Comparison of inland NG/LNG and imported LNG



Anton Putter, Freek van Heerden & Herman van Heerden
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This is the sixth article in a series by OTC specialists and partners on natural gas (NG) and liquefied natural gas (LNG).

The series comprises the following articles which are scheduled for publication on the dates listed:

1. Overview of the LNG industry – September 2020
2. Traditional gas transport modes – November 2020
3. Safe and clean storage of natural gas – January 2021
4. Alternative modes of natural gas transport – March 2021
5. Overview of LNG technologies – May 2021
6. Comparison of inland NG/LNG and imported LNG – June 2021
7. Outlets for NG and LNG – August 2021
8. Gas for power generation – September 2021
9. Small scale versus large scale LNG – November 2021
10. Gas utilisation in transport – December 2021

These articles are published over a period of 16 months and will be interspersed with articles related to aspects of project management and renewable energy.

Introduction

The question often arises on the best way to start a natural gas (NG) industry or grow the NG industry in a country. South Africa is a good case in point where the NG industry has stagnated over the past 10 years due to a lack of additional NG supply. Should such additional gas supply be sourced from imports of LNG or by exploitation of inland gas sources, or both?

Some background to this question is provided in some of the previous articles in this series, such as:

- *Overview of the LNG industry* (Putter, 2020) covered the growing role of LNG in the natural gas industry and the high capital costs involved in the LNG industry.
- *Traditional gas transport modes* (van Heerden et al, 2020) emphasised the importance of logistic costs in the overall natural gas value chain and provided some information on the traditional gas transport modes of pipeline, CNG (compressed natural gas) and LNG.

In this article we present the various considerations for comparing inland NG/LNG with imported LNG. The underlying assumption is that imported LNG will be available and could be delivered by LNG tankers at a market (contract or spot) price to local ports (no offshore resource or infrastructure development required, but local infrastructure development might be required), but inland gas would require both resource and infrastructure development. We also provide an order-of-magnitude case study on the situation in South Africa where we compare the possibility of imported LNG with the possibility of developing CBM (coal bed methane) in Botswana, converting this CBM to LNG or distributing it by pipeline for supply to the gas market in South Africa.

Considerations for comparison

Opening remarks

A variety of considerations needs to be contemplated when comparing inland NG/LNG with imported LNG as shown in Figure 1.

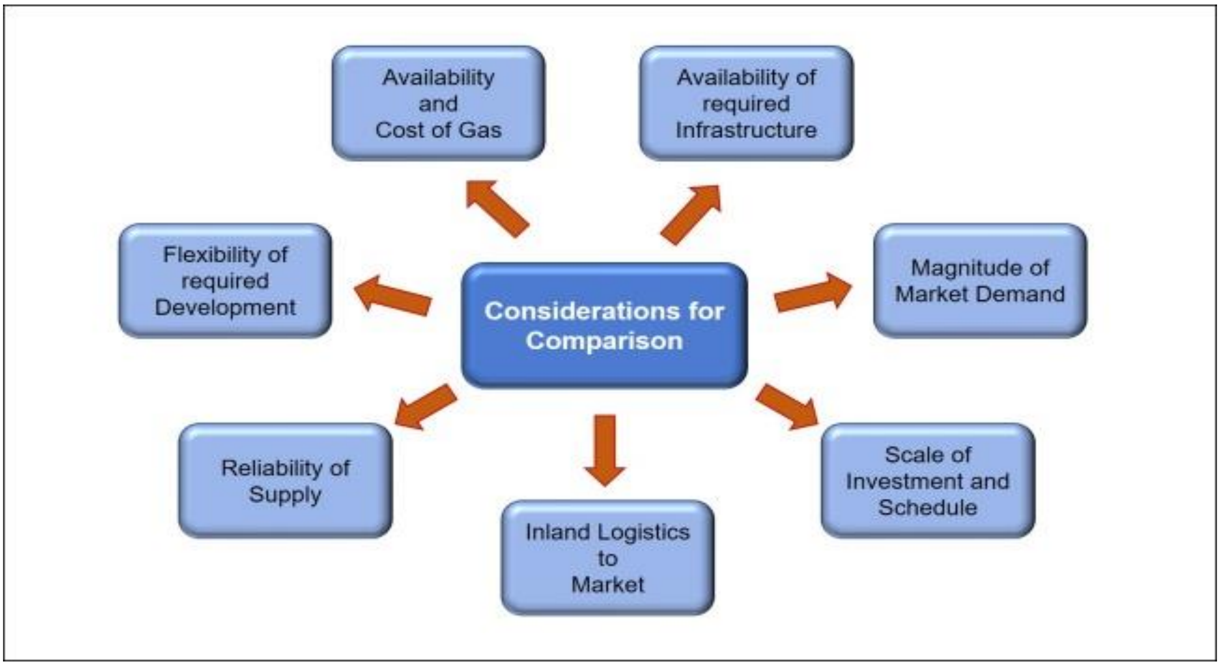

Figure 1: Considerations for comparing inland NG/LNG with imported LNG

Relevant considerations include the following:

- Availability and cost of gas.
- Availability of required infrastructure.
- Magnitude of market demand.
- Scale of investment and schedule.

- Inland logistics to market.
- Reliability of supply.
- Flexibility of required development.

A short discussion on each of these factors follows.

Availability and cost of gas

Globally gas markets are growing rapidly (average of 2,9% over the past 10 years) and in many cases gas supply struggles to keep up (BP Energy Review, 2020). This trend is to a large extent driven by the push for decarbonisation. As a result of this drive to reduce carbon emissions, coal use globally has peaked and is currently in decline, and this energy demand is mostly being replaced by natural gas (since it produces the least emissions of the fossil fuels). On the other hand, solar and wind energy still only constitute a small proportion of global energy supply and although wind and solar are growing fast (about 15% per annum over the past 15 years), the annual energy supply growth from these renewable resources cannot yet even supply the global annual growth in energy demand.

In many countries/regions the supply of NG (whether produced locally or imported requiring logistics infrastructure) cannot keep up with the fast growth in demand. Often the only way to keep up with demand is the importation of expensive LNG which explains the growth spurt currently experienced in the LNG industry (average growth rate of 6,8% in LNG exports over the past 10 years (BP Energy Review, 2020)).

South Africa is a good case in point where the NG industry has stagnated over the past 10 years. The gas supply from Mozambique via the ROMPCO pipeline is limited due to both the limited reserve in the Pande/Temane fields, as well as the capacity constraint of the pipeline itself, while the gas supply from the southern Cape offshore fields to the PetroSA GTL facility has been steadily declining over this period. Consideration is currently given to the importation of LNG and/or the development of other NG resources in southern Africa as discussed in this article.

The choice of local gas versus imported LNG is not only determined by the availability of local gas sources, but also by the cost of developing those NG resources. Onshore and easy-to-develop conventional gas resources could yield gas at a cost as low as $1/GJ, whereas unconventional and difficult gas resources could be as expensive as $6 to $10/GJ. The cost of internationally traded LNG fluctuates over time and is also significantly different between long-term contract pricing and spot pricing of LNG. As always, spot pricing is more volatile than contract pricing. The delivered contract price of international LNG has been declining over the past five years from highs of $15/GJ in some cases to lows of $8/GJ reported in the past year. Spot prices of LNG has been as low as $5/GJ over the past two years.

Availability of required infrastructure

Often an increase in gas supply is limited by the existing infrastructure. These infrastructure limitations could be the absence or capacity limitation of pipelines, or it could be the absence of LNG import facilities. Both long-distance pipelines and LNG import facilities are highly capital intensive, and such investment decisions are often difficult to make. Both options also require a base load of NG to justify the investment decision, and especially in the cases of fledgling markets, such a base load is difficult to come by.

These infrastructure challenges can be easily demonstrated in the case of South Africa:

- **NG by pipeline:** A pipeline supply option often discussed for South Africa is the possibility of an NG pipeline from the Rovuma basin in the north of Mozambique to the northern parts of South Africa. Such a pipeline of almost 3 000 kms long, would however have a price tag of somewhere in the region of \$6 to \$10 billion, an exceptionally large investment. Additionally, it would require an NG base load of perhaps 500 million GJ per annum, a gas volume 3 times the size of the current gas market in the northern parts of South Africa.
- **LNG Importation:** In the case of LNG importation, both the investment required, and the NG base load would be smaller, but would unfortunately deliver more expensive NG than in the case of a pipeline. The possibility of a floating storage and regasification unit (FSRU) in Richards Bay has often been mooted. These FSRU's are both typically lower cost as well as more flexible than a land-based terminal. The storage capacities of these FSRU's typically vary from 140 000 m^3 to 220 000 m^3 with the capital cost of an installation in the order of \$400 to \$500 million. The minimum throughput for the smaller FSRU's is 2 to 3 million tpa (equivalent to 100 to 150 million GJ/a), according to Songhurst (2017). This is more reasonable in the context of the current gas market in South Africa but would come at gas prices roughly double the current gas price in South Africa.

Magnitude of market demand

The importation of LNG needs a certain base load to become viable. In the case of inland gas, the market requirement can typically be a lot lower than for imported LNG or a long distance pipeline as discussed above. Therefore, inland NG resources can often be developed in smaller increments.

A rule of thumb for inland pipeline supply is that 10 million GJ/a of market is required to justify every 100 kms of pipeline. So, for example, if the gas source is 500 kms away from the market, a base load of 50 million GJ/a would be required. For smaller developments that cannot justify a pipeline, the possibility of compressed natural gas (CNG) can always be considered. CNG is a lot less capital intensive than the other options but is limited in terms of the distances it can be used competitively (probably not more than 200 to 300 kms).

Inland LNG can also make sense in some market circumstances. Compared to CNG this would be the case if the market is somewhat bigger and further removed from the source of gas. Compared to pipelines, inland LNG could be feasible if the market is dispersed (in different directions from the gas source) or if the market/distance combination is such that a pipeline is not justified. Even for bigger demand requirements where imported LNG becomes feasible, inland LNG might still be preferable. This is discussed further in the case study later in the article.

Scale of investment and schedule

The magnitude of the investment and the schedule for implementation are important considerations when choosing between inland gas and imported LNG. The magnitude of investments for different options have already been discussed in earlier paragraphs:

- For imported gas, an FLNG terminal would cost in the order of $400 to $500 million. According to Putter (2020), a comparable land-based terminal is even more expensive at around $750 million.
- If the source of inland gas is far removed from the market, long-distance pipelines (roughly defined as longer than 500 kms) might be the most economical means of transporting the gas. As already mentioned in the case of a Rovuma - South Africa pipeline, such long-distance pipelines are expensive projects (upwards of $500 million). As mentioned by van Heerden et al (2020), the recently completed Power of Siberia pipeline of 2 200 kms came at a capital cost of more than $15 billion (excluding the cost of field development).
- For smaller inland developments, the capital cost can be substantially less. In the cases of resource developments that are supported by CNG or short-distance pipelines, the resource developments (plus gas processing) would be the bulk of the overall investment, but in the case of LNG-supported developments the capital investment would be roughly split equally between the resource development and the LNG development.

Depending on the urgency of the gas need, the schedule of projects could be an important consideration to choose amongst options. Typically, the bigger the project and its capital cost, the longer the period to develop the project to final gas delivery. Large pipeline projects normally involve complex inter-government agreements and regulations, billions of dollars in capital investment with complex financing arrangements and long-term base-load contracts that need to be put in place, and an overall project schedule including concept development of less than 10 years would be difficult to achieve. LNG import projects are also large projects and the overall schedule for a land-based terminal would typically be at least 5 years, and for a FSRU possibly a bit quicker if an existing FSRU could be relocated or an existing LNG tanker refurbished. Smaller inland projects could be quicker than this and will depend on the scope and technology employed.

Inland logistics to market

Logistic costs play a big part in the gas value chain. In the case of LNG imports, the gas must be transported from the import terminal to the market, either by way of pipeline infrastructure or as LNG in road tankers. In the case of inland gas, both these options plus CNG are also available (although the LNG option would require a new liquefaction facility at the source of the gas).

The cost of logistics is influenced by the distance over which the gas must be moved. Therefore, inland markets far removed from the coast (import terminal) would have to carry a higher inland logistic cost for imported LNG than in the case of inland gas closer to the market.

As already mentioned, existing infrastructure versus new infrastructure would have an impact on the inland logistics cost. In the northern parts of South Africa there is limited pipeline infrastructure, but no LNG infrastructure.

Reliability of supply

Since energy is a crucial input in many industrial processes, power generation and consumer applications (such as transport fuel and space heating), reliability of supply is critical for the customers. In the case of new markets or market growth, it is therefore important that the supply chain is set up in a way that ensures reliability of supply to the customers.

So, for example, it will be almost impossible to convince an energy-dependent customer to switch to LNG if there is only one production line from a single LNG producer that would be able to supply the customer. Options for consideration would be the ability of the customer to switch back to the old method of energy supply for short periods, supply substantial strategic stocks of LNG and/or have some back-up plan in place such as importation of LNG isotainers. Customers would probably only get comfortable with the reliability of LNG supply if there are at least three sources of gas supply, of which one could be an import option.

On the other hand, conventional gas sources and pipeline supply are very reliable. In the 17 years since commissioning of the Pande/Temane gas fields and the ROMPCO pipeline for supply of gas from southern Mozambique to South Africa, there has not been one interruption in the main gas supply that the authors are aware of.

Flexibility of required investment

On top of the magnitude of investment required for the different options, the flexibility of these options must also be considered. From a risk management perspective, it is concerning if such large investments are dependent on assumptions that could turn against the investor during the 20-year life over which these investments are typically planned. Often an underlying assumption in the importation of LNG is that no new discoveries or further development of local gas will take place. This can have disastrous consequences on LNG import projects such as happened in the USA in the early 2000's when more than 10 LNG import projects failed due to the development of shale gas resources in the USA (IEA, 2019). Similarly, the discovery and development of the Zohr gas field in Egypt a few years ago made an LNG import terminal developed only a few years earlier, redundant (Sutherland, 2021). A few of these flexibility considerations are briefly discussed in this paragraph.

FSRU's offer a lot more flexibility than land-based LNG import terminals. Should the import market for LNG disappear completely, it is possible to relocate an FSRU to a different import location, probably in a completely different part of the world. Although there would be substantial costs that cannot be recovered, it is substantially better than the case with a land-based terminal where almost the total capital investment would be lost.

A similar situation exists in the case of small- or micro-scale LNG plants on small gas deposits or at inland locations. In the case of a stick-built or fixed LNG plant, almost the total investment would be lost in the case where the feedstock gas runs out or the market disappears. On the other hand, modular and containerised small- or micro-scale LNG plants can just be relocated to a different site with only a reasonably small part of the investment lost.

Delivering LNG to customers by road tanker is a lot more flexible than putting in pipeline infrastructure to deliver the gas. This is especially the case where there is just a single customer or a couple of customers at the end of the pipeline. Should a customer stop using gas in the case of LNG road tanker deliveries, the road tankers can just be diverted to other customers at different locations, while this is not possible with pipelines.

Case studies for South African situation

Opening remarks

Due to a dearth of inland gas sources and international isolation until 1994, South Africa has always lagged the rest of the world in terms of the contribution that NG makes to its overall energy supply. A substantial step-change occurred in 2004 when the ROMPCO gas pipeline from Mozambique to South Africa was commissioned. In the first few years after commissioning the gas flow down the pipeline increased strongly but was limited by pipeline capacity over the past 10 years (and now also by gas availability out of the Pande/Temane gas fields). The only other substantial source of natural gas to South Africa is the offshore gas supplied to the PetroSA GTL facility in Mossel Bay. Unfortunately, this gas flow already peaked in the early 2000's and has been in steady decline over the past 15 years.

This underdevelopment of the gas industry in South Africa is illustrated in Table 1 where the contribution of gas to primary energy in various jurisdictions is compared (BP Energy Review, 2020).

Table 1: Gas consumption in various jurisdictions in 2019

Jurisdiction	Gas consumption in million GJ/a	Gas contribution to primary energy
Russia	16 000	53,7%
United States of America	30 480	32,2%
Germany	3 190	24,3%
China	11 060	7,8%
Korea	2 010	16,2%
Egypt	2 120	54,5%
South Africa	180*	3,3%

*Adapted upwards to allow for PetroSA gas consumption

As can be expected, gas-rich jurisdictions such Russia, Iran and the USA have a high percentage of their energy coming from gas. Gas prices in these jurisdictions are also typically quite low. Even jurisdictions such as Germany and the rest of western Europe which depend heavily on long-distance pipelines for their gas supply, have an appreciable fraction of their energy coming from gas. What is significant, however, is that South Africa uses proportionately even less gas than jurisdictions which are totally dependent on expensive imported LNG, such as Korea and Japan, and jurisdictions which are largely dependent on imported LNG, such as China.

The pressing need for more gas supply into the South African energy market is obvious. The question is whether this gas will come from imported LNG or inland gas.

Various options could materialise as South Africa's gas supply increases into the future. For the development of the case studies, the target market has been considered as firstly Gauteng and secondly the mining/metal processing industry in the north-western part of South Africa such as around Rustenburg, Sishen and Mokopane where metals such as platinum, chrome, copper, iron, and manganese are mined and processed. The following options will be considered in the two case studies:

- **Case study 1:** Compare Botswana CBM plus a pipeline to Gauteng with LNG imported via an FSRU at Richards Bay and the gas transported via pipeline to Gauteng.
- **Case study 2:** Compare Botswana CBM plus a small liquefaction plant with LNG imported via a land-based LNG import terminal at Richards Bay and LNG truck transport to mines and metal processors in the north-western part of South Africa.

Importation of LNG

Currently there is no LNG import infrastructure in South Africa. To supply gas to the northern parts of South Africa an LNG import terminal (FSRU or land-based) will have to be established in Richards Bay or in Maputo (as currently under consideration by Total and GigaJoule). To ensure security of supply, a terminal owner will have to enter long-term LNG supply contracts (typically at least 15 years). Currently, the best prices obtainable on such LNG supply contracts would be LNG sourced from the USA which utilise Henry Hub cost-plus formulas in the determination of the gas contract prices. In such a case the build-up of the delivered gas price to Richards Bay would be:

Henry Hub price:	$3 to $4/GJ
Local costs in USA such as pipeline tariffs:	$0,5/GJ
Liquefaction costs at USA port:	$3/GJ
Shipping cost to South Africa:	$1,5 to $2/GJ
→ **Landed LNG price in Richards Bay:**	**$8 to $9,5/GJ**

The cost of LNG storage and possible regasification in Richards Bay will be different in the cases of a land-based terminal and an FSRU. For these case studies it is assumed that an FSRU will be used for the case of pipeline transport to Gauteng and a land-based terminal for LNG transport to the mining areas and metal processing facilities. Assuming that enough LNG will be imported to justify the erection of such facilities (3 million tpa of LNG), the cost associated with these facilities would be:

For FSRU (case study 1):	$1,1/GJ
Port and import charges for FSRU (case study 1):	$0,4/GJ
For land-based terminal (case study 2):	$1,8/GJ
Port and import charges for land-based (case study 2):	$0,7/GJ
→ **Total terminal costs for case study 1:**	**$1,5/GJ**
→ **Total terminal costs for case study 2:**	**$2,5/GJ**

From the above, the total despatched gas cost/price out of the Richard Bay terminals is then roughly calculated as:

→ **Gas pipeline inlet cost for case study 1:**	**$9,5 to $11/GJ**
→ **Road tanker LNG inlet cost for case study 2:**	**$10,5 to $12/GJ**

Gas production from CBM in Botswana

Over the past 20 years a substantial amount of work has been done on the exploitation of the coal-bed methane (CBM) resources in Botswana. Enough information is available to make reasonably accurate estimates of the cost of gas production, gas gathering, gas purification, and gas compression. It is roughly estimated that the gas price at wellhead would be between $5 and $6/GJ.

In the case of gas that will be transported to Gauteng by pipeline, there is a lower need for purification than for gas prepared for liquefaction. On the other hand, the pipeline would require higher compression of the gas than the liquefaction plant. Roughly, the costs for the two scenarios up to the point of despatch from Botswana, can be calculated as follows.

Case study 1:

Gas gathering:	$0,2/GJ
Gas processing/purification:	$0,2/GJ
Gas compression:	$0,5/GJ
→ **Total above-ground costs for case study 1:**	**$0,9/GJ**

Case study 2:

Gas gathering:	$0,2/GJ
Gas processing/purification:	$0,5/GJ
Gas compression:	$0,3/GJ
Liquefaction (for 60 000 tpa plant):	$4 to $5/GJ
LNG storage:	$0,5 to $1/GJ
→ **Total above-ground costs for case study 2:**	**$5,5 to $7/GJ**

Using the stated gas price at wellhead of $5 to $6/GJ, the total despatched gas cost/price from the Botswana CBM is then roughly calculated as:

→ **Gas pipeline inlet cost for case study 1:** **$5,9 to $6,9/GJ**

→ **Road tanker LNG inlet cost for case study 2:** **$10,5 to $13/GJ**

Gas market in South Africa and logistics

For case study 1, the gas market is assumed to be Gauteng. This market is well served by existing gas pipeline infrastructure and is equidistant from Richards Bay and the Botswana CBM resource. Some pipeline infrastructure is in place between Richards Bay and Gauteng, but at least the Lilly pipeline (from Richards Bay to Secunda) will have to be replaced or expanded substantially. From Botswana to Gauteng, a new pipeline will be required. Such a new pipeline would require a base load of roughly 100 million GJ/a, a volume that should be absorbed easily into the Gauteng market. At these flow rates, the main transmission pipeline tariff would then be:

For new pipeline from Botswana to Gauteng: $1,5/GJ

For pipeline from Richards Bay to Gauteng: $1/GJ

For case study 1, the estimated delivered cost/price to bulk customers in Gauteng would then be:

→ **Imported LNG delivered as gas by pipeline:** **$10,5 to $12/GJ**

→ **Botswana CBM delivered by pipeline:** **$7,4 to $8,4/GJ**

For case study 2, the market is assumed to be the north-western mining districts of South Africa. Using the mining town of Thabazimbi as the central point of this mining and metal processing district, the road distances are roughly 870 kms from Richards Bay and 520 kms from Botswana CBM. From previous work done on LNG road logistics, the road tariffs then come to:

Road tariff from Botswana to Thabazimbi: $2/GJ

Road tariff from Richards Bay to Thabazimbi: $2,8/GJ

For case study 2, the estimated delivered cost/price to bulk customers in north-western parts of South Africa would then be:

→ **Imported LNG delivered by road tanker:** **$13,3 to $14,8/GJ**

→ **Botswana CBM delivered by road tanker:** **$12,5 to $15/GJ**

Conclusions

Case study 1:

Case study 1 compared the supply of Botswana CBM via pipeline to Gauteng with LNG imported from the USA via a floating storage and regasification unit (FSRU) at Richards

Bay and the gas transported via pipeline to Gauteng. Cumulative cost for both these cases are shown in Figure 2, as calculated from the lowest cost of any price ranges.

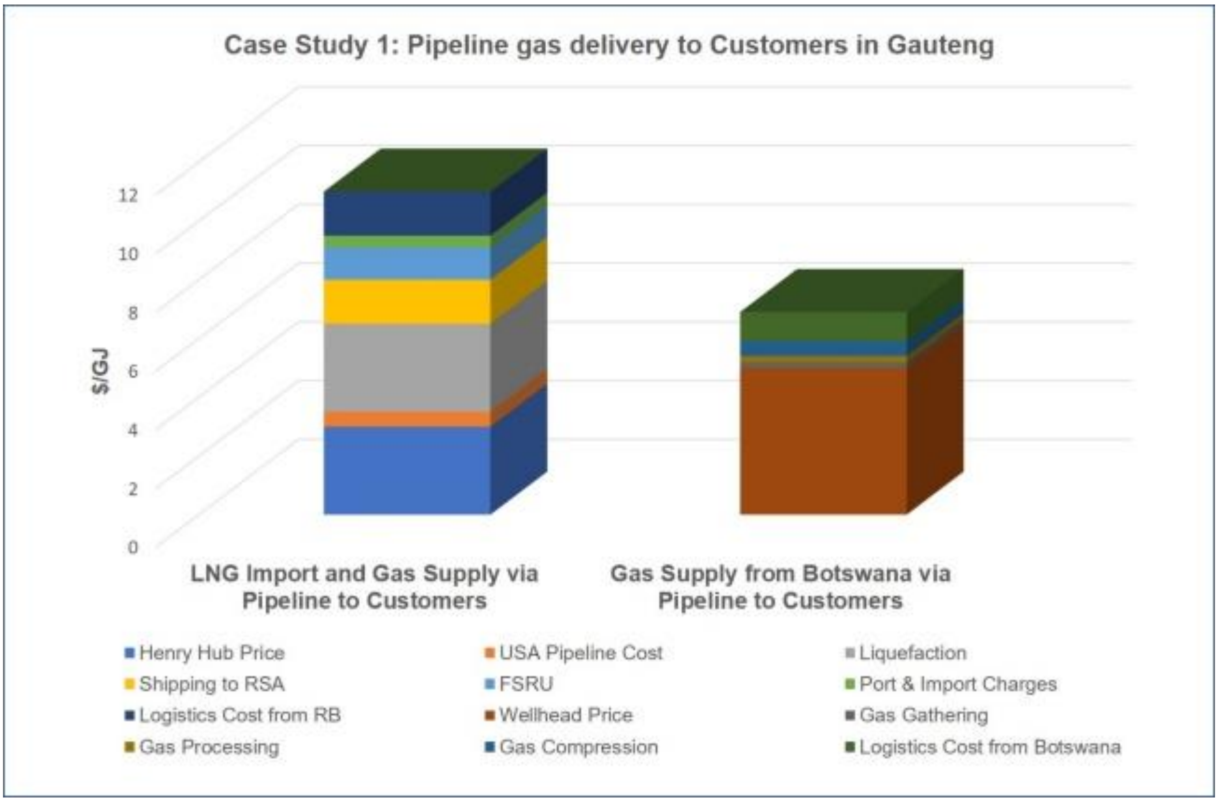

Figure 2: Case study 1 for pipeline gas delivery to customers in Gauteng

From Figure 2, it is evident that gas delivered by pipeline from Botswana is significantly cheaper than imported LNG delivered by gas pipeline to Gauteng. Despite the inaccuracies inherent to calculations at such a conceptual level, the advantage offered by Botswana CBM is so significant that this conclusion can be drawn with a high level of confidence.

Apart from the cost of the gas to the customer, other considerations that could play a role in the South African situation are as follows:

- The supply of LNG to South Africa would be secure since there are numerous LNG exporters around the world, while there would be concern with the supply of CBM from Botswana where not a single CBM supplier is operational yet. This situation would be mitigated if two or three CBM suppliers out of Botswana are operational.
- The market demand used here of 100 million GJ/a is reasonable in the context of the current inland South African market of 150 million GJ/a and the pent-up demand that can currently not be satisfied. For the pipeline from Botswana, this is even slightly more than the minimum amount to keep the pipeline economics reasonable, and the pipeline flow could even be reduced to 70 to 80 million GJ/a without having a major impact on the pipeline tariff. On the other hand, 100 million GJ/a is a bit low to justify an FSRU and a demand of 150 million GJ/a would be more sensible for the FSRU economics. Finding this market for an FSRU would pose a challenge since the gas price would be substantially higher than the current gas price in South Africa (and substantially higher than what could be delivered by pipeline from Botswana).

- As far as capital is concerned, it is difficult to compare like with like. If only considering the dedicated new logistics infrastructure required, then it appears as if the LNG import option carries a much higher capital cost with an FSRU costing $400 to $500 million, 4 dedicated LNG tankers $1 billion (at $250 million each) and the debottlenecking/expansion of the Lilly pipeline probably coming at about $600 to $700 million; thus, a total of $2,0 to $2,2 billion. Just considering the CBM gathering, processing and pipeline to Gauteng would probably cost in the order of $1,0 to $1,2 billion. However, the question is if one should also consider the capital of the CBM development. A rough estimate of CBM development to deliver 100 million GJ/a is $1,8 to $2,5 billion. Should one take this CBM development capital into account, the question is whether one should then also take a proportional part of the capital for shale gas development in the USA and a proportional part of the capital on the liquefaction facility in the USA.
- In terms of schedule, the two options are probably comparable, with either taking anywhere from 4 to 6 years to develop after the conclusion of the prefeasibility study. In the case of Botswana, it would probably be advisable to develop CBM on smaller scale first for power generation and/or LNG delivery, before embarking on a big pipeline project.

Case study 2:

Case study 2 compared the supply of LNG from Botswana CBM with LNG imported from the USA via a land-based LNG import terminal at Richards Bay and LNG truck transport to mines and metal processors in the north-western part of South Africa. Cumulative cost for both these cases are shown in Figure 3, as calculated from the lowest cost of any price ranges.

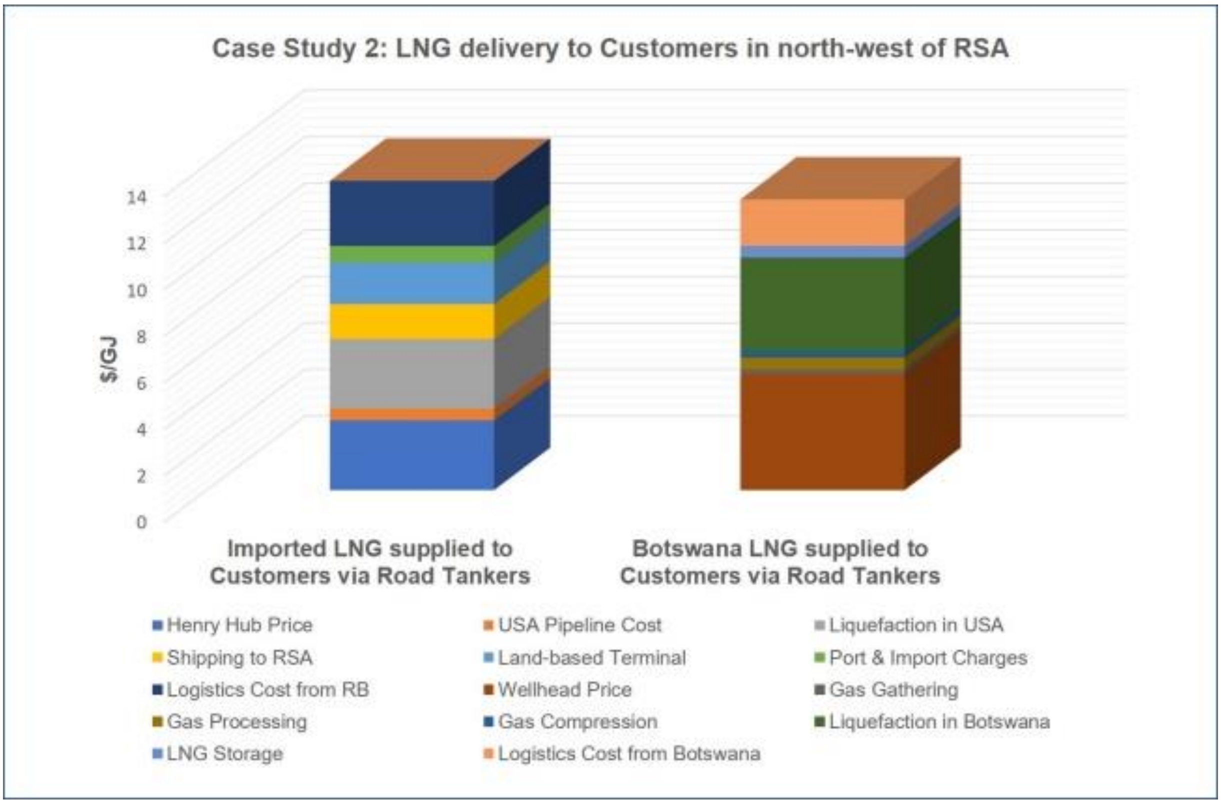

Figure 3: Case study 2 for LNG delivery to customers in north-west of SA

Within the accuracy of the numbers developed in the earlier paragraphs, it can only be stated that LNG produced from CBM in Botswana and a slipstream of LNG from a land-based import terminal at Richards Bay would be delivered to customers in the north-western regions of South Africa at similar prices. Other considerations will probably be the determining factor on which of these LNG options materialise first.

Some of these other considerations are as follows:

- The biggest uncertainty in this analysis is probably whether a land-based LNG import terminal will be erected in Richards Bay (or Maputo). The negative experience of jurisdictions such as the USA and Egypt where large amounts of money was lost in investments in LNG import terminals, will weigh heavily on the minds of investors and financiers, especially considering the many potential sources of local gas in the region, such as CBM in Botswana, Limpopo, Mpumalanga, Zimbabwe and Mozambique, conventional gas off the southern Cape coast, from the Rovuma basin in Mozambique, the Invictus gas field in Zimbabwe, and shale gas in the Karoo. A small offtake of 60 000 tpa for supply to customers in the north-west of the country is not going to impact the decision on a 2 to 3 million tpa import facility.
- The capital required for a LNG facility on Botswana CBM is significant, but pales in comparison to the $750 million capital required for a land-based LNG import terminal. A prior prefeasibility study done by OTC and GasConsult indicated the capital for a 60 000 tpa LNG facility on CBM in Botswana as $100 million (plus another $55 to $72 million for field development). Since the target market is further from Richards Bay than from Botswana CBM the imported LNG will also require more road tanker rigs to move the product to the customers than would be the case for Botswana LNG.
- A Botswana LNG project could be completed within 3 years compared to the 5 years or longer for a land-based LNG import terminal.
- A Botswana LNG plant could be a modularised containerised unit which would make it much more flexible than a land-based LNG import terminal in the case that the market disappears or the source of gas declines.
- The delivered LNG price of $12,5 to $15/GJ limits the applications where this gas would be competitive. It is probably only diesel and LPG markets that could be targeted successfully. Since it is only 60 000 tpa of LNG under consideration here, it should be possible to place it comfortably in diesel applications such as power generation on remote mines, yellow machinery, and mining trucks at mines, and even possibly in normal road transport applications. One large mine or a couple of smaller mines could absorb this total volume. It might even be possible to place the total capacity of the first LNG unit within Botswana itself.
- The one negative of the first Botswana LNG project would be reliability of supply. Customers would be uncomfortable about relying on one single supply source and this will need to be addressed.

Closing remarks

There are a variety of factors that needs consideration when comparing the development of local gas resources versus the importation of LNG. Every case will have to be decided on its own merits and different outcomes are possible.

With the current information available to the authors and the numbers as outlined in the article, the logical route in Southern Africa seems to be the development of local gas sources such as the Botswana coal-bed methane (CBM) rather than importing LNG. In the case of Botswana CBM, specifically smaller outlets such as power stations and LNG facilities will probably be first developed before a pipeline to South Africa materialises.

Decisionmakers in South Africa will have to be careful to avoid wasted expenditure on LNG terminals as happened in the USA and Egypt. Careful consideration needs to be given to the possible development of local gas sources and the growth of the local market (at different price levels) before commitment is made to large capital expenditure on LNG terminals.

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