargo in port.
or at sea.² LNG regasification and storage facilities have operated safely in populated cities in Asia, Europe, and the US for decades. Today LNG is transported and stored as safely as other liquid fuels as technological developments and safety measures have become more advanced. Although it was long ago, it should be noted that a major accident occurred in 1944 before tanks were designed for the cold temperatures of LNG. A tank in Cleveland, Ohio ruptured and spilled the uncontained liquid into storm drains, followed by a large deadly fire, which killed 128 people. Since then, NASA’s advancement that resulted in the race to the moon led to a much better understanding of cryogenic liquid storage which has contributed to the industry’s excellent safety record.

Safety Features in LNG Storage
Because they are often in populated areas, LNG storage tanks, which come in three primary designs, are among the most critical components of the LNG chain when it comes to ensuring safety.

- The least expensive storage tank is the ‘single containment’ tank, which consists of an inner nickel steel wall and roof to contain the liquid and vapor. An outer carbon steel wall surrounds this tank to provide insulation, however this second wall is not designed to contain LNG liquid or vapor.

- Another option is a ‘double containment’ tank, which consists of an inner nickel steel wall and roof. Outside of this is another barrier made of concrete, which is designed to contain LNG liquid, but it is not designed to contain LNG vapor. Release of vapor must be vented and sprayed with either water or foam to control the risk of fire.

- Based on conversations with industry contacts, it is the general consensus that the State would utilize ‘full containment’ storage. Full containment provides the maximum protection against LNG leakage. It consists of an inner nickel steel tank with an aluminum floating roof. This is surrounded by an outer tank made of concrete, designed to contain both LNG liquid and vapor.

² Of these voyages 2,400 have been to or from US ports.
Safety Features in LNG Transportation and Receiving Terminals

LNG tankers are designed with an array of safety features. These double-hull ships transport LNG at atmospheric pressure at temperatures of -256°F (LNG’s saturation point). The cargo containment utilizes several layers of protection to ensure that there is no leakage. The first layer consists of a primary liquid barrier followed by a layer of insulation, on top of this is a second liquid barrier with another layer of insulation. Each of these insulation layers are monitored for any signs of leakage with equipment sensitive enough to locate a pin-head size leak.

An LNG tanker features an extensive instrumental package that safely shuts down the system if it starts to operate outside of predetermined parameters. Ships are also equipped with radar and positioning systems that alert the crew to other traffic and hazards around the ship. At onshore receiving terminals, safety features include methane detectors, ultraviolet or infrared fire detectors, closed circuit TV, offsite monitoring, training requirements for personnel, and restricted access to terminal property.
Space Requirements
It is our understanding that there are no definitive regulations in terms of space requirements for LNG facilities. Space requirements at individual facilities are determined on a case-by-case basis by federal and local agencies.

Risk of Fire/Explosion
Contrary to popular belief, LNG itself does not explode or burn because it is not under pressure and it does not contain oxygen. In the case of an accidental release natural gas is only flammable within a narrow gas to air ratio. If the fuel concentration is lower than 5% it cannot burn because of insufficient fuel, and if the fuel concentration is higher than 15% it cannot burn because there is insufficient oxygen. Overall, for LNG to burn it must be released, vaporized, mixed with air at a ratio of 5-15%, and it must come in contact with an ignition source.

Although portions of an LNG vapor cloud are flammable under the right gas to air ratio, the flame speed of an unconfined cloud is slow and it will not explode. In contrast, LPG has a higher risk because it is stored under pressure and it is heavier than air so it does not dissipate as quickly. Fuel oil is toxic and if it spills, especially on water, the environmental impact can be very severe.

<table>
<thead>
<tr>
<th>Properties</th>
<th>LNG</th>
<th>Liquefied Petroleum Gas (LPG)</th>
<th>Gasoline</th>
<th>Fuel Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>Is it a carcinogen?</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Is it toxic?</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Can it form a vapor cloud?</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Is it stored under pressure?</td>
<td>No</td>
<td>Yes</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Flammability Range in Air, %</td>
<td>5 to 15%</td>
<td>2.1 to 9.5%</td>
<td>1.3 to 6%</td>
<td>N/A</td>
</tr>
<tr>
<td>What happens if there is a spill?</td>
<td>LNG will evaporate and will form a vapor cloud. The vapor cloud could be flammable under the right gas to air ratio</td>
<td>LPG will evaporate and will form a vapor cloud. The vapor cloud could be flammable under the right gas to air ratio</td>
<td>Gasoline will evaporate and form a potentially flammable pool.</td>
<td>Fuel oil will evaporate and form a potentially flammable pool.</td>
</tr>
<tr>
<td>Does a spill require a significant environmental clean up?</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Source: Based on Lewis, William W., James P. Lewis and Patricia Outtrim, PTL, "LNG Facilities-The Real Risk," American Institute of Chemical Engineers, New Orleans, April 2003, as modified by industry sources
LNG Regulatory Framework in the US

Regulatory approval for an LNG infrastructure in the US is a rigorous and detailed process that involves numerous local, state, and federal regulatory agencies, such as, but not limited to the Federal Energy Regulatory Commission (FERC), the Department of Transportation, and the US Coast Guard. The process can be time consuming as numerous agencies are involved. Recently, FERC has sped up the approval process as supply of natural gas is expected to be tight in the coming years. Once the permit approvals are in place it takes at least three years to build a receiving terminal depending on the necessary modifications to the current infrastructure. Offshore terminals can be built much faster depending on infrastructure needs.

If Hawaii were to build an onshore LNG receiving terminal the following federal agencies would be involved in the regulatory process:

- Federal Energy Regulatory Commission (FERC)
- Department of Energy (DOE)
- Department of Transportation (DOT)
- US Coast Guard (USCG)
- US Environmental Protection Agency (EPA)
- US Army Corps of Engineers
- US Department of Labor Occupational Safety & Health Administration (OHSA)
- US Fish and Wildlife Service
- US Minerals and Management Service

Various State and local agencies would also be involved, including (but certainly not limited to) the Honolulu Fire Department (HFD), the Honolulu Police Department (HPD), Department of Land and Natural Resources (DLNR), and the Public Utilities Commission (PUC).

If the State instead chooses to build an offshore receiving terminal, the following federal agencies would be involved in the regulatory process:

- National Oceanic and Atmospheric Administration (NOAA)
- Department of Energy (DOE)
• Department of Transportation (DOT)
• US Coast Guard (USCG)
• US Army Corps of Engineers
• US Fish and Wildlife Service
• US Department of Labor Occupational Safety & Health Administration (OHSA)

Four federal regulatory agencies have specific regulatory roles directed by statutes, specifically the DOE, FERC, the DOT, and the US Coast Guard. The DOE authorizes all LNG imports via Section 3 of the Natural Gas Act. FERC is responsible for permitting LNG import terminals that are not covered under the Deepwater Port Act. FERC’s duties include overseeing the siting, construction, and operation of the terminals under its jurisdiction. FERC also prepares an Environmental Assessment (EA) or an Environmental Impact Statement (EAS) for all onshore facilities as part of the certification process to construct or operate an LNG facility. The DOT is responsible for issuing permits to offshore LNG terminals in federal waters and also for ensuring the safe operation of LNG facilities. The USCG and Maritime Administration jointly process the license applications, and DOT issues the license. Lastly, the US Coast Guard is responsible for assuring the safety of marine operations at all LNG terminals and aboard all LNG tankers in the US.

Federal guidelines for the design, construction, and operation of LNG facilities are as follows:

• **49 CFR PART 193**: Liquefied Natural Gas (LNG) Facilities - Federal Safety Standards - This portion of the Code of Federal Regulation (CFR) establishes and enforces standards pertaining to siting requirements, design, construction, equipment, operations, maintenance, personnel, qualifications and training, fire protection, and security.

• **33 CFR Part 127**: Waterfront Facilities Handling Liquefied Natural Gas and Liquefied Hazardous Gas - This federal regulation governs import and export LNG facilities or other waterfront facilities handling LNG. Specifically, the scope of this standard is from the unloading arms to the first valve outside of the LNG tank.
• **NFPA 59A: Standard for the Production, Storage, and Handling of Liquefied Natural Gas** - This is an industry consensus standard, issued by the National Fire Protection Association (NFPA). 59A was first adopted in 1967 and covers general LNG plant considerations, process systems, stationary LNG storage containers, vaporization facilities, piping systems and components, instrumentation and electric services, transfer of natural gas and refrigerants, fire protection, safety, and security. Also covered are requirements for vehicle fueling for industrial and commercial facilities using American Society of Mechanical Engineers (ASME) containers. This standard includes the tank requirements for LNG facilities that ensure their ability to withstand natural events such as earthquakes, floods, and high winds.

• **NFPA: Standard for Liquefied Natural Gas Vehicular Fuel Systems** - This standard covers vehicular fuel systems, LNG fueling facilities, installation requirements for ASME tanks, fire protection, safety, and security for systems onboard vehicles and for infrastructures storing 70,000 gallons of LNG or less.

The following are federal regulations applicable to LNG ships:

• **33 CFR 160.1.0 Ports and Waterways Safety: Control of Vessel and Facility Operations** - This US federal government regulation describes the authority exercised by District Commanders and Captains of the Ports to insure the safety of vessels and waterfront facilities, and the protection of the navigable waters and the resources therein. The controls described in the subpart are directed to specific situations and hazards.

• **33 CFR 165.20 Regulated Navigation Areas and Limited Access Areas: Safety Zones** - A safety zone is a water area, shore area, or water and shore area to which, for safety or environmental purposes, access is limited to authorized personals, vehicles, or vessels. It may be stationary and described by fixed limits, or described as a zone around a vessel in motion. It is commonly used for ships carrying flammable or toxic cargoes, firework barges, and long tows by tugs, or event like high speed races.
- **33 CFR 165.30** *Regulated Navigation Areas and Limited Access Areas: Security Zones* - This section defines a security zone as an area of land, water, or land and water is so designated by the Captain of the Port or District Commander or such time as is necessary to prevent damage or injury to any vessel or waterfront facility, to safeguard ports, harbors, territories, or waters of the US or to secure the observance of the rights and obligations of the US. It also determines the purpose of a security zone: to safeguard vessels, harbors, ports, and waterfront facilities from destruction, loss, or injury from sabotage or other subversive acts, accidents, or other causes of a similar nature in the US and all territory and water, continental or insular, that is subject to the jurisdiction of the US. Generally, it covers ships with flammable or toxic cargoes, cruise ships, naval ships, and nuclear power facilities and airports.

**LNG in Hawaii?**

Will LNG make its way to Hawaii’s shores? We believe if the decision were based solely on LNG’s safety record and emissions, the answer would likely be “Yes.” Overall, LNG is a clean fossil fuel with a relatively benign impact to the environment that has achieved an excellent safety record over the past 40 years.
Chapter 7

LNG Sourcing and Security of Supply\(^1\)

One of the greatest challenges facing LNG terminals in the US is not permitting but finding the actual supply. A number of projects have been cancelled due to the tight global LNG market, as markets in Asia and Europe are competing for the same molecules. This chapter begins by looking at potential gas supply sources (domestic and foreign) for Hawaii. The chapter then goes on to discuss some details on each supply source and how they would fit in the context of Hawaii. In addition, we explore the issue of security of LNG supply, including past disruptions and the potential for future disruptions.

Gas Supply Sources

As discussed earlier in Chapter 2, currently eight of the existing thirteen LNG exporters have long-term contracts with Asia Pacific buyers, namely Japan, Korea, Taiwan, India, and China. Of these eight suppliers, four are located in the Asia-Pacific region (Australia, Brunei, Indonesia, and Malaysia) while the remainder are located in the Middle East. In addition, the Asia-Pacific region is poised to include a new regional supplier in late 2008; specifically Russia’s Sakhalin II LNG project, which will be monetizing gas reserves located offshore Sakhalin Island on the Russian Pacific Shelf and sending the gas to markets in Japan, Korea, and Baja, California. If Hawaii were to import LNG from a foreign source, the most likely suppliers, given available reserves and proximity to Hawaii, would be Australia and Russia (Sakhalin). Insofar as domestic gas is concerned, the only logical location that could potentially export gas (whether as LNG or CNG) to Hawaii is Alaska.

Domestic Gas—Alaska LNG or CNG

For decades Alaska has been exploring ways to monetize the estimated 35 tcf of proven stranded gas reserves located on the North Slope. The most discussed development plan included building a $20-30 billion pipeline to the Lower-48 states through Canada into a Chicago gas hub. Former Alaskan Governor Frank Murkowski was able to get the big-three North Slope producers to agree

\(^1\) This chapter draws on FACTS database and conversations with industry contacts.
to a contract for fiscal terms in February 2006 only to have it rejected by the State legislature on
grounds that Alaska was heavily subsidizing the producers via the state’s participation in the project
and decades-long guarantees not to raise oil and tax rates. New Alaskan Governor Sarah Palin was
victorious over Murkowski in the 2006 primary and during her election campaign pushed an
alternative development plan promoted by the Alaska Gasline Port Authority (AGPA). AGPA
plans to focus on building a trans-Alaska gas pipeline, liquefaction and gas processing facilities, and
related infrastructure for the transportation of North Slope natural gas to the market.\(^2\) The 800 mile
over land pipeline would run from Prudhoe Bay in the North Slope to the port city of Valdez and
would run parallel to the existing Trans-Alaska-Oil Pipeline (TAPS). While the gas in Valdez would
be liquefied for export to markets in the US and possibly abroad, plans also call for a spurline from
Glennallen to the South-central gas grid, thereby ensuring gas supply for in-state consumption.

On March 2, 2007 Governor Palin introduced a bill to the State legislature dubbed the Alaska
Gasline Inducement Act. The legislation sets the framework for what incentives the State would
give potential pipeline builders in exchange for their commitment to monetize Alaska’s gas reserves.
The bill would offer investors in the pipeline a dollar-for-dollar match on costs associated with
getting clearance to build the pipelines. Other characteristics include expediting the state permitting
process and offering state-funded training to ensure there are enough local workers to build the
pipeline. The bill also sets the “evaluative criteria” which will be used during the selection process.
The criteria the state will use to determine the best project includes: the proposed project timeline,
the proposed method to manage cost overruns, the proposed tariff rates, the ability of the project
design to accommodate expansion, the percentage of the state matching fund that will be used,
whether the project is feasible, and the applicant’s ability to perform.\(^3\) Once all the applications are
received the State will decide what development option will be chosen based on the aforementioned
criteria. The State is pushing for a strict timeline in which it hopes to move from legislative approval
to pipeline fieldwork by the summer of 2008.

What does all this mean for Hawaii? Well, if the gas goes to the Lower-48 via a gas pipeline through
Canada the answer is not much. However, if development plans call for gas to be routed to Valdez

\(^3\) http://www.gov.state.ak.us/news.php?id=170
or another port for export to US markets Hawaii could potentially procure some of the gas for LNG deliveries. The AGPA project team has the worldwide leader in LNG shipping as a partner—Mitsui O.S.K. Line—and Mitsui has eight US-built ships of 70,000 m³ that would meet the requirements of the Jones Act and could also fit into Barber’s Point Harbor without radical modifications. Moreover, another option would be to procure the gas at Valdez for transport via EnerSea’s CNG ships, which may be a more cost effective solution for Hawaii.

For various reasons, importing LNG or CNG from a domestic gas source such as Alaska would be the preferred import option. The benefits range from increased security of supply to a net positive affect on balance of trade payments. In the case of Hawaii, if one were to import from a domestic source, security of supply (as far as the stability of the government is concerned) should not be a problem. It’s highly unlikely that there would be a coup or a radical change in governmental regulations (i.e., nothing like the export policy being pursued in Indonesia which favors domestic gas consumption) that would affect exports. In addition, there could be a net gain in the overall balance of trade payments as our refineries would not have to purchase heavy sweet crude that is typically sourced from Indonesia in order to make the LSFO that HECO burns. In 2005, HECO paid over $400 million for LSFO sourced from the refineries to provide fuel to their power plants.

**Foreign Gas—Asian LNG**

If Hawaii were to import LNG from a foreign source, the most likely suppliers given available reserves and proximity to Hawaii would be Australia and Russia (Sakhalin). Australia is a stable country with a proven track record in the LNG industry. It has been delivering gas to Japanese utilities such as Tokyo Electric and Tokyo Gas since the startup of the Northwest Shelf (NWS) project in 1989. Russia, on the other hand will enter the LNG export fraternity once the Sakhalin II project is completed in late 2008. Russia is the world’s largest gas producer and exporter (of pipeline gas), yet it is still a minnow in the LNG industry. This is slated to change with a number of projects in the coming years. Below, we discuss briefly the details of each potential project in these two countries that could supply Hawaii.

**Australia NWS Project:** The NWS project is Australia’s largest resource development. The liquefaction plant—located at Karratha in Western Australia—receives gas from fields approximately 130 km offshore. The shareholders of the fields that feed the NWS project are
equally split among Woodside, BHP Billiton, BP, Chevron, Shell, and Mitsui/Mitsubishi. Currently the majority of supply is committed although there are enough available volumes from 2009 onwards to supply the Hawaiian market. In 2013, uncommitted volumes are approximately 1.6 mt, when existing capacity is weighed against contractual commitments, and increases to 6.5 mt in 2020. One point of concern from Hawaii’s standpoint is that this project has lofty price expectations as it has already achieved high FOB prices in the last year to large creditworthy buyers in Japan at around $7.00/MMBtu. In addition, the project may be reluctant to supply a small market such as Hawaii with limited growth potential.

**Australia Darwin LNG:** The Darwin LNG project is operated by ConocoPhillips and is monetizing reserves in the offshore Bayu-Undan gas field. Nearly all the output is committed to Japanese buyers through 2023. The project is expected to build another liquefaction train in the coming years, perhaps by 2013, as it seeks to monetize the Caldita gas field or bring in other nearby fields owned by other parties to the liquefaction plant. If additional trains are built it could supply Hawaii by 2013 at the earliest, although it likely has the same price expectations as NWS.

**Australia Gorgon LNG:** The Gorgon area gas fields are located approximately 130 km off the Northwest Shelf of Western Australia. The development plan calls for a 70 km sub-sea pipeline from the fields to a 10 mtpa liquefaction plant on Barrow Island. The Greater Gorgon area contains estimated gas resources in excess of 40 tcf, although the gas has high a CO₂ content which will have to be reinjected into the ground. Chevron operates most permits within the fields in the Greater Gorgon area and holds interests ranging from 50% to 100% in each field. The project is expected to commence production sometime in 2013. In late 2005, the Gorgon project signed preliminary agreements to supply Japanese buyers with LNG at FOB prices of around $4.00/MMBtu, which could compete with LSFO prices in Hawaii. However, it should be noted that Gorgon has faced massive cost over-runs and is likely going to have to renegotiate the contracts with the Japanese buyers. In addition, the project gave original buyers price preference and it’s unlikely that a buyer coming at a later date would be able to achieve such prices, particularly in the current market.

**Australia Pluto LNG:** Woodside’s proposed Pluto LNG plant is planning on monetizing gas reserves in the Pluto fields located approximately 190 km off the coast of Western Australia and 90 km southwest of NWS’ Goodwyn platform. Current plans call for production to commence in
4Q2010. The project is 100% owned by Woodside which allows for faster development and decision making. Pluto currently has approximately 1.3 mtpa of uncommitted capacity available from 2011 onwards. Woodside is planning on building an LNG receiving terminal off the coast of California (Ocean Way) so there is some potential for synergies with deliveries out of Australia to Hawaii and the US West Coast.

**Australia Browse Basin LNG:** Woodside’s proposed Browse LNG plant is planning on monetizing gas reserves in the Brecknock, Brecknock South, and Scott Reef fields located approximately 400 km north of Broome, western Australia. Estimated reserves are in the neighborhood of 20 tcf and current development plans call for a liquefaction plant to come on-stream around 2013/14. The company has recently begun to actively market the gas and is currently looking for buyers. This project could provide Hawaii an opportunity to get involved early in the Greenfield LNG plant, thereby allowing for the greatest possible price concessions.

**Australia Pilbara LNG:** BHP Billiton’s proposed Pilbara LNG plant is planning on monetizing gas reserves in the Scarborough field located approximately 270 km off the coast of Western Australia. The Scarborough field, located in retention Block WA-1-R, has estimated proven and probable reserves of 8 tcf. Currently, the pre-feasibility study is under way for a single 6 mtpa liquefaction train located onshore at Onslow in the Pilbara region of Western Australia. As is the case with Woodside, BHP is proposing an offshore receiving terminal in California (dubbed Carrillo Port). The project is targeting a completion date of 2013 and has yet to sign up any buyers although it is clearly targeting the California market.

**Russia Sakhalin II LNG:** The Shell-led Sakhalin II project comprises the development of two fields located offshore Sakhalin Island on the Russian Pacific Shelf with gas reserves estimated at 18 tcf. The two train liquefaction plant at Prigorodnoye in Aniva Bay will have a combined capacity of 9.6 mtpa with deliveries slated to commence in late 2008. The majority of the output has already been committed although uncommitted volumes range from 1.7 mt in 2013 to approximately 1.5 mt in 2020. Given the proximity to Hawaii (about 3,400 nautical miles) Sakhalin II is the best positioned to supply LNG to Hawaii from a foreign source if Alaska does not materialize. The consortium has sold to Japanese and Korean buyers at FOB prices of $3.50-5.30/MBtu at current JCC prices.
History of Supply Disruptions

While LNG supplies have proven to be extremely reliable, in recent years there have been two major LNG supply disruptions, one at Indonesia’s Arun in 2001 and the other at Malaysia’s MLNG Tiga in 2003. Both Japanese and Korean buyers were affected by these sudden supply disruptions, and were forced to look for spot supplies to cover the shortfall.

The Arun Disruption: Over the period of March-July 2001 ExxonMobil (the field operator) halted Arun gas production in North Aceh, Indonesia. This was due to the escalating activity of the Free Aceh Movement (an armed separatist movement), which led to fears for the safety of its workforce in North Aceh. The suspension of natural gas from the Arun field led to a sharp reduction in production from the Arun LNG facility. As a result, Arun LNG exports in 2001 dropped to 2.8 mtpa, down from 6.7 mtpa in 2000. Under existing contracts, Japanese buyers (Tohoku Electric Power and TEPCO) and South Korea’s KOGAS were to receive 5.8 mtpa and they were forced to look for spot/swap supplies to cover the shortfall. The supply volumes lost from Arun were covered by other sources, such as Indonesia’s Bontang and Malaysia’s MLNG facilities.

The MLNG Disruption: In August 2003 Malaysia’s newest LNG project, MLNG Tiga declared force majeure on its LNG export commitments. MLNG Tiga—a two-train 6.8 mtpa project—had just started operation of its first train in May 2003 when it was hit by a fire. The second train, which started operation in November 2003, delivered almost all of the contracted volumes—the damaged train was back in operation in March 2004. Japanese buyers (TEPCO, Tohoku Electric Power, and Japan Petroleum Exploration Co.) and South Korea’s KOGAS are the contracted buyers of MLNG Tiga.

How Have Concerns Been Addressed?

While it is a rare occurrence, when suppliers declare force majeure the buyers are responsible for finding alternative supplies to make up for the potential shortage. In practice, however, suppliers try to do what they can to find replacement cargoes for their buyers. MLNG Tiga, for example, attempted to arrange for replacement cargoes through Australia, Indonesia, and Brunei.
In general, when buyers have to find replacement volumes they often have to pay significantly higher prices, because such prompt purchases often face difficulty in not only finding spot LNG, but also in finding uncommitted LNG vessels. Most LNG vessels are committed to a specified long-term contract (see Chapter 6: Short-Term Trading).

It should be noted that a swap agreement of LNG cargoes among buyers is also a possible way to deal with a supply disruption. For example, Chubu Electric Power has agreed to a “seasonal swap” of LNG cargoes with KOGAS. Chubu Electric Power—its demand, which is related to electricity generation, reaches its peak in the summer—took rights to one 60,000 tonne cargo that KOGAS is slated to buy next summer from Indonesia in exchange for the same volume of LNG going to KOGAS this winter from Chubu’s suppliers.

The lesson from this is that in preparation for any emergency situation, it is important for buyers to maintain a relationship with other buyers as well as their suppliers. In the past, Japanese buyers have formed a consortium to buy a large volume of LNG on a long-term basis, and this consortium has played an important role in helping to limit supply disruptions. For example, five electric utilities and three gas utilities have been jointly buying 7.33 mtpa (ex-ship) from Australia’s NWS Trains 1-3 on a 20-year contract (1989-2009). In 2003, the NWS supplier agreed to allocate a portion of the LNG that was contracted for other consortium members to TEPCO, because TEPCO urgently needed to increase LNG-burning for power generation due to a series of shutdowns of its nuclear power plants.

It is critical to emphasize that these past supply disruptions were very unusual and shocked the industry. The disruptions could have longer-term implications that will be reflected in future contracts. Some LNG buyers are considering including a “deliver-or-pay” clause in future contracts to match the “take-or-pay” obligations they face. In addition, some Japanese buyers (including Kansai Electric Power, Chubu Electric Power, and Osaka Gas) are considering requiring a “dual supply source” concept for future Indonesian LNG contracts before they agree to take a large volume. Under this requirement, LNG from Indonesia’s Tangguh project will be supplied to Japan if Indonesia cannot supply LNG from its Bontang project, and vice versa.
Possible Options for Ensuring Security of Supply

With the exception of the two events described above, LNG supplies from the Asia-Pacific region have been very reliable. The lessons that can be gleaned from the recent disruptions are: (1) It is important to have relationships with an array of buyers and sellers, or at the very least to be aware of the possibilities for short-term trading in the event of a supply disruption. (2) Short-term cargoes can be procured in the event of a supply disruption, albeit sometimes at a higher price.

It is important to remember that host governments play a significant role in determining the long-term security of any LNG project. In evaluating a potential supplier it is critical that the host government fully supports the project (new or existing). Australia is an excellent supply candidate because the government has generally been supportive of current and potential projects. Other countries, such as Indonesia, may be perceived as higher risk, particularly as they have cut back exports in favor of the domestic market.

As a final note, although no contracts of this kind have been signed yet, the market may be open to the idea of a “deliver-or-pay” clause in a contract. This may help mitigate the financial risk associated with force majeure and put pressure on suppliers to assure that volumes are delivered as promised, even if they have to secure spot volumes themselves and deliver them to buyers.
Chapter 8

LNG: A Bridge to a Hawaii Hydrogen Economy?¹

Introduction

In the summer of 2005, Congress passed and President Bush signed into law the Energy Policy Act of 2005 (P.L. No: 109-058). This is the first comprehensive piece of energy legislation passed in over decade. While its overall affects are uncertain, its commitment to hydrogen research and development deserves applause. Title 8 of the bill demonstrates a commitment to reducing dependence on foreign energy sources through the advancement of alternative domestic transport fuels. This section coupled with the Advanced Energy Initiative and the President’s Hydrogen Fuel Initiative has helped to reduce many of the costs associated with hydrogen production, though further cost reduction is still necessary for hydrogen to be cost competitive with existing fuel sources.

What needs to be pointed out is, that under all aspects of creating a hydrogen economy, natural gas is only viewed as a transitional feedstock. Natural gas is not viewed as a viable long-term feedstock for hydrogen production for the following reasons:

1. not emission free
2. limited supply
3. price volatility
4. competing demands for supply from other sectors (power, residential, commercial, industrial)

One of the main reasons natural gas is favored as a transitional fuel for hydrogen production, however, is that there is an existing infrastructure for it in much of the 48 continental states and Alaska. This existing infrastructure helps lessen the cost of using natural gas to produce hydrogen until other fuel sources, not hindered by the above reasons, can lower their production costs. Using natural gas in Hawaii, via imported LNG, faces even greater problems than on the mainland because there is no existing infrastructure and many of the cost benefits do not exist as a result. Furthermore, the source of natural gas to Hawaii could be foreign, thus serving to increase foreign

¹ This chapter draws on FACTS database and sources; Energy Information Administration (EIA), California Fuel Cell Partnership, and the US Department of Energy.
fossil fuel dependence. While this is beyond the focus of the study, Hawaii’s best bet is likely to use wind as a feedstock. The wind would be used to generate electricity to yield hydrogen through water electrolysis. Electricity generated from wind as well as solar power has long been viewed as the ideal, emissions free means of producing hydrogen. Hawaii is fortunate enough to have the proper conditions for both.

In spite of such conditions, the high cost of producing hydrogen and developing a hydrogen infrastructure still hinders the creation of an emissions-free hydrogen economy. In this chapter we will briefly discuss the technology of hydrogen fuel cells and the feedstocks being used to produce hydrogen fuel. We will also examine the cost and distribution issues associated with this technology.

Although natural gas in the form of LNG or CNG could still be used as a bridge to a hydrogen economy in Hawaii, it must be noted that LNG prices have significantly increased since the 2004 publication of our original report. Furthermore, no forecasts envision the prices lowering or becoming less volatile any time soon. For reference, Chapter 5 covers current LNG pricing worldwide and chapter 9 focuses on the possible costs of importing LNG into Hawaii.

**Comparison of Feedstocks for Hydrogen Fuel Production**

While it is the most abundant element in the universe, on Earth hydrogen does not exist in a free state and must be extracted from feedstocks. In this section we will discuss the advantages and disadvantages of the most popular feedstocks being used to produce hydrogen fuel.

**Electrolysis of Water**

Electrolysis of water is the ideal means of producing hydrogen fuel as it is pollution free and it is the long-term goal of most proponents of fuel cell development. By running an electric current through water, the hydrogen and oxygen molecules are split apart.

- **Pros:** This method of hydrogen production is the most common next to steam reformation of natural gas and is widely understood. Using this method, hydrogen production could be emissions free if a renewable energy source such as, solar or wind is used to produce the electric current. Another energy source that can be used is nuclear energy, though this technology is in a relatively early stage of development. It involves
using high temperature heat from advanced nuclear reactors as the energy source for a sulfur-iodine thermochemical process to produce hydrogen from water. The produced hydrogen is then scrubbed of impurities at low pressure and compressed to deliver the hydrogen to the distribution system.

♦ **Cons:** Electrolysis of water requires a great deal of electricity and it is the most energy intensive of all the hydrogen production methods, current production costs would equate to a cost still ranging between $3-4 per gallon equivalent. If carbon-based fuels are used to produce the electricity for this process, greenhouse emissions will be quite high.

**Biomass**

Hydrogen can be extracted from biomass—a term used to describe organic wastes, forestry products, or agriculture byproducts. By utilizing the process of steam reformation, biomass is a relatively clean means of producing hydrogen fuel.

♦ **Pros:** Using biomass as a feedstock produces about one-tenth the greenhouse emissions than hydrocarbon alternatives.

♦ **Cons:** Hydrogen fuel production requires large amounts of biomass. In Hawaii the limitation of land size would likely be among the biggest barriers to this feedstock. Localized pollution (e.g., land, water) could also be an issue.

**Coal**

Hydrogen can be produced from coal using gasification technology. The hydrogen would be separated at low pressure and compressed before delivery. Oxygen is used to sequester the carbon dioxide.

♦ **Pros:** Using coal as a feedstock produces about one-third the greenhouse emissions than the natural gas alternative.

♦ **Cons:** Oxygen has to be provided and the process is relatively energy intensive compared to others. Biomass can essentially yield similarly priced hydrogen with about 30% of the emissions.
Methanol
Methanol has gained a great deal of popularity as a fuel cell fuel option because of its high energy density.

♦ **Pros:** Because of its liquid form, it can be easily stored within a vehicle without the added costs of expensive storage tanks that hydrogen fuel requires.

♦ **Cons:** Methanol is a more expensive feedstock than natural gas, with estimated costs of $11/GJ versus $4-5/GJ for natural gas. Methanol also produces higher levels of greenhouse emissions.

Gasoline
Gasoline can also be reformed to produce hydrogen and several auto manufacturers are researching the use of an onboard vehicle reformer, which would extract hydrogen for the fuel cell.

♦ **Pros:** The existing gasoline infrastructure is perhaps the biggest incentive to utilize gasoline as a feedstock for hydrogen fuel production.

♦ **Cons:** When used as a fuel cell feedstock, gasoline produces similar greenhouse emissions to methanol fuel cells. In addition, hybrid vehicles (like the Toyota Prius) are able to produce similar gas mileage at a much lower cost. Gasoline itself is already a product of a refinery and thus further processes only add to the cost with few if any benefits when compared to existing technologies.

Natural Gas
Natural gas is comprised of approximately 90% methane, which carries 1 carbon atom to 4 hydrogen atoms. Natural gas is odorless and colorless and extremely flammable, yet when ignited, gives off very little greenhouse emissions. Because of this, natural gas is becoming increasingly popular, especially in countries with strict environmental regulations such as Japan.

♦ **Pros:** Natural gas, when steam reformed, is the most cost competitive feedstock for hydrogen production. While using natural gas in Hawaii may help to lessen Middle Eastern oil dependency, it would also most likely involve creating a natural gas dependency in the form of LNG on an Asia Pacific supplier.
**Cons:** Natural gas is a hydrocarbon and produces greenhouse emissions, albeit, at lower levels than gasoline or methanol. The levels, however, are still much higher, for instance, than with biomass or coal gasification.

Natural gas does present the strongest case of any of the above for use as a feedstock, but as Hawaii has no infrastructure, there are many hurdles in the way. That said natural gas’ relatively low cost makes it the most viable, over all other feedstocks until their costs are reduced.

**Emissions**

The combination of greenhouse gases and air pollution has long been a side effect of using crude for our energy needs. Greenhouse gases are thought be the contributing factor in global warming—the effect of carbon emissions rising to the upper atmosphere trapping heat that would otherwise escape into space. Combustion of fossil fuels is also thought to lead to air pollution, such as smog and acid rain.

In Hawaii, we may never see the smoggy haze of Los Angeles due to the sweeping effects of our trade winds. However, we may eventually feel the long-term effects of global warming. As such, the use of environmentally friendly fuels is becoming an urgent matter.

The following figure indicates that the ideal solution in terms of emissions would be to use renewable energy to produce zero emission hydrogen fuel. However, as mentioned earlier, at present this technology is not cost effective. While natural gas produces greenhouse gasses, it produces nearly half the emissions of methanol, gasoline, and hybrid vehicles. It should be noted that since 2004, some feedstocks have been evaluated further and are currently viewed as being less favorable. For example, of the feedstocks that are being actively considered in 2007, natural gas is probably the feedstock with the highest emissions. Feedstocks such as methanol or gasoline have gradually disappeared from discussions due to their higher costs or minimal benefits. Natural gas may eventually suffer the same fate, but presently its costs compared to the other alternatives make it the most attractive in the US market.
Costs Associated with Natural Gas as a Hydrogen Fuel Feedstock

In 2005, the Department of Energy developed a new hydrogen cost goal of $2-$3 per gallon of gasoline equivalent (gge). This was raised from the previous goal of $1.50/gge, as the Energy Information Administration adjusted upward its forecast of 2015 gasoline costs and the relative fuel economy of hydrogen fuel cell vehicles. The $2-$3/gge figure is designed so that the 2015 operating cost ($/mile) in a hydrogen fuel cell vehicle will be equal to or less than a 2015 gasoline vehicle. These figures are for delivered and untaxed fuel in 2005 dollars.

With the above in mind, natural gas is a clear winner in terms of hydrogen fuel production costs. At present, steam reformation of natural gas is the most economical means of producing hydrogen fuel. This is the result of a relatively affordable feedstock and comparatively less expensive production process. Of the feedstocks mentioned earlier, biomass, wind electrolysis of water, coal, and steam reformed natural gas are the most ideal candidates for hydrogen production in terms of greenhouse emissions. As shown in the following figure, natural gas is the cheapest feedstock to produce hydrogen fuel, with biomass and coal coming in second. The $3.80/gallon of gasoline equivalent of hydrogen difference between the two wind calculations results from the expenses of compressing and piping the hydrogen to the location where it will be stored for the centralized process. The
distributed process is less expensive because basically the electricity produced from a wind farm would then be used locally to perform the water electrolysis, thus bypassing the need for a pipeline and additional compression.

![Average Hydrogen Production Costs](image)

Returning to natural gas, however, it must be noted that the cost for hydrogen produced from natural gas reformation is still relatively high when compared to Hawaii’s high cost of gasoline.

**Hydrogen Fuel Cells**

As we discussed earlier natural gas could be the stepping stone towards a hydrogen economy, but what exactly is a hydrogen economy? Imagine a world where all of our energy needs are supplied by a clean infinite energy source—hydrogen. Hydrogen fuel can be used to power fuel cells which in turn, can be used to run our homes, transportation, and industry.
Fuel Cell
A fuel cell is a direct energy conversion system with no moving parts. Fuel cells are much like batteries with the exception that they consume fuel to maintain a chemical reaction that produces electricity. In simplest terms a feedstock (natural gas) is fed into a reformer, which extracts the carbon atoms from the natural gas leaving hydrogen enriched gas. The hydrogen gas is then fed to the fuel cell where it mixes with oxygen to begin a chemical reaction that produces DC power. The DC current is sent to a power conditioner, which converts the current into AC current.

Fuel Cell Applications
Fuel cells are an extremely flexible power source and researchers have found many uses for them. They are perhaps most recognizable in transportation use, where the efficiency and reduced emissions these alternative power sources offer has sparked a race among automobile and fuel cell manufacturers to be the first to commercially mass produce fuel cell vehicles. That said, the increasing strength of hybrid gasoline-electric vehicle sales since 2004 has perhaps slowed down the drive towards commercial vehicle production.

Transportation
Honda, Toyota, and Ford are a few of the auto manufacturers currently researching the use of fuel cells in vehicles. Honda has released several of its fuel cell vehicles in Japan and California on a trial basis. These fuel cell cars have a driving range of about 220 miles and have achieved the US Environmental Protection Agency’s lowest vehicle emission rating.
Stationary Use

Stationary fuel cells are also gaining ground and are being implemented worldwide. Testament to this came in the installation of a 250 kilowatt (kW) fuel cell at the Sheraton Parsippany Hotel in Parsippany, NJ, a couple of years ago. The fuel cell runs on natural gas and supplies nearly 25% of the hotel’s electricity and heating.

Distribution Issues

Hawaii will require substantial infrastructure changes to accommodate natural gas and additional capital investments would be required to further upgrade the infrastructure towards hydrogen fuel production and distribution. This section has changed little since 2004 as the same issues remain.

There are several key questions that must be answered before the dream of a hydrogen infrastructure can be realized, as current research and development has not settled on several key issues related to fuel cells:

♦ Direct hydrogen fueling versus onboard reforming: Researchers are debating whether to store pure hydrogen directly on the vehicle/stationary fuel cell or use small onboard fuel reformers to process hydrocarbons such as gasoline or natural gas. It does, however, appear that there is a strong push for developing onboard hydrogen storage systems. The reason being that with onboard storage, a driving range beyond 300 miles is more easily attained.

♦ The above issue will have a direct impact on how we distribute hydrogen fuel or a feedstock for hydrogen fuel production. There are two options to consider: (1) Central distribution of hydrogen from a large-scale natural gas reformer (or another fuel source), which could produce large amounts of hydrogen, with either pipelines or ground transport to distribute the hydrogen fuel, or (2) small onsite reforming stations, where natural gas (or another fuel source) is either piped or transported to the stations to be reformed onsite into hydrogen fuel.

♦ Storage of hydrogen fuel is yet another dilemma that must be resolved. Hydrogen does not store as easily as gasoline and requires specialized containment, which is more costly.
Centralized Hydrogen Production

Large scale hydrogen production plants range in hydrogen output from 25 to 100 mmscf/d. This translates into enough hydrogen to fuel approximately 220,000 to 900,000 hydrogen fuel cell vehicles, driven 11,000 miles per year. Capital costs for a 20 mmscf/d steam reformer are about $200/kW of H₂ output, whereas the cost for a 200 mmscf/d steam reformer is estimated at $80/kW of H₂. A plant of this size, in theory, could easily accommodate the vehicles in the City and County of Honolulu (In 2005, there were 714,604 registered passenger vehicles). It has become widely accepted by the Department of Energy that a price range for automotive fuel cells of $30-$45/kW of H₂ (down from $80/kW) is necessary for them to become commercial.

It should be noted that none of these costs take into account the distribution of hydrogen. In December 2006, the Department of Energy’s and the Department of Transportation’s publication “Hydrogen Posture Plan: An Integrated Research, Development, and Demonstration,” a figure of $3.50/gge of hydrogen is used to estimate delivery costs for centralized hydrogen production. It includes liquefaction, truck transport, and forecourt operations. The forecourt operations are basically the equivalent of a filling station for the hydrogen. The other option from the 2004 study is to pipe the hydrogen and the table below lists the estimated capital costs of hydrogen pipelines compared to natural gas pipelines. It should be noted that the $3.50/gge of hydrogen estimate assumes that the truck transport does not exceed about 100 miles.

<table>
<thead>
<tr>
<th>Diameter of Pipeline (inch)</th>
<th>Natural Gas Pipeline ($/mile)</th>
<th>Hydrogen Pipeline ($/mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>200,000</td>
<td>400,000</td>
</tr>
<tr>
<td>9</td>
<td>500,000</td>
<td>900,000</td>
</tr>
<tr>
<td>12</td>
<td>600,000</td>
<td>1,000,000</td>
</tr>
<tr>
<td>14</td>
<td>800,000</td>
<td>1,400,000</td>
</tr>
</tbody>
</table>

Source: Department of Energy

Decentralized Hydrogen Production

Small refueling stations, which include a natural gas reformer, fuel storage, and pumps, are quite cost competitive and would be ideal if Hawaii implements a distribution network for natural gas (we believe this is the likely scenario). A study by Direct Technologies found that a station capable of fueling 183 fuel cell vehicles a day would have an initial capital cost of $253,000 and produce hydrogen fuel at $1.55/gallon of gasoline equivalent (state and federal taxes excluded). Note,
however, that this data dates back to the 2004 version of our study and we imagine that the $1.55/gallon of gasoline equivalent cost may since have risen.

The Department of Energy estimates a station that could fuel 1,400 vehicles a day would have an initial cost of $1.1 million. However, the cost of hydrogen would drop significantly, to 87¢/gallon of gasoline equivalent.

To put this into perspective, according to the DBEDT, in 2003 Hawaii had 314 gasoline service stations operating statewide. If we assume that Hawaii upgrades a quarter of the stations, the capital costs would be nearly $20,000,000 using the Direct Technologies estimated cost for a hydrogen fueling station.

Storage
The problems associated with hydrogen storage have retarded efforts to produce affordable fuel cells. Hydrogen is a rather complex fuel to confine and researchers face a variety of technical barriers. It is difficult to say which technology will emerge as the frontrunner, as each has their own advantages and disadvantages.

Gaseous Hydrogen: One gram of gaseous hydrogen occupies about 11 liters (or 2.9 gallons) of space at atmospheric pressure, which means that hydrogen must be heavily compressed in order to store sufficient amounts of energy. Current storage tanks range anywhere from 10,000-20,000 pounds per square inch (PSI). Due to the high pressures, these tanks have raised concerns of safety, and as such the tanks must be significantly reinforced and are quite heavy.

Liquid Hydrogen: Liquid hydrogen is ideal for transportation applications as it has a high energy to mass ratio, which is three times that of gasoline. Unfortunately, the process of liquefaction involves lowering gaseous hydrogen to extremely cold temperatures (-235°C), and during the liquefaction process up to 40% of the energy content may be lost. Liquefied hydrogen must also be stored in a specially insulated tank to maintain its liquid form.

Metal Hydrides: This method of hydrogen storage is perhaps the safest. Through a chemical reaction, hydrogen is bonded with metals or alloys. By applying significant amounts of heat to the
hydrides 300-350°C, the hydrogen is released from its bonds. This technology is not an ideal means for transportation purposes as the weight and size of the hydrides are a burden on vehicles and their efficiency.

The Reality of a Hawaii Hydrogen Economy

The future outlook of a Hawaii hydrogen economy is somewhat cloudy. To look on the bright side, hydrogen fuel cells appear to have the backing of governments worldwide. Industries are also investing considerable funds into research and development of fuel cells.

♦ There are several Hawaii based projects underway to explore the viability of hydrogen fuel cells. The Hawaii Fuel Cell Test Facility—a joint research initiative between the Hawaii Natural Energy Institute, the Hawaiian Electric Company, and UTC fuel cells (a leading manufacturer of fuel cells)—continues to explore the feasibility of establishing a commercially viable fuel cell for transportation.

However, the cost of this technology is a considerable drag on development, as fuel cells remain extremely expensive due to the high costs associated with hydrogen fuel production and the materials used in fuel cells. Current costs of fuel cell vehicles range anywhere from $2 to $4 million each. Stationary fuel cells are also expensive and range in costs anywhere from $3,000-$5,000/kW. The price of fuel cells will have to drop to levels reflected in the table below, in order to become commercially viable.

<table>
<thead>
<tr>
<th>Application</th>
<th>Price Point for Commercial Viability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transportation</td>
<td>$30-45 per kW</td>
</tr>
<tr>
<td>Distributed Residential</td>
<td>$300-500 per kW</td>
</tr>
<tr>
<td>Distributed Commercial</td>
<td>$1,200-3,000 per kW</td>
</tr>
<tr>
<td>Stationary Grid Connected</td>
<td>$1,000-1,500 per kW</td>
</tr>
<tr>
<td>Portable/Micro</td>
<td>$5,000-10,000 per kW</td>
</tr>
</tbody>
</table>

We believe that if Hawaii chooses to move further in the direction of a hydrogen-based economy, LNG could play a key role in the interim stages. A natural gas infrastructure will help to soften the
LNG as a Possible Feedstock for Ethanol Production?

LNG is an unlikely feedstock for ethanol production and is not presently done anywhere in the world. Generally speaking, ethanol is produced from one of two processes. The first is to produce ethanol as a petrochemical, where it is achieved through the hydration of ethylene, and the second is to do it biologically by fermenting sugars with yeast. To produce ethanol from natural gas as a feedstock would require Hawaii to not only import LNG, but then build a petrochemical plant to produce the ethylene. Analyzing this technical process, however, is beyond the scope of this section and we believe that there is, currently, no interest in Hawaii to establish a petrochemical industry.

Aside from the added costs of building a petrochemical plant, the LNG itself would unlikely be competitive versus direct ethanol imports due to the lack of infrastructure. There is also the question of importing LNG with specialized equipment over significant distances. Chapter 3 provides more information on LNG shipping. As an addendum, it should also be noted that there are companies that are presently researching converting ethanol to hydrogen.

In the US, ethanol is primarily produced from corn due to corn’s relative abundance, subsidies, relative low price, and protective tariffs for the ethanol produced from it. Elsewhere in the world, sugar cane and sugar beets are the most prevalent feedstocks for ethanol, with Brazil being the world’s largest producer.

If Hawaii envisions a strong potential demand for ethanol, it would be worthwhile to commission a study on producing ethanol on island as opposed to importing it. Beyond corn and sugar products, feedstocks can include wheat, sorghum, potatoes, and beverage wastes. Furthermore, the production can have byproducts to sell such as animal feed, carbon dioxide, corn syrup, corn oil, and other corn based products. While no commercial plants are operating yet, research and development is ongoing for using cellulose to produce ethanol. The idea would be to convert agricultural/municipal wastes to ethanol. While technically it is feasible in 2007, it is still too costly to produce on a commercial scale.
If Hawaii were to have an interest in producing ethanol, there may be some federal interest. During the President’s March 2007 tour of Latin America, George W. Bush pushed for strengthened regional relations and greater energy security by expanding sugar cane ethanol production. Also, he still did not waive the 54¢ per gallon tariff for importing ethanol and an ad valorem tariff of 2.5%. This provides significant protection for anyone within the US looking to produce ethanol. And if corn can be grown to produce ethanol, then producers earn a 51¢ per gallon federal tax credit. Even if the tax credit is for corn, it might be relatively simple to lobby for it to extend to other feedstocks within the US.

Returning to the question posed by this section, we feel that LNG is an unlikely feedstock for Hawaiian ethanol production. If interested, direct ethanol imports or biomass ethanol production from local crops is likely the best way for Hawaii to proceed.
Chapter 9

Cost of LNG: Can it Compete in Hawaii?¹

Introduction
While concerns about the project site, environmental impacts, security of supply, safety, etc., are all important, the most basic, and perhaps the most critical question that must be answered is: Can LNG compete with existing fuels? Although the marketers of LNG are somewhat hesitant to discuss prices in detail at such an early stage, their interest in the Hawaii market certainly signals that they believe LNG can be competitive. In addition, estimates of the costs involved in the LNG projects that would likely serve the Hawaii market indicate that LNG could be a competitive source of energy. This chapter takes a look at the competitive position of LNG in Hawaii relative to other fuels and ends with a discussion on the competitive position of CNG into the State.

Advantages and Disadvantages of Hawaii as an LNG Market
Before delving into numerical estimates, it may be productive to think of the advantages and disadvantages of Hawaii as a LNG market relative to other potential buyers. To the extent that Hawaii is an appealing market to sellers, it will be able to secure a lower price for LNG.

Hawaii has several clear advantages over alternative markets. First, although the regulatory details surrounding LNG have not been established, Hawaii has a well-developed legal structure and a very dependable major buyer in HECO. It is also unlikely to see large-scale deregulation and other potential turmoil which threatens some market players in Asia. This is of the utmost importance in the LNG market, which requires large capital investments and typically looks for long-term contracts to ensure that these costs can be recouped. A number of promising LNG markets, such as India, have in the past suffered from the fact that buyers are seen as unreliable.

A second advantage of Hawaii is that its potential demand is relatively stable, and it does not see the dramatic seasonal swings seen in a country like South Korea, where gas consumption spikes in the...

¹ This chapter draws upon FACTS database, presentations by several LNG marketers, information from various LNG focused seminars and conferences, and conversations with individuals involved in the gas and power industry.
winter. This limits the need for storage and allows producers to more fully utilize their capacity throughout the year.

A final major advantage of Hawaii is the emergence of the US West Coast and Mexico as a promising LNG market. Because Hawaii is located along the route from Asia to these markets, potential synergies exist that were not in existence even a few years ago. The fact that energy companies are looking to more creatively utilize their LNG shipping capacity also increases the interest in Hawaii as a potential market.

From the point-of-view of LNG providers, there are two major disadvantages to the Hawaii market. The first disadvantage is the size of the market. The Hawaii market is relatively small when compared to the huge existing markets in Japan and Korea, and the enormous potential markets of China, India, and the US mainland. However, a number of projects of Hawaii’s size or smaller have come to fruition in recent years (e.g., in Puerto Rico and the Dominican Republic), and Hawaii is likely to exceed the 1 million tonnes per annum that allows reasonable economies of scale.

The second major concern about Hawaii is the site for the regasification terminal. This is also a concern on the US mainland, where permitting is extremely difficult, but Hawaii presents an added challenge in that the likely location (the harbor at Barber’s Point), would likely require substantial modification, as discussed later in this chapter. Alternatives, such as offshore regasification, would add considerably to the cost.

To summarize, although there are some disadvantages to the Hawaii market, in our conversations with LNG providers they were quite interested in the opportunity to sign what they see to be a very secure long-term contract that could provide a stable, albeit small, supply outlet for a new or expansion LNG project. Should Hawaii seek to pursue LNG, it should certainly be aware of its position in the marketplace and seek out sellers that will value its unique attributes.

**Necessary Infrastructure and Estimated Costs**

**Onshore Receiving Terminal**

In terms of infrastructure, by far the most challenging and expensive aspect of establishing LNG in Hawaii would be the regasification terminal. Regasification in itself would be relatively inexpensive,
but the cost of building LNG storage is substantial, around $80 million per tank if built onshore. As discussed in Chapter 3, storage typically represents 40-50% of terminal costs. Therefore, based on two tanks, this would imply a total cost of somewhere in the region of $320 to $400 million for a 2 mtpa terminal. It may be possible that Hawaii could get away with the construction of one storage tank, thereby bringing down the capital cost to $240 to $320 million. However, this does not take into account the substantial costs that would go along with the port modifications, which could range from $55 to $100 million.

Other expenses worth noting would include two gas pipelines (estimated cost of $30 million) totaling approximately 17 miles in length to feed the existing boiler units at Kahe, Waiau, and Kalaeloa (note that it is likely that the Honolulu plant would continue to use low sulfur fuel oil and we understand that the Waiau peaking units would likely not be modified to use gas). Each of the boiler units would be retrofitted to use either gas or fuel oil at a cost of approximately $3-5 million each. (Total cost of approximately $36-60 million).

Taken together, total infrastructure costs for on onshore receiving terminal with one storage tank could be in the range of $360-510 million, while the addition of two storage tanks would increase the capital costs to $440-$590 million.

Given a number of reasonable assumptions we can translate our capital cost estimate into a $/MMBtu cost estimate. To summarize, we assume a 25-year project life, an 8% discount rate, operation and maintenance expenses are equal to 4% of the capital cost, and fuel use is equal to 2% of total gas input. Gas used as fuel is valued at $8.00/MMBtu and the project takes three years to complete. Under these assumptions, a $360-510 million dollar investment in a 2 mtpa terminal and the other required infrastructure translates into a unit cost of $.53-70/MMBtu. Under a two tank scenario of $440-590 million the cost is approximately $.62-.79/MMBtu.

**Offshore LNG Terminal—‘Energy Bridge’**

As discussed in Chapter 3, another option would be to build an offshore receiving terminal. Excelerate Energy promotes the Energy Bridge Regasification Vessels (EBRVs), which involves the use of purpose built ‘regas’ vessels that have vaporizers onboard to regasify the cargo. Excelerate Energy has been kind enough to provide FACTS Inc. with estimates of what it would potentially
cost to establish and operate a deepwater port off of Barber’s Point similar to their existing project in the Gulf of Mexico (another project is also being planned offshore Boston). As Hawaii would need a continual flow of gas due to non existent storage facilities, Excelerate would employ a dual buoy system so a second ship can connect to the pipeline while the first is completing unloading. The analysis was done assuming the three supply sources discussed in Chapter 7, namely Australia, Alaska, and Russia (Sakhalin). Please note that for the Alaska analysis Jones Act restrictions are not applied as it’s assumed that Hawaii could get a waiver as was done for the cruise industry.

<table>
<thead>
<tr>
<th>Cost Component/Supply Source</th>
<th>Australia</th>
<th>Alaska</th>
<th>Sakhalin</th>
</tr>
</thead>
<tbody>
<tr>
<td>EBRV Regas Rate</td>
<td>160,000 MMBtu/d</td>
<td>160,000 MMBtu/d</td>
<td>160,000 MMBtu/d</td>
</tr>
<tr>
<td>No. of EBRVs required for baseload supply</td>
<td>3</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>DWP Cost</td>
<td>1.29</td>
<td>1.29</td>
<td>1.29</td>
</tr>
<tr>
<td>Annual O&amp;M Cost</td>
<td>0.12</td>
<td>0.12</td>
<td>0.12</td>
</tr>
<tr>
<td>Transport Cost (excluding boil-off)</td>
<td>1.25</td>
<td>0.68</td>
<td>0.68</td>
</tr>
<tr>
<td>Regas cost</td>
<td>0.53</td>
<td>0.53</td>
<td>0.53</td>
</tr>
<tr>
<td>Total Cost (per MMBtu)</td>
<td>3.20</td>
<td>2.62</td>
<td>2.62</td>
</tr>
<tr>
<td>Other cost on customer’s account</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regas Fuel at $8.00</td>
<td>0.17</td>
<td>0.17</td>
<td>0.17</td>
</tr>
<tr>
<td>EBRV boil-off losses $8.00</td>
<td>0.33</td>
<td>0.15</td>
<td>0.15</td>
</tr>
<tr>
<td>Total Cost including Fuel and Losses ($/MMBtu)</td>
<td>3.70</td>
<td>2.94</td>
<td>2.94</td>
</tr>
</tbody>
</table>

Source: Excelerate Energy

Note: To simplify the comparison, the above are all based on an LNG cargo size (regasified) of 3,000,000 MMBtu. In reality, the quantities available for regasification will vary between supply sources due to difference in gross heating value (GHV) and vol.

With respect to the analysis above, it is assumed that the EBRV’s have cargo capacity of 138,000 m³ and the customer incurs the regasification fuel charges and boil-off losses. In addition, it is assumed that the natural gas price (for regasification and boil-off) is $8.00/MMBtu, the ship uses 25 tons of fuel oil a day at $250 ton, and that it requires 19 days (3,000,000 MMBtu/160,000 MMBtu/d) to discharge the cargo given Hawaii’s current estimated demand load.

The estimates yield some interesting results. The main difference lies in the distance between supply sources, and therefore the number of dedicated ships to the project. In the case of Australia, the round-trip voyage (excluding regasification) is estimated at 28 days, whereas from Alaska and Sakhalin it takes approximately 12 and 16 days, respectively, which are reflected in the shipping costs. As one can see, the estimate from Australia is on the order of $3.70/MMBtu and $2.94/MMBtu from Alaska and Sakhalin.
In the discussion on estimated costs for the onshore receiving terminal, we had substantially lower costs. Including transport, the cost is below $2.50/MMBtu in all cases. The robust costs for the Excelerate model is due in no small part to the fact that a vessel will be sitting idle for 19 days discharging at the rate of 160,000 MMBtu/d. Typically vessels can discharge in a day or so and then are off to their next destination. A ship sitting idle incurs costs and in this case the costs are substantial compared to a land-based facility.

**CNG—EnerSea Transport**

As mentioned in Chapter 3, CNG technology offers an alternative to transporting natural gas instead of using pipelines and LNG. One of the leading providers of CNG transportation is EnerSea through their proprietary VOTRANS natural gas carriers, also known as ‘V-ships’. EnerSea has been kind enough to provide FACTS Inc. with an estimated transport tariff, from an Alaskan supply source, which is essentially all-inclusive and accounts for the capital costs of all the ships, the transport of the gas from the point of origin to the final destination, and the construction and operation of the offshore storage facility. The tariff for all the related facilities would be somewhere on the order of $4.00/MMBtu. Under this scenario 4 ships each with a capacity of 830 mmscf would be used to service the route in conjunction with an offshore permanently moored CNG storage facility (560 mmscf). The CNG from the V-ships would be offloaded directly into storage and the facility would store and re-deliver the gas on a continuous (rateable) basis through a pipeline to shore. Unlike, the EBRVs the V-ship would offload in approximately 24 hours. Please note that the transport tariff does not include the cost of tie-in facilities such as a pipeline to shore. The summary of the project assumptions are illustrated below.

<table>
<thead>
<tr>
<th>Transit Distance from Alaska (nm)</th>
<th>Ship Speed (knots)</th>
<th>Gas Quality (btu/scf)</th>
<th>Fleet Size</th>
<th>V-ship Capacity (mmscf)</th>
<th>Storage Capacity (mmscf)</th>
<th>Supply Rate (mmscfd) (Note 1)</th>
<th>Fuel Gas Requirement (Note 2)</th>
<th>Tariff (USD/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2,400</td>
<td>18</td>
<td>1,050</td>
<td>4</td>
<td>830</td>
<td>560</td>
<td>187</td>
<td>14%</td>
<td>$4.00</td>
</tr>
</tbody>
</table>

Source: Enersea Transport LLC

Notes: 1. The supply rate includes fuel gas that will be required by the vessels, terminals, and storage.

2. Fuel gas is calculated based on a % of supply volume and it utilized for the V-ship fleet (propulsion & ship services), the gas handling facilities and the CNG storage facility at the delivery terminal. Fuel gas is assumed to be provided by the client (supply or off-taker).
Competitive Position of Natural Gas under Alternative Price Scenarios

**LNG—Recent Prices**

One of the most critical factors on whether natural gas can penetrate the Hawaiian market is price, particularly with respect to how it can compete in the power sector. The gas that lands in Hawaii (whether in the form of LNG or CNG) needs to compete primarily with LSFO and to a lesser extent diesel. Although there are differences in terms of efficiencies and maintenance costs, it is appropriate to compare the cost-competitiveness of the fuels on a $/MMBtu basis. HECO’s LSFO costs ranged from a low of $27.91/b in 2002 to a high of $52.26/b in 2005 over the last six years. In other words, their LSFO costs ranged from $4.88/MMBtu to $9.14/MMBtu.\(^2\) With respect to diesel, HECO’s fuel costs ranged from a low of $35.07/b in 2000 to a high of $75.95/b in 2005 over the last six years, which translates to $6.36/MMBtu and $13.78/MMBtu.\(^3\)

The cost of natural gas relative to fuel oil and diesel would obviously depend on the LNG price formula that is adopted and how it relates to oil. Because LNG is currently not imported to Hawaii, we must rely on recent LNG supply agreements as a guideline of the “market price.”

For this analysis we look at a couple of supply agreements that were signed in 2005 that are from previously identified possible suppliers, namely Australia and Russia. First, Australia’s Gorgon project operator ChevronTexaco signed heads of agreements (HOAs) with three Japanese utilities for a combined volume of 4.2 mtpa over a period of 20 years. The FOB price is around $4.20/MMBtu at JCC prices of $60/b. Also, in 2005 Russia’s Sakhalin project operated by Shell, signed a SPA with Korea’s KOGAS for the supply of 1.5 mtpa over a period of 20 years. The FOB price is capped at $3.54/MMBtu at oil prices of $25/b and above.

If we add estimated shipping costs (including boil-off) from these two supply sources to Hawaii in addition to our estimated cost of $0.53-0.79/MMBtu for onshore regasification, port costs, and other capital costs, we get a DES LNG price in the range of $4.92-$6.57/MMBtu, with an average price of $5.75/MMBtu. This range is depicted in the following figure under the category “Recent LNG contract.” For comparison, the high/low range of prices and average price that HECO paid for fuel oil and diesel over the period 2000-2005 is also reflected in the figure.

\(^2\) On a calorific basis, one barrel of fuel oil is equivalent to approximately 5.72 MMBtu.
\(^3\) On a calorific basis, one barrel of diesel is equivalent to approximately 5.51 MMBtu.
Given these estimates it is clear that LNG has the potential to be competitive with fuel oil, and especially diesel. However, it must be noted that deals offered by Gorgon and Sakhalin in 2005 were at a time when the market was still in a transition phase. In other words, it’s highly unlikely that suppliers will offer these types of prices in today’s market. In fact, the Gorgon project is facing such massive cost over-runs that they will surely have to invoke their price review clauses in order to secure a reasonable rate of return. If these prices aren’t indicative of the present and future market, then what is? The next section will examine this question.

**LNG—Future Prices**

In Chapter 4 we discussed how the market had begun to shift in favor of the sellers in 2005. While the transition was gradual, 2006 marked a clear transformation to a sellers’ market with the high prices achieved through the NWS allocation process and the diversion of Qatari volumes to Korea. In the NWS allocation process, the venture invited its remaining long-term buyers to submit requests for volumes of LNG at a non-negotiable price, equivalent to $7.90/MMBtu (DES) at JCC of $60/b. In the case of Qatar, 2.1 mtpa will be diverted from their initially targeted western markets to Korea under a 20 year contract which began in 2007. The FOB prices for the Australian
and Qatari deals were approximately $7.10/MMBtu and $9.20/MMBtu, respectively. As was done with the earlier analysis we add estimated shipping costs from these two supply sources to Hawaii in addition to our estimated cost of $0.53-0.79/MMBtu for onshore regasification, port costs, and other capital costs. This gives us a DES LNG price in the range of $9.20-$12.40/MMBtu, with an average price $10.80/MMBtu, nearly double the earlier estimates. Of course, the higher price estimate is from Qatar and it is unlikely that Hawaii would import LNG from this supplier given the distance. However, this discussion is included because these two most recent contracts for Asia Pacific regional buyers are the new benchmarks, with other suppliers attempting to position themselves in-between these prices.

Given the above, we now have an idea if Hawaii were to go to the marketplace today to procure LNG what type of prices suppliers would be asking for. While this is useful, Hawaii won’t be importing any LNG until 2013 at the earliest so it’s only logical to ask, what are suppliers’ price expectations over the next 5-10 years? There has been much discussion on the current tight market and how the sellers now have the upper hand. We see the market easing up a bit in the middle half of the next decade as substantial new amounts of liquefaction capacity comes onstream. However, we do not see a return of FOB prices on the order of $4/MMBtu and below due to gas’ increased popularity and continued high oil prices, which have a direct affect on the price of natural gas. Our mid-term Asian LNG FOB price forecast for new long-term contracts is around $6-10/MMBtu. If we add on average $2/MMBtu for shipping and onshore regasification costs to Hawaii we would get a DES LNG price in the range of $8-12/MMBtu, with an average price of $10/MMBtu.

Would this be competitive with HECO’s future LSFO and diesel costs? In order to answer this question we ran a regression examining the correlation between HECO’s LSFO and diesel costs compared to that of the Singapore market. We then applied the coefficients to our oil products forecasts and came up with the following results. Under our scenario, HECO LSFO prices average $63.26/b ($11.06/MMBtu) and range from a high of $76.25/b ($13.33/MMBtu) in 2014 to a low of $52.62/b ($9.20/MMBtu) in 2017. In the case of diesel, we forecast HECO diesel prices to average $76.01/b ($13.80/MMBtu) and to range from a high of $90.80/b ($16.48/MMBtu) in 2014 to a low of $64.20/b ($11.65/MMBtu) in 2017. Please note that all these figures are in real 2007 dollars.
The figure above clearly shows that LNG prices to Hawaii can compete with HECO’s LSFO and diesel costs if the receiving terminal is built onshore. What about an offshore receiving terminal? Using the figures provided by Excelerate Energy combined with our vision of the Asian LNG market, we can get a rough estimate of the costs to procure and deliver LNG to Hawaii using the EBRVs model. If we take our earlier assumption that the mid-term Asian LNG FOB price for long-term supply is around $6-10/MMBtu, and apply Excelerate’s cost assumptions for supply from Australia, Alaska, and Russia we get the following results. The DES price of LNG from Australia would be on the order of $9.70-$13.70/MMBtu, while that from Alaska and Russia would be around $8.94-12.94/MMBtu. Under this scenario, the gains in savings from fuel costs compared to LSFO are marginal if gas is sourced from Alaska or Russia and non-existent if the gas is sourced from Australia.

**CNG**

As a final note, the analysis above has focused primarily on LNG due to the amount of available data when compared with CNG, primarily as no large-scale commercial CNG trade exists. However,
we now have a clear idea of what the landed gas price in Hawaii has to be to compete with the future LSFO and diesel costs. With respect to LSFO, the gas price has to be competitive with the forecasted average price of $11.00/MMBtu. Given the earlier estimates by EnerSea of an all-inclusive transport tariff of $4.00/MMBtu for Alaskan gas, the FOB price of Alaskan gas would have to be somewhere on the order of no more than $5.00-6.00/MMBtu. Given, that CNG requires no liquefaction and hence no cryogenic technology, a price of $5.00-6.00/MMBtu for Alaskan gas seems within reach as the compression process is relatively straightforward and not a major expense in the overall supply chain. What’s more, the CNG could be easily transferable to the transport sector thereby potentially increasing demand for gas fueled vehicles when compared with importing LNG.
Chapter 10
Demand Scenarios for LNG in Hawaii

Introduction
If Hawaii chooses to pursue the LNG option there are several main areas where it would, and could possibly, be consumed. Initially, LNG would likely replace almost all of the fuel oil used on Oahu in power generation, as well as the synthetic natural gas that is used in the utility gas network, also on Oahu. Over time, LNG use would grow as demand grows in both of these systems, and there is also the possibility of other uses emerging, such as compressed natural gas for vehicles, neighbor island use, and reforming the natural gas into hydrogen for fuel cells. In this chapter, we briefly examine the consumption possibilities in each of these areas, a summary of which is provided in a figure at the end of the chapter.

Power Generation
When we first examined the LNG option in the Hawaii Hydrocarbon Outlook we examined a number of scenarios, including importing relatively small quantities of LNG, but after extensive conversations with industry contacts it appears that the most likely scenario is that LNG would replace almost all of the fuel oil that is used for power generation on Oahu. As indicated in the following table, LNG would be consumed in all of the units at Kahe, six of the units at Waiau (two combustion turbine peaking units would continue to consume diesel, at least initially). The two units in downtown Honolulu, which are used only when electricity demand is at its highest, would likely continue to use fuel oil. Because usage at the downtown units is so limited, it would not be worth the cost of converting these units to consume natural gas. In all, approximately 95% of the fuel oil that HECO currently uses in power generation on the island of Oahu would be converted to LNG.

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1 This chapter draws upon conversations with industry participants; input from DBEDT; the Hawaii Hydrocarbon Outlook, January 2003, which was prepared by FACTS Inc. for the Hawaii Energy Forum, HECO’s IRP-3, http://www.nrel.gov/vehiclesandfuels/; http://www.ngvc.org; and Hawaii Energy Strategy 2000.
### Capacities and Type of Existing HECO Generating Units

<table>
<thead>
<tr>
<th>Unit</th>
<th>Fuel Type</th>
<th>Gross (MW)</th>
<th>Net (MW)</th>
<th>Gross (MW)</th>
<th>Net (MW)</th>
<th>Year Built</th>
</tr>
</thead>
<tbody>
<tr>
<td>Honolulu 8</td>
<td>LSFO</td>
<td>24.0</td>
<td>22.3</td>
<td>56.0</td>
<td>52.9</td>
<td>1954</td>
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<tr>
<td>Honolulu 9</td>
<td>LSFO</td>
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<td>22.5</td>
<td>57.0</td>
<td>54.4</td>
<td>1957</td>
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<tr>
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<td>49.0</td>
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<tr>
<td>Kahe 6</td>
<td>LSFO</td>
<td>45.0</td>
<td>40.1</td>
<td>142.0</td>
<td>133.9</td>
<td>1981</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td>464.0</td>
<td>431.2</td>
<td>1,263.0</td>
<td>1,208.6</td>
<td></td>
</tr>
</tbody>
</table>

Note 1: Unit Minimum Ratings are the lowest rate at which it is practical to operate the unit.
Note 2: LSFO is low sulfur fuel oil.
Note 3: Gross numbers represent the nameplate rating of the units. Net numbers represent the power that the unit can deliver to the system after subtracting the power used by all ancillary equipment (e.g., pumps, blowers, etc.).
Note 4: All units are electric utility steam boilers except for Waiau 9 and Waiau 10, which are simple cycle combustion turbines.

Source: Hawaiian Electric Company, Inc.

HECO also has a power purchase agreement with independent power producer Kalaeloa Partners, which has a 208 MW dual-train combined cycle unit that is fueled by fuel oil provided by Tesoro. It should be noted that this fuel oil is “washed” for use in the combustion turbines. Also, as part of the supply contract, Tesoro receives steam heat from Kalaeloa Partners. While the fuel supply agreement and the units themselves would obviously have to be modified, the Kalaeloa units could certainly be fueled by LNG.

Currently, HECO’s final preferred plan (IRP-3), submitted in October 2005, calls for approximately 151 megawatts (MW) of energy efficiency, conservation, other demand side management (DSM) programs, 50 MW of combined heat and power (CHP) and distribution generation (DG) resources, a 100 MW simple-cycle combustion turbine unit, 1.2 MW of solar photovoltaic resources, 50 MW of wind power, and a new 180 MW coal unit in 2022. In general, even if Hawaii does not pursue LNG, there will clearly be a move away from fuel oil as a fuel source in power generation in the future, as illustrated by the commitment to renewable solar and wind energy, as well as HECO’s pledge to try and use 100% biofuels for the new 100 MW simple-cycle combustion turbine unit at Campbell Industrial Park. The following figure illustrates HECO’s final preferred plan.
In our projections of possible LNG demand in the power sector, we estimate future fuel oil and diesel demand by HECO and Kalaeloa Partners given the aforementioned final preferred plan and existing contractual commitments. Of HECO’s existing oil-fired capacity, we assume that LNG will be consumed in all the units at Kahe and six of the units at Waiau. Insofar as the Kalaeloa plant is concerned, we assume that fuel oil use remains constant from 2006 until its contract expires in 2016 (in 2005 Kalaeloa Partners added 28 MW of capacity, thereby bringing total capacity of the plant to 208 MW). Given these assumptions, we estimate that LNG substitution in the power sector would be approximately 1.35 million tonnes (mt) in 2007, increasing to approximately 1.5 mt in 2020. Currently, HECO plans on constructing 180 MW of additional coal-fired capacity in 2022, but because natural gas has environmental advantages over coal and the LNG infrastructure would
already be in place, Hawaii could build additional gas-fired capacity instead, if the LNG option is pursued. Under this scenario LNG substitution in the power sector could reach 1.8 mt in 2022.

**Utility Gas**

In comparison to the power sector, the amount of LNG that would be required by the utility gas sector would be very small, at least in the initial stages. It is our understanding that the infrastructure upgrades required to convert the existing infrastructure to accommodate regasified LNG would be minimal. Currently, synthetic natural gas is manufactured by the Gas Company from light ends (relatively, light petroleum products) provided by the Tesoro refinery. The synthetic natural gas accounts for 94% of all utility gas consumed on Oahu, with LPG accounting for the balance. Most of the utility gas is consumed in the Downtown-Waikiki corridor.

Currently, gas is very expensive in Hawaii, with prices 2 to 3 times what is typically seen on the US mainland. As a consequence, we believe that there is a lot of room for growth in the utility gas market with the introduction of LNG, which should bring cheaper gas. Because we believe that gas prices would likely fall by more than electricity prices with the introduction of LNG, the competitive position of gas would likely be enhanced. There would likely be an increase in gas demand for commercial water heating and gas-fired air conditioning. Additionally, this could improve the economics of combined heat and power systems (CHP) and the expansion of the utility gas network, both of which would boost demand.

At current levels, utility gas consumption would only be the equivalent of approximately 60,350 tonnes of LNG, which is only the size of about one cargo of LNG. The Gas Company’s current base-case forecast of utility gas demand anticipates that demand will grow by only 0.43% annually during 2000-2020, to 68,792 tonnes in 2020. Even the high-case forecast projects growth of less than 1% (0.81%), to 75,832 tonnes in 2020. To illustrate the possible impact of lower prices and increased interfuel substitution, if demand were to grow by 2% per annum after the (hypothetical) introduction of LNG in 2007, demand would reach 85,420 tonnes by 2020.
Other Uses

Other possible uses for LNG include: (1) encouraging the use of compressed natural gas (CNG)—first in fleet vehicles, then in private vehicles; (2) the development of fuel cells, where natural gas serves as a relatively inexpensive source of hydrogen in the early stages of development (as discussed in Chapter 9); and (3) barging LNG to the neighbor islands for use in power generation. It is important to note that while each of these options is technically feasible, their economic viability, particularly 2 and 3, is currently questionable.

Natural Gas Vehicles

As natural gas vehicles (NGVs) would potentially be the largest user besides the power sector, it is worth briefly discussing the costs and benefits of implementing such a program. NGVs have increased in popularity, particularly in Asian countries such as Pakistan, India, and China due to its environmental properties and relatively low fuel cost when compared with gasoline. In the continental US NGVs are popular amongst mass transit options such as buses, as demonstrated by the fact that roughly 22% of all transit bus orders are for natural gas. There are currently 150,000 NGVs on US roads today and over 5 million worldwide.\(^2\)

In its traditional gaseous form natural gas occupies more volume than traditional liquid fuels, so it is either compressed or liquefied and used as a vehicle fuel to make it practical for transport use. Compressed natural gas (CNG) is the most common application for NGVs, but liquefied natural gas (LNG) use is becoming increasingly common. CNG has a high octane rating (>120) and is used in spark ignition engines for both light-duty and heavy-duty vehicle applications. Some vehicles operate exclusively on CNG and some can use both CNG and gasoline. CNG is stored onboard vehicles in cylinders at pressures of 3,000 to 5,000 pounds per square inch, while an odorant is normally added for safety reasons. On per gallon basis, CNG stored in the vehicle tank has about one-third less energy content than gasoline, which limits driving range when compared to a gasoline vehicle. LNG on the other hand is considerably denser and has greater energy content than CNG. Therefore, a larger quantity of LNG can be stored in the same tank volume. However, because storing a chilled liquid onboard a vehicle is complex, LNG is only used on heavy-duty trucks and buses.

\(^2\) http://www.ngvc.org
Like gasoline, natural gas is combustible, which means it can be used in a combustion engine. Still, some modifications are required to make an NGV work efficiently. These changes are primarily in the fuel storage tank, the engine, and the chassis. Manufacturers charge a typical premium of $1,500 to $6,000 above the cost of a conventionally-fueled vehicle, while a retrofit conversion costs between $2,000 and $4,000. Some of these costs can be offset by federal tax incentives such as PL 109-58, which provides an income tax credit for the purchase of a new, dedicated alternative fuel vehicle at 50% of the incremental cost of the vehicle, plus an additional 30% if the vehicle meets certain tighter emission standards. These credits would range from $2,500 to $32,000 depending on the size of the vehicle. The credit is effective on purchases made after December 31, 2005 and expires on December 31, 2010. Moreover, PL 109-58 provides for an income tax credit equal to 50% of the cost of natural gas refueling equipment, up to $30,000 in the case of large stations and $1,000 for home refueling appliances. Additionally, PL 109-59 provides for a tax credit of 50¢/gge of CNG or liquid gallon of LNG for the sale of CNG and LNG for use as a motor vehicle fuel.

NGVs have a number of benefits over gasoline or diesel powered vehicles. The following are the main advantages of NGVs:

- **Environmentally friendly.** The biggest advantage of NGVs is that they reduce exhaust emissions. NGVs typically achieve a 70% reduction in carbon monoxide emissions, a 87% reduction in nitrogen oxide emissions, and a 20% reduction in carbon dioxide emissions.

- **Safe.** NGVs are safer. The fuel storage tanks on an NGV are thicker and stronger than gasoline or diesel tanks. There has not been an NGV fuel-tank rupture in more than two years in the US.

- **Cost effective.** Natural gas costs are typically lower than gasoline. On average in the US, natural gas costs one-third less than gasoline at the pump. On Oahu, gasoline currently retails at around $2.86/gallon or $120/b. This retail price is equivalent to about $24/MBtu.$^3$ Earlier we discussed importing natural gas to Hawaii at DES prices under $10/MBtu. While this is

$^3$Note: On a calorific basis, one barrel of gasoline is equivalent to approximately 5 MMBtu.
simply a rough estimation and more analysis should be done, there certainly seems to be room for natural gas to compete with gasoline in Hawaii’s transport sector.

- **NGVs have lower maintenance costs.** Because natural gas burns so cleanly, it results in less wear and tear on the engine and extends the time between tune-ups and oil changes. Vehicles typically last 2-3 years longer than their gasoline-fired counterparts.

Regarding the disadvantages of NGVs, one of the biggest complaints about NGVs is that they aren’t as roomy as gasoline cars. This is because NGVs have to give up precious cargo and trunk space to accommodate the fuel storage cylinders. Not only that, these cylinders can be expensive to design and build—a contributing factor to the higher overall costs of a natural-gas vehicle compared to a gasoline-powered car. Other disadvantages of NGVs are:

- **Limited driving range.** Typically about half that of a gasoline-powered vehicle. For example, Honda’s natural gas Civic (the Civic GX) can go up to 220 miles without refueling. A typical gasoline-powered Civic can go approximately 350 miles without refueling. If a dedicated NGV ran out of fuel on the road, it would have to be towed to the owner's home or to a local natural gas refueling station, which might be harder to find than a “regular” gas station.

- **It’s not a renewable resource.** It should be noted that natural gas, like gasoline, is a fossil fuel and cannot be considered a renewable resource. While natural gas reserves in the US are considerable, they are not inexhaustible.

**Projected Demand**

Given the discussion presented above, we have projected LNG demand for the period of 2010-2020. Of course, this assumes that Hawaii begins receiving LNG in 2010, which may be optimistic. However, for the purposes of this analysis, establishing the exact year that shipments are initiated is not critical.

To begin, we assume that Oahu power consumption grows at an average annual rate of approximately 0.8% from 2010 through 2020. This is roughly the same rate that is projected by
HECO, and is predicated on the assumption that gas will be used to satisfy future power demand from the existing oil-fired power plants discussed earlier. We follow the Gas Company in projecting that utility gas demand will grow at an average annual rate of 0.43% through 2020, although we feel that more rapid growth is certainly plausible if the introduction of LNG corresponds with lower gas prices. These growth projections could be considered quite conservative and thus, it is very possible that Hawaii LNG demand in the power and utility gas sectors would be approximately 1.42 million tonnes in 2010, growing to approximately 1.55 million tonnes in 2020.

In terms of the other possible uses of LNG discussed above, we choose a rather optimistic scenario where the use of CNG vehicles is encouraged. In 2012 CNG vehicles replace 1% of gasoline and diesel usage and the share of CNG vehicles increases by 1% each year, such that CNG accounts for 9% of transport fuel in 2020, equivalent to approximately 120,000 tonnes of LNG. Additionally, we optimistically assume that a fuel cell pilot project will be underway by 2018 and this will replace 1% of the transport fuels. We feel that the cost of barging LNG to the neighbor islands is likely to be prohibitive, so we do not include this scenario in our final demand projections, which are depicted below.
Chapter 11
LNG and Possible Disruptions to the Existing Energy Infrastructure: Implications for Energy Security and the Hawaii Economy¹

Introduction
Any discussion of LNG imports into Hawaii will inevitably raise the question of the impact on the refining industry. The State of Hawaii is extremely concerned about gasoline prices being too high due to lack of competition and the existence of only two refiners. Naturally, there is a great concern over the disappearance of one of the refiners and its impact on competition, prices, and energy security.

In a report entitled *Hawaii Hydrocarbon Outlook*, FACTS Inc. evaluated how alternative fuel substitution scenarios might impact refining margins, showing that LNG might have an impact on profitability of the refining industry. Also, Stillwater Associates released a detailed analysis of refining in the State, and while it is not a focus of their analysis, they did point out that LNG would threaten the viability of the refineries. Unfortunately, each of these analyses are somewhat static, in that they do not incorporate the wide array of responses that are available to the refineries if the LNG option is pursued. Indeed it may well be possible for both refineries to survive under different scenarios with LNG replacing fuel oil in power generation.

Hawaii Oil Demand: Contrasts with the Mainland
There are indisputable contrasts between Hawaiian oil-demand patterns and those seen in the rest of the country. First of all, people in Hawaii use considerably more oil per person than the US average—about 40 barrels per person each year, as opposed to the US average of 23 barrels. This might seem surprising, given the comparatively low need for heating and cooling in Hawaii, but

¹ This chapter draws upon conversations with industry participants; the *Hawaii Hydrocarbon Outlook*, January 2003, which was prepared by FACTS Inc. for the Hawaii Energy Forum; the *Study of Fuel Prices and Legislative Initiatives for the State of Hawaii*, August 2003, which was prepared by Stillwater Associates for DBEDT; and the Hawaii Energy Strategy Project 2, Task IV: *Scenario Development and Analysis*, December 1993, which was prepared by the East-West Center Program on Resources for DBEDT.
what it really reflects is the limited supplies of non-oil energy in the state—coal plays a very minor role, natural gas is unavailable, hydropower is used only on a small scale, and there are no nuclear powerplants in Hawaii. On a per-capita basis, Hawaii’s energy consumption is far lower than the US average, but about 90% of the energy consumed is Hawaii is provided by oil (as compared to less than 40% oil for the US total). The figure below shows the US demand for oil products by fuel type (using 2003 data).

As mentioned above, almost half of demand is for gasoline. This is followed by distillate demand (diesel oil, home heating oil, and light industrial fuel), which accounts for about a fifth of consumption. Demand for “other” oil products includes LPG, asphalt, petrochemical feedstocks, waxes, lubricants, and many miscellaneous materials, which together account for almost another fifth of demand. Jet and aviation fuels use about 9% of US oil, and fuel oil (often called ‘heavy fuel oil’, or ‘residual fuel oil’) makes up a mere 4% of demand.

Contrast this with the situation seen in Hawaii below. The least important major product in the US overall—fuel oil, at 4%—makes up the second-largest demand in Hawaii; fuel oil accounts for almost a quarter of Hawaiian oil consumption. The second-smallest product in the US—jet fuel, at 9%—is the largest demand in Hawaii, accounting for 30% of demand. Gasoline—at 48% of total oil
demand in the US, by far the most important product—is less than half as important in the Hawaiian demand barrel, making up only 21% of Hawaii’s oil demand. Distillate shares are comparable between Hawaii and the US average, but the use of ‘other’ fuels in Hawaii is small.

![Typical Hawaiian Oil Demand by Fuel](image)

The contrasts are partly explained by how oil is used in Hawaii in comparison with the US as a whole. As the following figure shows, the patterns of oil use in Hawaii have almost no relationship to the patterns seen in the rest of the country. Road transport, which consumes mostly gasoline and diesel fuel, is the biggest oil use in both, but in the US overall road transport eats up more than 60% of all oil, while Hawaii uses only a bit more than a third of the oil. The second-largest use of oil in the US overall is in the industrial and commercial sectors, which use only a tiny fraction of Hawaii’s oil.
To sum up, in volume terms the two most important oil products in total US demand are gasoline and distillate. In the same volume terms, the two most important oil products in Hawaii are fuel oil and jet fuel. The supply problems Hawaii faces have little in common with the supply problems of the US—even though gasoline supply and prices continue to dominate the headlines.

**Refining and Fuel Oil**

The most basic (and cheapest) refining process is crude oil distillation, where the lighter components are boiled off and the straight-run fuel oil is left behind. The problem for the refiner from the start has been that what the market wants are the lighter products—gasoline, jet fuel, and diesel—but the biggest single product from distillation is fuel oil. This varies depending on the crude oil used (and is one of the reasons crude oils vary so much in price), but typically about half of the crude oil is left over as fuel oil. (A ‘light’ crude might yield only 20% fuel oil on distillation, while a ‘heavy’ crude might leave 70% of its volume as fuel oil; most crudes are 40-60% fuel oil.)

In the US, about 90% of the oil consumed are ‘light’ and ‘middle’ distillates—products lighter than fuel oil. The other 10% is made up of ‘heavy’ products—fuel oil itself being important, but also including asphalt, lubricating oils, waxes, petroleum coke, and other minor products. If a typical
Evaluating Natural Gas Import Options for the State of Hawaii

crude yields 50% fuel oil and heavy products, but the market wants only 10% fuel oil and heavy products, there is an obvious problem for the refiner.

The main solution has been a series of inventions called ‘cracking’ technologies, which take fuel oils, or some fraction of fuel oils, and literally break the big molecules into smaller ones. These technologies can transform lower-value fuel oil into gasoline, jet fuel, and diesel (though some of the input material comes back as heavy ‘cracked fuel oil’). This was a great innovation, or rather series of innovations, and has allowed the USWC refining industry, which runs a crude slate that yields around 60% fuel oil on distillation, to produce a mere 5% of its final output as fuel oil.

The downside is that cracking is terrifically expensive. Cracking units often cost hundreds of millions of dollars; often costing as much or more than the rest of the refinery. And, cutting down fuel oil output is increasingly expensive: it is typically cheaper to go from 50% fuel oil output to 30% than from 30% to 10%, even though the magnitude of the change is the same.

Despite the high costs, all around the world the major consumer of fuel oil has become the refining process itself, cracking units now demand more fuel oil than any other use. Since this demand is mostly invisible from the outside, it does not appear in statistics, but it is now a major driving force in the market.

**Fuel Oil and Specifications in Hawaii**

There are two major onshore fuel-oil markets in Hawaii—the large Oahu power generation market, and the smaller market outside Oahu. (There are also many power stations outside Oahu that burn distillate/diesel oil rather than fuel oil.) These markets are divided not only by geography, but also by quality specifications.

Fuel oil can have a dozen specifications, but two are typically most binding—sulfur content and viscosity. Most viscosity problems can be ameliorated (albeit at some cost in terms of cutter stocks), so the critical ‘spec’ in most situations is the sulfur content. Outside Oahu, fuel oil sold to the power sector is limited to a maximum of 2% sulfur by weight. This grade of fuel oil is often referred to as medium-sulfur fuel oil (MSFO) or industrial fuel oil (IFO). A maximum level of 2% sulfur is
lower than can be manufactured from most Californian or Middle Eastern crudes, though it can be met with Alaska North Slope crude (which yields a fuel oil of around 1.8% sulfur).

The biggest demand for fuel oil in Hawaii, of course, is on Oahu, where current legislation limits fuel oil sulfur to 0.5% sulfur, often referred to as low-sulfur fuel oil (LSFO). The number of crudes—so-called ‘sweet’ crudes—that yield fuel oils of 0.5% sulfur or less is relatively small and concentrated in a few key regions: China, Australia, Southeast Asia, West Africa, North Africa, and the North Sea. (There are also some sweet crudes in Alaska, California, the Middle East, and elsewhere, but these are rare and tend to be very low in production volumes.)

As environmental specifications tighten, suppliers often find themselves furnishing similar volumes of fuel to buyers at sulfur specifications that change every few years. Thus, a contract for 3% sulfur fuel oil may over time become 2% sulfur, then 1.5% sulfur…

Hawaii thus has two major onshore fuel-oil demands—a large demand for 0.5% LSFO and a smaller demand for 2% MSFO. It is important to note that neither of these grades is a major ‘benchmark’ grade in neighboring markets. The most important grade on the US West Coast and in Singapore is high-sulfur fuel oil (HSFO) of ship-bunker grade, averaging 3.5-4% sulfur. There are quotations for a 2% sulfur, 180 cSt fuel oil on the Singapore market, but it is a relatively thin market that tends to follow the price trends of HSFO.

The market for 2% sulfur MSFO in the western US is tiny, but it is relatively easy to devise a reasonable linkage between this grade of MSFO and the large, worldwide HSFO market.

The touchstone for LSFO pricing in the Asia-Pacific region is the price of low-sulfur waxy resid (LSWR). The LSWR market is dominated by Indonesia, whose waxy crudes leave large volumes of LSWR after distillation. There are two grades of LSWR, virgin and cracked (virgin LSWR tends to be of interest mainly to refiners looking for cracker feedstock). Both have the same sulfur specification of 0.35% sulfur, which is somewhat tighter (and therefore more costly) than the Hawaiian grade.
The Hawaiian Refineries

An important point to note at the outset is that profits for the refiner are mainly in the gasoline, jet fuel, and diesel markets, where the prices of the products are higher than the prices of the crude, not in the fuel oil market. In Hawaii, where the amount of road travel is inherently limited, the important product is jet fuel, where there is a chronic deficit that often results in imports from as far away as the Middle East. Gasoline and, to a lesser extent, fuel oil, get all the attention in the press and the Legislature, but jet fuel is where the action is.

The two Hawaiian refineries are both relatively small facilities by current world standards; today, worldscale refineries are typically 125-250 thousand barrels per day (kb/d) in size. The Chevron refinery, the older of the two, is about 54 kb/d. The newer Tesoro refinery is about 93 kb/d. (The “size” of a refinery refers to the average daily intake of crude oil and is thus roughly the same as the size of the crude distillation unit’s daily capacity.)

As the table below illustrates, the refineries are both equipped with cracking facilities and other expensive units to assist in upgrading the output slate into more valuable products. To some extent, the choice of technologies may reflect the age of the facilities. The Chevron refinery is equipped with catalytic cracking, a technology that breaks part of the fuel oil into gasoline (and also creates ‘cycle oils’, which are blended back into the remaining fuel oil to lower the viscosity). Chevron also has alkylation and isomerization units, which take some of the gases from processing and turn them into high-octane blendstocks for gasoline. Some portion of Chevron’s fuel oil is diverted to asphalt manufacturing for the paving of roads.

<table>
<thead>
<tr>
<th>Hawaiian Refinery Capacities (kb/d)</th>
<th>CHEVRON</th>
<th>TESORO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude Distillation</td>
<td>54.0</td>
<td>93.5</td>
</tr>
<tr>
<td>Vacuum Distillation</td>
<td>31.3</td>
<td>43.0</td>
</tr>
<tr>
<td>Catalytic Reforming</td>
<td>13.0</td>
<td></td>
</tr>
<tr>
<td>Alkylation</td>
<td>5.0</td>
<td></td>
</tr>
<tr>
<td>Isomerization</td>
<td>3.2</td>
<td></td>
</tr>
<tr>
<td>Catalytic Cracking</td>
<td>22.0</td>
<td></td>
</tr>
<tr>
<td>Hydrocracking</td>
<td></td>
<td>18.0</td>
</tr>
<tr>
<td>Visbreaking</td>
<td></td>
<td>13.0</td>
</tr>
<tr>
<td>Asphalt</td>
<td>1.3</td>
<td></td>
</tr>
</tbody>
</table>
Tesoro’s central cracking technology is hydrocracking, a highly sophisticated (and very expensive) technology that converts some portion of the fuel oil to lighter products. However, unlike catalytic cracking—where the focus is on gasoline—hydrocracking is most often used to maximize the output of jet fuel and diesel, and it produces very high-quality jet fuel in particular. Since there are no cycle oils to lower the viscosity of the remaining fuel oil, the Tesoro refinery has a visbreaking unit specifically to cut fuel oil viscosity. While it could be said that the Chevron refinery is ‘gasoline-oriented’ and the Tesoro refinery is ‘jet-fuel and diesel-oriented’, the Tesoro refinery has a catalytic reforming unit to turn heavy naphtha into high-octane gasoline blendstocks. (The gasoline output of the two refineries is similar in volume, despite the fact that Tesoro’s crude intake is about twice that of Chevron; this demonstrates the impact of a catalytic cracking unit.)

The refineries are in competition with one another, but their structures are to some extent complementary, with one configuration aimed at gasoline and the other at middle distillates (jet fuel and diesel). What is similar in the two is that there is little desulfurization capacity. Regardless of the state of the fuel oil market in Hawaii, the two refineries are both constrained in the kinds of crudes they can process. Producing LSFO requires certain minimum runs of very sweet crudes, but even if this were not the case, neither refinery is in a position to move to a slate composed entirely of high-sulfur crudes. Without the addition of some naphtha, jet, and diesel desulfurizing units, a high-sulfur slate would result in unsaleable products.

Over time, refineries that survive tend to develop output patterns that reflect demands in their market—although there is seldom a perfect match. It is therefore not surprising that Hawaii, which has a very different demand pattern than the rest of the US, has a strikingly different output pattern from its refineries. As the following figure shows, other US refiners have slashed their fuel oil output by building cracking facilities to convert fuel oil into lighter products (mostly gasoline). Although, as discussed above, Hawaiian refiners have already installed some cracking facilities the continued market for fuel oil lobbies against the installation of additional facilities.
Although the Tesoro refinery is larger, more modern, and in many ways more sophisticated than the Chevron facility, its cracking capacity is undersized in comparison to its crude capacity. (This to some extent reflects the fact that the crude capacity has been expanded over the years, while the cracking capacity has remained static since the early 1980s.)

The following table helps put this issue in context. The table shows distillation capacities alongside cracking capacities (excluding visbreaking, which improves fuel oil quality, but converts very little of it to lighter products). Coking, which has not been discussed previously, is an aggressive cracking technology that converts the heaviest portions of fuel oil to lighter materials.
Other Oil Infrastructure and Oil Product Balance in Hawaii

There was a time when the refineries controlled almost all of the oil-import facilities in Hawaii. Today, only crude oil and fuel-oil imports are restricted to refinery channels. There is an independent product import facility and the airport has independent jet-fuel facilities. Outside Oahu, terminals are serviced by barge, and market presence is largely limited by terminal ownership.

As with other oil data in Hawaii the precise production and trade figures for any year are not available because of restrictions on the release of proprietary data. Despite this, however, the overall pattern in the table below (shown with our estimates for 2003) is fairly consistent and not really the subject of dispute.

<table>
<thead>
<tr>
<th></th>
<th>Demand</th>
<th>Production</th>
<th>Imports*</th>
<th>Exports*</th>
</tr>
</thead>
<tbody>
<tr>
<td>LPG</td>
<td>1.8</td>
<td>1.8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Naphtha</td>
<td>6.0</td>
<td>13.5</td>
<td>7.5</td>
<td></td>
</tr>
<tr>
<td>Gasoline</td>
<td>29.0</td>
<td>29.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jet Fuel</td>
<td>41.0</td>
<td>32.5</td>
<td>8.5</td>
<td></td>
</tr>
<tr>
<td>Diesel</td>
<td>26.0</td>
<td>26.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel Oil</td>
<td>33.0</td>
<td>30.5</td>
<td>2.5</td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td>1.5</td>
<td>1.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>138.1</td>
<td>134.6</td>
<td>11.0</td>
<td>7.5</td>
</tr>
</tbody>
</table>

*Imports and exports are on a net basis; there are small movements in and out for commercial reasons which are not captured in this table

Although virtually all of the gasoline sold in Hawaii is made in Hawaii, independent import facilities limit the extent to which prices can be raised above import price parity. Gasoline is not exposed to the same intensity of competition as some other fuels (since end-users are not taking direct bids from the external market), but it is not possible for prices to rise too steeply without drawing in supplies from elsewhere. (While it is a challenge for Hawaiian refiners to make USWC-spec gasoline, it is easy for most USWC refiners to meet Hawaiian specifications.)

Hawaii faces a persistent shortage of jet fuel, which is imported from many sources around the Pacific Rim (and even from as far away as the Middle East). This makes for a highly competitive market. Although Hawaiian refiners have the advantage of a large transport differential (jet fuel needs to be transported in small, clean cargoes, which makes it expensive to move), the tendering
and acquisition process gives no real advantage to the local refiners and they do not control the import facilities. Therefore, jet fuel remains an important and lucrative product, but there is a hard ceiling on its profitability.

Diesel fuel (and distillate) is in many ways similar to gasoline in Hawaii—the demands are met primarily from local supplies, but independent terminals mean that prices cannot get far out of line with import price parity. Additionally, the utility industry outside Oahu contracts for industrial-grade diesel on a formula directly tied to the external market, so the price is regulated to be close to the cost of delivery from elsewhere.

There is often a slight shortage of fuel oil, typically LSFO, but the balance shifts with changes in the crude slate. The price of LSFO to the utility is contracted to be the market price in Indonesia/Singapore plus the built-up cost of delivery. There is thus a tight control on prices at a level tied directly to the international market and there is also limited incentive to import except to fulfill contract shortfalls.

Compared to many supply/demand systems around the world, the Hawaiian refinery system is surprisingly well balanced (apart for the substantial jet fuel deficit). The system is also running fairly close to capacity. While economics might seem to favor production of more jet fuel, it is impossible to produce more jet fuel without also producing a small surplus of other products. There are also limits to how much these balances could be altered without cutting the supply of fuel oil. The balance apart from naphtha and jet fuel is good, but it is a very delicate balance.

Surplus products are, of course, exportable, but taking advantage of the export market would require a major reorientation of the current refining system. Hawaii’s specifications are not a good match to likely markets and establishing a profitable presence in the export market demands more than a few tiny cargoes. At present the economic pressures all point in the direction of maintaining something akin to the current balance.

**LNG Impact: Refinery Response**

Our analysis in the *Hawaii Hydrocarbon Outlook* and the report done by Stillwater Associates clearly indicate that the profits of the refineries will suffer if LNG displaces LSFO in power generation.
Whether one or both refineries will shutdown depends on a multitude of variables, such that even the industry players that are intimately involved are not certain what will happen.

If a Hawaii refinery were to shutdown, there are a number of potential drawbacks that should be considered, some of which have more merit than others. First, consider energy security. Importing LNG would serve to diversify Hawaii’s energy base, reduce oil use, and could help limit energy price volatility. However, if this leads to the closure of a refinery, the State would have to import larger quantities of refined petroleum products. Although it is true that these products are produced from oil, and thus overall oil use does not change with one or two refineries in operation, the State would require a variety of products, which may not be as widely traded as crude oil. In terms of energy security, diversifying through LNG is likely to be advantageous, but this caveat should be kept in mind.

Whether LNG comes to Hawaii or not in the longer term, both refineries face challenges in terms of changing environmental specifications (sulfur standards continue to tighten everywhere and the refiners have a limited ability to cope with these), scale (the refineries are on the small side), and high operating costs (industrial business in Hawaii is difficult). These challenges remain irrespective of the LNG entering Hawaii.

Looking to the US West Coast or to export refineries in Singapore or Korea, it becomes clear that competition in the Pacific market comes from refineries that are generally at least as large as the two Hawaiian refineries taken together (less than 150 kb/d) and more often larger than 200 kb/d. The scale of refining affects economics dramatically, as the number of personnel does not rise in proportion to increasing capacity; a typical 100 kb/d refinery might have 300-400 direct employees, but a 200 kb/d facility might have the same number.

The Hawaiian refineries employ an estimated 800-900 people, far above the number of employees that would be expected in most situations for a single 150 kb/d refinery. Add to this the fact that Hawaiian wage and benefit costs are comparatively high, include a substantial tax burden and generally higher costs for all inputs, and it is not surprising that Hawaiian refiners face a higher per barrel operating cost than most of their competitors. The refineries would face a better outlook as a
single, integrated unit with a consolidated overhead, but even in this case the per barrel costs would remain high.

The one advantage the Hawaiian refiners have is their remoteness; it is cheaper to transport crude oil than refined products (with the exception of fuel oil, which can be moved at prices similar to crude if it is wanted in large volumes). This transport differential gives a slight edge that goes some way toward canceling out the higher per barrel processing costs.

Nonetheless, having the Oahu fuel-oil demand vanish owing to the import of LNG would change the economic landscape of refining in Hawaii. The first immediate effect would probably be a change in the crude slate, shifting away from such a sweet diet to one higher in sulfur. The second immediate effect would probably be a further shift to light crudes (although the present slate is already fairly light). The third immediate effect would probably be a decline in overall crude runs to avoid large exports of fuel oil—though this would depend heavily on market conditions. In the latter case, it is likely that imports of light products would increase.

Thus, several outcomes for the refining industry are possible if the Oahu utility fuels market is eliminated. The industry might retrench and adapt. Modest new investments might be undertaken, possibly over many years, to allow the refiners more flexibility in the crude diet. Or, at the extreme, the industry might be consolidated, expanded, and upgraded to meet the needs of the export market on top of existing local demands.

What needs to be stressed is that any of these outcomes is possible with or without the displacement of Oahu’s utility fuel-oil demand. Slashing the demand for LSFO could put new pressure on the refiners (though it also allows them additional room to maneuver), but it is only one of many challenges they face and maintaining the existing market for fuel oil is no guarantee that one or both refiners will continue to operate.

**Concluding Remarks**

Hawaii is not by its nature a highly competitive market. Total demand is not large enough to allow many suppliers or duplication of infrastructure. When the Tesoro (then PRI) refinery was first proposed, one of the advantages stressed was that having two refiners would create a more
competitive market. How true is this idea? What risks does Hawaii face if one refiner closes, leaving the other as sole operator?

Two refiners do tend to create a more competitive environment than one, but the pressures are not as great as one might imagine. In a closed market, two, three, or even a half-dozen oil companies can learn to live and manage with each other. It is exposure to the external market and the trade connections with other sources of supply that creates a competitive situation. Therefore, while the establishment of a second refinery undoubtedly helped the competitive environment, imports, the threat of imports, and price formulas linked to markets elsewhere have had a major impact. As discussed earlier in this chapter, imports always act as a constant check on the price of fuels produced in Hawaii. LSFO is pegged to a formula that represents what delivery costs would be and other utility fuels are also tied to prices outside the Hawaiian market. The situation in gasoline and diesel is obviously less competitive, but the establishment of an independent import terminal on Oahu helps bring the pressure of import prices to bear on the local market for those fuels as well.

To summarize: the closure of one or both refineries is neither inevitable nor does it necessarily lower the competitiveness of the market in Hawaii, indeed, if steps are taken to ensure that a wider selection of fuel suppliers have access to the market (especially in terms of import infrastructure), then price competition might actually be strengthened. It should be noted, however, that this might not happen through purely market forces, the State might have to take a role in ensuring wider access to terminals and tankage.

Enhanced competition, however, may not be an unmitigated boon. Issues of liability for pollution events and other problems need to be considered carefully. Logistical and technical problems may also become more difficult to solve if the suppliers do not have major investment stakes in the Hawaiian economy—and this problem may be more acute in the case of suppliers owned by corporations with limited real assets. None of these difficulties are insurmountable, but if refinery closures seem imminent, the State of Hawaii needs to study policy options to deal with potential problems before they occur.
Chapter 12

Economic Impact of the Introduction of LNG to Hawaii

The introduction of LNG or CNG into Hawaii is bound to have an impact on the Hawaiian economy whether through potential savings in power and transportation bills or the creation of jobs. Moreover, there are various areas within the LNG chain, particularly in distribution and end-use activities, where relevant stakeholders could invest in the infrastructure and earn a reasonable rate of return. While a discussion on the full economic impact of the introduction of an LNG receiving terminal with respect to wage calculations and multiplier effects is beyond the scope of the report—and in fact would be a full study in and of itself—we can make some general comments.

Impact on Electricity and Transportation Costs

As most full-time citizens in Hawaii are all too aware, the State faces some of the most expensive electricity and transportation bills in the nation. As the graphs below illustrate, Hawaii by far and away pays on average the most of any state in the union for electricity and gasoline. With respect to gasoline, the State’s retail prices (excluding taxes) were 33% above the nation’s average last year and substantially above that of other western states; when looking at electricity prices, the difference was even higher as Hawaii paid in excess of 100% more than the US average in 2006.

1 This chapter is based on FACTS database, discussions with industry contacts, and the US Energy Information Administration (EIA).
As has been discussed earlier in this report and in many previous reports, the lofty cost of doing business coupled with the remote location and small market all contribute to the high cost of gasoline and electricity (and in fact many other items) in the State of Hawaii. While it is by no means a guarantee that the introduction of natural gas into the State’s energy system will decrease the costs of power and transportation, the analysis provided in Chapter 9 certainly lends credence to the possibility. If Hawaii were able to secure an LNG contract that was capped at a delivered price of around $9-10/MMBtu, the fuel savings to consumers would be substantial, on the order of tens of millions of dollars per year, as the price of gas to the power plants would be on average about $1-2/MMBtu less than the price forecast for LSFO. With respect to the transport sector, we discussed in Chapter 10 that the current retail price of regular gasoline on Oahu (including taxes) is about $2.86/gallon or $24/MMBtu. In 2005, Oahu consumed over 300 million gallons of highway fuels, specifically gasoline, diesel, and liquefied petroleum gas (LPG). Assuming a conservative $2.50/gallon retail price average of the aforementioned fuels, Oahu consumers spent well in excess of $750 million dollars on highway transport fuels in 2005. If natural gas were delivered at $10/MMBtu and below, it seems plausible that Hawaii consumers could see some savings in their transportation bills. This is especially relevant for lower income individual(s) whose electric and transportation bills account for a substantially larger portion of their overall income than those above the poverty line.
It is important to note that the discussion above is by no means a complete analysis of the full economic implications if natural gas were to penetrate the power and transport sectors. As mentioned earlier, a much more detailed study would have to be commissioned to fully understand the impacts. We describe the scenarios above to allow the reader to get a grasp of the current situation and to understand the potential cost savings involved.

**Possible Job Opportunities**

Transforming the State’s energy system through the introduction of LNG would certainly have an impact on Hawaii’s economy. On the positive side, in the short term a number of jobs would be created during the construction of an onshore LNG terminal and in the long term, employees would be required to operate and maintain the terminal.

Constructing an LNG receiving terminal typically takes approximately 3 years. One source estimates that about $100 million would be spent in local communities, but this obviously varies depending on the type of terminal that is selected. For example, if an offshore terminal is selected the number of jobs created would likely be less.\(^2\) At the peak of construction approximately 400 direct contract construction workers would be employed. If you include direct, indirect, and induced jobs (i.e., the employment multiplier—jobs created as a result of the initial job. For example, an employee at an LNG terminal could buy a new house, thereby creating construction jobs) approximately 891 jobs could be created over the course of the construction period.

When it is complete, an onshore LNG terminal would require approximately 45 direct full-time employees. Because it is not an established industry in the State, it is not clear what the employment multiplier is for LNG, but if the employment multiplier for the power industry (3.10) and the job multiplier for the petroleum industry (4.63) are taken as guidelines, between 140 and 208 jobs would be created in the overall economy.

It is critical to note that this is a narrow analysis and the full impact of LNG on the economy could be much larger, albeit difficult to discern, without more concrete information as to the final price of LNG. For example, if the introduction of LNG were to lower the price of electricity and utility gas,

\(^2\) In our discussion with Enersea, they mentioned that the number of people employed at the terminal, including onshore logistics and administration would be 8-10 people.
this would likely spur the overall economy and lead to the creation of even more jobs. Conversely, if LNG were to be introduced at a high price it could act as a drag on the economy. The key point in terms of minimizing possible negative impacts on the overall economy is to ensure that LNG is competitive with existing fuels, which we believe it can be, as discussed in Chapter 9.

As a final note on job creation, the most promising area beyond the above-mentioned LNG infrastructure additions is likely to be in the transportation sector. Due to Hawaii’s strong tourism industry, there are numerous opportunities beyond simply converting ‘The Bus’ to run on compressed natural gas. An Oahu-based industry would be needed to retrofit ‘The Bus’ fleet as well as other means of transportation. This could include the use of CNG in private bus and truck vehicles, taxis, private citizen vehicles, and state and local government vehicles. Again, it is difficult to estimate jobs created without considering the actual number of vehicles converted and maintained. Such a calculation would require an estimate of the initial commitment of buses and then developing various scenarios to envision how many people will be involved in converting the vehicles over time. With those calculations, it would then be possible to assess the number of jobs created as service industries for converted CNG vehicles. Essentially this study would be part of a separate Economic Impact Analysis and the employment numbers would be based on the detailed preliminary engineering and planning for a site-specific Hawaii LNG project and its end-uses. This study, however, cannot be completed until more advanced decisions on bringing LNG to Hawaii are made.

Possible Investment Opportunities

The investment opportunities considered here look at various aspects of the LNG chain and consider investments that are valued at under $30 million. Opportunities can be classified as to where they fall within the LNG value chain presented here:

1. Upstream
2. Liquefaction Facilities
3. Transportation
4. Regasification
5. Distribution
6. End-use activities
1. Upstream:
Upstream activities consist of owning a piece of the field that produces the natural gas that would then be liquefied and shipped to Hawaii. It is common in the LNG industry for LNG buyers to own a small, sometimes fractional, percentage of the gas field from which their LNG comes. As the fields are already producing, the buyer of the upstream percentage usually invests an amount that corresponds to the current estimated value of the proven gas reserves in the field. Thus it is unlikely that any large profits will be earned, unless the price that the gas is sold to the LNG facility greatly increases.

We do not recommend investing in the upstream as the benefits of investing in an already discovered and producing, or soon to be producing, gas field are limited. Furthermore, if the price of natural gas goes up significantly, the investor may be viewed negatively in the eyes of Hawaii as being responsible for rising fuel costs. We note that while the “big” money is made in the upstream, it is generally made by those companies who took the time to drill the well, discover the gas, and only then to develop the field and market the gas.

2. Liquefaction Facilities:
An LNG liquefaction facility makes a small profit to recover its expenses and earn a simple rate of return, but it is not where the money is made in the value chain. The money is made in the upstream. The only way LNG buyers end up owning a portion of the liquefaction facilities is if they are an integrated multinational oil and gas company or a utility such as HECO that insisted on owning part of the liquefaction facility. There are also some cases in the Middle East where Korean construction companies own a fractional portion of the liquefaction facilities.

We do not recommend investing in the liquefaction facility. It is unlikely that any added energy security will be derived from it and the profits earned can be greater in other areas.

3. Transportation:
An LNG vessel or CNG, as would be the case with Enersea, is an expensive piece of equipment to build and maintain. Owning a portion of such a vessel may be a good investment, especially as a tight LNG vessel market can at times drive freight rates quite high. The potential for investment may exist and needs to be discussed with the stakeholders to see if they may be in agreement. If the
sales and purchase agreement is ex-ship, then the investment is made through the supplier and if it is FOB, then it is made through the buyer.

We recommend such an investment for owning a portion of the shipping company or a vessel as the life of today’s LNG fleet has greatly surpassed initial expectations. As a long-term investment, it may be quite lucrative. Furthermore, any excess shipping capacity may potentially be contracted out for greater profits in order to maximize Hawaii’s dedicated fleet. This, however, may only be useful for LNG vessels as it is unlikely that a CNG vessel would be employable elsewhere in the Pacific Rim at present.

4. Regasification:
Owning a piece of the regasification terminal does not seem to be a very lucrative investment. Basically the regasification terminal charges a regulated postage stamp fee to recoup expenses and make a small profit. The estimated rate of return is unlikely to be attractive to investors.

We do not recommend such an investment unless the investor simply wants to own a portion of the Hawaii LNG supply chain. That said, the regasification terminal owner would likely be more than happy to have someone help fund the terminal’s construction. This would reduce their cost of capital accordingly.

5. Distribution:
We imagine that gas distribution, which is basically building and maintaining the pipelines to transport the regasified LNG to power plants and other end-use points, will be handled by the Gas Company. Like the regasification terminal, distribution will likely charge a regulated postage stamp fee. Again, the estimated rate of return is unlikely to be attractive to investors. Also, unlike on the mainland where there will likely always be a value for additional pipeline capacity, if LNG were to eventually cease coming to Hawaii, the pipeline would effectively have no value other than for scrap metal.

We do not recommend such an investment for the same reasons as mentioned above with the regasification terminal.
6. End-Use Activities:

End-use activities are likely the best area for locally-based investment opportunities. The primary sectors for end-use are power, industrial, residential/commercial, and transportation. Investment in the power sector is unlikely as it would require huge capital investments, on the order of $100 million or more. In addition any new gas-fired plants would likely render the proposed LNG import scheme unviable. The industrial sector usually is profitable because it builds its plants close to a relatively affordable source of natural gas. It is highly unlikely that profits could be made using imported LNG to fuel large-scale industry. The residential/commercial sector is not likely to have much potential as all such activities are likely to be handled by the Gas Company.

This leaves us with the transportation sector. We recommend such an investment as there will be a need for businesses that can be contracted to convert vehicles and to maintain and service vehicles running on natural gas. Such businesses will also need to cover refueling, which means increasing the number of service stations or piggybacking on existing ones.

Conclusion

The economic impact of the introduction of LNG to Hawaii will be significant. The initial construction impact will endure for the approximate three-year construction time, followed only then by the static number of employees required to regasify the LNG. The greatest opportunity for additional employment beyond the planned facilities will be through the service industries required for utilizing CNG in the transportation sector. There is also likely the greatest possible investment opportunity, as there is no existing business or group of services that will logically fill the need. There is also a strong incentive here to push for a firm CNG transportation development plan as it offers the greatest promise for further job creation. The only other area where we see a possible investment opportunity is in the shipping industry, though it will not offer the same job creation benefits.
Chapter 13

Timeline and Critical Path for Investing in a Hawaii LNG Project

Based on the analysis contained in the previous chapters, we will provide a commercial timeline for bringing LNG to Hawaii. We will then follow with our recommendations for building a consensus with the key stakeholders.

A Timeline: From Planning to Implementation

Below is a timeline for what needs to happen for Hawaii to import LNG. All of the above actions happen in the planning, marketing, and construction of an LNG import facility. The figure is divided into 4 phases over a six-and-a-half year time period. While the entire process can be fast-tracked, this timeline takes into consideration what we believe is a likely period for everything to happen. Please note that in our discussion with EnerSea Transport, a CNG offshore facility would take more or less the same time. In addition, the EBRVs promoted by Excelerate Energy would take about two years less than a land based facility.

Phase 1 involves the decision by an interested party to pursue LNG imports. This is the phase where HECO, the State, and the residents of Hawaii are currently at in April 2007. We put a likely timeframe on it of 1 year for an agreement to be reached on whether or not LNG imports are to be

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1 This chapter is based on FACTS database and conversations with industry contacts.
pursued. Of course this timeframe is really only constrained by how long it would actually take for the interested parties to decide to proceed.

Phase 2 commences once there is a formal agreement to import LNG. This phase is to make sure that the host government approves of the project. It is also where decisions are made on what types of processes are to be used and where an LNG marketing plan is developed. If the State is involved in phase 1, phase 2 can be significantly shorter or perhaps even nonexistent.

Phase 3 is estimated at 18 months and is where LNG marketing begins, all licenses, permits, and clearances for the project are obtained, and the contracts are awarded for the receiving terminal construction. The phase culminates with a signed sales and purchase agreement (SPA) with the LNG supplier. This phase may be shortened if Hawaii can find an existing supplier to sell and deliver LNG at an earlier date that coincides with the completion of the LNG import facilities.

This is also the phase where all of the permits are sought out for land use, or offshore use as well as pipelines to deliver the regasified LNG. If the permitting runs into significant opposition as some potential importers have on the US West Coast, the entire project can be delayed and may even fall apart. This is why the SPA is not signed until all the permits are in place. Further information on the approval process may be found on the FERC website at: [http://www.ferc.gov/industries/lng/gen-info/rev-proc/rev.asp](http://www.ferc.gov/industries/lng/gen-info/rev-proc/rev.asp).

Phase 4 is when construction begins. The construction of any ships needs to be timed so that ships are available for first gas and the receiving terminal is operational. If Hawaii wants to own its own ships, then the project needs to negotiate for their purchase and construction. It is estimated that ships will require 27-36 months for construction. If not, the supplier or a third party can provide the ships. The regasification terminal construction is estimated at 24-36 months depending upon the extent of the work to be done including jetty construction and storage tanks if the facility is built onshore. The construction timelines for shipping and the receiving terminal will be covered in great detail in the SPA to contractually obligate the LNG importer to have everything operational in time. Phase 4 culminates with the first imports of LNG arriving at the completed receiving terminal.
A Hawaii LNG import facility is possible, but the biggest potential roadblocks are public opposition and a lack of consensus among those required to purchase the gas. This next section will broadly discuss how to strengthen public support and build a consensus among the various stakeholders.

**How to Strengthen Public Support: the Biggest Stakeholder**

Strengthening public support for LNG is necessary to moving forward with any plans to import LNG. In no specific order, the three concerns that need to be addressed are economic, environmental, and safety concerns.

In Hawaii, where utility prices are already high compared with the rest of the nation, consumers must feel secure that their energy costs will not rise significantly from LNG imports. This may be hard to do with US market-linked gas prices, and thus Asian pricing formulas may be more attractive in stabilizing prices. Whatever pricing decision is made, transparency is necessary to show that LNG will not burden individual finances.

Environmental concerns will be addressed as various terminal sites are proposed. An LNG import terminal handling less than 2 mtpa is unlikely to have a huge environmental presence, but public opinion needs to be sought out on how acceptable a land-based Oahu terminal may be. Other options to lessen the presence would be offshore regasification facilities where floating platforms would be used and the “not in my backyard” (NIMBY) argument is significantly weakened.

Many environmental concerns also are addressed in the permitting process. Before FERC decides on anything regarding an LNG application, an Environmental Impact Statement is prepared to meet the National Environmental Policy Act (NEPA) requirements. The purpose of the statement is to clearly explain the possible environmental and safety impacts of a proposal and potential alternatives.

Safety concerns need the most attention not because LNG is unsafe, but because public opinion towards LNG is based on many misperceptions. We propose as series of educational briefings where LNG can actually be seen by residents and better understood. Viewing a lit cigarette being visibly extinguished in LNG without igniting is far more reassuring than sending educational pamphlets in the mail.
Environmental and safety concerns are discussed in more detail in Chapter 6. To address all of the above public concerns, the objective as always should be to educate and keep open lines of communication.

**How to Build Consensus among Key Stakeholders**

Assuming success in earning the support of the public, the main stakeholders to build consensus among are the state and local governments, HECO, the two refineries, and the Gas Company. We will first discuss the stakeholders and then address the main areas where building consensus is required.

**State and Local Governments**

The state and local governments are important as their support will determine the success of importing LNG. Without them, any plans will linger and never come to fruition. If LNG is to come to Hawaii, they need to feel as if they are a participating part of the process. It will be a challenge to earn the support of elected politicians as there will be a strong fear of being blamed if energy prices rise.

**HECO**

HECO will likely lead the charge in importing LNG. They will consume most of it in their power plants and likely underwrite a significant portion of the LNG import facilities. It would be appropriate for HECO to take a strong role in working with the other stakeholders to learn their concerns and work on building consensus.

**The Refineries**

Tesoro and Chevron will need to be consulted in importing LNG as their refineries currently provide HECO and its subsidiaries with petroleum products for power generation. If LNG is imported, it will replace a large portion of the petroleum products, particularly LSFO, consumed in power generation on Oahu. As a result, products will either have to be exported or refineries expanded to upgrade them into locally usable products. Either way, these are serious concerns with significant financial ramifications for both Tesoro and Chevron. These issues need to be addressed when building any consensus around importing LNG.
The Gas Company
The Gas Company needs to be factored in as they would likely need to be involved in the distribution of natural gas for residential and commercial uses and potentially for vehicular use as CNG. If they are to play a role, and we recommend that they do, then infrastructure compatibility issues need to be discussed for natural gas distribution to develop and operate efficiently and successfully.

Environmental Groups and Community Organizations
Groups such as the Sierra Club and the Hawaii based Life of the Land need to be included in the process as they represent values and ideals that are close to many people’s hearts. They have been involved in HECO’s IRP’s in the past and often comment on development projects and an endorsement would be valuable in helping the project move forward. In addition, the native Hawaiian community needs to be involved in the process as to make sure that the community understands the benefits of such a project. In addition, their input on cultural preservation areas and burial sites is critical to ensure the success of the project.

Ideas to Build Consensus Around
Below are the main ideas that should be the focus of any consensus building. We recommend that HECO take the lead role in building consensus as they will undoubtedly be the player with the biggest direct interest in Hawaii’s LNG industry.

1. **Political Support:** As mentioned above, earning the support and trust of the state and local governments goes hand-in-hand with winning the communities support. More than anyone else, they can make or break a project to import LNG.

2. **Stakeholder Needs and Concerns:** The stakeholders all have certain issues that are important to them as indicated above. These issues need to addressed and agreed upon if LNG imports are to be successful.

3. **Common Policies:** The above mentioned stakeholders need to agree on common policies regarding equipment, procedures, and practices. This enhances not only cooperation, but also ensures smoother working relations and enhances safety. These policies should include
a thorough agreement on the details of the overall LNG import and usage plan, technical standards, and pricing systems at all stages. Any area where common policies are yet to be created will only provide additional friction and potential longer term problems.

4. **Regulation:** Reasonable professional and independent regulation is necessary to avoid irregularities or unforeseen pricing problems. A consensus should be built around what specifically should be regulated and how. To avoid creating unnecessary new regulatory bodies, we envision this role as falling under the jurisdiction of the PUC.

Building consensus around these areas as soon as possible will only enhance the strength of any plan to import LNG. These are all issues that need to be addressed and doing so early helps increase the chance for success. One of the main issues in cancelled projects on the US West Coast has been a lack of consensus among stakeholders. There FERC is being sued by the California PUC regarding who has the right to decide where to build an LNG import terminal if at all. Clearly some of the stakeholders moved forward without taking the time to build consensus. The goal in building consensus is to foresee and avoid “turf” wars that unexpectedly have the potential to indefinitely postpone a project that could be publicly beneficial.

**Conclusion**

Is there any magic formula for building consensus? No. Basically it would mean organizing meetings where stakeholders can voice their concerns and then seeing what can be agreed upon. The power of building consensus is that theoretically all stakeholders are involved and nothing moves forward until all can agree on the final decision. Yes the process does have the potential to be long and it is open to failure if some of the major stakeholders cannot agree on the final decision. This is why we refer to building consensus rather than voting or deciding on it. If consensus can be built, the process is quite strong as all stakeholders agree to the final decision. In the case of Hawaii LNG, we will describe here a framework of one way to proceed.

1. **Proposal:** A well defined proposal to import LNG into Hawaii is made and presented to the stakeholders (and there may be more than the ones described above).
2. **Questions:** Stakeholders can then raise any questions to help clarify the issue to everyone’s understanding before it is discussed.

3. **Discussion:** With a thorough understanding of what importing LNG into Hawaii requires, the proposal is discussed, issues are raised, and changes suggested. To help build consensus, the proposal needs to be changed to accommodate the issues that arise.

4. **Opinions:** After the proposal is changed per step three, the opinions of the stakeholders should be loosely solicited to see if the updated proposal is any more acceptable or if further changes should be made. It may also be likely that some stakeholders object so strongly that there is no way to accommodate their needs. In this case, it may mean that Hawaii decides that for whatever reasons, LNG imports are not feasible and that the idea should be abandoned.

5. **Major Objections:** If the proposal makes it through step four, then it is time to see if there are any major objections by stakeholders. If there are, then it means that consensus cannot be built. Such a major objection could be that importing LNG may lead to a closure of a refinery and thus leave a significant number of people unemployed. It could also be that under current world natural gas prices and their associated volatility, LNG may pose too much of a risk by exposing Hawaii to unstable energy prices.

6. **Decision:** This step is similar to step four, but more serious. It has the power to decide the fate of importing LNG into Hawaii. Now there are three possible outcomes.

   a. **Move Forward:** If there are no major objections such as those of the nature mentioned in step 5, then it is time to move forward and import LNG into Hawaii. This would mean moving onto Phase 2 as shown in the earlier figure.
   
   b. **Cancel Plans to Import LNG:** There is a major objection(s) that cannot be overcome and thus consensus can never be built.
   
   c. **Revise the Proposal to Remove the Major Objection(s):** Find a way to address the concerns of the objecting stakeholder so that they are willing to approve of LNG imports. If a way is found, then the proposal needs to be amended to reflect this
and everyone repeats steps 5 and 6 to see if Hawaii can move forward with LNG imports.

With the above in mind, it is time to see if Hawaii can agree to import LNG. Is LNG something Hawaii can live with? Presently, the question of LNG imports has only been discussed amongst interested groups. While the proceedings have been made public, few people in Hawaii would really claim to be aware of or understand them.