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HOT AIR ABOUT GAS

An Economic Analysis of the Scope and Role for Gas-Fired Power Generation in South Africa

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All errors remain those of the authors.

EXECUTIVE SUMMARY

Large-scale gas use for power generation appears to be central to current energy policy direction in South Africa, but this rests on a 2012 vision which pre-dates dramatic reductions in renewable energy costs and carbon emissions space. The only economically rational role for gas in power generation for the foreseeable future is now as a fuel for peaking plants – a small, intermittent but crucial role currently provided by diesel. Liquefied Natural Gas (LNG) can replace diesel for some of the fuel requirement at some of the peaking plant sites, but due to practical, contractual and security of supply reasons can only supply around half of the 25 PJ/a-40 PJ/a peaking fuel required by 2030. Embarking on a large-scale gas-to-power strategy given these realities creates significant economic and environmental risk.

South Africa's Gas Master Plan (GMP)[1] relies heavily on the prospect of gas-to-power projects providing 'anchor' demand to feasibly grow the domestic gas market[2]. The GMP is based on the vision of the National Planning Commission's 2012 National Development Plan (NDP)[3], which sees gas as a clean, viable replacement for coal in power generation. However, the ten years since the NDP was published have seen unprecedented changes in both the cost of clean energy alternatives, and the global decarbonisation imperative. In 2012 power from wind and solar generators was 50% more expensive than large-scale power generated from gas, but by 2021 the economics had flipped completely with gas power now almost treble the cost of renewable energy. Additionally, in the ten years since 2012, South Africa's remaining carbon emissions space has halved. Not only has emission free power generation become the cheapest, but use of any fossil fuel technology now brings penalties into the future. Energy policy and planning that does not integrate these new economic and environmental realities will fill the power system with stranded assets and create climate risk for all electricity users.

Independent analysis of the power sector across multiple recent studies shows that South Africa's power needs can be met both now and in the future with very little use of gas. All studies show that the overwhelming majority of new generation capacity should be wind and solar, with an increasing requirement for flexible (dispatchable) capacity to support this. There is no evidence to support the large-scale gas envisaged in the GMP; this is uneconomical even before carbon emissions are considered.

The flexible capacity required consists of turbine machinery or reciprocating engines and could run on a variety of fuels such as diesel, gas or other combustible substances. Whilst significant flexible capacity is required (3 GW existing + 5 GW new by 2030), all modelling shows that its role is a standby or peaking function. This role sees the generators stand idle for most of the time (Capacity Factors[4] of 3% to 5%), requiring relatively little fuel over the course of a year (25 PJ/a – 40 PJ/a by 2030). The existing 3 GW peaking capacity uses diesel which could also be used to fuel all new capacity, however diesel is expensive with high carbon emissions (only 15% lower than coal-fired power). The opportunity for gas in power

[1] *Published in December 2021*

[2] *DMRE, 2021. South African Gas Master Plan: Basecase Report. Department of Mineral Resources and Energy.*

[3] *National Planning Commission, 2012. Our Future: Make it Work. National Development Plan, 2030. National Planning Commission, Pretoria.*

[4] *A measure of how often a plant is generating power over a specific period of time.*

generation is thus as a fuel for low-utilisation flexible capacity, in situations where it can displace diesel at a lower cost and with lower or comparable emissions.

With the question of gas in the power sector refined, we evaluated the economic and environmental case for LNG to replace diesel as the fuel for both existing and new peaking capacity, focusing on the current decade and imminent decisions on LNG infrastructure.

Use of LNG requires some form of terminal infrastructure to receive parcels of gas from ships on a regular basis. Whether land-based or floating (FSRU[5]), leased or purchased, the provision of this infrastructure carries a large annual fixed cost component – thus viability of LNG is heavily dependent on annual volume throughput at each terminal. LNG as a power fuel solution is therefore suited to fuel generation plant that runs most of the time, at high Capacity Factors (50%+) consuming large quantities of gas with a steady, predictable offtake pattern – exactly the type of generation role that modelling studies show is not economical in the South African power system. When the fixed costs are borne by limited volumes as are associated with the peaking plant role required by the South African power sector, LNG becomes uncompetitive with diesel. It is only if non-power demand (i.e. synfuels or other industrial volumes) through the same FSRU can provide sufficient additional offtake that LNG becomes a serious economic alternative to diesel.

However, some practical issues also reduce the scope for LNG to replace diesel as a peaking fuel. Existing peaking plant is scattered across the country at four separate locations, and new peaking capacity will likely be located at a fifth or sixth location. The gas volume required at different sites cannot be aggregated and supplied through the same FSRU economically, as this would require some form of more expensive containerised secondary distribution that would threaten any saving against diesel. Realistic scope for peaking plant to use LNG is thus predominantly for new capacity only, sited at Richards Bay or possibly inland at Komati or other old coal power stations[6]. These sites appear to provide the earliest opportunity for non-power users to provide the necessary 'anchor demand' to render LNG viable for peaking. Until then, new peaking plant at these sites would be more economically fuelled by diesel.

Once sufficient non-power demand exists for LNG to compete with diesel at any site, LNG could provide some but not all of the peaking power requirement. Peaking plant fuel offtake is both variable and unpredictable and increasingly will be characterised by long periods of minimal or zero usage as renewables and battery storage provide for daily demand cycles. LNG contract norms require predictable, steady offtake fed by scheduled replenishment vessels with take-or-pay terms. Erratic usage as characterised by peaking plant needs is fundamentally incompatible with these norms, requiring LNG usage to be limited to what will definitely be needed between replenishment cycles, with the balance of generation done by diesel.

We thus estimate the opportunity for LNG to replace diesel to be in the range of 11 PJ/a – 18 PJ/a by 2030, but only if non-power demand at each site is sufficient to materially defray the FSRU cost. Without 'anchor

[5] *Floating Storage and Re-gasification Unit*

[6] *Peaking plant located at Richards Bay will become viably fuelled by LNG once all inland customers of the Lilly line convert to LNG supply, as may happen later this decade. This would also allow for LNG use at the existing Avon peaking facility based on its proximity to the Lilly line. Viability of LNG-fuelled peaking plant at "re-powered" coal stations inland will need to wait for significant non-power demand to be supplied via the ROMPCO line.*

demand' from non-power sectors there appears to be no economic case for replacing diesel with LNG as a peaking fuel.

What if the current trajectory of energy policy and planning remains unchanged using high-volume gas-to-power projects to create anchor demand for gas in other sectors? Given that the most economic use of gas in power is at much lower volumes, forcing high-use gas into the power generation mix will merely increase the cost and emissions from power generation. Our calculations place this cost premium at 40% or more compared to the alternative combination of peaking plant and renewables, with seven-fold higher carbon emissions for the same power generation, whilst greatly exposing electricity pricing to volatility in global fuel and currency markets. Accounting for planned revisions to the domestic carbon tax, the cost premium will rise above 60% by 2030. Impending international border tax adjustments and other measures implemented will see all exports from South Africa penalised by the higher emissions.

With no economic rationale for large-scale gas use in power, following such a strategy would deliver assets that are stranded before their first kWh of power is generated. Our analysis finds that the economic role of gas in the South African power sector is small and its viability depends on 'anchor demand' from other sectors. We therefore strongly recommend a re-assessment of what appears to be the current energy policy direction before committing to any use of gas in the power sector at all.

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LIST OF ABBREVIATIONS

a	Annum
BW	Bid Window
CCGT	Combined Cycle Gas Turbine
CF	Capacity Factor
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CSIR	Centre for Scientific and Industrial Research
d	day
DFFE	Department of Forestry, Fisheries and the Environment
DMRE	Department of Mineral Resources and Energy
EPC	Engineering Procurement and Construction
FSRU	Floating Storage and Re-gasification Unit
GHG	Greenhouse Gases
GJ	Gigajoule
GMP	Gas Master Plan
Gt	Gigatonnes
GWh	Gigawatt-hour
GWP	Global Warming Potential
HHV	Higher Heating Value
IEA	International Energy Agency
ICE	Internal Combustion Engine
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated Resource Plan
kj	Kilojoule
kWh	Kilowatt-hour
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
m	Million (currency)
Ml	Million litres
MMBtu	Metric Million British Thermal Unit
Mscf	Million Standard Cubic Feet

Mt	Megatonnes
NDC	Nationally Determined Contribution
NDP	National Development Plan
NERSA	National Energy Regulator of South Africa
OCGT	Open Cycle Gas Turbine
PJ	Petajoule
t	Tonne
TWh	Terrawatt-hour
RE	Renewable Energy
REIPPPP	Renewable Energy Independent Power Producer Procurement Programme
RMIPPPP	Risk Mitigation Independent Power Producer Procurement Programme
USD	United States Dollar
ZAR	South African Rands

1 INTRODUCTION: A CONTESTED GAS PLANNING SPACE

Gas infrastructure investment has become a central topic in South Africa's energy, climate and industrial policy discourse. The role of gas as a 'transition fuel' has gained salience in the context of the South African Government's decarbonisation and just transition commitments[7], which require a phase down of the existing coal fleet whilst ensuring adequate and reliable power supply. South Africa's emergency power procurement process[8], intended as a policy response to mitigate the country's acute power shortages, saw the lion's share of capacity awarded to gas-to-power projects. These developments have all escalated the debate around gas use, required infrastructure investments and the economic benefits and risks associated with developing a large gas industry in South Africa.

The Department of Mineral Resources and Energy (DMRE) has recently published a draft version of South Africa's Gas Master Plan (GMP) [9] – proposed as the guiding policy instrument and roadmap for the development of South Africa's natural gas industry. The GMP's Base Case scenario relies heavily on the prospect of gas-to-power projects providing 'anchor' demand to feasibly grow the domestic gas market [1]. A significant gas-to-power strategy would indeed provide this anchor gas demand for the country, allowing development of infrastructure that would otherwise be cost-prohibitive based on non-power demand alone. However, underlying this approach is a foregone conclusion that generating significant quantities of electricity from gas would be an economically rational decision for the power sector, and thus for the country as a whole – but is this really the case?

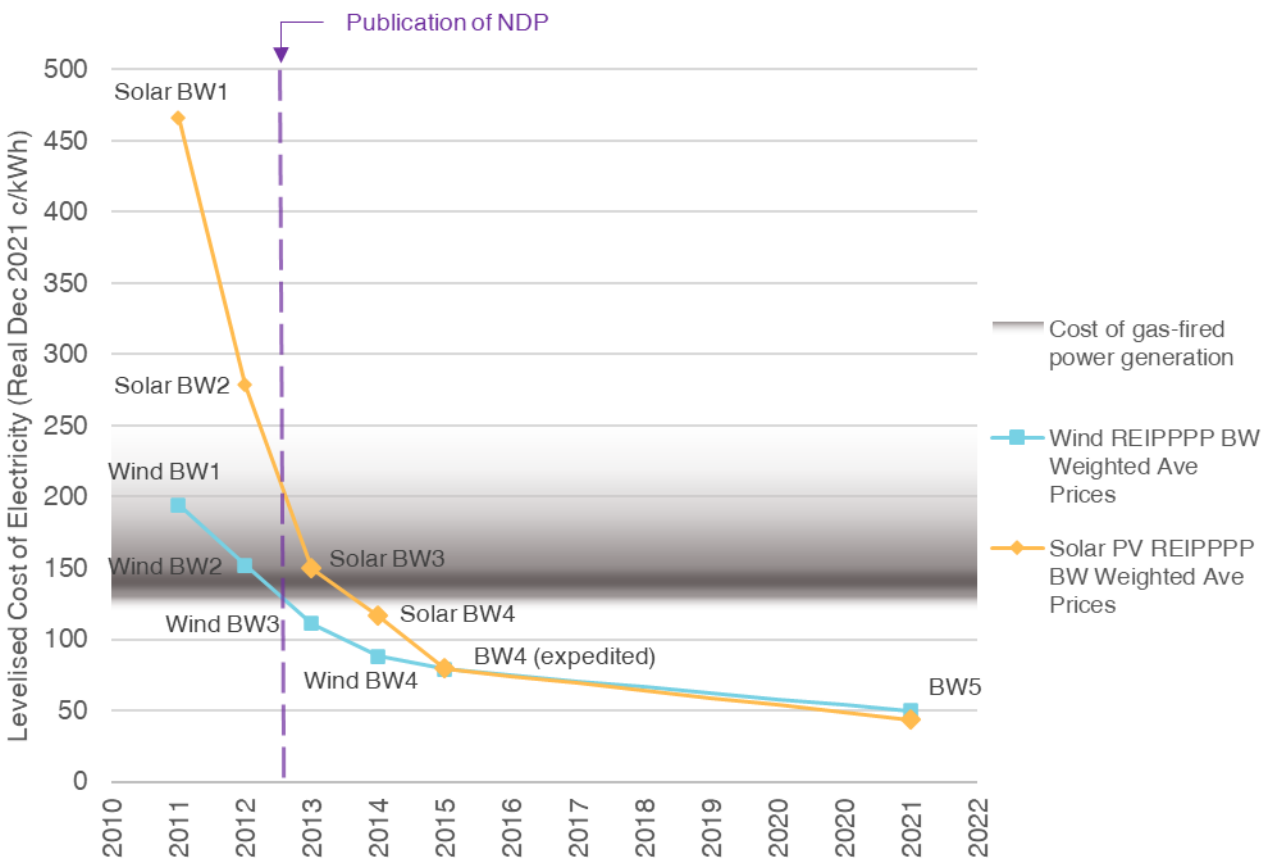
The GMP is based on the vision of the National Planning Commission's 2012 National Development Plan (NDP) [2], which promotes gas as a viable alternative to coal. However, the ten years since the NDP was published have seen unprecedented changes in both the cost of clean energy alternatives, and the global decarbonisation imperative. These changes undermine the relevance of a comparison between gas and coal as future energy sources – the pressure to reduce emissions has increased dramatically, matched only by significant cost reductions in zero emission power generation technologies. The assumption that gas-fired power generation would replace coal ignores the fact that other technology combinations are now better at replacing coal-fired power than gas, and it is against these technologies that gas-fired generation should *actually* be compared.

[7] *These include the establishment of the Presidential Climate Commission in December 2020, a statuatory multistakeholder body tasked with coordinating South Africa's climate action efforts; the announcement of South Africa's updated Nationally Determined Contribution (NDC) economy-wide carbon emissions targets in September 2021, which have been deemed commensurate with a 'fair' contribution to the Paris goal of limiting warming to 1.5 degrees; and the establishment of the Just Energy Transition Partnership – a partnership between the SA government and a group of developed country governments – which includes a substantial financing package being made available to assist SA in its transition efforts.*

[8] *South Africa's Risk Mitigation Independent Power Producer Procurement Programme (RMIPPPP)*

[9] *Published in December 2021*

Figure 1: Dramatic changes in the cost of renewable power generation since publication of the NDP in 2012



In 2012, when the NDP was published, the cost of renewable generation was wholly uncompetitive with gas – large scale gas-powered generation could conceivably deliver power at close to R1.40/kWh[10], whilst wind and solar power were procured in the same year at R1.50/kWh[11] and R2.80/kWh[12] respectively – on average costing 50% more than gas-fired power [3]. By 2021, as illustrated in Figure 1, both wind and solar prices had plunged dramatically to below 50c/kWh[13]. Whilst a direct comparison of prices per kWh is potentially misleading given the different roles played in power generation by solar, wind and gas, the disruptive cost decline of renewables has forever changed the make-up of future-oriented power systems. The lowest emission technologies are now also the lowest cost technologies – there is no longer a cost trade-off required to achieve emission reductions for new generation in the power sector.

In tandem with the drop in cost of renewable energy has been the narrowing of the remaining carbon space into which South Africa can emit. The benchmark trajectory range that flowed from the NDP was characterised by an assumed peak-plateau-decline in the country's acceptable emissions band. This implied that although emissions would need to be lower in 2050, the upper bound of the range would still allow for

[10] *See technology and cost assumptions for CCGT in section 8.1. The range of the cost of gas-fired generation in Figure 1 (grey smudge) is constructed based on the history of gas fuel prices as if they were to be used to fuel the CCGT plant. [4]*

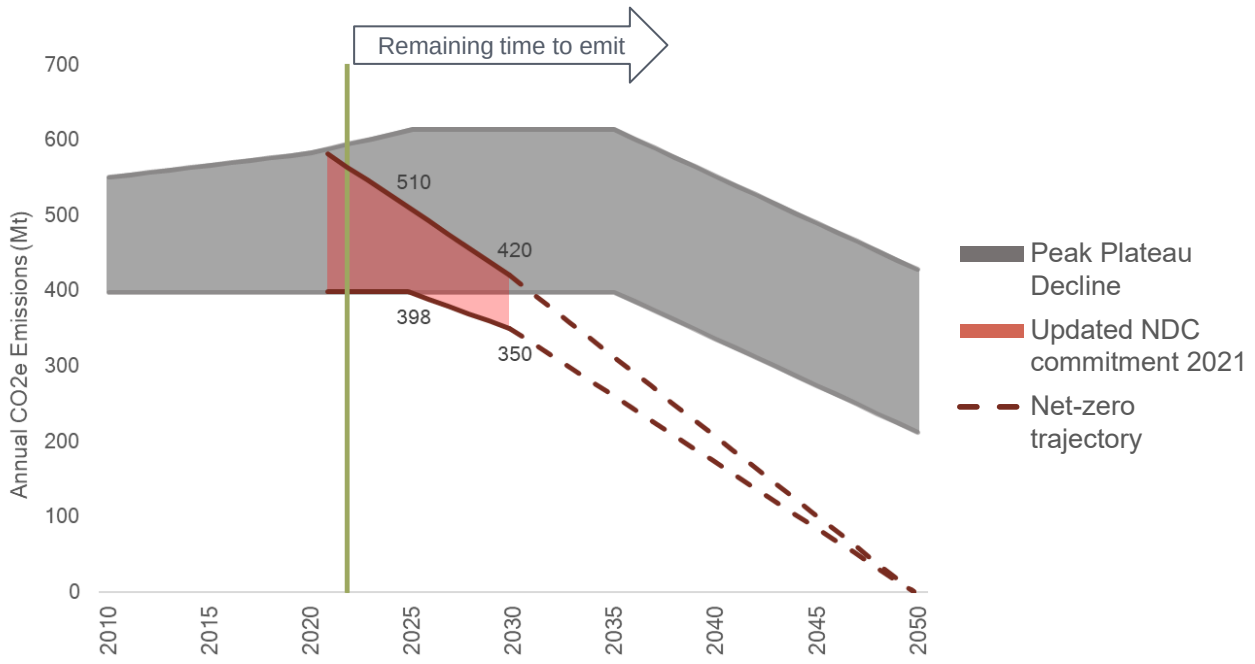
[11] *BW2 wind in 2021 Rands*

[12] *BW2 solar in 2021 Rands*

[13] *Although BW5 is yet to reach financial close, all winning solar bids were below 50 c/kWh as well as more than half of the winning wind capacity bid.*

emissions not much lower than those seen in the recent past (2017: 482 Mt). This reality has vanished, with a clear imperative now that it is insufficient to merely reduce emissions but that at some date around mid-century we will need to effectively halt emissions altogether. South Africa's recent commitments under the NDC process [5] and net zero aspirations set it on a path to eliminating emissions by 2050 resulting in a finite carbon space – the upper bound of this finite space is now 50% lower than the upper bound of the range envisaged as acceptable at the time the NDP was drafted. Serious tangible economic consequences now attend the prospect of an emission trajectory that does not comply with the recent commitments, in the form of carbon border tax adjustments and other measures that at best would render South African exports uncompetitive. At worst, ignoring the new carbon space reality will result in the economic stranding of entire sectors of the economy.

Figure 2: Reduction in remaining available carbon space since publication of the NDP in 2012



The paradigm-changing developments in both cost and carbon space have all played out in the last decade – i.e. since the NDP was published in 2012. Any policy that is based on the outlook of the NDP for the power sector is necessarily stuck in the world as it was known in 2012 – a world that no longer exists. In the current reality on both economic and environmental grounds, it is no wonder that all power sector modelling demonstrates that for the foreseeable future the power sector must develop by the deployment of as much renewable generation as possible. Fossil fuel generation, especially new capacity is necessarily kept to the minimum required to retain security of supply to allow for the needed decarbonisation (see section 2.3). It is within this new context that gas must earn its role in the power sector of the future, with of course the additional considerations of the prospects for domestic job creation, value chain localisation and consequent overall contribution to economic growth.

Box 1: Existing analysis on the potential role of gas in the South African Power Sector

Following the publication of the draft GMP, two key pieces of analysis have been released exploring the potential role of gas in the South African power sector. The National Business Initiative's (NBI) analysis[14] on the role of gas in South Africa's path to net zero concludes that gas can, if affordably supplied, play a key role as a 'transition fuel' to replace more emissions-intensive fossil fuels like coal and diesel, and that gas-to-power peaking plants can serve as a demand anchor for the South African gas industry if strategically located. Given escalating concerns around the climate crisis and pressure to achieve net zero, the study highlights that new gas investments should consider the future repurposing of assets for the usage of green fuels (e.g. green hydrogen) to avoid stranding risk. On the other hand, the International Institute for Sustainable Development's (IISD) study[15] 'exploring the case for gas-fired power in South Africa' concludes that there is not enough evidence to make new investment in any type of gas-to-power plants now, given the rapid cost declines and improvements in alternative technological options and the risks associated with gas investments.

The analysis in this report is guided by three main questions:

1. **Is there a role for gas in the South African power sector?** If we are looking to consider the deployment of power generation technologies that could be fuelled by gas, the logical point of departure must be to understand the requirements and needs of the power sector (not the needs of the gas sector).
2. **If there is evidence that gas may play a role in SA's power sector – what does this look like?** If power system modelling studies do indeed conclude that there is a role for power generation technologies that could be fuelled by gas, we need to investigate the economically rational way of supplying the fuel required.
3. **What are the risks of diverting from this role?** If the optimal role for gas is small and does not render the power sector as an 'anchor' for gas demand – what might be the risks of investing in and committing to large-scale 'anchor' type gas usage anyway?

The report begins in section 2 with a summary of what recent power system modelling studies suggest about the types of generation technologies required for the optimal future development of South Africa's power system and by when – with common findings that large quantities of renewable energy plus an increase in flexible dispatchable capacity will be necessary. In section 3, recognising that the new flexible dispatchable capacity required could be fuelled by gas – we identify the type and scope of the role that gas could play, considering fuel price, contracting practicalities, logistical issues and emissions intensity compared to the use of other fuels such as diesel. In section 4 we investigate what the risks are of diverting from the optimal role for gas defined in section 3. We interrogate the implications of committing to

[14] *NBI, 2022. "The role of gas in South Africa's path to zero. Just Transition and Climate Pathways Study for South Africa", National Business Initiative. [6]*

[15] *IISD, 2022. "Gas Pressure: Exploring the case for gas-fired power in South Africa". [7]*

"big gas"[16] in line with the GMP assumption that there is a case for anchor demand in power – including economic and environmental implications. In section 5 we use the evidence presented in the report to debunk some key prevailing myths in the narrative around gas in South Africa. Section 6 contains the conclusions and recommended next steps for gas-decision-making in the context of South Africa's power sector.

[16] *"Big Gas" in the context of this report refers to the use of gas in the power sector beyond a minimal role to provide standby/peaking power – i.e. the use of gas generators operating at Capacity Factors of 50%-55% or higher compared to 5% or lower (these roles are explained in more detail in section 2.1).*

2 NEEDS OF OUR POWER SYSTEM - WHERE COULD GAS FIT IN?

The starting point for this analysis is to investigate the results of recent South African power system modelling studies to determine what types of generation technologies are required and by when. Based on these learnings, we identify the type and scope of the role that can feasibly be played by gas in the power sector – in other words, which of these required technologies could be fuelled by gas. Section 2.1 introduces the terminology relied upon for this section.

2.1 FUNCTIONS OF DIFFERENT POWER GENERATION PLANT

Different types of generation plant have different functions and attributes which are available to the power system. It is the role of the system operator to ensure that the suite of plants is utilised to ensure secure and economically optimal power supply.

Generation plant can be described as being **dispatchable** or **non-dispatchable**. "Dispatchable" generation plant can be switched on and off (and turned up and down) by the system operator to balance supply and demand, whilst "non-dispatchable" generation increases and decreases due to exogenous factors (e.g. variations in the wind or solar resource) [8].

The **Capacity Factor** of a plant is a measure of how often a plant is generating power over a specific period of time (the number of hours in a year, for example). The Capacity Factor is expressed as a percentage and is calculated by taking the actual power produced over a period and dividing it by the theoretical power output of the plant were it to be running constantly during that period.

Dispatchable generating capacity is conventionally classified into three main functional categories: peaking capacity, mid-merit capacity and base supply (commonly termed 'baseload' in the South African discourse)[17]. A power system can include plant that is run most of the time (i.e. at high Capacity Factors greater than 50%), and those that hardly ever run (low Capacity Factors of 5% or less) but are critical to maintaining security of supply for infrequent moments of supply-demand gaps, usually caused by loss of supply from other generation plant in the system. The utilisation rates of dispatchable plant can vary according to the needs of the system.

Dispatchable plant can also be described in terms of their flexibility. **Flexibility** refers to how quickly, easily and economically dispatchable plant can be brought online or ramped up or down to provide power to the system. There is a continuum of flexibility – peaking plant are more flexible than mid-merit, which are in turn more flexible than base supply plant.

Natural gas is used in power systems to fire dispatchable plant – typically mid-merit or peaking-type plants – with a variety of flexibility characteristics (see Box 2 below). Whilst these plants are identified as 'gas' turbines or engines, they do not have to run on natural gas. They can run on many types of liquid fuels and or gases – including green hydrogen in the future. Therefore, to establish whether there is a role for natural gas in the South African power system, we first have to understand the requirement for flexible dispatchable generation plant, and from there, whether natural gas is the optimal fuel to fire this plant, and at what volumes (which relates to the plant's Capacity Factor – i.e. how frequently the plant is utilised by the system).

[17] *See Appendix 8.2 for further elaboration of these categories*

Box 2: Flexible dispatchable power generators that can be fired by natural gas

Open Cycle Gas Turbines are fast-acting combustion turbines that compress air and heat it using gaseous fuel, and then run the expanding air through a generator rotor to produce electricity [5]. OCGTs can provide power to the grid quickly (within 5-12min) and are therefore one of the main sources of flexible peaking power on grids across the world [6]–[8]. The term 'gas' in OCGT does not mean these plants are limited to being fired by gas, they can be fired by a variety of fuels including diesel and green hydrogen. South Africa has six OCGTs including Acacia, Ankerlig, Gourikwa, Port Rex, Dedisa and Avon – with a cumulative capacity of ~3.8 GW [9]. All OCGTs are currently fired by diesel but Eskom has signalled their intent to convert some of the fleet to run off gas for cost-optimisation reasons [10].

Internal Combustion Engines are fast-acting engines that involve the burning of fuel in a combustion chamber and expansion of hot gas to push a piston in a cylinder, which in turn rotates a crankshaft to generate power. ICEs can provide power to the grid even more rapidly than OCGTs (with a start-up time of 3-10min) and are typically used for backup, standby, or emergency power [6], [7]. They tend to be smaller in size and therefore can be added more incrementally than OCGTs.

OCGTs and ICEs are the most flexible type of dispatchable generators and perform very similar functions within a power system. The uptake of such technologies is increasing for larger utility-scale power generation applications, especially in areas with high levels of electricity generation from intermittent sources [11].

Combined Cycle Gas Turbines are similar to OCGTs but have a secondary cycle, where exhaust heat from the initial combustion process is utilised to make steam that is run through another rotor to generate additional electricity [12]. CCGTs are more complex than OCGTs and therefore more expensive to build but are more efficient as they allow for more electricity to be produced for the same amount of fuel. CCGTs have a longer start up time than OCGTs (90-240min) and are therefore less flexible. They are generally used to provide mid-merit capacity in power systems [6].

2.2 THE RELEVANCE OF THE EXISTING PORTFOLIO OF GENERATION ASSETS

What does an optimal future South African power system look like? This is a classic techno-economics question and is solved through well-established practices of power system modelling. The question is complex and involves understanding the current generation resources available on the grid, the remaining lives of this equipment, the cost and performance characteristics of new replacement generation technologies, and the expected growth in demand. Determination of the optimal build plan for new power generation capacity integrates lowest cost, system adequacy[18], and emissions limitations – the latter increasingly important as we transition to a low carbon future and a world of net zero emissions.

One question that modellers have to grapple with is the timeframe to use for analysis. Power systems include assets with long lifetimes – of fifty years and beyond in some cases. In addition, the decarbonisation imperative is considered in timeframes of thirty to forty years into the future. However, we live in a world of increasing uncertainty, and in a period of disruptive change in the global power sector. We therefore in reality have very little foresight beyond the next five to ten years (see Box 3 for a discussion on this and some of the benefits of technologies that allow for incremental decision-making). Taking these factors into consideration, whilst most of the modelling exercises we refer to in our evidence base have timeframes to 2050, we focus very closely in this report on the current decade to 2030 and decisions required during this period.

Each country's power system is unique and making optimal decisions about its future is influenced by historic path dependence – decisions based on technology options that were available at the time (leading to the current state of the system) as well as future available technologies.

Technology availability has significant impact on the shape of different countries' power systems – the United Kingdom (UK) for example was predominantly powered by coal until the advent of cheaper, cleaner gas from the North Sea in the early nineties resulting in a dash to replace coal with gas. The UK did not move away from coal because the coal ran out, coal was simply superseded by a better cheaper way of generating power – gas was an economically rational choice at the time. The North Sea now provides the UK with an increasing supply of wind power. Roughly 80% of its total power as of 2021 comes from wind and gas in almost equal measure [9] – but little from solar for obvious reasons. In South Africa, by contrast we are still heavily reliant on coal (81% of generation[10]) as this was until recently the cheapest available energy source, but we have some of the best untapped resources for both wind and solar generation in the world.

The important point is that new generation capacity comes into an existing portfolio of generation assets unique to the historic and geographical context of the country – the existing assets continue to provide power until they are retired, as new assets are added. In the South African context, despite the retirement of many coal generation assets over the next ten years anticipated in the current Integrated Resource Plan (IRP 2019) (~10.5 GW, 18% of coal power to be decommissioned by 2030 [11]), a significant

[18] *An "adequate" power system is essentially one that has no load shedding – being able to meet demand in every hour of the year.*

but diminishing coal generation capacity will remain available during this period. This is a very different conceptual prospect to the greenfields build of an entire new power sector.

2.3 COMMON FINDINGS FROM RECENT STUDIES OF THE SOUTH AFRICAN POWER SYSTEM

Our analysis in this report draws on a number of recent independent system modelling studies of the South African power system.[19,20,21,22] Further details on these studies can be found in section 8.3 of the Appendix. Despite the use of different modelling platforms, assumptions and conceptual approaches, the results of these studies reveal significant common findings that should guide economically rational choices for new generation capacity:

- The bulk of new build generation capacity should be wind and solar PV, with significant requirements for immediate increase in the contribution from these technologies. Although not dispatchable, the energy generated from wind and solar resources is now by far the cheapest of all technologies – so much so that it makes economic sense to build much more capacity than would be required on an average resource day, ensuring sufficient generation on low resource days. Wind and solar generation capacity provides the overwhelming majority of the energy requirements of new generation on the power system in all studies.
- Some quantity of new-build battery storage capacity is common to all modelling results. Although still relatively expensive, battery storage costs are falling rapidly – faster than the revisions to modelling efforts can adjust.
- No new coal or nuclear capacity should be built under any optimal development pathways – these technologies have been superseded on both economic and environmental considerations. Even under highly constrained emissions scenarios which would favour nuclear power, nuclear remains more expensive and less attractive from an emissions perspective than a combination of renewables and flexible dispatchable capacity (even if the latter uses fossil fuels) and is not recognised as being viable.
- For at least the next fifteen years, until the bulk of the coal is off the system, gas-to-power plants are not chosen by the power system models to generate significant quantities of energy (i.e. to perform the function of mid-merit or base supply).
- There is an increased requirement for flexible, dispatchable capacity to cater for short-term differences in power supply and demand as the penetration of wind and solar technologies increases. Gas could play a role in fuelling flexible generation plant and therefore this becomes the subject of the remainder of this section (section 2.3.1- 2.4).

[19] *Meridian Economics-CSIR, 2020. "A Vital Ambition: Determining the cost of additional CO_2 mitigation in the South African power sector." [12]*

[20] *Marquard, A., Merven, B., Hartley, F., McCall, B., Ahjum, F., Hughes, A., Blottnitz, H.V., Winkler, H., Stevens, L., Cohen, B., 2021. "South Africa's NDC targets for 2025 and 2030 – further analysis to support the consideration of more ambitious NDC targets." [13]*

[21] *National Business Initiative, 2021. "Decarbonising South Africa's power system," and NBI, 2022. "The Role of Gas in South Africa's Path to Zero." [6]*

[22] *Clark, S, 2020. "The Use of Natural Gas to Facilitate the Transition to Renewable Electric Power Generation in South Africa." Stellenbosch University PhD Thesis. ** Due to the specific focus of this study on the requirement for dispatchable generation, we draw on it predominantly for section 2.3.1 onwards. [14]*

2.3.1 All scenarios require an increase in flexible, dispatchable capacity

In the medium (5-10 years) and longer term, substantial new flexible dispatchable generation capacity will be required in the form of Open Cycle Gas Turbine (OCGT), Combined Cycle Gas Turbine (CCGT) or Internal Combustion Engine (ICE) generators. This need is primarily driven by the increase in the non-dispatchable wind and solar capacity that will need to come online during this period. Estimates of the new flexible, dispatchable generation capacity required by 2030 vary across studies from 3.08 GW to 7.27 GW depending on different economic scenarios, but 5 GW is a reasonable central assumption.

Studies show that the installation of battery storage reduces the need for flexible dispatchable generation in the form of turbines or engines to balance the system – but that this mainly reduces the *energy* generated by the dispatchable plant, not the required installed capacity (i.e. the plants are utilised even less, but are still required to be there on standby should the need arise). Table 1 below compares particular scenarios from the modelling studies examined (see section 8.3 of the Appendix for a descriptor of each) in terms of the cumulative new flexible generation capacity required. The scenarios drawn from the different studies are all cost-optimised modelled pathways that include carbon constraints which limit total emissions to align with South Africa's decarbonisation imperatives.

Table 1: Cumulative new flexible dispatchable capacity (CCGT, OCGT and ICE) across different modelled scenarios (GW)

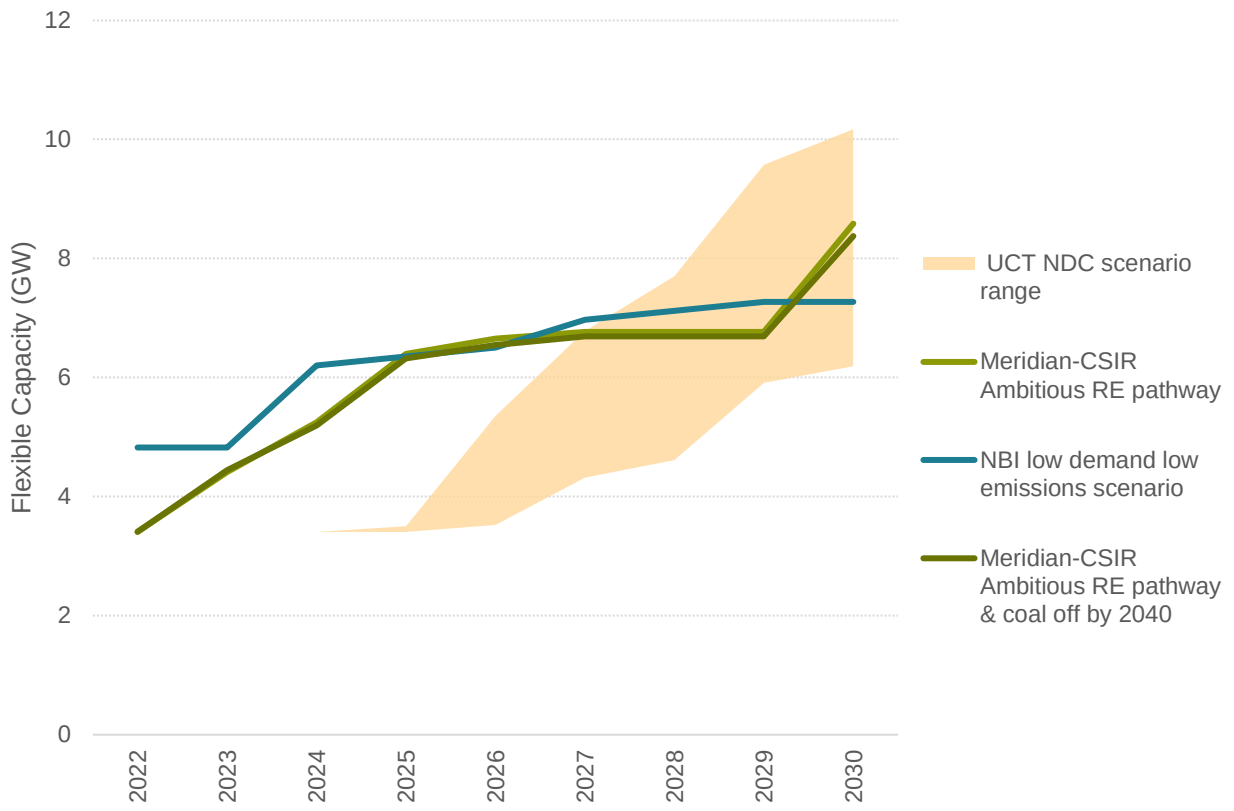
Cumulative New Flexible Dispatchable Capacity Built (GW)	2022	2023	2024	2025	2026	2027	2028	2029	2030
Meridian-CSIR Ambitious RE pathway	-	1.00	1.84	2.99	3.59	3.7	3.7	3.7	5.52
Meridian-CSIR Ambitious RE pathway & coal off by 2040	-	1.04	1.79	2.92	3.48	3.63	3.63	3.63	5.31
NBI low demand low emissions scenario	1.00	1.00	2.38	2.53	3.02	3.49	3.64	3.79	3.79
Minimum capacity in UCT scenarios within NDC Range	-	-	-	-	0.1	1.18	1.51	2.81	3.08
Maximum capacity in UCT scenarios within NDC Range	-	-	-	-	2.33	4.14	4.98	6.89	7.06

When added to existing flexible generation capacity, the resulting totals are given in the table below, and presented graphically in the figure thereafter.

Table 2: Total installed flexible dispatchable generation capacity (GW) in different modelled scenarios

Total Installed Flexible Dispatchable Capacity (GW)	2022	2023	2024	2025	2026	2027	2028	2029	2030
Meridian-CSIR Ambitious RE pathway	3.41	4.41	5.25	6.39	6.65	6.77	6.77	6.77	8.58
Meridian-CSIR Ambitious RE pathway & coal off by 2040	3.41	4.44	5.19	6.32	6.55	6.69	6.69	6.69	8.37
NBI low demand low emissions scenario	4.82	4.82	6.20	6.35	6.50	6.97	7.12	7.27	7.27
Minimum cap in UCT scenarios within NDC Range	3.41	3.41	3.41	3.41	3.52	4.32	4.61	5.91	6.19
Maximum cap in UCT scenarios within NDC Range	3.41	3.41	3.41	3.50	5.36	6.78	7.70	9.57	10.17
Clark (2020)									5 - 15

Figure 3: Total installed flexible dispatchable generation capacity (GW) in different modelled scenarios



2.3.2 The flexible dispatchable capacity is seldom used, with corresponding low fuel offtake requirements

The major question upon which the entire gas debate hinges is then the optimal use of flexible, dispatchable generation capacity once it is built. In other words, should it be used in a standby or 'peaking' role to address short term, infrequent periods when demand exceeds supply from the rest of the generation portfolio, or should it be used in a

'base supply' or 'mid-merit' role to generate a significant portion of the power system's annual energy requirements?

Although the required increase in flexible dispatchable capacity is significant, an analysis of how often the capacity is utilised during the period to 2030 in the various simulations reveals unequivocally that its economically rational role is that of standby or peaking capacity[23]. This standby or peaking role requires that the capacity is available at all times, but actually used very little – with utilisation less than 5% and optimally less than 3% in most years. This is the same role that should be played by the existing 3.1 GW of OCGT capacity available to the South African power system (for details see Appendix 8.3), although its current use to prop up ailing coal plants in an energy-short power system results in Capacity Factors often above 10% (12% for 2021)[24]. It is vital to appreciate that the current utilisation of OCGT capacity is not reflective of the role it is designed to fulfil in a power system – for example a significant amount of OCGT-generated power is used to recharge the pumped storage facilities. This is a preposterous use of the most expensive generation capacity[25] but a situation that is unavoidable due to a lack of available energy on the system. Our recent publication on the causes of load shedding[26] demonstrates how the Capacity Factor of the OCGT plant will fall to levels well below 5% once sufficient wind and solar generation capacity is available.

The Capacity Factor at which the flexible generation plant runs is relevant in that it determines the quantity of fuel required. These factors are provided in Table 3 below.

Table 3: Optimal Capacity Factor for flexible generation across differing modelling studies

Flexible generation Capacity Factor	2022	2023	2024	2025	2026	2027	2028	2029	2030
Meridian-CSIR Ambitious RE pathway	1.5%	1.6%	1.6%	1.7%	1.8%	1.7%	2.9%	2.3%	2.2%
Meridian-CSIR Ambitious RE pathway & coal off by 2040	1.4%	1.6%	1.6%	1.7%	1.7%	1.7%	2.8%	2.2%	2.2%
NBI low demand low emissions scenario	7.3%	4.3%	2.4%	1.9%	1.6%	3.7%	3.2%	3.0%	1.8%
UCT scenarios within NDC Range	Minimum Capacity Factor set as modelling assumption and not optimised								
Clark									2 - 6%

[23] *Although some models include CCGT capacity, the Capacity Factors are such that the function is that of a peaking/standby role*

[24] *Based on Eskom data calculated for Meridian Economics, "Resolving The Power Crisis Part A: Insights From 2021 - SA's Worst Load Shedding Year So Far,"*

[25] *Not least because the 75% round-trip efficiency on the pumped storage means that the power when finally used is actually a third more expensive than the already high dispatch cost of the OCGTs. Power system storage is designed to be charged by the cheapest source of power at times when the power is generated but not immediately required.*

[26] *See Meridian Economics, 2022. "Resolving the Power Crisis Part A: Insights from 2021 – SA's Worst Load Shedding Year So Far."*

Whilst it might seem a waste of capital to pay for significant generation capacity to stand idle most of the time, this is precisely the role that OCGT and ICE[27] technologies are designed for, with relatively low capital costs and high dispatch cost driven by the fuel price. CCGT plant is typically only the economically rational choice for sustained Capacity Factors exceeding 20%.

Flexible dispatchable capacity that operates in a peaking role can be seen as a form of insurance against load shedding – it is only run as an expensive last resort for the short, intermittent periods when there is a supply shortfall, but this insurance is worth paying for as the cost of other sources of backup power or failure to meet demand is far higher.

For as long as significant coal capacity remains on the system (at least another ten years) fulfilling a mid-merit or base supply ('baseload') function, all modelling shows that it is not economic to generate a large amount of energy from turbines or engines using gas or other combustible fuel. By the time major coal capacity has closed in the mid/late 2030s there may well be storage or hydrogen solutions that have matured to a point that when combined with low-cost renewables render new fossil fuel capacity infeasible completely. However, if this is not the case and gas-fired CCGT capacity (run at higher Capacity Factors to serve a mid-merit type of role) is required to replace coal's role in the power system, the decision to build the CCGT capacity does not need to be made before 2030, given that short three year lead times would be involved (this is discussed further in Section 2.4 below).

The additional 5 GW of new peaking/standby capacity that is required by 2030 will generate about 2TWh of power per year when run as standby generation at a maximum 5% Capacity Factor, requiring about 20 – 25 PJ of fuel per annum depending on technology (ICE or OCGT). This would be in addition to the fuel required in 2030 to fire the existing peaking capacity of 3.1 GW at a 5% Capacity Factor – a further 15 PJ.

Therefore, the total fuel requirement for flexible generation will likely be a maximum of 40 PJ/annum (PJ/a) by the end of the decade assuming a 5% Capacity Factor although optimal use of the peaking plant would result in lower volumes of around 25 PJ/a (8 GW at 3% Capacity Factor). This assumes electricity demand recovers and grows from pre-Covid-19 levels and significant renewables rollout is implemented this decade to address and close the generation gap. For context, the 12% average Capacity Factor at which the existing fleet of diesel-fuelled peaking capacity was run in 2021 generated 3.2 TWh and consumed approximately 37 PJ (or ~950 Ml of diesel).

2.4 IF THERE IS A ROLE FOR GAS IN THE SOUTH AFRICAN POWER SECTOR IT IS SMALL

Based on the outcomes of key optimised system modelling studies, we can conclude that there is an increased requirement for additional flexible dispatchable capacity in South Africa's power system – some of which *could* be fuelled by gas. However, this capacity plays a peaking role and therefore is

[27] *As highlighted in Box 2, ICEs and OCGTs perform very similar functions in the power system. ICEs may be preferable to OCGTs as they operate well at altitude and the coast, they are more modular and can therefore be added incrementally and easily moved from one place to another, their operational efficiency is higher than that of OCGTs and they also have a greater operating range – i.e. they can meet requirements for peaking (high power output for short period) as well as more mid-merit type (medium output for longer period) requirements if needed, their ramp rates and start up times are higher and faster than that of OCGTs. The choice between OCGT and ICE will be specific to the duty cycle required and other site-specific issues. See recommendations in section 6.2.*

seldom run, meaning that the total fuel volume required is small and will be highly variable (there will be times of high need where all plant needs to run flat out for a few hours, but there will also be extended periods where plant will not need to run at all). Gas could potentially meet some of this fuel volume requirement – where it is the optimal economic and environmental choice. Quantifying this volume is the subject of the following section 3.

Box 3: What the common findings in section 2.3 imply for future power system planning

Taken together, the common findings presented in section 2.3 reveal characteristics of future South African power systems in terms of asset timeframes and lead times that have a number of important and fundamental implications for power system planning. Coal and existing proven nuclear technologies are no longer economically rational choices for new generation capacity in the South African context. Coal with yet-to-be-commercialised carbon capture technologies and new, unproven small modular reactor nuclear are insufficiently mature to be considered for the system planning task and until proven otherwise should be excluded from serious debate around the future of the power sector, certainly in the short-term.

Apart from the critical focus that this provides on the remaining available technologies, the removal of coal and nuclear from the technology basket allows for a fundamental improvement to the planning process – we are relieved of the requirement to make decades-long forecasts into a future which is unknowable. Both coal and nuclear suffer from exceptionally long lead times – in practice it can take at least a decade or more from award to commissioning[28]. Furthermore, coal and nuclear capacity are characterised by economies of scale that require large installations, with great chunks of generation capacity at risk during the construction period. Planning processes that contemplate coal and nuclear must necessarily rely on forecasts of demand and competing technology costs more than a decade into the future. In the current process this would mean that any capacity shortfall identified by increasingly shaky forecasts any time up to 2035 would require almost immediate commencement of new build.

The viable technologies that replace coal and nuclear do not suffer from such long lead times. As long as sufficient grid capacity exists – wind, solar, battery storage and flexible dispatchable capacity can all be installed in less than three years including the associated infrastructure. Wind lead times are three years, and solar and battery capacity can be installed within a year [18]. Phase one of the existing OCGT capacity at Ankerlig and Gourikwa was installed in 18 months (more than 15 years ago). All the renewable technologies can be added in increments as low as 100 MW without impacting cost. Turbine size viability is impacted by the fuel supply chain, but if new capacity can be co-located with existing fuel off-take, new capacity can be built in increments of 10 MW, 150 MW, or 500 MW for ICE, OCGT and CCGT generators respectively.

These facts fundamentally change and benefit the system planning task – we know attempts at predicting future demand and technology costs beyond even five years are subject to significant uncertainty. Global events of the last years and months bear this out, with impacts on fuel prices and component supply chains wrought by the Covid-19 pandemic and war in the Ukraine being impossible to have predicted. Further, the rate of change at which the viability of new technologies advancing is increasing and already presents a challenge to decision making. Fortunately, with such short lead times on the most viable technologies and new economies of scale at bite-sized capacity we can now afford to revise the system planning process to focus on the period for which we have the best information – the next five years, and incrementally assess and build new capacity almost as it is required. This saves us from the worst stranding risks, almost eliminates the risk of being unable to meet supply due to underestimation of demand, and reduces the capacity at risk in the event that a single project falls behind schedule or fails. It also provides the benefit that where we see future supply gaps opening up, such as when coal plant retires in ten to fifteen years' time, we can afford to wait and see if the intervening years bring new technologies that supersede existing options.

[28] *South Africa's coal megaprojects, Medupi and Kusile, are prime examples of this reality. Medupi's last unit reached commercial operation in August 2021, fourteen years after construction commenced in 2007 and seven years after its scheduled delivery date. The total project cost is almost three times what was originally budgeted for, and the plant is still functioning sub-optimally. Kusile has also experienced severe delays, with its last unit set to come online in the 2024/2025 financial year, sixteen years after construction commenced and almost ten years after its scheduled delivery date [15]–[17].*

3 POWER SYSTEM NEEDS ONLY PEAKING ROLE FROM GAS - HOW MUCH GAS IS THAT?

The analysis in Section 2 leads to the question: how much of the 25PJ/a-40 PJ/a demand for fuel required by 2030 could practically and economically be met with gas? The new peaking capacity required this decade could be fired by a variety of fuel alternatives including diesel, piped natural gas, Liquified Natural Gas (LNG), Liquified Petroleum Gas (LPG), hydrogen, and ammonia to name a few although not all of these options are currently economically feasible. Similarly, existing capacity could be modified to burn the same fuels with feasibility dependent on a case-by-case analysis.

Realistically the available options reduce to diesel and LNG[29] for implementation in the next ten years, given the cost and early-stage development of the hydrogen possibilities, constraints on supply of piped natural gas from existing sources, and undeveloped nature of other domestic gas opportunities. Any new flexible dispatchable capacity should however be able to burn a multitude of fuels including hydrogen, ammonia and other low or zero emission options in order to be useful into a low-carbon future.

South Africa's current diesel usage across all sectors is well in excess of the 40 PJ that will be required for flexible dispatchable power generation by 2030. Total annual diesel consumption is typically more than ten times this amount already, and 37 PJ was burned in OCGTs in 2021. The fuel is relatively easy to handle, resulting in less complex logistical requirements, all of which are in any case existing.

South Africa does not, however, have any established LNG infrastructure, with existing gas supplied by the ROMPCO pipeline from Mozambique. The last twenty years have seen great development in the global LNG market and particularly more recently in the Floating Storage Re-gasification Unit (FSRU) market.

An FSRU is a ship or offshore installation with the capability to vaporize LNG and deliver natural gas to land, from where it can be transported via truck or pipeline to sites of use. Early developments in the LNG industry required land-based storage and re-gasification facilities – only feasible when truly large volumes of LNG throughput are contemplated. The FSRU solution additionally provides greater flexibility than a large land-based terminal option, as it requires only a fraction of the capex in order to become operational, and vessels can be moved if required to other locations. Contract flexibility also allows for the procurement of the service on a lease basis – removing the obligation to sink large capital costs into on-shore infrastructure from the beginning.

A reasonable sized FSRU can deliver up to 180 PJ/a of gas provided there is a steady offtake profile – for context this is approximately the entire current South African demand, and far in excess of the 40 PJ/a identified in section 2 above as being the maximum requirements of the power sector to 2030.

In theory, then, one FSRU is all that will be required to supply gas demand in the South African power sector for the foreseeable future. However, getting LNG from the port to point of use requires either rail, trucking or

[29] *LPG could also potentially provide the fuel to some new generation capacity although this is likely to be a small role as we discuss in relation to Saldanha Bay as a potential site for new generation capacity. We have not evaluated the full potential for LPG in power in South Africa in this report.*

pipeline solutions. For the purposes of the analysis in this report we have restricted ourselves to the evaluation of sites that would be most favourable to LNG - i.e. where FSRU-supplied LNG generators are situated at ports (requiring no further transport cost) or alongside existing pipelines (requiring little or no new pipeline infrastructure to be built).

We proceed in this section to consider the case for FSRU-supplied LNG to replace diesel as a fuel for existing or new flexible plant capacity at such sites where LNG would most easily compete with diesel. Whilst we do consider inland locations for this comparison our major focus has been on the economics of coast-located sites. We base our comparison on pricing considerations, which are influenced both by the cost of the fuel itself and logistical considerations for delivering the fuel to the generator, as well as emissions considerations.

3.1 FUEL PRICE CONSIDERATIONS

3.1.1 Diesel pricing

The pricing basis for diesel fuel in South Africa is well established and is based on the import-parity price of diesel. This consists primarily of the Basic Fuel Price (BFP) derived from a number of global refined product hubs plus logistical cost recoveries in the order of 5% of the total to deliver landed product in a South African harbour. The price is subject to further margins, plus levies and taxes based on the use of diesel for transport purposes, and cost recoveries related to delivery and storage costs.

When the existing Eskom peaking facilities at Ankerlig and Gourikwa were built, National Treasury implemented a rebate mechanism[30] to relieve power generation of paying the Road Accident Fund levy and the Fuel levy. In April 2016 this rebate was partially repealed[31] as National Treasury perceived it to be contributing to a perverse incentive for Eskom to burn more diesel given the high Capacity Factors of OCGTs in the previous year.

Power from OCGTs with or without this rebate is always the most expensive of all generation options and is only ever dispatched as a last resort – the high use of OCGT capacity in 2015/16 was a result of desperate attempts to maintain security of supply and avoid load shedding. If anything, imposing additional taxes on diesel for power generation (as created by repealing the rebate) could create a perverse incentive for Eskom to shed load in extreme circumstances rather than burn expensive fuel – a cost that may not be approved by the National Energy Regulator of South Africa (NERSA) in subsequent revenue applications.

For purposes of our evaluation of the price of diesel against gas we have excluded the R50/GJ impact of the current fuel tax policy, our view being that a rational application of such a tax would need to equally apply to all fuels used for power generation.

Whilst actual supplied prices will be based on individual contracts between suppliers and Eskom or Independent Power Producers (IPPs), we have assumed the same wholesale margin, secondary distribution and storage costs as per the Central Energy Fund (CEF)'s published indicative diesel pricing[32]. These margins would allow for appropriate profit and provision for delivery and necessary storage infrastructure. Table 4 thus provides a

[30] *Schedule 6 of the Customs and Excise Act, rebate in place since April 2006*

[31] *Since 1 April 2016 diesel for power generation includes 50% of the Fuel levy. As at December 2021 this amounts to 190c/l or approximately R50/GJ*

[32] *Found in the DMRE Petrol Price Archive: http://www.energy.gov.za/files/esources/petroleum/December2021/Diesel-margins.pdf*

reasonable indicative price as at December 2021 for supply of diesel fuel to coastal OCGT facilities:

Table 4: Diesel cost as at December 2021 for supply of fuel to coastal OCGT facilities

Diesel cost assumptions	ZAR c/l	ZAR/GJ
Basic Fuel Price (BFP)	955.63	251.48
Zone Differential Coast	2.50	0.66
Wholesale Margin	80.22	21.11
Fuel Levy	0.00	0.00
Secondary Storage	30.70	8.08
Secondary Distribution	17.94	4.72
Total Fuel Cost	1 086.99	286.05

Approximately 88% of the diesel price is exposed to exchange rate fluctuations and a similar portion exposed to the dollar price of global oil markets.

We have not explicitly modelled any economies of scale in extending the use of diesel as a fuel for peaking plant. This rests on the assumption that small incremental generation capacity increases could be accommodated at sites where existing storage capacity exists and that storage provision for larger capacity would not cost more than the existing provision in the price. The future use of pipeline transport (as opposed to truck) such as what may be achievable at Ankerlig has not been accounted for, although this would likely favour diesel cost-wise over LNG.

3.1.2 LNG pricing

LNG is procured in a global market and a multitude of mechanisms exist for price formation and contracting. Contract pricing terms range from spot pricing based on one or more of a number of international gas spot markets to multi-year fixed price contracts, and a range of market-linked pricing mechanisms in between. The pricing risks demonstrated by recent unprecedented spot market volatility and the need for some price certainty would mean that any gas procurement for South African power generation would need to be done on the basis of a long-term contract.

Although fixed price contracts have been and are implemented it is highly unlikely this option would be available given the low quantities that South Africa would consume. The contractual reality is far more likely to be subject to the more standard norms of LNG contracting in which the price is indexed against an international marker.

Historically LNG was indexed against the crude oil price resulting in significant correlation between changes in LNG and other hydrocarbon prices such as diesel. More recently with the advent of shale-gas and other unconventional sources a position of structural gas over-supply in the United States (U.S.) has resulted in a decoupling of the markets for liquid fuels and LNG, resulting in prices for LNG and diesel that now sometimes move against each other based on the supply/demand dynamics in the different markets.

Since 2016 the U.S. has become the marginal supplier of LNG with pricing based on the Henry Hub LNG pricing formula [19]. We have

assumed this formula in modelling the LNG price at which gas could be procured in South Africa. The formula links the contract price to the Henry Hub price marker (which is much less volatile than European hub prices or the Japanese Korea LNG spot marker (JKM) due to the structural over-supply in the U.S. with a 15% premium to cover the cost of actually procuring feedstock. A further cost of liquefaction is added plus the cost of shipping via LNG carrier to derive a Delivered Ex-Ship (DES) price for delivery into an FSRU moored in a South African port. Table 5 below shows indicative pricing for December 2021.

Table 5: Indicative pricing for December 2021 for LNG Delivered to an FSRU moored at a South African port

LNG cost assumptions	$/MMBtu	ZAR/GJ
Henry Hub Price	3.67	53.92
Gas feedstock premium (15%)	0.55	8.09
Liquefaction fee	2.50	36.73
LNG Carrier fee	1.50	22.04
Total DES Price Delivered to FSRU	**8.22**	**120.77**

LNG is stored cryogenically in the FSRU in liquid form, re-gasified and piped to shore as required. Contractual terms for deployment of the FSRU also vary considerably and include outright purchase versus long term lease agreements for the FSRU. Given the need for flexibility we have assumed a lease contract would be preferable and that the only capital required would be the cost of necessary marine and portside infrastructure to connect the FSRU via pipeline directly to a generation facility.

We assume capital and fixed cost recovery to be the same under a lease or outright purchase agreement – the only difference being whether the ongoing FSRU cost is denominated in dollars (in the case of lease) versus rands (in the case of purchase) i.e. the extent to which the FSRU cost component is exposed to exchange rate fluctuations. Detailed FSRU cost assumptions are to be found in the Appendix section 8.5. The presence of fixed costs in the value chain means that volume of LNG required has a significant impact on pricing, particularly at low volumes.

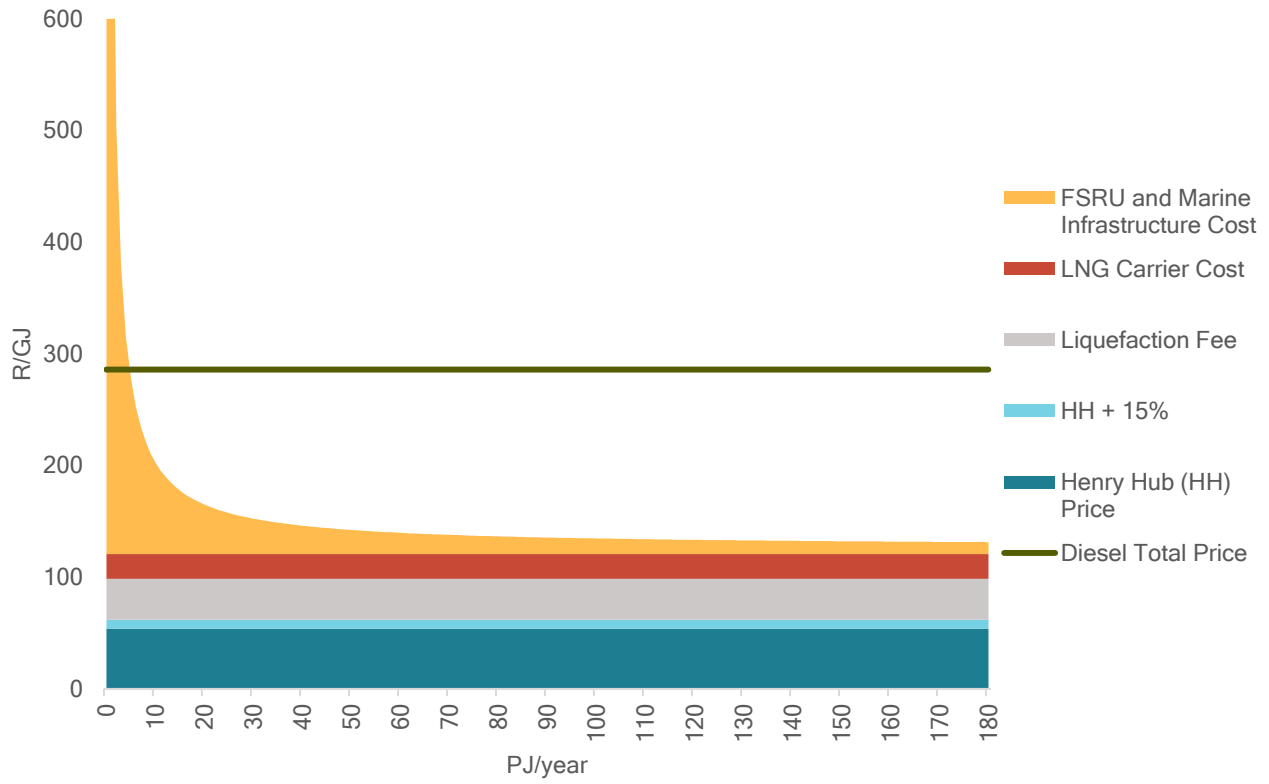
Figure 4 depicts the build-up of the price components at increasing fuel offtake levels for LNG assuming a single FSRU is moored in a South African port, as at December 2021. The majority of the FSRU and marine infrastructure costs are fixed, resulting in significant dis-economies of scale at fuel offtake volumes below 10 PJ, the left-most side of the figure – regardless of whether the FSRU is procured on a lease or purchase basis.

The cost of diesel in December 2021 (R286/GJ) is also plotted (recalling that diesel for power generation is not similarly subject to economies of scale given the existing infrastructure and extensive use of diesel elsewhere in the economy), illustrating that at very low volumes, the price of LNG in fact comes at a significant premium to that of diesel.

Whilst the 40 PJ/a potentially required for flexible dispatchable power generation as justified in section 2 sits comfortably within the economies of scale for LNG, this assumes that all this demand is located at generators

that could be supplied directly from a single FSRU. This is far from the case with existing and realistic potential new sites scattered geographically. We consider this question in more detail in section 3.2.

Figure 4: Build-up of the LNG price at December 2021 showing relationship between volume and price for the FSRU and marine infrastructure component. December 2021 Diesel price plotted.



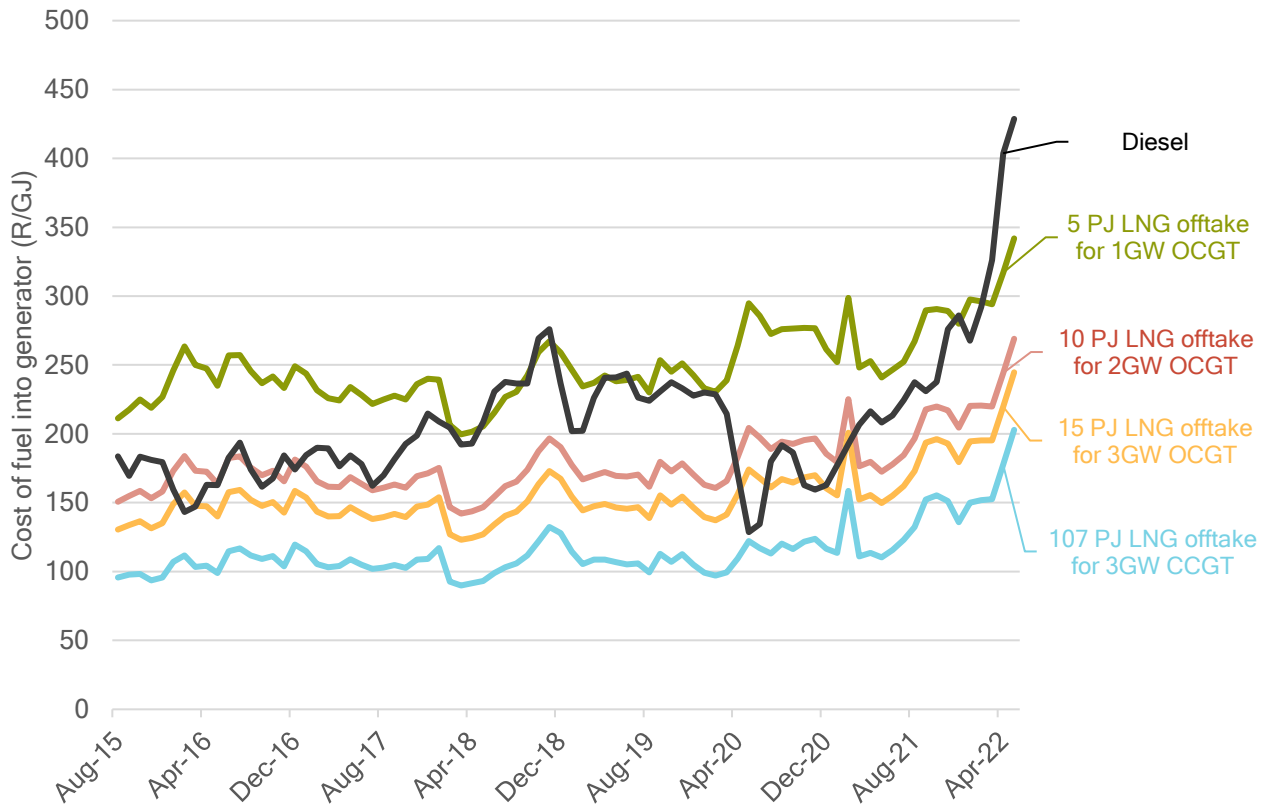
3.1.3 The impact of fuel price volatility over time

Figure 4 provides a price snapshot at one point in time – December 2021. But how does LNG pricing compare to diesel over a period of time? In order to gain a better understanding of this, we looked back at historical data on the price of each fuel from August 2015 (the time when Henry Hub pricing became available) to May 2022. Figure 5 illustrates the price histories of diesel and LNG over this period for various levels of LNG offtake volume – including offtake associated with 1 GW, 2 GW and 3 GW of OCGT capacity running at a 5% Capacity Factor, as well as 3 GW CCGT capacity running at a 55% Capacity Factor.

The current state of the liquid fuels and LNG markets results in diesel prices far in excess of LNG prices implying that LNG could feasibly compete with diesel (black line) even for a dedicated FSRU supplying only 5 PJ/a (green line indicating offtake for 1 GW of peaking capacity in a year of reasonably high use).

However, even the limited history over the last seven years shows that there is significant volatility of the discount between LNG and diesel and that on average over this period such low volumes of LNG would have actually priced at a *premium* rather than a discount to diesel.

Figure 5: Price history of diesel vs LNG for different offtake volumes



In order to gauge what level of fuel offtake would be required in order to be secure of the discount between LNG and diesel, we plotted the volume versus discount curve between the two for their respective prices for each month of the available history from 2015 to 2022.

Figure 6 illustrates the % premium or discount of the price of LNG over Diesel[33] with increasing fuel offtake for each of the months during this period. The figure shows that in recent months (the green and blue lines representing December 2021 and May 2022), LNG became a cheaper fuel option than diesel for any volume exceeding 5 PJ/a, and substantially so (more than 40% cheaper) at larger volumes.

However, from the historical context in Figure 6 (plotting the discount curve for all months from August 2015 onwards) we see that on average (red line) any offtake volume lower than 8.5 PJ/a would have resulted in LNG pricing at a *premium* to diesel.

For an offtake volume of 10 PJ/a LNG would have on average priced at a discount of a little under 10% to diesel, but the difference ranged from a 40% discount to a 70% premium over the period. Over the past seven years, with the decoupling of the LNG and liquid fuels markets, not only have the respective fuel prices become highly volatile, but so has the *difference* between them.

[33] *Prices reflect the cost of delivering the fuel to a turbine generator at the coast (i.e. LNG includes price of FSRU and marine infrastructure, LNG carrier, Liquefaction and Diesel includes Wholesale Margin, Storage and Distribution costs)*

Figure 6: Range of Gas Price premium/discount over diesel with increasing volume (PJ/year)

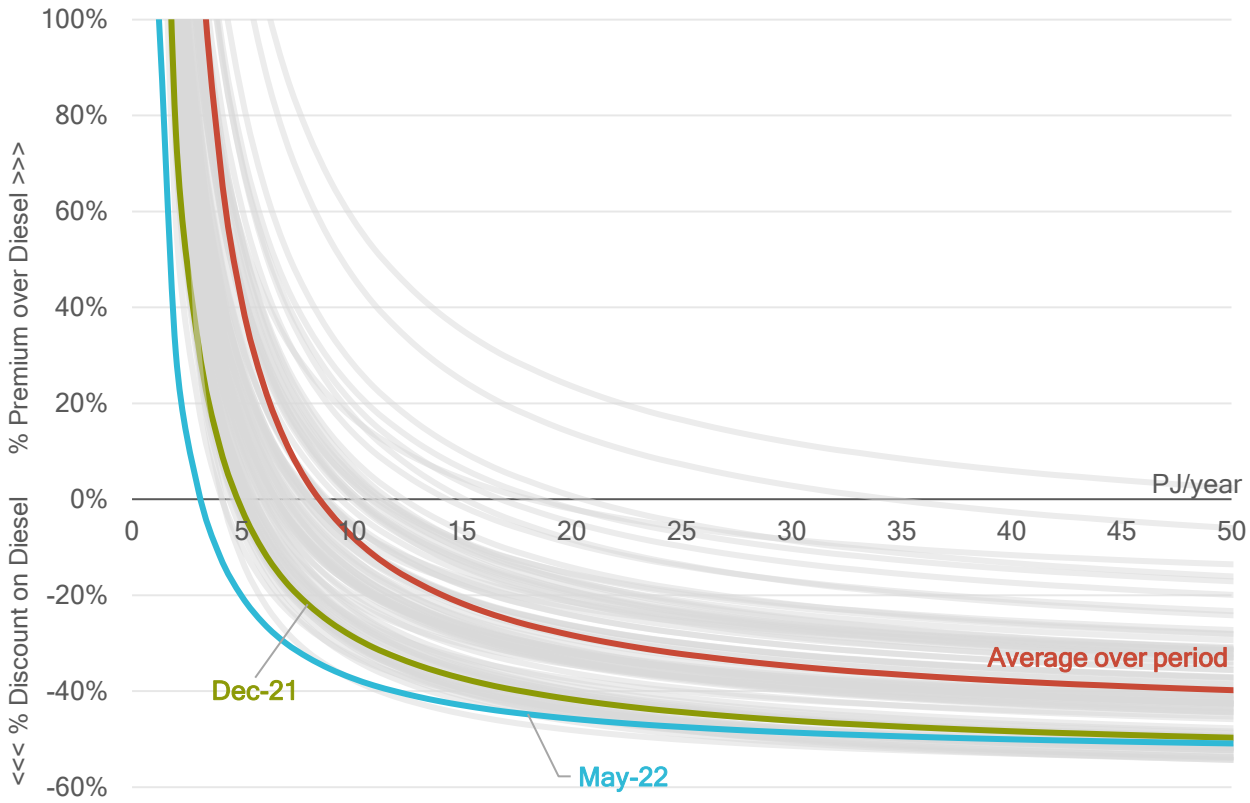


Figure 6 shows that the minimum offtake volume required for LNG to become a cheaper fuel option varies significantly across the period, but to be secured of a reasonable discount of 10% to 20%, offtake volumes would have needed to consistently exceed 10 PJ/a – 15 PJ/a. If the gas-to-power offtake were required to provide this demand on its own, then at least 3 GW[34] of peaking capacity would need to be supplied by the FSRU, and LNG would have to provide all the peaking fuel requirement at these plants.

As we discuss in section 3.3.1, it is highly unlikely that LNG will be able to entirely dispense with diesel as a fuel option for peaking plant and more likely that LNG could only account for 50% of the peaking fuel required. If this is the case, then 6 GW of peaking capacity would be required to be supplied from a single FSRU in the absence of other demand in order for LNG to reliably be cheaper than diesel. Grid constraints and other practicalities associated with a concentration of so much generation capacity would likely render this infeasible.

Given the fixed FSRU costs it should also be borne in mind that the effective gas price would be substantially higher in early years if an incremental build approach were to be adopted – i.e. if not all peaking capacity were to be built at once, as would be prudent given that the expansion of the peaking capacity is required only in tandem with the rollout of renewable resources.

Under the assumption that diesel storage would be required anyway (see section 3.2), the incremental issue could be addressed by first building the diesel infrastructure and

[34] *3 GW of peaking plant requires 9 PJ – 15 PJ of fuel per annum based on a Capacity Factor of 3% to 5%*

running initial capacity on diesel until sufficient port or pipeline located demand existed to warrant a dedicated FSRU.

Analysis by the NBI [6] (referenced in section 2.3) made use of a static price assumption for LNG (R140/GJ) and a range for diesel (R200/GJ – R300/GJ) implying that a saving of 30% to 53% on fuel cost could be realised by switching to LNG from diesel. Savings of this magnitude whilst possible at high throughput volumes of LNG, are unlikely to be achieved at volumes associated with the peaking role for gas needed by the power system.

What is clear from a more detailed analysis (see Figure 5 and Figure 6) is that any degree of cost benefit is far from guaranteed given fuel price volatility and is only likely to be achieved at generation sites where significant non-power offtake provides the anchoring demand to reduce the FSRU costs.

In summary, the pricing case for LNG requires offtake volumes of 10 PJ/a – 15 PJ/a in order to secure a discount of at least 10% to 20% against diesel as the alternative fuel. If peaking plant were to be the only user of the LNG, 3 GW of peaking capacity would need to be located at the port or existing pipeline locations fed by a single FSRU, provided 100% of the peaking plant utilisation could successfully be fuelled with LNG. 6 GW of peaking capacity would be required if only 50% of its fuel requirements could be provided by LNG.

Based on the practical considerations discussed in the next section it is questionable whether more than 50% of a peaking plant's fuel requirement can be met with LNG and unlikely that 6 GW of peaking capacity can be co-located or feasibly supplied from a single FSRU. If this is indeed the case, LNG will only be able to economically replace diesel at sites where significant (~10 PJ/a) non-power demand exists to lower the fixed infrastructure costs associated with the FSRU.

3.2 GREENHOUSE GAS CONSIDERATIONS

Burning LNG results in lower greenhouse gas (GHG) emissions than burning diesel to produce the same amount of electrical energy and therefore would appear to be a better option than diesel if it can be procured at lower cost. However, significant questions surround the life-cycle emissions generated by LNG compared to diesel when considering all emissions from well to burner, particularly around methane leakage in the logistical chain – including liquefaction, ocean-transport, and re-gasification.

Methane emissions have orders of magnitude worse of an impact on global temperature rise than the carbon dioxide generated at combustion. In this respect, marine-transported LNG has a higher carbon intensity than land-based gas supplied through pipelines [20]. The literature on leakage from the LNG value chain is undecided on what reasonable value to assume, with published leakage rates ranging from 0% to 9% [21].

Based on our calculations, an assumption of 3.5% leakage along the value chain would eliminate the emissions savings gained by burning LNG instead of diesel[35]. For the purpose of this report, we assume a conservative value of 2.5% leakage in the

[35] *See section 8.4 of the Appendix for a summary of the calculations. We consider the GWP100 value for methane emissions in this calculation, which considers the temperature influence of a gas relative to CO_2 over a 100-year period (conventionally used in most national GHG reporting). Methane's GWP100 value is 28 – i.e. an amount of methane causes 28x more warming than an equivalent amount of CO_2 over a 100 year period. Given that methane is a short-lived climate pollutant (i.e. its effect on warming is most pronounced over a period of less than two decades) its GWP20 value (warming over 20 year period) is much higher – around 83x that of CO_2. Our calculations are therefore very conservative in terms of LNG's impact.*

lower part of the range – this results in minimal emissions savings arising from the use of LNG instead of diesel (roughly 7% per GWh produced), leaving the main motivation for an LNG-only solution over a diesel-only solution to be that of cost.

3.3 PRACTICAL CONSIDERATIONS

Having established that there is an economic and (potentially small) environmental case for the use of some gas for peaking power generation in a particular range of circumstances, we now explore some of the practical considerations that inform the scope of this opportunity in South Africa to 2030.

3.3.1 FSRU practicalities associated with using LNG to fuel peaking plant

The utilisation of peaking/standby capacity in the power system is by nature intermittent, and being the most expensive power on the system should be run as infrequently as possible. Currently the South African power system is in a crisis situation. At present the peaking capacity is run far more frequently than is optimal due to the constrained supply situation, although even at the 12% Capacity Factor utilisation in 2021 there were 74 days when the OCGT capacity was not run at all including continuous inactive periods of 5 or 6 days.

The next ten years will likely see a fundamental change in the composition of the generation portfolio with a vastly increased capacity of wind, solar and battery storage by end of the decade. As the system becomes more energy-secure with more storage capacity, the daily predictable demand fluctuations will be met optimally using batteries and pumped storage to release cheap renewable energy generated in earlier periods of lower demand.

The peaking plant's role will become reduced in frequency and predominantly be used in the case of unexpected demand-supply gaps (such as due to the failure of aging coal units) and to support the renewables/battery capacity through prolonged periods of low wind and insolation during which batteries are depleted. Thus the 5% maximum annual Capacity Factor utilisation will increasingly be comprised of less frequent but longer or more intense events. The utilisation for any particular month or week will become harder to predict and resemble less and less the pro-rata annual utilisation. This creates a number of practical challenges if LNG is used as the fuel to replace diesel.

The primary challenge relates to the FSRU replenishment cycle, associated scheduling of LNG carrier vessels and the requirement of take-or-pay commitments[36] that attend these. Bearing in mind that the source of LNG will likely be at least a three-week voyage away, and vessel scheduling requires significant lead time and forward visibility of demand. Resupply vessels typically need to be scheduled on a six-month rolling programme, committed to three months from delivery by the supplier, and made firm one month from delivery by the buyer, with penalties if not taken. Increasingly unpredictable but intense use of the peaking capacity when it does run will create one of two problems in this supply environment –

- As the scheduled replenishment date approaches after a period with lower-than-average utilisation, either plant will need to be run unnecessarily to make space for the new fuel (incurring a perversely incentivised financial cost and

[36] *A take-or-pay provision obliges the buyer with a supply contract to either buy and take a minimum supply of a product (e.g. a fuel), or pay for it even if the product is not required or used.*

further potential environmental cost if LNG-fuelled power displaces renewables) or only partial delivery of the load will be taken incurring hefty take-or-pay costs.

- When a period of higher-than-average utilisation eventuates, there would be a high likelihood that the FSRU would be emptied before the next scheduled vessel arrived – with complete loss of the peaking capacity to the power system for this period of time. This situation frequently occurs with the existing diesel OCGT capacity due to insufficient onsite diesel storage and accounts for a significant portion of load shedding.

The first issue would erode the economic and environmental case for LNG over diesel, but the second issue if not addressed would undermine the crucial role that the peaking capacity will play in maintaining security of supply. One way to deal with both problems would be to retain diesel storage capacity and dual-fuelling capability of plant at any site where LNG will be used, allowing for less frequent scheduling of LNG cargo vessels with less frequent application of the take-or-pay criteria whilst maintaining security of supply with diesel between deliveries.

This issue is illustrated in Figure 7 and Figure 8 which chart the actual existing daily OCGT usage data for the years 2018 and 2020 on the right-hand axis. The lines on the chart indicate the fuel consumption over rolling 60-day (green), 90-day (blue) and 120-day (black) periods expressed relative to the fuel that would have been consumed over the same rolling period if daily fuel consumption were constant (i.e. the pro-rata annual utilisation). The pro-rata consumption rate – i.e. where the output and hence consumption of fuel by OCGTs was the same each day – is indicated by the grey line.

The years 2018 and 2020 were chosen from the last five years as the OCGT Capacity Factor in these years best matches that which could be expected with an adequate system and significant increase in renewables capacity (i.e. 3% to 5%). The figures clearly illustrate the two problems highlighted above, demonstrating that the annual offtake from the peaking plant will be characterised by long periods of little or no use, and shorter periods of intense use.

The data from both years show that contracting for more than 50% of the annual demand on a continuous take-or-pay basis would result in multiple situations in which the take-or-pay provision would have been triggered over 60, 90 and even 120-day periods[37]. This is illustrated by the instances where the green, blue and black lines fall below the 50% mark on the left y-axis – i.e. the fuel that is consumed by the OCGTs is less than that which was paid for in the contract.

The graphs also show the problem of attempting to meet infrequent, high intensity usage events with a continuous fuel supply – there is clearly a significant risk over 60-, 90- and 120-day periods that fuel requirement would *exceed* that supplied from a continuous offtake by 50% to 100%.

[37] *For context 3 GW of peaking plant operated at a 5% Capacity Factor would require a replenishment vessel every 73 days if usage was continuous throughout the year.*

Figure 7: Actual fuel consumption relative to continuous monthly offtake for the existing peaking plant – 2018

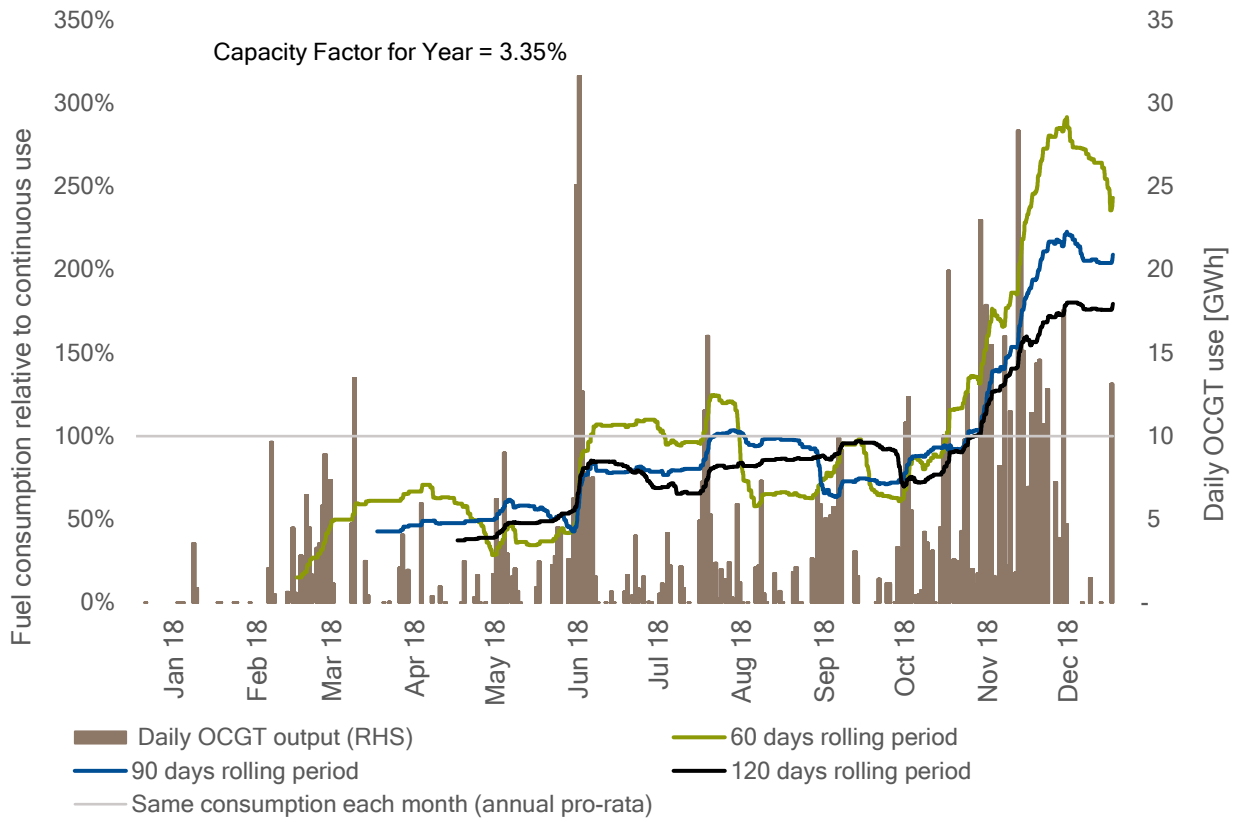
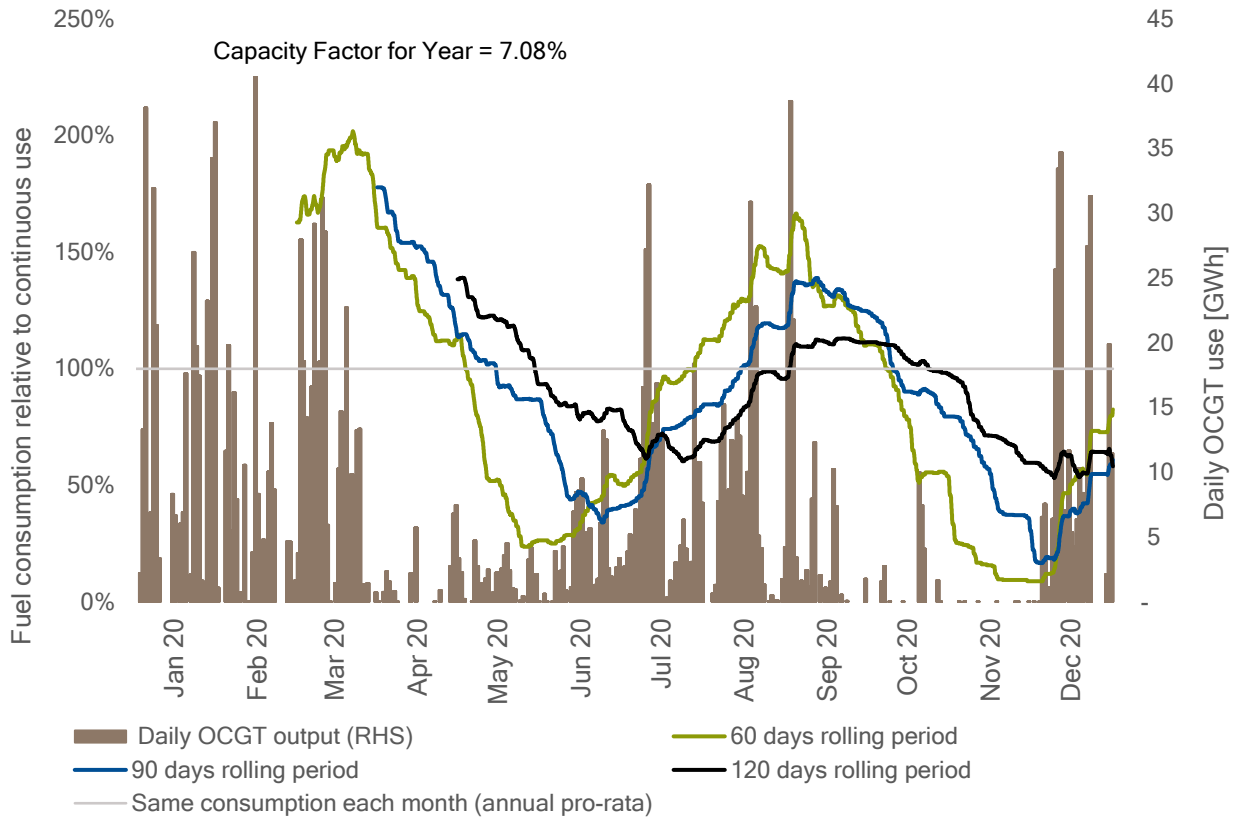


Figure 8: Actual fuel consumption relative to continuous monthly offtake for the existing peaking plant – 2020



Further detailed system modelling of the likely peaking plant dispatch must be done to ascertain the expected duty cycle of the peaking plant as renewable and battery storage penetration grows. This will enable a better understanding of the economics of using LNG to fire peaking capacity. Such further analysis would also need to integrate impending changes to the liquid fuels supply environment in South Africa. With most refinery capacity closed or closing, we will need to import a far larger percentage of refined product than has been the case in the past.

Although historically most diesel burned in existing OCGT plants will have been imported in any case, the changing supply source for the majority of diesel used elsewhere in the economy may have impacts on the future price and ability to source diesel for power generation. The potential for LNG to provide an alternative fuel source at some generation sites should also be considered from a security of supply perspective, with the benefit of diversifying reliance away from the single diesel supply chain.

Without further analysis but guided by the above evidence from the existing peaking plant utilisation, it is highly unlikely that LNG will be able to supply all the fuel required for peaking usage, even at new plants with dedicated close-located FSRU supply. Unless storage options for gas or other fuel emerge that allow for economic storage of large quantities, it will be necessary to retain the capability to burn diesel at all peaking sites in considerable quantities to ensure security of supply through longer periods of continuous plant usage.

It will also likely be necessary to burn diesel at other times through the year - the prudent contracting volume for LNG will be far lower than the average annual use and will be determined by the highest volume that could feasibly be contracted without unacceptably frequent triggering of take-or-pay provisions during low usage periods.

Based on the limited analysis of the existing peaking plant, and the fact that optimal use of peakers would result in Capacity Factors of less than 3% (i.e. the issues identified would manifest more severely than the example years illustrated in Figure 7 and Figure 8) we estimate that it is likely no more than 50% of the total maximum annual peaking fuel requirement can be met by LNG. This is unless non-power volumes dwarf the peaking offtake at a given site and can act as an absorbing buffer for the intermittency issues demonstrated in this section.

Contracting for more than the 50% volume would appear to incur significant risk of triggering take-or-pay provisions that would undermine the financial and any emissions advantage over diesel.

If LNG can only provide 50% of the peaking fuel required at any site, the minimum feasible port or pipeline-fed peaking capacity requirement would rise to well above 3 GW in order to maintain annual demand of 10 PJ-15 PJ (and thus secure a reasonable discount over diesel, recalling Figure 6), most likely requiring 6 GW, given that this would imply annual contract volumes in the region of 15 PJ[38] per year. If LNG could provide say 80% of the peaking fuel volume, the minimum capacity supplied by a single FSRU would need to be around 4 GW[39] to successfully compete with diesel on price.

A further if less consequential consideration is the management of boil-off gas. LNG is stored in insulated containers on the FSRU at

[38] *6 GW @ 3% to 5% Capacity Factor = 18 PJ/a – 30 PJ/a total fuel requirement x 50% = 9 PJ/a -15 PJ/a*

[39] *4 GW @ 3% to 5% Capacity Factor = 12 PJ/a – 20 PJ/a total fuel requirement x 80% = 9 PJ/a -16 PJ/a*

cryogenic temperatures, but a small amount gasifies or 'boils off' on an ongoing basis as the insulation is imperfect. This boil-off gas ("BOG" - about 0.15% of the storage per day) must be consumed daily or incur additional costly reliquefication plant on the vessel.

Without steady industrial demand twinned with the peaking capacity that could absorb this gas it would require daily running of the peaking plant with associated cost and emissions, depending on what other generation it displaced from operation at the time.

Again, without a detailed analysis of the dispatch schedule of the peaking plant at higher renewable penetration it is difficult to quantify this impact. In the extreme, with highly concentrated peaking requirements and long periods of standby the BOG could account for 10% to 15% of all gas usage from the FSRU although the actual figure will be much smaller than this. A proper feasibility study would need to take into account any forced generation of the peaking plant necessitated by consumption of the BOG.

Some of the FSRU practicalities would be mitigated but not eliminated if the peaking capacity offtake was dwarfed by a much larger industrial or synfuel offtake from the same FSRU – in other words if the non-power offtake could provide the anchoring demand and buffer some of the offtake volatility. This would be the case if for example the peaking capacity were located at Komati or other of the older power stations and could connect directly to the ROMPCO pipeline (see Figure 10). In this case the replenishment cycle and BOG issues would disappear and the FSRU cost per GJ would be vastly reduced – the only constraint would then be the ability for the ROMPCO system to deliver instantaneous capacity (see section 3.3.3.7).

Non-power demand from the same FSRU that is not orders of magnitude larger than the power usage volumes will likely be of little use in mitigating the intermittency issue, even with an aggregator pooling a portfolio of offtake volumes. If the power generation offtake in such circumstances were to double for a short period of time as clearly it often does, this would put industrial customer volumes at risk until the next replenishment cycle.

Even if this could be accommodated from time to time it is hard to see how such usage could be contractually secured, which would result in a security of supply risk without the use of diesel as an alternative fuel. A more likely economic scenario would be a situation in which non-power demand allowed for lower offtake volumes of LNG for peaking power to be competitive with diesel. This would facilitate contracting LNG for the fraction of the fuel requirement that would be burned with certainty between replenishment vessel cycles, using diesel for the remaining requirement. Such an arrangement could work for example at Richards Bay once the Lilly line customers have converted from MRG to LNG at some future point (see section 3.3.3.6).

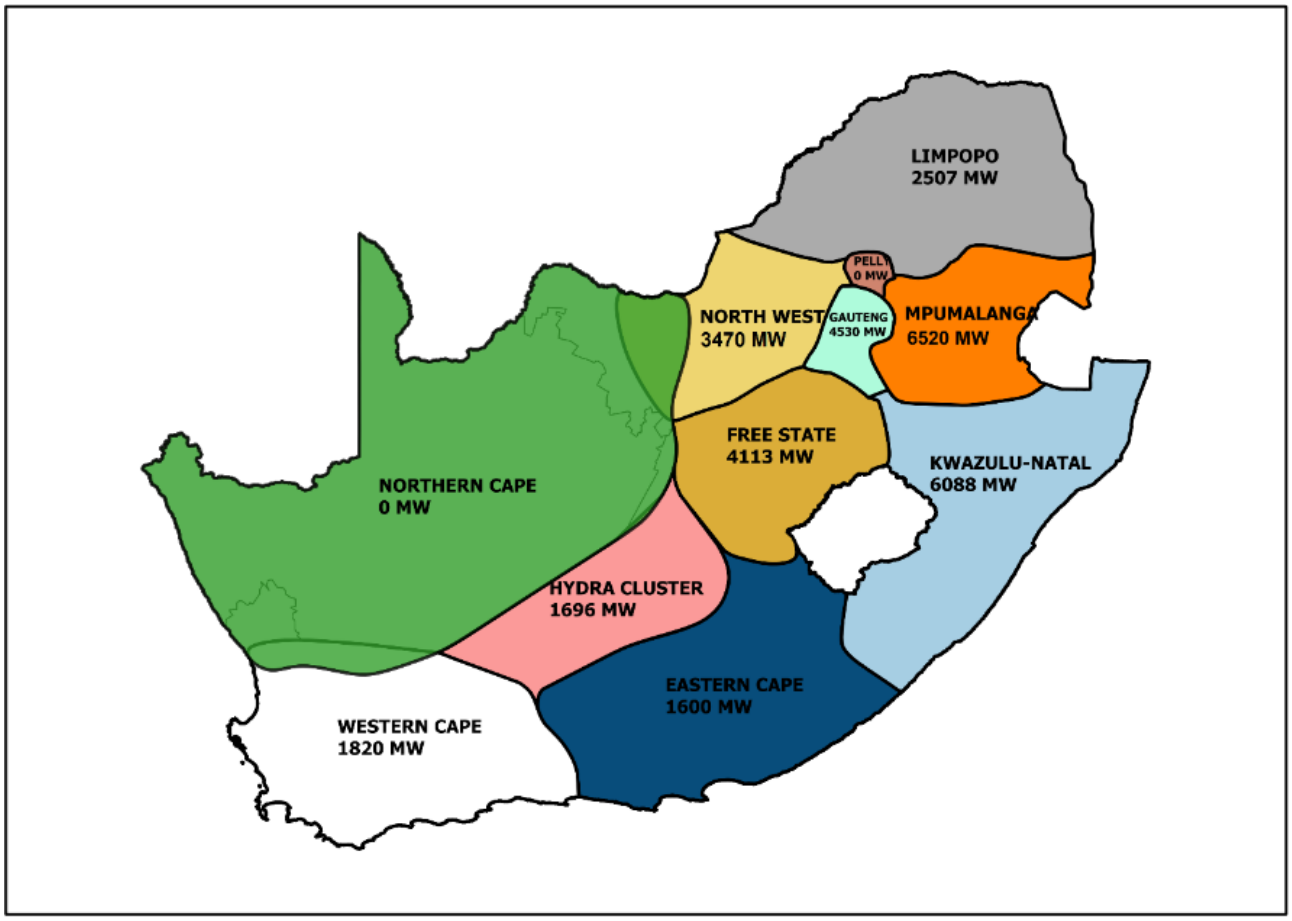
3.3.2 Grid constraints

The value of new peaking capacity to the power system depends crucially on the ability to evacuate the generated power and transmit it to nationally dispersed load centres where and when it is required. Current constraints on evacuation of power are subject to limitations on both the local network (grid and transformer infrastructure) and the broader national transmission network, with varying lead times and costs required to resolve bottlenecks.

In general, congestion in the local networks is easier and quicker to resolve but current lead times in the development of transmission

infrastructure to facilitate evacuation of power nationwide are as long as 7 to 10 years. Figure 9 below shows the near-term availability of grid capacity for the connection of new generators as recently published by Eskom [22] - this document is released to assist IPPs in locating viable sites for generation facilities, particularly in respect of the next REIPPPP BW6 (Bid Window) which in its current guise will see a further 2 600 MW procured.

Figure 9: Generation connection capacity for new projects operational from 2024



A number of things are worth noting from the state of available grid capacity. Firstly, with the Northern Cape completely sterilised in the near term as far as new generation is concerned, the next best resources for renewables are likely to be the Western and Eastern Cape. The available grid capacity in these provinces (1.8 GW plus 1.6 GW) will thus largely be exhausted by BW6 projects.

Additionally, the methodology Eskom employed in assessing available capacity assumed that the 2 GW of the existing OCGTs at Ankerlig and Gourikwa would not run concurrently with any new capacity built – this means that there is not sufficient grid capacity to evacuate more peaking power from the Western Cape. This has implications for the siting of new peaking plant and for the viable conversion of existing OCGTs at Ankerlig and Gourikwa (together ~2 GW) to gas, certainly in the short term.

The significant grid capacity available in KwaZulu-Natal stems largely from the fact that there are areas with substantial concentrations of electricity demand there with very little generation capacity at present, this is particularly so at Richards Bay. This provides the opportunity to site generation capacity at Richards Bay that would supply the local demand and exploit the transmission

capacity that currently brings power to that load – this would allow for the power to be evacuated out to the rest of the grid.

Major available grid capacity exists in Mpumalanga and is as a result of the beginning of the decommissioning process that will see close to 10 GW of coal retired by the end of the decade – grid capacity is likely to increase if anything in this area over the next ten years [11].

3.3.3 Evaluating potential sites and their specific considerations

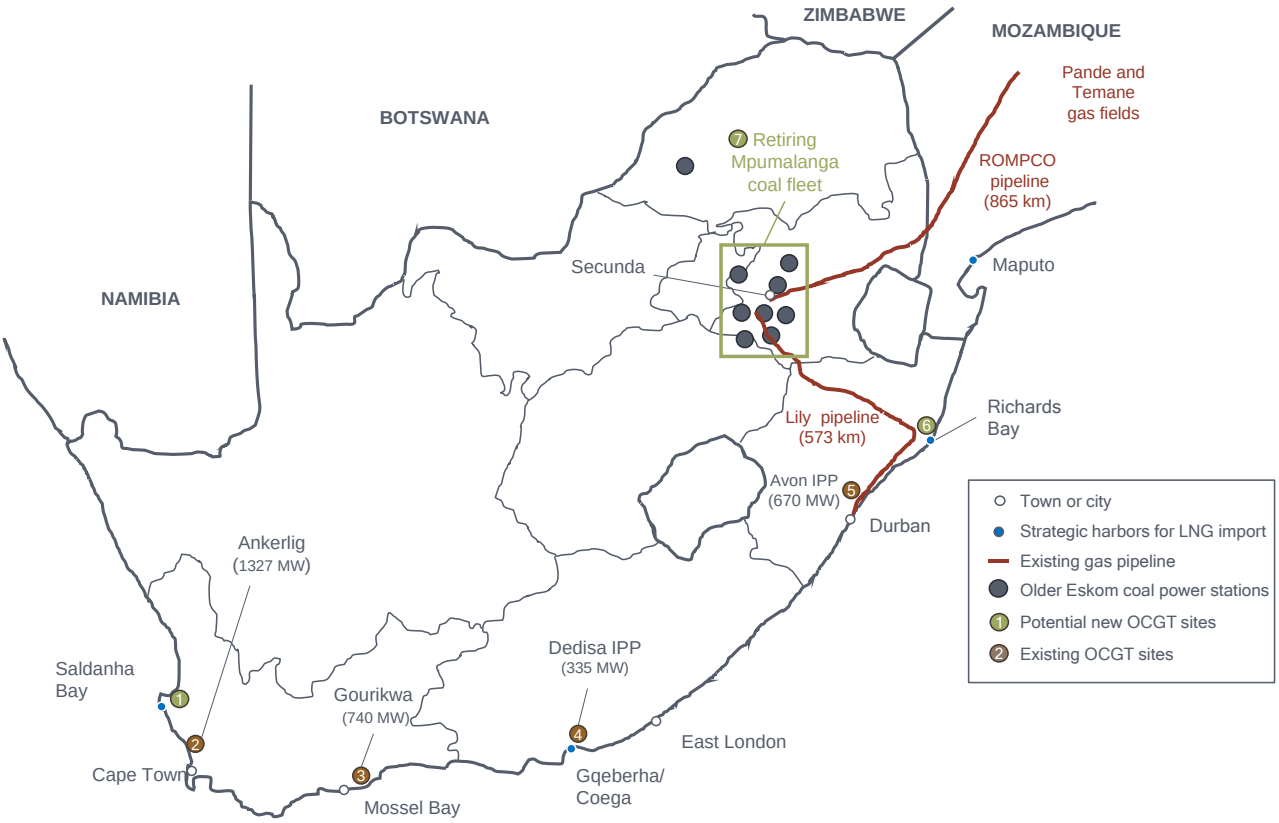
In the sections above, we have established that there is a limited role for gas in the power sector where it can practically and economically replace diesel as the fuel for peaking capacity. Based on the practical replenishment/stock-out issues that attend the combination of LNG supply chain and peaking power requirements (section 3.3.1) it is clear that diesel capability will need to be retained at all potential peaking plant sites to ensure security of supply.

In this section we identify some of the site-specific issues that will influence the ability to economically replace diesel with gas for existing and potential new facilities. This is neither a comprehensive nor exhaustive assessment, rather an initial evaluation in order to highlight the practical complexities that will need to be understood before progressing LNG infrastructure decisions. In evaluating different sites, the following factors need to be considered:

- Proximity to diesel supply, or other alternative fuel source
- Proximity/access to possible FSRU location, either near port or via existing pipeline
- Existing and likely non-power demand for gas – this will heavily influence the FSRU viability
- Electrical grid capacity to evacuate power. Without significant non-power volumes with which to share the FSRU costs, co-located capacity will need to be in the order of 3 GW – 6 GW in order to generate sufficient offtake to compete with diesel.
- Altitude (OCGT performance is compromised at altitude, favouring ICEs at non-coastal locations – see footnote 27)
- Non-power demand. As we have demonstrated, the viability of LNG for peaking plant is heavily influenced by the size of other non-power volumes that could be supplied through the same FSRU. The most viable sites for LNG to compete with diesel will this be those with the highest likelihood of significant non-power demand in the medium term. Sasol has announced [23] its intention to use LNG to replace coal in its petrochemicals operations, estimated at requiring 40 PJ/a – 60 PJ/a by 2030 to do so. This LNG will initially be imported through Maputo but discussions are already under way to supply some volumes via Richards Bay. Given the advanced status of the Gigajoule Matola LNG project [24] that intends to connect with the ROMPCO pipeline for import to South Africa, we assume that Sasol's Maputo-sourced LNG would be delivered to Secunda via these facilities. Similarly, given the proximity of Richards Bay to the existing Transnet Lilly gas pipeline, we assume that Sasol-bound LNG sourced at Richards Bay would make use of this pipeline.

The sites we considered are shown in Figure 10 below:

Figure 10: Existing and potential sites for peaking capacity[40]



3.3.3.1 Saldanha Bay

This would be a greenfields development (i.e. no existing power generation or gas infrastructure) with some possible potential for non-power demand from industry – FSRU would be berthed in the port providing access to LNG with limited pipeline build required. Grid evacuation is constrained in the medium term by the Western Cape supply area capacity which will likely be required for renewables, and would likely constrain co-locatable peaking capacity into the future. Saldanha already hosts the Sunrise Energy LPG terminal providing a possible alternate fuel source potentially cheaper and cleaner than diesel. Saldanha also hosts the Strategic Fuel Fund's crude storage facility, one of the biggest in the world with some 7 000 Ml of storage. Given the reduction in refinery capacity in the country the possibility of converting some of this facility to diesel should be considered. This diesel could potentially be transported to Ankerlig via the existing crude oil pipeline that runs to the Astron refinery, with appropriate modifications.

3.3.3.2 Ankerlig

Existing diesel-fired facility with 1.3 GW capacity. Currently fuel is delivered by truck into inadequately sized storage which needs to be substantially increased under any future circumstances to eliminate security of supply risks currently resulting from stock-out. Diesel delivery could be enhanced by use of existing pipeline infrastructure both from Cape Town harbour and Saldanha, with appropriate new pipeline tie-in near Atlantis. Additional generation units could be added to this facility subject to Western Cape supply area

[40] *Map was adapted from IISD, "Gas Pressure: Exploring the case for gas-fired power in South Africa." International Institute for Sustainable Development, 2022.*

constraints and local grid capacity. It is unlikely that LNG could be delivered cost-effectively to this site via pipeline due to the distance from port infrastructure and would require a containerised solution at much greater cost than the portside pricing contemplated in section 3.1.2.

3.3.3.3 Gourikwa

Existing diesel-fired facility with capacity of 740 MW – sufficient storage is available through use of capacity at the adjacent PetroSA site. Additional generation units could be added to this facility subject to Western Cape supply area constraints and local grid capacity, although the size of the additional capacity that would be required to make LNG viable would be similar to a greenfields site as it is unlikely that substantial non-power demand exists. The size of viable generation capacity (i.e. 3 GW – 6 GW without anchoring non-power demand) will likely challenge grid availability into the long term. Diesel is currently pumped from the port to the PetroSA site but LNG would likely require significant new pipeline infrastructure which would increase the LNG cost.

3.3.3.4 Coega/Dedisa

Existing IPP diesel-fired facility with capacity of 335 MW. Essentially a greenfields site as the existing capacity is so small. A recently released RFI [25] for FSRU and aggregation providers suggests that there is 5 PJ/a of existing industrial demand, although this presumably refers to potential gas demand, with there being no gas infrastructure or supply in place at present. If industrial demand does rise to 5 PJ/a it could reduce the size of new peaking plant required for LNG to be viable against diesel to 2 GW – 3 GW, although grid evacuation would be an issue for new capacity greater than 1 GW in the short term due to constraints on the Eastern Cape supply area and the need to use this capacity for renewables. Existing liquid fuels port import capacity could be used to supply diesel to the increased on-site storage that would be required if further generation capacity is built. The current intention appears to be construction of 1 GW of CCGT plant at Coega although this would not be economic or environmentally efficient compared to the alternative of renewables and peaking plant.

3.3.3.5 Avon

Existing IPP diesel-fired facility with capacity of 670 MW. This site lies between Richards Bay and Durban and is close to the Lilly line that brings Methane Rich Gas (MRG) from Gauteng. With existing volumes of MRG spoken for Avon's conversion to gas would need to wait until sufficient demand for LNG existed among all customers of the Lilly line to warrant deployment of an FSRU at Richards Bay and complete replacement of the existing pipeline-fed demand with LNG (MRG and LNG are not fungible). This is unlikely to happen until late in the decade when Sasol has indicated it may seek further LNG supply via this route after initially replacing declining Pande-Temane volumes with LNG from Maputo.

3.3.3.6 Richards Bay

Richards Bay has no existing generation capacity but is an attractive site for new capacity for a number of reasons. Significant electricity demand exists in Richards Bay from smelters and mining users which, coupled with the long transmission distance from the nearest generators creates substantial grid capacity for power injection – at least 3 GW of co-located peaking plant. It has an existing port with existing liquid fuels infrastructure.

The Lilly line is currently at capacity and due to the long transmission distance from

Gauteng can only supply approximately 20 PJ/a. However, were LNG available in Richards Bay a short (6 km) section of new pipeline could connect into the Lilly line from the port allowing LNG to be made available to customers downstream in Durban, as well as by reversing the current flow of the northern leg of the pipeline and supplying Gauteng-based industry including Sasol. Injecting gas in Richards Bay would improve the hydraulics of the pipeline and increase its current capacity to about 50 PJ/a (30 PJ/a downstream to Durban and 20 PJ/a upstream to Gauteng). This of course would be predicated on the assumption that existing and new customers would be able to switch from MRG to LNG (the gases are not fungible), with LNG likely to be at significantly higher cost.

In the short term, the existing liquid fuels capacity could be supplemented with substantial increase in storage providing for an incremental diesel-fired peaking solution to be put in place which could include LNG at some later date if sufficient existing customers were able to switch to LNG. Industrial demand of 50PJ/a or close to this figure would secure the discount of LNG over diesel on any power generation volumes consumed from the same FSRU as can be clearly seen from the figures in section 3.1.2, although the intermittency issues would still limit LNG from providing all peaking fuel requirements. Building peaking plant, diesel supply and storage capacity at Richards Bay in the short term is thus a no regret solution provided generators will be able to burn LNG or other fuel in future.

3.3.3.7 Retiring inland coal stations/Komati etc

Eskom has recently released an RFI[41] suggesting the possibility of installing 0.5 GW of gas-fired peaking capacity (and/or 0.75 GW of mid-merit capacity) at the Komati power station – the latest of its older power stations to be finally retired. Although the intention has to date appeared to centre on the prospect of only CCGT and therefore high Capacity Factor usage, Komati and other retiring inland power stations could potentially provide useful sites for the peaking plant that is actually required. Power station sites have of course all the infrastructure in place to access the electricity transmission network, and the steady flow of retiring coal plant over the coming years creates significant grid capacity for new generation at these sites.

Many of the older stations in Mpumalanga are also relatively close to the ROMPCO pipeline that brings gas from Mozambique to Secunda. Although the existing onshore gas fields at Pande and Temane are depleting, Sasol has indicated its intention to source LNG via Matola in Mozambique, to be transported to Secunda via the ROMPCO pipeline. In theory, a peaking plant located at one of the old power stations could be fuelled by LNG from the ROMPCO pipeline. This would create a situation where the total peaking fuel requirement (3 PJ – 5 PJ/a if 1 GW peaking capacity was installed) was a very small fraction of non-power demand on the pipeline (existing volumes to Secunda are approximately 150 PJ/a) and substantially lower than non-power demand through the same FSRU (assuming the bulk of the 40 PJ – 60 PJ by 2030 came via Matola).

In such circumstances it may be possible to provide a greater percentage of the peaking requirement with gas, but only on the assumption that the intermittency issues could be partially absorbed by diversification over the larger industrial/synfuels offtake.

[41] *RFI number MWP1409GX*

Use of the ROMPCO pipeline for peaking fuel supply, even if only a small fraction of overall pipeline throughput, would challenge the typical contracting regime for pipeline capacity. This requires shippers to limit the variability in daily offtake to within a small fraction of the annual pro-rata volume, in order to maximise the throughput utilisation of the asset.

Contracting for pipeline volumes without such a constraint can result in the sterilisation of some of the pipeline capacity –the capacity must be kept available year-round for instantaneous offtake but results in low annual throughput due to the intermittent use. This issue is probably not insurmountable but would likely see higher pipeline tariffs for the supply of gas to peaking facilities unless significant onsite gas storage could be put in place to allow for steady offtake.

Being at altitude it is likely that a generation solution using ICEs rather than OCGTs would be more economical. Further work on technology choice, the contracting / sterilisation and storage issues is required to properly understand the full scope of possibility at inland power station sites. It should be noted that these sites do already have existing liquid fuel storage capacity (although small) as liquid fuels are needed to support certain running modes of the coal stations – so diesel as an alternative fuel could easily be accommodated.

3.3.3.8 Other possible sites

Other potential sites worth considering would be:

- Durban-located refineries – with refinery capacity closing some of the old refinery sites could provide useful positions for some peaking capacity. These sites have significant liquid fuel storage capacity of course, are connected to the Lilly gas pipeline (for future use of LNG) and as large electricity users probably have reasonable grid access as well. Durban, and the Natal supply area have significant grid capacity available for evacuation of power.
- The MOTRACO transmission line that takes electricity to the Mozal smelter located near Maputo could provide grid access for up to 1GW of peaking capacity located in or near to Maputo/Matola. Because the Mozal smelter is on the end of a long transmission line it provides opportunity to "reverse" the flow in that line and allow a generator located near the end to access the South African transmission grid.
- Sasol/Secuda – existing generation plant at Sasolburg and Secunda could be expanded. The industrial processes at these sites use a large amount of electrical power therefore grid access would be available, with of course gas and liquid fuel capacity inherent in the processes on both sites.

3.4 SCALE OF ECONOMICALLY RATIONAL GAS USE IN POWER TO 2030

More detailed investigation of the peaking duty cycle, site–specific issues identified above as well as the possible scope and flexibility in the LNG contracting environment is clearly required as a next step in understanding the true extent of the role gas could play in the power sector. In order to reasonably estimate the scale of the gas opportunity based on the current information we have constructed two scenarios: (1) A likely scenario based on the assumption that no more than 50% of the peaking fuel can economically be contracted as LNG, and (2) an optimistic scenario where LNG could replace diesel for 80% of the total provided other site-specific aspects allow for economic

LNG use. Based on this analysis we estimate that of the 25 PJ/a – 40 PJ/a of fuel required annually by 2030, between 11 PJ/a and 18 PJ/a could economically be provided by LNG on average. We arrive at this estimate as follows:

3.4.1 Existing installed capacity

The existing peaking plant capacity of 3 GW will require fuel of 9 PJ/a – 15 PJ/a by 2030 based respectively on a Capacity Factor of 3% - 5%. However, considering the issues with supplying LNG to Gourikwa and Ankerlig at competitive prices with diesel there does not appear to be an economic opportunity to burn LNG at these stations. We have not analysed the costs and storage/scheduling/logistics implications of a containerised LNG solution for peaking usage, but the cost of this would necessarily be much higher than our calculations which are based on direct delivery from FSRU to port-side generation plant. The higher cost of the containerised solution would be much closer to or foreseeably higher than the cost of the competing supply of diesel, obviating most if not all savings.

LNG usage to fire the existing peaking operation at Dedisa would barely be worth doing based on the existing capacity (335 MW requiring 0.5 PJ/a-1.3 PJ/a) and would only be economic if more than the assumed 5 PJ/a of industrial demand materialised or additional peaking capacity of 2 GW – 3 GW were built, however other sites such as Richards Bay make far more sense for initial new capacity. Without 10 PJ/a of non-power demand it is hard to see an economically rational case for the existing Dedisa capacity, even under optimistic assumptions.

The only real contender for LNG among the existing capacity will materialise at Avon and only once the Lilly line MRG is replaced with LNG – possible by 2030. In the most optimistic case of 50 PJ/a of non-power demand met via the Lilly line by 2030, it is possible that more than 50% of the 2 PJ/a-3.5 PJ/a fuel required annually by Avon could be provided by LNG from Richards Bay, assuming an aggregator could use non-power demand to balance the intermittent peaking offtake. We assume that a likely scenario is 50% LNG use at Avon and optimistically 80%.

We thus see the opportunity for economic replacement of diesel with LNG burnt in the existing OCGTs by 2030 to likely be in the region of 1 PJ/a – 2 PJ/a, or 1.5 PJ/a – 3 PJ/a with more optimistic assumptions.

3.4.2 New installed capacity

Richards Bay appears to offer the best site for new generation capacity and assuming 3 GW (of the 5 GW new capacity required by 2030) is installed there, could likely absorb 4.5 PJ/a – 7.5 PJ/a of LNG per year assuming diesel would still be required for 50% of the peaking power generated due to the occurrence of longer peaking events. On optimistic assumptions where LNG could provide 80% of the fuel burned, LNG usage would be 7 PJ/a – 12 PJ/a. However, based on the relative price volatility between LNG and diesel per Figure 6, these volumes would not be reliably cost-competitive with diesel without non-power demand from the re-configured Lilly line to absorb the majority of the FSRU cost. LNG for peaking power generation at Richards Bay will thus <u>only</u> become economic closer to 2030 when/if all Lilly line customer demand is switched to LNG.

Depending on the outcome of further analysis, it appears possible that 2 GW of peaking plant could conceivably be located at old coal stations in Mpumalanga. Using the ROMPCO pipeline to provide as much fuel burn from LNG as possible could conceivably cover a

reasonable proportion of the 6 PJ – 10 PJ total annual fuel required, but this would be subject to affordable access to appropriate instantaneous pipeline delivery capacity. On the likely assumption that diesel would still be required 50% of the time, the opportunity at these locations for LNG use would range from 3 PJ/a – 5 PJ/a, if some intermittency could be buffered by larger customers and LNG could replace diesel for 80% of the burn the range is 5 PJ/a – 8 PJ/a per year.

In total the opportunity for LNG to economically fire generation from new peaking capacity by 2030 appears likely to be in the range from 7.5 PJ/a – 12.5 PJ/a (optimistically 12 PJ/a – 20 PJ/a).

3.4.3 Total opportunity for gas in power by 2030

Table 6 summarises our estimate of the opportunity for LNG to replace diesel in peaking by 2030 and shows that under a likely outcome the range is 8.5 PJ/a – 14 PJ/a per year, with the optimistic upper bound being in the range of 14 PJ/a – 23 PJ/a per year (i.e. on average 11 PJ/ – 18 PJ/a). Without anchoring demand at Richards Bay from non-power customers via the Lilly line, the opportunity would reduce and be only the inland power station options – (i.e. 5 PJ/a – 8 PJ/a). However, this volume would still require inland anchoring non-power demand, without which there appears to be no opportunity for LNG in power at all.

Table 6: Opportunity for LNG to economically replace diesel as peaking fuel by 2030

		Total Fuel required per annum (PJ/a)		Estimated % of fuel where LNG could displace diesel		Estimated LNG opportunity (PJ/a) Likely Scenario		Estimated LNG opportunity (PJ/a) Optimistic Scenario	
		Year of optimal use	Year of high use	Likely	Optimistic	Year of optimal use	Year of high use	Year of optimal use	Year of high use
Existing Capacity	GW								
Ankerlig	1.33	4.0	6.7	0%	0%	0.0	0.0	0.0	0.0
Gourikwa	0.74	2.2	3.7	0%	0%	0.0	0.0	0.0	0.0
Dedisa	0.34	1.0	1.7	0%	0%	0.0	0.0	0.0	0.0
Avon	0.67	2.0	3.4	50%	80%	1.0	1.7	1.6	2.7
New Capacity	GW								
New sites	5.00	15.0	25.0	50%	80%	7.5	12.5	12.0	20.0
		24.2	**40.4**			**8.5**	**14.2**	**13.6**	**22.7**

4 WHAT ARE THE RISKS OF COMMITTING TO BIG GAS IN THE POWER SECTOR?

We demonstrated in Section 2 that existing modelling provided no economic rationale for "big gas" in the power sector. In this section, we demonstrate that significant economic and environmental harm will be created by using high-volume gas-to-power projects to create anchor demand for gas in other sectors. Given that the most economic use of gas in power is at much lower volumes and results in much lower emissions, forcing high-use gas into the power generation mix will merely increase the cost and emissions from power generation.

4.1 ECONOMIC COST

The impact of using large volumes of gas to generate power will be borne by all electricity consumers and will essentially be a subsidy provided by power consumers to otherwise unviable gas use in other sectors. The full economic cost of this subsidy is far greater than merely the additional increased cost of the power, as it includes the damage to the economy caused by the loss of business activity that will be made impossible by the higher cost of electricity. Added to this is the further impact to all consumers of electricity occasioned by impending border tax adjustments and similar measures taken by other countries to ensure that global emissions trajectories move towards those compliant with the necessary net-zero aspirations. The cost of subsidising non-power gas demand through the power sector will render products from all businesses that use electricity less globally competitive.

Despite the common finding across all studies (section 2.3) that any new flexible capacity is only economic in this standby role, there is a current narrative that would suggest that the intention is for new flexible capacity to be gas-fired and provide mid-merit or base supply generation – i.e. to be run at Capacity Factors of 50% to 60% [1]. This is certainly the intent for the bulk of the gas power procured under the RMIPPPP which envisages 1.22 GW of gas-fired power from the Karpowership consortium operated at minimum annual Capacity Factors of 50% [26]. Eskom's plans to develop 3 GW of capacity at Richards Bay [27], and the 3 x 1000 MW gas-to-power plants proposed by Coega Development Corporation [28] appear to suggest similar intentions.

In order to illustrate the impact of forcing uneconomic gas use into the power sector we have calculated comparative costs of two scenarios, with each utilising the 3 GW of gas-fired capacity envisaged in the IRP 2019 differently. The first scenario, 'Big Gas', contemplates the capacity implemented for large-scale power generation. The second, 'Peaking Gas', assumes the capacity is deployed in a peaking/standby function mode with renewables providing the bulk of the energy. Technical assumptions for these scenarios can be found in section 8.1 of the Appendix.

4.1.1 A premium on the price of electricity

Figure 11 below shows the annual cost difference between the Big Gas solution - where the 3 GW of gas-fired capacity is deployed as high Capacity Factor (55%) CCGTs - as opposed to the Peaking Gas solution where OCGTs/ICEs run in a peaking mode with a Capacity Factor of 5%. In the peaking gas scenario the balance of power would be provide by a portfolio of 4.7 GW of renewables, resulting in the same total generation of 14.5 TWh energy per year for both scenarios. Given the fact that this new 3 GW capacity comes into a portfolio of existing capacity (almost 95% of customer demand would be met by the existing portfolio

of generators, mainly coal), the two scenarios provide similar value to the overall power system (in respect of both capacity and energy) which allows for a reasonable comparison of costs.

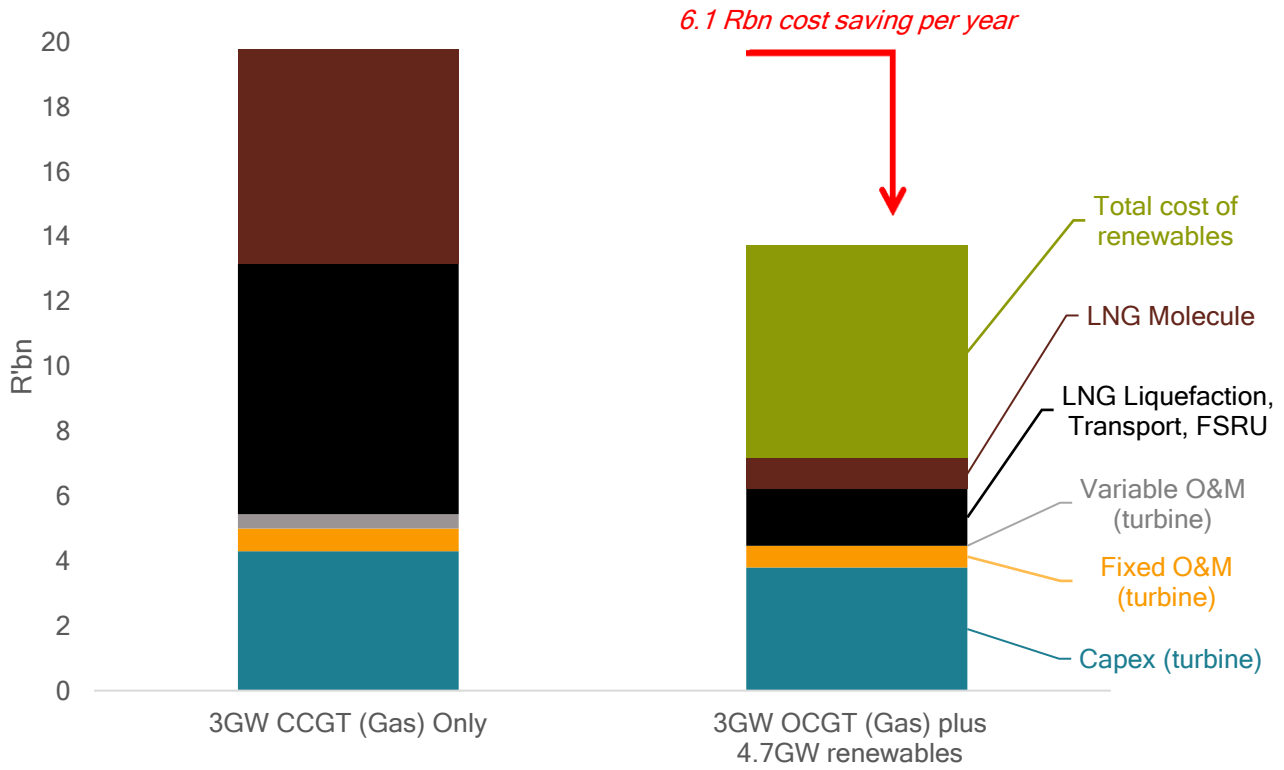
Deployment of the 3 GW of gas-fired capacity in a peaking role as supported by current system modelling studies (Peaking Gas scenario) results in an annual saving of R6.1 Bn when compared to the large-scale gas use scenario (Big Gas). Given that the economically rational procurement of the 3 GW of capacity would be for the peaking function, a large-scale gas solution using CCGTs would result in an unnecessary, unjustifiable premium of more than 40% on the cost at which the same electricity could and should be generated. In addition, the Big Gas scenario incurs 7.4 $MtCO_2e$ per year as opposed to the 1 $MTCO_2e$ of the Peaking Gas scenario. These differences are shown in Table 7 below. In this instance we have assumed OCGTs as the peaking technology, but ICEs could equally be used and provide very similar overall results.

Table 7: Total cost, emissions and fuel requirement for a set of scenarios designed to meet 3 GW of additional dispatchable capacity in the South African power system

Variable	Big Gas Scenario	Peaking Gas Scenario
Capacity Configuration (GW)	3 GW CCGT Only	3 GW OCGT + 4.7 GW RE
Fossil Fuel Generation (GWh)	14 454	1 314
Renewables Generation (GWh)	0	13 140
Total Cost Per Year (R'Bn/a)	19.8	13.7
Cost (R/kWh)	1.37	0.95
Emissions Per Year ($MtCO_2e/a$)	7.4	1.0
Fuel Requirement Per Year (PJ/a)	107	15
% Cost increase under Risk Stress Test*	+ 23.1%	+ 5.7%

**We stress test each scenario to see the resultant overall cost impact in the event that international gas prices were to increase by 50%, coupled with a 20% weakening of the Rand. See more on this in section 4.1.2.*

Figure 11: Total annual cost build-up for 3 GW additional gas capacity in the form of CCGT (Gas) only vs 3 GW OCGT (Gas) plus 4.7 GW of renewables



The cost comparison of Figure 11 is predicated on renewables pricing at 50 c/kWh (slightly higher than the average of the BW5 pricing), and LNG gas sourced on the basis of a Henry Hub linked price at $3.67/MMBTU as was the case in December 2021. Of course, gas prices are highly volatile (we address the risk associated with this in the following section) and under the current geopolitical conditions even the typically stable Henry Hub price has more than doubled since December 2021 ($6.84/MMBTU as of end April 2022, more than $8/MMBTU at time of writing).

Short term supply chain issues occasioned by both the Covid-19 pandemic and effects of the Russian invasion of Ukraine have also impacted the price of components needed for both wind and solar generation capacity. It is highly likely that some of the renewables projects bid into BW5 will not be able to reach financial close at the prices bid, and it is generally expected that renewables prices for BW6 (due for submission 11 August 2022) will be higher in real terms than those from BW5.

In order to stress-test the finding that large-scale gas is sub-economic in the South African power sector we constructed a sensitivity analysis for the full range of conceivable prices of renewable energy and LNG. Table 8 tabulates the premium of large-scale gas-fired power over a peaking / renewables alternative, presenting the same calculation as expressed in Table 7 but for the different intersecting values of renewables cost and gas price.

The first two columns contain the Rand price of gas at entry into the CCGT or OCGT plant based on the Henry Hub gas price in the third column. Note that provision has been made for a higher FSRU cost that would attach to a peaking usage mode as we assume that the

full FSRU and infrastructure cost would be recovered only from the 15 PJ/a of gas required under this scenario. The gas price into the CCGT reflects the same FSRU cost recovered from the large 107 PJ volume of gas required.

Table 8 illustrates that for all realistic combinations of gas and renewables prices (historically the lowest Henry Hub price of gas seen has been $1.20 in real 2021 terms) there is no economic case for large-scale gas use in power generation. Even if renewable prices in the short-term increase by 30% to 65 c/kWh and gas prices were immediately to drop to their lowest levels ever and remain there for the 20 year duration of a REIPPPP power purchase agreement, there would still be no case for large-scale gas use in power.

Table 8: Sensitivity analysis of the premium of large-scale gas over a peaking/renewables solution (all figures real 2021)

R/GJ into CCGT	R/GJ into OCGT	Henry Hub $/MMBTU	Renewables Cost R/kWh										
			0.40	**0.45**	**0.50**	**0.55**	**0.60**	**0.65**	**0.70**	**0.75**	**0.80**	**0.85**	**2.10**
70	115	**0.00**	15%	10%	5%	0%	-5%	-10%	-15%	-20%	-20%	-25%	-60%
90	135	**1.00**	30%	20%	15%	10%	5%	0%	-5%	-10%	-10%	-15%	-55%
100	140	**1.50**	35%	25%	20%	15%	10%	5%	0%	-5%	-5%	-10%	-55%
105	150	**2.00**	40%	35%	25%	20%	15%	10%	5%	0%	-5%	-5%	-50%
115	160	**2.50**	45%	40%	30%	25%	20%	15%	10%	5%	0%	0%	-50%
125	165	**3.00**	50%	45%	35%	30%	25%	20%	15%	10%	5%	0%	-45%
130	175	**3.50**	55%	50%	40%	35%	30%	25%	20%	15%	10%	5%	-45%
140	185	**4.00**	65%	55%	50%	40%	35%	30%	25%	20%	15%	10%	-40%
150	190	**4.50**	70%	60%	55%	45%	40%	35%	30%	25%	20%	15%	-40%
155	200	**5.00**	75%	65%	60%	50%	45%	40%	35%	30%	25%	20%	-35%
165	210	**5.50**	80%	70%	65%	55%	50%	45%	35%	30%	25%	25%	-35%
175	215	**6.00**	85%	75%	70%	60%	55%	45%	40%	35%	30%	25%	-30%
180	225	**6.50**	90%	80%	70%	65%	60%	50%	45%	40%	35%	30%	-30%
190	235	**7.00**	95%	85%	75%	70%	60%	55%	50%	45%	40%	35%	-30%
200	240	**7.50**	100%	90%	80%	75%	65%	60%	55%	50%	45%	40%	-25%
205	250	**8.00**	105%	95%	85%	80%	70%	65%	60%	50%	45%	40%	-25%

4.1.2 Exposure to volatility, pricing risk, and security of supply

In addition to being more expensive than a peaking/renewables solution, the use of large-scale gas in power generation will expose electricity users to much greater volatility of prices and the risk that future price increases may outstrip inflation. Renewables are typically contracted on a twenty-year power purchase agreement under which the buyer assumes no pricing risk for the tenure of the agreement, other than an annual inflationary increase. All future pricing risk is thus transferred to the seller of the power resulting in power being made available to the grid at a price that is constant in real terms.

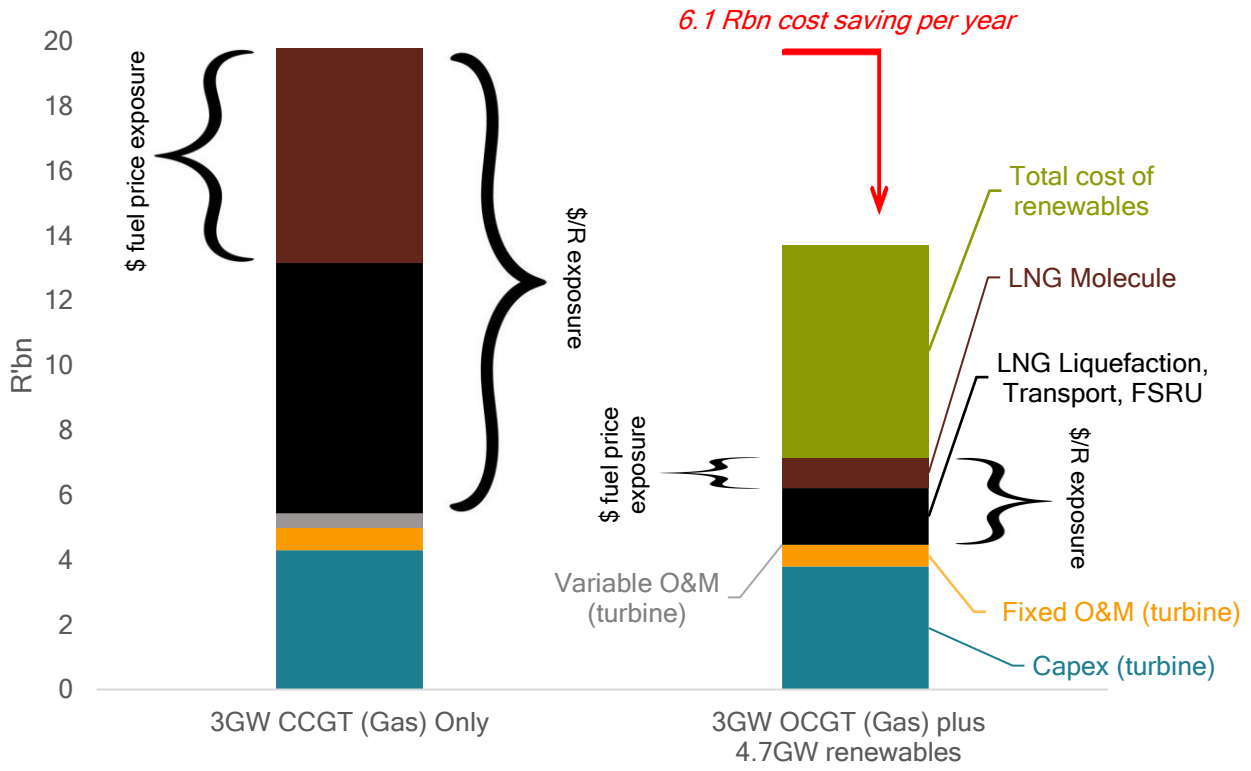
Fossil-fuelled generation is contracted in a manner that passes through all future increases in fuel and carbon costs to the buyer of the power, resulting in the future price of electricity from these sources being highly volatile and unpredictable. Since South Africa would need to import all fuel for fossil power generation at dollar denominated

prices, the resultant exposure is to both international energy markets and the ZAR/USD (R/$) exchange rate. Renewable energy on the other hand is priced in South African cents per kWh and once signed, the power is delivered at a constant price in real rand terms for the duration of the contract, with no further pricing risk.

Figure 12 illustrates the net impact of the pricing risk under the two options for the 3 GW of gas-fired capacity. In the peaking/renewables configuration, pricing risk is limited to the much smaller fraction of fuel burn required – this results in a R/$ exposure of less than 20% of the large-scale gas solution, and international gas price exposure of less than 15% the large-scale gas option.

Such exposures result in price shocks that usually entail a combination of energy price changes and currency weakening. Table 7 shows that under a price shock scenario where international gas prices increase 50% coupled with a 20% weakening of the Rand, the large-scale gas solution would see a 23% increase in the price of electricity, compared to the peaking/renewables solution which would only rise by 6%.

Figure 12: Pricing risk exposure of large-scale gas generation versus the peaking/renewables alternative



Although both solutions are reliant on the same fossil fuel logistics chain, the large-scale gas solution is *completely* reliant on the smooth functioning of this value chain for security of supply. As has been amply demonstrated in the recent months, relying on a fuel supply that is exposed to the whims of international geopolitics carries significant risk to security of supply. With a peaking/renewables configuration, more than 90% of the energy is generated on South African soil from domestic wind and solar installations, requiring no fuel and no reliance on global supply chains once operational.

4.2 ENVIRONMENTAL COSTS BECOME ECONOMIC COSTS

A shown in Table 7, the greenhouse gas emissions associated with a Big Gas scenario is seven times that of a Peaking Gas scenario.

The direct cost of emissions in the power sector is reflected in the current environmental levy of 3.5 c/kWh that is recovered by Eskom from electricity users on all non-renewable generation and is not reflected in the comparative economics of the previous section. The environmental levy is due to be phased out and replaced with a carbon tax which National Treasury has indicated [29] by 2030 will amount to at least $30/ton. This would increase the premium of the large-scale gas over the peaking / renewables solution by a further R2.9 Bn per year or a *further* 21% over and above the pure economic premium that already exceeds 40%. Thus, when taking consideration of the direct impact of the increased emissions the large-scale gas solution will deliver power at prices more than 60% higher than the peaking / renewables solution.

Although the direct impact on electricity users of increased emissions from large-scale gas deployment will be a crippling 60%+ premium on power costs, the indirect impact is arguably much worse. Forcing large-scale gas into power will increase the price of electricity forcing some businesses to become unviable with consequent lost GDP[42], but at least the carbon tax levied on electricity is retained within the fiscus, amounting to a transfer from electricity consumers to other spending priorities.

Impending border tax adjustments and other mechanisms introduced by South Africa's international trading partners will however ultimately have a far greater negative impact if a higher emission electricity pathway is adopted. Such measures will see South African products and services that use electricity penalised by any decisions that result in higher power sector emissions, particularly as our electricity is currently among the world's most carbon-intensive [30].

Contrary to the Gas Master Plan's statement that introduction of large-scale gas into electricity generation will reduce emissions, large-scale gas will significantly *increase* power sector emissions delivering environmental and economic harm as it does so.

4.3 SOCIO-ECONOMICS

The example comparison of the two scenarios presented in sections 4.1 and 4.2 provides a useful platform to interrogate the competing socio-economic benefits from a large-scale gas versus a peaking / renewables solution. Whilst accurate comparative employment numbers are notoriously hard to find for comparisons between renewables and other generations technologies, we can at least quantify the socio-economic benefits that would be required from large-scale gas in order to offset the sum of the other benefits already highlighted.

Firstly, it is useful to consider the localisation potential of the cost build-up in Figure 11 for the Big Gas vs Peaking Gas scenarios. More than 70% of the Big Gas scenario cost relates to fuel, as opposed to less than 20% for the Peaking Gas option. Bar a small fraction of this (common to both solutions) that would involve marine infrastructure construction and operation, there is virtually no opportunity to localise the fuel component.

[42] *Gross Domestic Product*

Similarly, whether OCGT, ICE or CCGT machines are used, these would likely be fully imported with only site civils work that could be localised, also common to both solutions.

The Big Gas solution requires slightly more operational and maintenance expenditure on the gas generation assets – approximately R460 m more than the Peaking Gas solution per year, which conceivably could almost all be localised. However, the renewables portion of the Peaking Gas solution presents a major localisation opportunity. Assuming that 50%[43] of the total annual renewables cost can be localised (this is likely to rise by 2030 as the domestic renewables industry grows) the peaking / renewables solution provides annualised localisable spend of R3.3 Bn – this is R2.8 Bn more than and almost seven times the R460 m potential from the large-scale gas solution.

It has been suggested that the exploitation of domestic gas resources could result in the localisation of some of the gas supply value chain, thus creating socio-economic benefits in the supply of the gas itself and so motivating for the large-scale use of gas in power. It is worth understanding the extent of benefits that would need to be realised from a domestic source of gas in order for this proposition to hold.

Again, returning to the Big Gas scenario, we see that a large-scale gas solution would use approximately 90 PJ (107 PJ vs 15 PJ) more gas than the Peaking Gas alternative. For it to be worth following a large-scale gas solution, the upstream socio-economic benefits from this additional 90 PJ of gas would need to outweigh the totality of the relative benefits generated by following the peaking / renewables solution, including those of cost described in sections 4.1 and 4.2. Downstream benefits, in other words any benefits generated from the actual power supplied would be the same in both scenarios and would therefore drop out of any comparison.

Thus, for it to make sense to follow a large-scale gas solution instead of the peaking / renewables option from a socio-economic perspective, the net upstream socio-economic benefits flowing from prospecting, extraction and delivery of 90 PJ of gas would need to outweigh the following:

- The annual direct power cost saving of R6.1 Bn
- The additional multiplying economic benefit of power that does not carry a 44% cost premium
- The additional annual saving in carbon tax that by 2030 will be R2.9 Bn
- Any impacts to South Africa's global competitiveness and GDP that will result from border tax adjustments or similar initiatives due to the seven-fold higher emissions intensity of the large-scale gas solution
- The socio-economic benefits flowing from an annualised R3.3 Bn of localised renewables industrial activity, supporting a growing local renewables industrial complex, versus R460 m per year of maintenance spend on turbine infrastructure

We have not seen any compelling analysis to suggest that upstream benefits from domestic gas use would at all be able to outweigh these benefits. Of course, if LNG is used as the fuel the 107 PJ used in the Big Gas option would

[43] *The actual local content percentage achieved in BW4 was 58% for solar PV and 44% for wind capital expenditure, with a weighted average just below 50% [31]. Assuming that most of the operational expenditure for renewable plants is localisable (confirmed by industry experts), the total localisable portion of the annual cost of renewables (including capital outlay and operational expenditure) will be greater than 50%.*

generate no more socio-economic benefits for South Africa than the 15 PJ consumed in the Peaking Gas scenario – there would merely be a more frequent replenishment of the FSRU.

Although in this report we address only the role and economic case for gas in the power sector, it is worth mentioning that the arguments unpacked above in respect of benefits necessary from additional gas use apply equally to other sectors that might benefit from large-scale gas use being forced into the power sector.

If the economic case for industrial, transport, and synfuels gas consumption is to rely on anchoring demand in the power sector then the benefits so gained in these sectors must first outweigh the substantial destruction of benefits outline above before any consideration of what would in effect be a subsidy to these industries.

5 DEBUNKING MYTHS IN THE NARRATIVE AROUND GAS

The research and calculations in this report have serious implications for common perceptions about gas in the South African discourse. Based on the evidence presented, this section debunks five prevailing myths.

5.1 MYTH 1: "BIG GAS REPLACES COAL AND IS THEREFORE A CLEANER ALTERNATIVE"

"Big gas"[44] does not replace decommissioning coal in the power sector for the foreseeable future - it displaces new renewable capacity that provides the more rational generation choice for replacing the energy from decommissioning coal. The energy from renewables is both cheaper and cleaner than the energy from gas.

A common finding across all power sector studies as discussed in section 2.3 is that the overwhelming majority of new energy generation in the power sector comes from wind and solar resources for at least the next decade if an optimal economic and environmental decision-making process is applied. This finding is in the context of coal power decommissioning over this period, thus the energy from wind and solar resources is found to be the optimal replacement for the retiring coal capacity, in the context of the entire portfolio of generators. The fact that gas may have lower emissions than coal does not mean that if gas is forced into the system, it will replace the coal and reduce emissions. The coal is the wrong counterfactual for "big gas" in the South African power sector at this juncture in its history and for at least the next decade. Building "big gas" during this period can therefore only result in one or more of the following perverse outcomes:

- Retarded rollout of (cheaper and cleaner) renewable capacity – if "big gas" capacity were built and used at high Capacity Factors there would be less need to install renewables. This would stall or delay future rounds of the REIPPPP.
- Curtailed[45] renewable energy – if "big gas" capacity was built and dispatched with a priority for high gas utilisation whilst still continuing with accelerated renewables procurement, at some point the (cheaper, cleaner) renewable energy from new installed capacity would need to be curtailed to make way for energy generated by gas. This would be absurd but is an almost inevitable outcome from the gas generation capacity procured under the RMIPPPP remuneration framework which has contractual minimum Capacity Factors of 50%[46].
- Idle gas capacity – if significant CCGT capacity is built in the next decade in conjunction with the large renewable capacity required to fulfil least cost build requirements, and is dispatched in an economically rational manner in accordance with a least cost merit order, the CCGT capacity will stand idle much of the time. The high Capacity Factors are not required for system adequacy and the CCGT will be used at Capacity Factors close to 5%. This will impose unnecessary costs on the system. CCGT capital costs exceed those of OCGT / ICE and the gas supply contracts may not allow for such

[44] *"Big Gas" in the context of this report refers to the use of gas in the power sector beyond a minimal role to provide standby/peaking power – i.e. the use of gas generators operating at Capacity Factors of 50%-55% or higher compared to 5% or lower (these roles are explained in more detail in section 2.1).*

[45] *Curtailment refers to the practice of dumping energy to waste as it exceeds the ability for demand or storage to absorb it at the time it is produced.*

low gas usage as they are likely to be contracted on a take-or-pay basis.

Beyond the mid-to-late 2030s, there may be a role for "big gas" in the form of the CCGT capacity, however, decisions on this do not need to be made before 2030, given that short three year lead times would be involved (this is discussed further section 2.3.2 and in Box 3). The option to delay this decision has immense value for South Africa, allowing us to evaluate technological developments as they arise and not commit ourselves to carbon lock-in / stranded assets.

5.2 MYTH 2: "GAS IS REQUIRED AS A 'TRANSITION FUEL'"

A pervasive view in the debate around gas in the power sector revolves around it being a required "transition fuel" in the journey from a coal-dominated system to a renewables-dominated one. Whilst the notion of a "transition fuel" is poorly defined, we take it to mean a fuel choice that is necessary for a limited period due to the unavailability of economic alternatives to fill the hole in the power system created by impending coal retirements.

Going via gas from coal to renewables may make sense in some countries where expensive coal, cheap gas and poor renewables combine to make this an economically rational path, but this is not the case in South Africa. For example, the UK replaced coal with gas in the 1990s as gas was the better alternative – that gas is now being replaced by wind. However, the studies of the South African power system show that we can migrate from coal to renewables whilst maintaining our climate commitments and security of supply at least cost without resorting to "big gas", for at least the next decade.

Gas-fired flexible capacity as anything more than a provider of standby / intermittency support does not become economically rational until the mid-to-late 2030s, and only then once all coal capacity is closed (as it will likely need to be in order to comply with emissions constraints). Thus, the transition for which gas *may* be necessary does not occur in South Africa in the next decade, and the role of gas in the final exit from coal can be re-evaluated closer to the time (see section 2.3.2 and Box 3). It would be prudent to continually evaluate this position, perhaps every three to five years or more frequently to align with IRP updates. It is highly likely given the pace of change of alternative technologies that less emitting technology alternatives to gas will have matured by the time coal is finally completely retired.

In evaluating the possible role of gas as a transition fuel for flexible capacity against still-maturing technologies such as batteries it is important to bear in mind some additional 'hidden' costs of committing to a large-volume gas-to-power programme. These include the ongoing exposure of power prices to the vagaries of the exchange rate and the global gas market, both impacted by geopolitical factors outside of our control and difficult to predict (as outlined in section 4.1.2). Battery storage, wind and solar technologies are not exposed to these risks and provide price trajectories that are predictable and usually linked to inflation once commissioned. Existing power system models do not take this risk explicitly into account and thus if anything would tend to overstate the economic role that gas should play in the power sector.

5.3 MYTH 3: " 'ANCHOR DEMAND' EXISTS FOR GAS IN THE POWER SYSTEM"

There is no 'anchor demand' for gas in the South African power system to underwrite

nascent industrial demand. Anchor demand for gas in the power sector would be present if the optimal economic choice for new power generation required large-scale deployment of CCGT capacity running at high (50%-60%) Capacity Factors. Not one power system modelling study shows this to be the case, whilst all studies suggest that the role for gas should only be to fuel peaking / standby capacity – a role that increases with increased penetration of wind and solar capacity.

Peaking power generation is characterised by low annual gas volumes, with intermittent offtake and large instantaneous flow rate requirements for a limited number of hours at a time. This restricts the viable capacity for gas-fired peaking plant to circumstances where it can be twinned with a much larger industrial gas offtake so that infrastructure costs of storage and re-gasification can be spread over sufficient volumes to be economic (see section 3.3.1).

Additionally, if the peaking capacity becomes sizable relative to the industrial offtake supplied through the same infrastructure it is questionable whether the peaking flow rate requirements could be met without impacting on the ability to deliver volumes to the industrial customers.

The reality is thus that, far from power providing anchor demand for gas, the viable use of gas in the power sector requires larger anchor gas demand from other sectors at each supply point in order to be technically and economically feasible.

"Big gas" in power is sub-economic compared to other holistic power system alternatives that combine large renewables build and peaking plant. Ignoring this reality will impose substantial additional costs on electricity consumers (who are already suffering from very large tariff increases).

5.4 MYTH 4: "BIG GAS IS REQUIRED TO SUPPORT 'UNRELIABLE' RENEWABLES"

It is necessary to debunk the myth that wind and solar resources require support from high-utilisation flexible capacity in order to maintain security of supply. This argument is typically made to motivate for the use of CCGT capacity operating at Capacity Factors of 50%-55% or higher – the sort of operational mode that would be expected from a power system reliant on gas for a large fraction of its energy generation. An archetypal power system consisting of only wind and solar resources is often invoked to make this argument and the obvious question posed – "what about when the wind doesn't blow and the sun doesn't shine?".

If South Africa's entire power needs were to be met using wind and solar alone, there would indeed be a need for significant generation from some flexible dispatchable resource in order to maintain a secure electricity supply, although improvements in storage technology are rapidly reducing this requirement.

In the real world however, new wind and solar capacity come into an existing power system with a portfolio of other generation assets. System modelling that takes the entire portfolio of generation assets in the South African power sector into consideration sees little or no requirement for CCGT capacity or high gas utilisation rates for as long as material coal capacity exists on the system – i.e. well into the late 2030s.

The reality is that a portfolio of wind and solar generators provides a significant proportion of its energy over the course of the year at times when there is demand to use it. As the proportion of wind and solar generation increases in the system, existing and new

storage capacity is used to move the additional renewable energy from times of lower to higher demand. Flexible dispatchable capacity is only required to fill in the gaps over the course of the entire year when weather events result in sustained periods of lower-than-average generation from the renewables. These events are however rare and over the course of the year are unlikely to require utilisation of supporting flexible capacity exceeding 5% of the time.

Our recent report[47] on the role that renewables could play in ending load shedding demonstrates that in the context of the current power system, dominated as it is by distressed coal generation and over-use of the existing peaking plant, the addition of renewable generation capacity dramatically reduces the required peaking generation.

5.5 MYTH 5: "DEDISA (OR ANY OTHER OCGT FACILITY) UTILISATION AT 12% IS PROBLEMATICALLY LOW"

The RFI for Ngqura LNG [25] suggests that the operation of Dedisa could be revised to increase its capacity utilisation – currently around 12%, implying that this is problematically low. Of course, 12% is actually far too high for this facility given that it is an OCGT and therefore designed to operate as a standby / peaking plant.

Considering an intervention that would increase Dedisa utilisation above 12% is merely indicative of an incorrect point of departure that seeks to maximise gas use as opposed to minimise power system cost. OCGT use above 10% is simply a reflection of problems elsewhere in the system – these problems are not fixed by increasing the Capacity Factor of the OCGTs but by adding cheap energy generation to the system to decrease the OCGT Capacity Factor.

Increasing the Capacity Factor of the generator at Dedisa could only make economic sense if it was converted to a CCGT facility (unlikely to be cost-effective given its small size of 335 MW) and if the use of CCGT power was economically rational for the power system which, according to multiple system modelling studies, is not the case.

[47] *Meridian Economics, "Resolving The Power Crisis Part B: An Achievable Game Plan to End Load Shedding," p. 67, 2022, [Online].*

6 CONCLUSION AND NEXT STEPS - A PROPOSED STRATEGY FOR GAS IN POWER

6.1 CONCLUSIONS

1. Current policy direction in the form of the Gas Master Plan's vision for the power sector is predicated on a contextual reality from the 2012 NDP. This does not reflect the paradigm-changing reductions in renewables costs and available carbon space that have occurred in the ten years since then. Ignoring this reality and proceeding with the current policy direction unchanged risks locking the South African power sector into an economically and environmentally damaging future.
2. The economically rational role for gas in power generation is in the small but critical role of fuel for peaking or standby capacity - this generation capacity optimally stands idle 97% of the time. There is no role for large-scale gas-fired power generation in the South African power system for the foreseeable future. If this changes due to future unforeseen circumstances, the short lead times of gas to power projects will permit capacity to be built when it is required.
3. The total peaking generation capacity required by 2030 is approximately 8 GW, requiring approximately 25 PJ – 40 PJ of fuel per year – there is likely an opportunity for LNG to supply a portion of this demand.
4. The realistic portion of fuel demand for peaking that could be supplied by LNG is restricted to sites and circumstances where LNG can economically replace diesel for some fraction of the total fuel requirement each year. This fraction is limited by site-specific issues at existing and potential sites, by LNG contracting constraints and is probably in the range of 11 PJ to 18 PJ per year by 2030 – roughly half of the total required, the balance being met with diesel. However, without material (~10PJ/a) non-power demand supplied through the same FSRU as the peaking plant, LNG will be more expensive than diesel. In such circumstances whilst there may be a case for LNG based on fuel source diversification and emissions (very small), there will be no economic case for LNG in power at all.
5. There is likely little or no emissions benefit from burning LNG instead of diesel once a reasonable accounting for fugitive emissions is considered.
6. Forcing large-scale gas use into the power generation portfolio in South Africa instead of the much smaller alternative peaking role to support renewables will increase the cost of the electricity so generated by more than 40%. It will increase emissions seven-fold compared to the alternative whilst reducing the socio-economic benefit that would accrue to the country by a similar multiple. Accounting for National Treasury's stated carbon tax intention by 2030 a further 20% cost premium over the alternative will be incurred (total premium 60%+).
7. An irrational decision to implement a large-scale gas-fired power solution in the face of a much cheaper, much lower emission alternative will expose most of South Africa's exports to potential border tax adjustments and other international measures that will at best reduce export competitiveness. Such a decision would likely impact developed country appetite to provide financial support to assist South Africa with its just energy transition, putting concessional or conditional funding at risk.

8. Given the ongoing rapid developments in generation and storage technology, a cautious incremental approach that maximises the use of existing infrastructure and minimises the risk of lock-in to gas use in a future that may not require it is prudent. Immediate solutions to any further peaking requirement should first consider maximising the use of the current assets by providing more on-site diesel storage, and greater use of the current pumped storage facilities.
9. The availability of grid capacity at Eskom's old power stations and their proximity to the ROMPCO pipeline with Sasol's apparent intention to use this to source LNG via Matola provides potential for gas-fired peaking plant in the short term. This would capitalise on existing infrastructure and provide the lowest cost LNG. Richards Bay would appear to be the best site for any new greenfields peaking projects that could use LNG – these could initially be diesel-fired as diesel storage and supply infrastructure will almost certainly be required in any case.

6.2 RECOMMENDED NEXT STEPS FOR GAS IN POWER

The following next steps should be considered before any decision is taken to procure gas-fired power generation capacity:

1. Update relevant policy/planning documents including the Gas Master Plan and the IRP to reflect the true current reality of renewables costs and available carbon space. Continuously monitor developments in battery storage, hydrogen and other emerging opportunities that will affect the viability of gas in power and ensure these are reflected in regular policy updates.
2. Conduct a proper detailed analysis of the peaking plant duty cycle and associated fuel supply requirements that would ensure security of electricity supply to 2030. This study would need to consider the current requirements dominated by the need to support failing coal plant and the evolution of this role over the next ten years as increased renewable generation increases the system security and reduces the peaking requirement. The study would need to contemplate the changing nature of peaking events as renewable penetration increases and events become potentially fewer but of longer duration.
3. Conduct analysis of the potential for some portion of the peaking requirement to be met by gas supplied by the ROMPCO pipeline at one of the older Eskom power stations. This study would need to take account of the duty cycle needs resulting from the above and the ability for site storage and other customer offtake to absorb the intermittency requirement.
4. Conduct site-specific analysis of existing and potential new sites within the context of the peaking fuel offtake requirement determined from the above to determine the opportunity for LNG to realistically replace diesel with a certain cost saving. This analysis would need to include the ability and extent to which the LNG contracting environment could be adapted to provide a no-regret fuel supply where any necessary take-or-pay requirements do not create perverse incentives to burn more LNG than is economical in the short or long term.
5. Investigate opportunities to use the SFF facility to store diesel. This could be distributed to peaking plant by vessel or potentially by pipeline to Ankerlig.
6. Ensure that any new flexible capacity is able to run on multiple fuel options including diesel, LNG, hydrogen, etc. Consider greater use of ICE generation

capacity where feasible. This is modular, economic over a greater range of duty cycles, can be moved to different sites as the need arises and is able to run at the coast or at altitude with minimal loss of efficiency.

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8 APPENDIX

8.1 TECHNICAL AND COST ASSUMPTIONS

This section outlines the assumptions used for the comparison of a Big Gas versus Peaking Gas Scenario in section 4.1 on economic and environmental bases.

8.1.1 Technology assumptions

The technology and cost assumptions are from EPRI (2017) Power Generation Technology Data [32], compiled for the country's Integrated Resource Plan (IRP2019) unless otherwise stated. All costs are expressed in December 2021 Rands. Fuel cost assumptions can be found in section 3.1.2.

Table 9: Technology assumptions

Variable	Unit	CCGT (Gas)	OCGT (Gas)
Economic lifetime	a	20	20
Capacity Factor (typical)	%	55%	5%
Electricity production (typical)	kWh/kW/a	4 818	438
Heat rate	kJ/kWh	7 395	11 519
Electrical efficiency (HHV)	%	48.68%	31.25%
CAPEX per capacity	R/kW	13 879	12 235
Annualised CAPEX	R/kW	1 435	1 265
Fixed O&M	R/kW/a	231	224
Variable O&M	R/MWh	31	4
LCOE	R/kWh	1.37	5.45

Renewables are assumed at a cost of R0.50/kWh and with a combined (solar and wind) Capacity Factor of 32% (which was the portfolio average for 2021 according to Eskom's data[48]).

8.1.2 Emissions intensity assumptions

Emissions intensity values are from the Department of Forestry Fisheries and the Environment (DFFE)'s Greenhouse Gas Inventory report published in 2021 [33]

Table 10: Emissions intensity assumptions

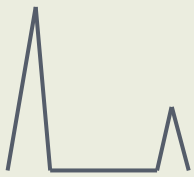
Variable	Unit	CCGT	OCGT
Carbon intensity (gas)	$kgCO_2e/kWh$	0.512	0.798
Carbon intensity (diesel)	$kgCO_2e/kWh$	-	0.856

[48] *See Meridian Economics, 2022. "Resolving the Power Crisis Part A: Insights from 2021 – SA's Worst Load Shedding Year So Far."*

8.2 CAPACITY FACTOR CLASSIFICATION OF DISPATCHABLE GENERATION PLANT

Table 11 illustrates a conventional categorisation of different types of dispatchable generators. We follow the Council of Scientific and Industrial Research (CSIR)'s categorisation [34] of peaking, mid-merit and base supply whereby peaking-type capacity is considered as capacity that would operate for <1 000 hrs/yr (< 11.4% Capacity Factor); mid-merit type capacity is considered as capacity that would operate for between 1 000 and 6 000 hrs/yr (11.4 – 68.5% Capacity Factor); base-supply type capacity is considered as capacity that would operate >6 000 hrs/yr (> 68.5% Capacity Factor). These functional categories are a continuum. Natural gas is conventionally used to fuel peaking and mid-merit type plants.

Table 11: Classification of dispatchable generators into functional categories

Classification		Utilisation	Generator examples
	**Peaking plants** are fast-acting plants that are used to cater for quick changes in power demand. They tend to be the most expensive category of plant to run and are therefore run infrequently, standing idle the rest of the time.	• Low • < 1 000 hours per year (< 11% Annual Capacity Factor)	• Open Cycle Gas Turbines (OCGT) • Internal Combustion Engines (ICE)
	Mid-merit plants are 'load-following' plants and are able to adjust power output in response to fluctuating demand.	• Medium • 1 000-6 000 hours per year (11%-69% Annual Capacity Factor)	• Combined Cycle Gas Turbines (CCGT)
	Base supply plants are generators that are optimised for operation at full output with minimal interruption, to meet a minimum level of demand over a particular period.	• High • > 6 000 hours per year (> 69% Annual Capacity Factor)	• Nuclear plants • Coal plants

8.3 POWER SYSTEM MODELLING STUDIES AND SCENARIOS

We investigate the results of four recent power system modelling studies – specifically examining their conclusions on new build generation plant which could be fuelled by gas. We select comparable scenarios from these studies for the analysis in section 2.3.1 and section 2.3.2. They are comparable on the basis that they are all cost-optimised modelled pathways that include carbon constraints which limit total emissions to align with South Africa's decarbonisation imperatives.

1. NBI (2022): *The Role of Gas in South Africa's Path to Net-Zero* – As part of the Just Transition Pathways Project, the NBI in partnership with Boston Consulting Group (BCG) analysed four potential gas demand scenarios for the South African economy which varied based on their level of decarbonisation ambition, and the availability of gas supply. These scenarios are structured to have either 'low demand' or 'high demand' for gas in the power sector, with the demand for gas ranging from 7 – 170 PJ by 2030, respectively. We only consider the NBI's low demand scenarios in our analysis, as these are aligned to the NBI's cost-optimised 'low emissions' power sector pathway – which does not include gas-to-power run at high Capacity Factors forced in to align with current policy direction (which proves to be economically sub-optimal).
2. UCT Energy Systems Research Group (ESRG) (2021): *Analysis to support SA's NDC update* – UCT ESRG were commissioned to provide technical input into the process for updating the emissions targets in South Africa's Nationally Determined Contribution (NDC) to the Paris Agreement. Their study utilised an energy-economy-linked model to analyse emissions and macro-economic outcomes under a set of policy interventions, carbon emissions constraints, and high/low economic growth rates. For the purposes of our analysis, we only consider the outcomes of the modelling cases that fell within the 2021 draft NDC target (398 – 420 CO_2e Mt by 2030) – which demonstrate that a significant ramp-up of renewable energy capacity, along with varying levels of flexible dispatchable capacity and storage, will be required to stay within this emissions range.
3. Meridian-CSIR (2020): *A Vital Ambition* Study - This study, undertaken in collaboration with the CSIR, assessed the cost of additional climate mitigation in the South African power sector to align with the Paris climate change temperature goals. The modelling outputs revealed that a modest addition of peaking capacity – run at low Capacity Factors and served by existing liquid fuel infrastructure – will be sufficient to meet the needs of the power system until at least the mid-2030s, even for scenarios with the highest-renewables penetration including the "Ambitious RE pathway" and "Coal off by 2040" scenarios. The study therefore suggests that any decisions on large-scale gas infrastructure for the power sector could be delayed by 10 – 15 years in order to prevent a lock into long-term gas commitments. This preliminary finding and its implications piqued our interest in the role of natural gas in South Africa's energy transition, and led to the analysis reported in this report.

We also consider a recent doctoral thesis conducted by Clark (2020) which contemplates the appropriate role for gas-

fired power in line with the country's planned capacity additions per the IRP2019 up to 2030.

4. Clark, S (2020) Stellenbosch University PhD Thesis: The Use of Natural Gas to Facilitate the Transition to Renewable Electric Power Generation in South Africa – Clark utilises a simple Energy Dispatch Model to explore the appropriate role for gas in meeting the requirement for dispatchable energy in South Africa's power sector. The study finds that the dispatchable energy requirement from the system in 2030 could vary from 5 to 15 GW, with an expected Capacity Factor between 2 % and 5 %. This corresponds to a fuel requirement of 9 to 78 PJ per year, with an expected value of 27 PJ/a. Importantly, Clark finds that the installation of battery storage reduces the need for dispatchable energy to balance the system, but that this will likely only reduce the energy that must be generated by the dispatchable generation facilities, without reducing the required installed capacity.

Table 12: Existing peaking plant capacity

OCGT facility	Capacity (MW)
Ankerlig	1,327.00
Gourikwa	740.00
Avon	670.00
Dedisa	335.00
Acacia	*
Port Rex	*
Total	3,063.00

*The Acacia and Port Rex facilities are used for reserve purposes only and will retire in the period to 2030

8.4 EMISSIONS CALCULATION ASSUMPTIONS

This section outlines the assumptions used to calculate the emissions savings of LNG versus diesel-fired power in section 3.2. Table 13 illustrates the carbon intensity of natural gas assuming different rates of leakage in the LNG value chain (0%, 2.5% and 3.5%) and the corresponding carbon intensity of the power assuming it is generated by an OCGT[49]. The emissions intensities per kWh are compared with that of diesel (which is 0.856 kgCO_2e per kWh) to determine the % emissions savings achieved by switching from diesel to LNG-fired power (column 4).

[49] *Heat rate (HHV) of OCGTs assumed at 11 519 kJ/kWh*

Table 13: Carbon intensity of gas-fired generation and emissions savings relative to diesel

Leakage rate	Carbon intensity (fuel)	Carbon intensity (OCGT power)	Emissions savings relative to diesel*
	Kg CO_2e / GJ	Kg CO_2e / kWh	% Per kWh
0% leakage	56.16	0.647	24%
2.5% leakage	69.28	0.798	7%
3.5% leakage	74.35	0.856	0%

**Diesel comparator: 0.856 Kg CO_2e / kWh*

The baseline carbon intensity value for the stationary combustion of gas is drawn from the DFFE's latest Greenhouse Gas inventory report, which is 56 kgCO_2e per GJ of fuel (see 0% leakage row in the table)[50]. We then quantify the increase in emissions intensity caused by leakage along the LNG value chain (i.e. what additional amount of CO_2e emissions are released into the atmosphere per GJ of LNG through leakage).

The energy density of LNG is 20.8 kg/GJ. Therefore, at a 1% leakage rate, an additional 0.21 kg would be leaked into the atmosphere for each GJ of LNG finally burned, before it reaches the power plant. Assuming that this leakage is constituted of 90% methane[51], the CO_2e value would be 90% x 0.21 x 28[52] = 5.3 kgCO_2e per GJ.

The increased emissions intensities associated with increasing leakage rates are demonstrated in column 2 of Table 13. The literature on leakage from the LNG value chain is undecided on what reasonable value to assume, with published leakage rates ranging from 0.6% to 9% [21].

We use an assumption of 2.5% leakage for the emissions calculations in this report, which is at the lower end of the published range. This adds an additional 13.1 kgCO_2e per GJ of LNG burned[53], resulting in a 7% emissions savings per kWh in the switch from diesel to LNG. Based on our calculations, an assumption of 3.5% leakage along the value chain would eliminate the emissions savings gained by burning LNG instead of diesel.

When using the GWP20 value of methane, (where it has 82.5x more warming potential than CO_2 over a 20 year period) which is arguably a better representation of the effect of methane over the period it is most impactful – the **emissions savings of LNG over diesel is eliminated at a 1.2% leakage rate.**

Overall, this demonstrates that in principle and considering no leakage, LNG-fired plant could provide emissions savings relative to diesel. However, as soon as small amounts of leakage are considered (in the lower part of the range suggested by the literature on actual leakage rates) – the savings are small or negligible.

[50] *74 kgCO_2e per GJ of fuel for diesel – which when taking into account the efficiency of the OCGT provides us with the 0.856 kgCO_2e/kWh reference point.*

[51] *We assume 90% methane for this calculation. LNG is 85 to 95-plus percent methane, along with a few percent ethane, even less propane and butane, and trace amounts of nitrogen. The exact composition of natural gas (and the LNG formed from it) varies according to its source and processing history. [35]*

[52] *28 is the GWP100 value of methane according to the IPCC's Sixth Assessment Report [36]. This means that 1kg of methane causes 28 times the warming caused by an equivalent amount of CO_2 over a 100 year period.*

[53] *This is a very conservative estimate relative to other studies in this field such as [37] and [38] which show that precombustion emissions for LNG transported via ocean range from 17.8 – 21.6 kgCO_2e/GJ.*

8.5 FSRU COST ASSUMPTIONS

The FSRU cost analysis is based on a leased vessel with capex only incurred for the necessary marine infrastructure and pipeline required to transfer gas from the FSRU to generation capacity located in the port precinct.

8.5.1 Vessel specification

Vessel specification	Unit	
FSRU Containment (Gross)	m3	173 000
Replenishment Vessel Cargo Capacity (Gross)	m3	156 000
Cargoes per Annum*	#	5
Delivery Interval*	days	73.0

**Cargo number per annum and delivery interval for 3GW @ 5% Capacity Factor*

8.5.2 FSRU costs

FSRU Costs	Unit	
Marine Capex	USD m	113.0
Development Cost	USD m	**5.0**
Owners Cost	USD m	**8.0**
EPC	USD m	**100.0**
Day Rate - Lease**	USD/d	94 320
Day Rate - Fixed Opex	USD/d	15 000
Variable Opex	USD/mscf	**0.41**

***includes provision for 6 vaporisers*

8.5.3 Pipeline costs

Pipeline costs	Unit	
Unit Pipeline Cost	USD/"/km	100 000
Pipeline Length	km	5.0
Fixed Opex	1.5% of EPC	
Variable Opex	USD/Mscf	0.03

8.5.4 Financing assumptions

Financing assumptions	Unit	
Dollar nominal cost of Equity	%	10.00%
Dollar nominal cost of Debt	%	3%
Gearing	%	70%
R/$ exchange rate	ZAR/USD	15.50
Contract Term - years	Years	20.0