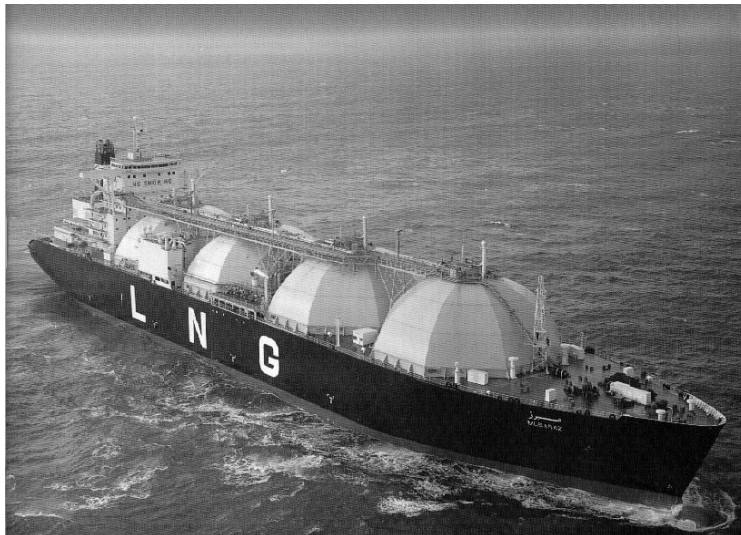


# LIQUEFIED NATURAL GAS FOR EMERGING MARKETS



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# LNG FOR EMERGING MARKETS<sup>1</sup>

## I. SUMMARY

1. This study analyzes the potential utilization of LNG in smaller, emerging markets which have traditionally been considered too small to justify import facilities and have therefore been ignored by the LNG industry. In turn the developers of power projects in these markets have considered LNG to be a fuel too expensive, too large in scale and too constrained in its trading patterns to be a viable competitor for the more conventional fuels such as oil and coal. The results of this study suggest that these views should be re-considered. LNG can be quite competitive when compared to other fuels, can be economic on a scale much smaller than previously understood, and is experiencing an evolution of commercial development which is demonstrating increasing flexibility and lower overall costs. The analysis suggests that LNG could be viable in the context of power projects as small as 250 - 300 MW, about half the size previously considered as a minimum for viability. The use of LNG in emerging markets should be afforded similar considerations to other competing sources of energy when power generation projects are being developed and financed. However, as is the case with all these fuels, LNG cannot be viable in a market environment where inadequate regulatory or market policies result in distortions to the true costs of projects, or where the end market is unduly distorted such that projects cannot recover their costs and make a reasonable return on investment.

## II. INTRODUCTION

2. LNG was long considered a complex, high cost fuel for use in anything but advanced economies without access to large indigenous gas resources. Certainly it was traditionally viewed as too expensive or precious to be used for the generation of electricity, at least in the Atlantic and Mediterranean Basins. The experiences with the Dabhol project in India could be seen as a confirmation of these beliefs, with root problems being the extremely high initial cost of electricity from the project which was awarded on a no-bid basis, and the lack of paying customers to underwrite the investment and power purchase contracts. While neither of these problems arose from the choice of LNG *per se*, the attempt to develop a very large, complex project was driven by the apparent need to offset the perceived diseconomy of scale associated with the introduction of LNG to the Indian market. Dabhol and LNG are inextricably linked in the

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minds of policy makers, and the failure of the first certainly casts doubts as to the applicability of the second.

3. Within the last decade, the business of LNG supply, production, liquefaction, shipping and regasification, has been changing. Costs have been falling sharply across all elements of the "chain", by as much as 50% in some segments. On the demand side of the chain, the improvements in costs and efficiency of combined-cycle gas-fired technology are well understood, but similar cost reductions have been experienced in the upstream segment of the industry, in liquefaction and in shipping. On the commercial side, the LNG industry has experienced rapidly growing production capabilities (tied to growing, remote gas resources), while demand growth has slowed significantly as markets have matured and economic problems have depressed demand for electricity. Surprisingly, North America has re-emerged as a significant potential market for LNG for the first time in three decades. The confluence of these forces has resulted in a sharp increase in spot and short term LNG trading as exporters and importers seek to adjust the terms of business with each other.<sup>4</sup> In this environment of lower costs, more liberal trading relationships and a search for markets, the potential for LNG to enter developing markets (such as those found in the Caribbean, India, China, and sub-Saharan Africa) has improved. The model for doing so will likely not be the traditional one of rigid long-term relationships, but more likely based on looser arrangements which recognize and exploit the coming changes in the industry and the markets it serves. These new structures are, however, not without their disadvantages. The LNG "chain" remains highly capital intensive. At the same time a more flexible trading arrangement will not work in an end market which is still rigidly organized and where the regulatory and ownership structure of power generation does not permit appropriate returns to private investors. This report assesses these changes and analyzes a possible model for LNG development in small, developing country markets.

### **III. TARGET MARKETS**

5. The focus was on sub-Saharan Africa, both because of the Bank's experience with projects in the region, as well as the relative proximity to emerging new LNG supplies which could be readily delivered there. While the market analysis appears somewhat brief, this reflects the evolution of the study as the project developed. The key attributes of each market were quite similar. All have limited access to domestic sources of energy; all had poorly performing power sectors which hamper potential economic growth; all had ports which could reasonably be expected to host an LNG receiving terminal; and all would need regulatory and market reforms which would permit such a project to be developed by the private sector in a lead development role.

6. Three markets were chosen – Ghana, Kenya, and Senegal. A detailed market assessment was out-of-scope of this study. The countries were selected because they are on the coast, have developed harbors, have large populations and have a growing need for electricity. They also have to have a certain minimum electrical demand since there is a limit to the extent to which LNG can be "down-sized" and still prove cost competitive against alternative fuels for power generation applications. While the base case in this

analysis assumed a power plant with nameplate capacity of about 640 MW, sensitivities were run that included cases as low as 200 MW.

7. In evaluating each potential market, the existing port infrastructure was reviewed (to the extent possible within the scope of the study) since the existence of infrastructure will have a major impact on LNG development costs. Equally the size of the local market (population driven) is important since LNG-fired power may lose its advantages (compared, say, to pipeline gas from a nearby producing country which can be delivered directly to an inland market) if it requires long transmission lines to move it to market.

#### **IV. PORT ASSESSMENT**

8. Port access is absolutely critical to the development of an LNG import project. LNG tankers are large, hard to maneuver vessels, although for their size they require relatively shallow draft, at least 35 feet (11 meters) with 40 feet being preferable. To site a small LNG terminal requires about 40 acres of open land without incompatible adjacent uses. The berthing facilities must be dedicated. LNG off-loading equipment is unique to the industry, and does not allow for alternative uses. Finally, there must be a reasonable tug fleet in the harbor to permit the LNG tankers to enter, transit and berth safely, as well as provide fire-fighting support in the remote event of an accident.

9. Port attributes that were considered were the following:

- Approach channels – The approach channels to the harbor, the configuration of the inner harbor and the layout of marine berths have a bearing on the ease with which an LNG tanker cannot enter the port a reach its berth safely. LNG tankers are about 300 meters in length and can be difficult to maneuver especially if there are prevailing winds or currents. Wide, straight channels offer the best access; narrow twisting ones do not.
- Channel Depth – To the extent the channel has insufficient depth (at least 11 meters, ideally 13 meters) to accommodate an LNG tanker, the ability to dredge the channel is important, as well as having an acceptable method of disposing of dredge materials, which are often contaminated. For some ports, silting is an issue and dredging is an on-going requirement.
- Access to Berth – Access to the LNG tanker berth is also important, and the berth must be designed to accommodate large vessels and permit them to lie safely alongside while they are discharging their cargo. LNG tankers cannot berth or maneuver in channels without the aid of tugs, and sufficient tugs of adequate size must be available at the port. To the extent the port has strong currents or is exposed to high winds, additional tugs may be required or restrictions placed on the conditions of entry of the LNG tanker (which will add to the cost of shipping the LNG to the terminal). Typically, in many ports an LNG tanker would not be permitted to enter the harbor with wind speeds in excess of 25 knots, or visibility of less than one-half mile. The channels must be well marked and the local pilots competent in handling ships of the size

involved. In well marked ports with good navigation aids, night-time transit of the vessel may be permitted, other wise the entry may be limited to daylight hours.

- Other issues -- Other marine traffic and control of the channel during the LNG tanker's approach is important. LNG tankers have limited maneuvering capability at slow speeds, so other traffic cannot readily occupy the channel space while the LNG tanker is in transit. Similarly the berth needs to be protected from other shipping which could cause serious damage if an errant vessel were to run into the LNG tanker or even the berth itself. Finally, if the project is to expand, the availability of additional land in the berth area, and the protection of that land from incompatible uses will be key.
10. Based on these criteria, each of the major ports in the selected countries was evaluated as a "first pass" assessment of their suitability for hosting an LNG terminal. The results are summarized in Table 1 below for each port. Based on this limited initial evaluation it appears that each of the ports could potentially host an LNG receiving terminal, but a final assessment cannot be made without an actual site visit (please note that site visits were outside the scope of this study).

**Table 1: Port Assessment in Selected Countries**

PORT	POSITIVE POINTS	NEGATIVE POINTS
Takoradi, Ghana	<ul style="list-style-type: none"> <li>⊕ 12-meter entrance channel</li> <li>⊕ Existing 660 MW oil fired power generation facility which could be converted to gas</li> </ul>	<ul style="list-style-type: none"> <li>✗ Older infrastructure (built 1928)</li> <li>✗ Tight turn inside breakwater, potential ship maneuvering problem</li> </ul>
Tema, Ghana	<ul style="list-style-type: none"> <li>⊕ Largest man-made port (by area)</li> <li>⊕ Recent dredging to 12.5 meters –(channel), 11.5 meters (berths)</li> <li>⊕ Ease of berthing/maneuvering (long quay)</li> <li>⊕ Remote port (isolated from urban congestion)</li> </ul>	<ul style="list-style-type: none"> <li>✗ Crowded finger pier (west of breakwater)</li> <li>✗ Potential marine traffic congestion</li> </ul>
Mombassa, Kenya	<ul style="list-style-type: none"> <li>⊕ Very deep entrance and inner channel (13.75 meters, 16 berths)</li> <li>⊕ Many potential LNG import terminal sites</li> <li>⊕ Very large port/large hinterland</li> <li>⊕ Gateway port to East Africa</li> <li>⊕ World-class expansion vision</li> </ul>	<ul style="list-style-type: none"> <li>✗ Deteriorating infrastructure</li> <li>✗ Bureaucratic problems in port environment</li> <li>✗ Lengthy inner channel/urban environment</li> </ul>
Dakar, Senegal	<ul style="list-style-type: none"> <li>⊕ Isolated Port</li> <li>⊕ Short channel (very deep)</li> <li>⊕ Relatively good tugs (3 at 2000 hp)</li> <li>⊕ Recent dredging (11+ meters)</li> <li>⊕ Large port aspirations</li> <li>⊕ Round-the-clock harbor access</li> <li>⊕ Potential for conversion of existing oil-fired power generation on site</li> <li>⊕ Seeks privatization</li> </ul>	<ul style="list-style-type: none"> <li>✗ Navigation aids, channel markers (low visibility)</li> <li>✗ Finger piers vs. extended quays</li> <li>✗ Economic growth dependent on agriculture</li> </ul>

## V. LNG SUPPLY ANALYSIS

11. A less conventional analytical route was chosen than would be normal in this type of project. Most LNG project studies utilize an integrated model of capital investments, operating costs and returns along the entire supply chain from wellhead to busbar as if these projects were being developed from scratch to demonstrate the overall project feasibility. In this case an assessment was made of the landed cost of LNG at the selected locations based on existing LNG supply projects and their alternative markets. The landed cost of LNG, as a proxy for market value, allows one to assess the feasibility of the LNG import project compared against alternative fuels. The logic of choosing this route is that it recognizes that an emerging market customer looking to buy gas in these quantities would never be the “launch” customer for new production capacity – rather they will be attractive customers for additional sales from existing capacity, or from new or expanded projects that have already made their baseload sales.

12. Once an LNG supply project is established and operational its capital investments become "sunk costs". The variable costs of LNG production and delivery are small (and may even be negative if the project has significant associated condensate or LPG production which would otherwise be shut-in if LNG production was curtailed). As a consequence, small increments of additional demand which can be satisfied without undermining long-term sales arrangements or requiring investments in new facilities can create high marginal value. This can be seen in growing “spot” LNG sales into the European and especially the North American market. These spot sales can be considered marginal in the context of the suppliers’ long-term arrangements. The relatively small scale of the import projects we considered would fit this criterion. Most LNG export projects today have sufficient size and spare capacity that they could serve these developing end markets without disturbing their primary customer relationships and contracts.

13. As a general proposition, we have assumed the current marginal markets for Atlantic and Middle Eastern LNG supply projects to be the US Gulf Coast (Lake Charles, Louisiana LNG terminal) and Northwest Europe (Zeebrugge, Belgium LNG terminal). In both cases, these represent the least attractive markets for LNG sales given their ready access to regional pipeline supplies and their greater distance from the supply projects than other import terminals in the same region. As a general proposition LNG suppliers will target the more attractive markets first, but in an increasingly "LNG supply long" world, the more attractive markets are becoming saturated and the marginal markets are being considered for long-term sales.

### (i) West Africa

14. For West Africa, the supply source was assumed to be Nigeria. With an established and growing liquefaction plant on the Bonny River by Nigeria LNG (NLNG), and three more in development, Nigeria is the natural supply source. We used Ghana as the target market, but the general principles can easily be extended to Senegal or other West African markets. NLNG controls its own shipping fleet and has capacity both in the liquefaction plant and the fleet in excess of its firm sales obligations to its customers. To

meet the pro-forma case of a 640 MW power plant (The pro-forma case was selected using the Takoradi project in Ghana. The sensitivity of project size was one area tested later.), the equivalent of 25% of the annual capacity of one NLNG ship would be enough to deliver the annual fuel requirements. Given this requirement it would make no sense for a Ghanaian import terminal to source fuel other than a on delivered basis. Since LNG tankers are generally chartered under long term, fixed cost arrangements, a customer with limited demand could not justify the cost of committing to such a ship for partial requirements unless they also intended to speculate in the LNG shipping business with the resulting spare capacity. By acquiring LNG on a delivered basis the importer would gain access to a more diversified fleet as well as avoid the capital outlay required to acquire its own shipping. Using current market charter rates (around US\$65,000 per day for a 135,000 cubic meter vessel), the cost to ship LNG from Nigeria to Ghana on a full loaded basis would be approximately \$0.20 per MMBtu which is about \$0.50 per MMBtu less than shipping to Northwest Europe (Zeebrugge), and about \$0.70 per MMBtu less than shipping to the US Gulf Coast (Lake Charles). Full shipping costs assume the vessels are used 100% of the time by the export project, and would include the cost of bunker fuel, boil-off gas and port charges in addition to the cost of the charter hire.

**(ii) East Africa**

15. For East Africa the assumed supply source was Qatar, which has two existing liquefaction plants, essentially unlimited gas reserves and ambitious expansion plans. While the Qatar projects do not control any shipping at present this is likely to change as they continue to expand and make some portion of their sales on a delivered basis. The cost to ship LNG from Qatar to Kenya is about \$0.50 per MMBtu which is \$1.00 per MMBtu less than shipping to Northwest Europe and \$1.10 less than shipping to the US Gulf Coast. To meet the pro-forma case would require 70% of the equivalent capacity of a single LNG tanker. As described earlier it would make little sense for a small import project to acquire its own shipping. In addition to cost considerations, the logistics of the deliveries would probably mean that the importer would be unable to do anything with a single vessel's spare capacity, thus effectively increasing the cost of shipping by over 40% compared to the case presented here.

16. Using these basic assumptions, an "inland" price for both Northwest Europe and the US Gulf Coast of \$3.00 per MMBtu was picked (although the analysis could easily be adapted for any price level one might care to forecast in the future). Based on estimates of shipping costs and terminalling costs, we derived a price for LNG delivered to the African markets which would make the suppliers indifferent to sales to these markets as opposed to the alternatives. The results are shown in Table 2 below.

**Table 2: Africa Location Advantage**  
(\$ per MMBtu)

Alternative Destination	M.E. to Kenya		Nigeria to Ghana/Senegal	
	Lake Charles	Zeebrugge	Lake Charles	Zeebrugge
Inland Price	\$3.00	\$3.00	\$3.00	\$3.00
Terminal Charge	(\$0.40)	(\$0.30)	(\$0.40)	(\$0.30)
Ex-ship	\$2.60	\$2.70	\$2.60	\$2.70
Shipping to US/EU	(\$1.60)	(\$1.50)	(\$0.90)	(\$0.70)
FOB	\$1.00	\$1.50	\$1.70	\$2.00
Shipping to Africa	\$0.50	\$0.50	\$0.20 – \$0.35	\$0.20 – 0.35
Ex-ship	\$1.50	\$2.00	\$1.90 – 2.05	\$2.20 – 2.35

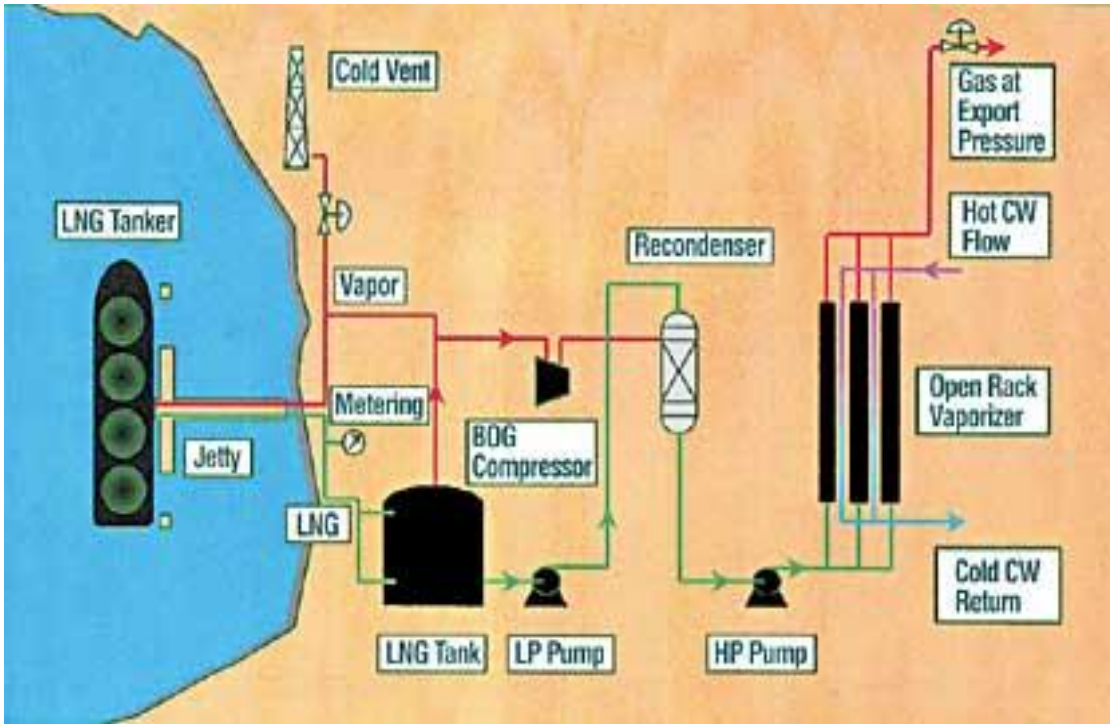
17. Breakeven tariff charges for Lake Charles would result in a terminalling charge at that location of \$0.45 per MMBtu. For Zeebrugge, the derived terminalling charge plus the cost to access the European grid at the Zeebrugge Hub results in charges closer to \$0.70 per MMBtu. The result would be a delivered breakeven price to Kenya of between \$1.45 and \$1.60 per MMBtu. For Ghana the current price range would be \$1.85 to \$1.95 per MMBtu. Inland market values are presently (May 2002 delivery) about \$2.00 per MMBtu in Zeebrugge and \$3.60 per MMBtu in Lake Charles. Volatility in the alternative markets is a factor which a small import project buying on the margin would have to contend with. However, the current US gas prices are also arising in the context of an oil market priced in excess of \$25 per barrel, giving a heavy fuel oil cost in excess of \$3.00 per MMBtu before accounting for efficiency differentials in generation technologies. A small import project today would be looking at delivered LNG costs on the order of \$2.00 per MMBtu in the case of East Africa, and \$2.50 per MMBtu in the case of West Africa. That would leave an attractive spread against oil in conventional steam boilers, let alone if the gas were to be used in gas-turbine based power plants with their higher conversion efficiencies. This inter-regional and inter-fuel arbitrage creates opportunities for small LNG projects, although it does not make the financing of them any easier, since it clearly carries a much lower level of predictability.

## VI. LNG TERMINAL/POWER CHAIN COST ANALYSIS

18. We disavowed the use of this modeling approach earlier in the context of making the assessment of landed LNG costs. However, it is appropriate to use it here in understanding how and whether an LNG import terminal and associated power generation project would provide a competitively priced source of electricity. The pro-forma power project was a 640 MW gas turbine power plant running in combined cycle

mode. It could be multi-fuel capable - natural gas, distillate, naphtha and propane (LPG). (The EcoElectrica project in Puerto Rico can operate on LNG, LPG or distillate, depending on the relative costs of the fuels). The capital cost was estimated to be \$370 million. In the context of capital costs, it is important to note that US capital costs were used for benchmarking purposes. These costs would have to be adjusted for specific location factors, but since we are looking at comparative generation technologies the impact should not be great since similar adjustments would have to be applied to the alternative oil-based generation plants. However, in absolute terms, country and location specific factors could add as much as 30% to plant costs. Among the factors to be considered in the plant design would be the choice of water-cooling technology over air-cooling, and whether the project would be implemented in stages beginning operations in simple-cycle mode. Another choice with cost implications would be the decision to incorporate multi-fuel capacity measured against the potential value that could be perceived to have (and specific local factors such as the availability of oil product storage in the immediate area).

19. For the LNG terminal, the design choice was to construct a 165,000 m<sup>3</sup> LNG storage tank with dual containment technology, the most conservative design from a safety standpoint. This would provide sufficient storage to run the power plant for 40 days or more, and also permit the largest LNG tankers to unload. The plant would be designed with minimal equipment redundancy (i.e. vaporizers would be sized to the power plant load and not with additional capacity). In assessing costs of the terminal options, nothing was included for land costs (assumed to be similar for all projects), and a single cost was used for the marine infrastructure cost. This latter area can be subject to significant variability (dredging, berth/pier construction, tugs, navigation aids) but the scope of this study cannot address that issue. The diagram below shows the key elements of an LNG terminal.



20. The estimated capital cost breakdown for the terminal was estimated to be as shown in Table 3.

**Table 3: Capital Cost Breakdown for LNG Terminal**  
(US\$ millions)

	US\$ millions
LNG storage tank	50
Marine berth and dredging	35
Tank pumps, piping & vaporization	30
Fire protection	5
Control room, offices	10
Civils	10
Engineering & project management	10
<b>Sub-total</b>	<b>150</b>
Contingency	25
<b>Total</b>	<b>175</b>

21. To place this in context, the design criteria are similar to the EcoElectrica terminal in Puerto Rico which had an estimated cost of \$160 million.

22. There are several elements of variability in the terminal design.
- The choice of containment technology would tend to be a trade-off between land costs and availability. A full containment tank would require about one third of the land area but cost 30% more than a single containment tank. The analysis presented here assumed full containment since it is likely most ports would be quite constrained for open space.
  - The degree of redundancy in vaporization would involve trade-offs with the availability and costs of alternative fuels. If there was available oil product storage nearby it would probably make sense to minimize redundancy and accept that alternative fuels would be used if there was unscheduled downtime on the vaporization.
  - Another factor not incorporated is the potential benefit of hot/cold integration between the power plant and the LNG terminal. The LNG terminal represents a large potential source of cold energy which can be used to cool the air intakes on the turbines. In tropical settings this could yield a 10% improvement in power generation capacity as well as a better heat rate (better fuel efficiency). On the reverse side of this closed loop system, low-grade waste heat from the steam turbine can be captured and used to vaporize the LNG thus limiting the need for fuel-gas to be burned in the vaporizers.
23. Based on these assumptions and the others described below, the resulting power costs for the pro-forma plant as well as for competing technologies of a similar size were calculated and are presented in Table 4 below.

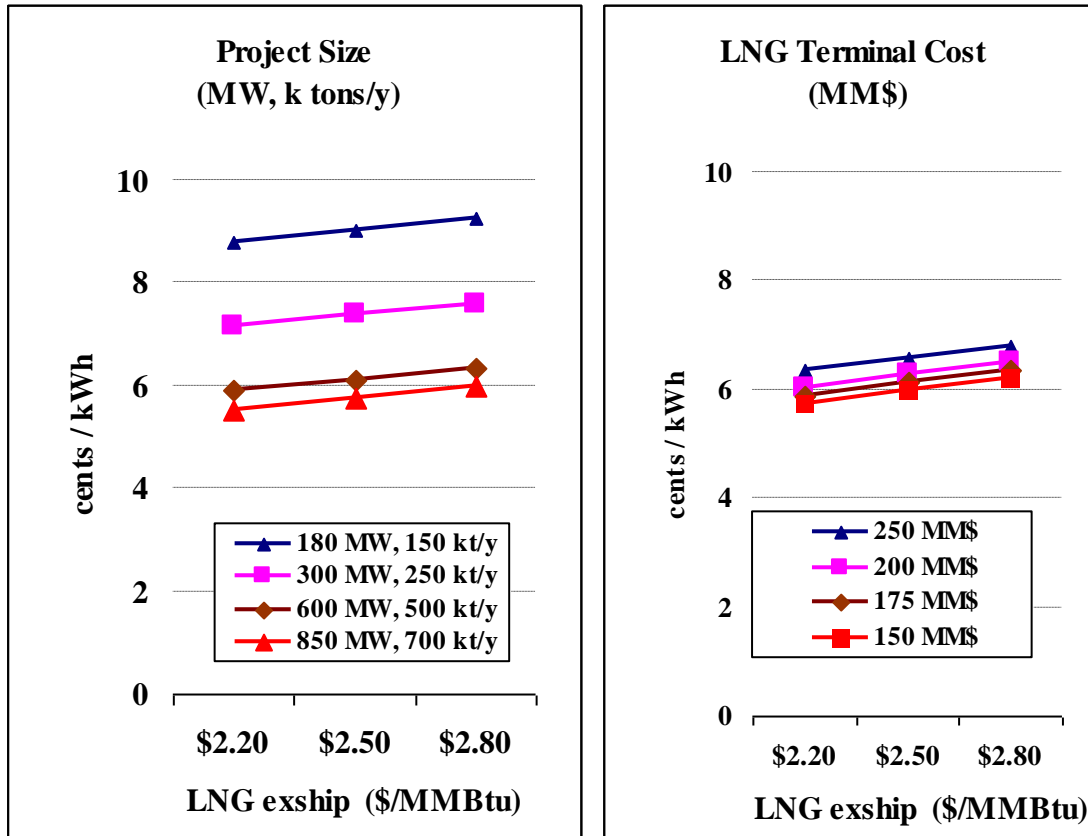
**Table 4: Electricity Chain Costs – Key Assumptions**

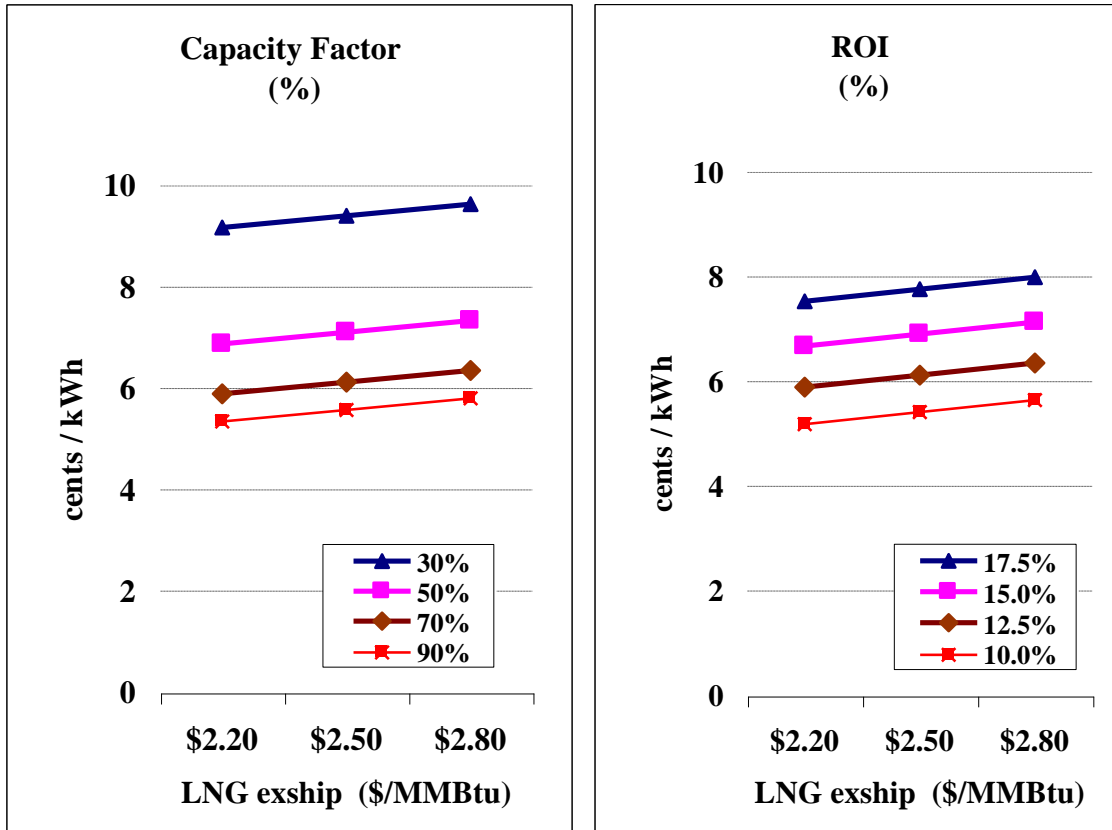
<b>Key Parameters — Base Case</b>		<b>Gas</b>	<b>Distillate</b>	<b>Fuel oil</b>
<b>Size</b>				
Fuel Input	K ton ex ship	500	614	810
	TBtu input	26	26	32
Electricity output	MMKwh	3,705	3,705	3,705
Capacity (nameplate)	MW	643	643	671
<b>Powergen Operating Factors</b>				
Capacity factor	%	70	70	70
Efficiency	% (HHV)	49	49	39
Availability	%	94	94	90
<b>Fuel price (ex ship)</b>		<b>\$/b</b>	<b>\$/b</b>	<b>\$/b</b>
Oil (@\$20/b crude)			25	16
Fuel per MMBtu	\$/MMBtu	2.50	4.31	2.54
<b>Facility Costs</b>				
Import terminal	MM\$	175	20	20
Generation capacity	\$/kWh	600	600	800
<b>Tax structure</b>				
Import duties	%	10	10	10
Income tax rate	%	35	35	35
<b>Financial structure</b>				
Debt capacity	%/Y	75	75	75
Debt rate	%/Y	10	10	10

24. Detailed tables showing the assumptions and elements which make up the above summary are included in Appendix 2. The relative costs of the oil options will move in relation to oil prices, but the price of the gas option will not necessarily do so as gas prices are already de-coupled from oil prices in the American market (at least in the short term) and appear likely to show similar de-coupling in the European market as it is deregulated and more gas-on-gas competition emerges.

25. In considering the LNG option, a series of sensitivity analyses were made to examine the key variables which seemed most likely to affect the ultimate cost of electricity. These are summarized in Figure 1 and Table 5 below.

**Figure 1: Electricity Cost Sensitivities (¢/kWh)**





26. Not surprisingly, the cost of electricity is most sensitive to utilization rates and capital return considerations since the LNG option is the most capital intensive option and any ability to increase the utilization rate or lower the required return on investment will have the largest impact on the ultimate cost of electricity. No attempt was made to model the impact of fuel cost variability. As discussed above, fuel costs for the LNG plant will be a function of prices of gas in two disconnected gas markets (North America and Europe), and the cost of fuel for the oil-based alternatives is in turn a function of oil prices. Attempting to forecast the price differentials between these three fuels lay well beyond the scope of the study. However, as described above the more critical issue in fuel cost lies not in the long-term view of comparative prices, but rather in the short term given the high volatility in gas and oil prices. Opportunistic LNG purchasing, combined with hedging programs should allow an LNG-based project to lower its fuel costs below what a simple analysis of long term gas costs in either North America or Europe (the suppliers' alternative markets).

27. The cost impact of significantly downsizing the LNG project was also examined. Two cases were considered - 300 MW and 200 MW (see Table 5). In both cases it was assumed that the LNG terminal costs could be reduced by about \$25 million, mainly through utilizing a smaller storage facility, and some cost reductions in the vaporization, and other project elements. The relative capital cost of the power plant was kept the same, although in reality this could be expected to rise disproportionately as the plant became smaller. However, this would also be true of the oil-fired plants, and the

comparative costs are of most interest. The following results were obtained for the smaller scale options:

**Table 5: Cost Impact of Downsizing LNG Project**

	<b>LNG @ \$2.00</b>	<b>LNG @ \$2.50</b>	<b>Distillate</b>	<b>Fuel oil</b>
300 MW	6.1 ¢/kwh	6.5 ¢/kwh	6.2 ¢/kwh	5.2 ¢/kwh
200 MW	7.3 ¢/kwh	7.7 ¢/kwh	6.4 ¢/kwh	5.4 ¢/kwh

28. It appears that LNG would work as an option at the 300 MW size, but below this level towards 200 MW, the LNG becomes less attractive. A 200 MW project running on LNG would then only appear to make sense when other considerations come into play. For example, it is clear from the preceding analysis that LNG offers the lowest expansion options on the margin, so if the initial project was only 200 MW in size, but there was a high probability of expansion in the near future, this could be a major consideration in fuel choice. Likewise, if other markets nearby offered the prospects for additional gas demand this would also have a significant role to play.

## **VII. FUEL SOURCING STRATEGY**

29. The preceding analysis of the likely LNG costs and their impact on power prices indicate that LNG *could* be made available on terms which on the surface appear relatively attractive to both the exporter and the importer. In order to assess a procurement approach, Poten has made some assumptions relating to the long-term structure of the LNG market, and has proposed an LNG supply strategy which is somewhat different than the conventional industry wisdom.

### **(i) Assumptions**

30. It is believed that as a general proposition the world has a surplus of LNG production capacity and that over time this surplus will tend to grow, mostly as a result of rising gas resources, falling costs and maturing markets. At the same time LNG shipping capacity will be available to move these volumes to market as a result of LNG producers either acquiring through purchase or charter (short or long term) the tankers they need. For this study the assumed cost of such shipping capacity would tend to average long-term charter rates which are presently about \$65,000 per day. Short-term charter rates will exhibit much more volatility, probably tied to US Gulf Coast gas prices with the US being the destination of "last resort" for most export projects serving the Atlantic Basin. Further driving volatility of short term charters will be the emergence of "merchant" LNG traders who will commit to purchase LNG supplies under varied arrangements without assured markets, or to sell to LNG import markets without identified supply sources. This trend can be seen in Shell's purchase of the Australian Northwest Shelf "wedge" volumes for a seven-year period without an identified market, and BP's sale of "branded" LNG to the AES import project in the Dominican Republic for twenty years without an identified supply source. Finally, as the pro-forma analysis showed and given practical experience

(Dominican Republic, Puerto Rico), it is clear emerging LNG markets of the scale likely to develop in Africa are much too small to buy on an FOB basis and take on shipping commitments separately. Rather they will buy on a delivered basis leaving either the exporters or the merchant suppliers to arrange the shipping to their terminals. Shipping could, for limited periods of time, become tight. However, the shipyards have reduced construction lead times on ships to about two and one half years, and the world capacity for LNG tanker construction is now about 30 ships per year compared to an apparent requirement of about 10 per year. Thus any short-term squeeze in shipping will likely be mitigated quickly by expanding new construction.

**(ii) Conventional Supply Strategy**

31. The standard industry model for LNG sales arrangements has changed little over the past twenty or thirty years. It has the buyer and seller entering into a long-term contract (15 years or more) calling for "take or pay" commitments on the part of the buyer to "secure" the seller's investment risk in the liquefaction plant. Volume flexibility is very limited (no more than 5% or 10% per year). Pricing in the Far East and Europe has been traditionally set with reference to crude oil or oil product baskets, and for the US with reference to US natural gas prices.

**(iii) Emerging Supply Model**

32. As the industry matures, the emerging model is much more along the line of a "portfolio" approach on the part of both buyers and sellers. Supply contracts are increasingly being written with terms between spot (one or two cargoes at a time) and twenty years' duration. This offers both buyers and sellers increased flexibility in dealing with market uncertainty. Pricing may be linked to more than one market as buyers and sellers gain the freedom to move cargoes into these markets to take advantage of price arbitrage opportunities. Both buyers and sellers can diversify their supplier and customer bases respectively, bringing increasing security of supply to each. In such a world, off-take guarantees are less critical, since the sellers are increasingly assuming they will always be able to move volumes to marginal markets if they are prepared to live with the possibility of lower yields from these markets.

33. It is this emerging model that is recommended for adaptation in the African market context. Any new or emerging market, viewed from either a buyer's or seller's perspective presents a degree of demand uncertainty. Even with a power plant as an "anchor tenant", the tendency to create dispatchable power pools in liberalizing markets will make the power plant itself a source of uncertainty. For example, in the West African context it would make little sense to run an LNG-fired power plant if high levels of rainfall allowed an increase in hydro generation. A buyer who has not committed its full requirements to a single seller has the ability to purchase fuel on an opportunistic basis, often leading to lower costs, especially if the power plant has access to alternative fuel such as distillate oil. Sellers interested in this fuel arbitrage will seek out buyers who offer this kind of flexibility and these sellers should be willing to compensate the buyer

for this flexibility through better LNG sales terms (such as lower costs) than they might offer their more traditional and established customer base. By avoiding long term contracts the buyers also limit their exposure to providing financial guarantees to the sellers. It is also unlikely that emerging market buyers would be able to offer long-term credit which would be “bankable” by the sellers. Even if an emerging market offered creditworthy guarantees, it seems this would not be the best use of what is often a limited debt capacity.

34. However, this approach requires one fundamental decision which in the conventional world would be seen as a high risk. The buyer will need to construct an LNG terminal without an assured source of supply - essentially on a "speculative" basis. This places the capital risk of the terminal on the power project and ultimately the power buyer/host country. However, if one accepts the view of a changing LNG market this risk should be minimal. Moreover it does not preclude the buyer from committing to the conventional approach at a later date, or adopting a "mixed" buying strategy involving long and short term commitments. The recent experience on the US LNG market should reinforce this view where each of the four terminals has re-entered or is re-entering service after various periods of enforced idleness and without securing LNG supplies as a pre-requisite to restarting operations. There are other potential risks.

- LNG supply could be hard to source cost-effectively on a short-term basis if the Atlantic gas markets were to suddenly tighten. The 2000-01 winter's experience with \$10 per MMBtu gas in the United States dramatically illustrated this. However, a dual-fired plant has mitigation available through access to alternative fuel sources. Also, experience suggests that such price spikes will tend to be short-lived as market forces quickly cause re-adjustment.
- Another risk lies in cargo access. The "speculative" buyer will generally be last in line for cargo scheduling from the export plant. This could result in cargo delays which could only be mitigated by the burning of more expensive substitute fuels or through incurring additional capital costs to increase the volume of LNG storage.

35. Another concern is the potential vulnerability of small import projects to a shipping "squeeze" should shipping capacity become tight. We believe this concern could be mitigated contractually. As we have already described, the advantage of the emerging markets is their relative close proximity to the export projects. If one accepts that shipping tightness will be manifested in shipping charter rate "spikes" then the African markets become even more attractive than the alternatives. If marginal shipping rates are very high the closer markets become relatively more attractive than the distant markets. The 2000-01 winter's US gas prices had a dramatic impact on the shipping market. Charter rates which had been running in the sub-\$40,000 per day range suddenly jumped over \$150,000 per day as shipping owners took advantage of the high US gas pricing and market tightness to capture a share of the price increases in the end markets. For a West African importer the delivered cost using this rate level is still much lower than would apply to a US Gulf importer. However, the delivered price of fuel might still be

unappealing, especially if the power project had the capacity to burn alternative fuel. If the import project had access to alternative fuels, and had made seasonal commitments to purchase LNG ahead of the winter period, the buyer could agree to release the LNG back to the seller to deliver to the higher value market for a share of the price uplift. This arbitrage sharing process is increasingly emerging in the LNG industry as a way of exploiting the flexibility of the industry's delivery systems (i.e. ships) and sharing the benefits between the established contractual players. Dual fuel capable power plants add another dimension of arbitrage potential to this. Finally to protect themselves from an excessive price run-up in an alternative market the importer/buyer could use financial derivatives to mitigate price risks. It is perfectly conceivable for an importer to buy LNG on a price indexed to the US Henry Hub, then to protect themselves against sudden price increases through the purchase of an "out of the money" cap on the upside. Such a price cap would cost very little if set high enough and would protect the buyer from being priced out of the LNG market. Another risk mitigation strategy would be to permit the LNG sellers to deliver an alternative fuel at the same cost as the LNG, and retain the arbitrage benefit for themselves, while the power project remains indifferent. This form of fuel flexibility should be attractive enough to an LNG seller as to warrant a discount on the price the seller might otherwise be seeking from the buyer.

### VIII. THE PIPELINE ALTERNATIVE

36. Where gas is available regionally, the preferred alternative has usually been to secure the delivery by pipeline. The shorter the distance from the reserves to the market, the more compelling the economic benefits of pipeline gas are to LNG. However, economics are never the only driver in energy projects, especially energy projects which involve cross-border energy deliveries. Table 6 summarizes some of the other benefits and costs of the two alternatives.

**Table 6: LNG vs. Pipeline Gas**

<b>LNG</b>	<b>PIPELINE GAS</b>
<b>BENEFITS</b>	<b>BENEFITS</b>
<ul style="list-style-type: none"> <li>• More supplier options</li> <li>• Limits cross border issues</li> <li>• Volumes can be matched to market evolution more closely</li> <li>• Reduced buyer country capital exposure (not underwriting entire supply chain)</li> <li>• Storage has value in managing variable electric loads</li> </ul>	<ul style="list-style-type: none"> <li>• Lower commodity price (avoid LNG conversion costs)</li> <li>• Aggregate capital costs lower</li> <li>• Limited competition from other markets may lower prices</li> <li>• Better for short distances to small markets</li> <li>• Only option for inland markets</li> </ul>

RISKS	RISKS
<ul style="list-style-type: none"> <li>• Commodity fuel price higher</li> <li>• Supply price driven by other markets</li> <li>• May require more infrastructure on buyer's part</li> <li>• Works best for near-coastal markets</li> </ul>	<ul style="list-style-type: none"> <li>• Single supplier risk</li> <li>• Market overestimation may leave larger "stranded" assets</li> <li>• Multi-country exposure on cross border pipelines</li> <li>• No storage – harder to match to dispatchable power plants</li> </ul>

37. LNG offers other benefits, some of which are complementary to the pipeline alternative. The LNG option can "pre-build" the gas market until it reaches a sufficient size to support the pipeline option. An LNG terminal can also offer the possibility of supplying remote users with a natural gas option via road transport. This technology is established in the US, Europe and the Far East. Again it allows the development of markets which cannot be economically served by pipelines.

38. From the perspective of the LNG/power project development, the LNG option can provide a much better load following option for generating units operating in dispatchable power pools, by allowing near perfect short-term "load following". In a power market with large hydro resources LNG can also offer supply flexibility better suited to the vagaries of the hydro generation, and permitting the lowest marginal cost option to be fully utilized. Finally, while the initial cost of the LNG option is quite high, expansions of capacity from that base can be made at a relatively low capital investment.

39. While the LNG option was compared to oil based alternatives, no attempt was made to value the environmental benefits. Compared to oil and especially high sulfur fuel oil, natural gas produces far fewer air emissions, since it is both more efficient as a fuel and contains no measurable sulfur content. Also, LNG carries none of the environmental degradation risks associated with oil spills. Another factor which may not be clear from the earlier analysis, is that once the initial investment has been made (most of which will come as hard currency outlays given the need for sophisticated equipment sourcing), the LNG option actually has lower hard currency requirements, as Table 7 illustrates.

**Table 7: Project Annual Outlay**  
(\$MM/year)

	<b>Gas</b>	<b>Distillate</b>	<b>Fuel Oil</b>
Fuel ex-ship	65	111	93
Import duty on fuel (10%)	6	11	9
Terminal capital recovery (depreciation and return)	28	8	8
Taxes on terminal	11	2	2
Terminal operating costs	7	1	1
Power plant capital recovery (depreciation and return)	59	64	108
Taxes on power plant	23	18	27
Power plant operating costs	28	31	39
<b>Total annual costs</b>	<b>227</b>	<b>247</b>	<b>287</b>
<b>Hard currency outlays*</b>	<b>169</b>	<b>199</b>	<b>229</b>

\*Fuel, capital return, 50% of operating expenses

## **IX. PROJECT STRUCTURE**

40. In order to turn a concept into reality the developer who wishes to construct such a project must possess a variety of skill sets. They must have strong project management skills, and not just in the technical area. To keep costs down, the project must seek the most competitive terms for equipment and fuel procurement. Transparency through open bidding processes would be the most efficient method, but is often at odds with the realities of emerging markets. The host government must be willing to offer competitive fiscal terms and ones which do not favor the development of one project option over another. On the power sales side, the power buyer from such a project must have a reasonably efficient dispatch and distribution network, and, ideally, a transparent power market which enables the clear valuation of power. In turn this can allow the power project the ability to arbitrage its cost and price advantages as we have described above. Power tariffs must be high enough to cover costs and the economic policies must be strong enough to permit currency convertibility which will enable the project to repay what will most likely be hard currency loans. As identified earlier, an LNG based option is the most capital intensive of the choices available. In this respect, the ability to mitigate political risk and the potential for access to concessionary loan terms for some portion of the project financing can bring down the overall borrowing cost and in turn reduce the required overall investment return. In turn this clearly translates into lower cost power for the end consumer.

## **X. CONCLUSION**

41. LNG can offer a viable fuel option in small emerging markets. However, to achieve this goal requires the project sponsors and their bankers to adopt a new model for the LNG industry, one which is less predictable and more flexible than has been accepted in the past. This analysis may assist those sponsors and financiers advance their understanding of the changing world of LNG.

## Cost of Services: Import Terminal and Power Plant

		Gas	Distillate	Fuel Oil (HS)
<b>Import Terminal – Cost of Service</b>				
Project Costs				
Capex	MM\$	175	20	20
Opex	MM\$/Y	7	1	1
Finance				
Construction time	Years	3.0	1.5	1.5
Required ROI	%/Y	12.5	12.5	12.5
Tax rate	%	35	35	35
Annual Cost				
Capital recovery-owners	MM\$/y	28	3	3
Capital recovery-tax	MM\$/y	11	1	1
Operating cost	MM\$/y	7	1	1
Total	MM\$/y	46	5	5
Memo: Throughput	Tbtu/y	26	26	32
<b>Terminal COS</b>	<b>\$/MMBtu</b>	<b>\$1.79</b>	<b>\$0.19</b>	<b>\$0.15</b>
<b>Fuel Prices – Base Case</b>				
Fuel Prices – ex ship and plant gate				
Ex ship – crude oil @\$20/b	\$/b		25	16
Ex ship	\$/MMBtu	2.50	4.31	2.54
Import duty	\$/MMBtu	0.25	0.43	0.25
Terminal COS	\$/MMBtu	1.79	0.19	0.15
Plant gate	\$/MMBtu	\$4.54	\$4.93	\$2.94
<b>Power Plant – Cost of Service</b>				
Project costs				
Capex	\$/kW	600	600	800
Fixed Opex	\$/kW/y	14	20	20
Variable Opex	¢/kWh	0.5	0.50	0.70
Finance				
Construction time	Years	2.5	2.5	3.0
Required ROI	%/Y	12.5	12.5	12.5
Tax rate	%	35	35	35
Tax life	Years	20	20	20
Annual cost	MM\$/y			
Capital recovery-owners		59	64	96
Capital recovery-tax		23	18	24
Operating cost		9	13	13
Fuel		117	127	95
<b>Total</b>		<b>227</b>	<b>241</b>	<b>255</b>
Electricity cost	¢/kWh			
Capital recovery-owners		1.6	1.7	2.6
Capital recovery-tax		0.6	0.5	0.7
Fixed operating cost		0.2	0.3	0.4
Variable opex		0.5	0.5	0.7
Fuel		3.2	3.4	2.6
<b>Total</b>	<b>¢/kWh</b>	<b>6.1</b>	<b>6.5</b>	<b>6.9</b>