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GAS SALES AGREEMENTS FOR ROVUMA LNG:

How Price is Determined and What it Means for Government Revenue

Sales agreements for Rovuma LNG are being negotiated at a time when gas prices are more volatile than ever. Past projections for government revenue have been based on price forecasts for Asian LNG that are no longer credible due to shale gas production in the United States and plummeting international oil prices. Lower prices mean less government revenue and might put the future expansion of Rovuma LNG at risk.

Summary

Assessments of potential revenues to the Government of Mozambique from Rovuma LNG focus overwhelmingly on the volume of gas to be produced and the tax rates that were agreed in the 2006 contracts. Little attention is given to the single most important determinant of government revenue – the price at which the LNG will be sold. If prices are lower than expected, early revenues will be greatly reduced and will grow much more slowly than current projections assume.

The future price of LNG is largely outside the control of Mozambique; it will be determined by international market prices. But government revenue will also be determined by the long-term gas sales agreements currently being negotiated by Anadarko and ENI, and by the way in which the vague valuation clauses in the 2006 contracts are interpreted.

Mozambique already has painful experience from the effects of a bad deal on the sale price for natural gas, where Pande Temane gas is sold in Mozambique for 1/5th of its value in South Africa. The pricing formula agreed in 2002 guarantees that Mozambique will never receive a fair share of the financial benefits. Case studies below on Equatorial Guinea and Yemen reveal that other developing countries have lost massive revenue on LNG due to unfavorable pricing agreements.

Due to the shale gas revolution in the United States and the result crash in oil prices, there is greater price uncertainty in the international LNG market now than at any time in recent decades. Although first exports of gas are still at least five years away, these long-term sales agreements are being negotiated now as the basis on which the companies will borrow tens of billions of dollars to build LNG facilities in Mozambique. The plausible sale price for Mozambique LNG is much lower, therefore, than has been assumed in the revenue forecast efforts by the IMF and Standard Bank.

In order to protect future revenues, the Government should:

- Develop an independent position on

trends in the international LNG market in order to protect Mozambican interests and actively participate in the negotiation of these long-term sales agreements;

- Divide potential sales markets between Anadarko and ENI (as was done by Qatar) in order to ensure that competition between the two companies does not drive down price;
- Ensure that the gas sales agreements follow international best practice and include both price review clauses (at least every five years) and destination clauses that guarantee a fair profit split if gas is shipped to an alternative market (see case study on Equatorial Guinea); and,
- Resolve gaps in the 2006 Rovuma contracts on how LNG should be valued by agreeing to a "netback" price based on final sale value less shipping and regasification costs.

There are only two transportation options for natural gas: a pipeline or liquefaction.

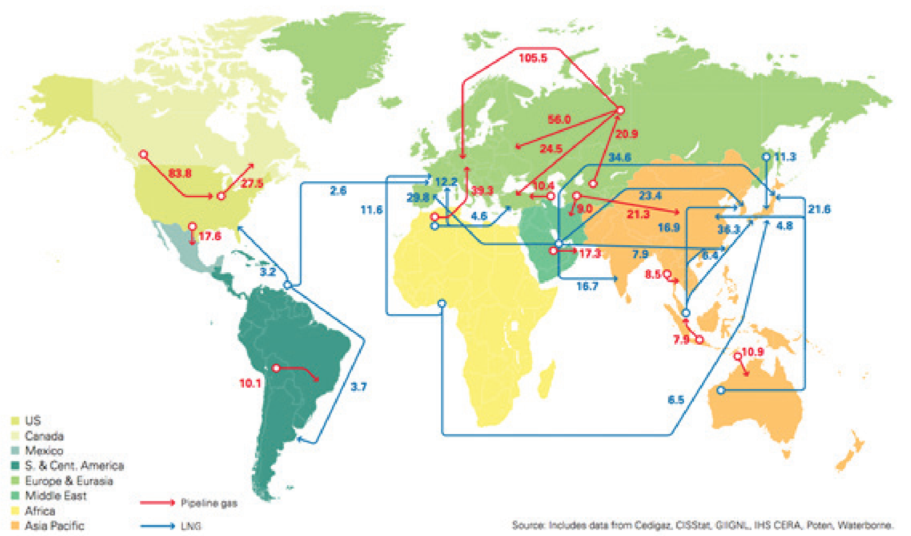
Pipelines are possible where gas reserves are found within about 2,000km of a sufficiently large market and account for roughly 90% of global natural gas sales. Where the distance to market is greater, the only alternative is to convert the gas into a liquid and send it by ship. The global trade in liquefied natural gas (LNG) began in the 1950s, and expanded first in the mid-1980s and then again in the mid-2000s, driven largely by demand from Japan, South Korea and Taiwan.

As the map in Figure 1 shows, due to the challenges of transportation, the international market for natural gas is not global but regional. The gas market has traditionally been divided into three regions: North America, Europe and Asia. European gas comes predominantly by pipeline, mostly from Russia but also from North Africa.

1. The International Trade in LNG

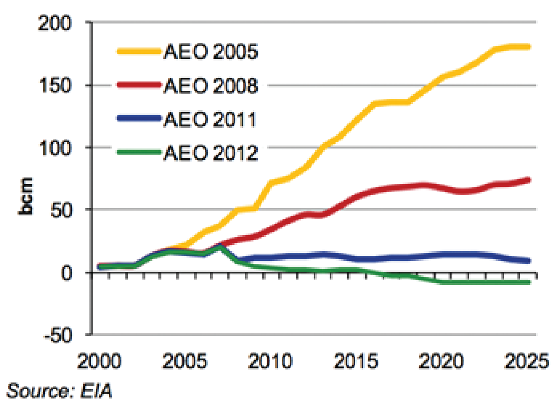
Companies exploring for petroleum hope to find oil. As it is already in a liquid state, oil is easy to extract, easy to store and easy to transport. For nearly a century there has been a global market for the buying and selling of oil. No parallel global market exists for natural gas. Natural gas is obviously not in a liquid form and, as a result, is easier to extract but more difficult to store and transport. It is so difficult to transport that where gas is found alongside oil, it is often simply burned off (flared). The World Bank estimates that in 2011 more than $50 billion worth of natural gas was flared[1].

Figure 1: Regional Trade in Natural Gas (Pipeline and LNG)



The North American market is also predominantly regional, with substantial pipeline trade between the United States and Canada, and LNG from Trinidad. LNG dominates the Asian market, with only a minority of the natural gas transported by pipeline.

Figure 2: EIA Forecasts for US LNG Imports



LNG prices are driven by the laws of supply and demand. For many years, it has assumed that the demand side of the equation was predictable with strong growth projected for traditional Asian buyers (Japan, Taiwan and Korea) as well as well as newcomers (China and India). Projections however are inherently uncertain and LNG demand is currently softening in Asia due to an economic slow-down.

The supply side is even less predictable. Production of LNG is expanding rapidly, with a 50% increase from 2009-2013, mostly from Qatar. Further expansion is expected in the coming years with seven new facilities scheduled to come on-line in Australia between 2014-17. Additional supply will also come from Angola, Indonesia, Nigeria and Papua New Guinea.

Further complicating projections is the massive expansion in non-conventional gas, previously thought to be locked in shale, but now extracted through hydraulic fracking. This new technology has opened up an estimated additional 6,600tcf of potential supply[2]. The impact has been most pronounced in the United States where the Energy Information Administration (EIA) now projects a transformation from major LNG importer to a net exporter by 2017[3]. The extra-ordinary expansion of US natural gas production has stunned the United States and the rest of the world. Figure 2 is the US Energy Information Agency's own estimates of US natural gas imports and exports. The presumption in 2005 and 2008 was that the United States would be a significant gas importer. Now the United States is expected to be a net exporter.

The surplus of natural gas in the United States will have a profound impact on the LNG market. As shown in Figure 3, LNG export permits have been filed in the United States for more than 210 million tons per year. Even if the majority of these ultimately do not proceed, the additional LNG that does come onto the market will have a significant effect on global prices. Existing suppliers of LNG to the United States including Trinidad, Norway, Nigeria, Yemen, Qatar, will all be looking for new customers. Canada, a traditional supplier of pipeline natural gas to the US, is preparing major new LNG exports capacity as well.

The massive increase in North American gas supply has had a dramatic effect on prices. Figure 4 shows natural gas prices in two key markets – the US and Japan. Through 2007, the prices moved in broadly the same direction. But increasing Asia demand coupled with the US shale gas revolution has resulted in a staggering divergence between North American and Japanese prices. Benchmark prices in the

Figure 3: LNG Export Capacity (Existing and Proposed)

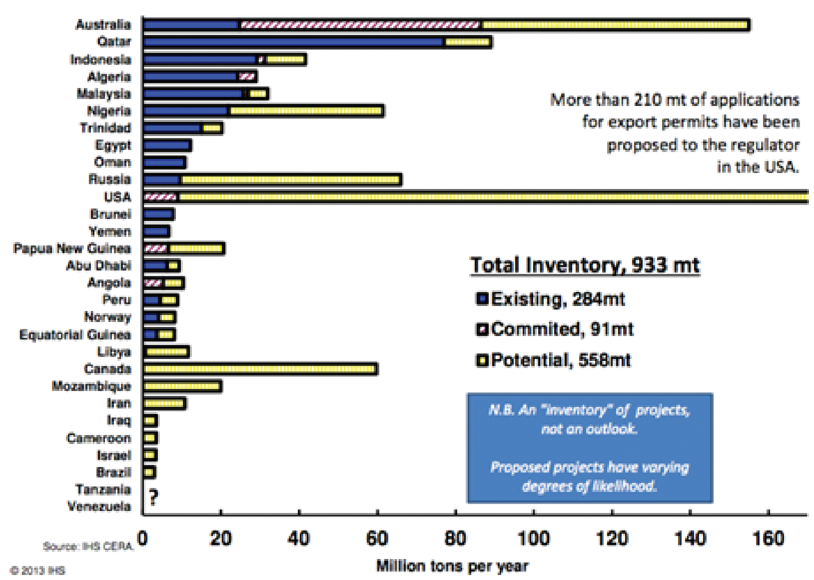
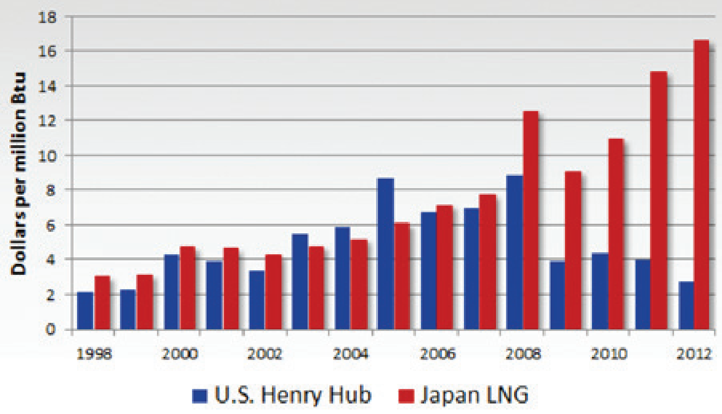


Figure 4: Comparing US and Japan Gas Prices



US (known as 'Henry Hub") are now around $3/mmbtu while LNG in Japan is currently priced at $14-15/mmbtu. Countries that based natural gas prices on US benchmarks, like Equatorial Guinea[4] and Yemen, have lost billions of dollars in government revenue (See Textbox 1 and 2).

2. Asian LNG Markets and Prices

The Asian LNG market has the highest prices and is the destination of choice for nearly all LNG projects under development, including those in Mozambique.

The extraordinary spread between North American and Asian gas prices is beginning to destabilize the traditionally separate regional markets. The international benchmark price for LNG is set in Japan – the largest single importer. As is the case with many East Asian economies, Japan has very limited energy sources and cannot bring natural gas in by pipeline. The original source of their LNG was Alaska and South East Asia (Indonesia and Malaysia), but major contributions are now also coming from Qatar (more than 16 mtpa) and Australia (more than 17 mtpa).

Textbox 1: Equatorial Guinea Loses Revenue on Bad Pricing Deal

In 2007, BG Group (British Gas) concluded a contract to purchase the full LNG production of Equatorial Guinea 3.4 million ton per annum until 2024. The sale price was based on a fixed discount (about 90) of the U.S. benchmark futures price known as "Henry Hub."

Tying the price to the US benchmark seemed to make sense at the time, as the LNG was destined for the US market. In 2004, U.S. prices were $6 per million British thermal units (mmbtu), and with growing demand surged to $15 the next year. The contract also contained a "floor price" necessary to secure financing for the LNG project.

However, the shale gas revolution in the United States has resulted in US gas prices of less than $4/mmbtu. The low Henry Hub price affects the price at which BG buys the gas, but not the price at which the gas is sold. With low prices in the Atlantic region, BG ships the LNG to the Pacific market where prices are five times higher. BG keeps the profits, reportedly nearly $1 billion each year.

Often, contracts contain a clause requiring additional profits from the diversion of gas to a more lucrative market to be shared 50-50, but no such provision exists in the BG contract. Tensions flared in 2009 when then Deputy Energy Minister Gabriel Obiang Lima publicly objected to the profits BG made by selling to Asian markets. As a concession, BG privately agreed that the government would receive 12.5 percent of the additional profit.

Last year, BG generated around 40 percent of its $2.6 billion operating profit on LNG from Equatorial Guinea the one deal, even though it accounts for only a quarter of overall sales volumes. Media reports now suggest that the 12.5 deal in unstable and that Equatorial Guinea is once again renegotiating the pricing deal.

Asian economies are highly dependent on imported energy. A guarantee of supply is of the utmost importance, with price predictability an important but secondary consideration. These twin objectives were pursued through long-term sales agreements, benchmarked to crude oil prices but with mechanisms to offset serious price spikes.

Figure 5: Sample Japanese S-Curve – LNG Linked to Crude Oil

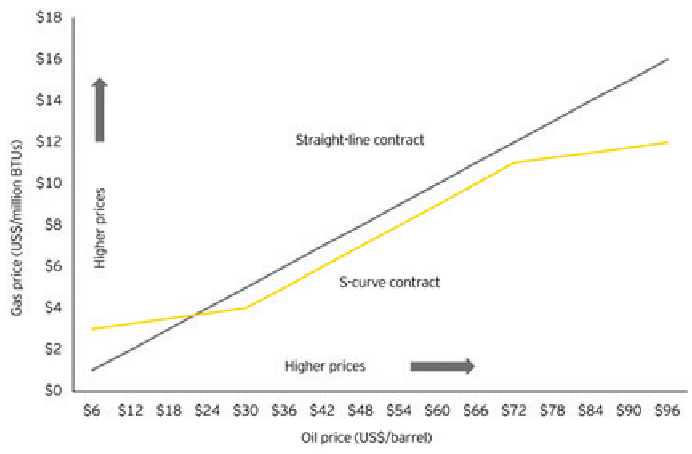


Figure 5 shows the traditional approach to pricing LNG in Japan – the "S-curve." LNG price is linked to the price of imported crude oil (known as Japanese Crude Cocktail or JCC)[5]. In the middle band, the two prices are directly linked, with a small discount for gas compared to crude. The slope of the line determines the relationship between the price of oil and the price of LNG. When the slope is 16.7, LNG prices are equal to crude oil in energy terms. Slopes less than 16.7 mean that LNG is sold at a discount to crude oil. Average slopes in recent years have been between 14 and 15.

Textbox 2: Yemen Loses Government Revenue

Oil exports have accounted for 75 of revenues and 90 of export earnings for the Government of Yemen. Production volumes have been steadily falling however as the oilfields move towards the end of their lifecycle. Yemen signed a "Gas Development Agreement" in 1995 with the French petroleum company Total in the hopes that LNG exports could offset falling oil revenues. LNG project development was delayed due to the Asian financial crisis and was re--launched following the signing of three "sales and purchase agreements" in 2005.

The three twenty--year sales agreements are broken down as follows: GDF--Suez (2.7mtpa), Total Gas and Power (2mtpa) and Korean Gas Corporation (2mtpa). The first two contracts were initially destined for the U.S. Market with prices indexed to Henry Hub (HH). The third contract destined for the Korean market is price indexed to Japan Crude Cocktail (JCC). None of them were designed to protect the Government of Yemen revenues in the face of large price fluctuations.

Yemen has lost billions of dollars in revenue over the first five years of the project because the pricing formula included a cap on the sale price resulting in a price ceiling of only $3.80/mmbtu when the price of Japanese crude exceeds $40/bbl. Average JCC prices over the life--span of Yemen LNG exports have exceeded $90, more than double the price ceiling contained in the contracts.

The results for Yemen government revenue are clear. Kogas of Korea paid

$3.80/mmbtu for LNG imported from Yemen in 2013. The average price of LNG important into Korea from all suppliers was $14.60/mmbtu. Reports suggest that prices paid for LNG by Total and GDF Suez, based on the original sales contracts, were even lower at around $3.20/mmbtu.

Rumors swirled in 2010 that Yemen would seek to renegotiate the contracts. Two years later the Government of Yemen announced that Total and GDF Suez had agreed to more than double the price from US$3.20/mmbtu to more than US$7.20/mmbtu.

Recent media reports indicate that Yemen has decided to demand that all three sales agreements be benchmarked against global market prices starting in 2014. Media reports indicate that under these new deals the sale price will be around $14/mmbtu. Under these new terms, government revenue should rise from about $300 million per year to more than $1 billion.

The two kinks in the yellow line – below $30 and above $72 in this example – act as a weak cap and collar. The result is that the sensitivity of the link between the LNG price and crude oil is weakened when oil prices are very low or very high. At the low end, a price floor ensures that the LNG project will generate sufficient revenue to repay loans. At the high end, the ceiling protects the buyer from spikes in international oil prices.

The s-curve formula has dominated LNG pricing for decades, not only in Japan but also for other Asian buyers such as South Korea and Taiwan. The pressure for change however is growing.

Industry analysts predict that the biggest shake-up in the international market for LNG in decades is coming. Almost no one believes that a truly global market for natural gas will emerge; the costs of transportation are simply too high (see analysis below). But there is a growing sense that Asian LNG linked to high priced Asian crude oil is unsustainable: gas is cheap, oil is expensive and Asian countries currently buy gas benchmarked to oil. Japan and India agreed in 2013 to create an Asian "buyer's group" in order to fight for lower LNG import prices. New buyers such as China and India are refusing to accept the old-style crude oil benchmarking. And with a growing volume of LNG traded not in long-term agreements, but on the so-called "spot market," the leverage of buyers is increasing (see Textbox 3).

Textbox 3: Sales Agreements v "Spot" Prices

The infrastructure to export LNG requires an investment of tens of billions of dollars. Companies normally borrow the money to develop the project on the basis of the future revenue of the project (known as project or "non-- recourse" financing). Lenders seek assurances of long-- term project revenue to repay the debt. LNG projects are based, therefore, on 20--25 year sales contracts, known as either gas sales agreements (GSA) or gas purchase agreements (GPA).

Twenty years ago, nearly all LNG was sold through long-- term sales agreements. But since the late 1990s, a short term trading market, known as a "spot market," has emerged. These are sales contracts as large as a one-- year supply and as small as the cargo of a single vessel. The spot market now accounts for about 20% of global sales. The combination of the expiration of old contracts and excess capacity in the US has created a substantial supply with no fixed destination, while seasonal requirements and other shortages (i.e. Japan nuclear) have created demand in the UK, Japan, Korea, Taiwan and China.

3. Long Term Sales Contracts for Rovuma Gas

Long-term gas sales agreements must be signed before Anadarko and ENI will make their final investment decision. These sales agreements will also be the basis on which to secure financing for tens of billions of dollars in order to construct LNG facilities in Mozambique. The prices negotiated at this stage are of crucial importance to all parties concerned, yet they are being negotiated under the most volatile circumstances in decades.

The Government of Mozambique must carefully analyze price trends and associated risks in order to avoid the failures of Sasol Pande Temane as well as Equatorial Guinea and Yemen (See Textbox 4 on contract provisions that can help). The Government must also intervene to ensure that competition between ENI and Anadarko does not further drive down price (See Textbox 5[6]).

All revenue projections for LNG from Rovuma have assumed that the price for LNG would be based on the traditional Japanese formula benchmarked to crude oil. The Gas Master Plan, published in early 2013 stated: "Given the market situation, it will be possible for

Textbox 4: **Contract Terms Protect Government Revenue**

As the cases of Sasol Pande Temane, Yemen and Equatorial Guinea reveal, government revenue can be fundamentally undermined by unfair pricing agreements. There are contractual clauses, however, that governments can use to protect their interests.

Price Review Clauses are often included in gas and LNG contracts, allowing parties to review the pricing formulae every 3-5 years or if market conditions have changed significantly from the initial intention of the contract. These clauses should identify a trigger event that can entitle parties to invoke a price review and the elements of the formulae that can be changed.

Diversion Pricing Clauses: LNG price formulas in long-term agreements are determined by the price at the expected destination. But changing market conditions can result in the gas being "diverted" to other markets offering higher prices, thereby generating much higher profits (see Equatorial Guinea case). Contracts should establish the basis for sharing extra profits that result when LNG is sent to high priced markets.

There is no indication that these clauses are being incorporated in the gas sales agreements currently being negotiated for Rovuma LNG.

Mozambique to secure deals with oil linked prices with slopes of around or higher than 14.5."[7] The IMF has also based all projections on a price linked to crude oil though their projections in June 2012 and November 2013 are both based on a slope of 14[8].

It is now clear however that the sales agreements being negotiated by Anadarko for Mozambique LNG will not be based on a traditional Japanese formula.

Anadarko has signed non-binding agreements with Asian buyers for about two-thirds of the LNG from the first train.

Specifically, Anadarko is to supply 2.6 mtpa to Thailand's PTT,[9] and India's ONGC Videsh (OVL) is in negotiations with the consortium to import LNG[10]. Industry reports indicate that these sales agreements are 50 linked to Japanese oil and 50 linked to the US natural gas benchmark price known as "Henry Hub."[11]

Anadarko has no previous experience with LNG. When CEO Al Walker was asked about delinking LNG prices from crude oil benchmarks at a Tokyo summit meeting on Japanese energy costs, he said, "I'm agnostic. We don't have oil-linked contracts now," adding "we want a price that gives an attractive rate of return for the risks we took."[12]

ENI is also reportedly negotiating agreements in China indexed in part on US (Henry Hub) prices.[13]

The challenge now is for Anadarko and ENI to convert these initial agreements into binding gas sale contracts. Changing market dynamics in recent months however have given additional leverage to the buyers. The US benchmark for natural gas remained below $3/mmbtu through the start of 2015. Crashing oil prices have had a major impact on Asian LNG markets with spot prices having fallen to below $8/mmbtu. And ongoing negotiations on gas pipeline sales between China and Russia at just over $10/mmbtu are seen to be setting a new benchmark for future Asian LNG prices. Industry analysts therefore expect that the prices in the final agreements for Rovuma LNG will be significantly lower than had been expected.

What kind of price might realistically be expected? Anadarko asked Standard Bank to undertake a macro-economic analysis based on a forecast sale price of $12/mmbtu, a price that no independent industry analyst considers credible.[14] The IMF, in a report in early 2014 on LNG prospects in Tanzania, prepared prior to the fall in oil prices, based their forecasts on $11/mmbtu.[15] Many analysts now think that a price forecast of somewhere between $10 and $10.50/mmbtu is credible. Such a price would still make Rovuma

LNG viable. According to Paulo Scaroni, chief executive of ENI, a price of $9/MMBtu will be required for the project to break even.[16] But the profit margins would be much lower, with a corresponding impact on potential government revenue.

Textbox 5: ENI / Anadarko Competition Drives Down Price

Since gas fields cut across the boundary of the Anadarko and ENI concessions, Mozambican law requires that they merge (unitize) the offshore operations. From the outset of the negotiations, however, the two companies were clear that they planned to market their gas separately. As both companies see Asia as the destination for their gas, there is a risk that competition from Mozambique gas marketed by Anadarko and ENI will drive down prices and reduce government revenue.

Giles Farrer, a senior analyst at Wood Mackenzie, says "If you think about this project in 20 years' time, with all of that gas in Mozambique, how do they ensure that volumes get sold without competing with each other? That fundamentally goes against the interest of the government."

When Qatar faced the same risk, they divided up the available markets to ensure that there would be no direct competition. No similar strategy is being adopted in Mozambique. In fact, there seems to be no coordination at all. John Christiansen, Anadarko's director of communications has said, "The markets ENI may be targeting are unknown to us."

The Government says that they are present in the negotiations on long term LNG sales agreements and that they will intervene if necessary to ensure that competition between the two companies does not undermine future government revenue. Leading LNG analysts disagree: "ENH has not had a strong presence in SPA negotiations."

4. The "Netback" Price Calculation

The price at which Mozambican LNG could sell for in Asia is of vital importance in determining potential government revenue. But government revenue is not calculated on the final sale price, but rather on what is know as a "netback" price. The contracts for the Rovuma Basin were written in the hopes that oil would be found. If natural gas was found, it was assumed that it would be transported by pipeline as is the case with Pande Temane gas. As a result, the contracts are vague on vital questions of valuation and pricing.

The Sasol Pande Temane project demonstrates the risks posed where sale price is not linked to market value. As CIP analysis has shown, in the case of Pande Temane gas, there is no linkage between the price at which Sasol buys gas in Mozambique and value of that gas in South Africa (See Textbox 6).

The draft version of the Gas Master Plan, pointed to the importance of securing a netback price. Specifically, it stated that: "Negotiations with producers will determine the price at which the government's share and revenues will be determined. The "netback" price is the value of LNG in the market less the costs of transporting to market and the cost of liquefaction. The GoM will maximize the value of its royalty share and its share of profit gas by basing the calculations on the value of LNG net-backed to Mozambique."[17]

On the assumption that the Government of Mozambique will not repeat the mistakes of Sasol Pande Temane, the analysis below assumes that a netback prices will be negotiated. This means that the price for gas used to calculate government revenue is the value of the gas before it enters into the liquefaction train.

Working backwards from the sale price in the Asian market, costs to determine the netback price include regasification (1), transportation (2), and possibly liquefaction (3). The different steps in the process are illustrated, with corresponding numbers, in Figure 6.[18]

Textbox 6: **Gas Pricing for Pande - Temane**

Gas sales agreements are not necessarily based on netback pricing. The price at which Sasol Pande Temane sells gas to Sasol in South Africa is based on a complicated formula that makes no reference to the value of the gas where it is sold. In fact, the price of the price that Sasol pays for the gas in Mozambique is about 1/5th what it sells it for in South Africa.

During the early years of that project, the sale price in Mozambique was just over $1.66/GJ while Sasol sold the gas in South Africa for more than $7.00/GJ.

Future sale price in Mozambique is expect to be between $2.50 and $3.00/GJ while Sasol has just received approval from the South African Energy Regulator to charge its customers more than $12/GJ.

Regasification Costs: Regasification refers to the process by which LNG is reconverted to a gas for distribution to consumers. Regasification costs vary between $0.30 and $0.50 per mmbtu for LNG exports to Asia.

Transportation Costs: Shipping costs are much higher for liquid natural gas than for oil. In addition to the standard shipping expenses, LNG must be kept at a temperature of -161°C. This not only requires specially insulated tanks, but some of the fuel is used to maintain this low temperature, a process known as "boil-off." While enroute, therefore, a typical LNG tanker uses about 0.15 of inventory per day. There are significant differences in shipping distances for potential buyers of Mozambique gas with India being about 7,500km (9 days) and northeast Asia being about 14,000km (17 days)[19]. Estimates of transport costs to the further Asian markets range from $1.20-$1.40/mmbtu[20].

Liquefaction Costs: The liquefaction facility purifies and liquefies the natural gas supplied from off shore and delivers it to LNG vessels for export. For calculating the netback price, the cost of liquefaction is determined by include the initial capital investment, the annual operating expenses and the costs of financing. Estimates of the cost of liquefaction in Mozambique vary. The Gas Master Plan, estimates liquefaction costs at $3.67/mmbtu [21]. The IMF provides a range $2.86/mmbtu to 4.45/mmbtu depending on the estimated rate of return[22]. Increases in capital costs for LNG plants suggest that actual liquefaction costs are likely to be at the higher end of these existing estimates. It seems probable that a netback price will be used to calculate government revenue from Rovuma LNG. The specific valuation point however is unclear. It will depend on whether the upstream gas and LNG facilities are an integrated project within the terms of the 2006 contracts, or whether the LNG facilities are a separate economic entity. If the projects are integrated, then the valuation point will be where the gas leaves the LNG terminal with the capital and operating costs of liquefaction being part of cost recovery. If the projects are separated, then the valuation point will be at the entry to the LNG facility (the Feedstock price).

Figure 6: LNG Cycle from Gas-Field to End-User

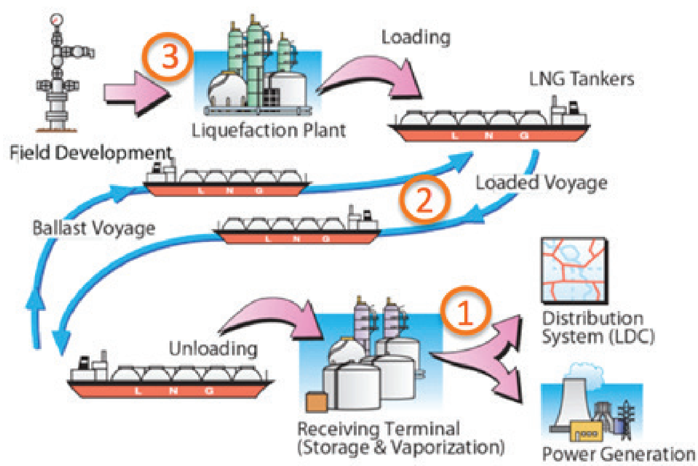


Table 1 shows how the netback price calculation beginning with the final Asian sale price and deducting regasification, transportation and liquefaction costs.

Table 1: Calculating a Rovuma "Netback" Price

	Netback Price Calculation
FINAL SALE PRICE	**$10.25**
Regasification Costs	-$0.40
Shipping Cost	-$1.30
LNG TERMINAL PRICE	**$8.65**
Liquefaction Cost	-$4.35
FEEDSTOCK PRICE	**$4.30**

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Revenue projections on Rovuma LNG have been based on best-case scenarios. CIP has shown that the timelines to first production in 2018 have been unrealistic. Few analysts now expect any LNG exports before 2020 at the earliest. CIP has also shown that promising revenue projections have been based on an unrealistic scale and pace of LNG expansion. It is easy to write about 6 or 10 LNG trains operating in Palma by 2026. But to meet those targets would require a pace of expansion unmatched anywhere in the world other than Qatar.

Price is another significant variable in determining potential government revenues. As has been shown above, lower than expected prices – as being experienced in the current Asian LNG market - will obviously have a direct impact on government revenue. The Rovuma contracts are heavily rear-loaded from the Government's perspective. Revenue for Mozambique starts very small and grows over time, based on the profitability of the project. A lower price will result in lower profitability and a longer period where government revenues are only a small fraction of the revenue generated by the project. Furthermore, lower than expected prices could put future expansion of LNG production capacity at risks. Each phase of potential expansion will be assessed based on the economic prospects at that time. Large gas reserves in the Rovuma Basin create the potential for major expansion, but there are no guarantees.

Decisions on the potential development of Rovuma natural gas are being taken at a time when LNG prices are more volatile than ever. The binding sales agreements currently being negotiated will not be as lucrative as the non-binding agreements signed in the recent past. Price will likely not be a barrier to the development of Rovuma LNG. But lower LNG prices and higher costs will certainly have an impact on potential government revenues and may limit the potential growth of LNG gas exports from Mozambique.

Units Used to Measure Natural Gas

Measuring Reserves: Oil is normally measured in barrels (42 US gallons or 158.978 litres) while natural gas is measured in cubic feet or cubic meters: billion cubic feet (bcf) or trillion cubic feet (tcf) are the most commonly used. Barrels of oil equivalent (boe) allows for gas to be included into overall reserve estimates and is based on the amount of heat released through burning: 6,000 cubic feet of gas equals one barrel of oil.

Measuring Production: Natural gas production is normally measured in cubic feet per day (cf/d) and is commonly seen as mmcf/d (millions) and bcf/d (billions). LNG Production is commonly measured in millions of tons per year or annum (mtpa). For example, an LNG processing facility known as a "train" could have an annual production capacity of 5mtpa.

Sale of natural gas, whether liquefied or not, is normally measured by units of energy. Traditionally, the unit of measure was the "British thermal unit" (btu): a unit of energy defined as the quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit. The normal measure is million btus (mmbtu). The metric equivalent is the Gigajoule (GJ): an international unit of energy defined as the energy produced from one watt flowing for one second. The normal measure is million giga-joules (mGJ).

	cubic metre	cubic foot gas	million Btu	therm	gigajoule	kilowatt hour	cubic metre of LNG	ton of LNG
1 cubic meter gas	1	35.3	0.036	0.36	0.038	10.54	0.00171	0.000725
1 cubic foot fas	0.0283	1	0.00102	0.0102	0.00108	0.299	0.00005	0.00002
1- million Btu	27.8	981	1	10	1.054	292.7	0.048	0.0192
1 therm	2.78	98.1	0.1	1	0.105448	29.27	0.0048	0.00192
1 gigajoule	26.3	930	0.95	9.5	1	277.5	0.045	0.018

(Endnotes)

[1] See EBRD President, Suma Chakrabarti, Opening Address to the Global gas flaring reduction (GGFR) Partnership Forum, London, 24 October 2012.

[2] (For a discussion of the potential implications for a developing country see, IMF analysis for LNG producer Trinidad: Trinidad and Tobago: Selected Issues, IMF Country Report No. 12/128, June 2012)

[3] US Energy Information Administration, Annual Energy Outlook 2015

[4] See "How one West African gas deal makes BG Group billions," Reuters, 12 July 2013.

[5] See Ernest and Young, Global LNG: New pricing ahead? The overarching economic issues,

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[7] See ICF, Towards a Natural Gas Master Plan, 22 February 2013, p. 5-28.

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[10] See ONGC Videsh in talks to import LNG at $15 from Mozambique, Economic Times, 7 April 2014.

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[14] Mozambique LNG: Macroeconomic Study, Standard Bank, 2014, p. 52.

[15] Thomas Baunsgaard, Fiscal Implications of Offshore Natural Gas, IMF Tanzania

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[16] Colin Shek, ENH looks for an apprentice role in Mozambique LNG marketing, Interfax Global Energy, 25 September 2014.

[17] See ICF, Towards a Natural Gas Master Plan, Version 20 December 2012, page 2-11.

[18] On average, liquefaction comprises 30-45% of costs, shipping accounts for about 10-30% and regasification and storage accounts for about 15-25%.

[19] See David Ledesma, East Africa Gas: Potential for Export, Oxford Institute for Energy Studies, 2013, p. 3.

[20] Estimated shipping and regasification costs tally with the Gas Master Plan combined estimate of $1.70/mmbtu. Towards a Gas Master Plan, p. 5-24.

[21] Towards a Gas Master Plan, p. ES-28.

[22] IMF, Mozambique: Reforming the Fiscal Regimes, 2012, p. 71.

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