Optimizing the South African Power System with Ultra-Flexible LNG Power Plants

WAYNE GLOSSOP & JYRKI LEINO

WÄRTSILÄ ENERGY SOLUTIONS

SOUTH AFRICA FINLAND
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EXECUTIVE SUMMARY

South Africa (SA) will soon embark on large new-build gas Independent Power Producer’s (IPP) programme for 3,126 MW in accordance with the IRP2010 and Ministerial Determinations, the majority of which will likely be initially supplied using imported Liquefied Natural Gas (LNG). However, what SA does with this capacity is yet to be fully defined in terms of what plant performance criteria should be considered in order to ensure the maximum system benefit is realised. Realisation of these benefits should recognize the variable nature experienced from increasing intermittent renewable energy and uncertainty caused by varying coal capacity availabilities and demand variations. Further recognition must also be given to the limitations and inflexible preferences traditionally experienced in the LNG supply industry. Herein lies the challenge of marrying two opposing sets of requirements of power flexibility and LNG supply inflexibility.

This paper seeks to unpack the relationship between the power system perspective and the LNG supply perspective. Using complex power system modelling software, we re-create the SA power system, based on inputs from the IRP2010, and analyse a range of scenarios which considers the impact of integrating a 3 GW gas power plant over the period 2020 – 2030. From our analysis, we learn that gas serves primarily two functions: 1) displace expensive diesel generation and 2) optimize the inflexible coal generation. We also learn that significant variations in the annual gas plant load factor of between 20%-80% occurs depending on what the supply/demand status is. These system requirements are best met with ultra-flexible gas capacity, such as Wärtsilä’s Flexicycle power plant, which is able to efficiently provide system energy and regulating reserves. In consideration of the regulating reserve requirements as defined in the SA Grid Code, engine based technologies are the only technology that is able to fully satisfy those requirements from a non-spinning state. This essentially allows the system to realise further significant savings when compared to less flexible solutions such as turbines.

To understand the impact of having both flexible and inflexible Gas Supply Agreement’s (GSA’s), we introduce into the model two Gas Supply Agreements (GSA) structures which represents both flexible and inflexible LNG supply options. In the inflexible GSA, we have a 100% take-or-pay agreement priced at 10 USD/GJ and for the flexible option, an unconstrained LNG volume (or 0% take-or-pay) agreement priced at 15 USD/GJ. The results prove that even with a significant premium for flexibility built into the GSA, the overall power system operating cost is lower than for the cheaper, inflexible, GSA option. Over the ten year period, this total system savings accumulates to 4.7 billion USD.

In conclusion, our findings reveal that it is the flexibility requirements of the power system which should be prioritised over any project level cost optimisations and that flexible LNG project solutions should hold greater value than inflexible solutions to the system. The integration of this flexible capacity will also support the improvement of system reliability and sustainability by enabling greater levels of renewable energy to be introduced onto the grid.
1. INTRODUCTION

1. THE REGULATORY CONTEXT FOR NEW GAS CAPACITY

South Africa for many years has been in the fortunate position of obtaining the vast majority of its energy needs through the use of large scale coal fired power stations. The low tariffs from these stations have enabled many key industries to be established and supported the growth needed by South Africa over the past forty years. The figure below provides an indication of the current generation capacity mix in South Africa.

![Generation Mix for 2015](image)

Figure 1: In future, coal will start to play a less dominant role in the generation mix as cleaner sustainable energy is introduced.

This capacity mix is changing rapidly due to the increasing environmental pressures and the need for a diversified energy mix as discussed within the Integrated Energy Plan (IEP) and the Integrated Resource Plan (IRP). Of primary interest to us is the IRP2010 which provides the blueprint upon which all new-build capacity is defined for South Africa up to 2030 (refer to Table 1).

Table 1: New build options from IRP2010.

<table>
<thead>
<tr>
<th>Year</th>
<th>Coal</th>
<th>Nuclear</th>
<th>Import</th>
<th>Hyrd</th>
<th>Gas - CCGT</th>
<th>Peak - OCGT</th>
<th>Wind</th>
<th>CSP</th>
<th>Solar PV</th>
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<tbody>
<tr>
<td>2010</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2011</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
<td>2012</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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</tr>
<tr>
<td>2013</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>300</td>
</tr>
<tr>
<td>2014</td>
<td>500</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>400</td>
<td>0</td>
<td>300</td>
</tr>
<tr>
<td>2015</td>
<td>500</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>400</td>
<td>0</td>
<td>300</td>
</tr>
<tr>
<td>2016</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>400</td>
<td>100</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>400</td>
<td>100</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>400</td>
<td>100</td>
<td>300</td>
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<tr>
<td>2019</td>
<td>250</td>
<td>0</td>
<td>0</td>
<td>237</td>
<td>0</td>
<td>400</td>
<td>100</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td>250</td>
<td>0</td>
<td>0</td>
<td>237</td>
<td>0</td>
<td>400</td>
<td>100</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>2021</td>
<td>250</td>
<td>0</td>
<td>0</td>
<td>237</td>
<td>0</td>
<td>400</td>
<td>100</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td>250</td>
<td>0</td>
<td>0</td>
<td>1143</td>
<td>0</td>
<td>400</td>
<td>100</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td>250</td>
<td>1600</td>
<td>1183</td>
<td>0</td>
<td>805</td>
<td>400</td>
<td>100</td>
<td>300</td>
<td></td>
</tr>
<tr>
<td>2024</td>
<td>250</td>
<td>1600</td>
<td>283</td>
<td>0</td>
<td>800</td>
<td>100</td>
<td>300</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td>250</td>
<td>1600</td>
<td>0</td>
<td>0</td>
<td>805</td>
<td>1600</td>
<td>100</td>
<td>1000</td>
<td></td>
</tr>
</tbody>
</table>
In 2012, the Minister of Energy released determinations for the construction of 3,126 MW to be procured through the establishment of IPP’s. This was subsequently followed up with an Request for Information released in May 2015 which sought for a wide range of gas related energy projects but with particular focus on LNG supplied projects (The Republic of South Africa - Department of Energy, 2015). Key features of this RFI of relevance to our discussions include:

- 3 GW of capacity would have a 35% load factor for the years 2020, 2025, 2030
- Power Plants would be required to provide flexibility as quoted “intra-day flexibility is required with lower load factors during night and higher load factors during the day and evening peak hours”.

It is within this context that we will seek to further unpack the flexibility requirements of gas as applicable to the South African power system and link it to the complexities related to LNG supply. But first, we highlight some of the variables which will have an influence in determining what the system will require from future gas capacity.

### 2. FUTURE SYSTEM VARIABLES

In this section we highlight a few events which contribute to both the long term and short term uncertainty and variability of the power system. As we will find, all these events have a significant impact on the role of gas in the power system hence the importance of identifying and describing them. These events include:

- Increasing Renewable Energy;
- Increasing Coal Plant unavailability/decommissioning and;
- Varying Country Demand.

Through the successful REIPPP (Renewable Energy Independent Power Producer Programme), South Africa has a total of 6.3 GW already procured with a total allocation of 13,225MW to be built predominantly through wind and solar energy (Creamer Media, 2015). The drawbacks however arise through the...
intermittent nature which these sources are able to provide energy as is highlighted in the actual wind and solar (PV) production profiles for the Renewable Energy Independent Power Producers Programme (REIPPP) projects between 1st September 2014 and 30th September 2014 in Figure 2.

![1 Sept 2014 - 30 Sept 2014 Renewable Data](image)

*Figure 2: South Africa is no exception to the fact that renewables are highly intermittent as can be seen from aggregated energy production of PV and wind over 1 month from the REIPPP.*

Based on this intermittency, one must recognize that by increasing the relative share of renewables in the power system, system imbalances will be created for which flexible measures must be introduced in order to stabilize the system. If SA follows the planned capacity increases as per the IRP (which is likely to be the case given the current successes of the REIPPP), one can anticipate an 11% penetration by 2020 and 26% by 2030. According to the International Energy Agency, a power system will start to experience the effects of variability from renewables sources after 5% penetration levels are reached (International Energy Agency, 2014). It is thus clear that there is a need to start planning today for this increasing level of intermittency or risk decreasing the reliability of the grid.

In parallel to the increase in renewables, the system will start seeing the loss of coal baseload capacity due to the lower availabilities and decommissioning taking place from 2019 (Republic of South Africa, 2011). Eskom’s coal stations have been rapidly decreasing their availabilities from 90% in the early 90’s down to 75% in 2015 (NERSA, 2015) (Moneyweb, 2015). On top of the increasing unavailability, the majority of the existing coal fleet is planned for decommissioning between 2025 – 2030 (Republic of South Africa, 2011).

But probably the biggest factor influencing the future health of the power system is based on the country’s growth and demand for electricity. SA’s GDP is yet to rise above 2.9% since 2012 and current predictions are for <1% growth in 2016 (Trading Economics, 2016). If we consider that the IRP2010 was based on achieving almost 5% GDP and an electricity demand increase of over 3%, South Africa is barely reaching even half of the predicted growth. This slow growth rate is already reflecting on the total system demand with there being a 5% drop in average demand between 2014 and 2015 and a further drop anticipated for 2016 (ee-Publishers, 2015). So whilst SA is experiencing a temporary slowdown in the economy, this may (and hopefully) will change in the near future to once again re-instate the pressure for more capacity additions onto the grid.

As can clearly be seen, the power system is subject to a multitude of variables which continuously alter the energy supply and demand balance. It is exactly this ongoing uncertainty balancing act where we see gas power playing a pivotal role in ensuring the long term reliability of the South African power system.
2. GAS TECHNOLOGY OVERVIEW

When one considers the technology options available for converting gas into electricity, two options for the prime movers are available, namely; **Internal Combustion Engines (ICE)** and **Gas Turbines (GT)**.

For applications that utilize LNG as their feedstock, a relatively expensive source of gas when compared to prospective indigenous sources, it is likely that plants will be configured to optimize on efficiency. As such, we limit our descriptions to the following configurations\(^1\): Wärtsilä Flexicycle technology (combined cycle technology in engines); and CCGT’s\(^2\).

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\(^1\) Only dry-cooled technologies are considered due to the water limitations that exist in South Africa.

\(^2\) OCGT’s are not considered as their open cycle efficiency is too low to be considered for this application.
The combination of flexibility and efficiency make Wärtsilä Flexicycle power plants ideally suited to load following in a power system whilst also being competitive at near baseload dispatch profiles.

Wärtsilä’s Flexicycle power plants are designed based on standardized modular units which allows for fast construction times and easy expansions. Dry-cooling technologies may also be considered which use approximately 96% less water than a conventional CCGT plant.

The table below provides a summarised view of the key features between a Wärtsilä Flexicycle plant and a CCGT plant which have been integrated into the power system modelling software for the analysis.

Table 2: Key parameter comparisons between a Wärtsilä Flexicycle power plant and a CCGT power plant.

<table>
<thead>
<tr>
<th>Conditions</th>
<th>Wärtsilä Flexicycle [14-1-1]</th>
<th>CCGT [1-1-1]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Output</td>
<td>250 MW</td>
<td>250 MW</td>
</tr>
<tr>
<td>Efficiency (Net, LHV)</td>
<td>100% (25degC)</td>
<td>50%</td>
</tr>
<tr>
<td></td>
<td>50% (25degC)</td>
<td>47.8%</td>
</tr>
<tr>
<td>Start up Times</td>
<td>Hot Standby</td>
<td>10min (90%) / 1:20min (10%)</td>
</tr>
<tr>
<td>Start up Costs</td>
<td>EUR/MW/start</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>minimum 90% capacity</td>
<td>92/98</td>
</tr>
<tr>
<td>Water Consumption</td>
<td>0.04m3/MWh (Dry Cooled)</td>
<td>~1.2m3/MWh</td>
</tr>
<tr>
<td>Plant Construction Time</td>
<td>Months</td>
<td>12-24</td>
</tr>
</tbody>
</table>

3. SA’S ENERGY AND RESERVE REQUIREMENTS

In understanding the true role of gas for South Africa, it is necessary to divide our discussions into the two main areas in which gas power traditionally plays a role, namely; Electrical Energy and Regulating Reserves. Below we highlight very simply what the distinctions are between these two roles.

- **Electrical Energy Requirements** refers to the forecasted energy requirements of the grid based on a predicted demand/supply balance. Generators that are used to supply energy to the system will have a pre-defined dispatch profile which will vary depending on the cost of providing energy versus the demand for that energy. The most familiar, and simplified, profiles are that of baseload; mid-merit; and peaking.

- **Regulating Reserve Requirements** refers to the capacity that is made available to the power system within a short interval of time in the event of an imbalance between supply and demand (such as a generator trip). Generators that are used to provide reserves are continuously activated to maintain system frequency within acceptable bounds and are classified according to the time for activation (see side block ‘SA GRID CODE AND RESERVES’ for definitions specific to SA).
Whilst it is easily understood what the electrical energy requirements of a system would be, the role of the regulating reserves is somewhat less understood but equally important in ensure reliability and quality of supply is maintained. This fact becomes even more apparent the as level of renewable energy increases in the system.

Globally, gas generation capacity, more so than most other types of capacity, is used to meet one or both of these requirements depending on the project economics in the respective locations. We now discuss if and how gas satisfies these roles for the South African context.

### 1. ENERGY REQUIREMENTS

In order for one to understand the energy requirements of gas, it is important to understand where it ‘fits’ in the total system merit order in terms of the tariff costs. For this, we take guidance from the work done by the Council for Scientific and Industrial Research (CSIR) who have performed calculations to compare the new build tariffs for various technologies as depicted in Figure 5.

![Figure 5: As long as LNG is used as a feedstock, it is unlikely that gas tariffs will be lower than coal or nuclear tariffs.](image)

*Note: Gas Price used was R150/GJ.*

From the figure, it is clear to see that gas capacity (whether it is from engines or turbines) sits comfortably between coal and diesel capacity due to the high fuel component which has been assumed to be R150/GJ.
Even if one considers gas prices of either R100/GJ or R200/GJ, it still will not change the relative merit order for gas. But, in order to understand the true energy requirements of the system, one needs to understand how variations experienced in the power system (as described in the sections above) will influence the energy requirements from gas. This is best visualized using a load duration curve.

Figure 6 indicates a projected load duration curve (based on actual demand data taken from 2014/15) set against the planned capacity, as per the IRP, but with 3,126 MW of gas capacity installed.

![Load Duration Curve](image)

Figure 6: Gas capacity from LNG will almost always sit between coal and diesel capacity which means its dispatch requirements will continuously vary according to the status of the system.

*Note: Demand Projections based on the ‘Base Case 0.0’ path as per IRP2010.*

*Note: Other sources such as wind; hydro; solar; and embedded generation are ‘must run’ generators and are therefore un-affected by the demand requirements. It should further be noted that the variability generated from renewables is not reflected in these representations.*

By observing the load duration curve cross over point with the gas capacity, one can note that the typical load factor range required of gas capacity is only between 30-60%. But this is not to say that it will remain within this range for the life of the plant. In fact, as new capacity is added, or old capacity is removed, or as the demand varies, the required load factor will continuously vary as highlighted in Figure 7.

![Load Duration Curve](image)

Figure 7a; 7b: As either the supply or demand varies, so does the required load factor from gas vary.

In Figure 7a, we decrease the anticipated coal availability by 5% which effectively means that gas capacity is required to operate at 50-70% load factor. Similarly, in the second figure, we reduce the electricity demand rate to only 1% per annum, then gas capacity is only required to operate at load factors between
5 – 10%. This effect highlights the importance of having accurate and up to date planning so one has a thorough understanding of the requirements from new capacity.

To take this analysis one step further, let us expand this study over a 10 year period which considers a new build programme as defined in the IRP2010. Assuming a ‘base case’ scenario where a ‘Moderate Growth’ situation is realised, and a 73% coal availability is provided from the ageing coal fleet, one arrives at the varying load factor for either 3GW of CCGT’s or 3GW of Wärtsilä Flexicycle capacity as shown in Figure 8.

![Gas Energy Annual Load Factor](image_url)

*Figure 8: Engines and Turbines play a similar role in providing the constantly varying energy requirements of the power system.*

**Note:** Assumptions: 3,126MW available from 2020; ‘Mod Growth’ path for demand used; Old Coal plant availability is 73%.

An important observation to note is that every year there is a change in the energy load factor requirements. These changes coincide predominantly with changes in baseload capacity where either new capacity was coming online (i.e. Nuclear coming online from 2022) or old capacity was going offline (i.e. the old coal stations in 2027). As a result, this graph disputes the fact that gas projects should be designed according to a fixed dispatch profile (e.g. Mid-merit or baseload) for the length of the Power Purchase Agreement (PPA), which may typically be 20 years, since in doing so, one forces the total system to operate sub-optimally as the need for energy from gas power constantly varies with time. It is thus essential that any gas plant that gets installed must be able to meet the varying energy dispatch requirements in order for the system to remain operational in an optimised manner.

**Key Takeaways:**

- **With LNG based gas power placed comfortably between the new build alternatives of nuclear/coal and diesel, the relative cost is insensitive to gas price variations (i.e. large changes in gas price will not change the order of preferences to the alternatives).**
- **System demand/supply variations continuously change throughout the life of the plant which impacts the annual load factor requirements of gas generation.**

### 2. REGULATING RESERVE REQUIREMENTS

To date, Eskom has been predominantly reliant on their newest coal fleet to meet the system balancing requirements as these are the only plants, of sufficient capacity, that are technically capable of meeting the sudden demand and supply variations. This entails that their most efficient coal stations are being used at sub-optimal efficiencies whilst their older, less efficient stations are used to provide baseload power. In
addition, this need to provide constant balancing energy increases the amount of degradation experienced by these units leading to increased operational costs and reduced reliability levels. However, in times where there is insufficient capacity on the system, Eskom is actually reliant on the emergency diesel fired OCGT’s to balance the system at a significant cost.

Let us now consider the future reserve requirements for South Africa. As per the Grid Code, South Africa have their own definitions for certain reserve categories however, of primary interest to us is the regulation reserve as this is the reserve capacity that is used to balance the system on a continuous basis. According to Eskom (Eskom, 2015), the system will require 1,300MW of regulating reserves (650MW up and 650MW down as per winter requirements). This value will likely increase significantly more as the level of intermittent renewable energy introduced into the system increases.

If we now consider the respective roles that the gas technologies are able to provide given the reserve definitions and requirements. The table below indicates the extent to which each technology is able to satisfy the three operational reserve types based on their definitions in the Grid Code:

Table 3: Technology compliance comparisons against the SA Grid Code Regulating Reserve categories.

<table>
<thead>
<tr>
<th></th>
<th>Wärtsilä Flexicycle</th>
<th>CCGT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Spinning</td>
<td>Non-Spinning</td>
</tr>
<tr>
<td>Regulating Reserves</td>
<td>Yes*</td>
<td>Yes (90%)</td>
</tr>
<tr>
<td>Instantaneous Reserves</td>
<td>Partial</td>
<td>No</td>
</tr>
<tr>
<td>10-Minute Reserves</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

* For all “Yes”, the full plant capacity can be made available within the reserve time requirements.

**WHAT DOES SPINNING AND NON-SPINNING MEAN?**

Descriptions of whether a plant is operating in a spinning or non-spinning mode means exactly what it says, that the prime mover (either the engine or the turbine) is physically rotating (spinning) or not (non-spinning). This simple distinction however has significant economic relevance as plants operating in a spinning mode will suffer from ongoing variable maintenance requirements and reduced part load efficiencies which results in a higher net tariff. It is therefore preferable that technologies that are able to provide reserves from a non-spinning state do so in order to avoid the wasteful expenditure being incurred on the spinning plant.

The key differentiating factor between engines and turbines is that engines are able to fully satisfy the regulating reserve requirements from both a spinning and non-spinning state whereas turbines are only able to partially fulfil this from a spinning state. Based on this, the power system has the capacity to realise overall efficiency improvements by allowing existing spinning reserves, which were operating at sub-optimal output efficiencies, to be replaced by fast starting non-spinning reserves thereby allowing that capacity to operate at its maximum efficiency. System cost benefits are further realised through the reduced operating costs incurred by reducing the cycling technical degradation previously imposed on unsuited capacity (such as coal) and placing that burden on engines who sustain negligible start-up and cycling costs.

**Key Takeaways:**

- **New Coal capacity is currently used to balance the system which results in plant and system inefficiencies.**
- **According to Eskom studies, 1,300MW of regulating reserve capacity will be required by 2019 but this will increase significantly as more renewable energy is introduced.**
ICE technology is able to provide regulating reserves from a non-spinning state which supports greater system savings and efficiency improvements.

4. SYSTEM EFFECTS FROM GAS ENERGY

Having established the technical differences between the two primary technology options available for gas based power generation, and highlighted the respective reserve and energy requirements of the system, we now present an analysis of how these technologies are able to satisfy these requirements and highlight the system level impact for each technology.

We begin our analysis by introducing 3,126MW’s of either turbine or engine technology into the system and allow the software to determine how this capacity is best utilized. The parameters we observe for our analysis includes the following:

- Energy Load Factor
- Regulating Spinning Reserves Load Factor
- Regulating Non-Spinning Reserves Load Factor

Figure 9 indicates the cumulative turbine and engine load factors for energy and regulating reserve provisions over a 10 year period.

![Gas - Energy + Spin/non-Spin reserve](image)

Figure 9: The ability of engines to provide reserves from a non-spinning state increases their total effective load factor by 20-30%.

If we first consider the CCGT’s, one notices that in the earlier years, only 5% of the installed turbine capacity is allocated to providing regulating reserves from a spinning state and energy requirements in 2020 are 62%. For the engines, whilst we see a lower demand for energy supply (55%), there is significantly more demand from the system for the engines to provide regulating reserves from both a spinning and non-spinning state. This high regulating reserve requirement effectively pushes the total engine plant load factor to over 75% in 2020 and which remains between 15-20% higher than the total turbine load factor throughout the 10 year period. It is also interesting to note from the model only selects engines to provide the entire amount of regulating reserves required by the system whereas in the turbine case, coal capacity is the preferred reserves provider. These findings are perfectly aligned with the technical differences between the technologies. Engines have the capability to provide regulating reserves from both a spinning...
and non-spinning state due to their fast start up capabilities whilst turbines can only provide regulating reserves from a spinning state due to their slower start up times (refer to Table 3).

As the model dispatches plants to find the least total system cost, we are able to extract the total system savings attributable to having both Flexicycle and CCGT’s provide reserves onto the system. Figure 10 shows the annual savings that are realised by allowing both Flexicycle and CCGT plants to provide spinning and non-spinning reserves with the system cost with CCGT’s providing the baseline (the savings derived from the spinning and non-spinning reserves are cumulative).

![Annual System OPEX delta](image)

**Figure 10**: ICE technology creates savings as both an energy and reserves provider to the power system.

From the graph, it is clear that not only do engines provide system savings as an energy provider, when also allowed to provide regulating reserves, the system savings start exceeding 250 million USD per year.

But where do these savings come from? To answer this, one can compare the total generation cost of each technology on the system and identify where these amounts varied for each of the gas technology scenarios considered. In doing so, we find that generation cost variations predominantly occurred in two areas, namely; diesel replacement and; coal optimisation; as divided in the Figure 11.

![Source of System Savings from Flexibility](image)

**Figure 11**: The system savings generated by having flexible capacity on the system originate through optimising the coal fleet and reducing diesel consumption.

As was predicted in Figure 7, gas plays a major role in displacing diesel capacity which in turn generates significant system savings through the avoidance of combusting expensive diesel fuel. The savings realised from coal optimisation are generated predominantly through two avenues:

- Reducing the costs incurred for starting and stopping of the coal units and;
- By reducing the part load operational requirements thereby allowing the coal fleet to operate at their maximum output efficiency level.

These findings once again prove that gas is best used as a flexible energy source on the system as this is how the system is able to realise the most benefit from these projects.

Key Takeaway:

- The ability for gas power to provide reserves enables greater system savings by reducing the diesel dispatch and optimisation of the coal fleet.

5. CONSIDERATIONS FOR LNG SUPPLY

Now that we have proven what the power system requirements are for gas based power generation, the next step to consider is understanding how this flexibility can be extended into the LNG GSA. The convergence of these two distinct industries however does present one with certain challenges as the LNG value chain has traditionally favoured stable energy supplies whilst the power value chain clearly favours flexible energy supplies as proven above.

In this section, we provide a cursory overview of key market; technical; and contractual related aspects which have an influence on the ability to provide flexible LNG.

1. TRENDS IN LNG SUPPLY’S

The LNG trading market is rapidly evolving as new gas discoveries and new consumers enter the market. Past trends and future predictions reveal higher growth in the LNG production than on the consumption thus supporting a ‘buyers market’ allowing new consumers to negotiate better terms. As echoed in BP’s Energy Outlook (2014):

“The trend towards diversification is expected to continue as new exporters and importers join the LNG trade. Increased market flexibility and integration is also supported by the expansion of the physical infrastructure, creating an ever-expanding network of trading nodes.”

This increased flexibility manifests through the GSA negotiations whereby purchasers are pushing suppliers for greater volume flexibility to better suit their energy demand requirements. A widely seen concept within GSA’s is that of the ACQ (Annual Contracted Quantities) which refers to the volume of gas contracted on an annual basis and which is commonly the target for volume flexibility negotiations. From a specified ACQ, buyers may negotiate a portion to be flexible and a portion to be bound to ‘take-or-pay’ obligations. Key areas of negotiation with GSA’s requiring flexibility revolves around the level of take-or-pay with their respective penalties; and how buyers make good on the quantities not received in terms of costs and timing. In the early years of LNG trading, buyers could negotiate annual downward flexibility of 5-10% on the ACQ (Globe Law and Business, 2012). Today, one may easily find GSA’s with 50% take-or-pay obligations and even down to 0% (or 100% flexible supply) in some cases.

It should be noted that even with a full or partial degree of flexibility in the GSA, that buyers are not fully exempt from requesting or discarding LNG cargoes at very short notice. Buyers will still have to present their requests in advance in order to allow for LNGC’s to be identified and travel to the port of delivery. This notice period is a negotiated aspect but can be up to 90 days. Furthermore, it is estimated by the author that as power demand forecasting accuracy improves by the system operator (especially with regards to the renewable capacity production), that the need for very short notice periods will decrease thereby making this LNG cargo forecasting more predictable.
Naturally, as the take-or-pay obligations reduce, so too will the price of LNG increase as the LNG suppliers now have a greater financial risk exposure. But this price increase needs to be evaluated against the benefits of having flexibility downstream which in our case, is the system savings from having flexibility on the grid. In the section to follow, we review exactly how these gas contract limitations and costs were considered in the integrated power system modelling.

2. MODELLING THE LNG SUPPLY

In this section, we present two approaches which favours either a cost optimised LNG GSA (Option A) or a power system requirements (Option B).

OPTION A: OPTIMAL COST LNG GSA APPROACH

If one considers the entire LNG value chain, there are a number of distinct stages which gas must past through before reaching the power plant in a usable form. These may briefly be described as:

Production – Liquefaction – Maritime Transport – Storage/Regasification – Pipeline – Power Station

Whilst our intention here is not to discuss the complexities between each interface, we can highlight some broad principles which will help to achieve the lowest delivered cost of gas to the power plant.

The principles of high fixed volumes of supply stand true when attempting to minimize ones LNG costs. By fully utilizing the infrastructure investments, which are sized to take advantage of the economies of scale, made at each stage, one is able to reduce the per unit cost for each molecule delivered. Particular pressure to maximise and stabilise the volumes is seen at the liquefaction plants which represent massive investments requiring long term certainty of throughput to finance them. Pressure is also found at the storage and regasification facilities which in South Africa’s case, may potentially be an FSRU solution (Reuters, 2015). Depending on various ocean conditions; jetty design; and FSRU design; maximum LNG throughputs typically range between 3-4 Mtpa. To contextualise this, 3 Mtpa of LNG is enough to supply 3 GW of Flexicycle capacity at a load factor of 75%.

On top of this, having a 100% take-or-pay obligation on the buyer over a long term contract (such as 20 years) also provides financial comfort to the supplier and for which they will be able to provide the lowest molecule price to you which for purposes of this study we have estimated to be 10 USD/GJ.

OPTION B: OPTIMAL POWER SYSTEM APPROACH

As shown in Figure 9, the 3 GW of gas capacity may experience annual load factors between 80% (with reserves) and 20% (without reserves). This equates to potential LNG volume supply variations of approximately 1-3.5 Mtpa! Requesting this degree of flexibility will result in LNG suppliers imposing a premium for LNG cargoes that potentially won’t be delivered as a result of cancellation by the power plant dispatcher. What this cost increase will be is largely determined by the project specifics but for purposes of our analysis, we have adopted an ultra-conservative value by assuming that a 5 USD/MMBtu premium is incurred to achieve this level of flexibility.

Based on the above options, for modelling purposes, we have proposed the following two GSA structures:

- **OPTION A – Inflexible**: 3 Mtpa of 100% take of pay at 10USD/MMBtu
- **OPTION B – Flexible**: Unrestricted volume with no take-or-pay obligations at 15USD/MMBtu

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3 This value may vary depending on the detailed LNG energy content assumed, the power plant efficiency and mode of operations.
6. INTEGRATING THE LNG AND POWER PERSPECTIVES

We have already demonstrated the financial impact of not having a flexible power supply on the system but what we haven’t yet considered yet is the cost of achieving that flexibility from the LNG supply perspective. In this section, we assess the impact of integrating an inflexible (Option A) and flexible (Option B) LNG supply by varying the delivered LNG price and imposing specific contractual obligations onto the LNG supply. We then review the system impact to see whether this ‘cost of LNG supply flexibility’ has a material impact on whether the gas plants should be operated in a different manner or not.

1. GAS POWER LOAD FACTORS

After imposing the LNG GSA constraints, one would anticipate there to be variations in how the gas plant is dispatched when compared to our initial calculations as depicted in Figure 9. Comparisons in plant load factors between our initial calculation (which assumes LNG is flexible and priced at 12USD/GJ) and scenarios with Option’s A and B GSA’s are shown in Figure 12.

![Gas Plant Energy Load Factors with GSA constraints](image)

Figure 12: Imposing the take-or-pay constraints causes the plant to be dispatched at a constant load factor but a premium placed on a flexible LNG supply will have no effect on the plant dispatch.

Observing the Option A GSA (i.e. fixed 3Mtpa take-or-pay), we notice a fairly constant load factor of approximately 64-67%. However, as this is a lower than the 3 Mtpa capacity to supply a 75% load factor, we find that approximately 15% of the LNG delivered is not consumed but yet is still paid for from the take-or-pay obligations. This means that even if the gas power is not required by the system, it is still optimal to not dispatch the power plant and incur the heavy take-or-pay penalties.

If we now consider the Option B GSA and compare that to our original simulation, the only difference between them being the gas prices of 12 USD/GJ and 15 USD/GJ, we see absolutely no difference in how the system dispatches the plants. This finding reflect the fact that the merit order of gas power (as discussed in 3.1 ENERGY REQUIREMENTS) will not change even with large variations in the LNG price.

2. TOTAL SYSTEM COST IMPACT

Now with the understanding of how the plant is dispatched under the Option A and Option B GSA’s, we now take a look at how the system cost varies between these two options when compared against the option of having no gas at all in the power system. Figure 13 shows the total system cost differentials between these three scenarios.
As one can observe from the graph, even after applying a heavy premium for flexibility on the gas supply, the ability to provide flexible power still generates overall system savings every year. In the earlier years of 2020-2022, where the plant load factors are relatively closely aligned (67% and 62%), there is a small system saving incurred. However, as the system requests a lower load factor from the gas plants, then we see large system cost differences as the system is now forced to pay for gas energy that is not necessarily needed. It is also interesting to note that for the years 2025 and 2029, there is actually no benefit of having the inflexible gas solution in place at all!

Over the ten year period, the total savings between the two GSA options amounts to **4.7 billion USD**.

Based on this result, a reasonable question which may then be asked is “at what LNG price will it make sense to have a fixed LNG supply whilst still achieving a total system benefit?” The answer is easily tested for in the model which reveals that unless the delivered LNG price can be less than 7 USD/GJ, it will continue to generate similar results as shown in our analysis. This is of course a simplistic answer which doesn’t consider indices and exchange rate risks which are major challenges LNG supply contracting.

**Key takeaways:**

- *Increases in LNG price for flexibility has no effect on the dispatch of the plant.*
- *The system cost savings from having flexible power outweigh the premiums one has for having a flexible LNG GSA.*
7. CONCLUSION

Using rigorous analysis and complex system modelling software, this paper reveals what the true operational requirements are for SA’s future gas to power opportunities. It is shown that a 3 GW LNG power plant is able to generate high system cost savings through the provision of regulating reserves and the ability to provide a varying annual load factor according to the system’s requirements. Combined cycle reciprocating engine technology (Wärtsilä Flexicycle) is ideally suited to satisfying these requirements due to their high efficiencies and fast operational capabilities. These capabilities enable these plants to provide regulating reserves, as defined in the SA Grid Code, from a non-spinning state which results in significant system savings through improved system optimisation. Main sources of system savings occur from being able to effectively displace diesel generation and optimise the coal based capacity by reducing the burden of operating in a flexible manner.

In order to reflect the LNG GSA limitations, two possible GSA structures were proposed for integration into the model to represent flexible or inflexible options. The inflexible GSA was for 3 Mtpa with a 100% take-or-pay obligation and priced at 10USD/GJ whilst the flexible GSA had no volume limitations but was priced at 15USD/GJ. Despite the addition of this conservative GSA flexibility premium, it is shown that the system level benefits of having a flexible solution still outweigh the project level costs savings from having a cost optimised GSA. The total ten year system savings by having the flexible solution amounts to 4.7 billion USD.

Whilst it is arguable that this modelling is based on an outdated IRP, the principles still apply and the messages remain the same. In fact, given that it is virtually impossible to predict what the system demand/supply requirements will be in the future makes it even more important to adopt flexible solutions to accommodate the uncertainty. Even if this means accepting the associated flexibility premiums at the sacrifice of not having an optimised project cost solution in place. In conclusion, the LNG power project is there to support the power system and hence it is the power systems’ requirements which take precedence over project considerations.

Recommendations from this paper are that future gas-to-power IPP programmes should include the following:

- Power Plant flexibility should form part of the evaluation criteria;
- Flexible LNG contracting options should be recognized and appropriately valued in the future gas to power programmes.
Bibliography


