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Track 1, Session 2b: Focus on the Philippines

SMALL SCALE LNG BASED POWER GENERATION IN THE PHILIPPINES

by
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1. INTRODUCTION

Over the last two decades, the possibility of LNG being introduced to the fuel mix of the Philippines has regularly emerged but never materialised. It seemed that energy security parameters, economics and the regulatory frameworks were finally not satisfying enough to justify such an introduction. However, recent developments tend to indicate that LNG arrival in the Philippines is now imminent.

A strong evidence of that is that at the end of 2013, in order to be better informed and independent in their energy policy establishment, the Department of Energy (DoE) has commissioned a specific study carried out by The Lantau Group. This study is financed by the World Bank and Australian Aid. Its objectives were to determine: a) whether LNG would be beneficial or not for the Philippines if introduced in the energy mix? b) if beneficial, for what application? and in which quantity? c) what would be the best regulatory framework to make it benefit the Philippines people as much as possible?

Other evidences are the number of large LNG projects that various developers are already mentioning openly in their external communication. At the time of writing this article, these projects are at different development stage, going from basic feasibility studies (Shell, First Gen, Trans Asia...) to having external walls of LNG storage tanks being erected (EWC project).

In this paper, we will initially briefly describe the large LNG infrastructure development that is likely to soon see the light soon in Luzon. Then, we will essentially focus on discussing opportunities for small and medium scale LNG based power generation projects outside of Luzon that could emerge once the main LNG hub(s) in Luzon is(are) set up. This will lead us to describe and assess the commercial viability of a “satellite power plants” concept that could revolve around a central LNG storage facility.
2. IS IT TIME FOR LNG IN THE PHILIPPINES?

As mentioned earlier, the introduction of LNG into the Philippines has for long been debated and considered. Today, at the time of writing this article it seems that both public and private sector see some interest in having a large scale LNG terminal in Luzon.

Assuming the DoE agrees with and backs up the conclusions of the first two phases of the Gas Master Plan Report that was ordered from the The Lantau Group, we could summarize their position as follow:

A) Introduction of LNG could be justifiable in order to:
- Diversify the primary energy mix of the Philippines and therefore increase its energy security
- Allow the coal fired plants of the Luzon Visayas grid to be operated purely for base load (instead of load following as it is largely the case today) while LNG fired power plants would be devoted to mid merit and peaking application.
- Provide back-up gas supply to the power plants currently operating on the Malampaya pipeline gas in case of incident or maintenance.

B) Intermediate and peaking gas power plants with a total capacity of 600 to 800MW would be the anchor users necessary for the investment in a main LNG terminal that would ideally be situated in the Batangas bay.

C) Other sectors, such as the transportation sector or other industries in the Manila metropolitan area could also benefit from having access to new sources of gas.

On the private sector side, several projects have been talked about and are at very different stage of development. All of these projects have in common a large LNG receiving terminal based in Luzon with a large gas power plant as anchor customer.

Some companies (Shell, First Gen, Trans Asia, AG&P...) are carrying out feasibility studies for Onshore terminals while others consider floating terminals. The most advanced project seems to be the Energy World Corp (EWC) project with the concrete walls of a 130,000.00 storage tank being under erection. EWC’s intention is to ultimately feed a 600MW power plant.

On the Wärtsilä side, we are not fully qualified to advise anyone on whether or not LNG import is necessary for the Philippines. Energy security and environmental policies are essentially political decision that are beyond or realm of expertise. On the other hand, we can confirm that if LNG has to be used to produce electrical power in the Luzon grid, it should be for mid merit and peaking applications.

Our in house system analyst team has performed a study on this subject. In this study, we assumed that LNG would be available in the Philippines for the Luzon grid and we looked at two horizons. The first horizon is 2020 when the Malampaya pipeline gas is still part of the energy mix. The second horizon is end of 2022 when it is assume that the Malampaya pipeline gas is not available anymore as the field is supposed to be depleted by this time.
In order to carry out this study, we made a number of assumptions concerning the efficiency of the different type of power plants that could be used in the system. On the fuel price side, the following assumptions were made: Coal PHP 2400/ton (with a heating value of 21200kJ/kg), pipeline gas (Malampaya) $ 9.9/MBTU while LNG $15.5/MBTU. This LNG price of $15.5/MBTU was reached by assuming that the spot delivered price of LNG with a large scale vessel (above 120000m3) was $14.5/MBTU while the price of large scale LNG storage and regasification would come to around $1/MBTU.

In the first place, we had to understand how the power plants of the Luzon grids were operated in 2013. For that, we aggregated publically available generation data of all the power plants present in the system on a particular day (Sept 3rd 2013).

![Figure 1. Luzon grid system operation profile by fuel type derived from the aggregation of individual power plants data.](image)

The main comment that can be made from this operation profile is that geothermal, hydro and diesel power plants are operated in a traditional economical way but the same is not true for the gas and coal fired plants. In the Philippines, the gas power plants are operated on base load while coal fired plants are taking care of some of the base load and of almost all the mid merit (less than 12 hours a day) and peaking (less than 5 hours a day) load. Because pipeline gas is much more expensive than coal, this is not the most economical dispatch order. This situation is due to the fact that for some historical reasons that were probably valid at the time, the Malampaya pipeline gas contracts have been signed on take or pay basis with the gas power plant owners.

Knowing the current operation profile of the Luzon Grid, in order to obtain a default system operation profile for 2020, we incorporated the system growth assumptions of the “Power Situationer” available on the DoE website.

We then assumed that by 2020, LNG would be available in the Philippines and we compared two different usage of this LNG. In one case, LNG is used by CCGT plants for baseload on the same operating profile as the power plants fired by the Malampaya pipeline gas. In a second case, we assumed LNG would be used by large gas engines power plants for mid merit and peaking applications. Due to their low capex, good fuel efficiency at part and full load and high operational flexibility large gas engine plants such as the Wärtsilä Flexicycle™ are often the best choice for mid merit and peaking applications.
This exercise showed substantial overall system fuel cost savings could be obtained by using LNG for mid merit and peaking instead of baseload. In this particular case it amounted to USD 1.4 million per day or 16% of the daily fuel system cost!

In light of all these elements, it seems that there is a defendable case for having a LNG terminal in Luzon that could feed some anchor mid merit and peaking gas power plants for a total capacity in the 600 to 1000 MW range.

### 3. POTENTIAL OPPORTUNITIES FOR SMALL SCALE LNG OUTSIDE OF LUZON.

In this section and the followings, we will explain why it would make sense for both the DoE and/or the developer of the large scale LNG terminal in Luzon to ensure that smaller quantities of LNG can be shipped to other locations in the Philippines from this central point. We will cover the potential demand and the required infrastructure required to satisfy this demand. Finally we will assess the commercial viability of such concepts.

As can be seen from the Visayas and Mindanao grids power generation fuel mix (fig.3) , due to the nature of their geography and current state of their infrastructure development, liquid fuel is still being used significantly in these grids (18.7% for Mindanao and 7.75% for Visayas) despite the fact that it is the most expensive fuel among the fuels available (USD
850/ton delivered in Mindanao for HFO). These liquid fuel plants are often referred as diesel plants but in practice really mostly operate on Heavy Fuel Oil (HFO).

It should be noted that these diesel power plants are typically of the very small (few MWs) to medium size (around 100 MW). On the downside, HFO power plants have a high marginal cost of production due to the high fuel price. On the upside, they have a low capex requirement, good part and full load efficiency and are extremely flexible in terms of operation. Therefore, they are typically only used for intermediate and peaking application in places where the grid is available with hydro (when available), geothermal or coal ensuring the base load production. In other places that are completely off grid, liquid fuel power plants are operating in flexible base load mode, providing both the base, intermediated and peaking load.

If power plants having the same technical characteristics (low capex, good part and full load efficiency and high operation flexibility) as the HFO plants but operating on a cheaper fuel could be developed, they would certainly be able to displace the HFO plants in the dispatch order.

This is indeed the case of gas engine based power plants. A low hanging fruit in terms of system generation cost optimization would therefore be to introduce in the future power development plans of Visayas, Mindanao or SPUG areas some gas engine based power plants instead of liquid fuel power plants provided that it can be demonstrated that their cost of power production would be lower if LNG was made available for them. An additional side benefit of the gas power plants would be a reduced emission level.

We will explore the technical requirement for such an introduction in the next parts of this paper.
4. THE SATELLITE LNG DISTRIBUTION CONCEPT

As we explained earlier, the existing diesel plants in Mindanao and Visayas are typically in the 10 to 100MW size. A 100 MW LNG fired gas power plant with a capacity factor of 33% would consume only around 96000m³ of LNG in a year. For such quantity, it is obvious that delivery of LNG with a large LNG carrier (120000m³ to 260000m³) bringing gas directly from the LNG production source would not be economically viable. That’s because it would either require to oversize the jetty and storage capacity in order to have one LNG delivery a year or alternatively it would mean derouting a large LNG vessel (120000m³ to 260000m³) to a specific destination for small partial more regular deliveries. Both of these options would drive prices tremendously upwards. The case would even be worse for smaller size power plants.

Now, assuming a main large scale terminal as discussed in the first part of this paper would be available at a reasonable distance and if a sufficient total demand could be served to make sure that a small scale LNG carrier (below 60 000m³ capacity) could be operated efficiently from the main terminal to the LNG demand locations, the economics of LNG fired power generation could become competitive.

This intuition, led us to carry some feasibility study for a satellite LNG Distribution to power plants concept revolving around the central terminal in Luzon.

Figure 4. The Satellite small scale LNG distribution concept revolving around a central LNG receiving terminal
4.1 The Central LNG receiving terminal:

At the heart of the Satellite power plants concept would be the large central LNG receiving terminal. As discussed in the first part of this paper, this terminal will be serving one or several mid merit gas anchor power plants each in the 200 to 600MW size totalling around 600 to 1000MW. The central terminal would also very likely supply additional gas to surrounded industries that could be connected to the terminal via a pipeline.

Assuming a total capacity of these mid merit anchor power plants of 1000MW with a capacity factor of 33%, the estimated yearly gas consumption would be around 1 000 0000 m3. Depending on the type of contract that would be finalised with the LNG supplier, different configurations of large scale delivery and storage would be looked at. In all cases, it is can be expected that LNG deliveries will be made with large scale LNG carriers that are traditionally in the 120000 m3 to 260000 m3 capacity range. Depending the regularity of the rotations, a LNG storage capacity between 100 000m3 to 260000m3 will probably be considered.

Image 1. LNG storage terminal with capacity for LNG reloading to smaller LNG vessel

Whether this storage and regasification terminal will be onshore (flat bottom self containment tanks) or offshore (FSRU), it is important that it will be designed to allow transhipment to small vessels that could bring LNG to other destinations. That requires some design arrangements for the mooring of the smaller vessels as well as on the design of the reloading arms and LNG pumps.
4.2 Small scale LNG carrier

Optimizing the size of each piece of equipment in the LNG to electrical power production chain is an iterative process that can lead to several acceptable solutions.

The first phase of this sizing process is to make assumptions on what could be the initial demand from small power plants located in different places outside of Luzon. This is a completely fictional case study but to make as realistic as possible, we have chosen four places where HFO power plants (that are often aged assets) are still currently being used quite extensively for mid merit and peaking applications. The places are Iloilo (Panay), Toledo (Cebu), Nasipit (North Mindanao) and Puerto Princessa (Palawan). For the sake of the simulation, we have assumed that the respective capacities of these LNG fired power plants would be: 50MW in Iloilo, 30MW in Toledo, 100 MW in Nasipit and 30MW in Puerto Princessa.

From fig. 5, we can derive that the travelling route of a small scale LNG carrier that would on a regular basis make partial delivery of LNG to these four plants would be around 1200 Nautical Miles (NM).
Typical Small scale LNG carriers in the 6000m³ to 60000m³ capacity range have an approximated cruising speed of 15 Knots per hour. In theory, the 1200 NM distance could be covered in around 3 to 4 days but with multiple stops to first fill in the small LNG carrier at the central storage point in the Batangas bay and then offloading partial shipments in the four different places identified, it can be concluded that this delivery route could comfortably be served within 15 days.

Now that we have roughly determined the time it would take to serve this route, we can be a little more accurate with the sizing of the small LNG carrier.

Assuming all four LNG fired power plants have a similar mid merit/peaking operating profile leading to a capacity factor of 33%, two weeks LNG consumption would amount to 8525 m³. This is considering a net heat rate with 0% tolerance of 7400kJ/kWh for the 100 MWe power plant and 8000 kJ/kWh for the 50 and 30MW power plants.

Knowing a typical LNG carrier has a heel requirement of around 10% of its capacity. The small LNG carrier that could serve our imaginary route for deliveries every two weeks should at least have a capacity of 9472m³. This value can be rounded to 10000m³ as it is one of the common sizes of small scale LNG carriers that have been seen on the market (Image.2). In such case the heel requirement becomes 1000m³ while the reserve capacity is 475m³.

<table>
<thead>
<tr>
<th>Plant Capacity</th>
<th>LNG Consumption / 15 days</th>
</tr>
</thead>
<tbody>
<tr>
<td>Iloilo 50MWe</td>
<td>2105 m³</td>
</tr>
<tr>
<td>Toledo 30MWe</td>
<td>1263 m³</td>
</tr>
<tr>
<td>Nasipit 100MWe</td>
<td>3894 m³</td>
</tr>
<tr>
<td>Puerto Princessa 30MWe</td>
<td>1263 m³</td>
</tr>
<tr>
<td>Total Consumption</td>
<td>8525 m³</td>
</tr>
<tr>
<td>Suitable small LNG carrier size</td>
<td>10000 m³</td>
</tr>
<tr>
<td>Heel requirement for small LNG carrier</td>
<td>1000 m³</td>
</tr>
<tr>
<td>LNG carrier Reserve capacity</td>
<td>475m³</td>
</tr>
</tbody>
</table>

Table 1. Small LNG carrier capacity sizing.
4.3 Small scale LNG storage and regasification facilities

Having determined that a LNG carrier with a 10000m3 capacity would be adapted to serve our route every 15 days, the LNG storage size at the satellite power plants side can in turn be estimated. Having that a regular delivery of LNG helps in minimizing the investment required for LNG storage.

In the case we are studying, the LNG storage capacities for each site will be determined by taking into account the two weeks gas consumption of the power plants, adding a requirement for a safety inventory of 5 days of operation to it and finally adding another 10% heel requirement. (Table 2)

<table>
<thead>
<tr>
<th>Plant Capacity</th>
<th>LNG Consumption / 15 days</th>
<th>5 days safety Consump.</th>
<th>10% heel requirement</th>
<th>LNG storage capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Iloilo 50MWe</td>
<td>2105 m3</td>
<td>702 m3</td>
<td>281m3</td>
<td>≈3500 m3</td>
</tr>
<tr>
<td>Toledo 30MWe</td>
<td>1263 m3</td>
<td>421 m3</td>
<td>168 m3</td>
<td>≈2000 m3</td>
</tr>
<tr>
<td>Nasipit 100MWe</td>
<td>3894 m3</td>
<td>1298 m3</td>
<td>519 m3</td>
<td>≈6000 m3</td>
</tr>
<tr>
<td>Puerto Princessa</td>
<td>1263 m3</td>
<td>421 m3</td>
<td>168 m3</td>
<td>≈2000 m3</td>
</tr>
</tbody>
</table>

Knowing the required storage capacity helps in turn in making the right techno commercial choice for the LNG tanks technology.
There are two main families of onshore LNG storage tanks to choose from. The first type of LNG storage tanks are the flat bottom self containment tanks (single, double or full containment). The second type is pressurized double wall steel bullet tanks.

The flat bottom self containment tanks are normally tailor made for a project. They require extensive engineering and a lot of local civil work. For these reasons, they are traditionally a suitable choice for storage capacity above 10 000m³ and for projects where long completion time is not an issue.

On their side, the pressurized double wall steel bullet tanks come in standard unit sizes (500m³, 1000m³ and 1500m³). In order to reach bigger storage capacity, these tanks can be installed in parallel. Because they are pre engineered and do not require an extensive amount of local civil work, they are often a preferred choice for onshore storage capacity requirements under 10000m³.

In the case of our considered gas power plants around the satellite distribution route, pressurized double wall steel bullet tanks would therefore be the adequate solution. For Puerto Princesa and Toledo powers plants, two bullet tanks of 1000m³ would used in parallel while four of these same tanks could be used in Iloilo and six in Nasipit.

Since gas is not consumed in its liquid form by the power plants, it needs to be regasified. Regasification units will be installed next to the LNG storage tanks area. These regas units essentially consist of a Main Gasification heat Exchanger (MGE) that can either use air, hot water or steam as a heating media. (Fig 6)

![Figure 6. LNG process diagram from LNG storage tank to power generation prime mover](image-url)
4.4 Gas power plants

The last pieces of the technical puzzle that needs to be put together in order to produce electricity from LNG are the gas power plants themselves.

Gas fired power plants can be built around two potential technologies: gas turbines and gas engines.

Gas turbines in open cycle mode have quite a low efficiency. On the other hand, when they are set up in a combined cycle mode (CCGT), they can offer a high efficiency especially when the plant size is large (above 200MW) and when the true load profile is stable. Since a combined cycle is required in order to achieve good efficiency figures, it constitutes an additional capex element that generally requires baseload type of generation in order to be economically competitive.

Gas engine power plants, on their side, can offer the best open cycle efficiency (and a slightly higher efficiency in combined cycle mode). This is true irrespective of the expected load profile thanks to the fact that gas engine power plants being built with multiple units can utilize effectively only the required number of units. Gas engines power plants are also extremely flexible in terms of operation and can provide high power availability.

It can generally be argued that for any project requiring flexible operation, gas engines would be a better choice than gas turbine. It is at least definitely the case when the plant capacity is
below 200MW and when the plant is expected to operate for mid merit and peaking applications as it is the case for the fictional plants we have considered.

Therefore, our assumption is that gas engine power plants would be used in the case of the four projects we selected. To make our case study more realistic, we imagined that the two 30MW power plants would be powered by three Wärtsilä 20V34SG gas engines in open cycle, the 50 MW plant would be equipped with six of the Wärtsilä 20V34SG while the 100MW plant (fig 7) would be using six Wärtsilä 18V50SG units in combined cycle mode (Wärtsilä Flexicycle™). The reason for having the gas engines in combined cycle mode only for the 100MW plant is that it is generally observed that adding heat recovery boilers and a steam turbine to close the cycle normally becomes competitive only for capacities above 60MW.

![Figure 7. View of the 100MW Nasipit combined cycle gas engine plant with 6000m3 LNG storage and regas capacity](image)

4.5 Economics

Our satellite LNG distribution to small gas power plants outside of Luzon concept is now complete:

. The LNG supply chain is in place with a 10000m3 LNG carrier that brings gas from the central terminal in Luzon to our four plants every two weeks.
. Each gas engine power plant is also optimized in terms of their prime mover technology based on their required size and operational profile.

. These power plants have their own small LNG storage and regasification facilities that have also been optimized based on the expected gas consumption and delivery pattern of the small LNG carrier.

The essential question that remains to be answered now is whether producing power under this sort of set up would be competitive, especially when compared to power produced by HFO.

In order to answer this question, we have carried out an electricity tariff calculation and comparison using a wide number of techno commercial assumptions based on the technical logistic and project set up described in the previous parts of this paper.

The general assumption that we used are listed in the table 3:

<table>
<thead>
<tr>
<th>Description</th>
<th>Unit</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>General</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project lifetime</td>
<td>Years</td>
<td>25</td>
</tr>
<tr>
<td>Exchange rate</td>
<td>USD/EUR</td>
<td>1.39</td>
</tr>
<tr>
<td>WACC</td>
<td>%</td>
<td>10</td>
</tr>
<tr>
<td>Cost of HFO (delivered)</td>
<td>$/ton</td>
<td>850</td>
</tr>
<tr>
<td>Cost of LNG delivered to satellite power plants</td>
<td>$/MMBTU</td>
<td>17.5</td>
</tr>
<tr>
<td>small LNG storage</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Power plant operating profile</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Plant running hours</td>
<td>h/Day</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>h/Year</td>
<td>3650</td>
</tr>
<tr>
<td>Average loading</td>
<td>%</td>
<td>80</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>%</td>
<td>33</td>
</tr>
<tr>
<td><strong>Design conditions</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Temperature</td>
<td>Deg C</td>
<td>30</td>
</tr>
<tr>
<td>Altitude</td>
<td>Meters</td>
<td>Sea Level</td>
</tr>
<tr>
<td>Relative humidity</td>
<td>%</td>
<td>65</td>
</tr>
<tr>
<td>Gas methane number</td>
<td></td>
<td>80</td>
</tr>
</tbody>
</table>

Table 3. General project assumption for electricity tariff calculation

As can be noticed from table 3, a key assumption is that we are using a price of LNG delivered to the Satellite plants of USD 17.5 /MMBTU. We have reached this price by assuming a delivered price of LNG to the central terminal in Luzon of USD 14.5/MMBTU.
This seems to be a realistic spot price for LNG in Asia. An estimated cost of USD 1/MMBTU for storage and reloading to the small LNG carrier at the central terminal was then added. Finally, another USD 2/MMBTU for small scale LNG transportation and unloading to the satellite power plants also had to be included. This USD 2/MMBTU was reached after discussions with small LNG carrier charter companies that we informed of the expected route, delivery rotation, size of ship and LNG quantities.

On the gas power plants side, technical and commercial assumptions were also made (Table 4). In order to obtain accurate and realistic results, we used site conditions performances with 0% tolerance. The EPC figures considered for the power plants include the total scope required for the gas power plants themselves plus the storage and regasification facilities attached to them as described in table 2.

<table>
<thead>
<tr>
<th>Configuration</th>
<th>Puerto Princesa 30MW</th>
<th>Toledo 30MW</th>
<th>Bohol 50MW</th>
<th>Nasipit 100MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPC Price (incl. Gas engines, LNG storage and regasification...)</td>
<td>USD millions</td>
<td>48.8</td>
<td>48.8</td>
<td>74.4</td>
</tr>
<tr>
<td>Full load net output</td>
<td>MW</td>
<td>28</td>
<td>28</td>
<td>56</td>
</tr>
<tr>
<td>Plant net efficiency</td>
<td>%</td>
<td>44</td>
<td>44</td>
<td>44</td>
</tr>
</tbody>
</table>

Table 4. Power plants related techno commercial inputs

With all these assumptions made, we were finally able to run our tariff calculation model and compared the results obtained for the gas power plants to the results that would have been obtained for similar size HFO based power plants.
The results shown in figure 8 indicate that the slightly higher capex component of the gas power plants compared to the HFO power plants (due mostly to the extra cost of small LNG storage and regasification equipment) is largely offset by the cheaper fuel component.

In total, electricity produced from LNG power plants in the four locations chosen would be around 8 to 9% more competitive than electricity produced by HFO power plants if all the assumptions we made in terms of LNG logistic chain would materialize. This is an extremely significant difference in the competitive world of power generation.
5. CONCLUSION

As we have seen in the first part of this paper, a combination of factors indicates that large scale LNG receiving facilities will be built in Luzon in the coming months or years.

The main usage of this LNG will initially be for large the fuel consumption of mid merit gas power plants in the Luzon grid. Some small part of this LNG will also probably be used for industrial and transport applications providing that a pipeline or logistical network is developed in the Manila Metropolitan area.

In this paper, we have demonstrated that in addition to these applications, some part of the LNG could also be redistributed from the central LNG terminal in Luzon and brought to different gas power plants across the archipelago. If the central LNG receiving facilities are designed correctly, a small scale LNG carrier could handle the satellite distribution of LNG to decentralized locations in the country.

As we saw in our feasibility study, providing that a sufficient aggregate quantity of LNG can be consumed by this gas power plants in order to maximize the utilisation of the small scale LNG carrier, the price of electricity generated with gas engines power plants using LNG as a fuel would be 8 to 9% cheaper than HFO generated electricity. With HFO still being used significantly for power generation in Visayas and Mindanao, this potential for tariff reduction should attract attention of both the public authorities and the private sector.

It should be noted that for these potential savings to materialise, there shall be a first mover who shall take the risk to invest in the small LNG carrier and bring the gas to what might well be only a small single plant at the beginning. Once this first infrastructure will be in place other gas plants in Mindanao and Visayas will for sure be developed.

Who should be this first mover? Government or private sector? Are adequate regulations in place to enable the development of such a concept?

Those are all questions that will need to be answered.