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ECONOMIC FEASIBILITY STUDY OF SEVERAL UTILIZATION ALTERNATIVES FOR A STRANDED OFFSHORE GAS RESERVOIR

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ECONOMIC FEASIBILITY STUDY OF SEVERAL UTILIZATION ALTERNATIVES FOR A STRANDED OFFSHORE GAS RESERVOIR

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Abstract:

Floating Liquefied Natural Gas (FLNG) has been on the rise in recent years to meet growing energy demand, worldwide. As energy consumption and exploitation of onshore unconventional gas reservoirs continue to grow while gas price remains almost steady, FLNG can potentially become the winning card for operators in conventional offshore gas fields through integration of upstream and midstream processes on the spot.

This thesis compares project economics of a FLNG utilization to those of onshore LNG plant, and Gas-to-Wire (GTW) processes. We primarily conducted sensitivity analysis and tornado charts to evaluate importance of various uncertain parameters associated with FLNG construction and operation. Costs for the hypothetical FLNG vessel is taken from Shell's Prelude FLNG; while pipeline, LNG plant, and gas-to-wire costs were obtained from typical industry standards. A typical hyperbolic decline curve model is applied to model depletion flow regime of production life after 5 to 10 years constant rate plateau time.

Several factors are included in the sensitivity analysis: LNG price, interest rate, initial production rate, and condensate-to-gas ratio (CGR), plateau time, distance from onshore, electricity price, natural gas price and percentage share of overnight capital cost of building a power plant to convert gas to electricity. The factors are used to gauge their effects on the net present value (NPV) of each scenario and are ranked based on their sensitivity on a tornado chart. The analysis suggest that initial production rate has the strongest effect on NPV, followed by discount rate, LNG price, CGR, and the distance from onshore when the reservoir is dry gas. Our analysis showed that, the longer the distance from onshore, the more attractive the FLNG alternative becomes. However, when gas price is low, and a subsidy from the Nigerian government can be obtained, GTW becomes attractive.

This economic feasibility study will be helpful for future considerations to use FLNG to make previously considered stranded offshore gas reservoir economically viable. This will certainly play a key role in the future of natural gas industry and energy market, especially in West Africa.

1. Introduction:

The future of the world's energy supply and usage has always been a highly discussed topic over the past decades. Demand for cleaner energy grows, and many countries in the world are shifting towards the expansion of natural gas production, due to its cleaner burning capabilities compared to other sources such as petroleum.

Natural gas produces significantly less pounds of CO_2 per 1 MMBTU, at 117. When compared to coal, which produces more than 200 pounds of CO_2 per MMBTU, and fuel oil, at 160 pounds CO_2 produced per MMBTU, natural gas emits much less air pollutants to produce the same amount of energy (EIA 2019c)

However, this transition relies on the rising natural gas supply, which currently faces rapid depletion and geographical constraints (APERC 2015)

Meeting future energy demand has proven to be a difficult task. This task is far beyond the scope of this analysis. Rather, this report aims to highlight one development which has been on the rise in recent years: Floating Liquefied Natural Gas (FLNG). As energy consumption continues to rise and the need to produce more gas from additional reservoir grows, FLNG could prove to be a heavy hitter in making production of stranded offshore natural gas fields economical. The benefit of this technology will be discussed in a later section. Moreover, this report aims to create an economic analysis model among utilizing an FLNG as opposed to the tradition pipeline and onshore processing facilities or gas-to-wire.

2. Overview of Natural Gas:

2.1 Origin of NG: Natural gas is the term used to described naturally occurring hydrocarbon gas found deep within the earth's underground formation. Millions of years ago, remains of plants and animals built up in different layers in the Earth's surface. Over time, these layers were buried under sand, silt, and other minerals. Changes in pressure and heat converted these materials into different forms of hydrocarbon such as coal, oil, and natural gas (EIA 2019a).

Natural gas found in the underground can be classified into two main types: conventional gas, and tight/shale gas. Conventional gas is when natural gas can move into large spaces in between the layers of the formation rocks. On the other hand, natural gas occurring in the tiny pores within some formation of shale, sandstone, and other sedimentary rocks is called shale or tight gas. This type of gas is also sometimes called unconventional gas. Additionally, natural gas can also form within deposit of crude oil, called associated gas. Coalbed methane is another type of natural gas found in coal deposits.

2.2 Composition: As mentioned above, natural gas is primarily composed of hydrocarbon in gaseous form. However, the exact chemical composition will vary from field to field; as well as well to well. Typically speaking, natural gas will be composed of methane, ethane, and propane; some heavier components like butane, pentane, hexane, may also be present. **Table 1** illustrates a typical natural gas composition (GPSA 2014)

Component	**Feed gas mole %**
N_2	1
CO_2	3
C_1	85
C_2	5.8
C_3	3
i-C_4	0.7
n-C_4	0.8
i-C_5	0.3
n-C_5	0.2
C_6+	0.2
Total	100

Table 1. Typical Natural Gas Composition (Source: GPSA 2014)

2.3 Some statistics for the US: The United States produces and consumes many different types of energy sources. Fossil fuel makes up the majority of this. **Fig.** 1, from the EIA, 2019d, illustrates the US primary consumption by energy source in 2018. Looking at the graph, natural gas takes up the second most amount, at 31%, behind petroleum at 36%; out of a total 101.3 quadrillion BTU. Additionally, in 2018, the US produced 30.6 MMCF dry natural gas (EIA 2019b)

In the Natural Gas Annual 2018, also by the EIA, 2019f, states that the US set new record for natural gas production, consumption, and exports. During the year, consumption increased by 12%, reaching the record high of average of 83.8 BCF/D. Additionally, Enerdata indicated that, in 2018, 848 BCM (about 30 TCF, this number is also reported by the EIA in November of 2019[1]) of natural gas was consumed in the US, the highest of any country in the world[2]. Consumption also increased by 11% in 2018, due to increase demand in the electric power sector[3]. **Fig.2**, from Natural Gas Annual 2018, shows the country's consumption from 2010 to 2018, by sector.

[1]https://www.eia.gov/tools/faqs/faq.php?id=50&t=8
[2]https://yearbook.enerdata.net/natural-gas/gas-consumption-data.html
[3]https://www.eia.gov/todayinenergy/detail.php?id=41955

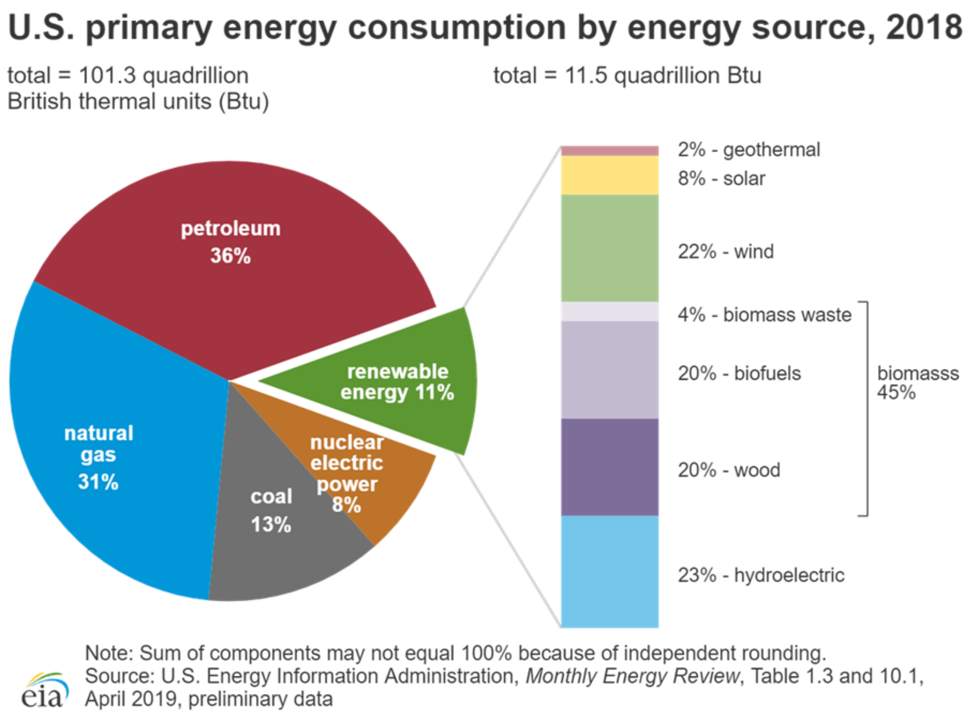

Fig. 1. U.S. Primary Energy Consumption by Energy Source, 2018 (EIA 2019d)

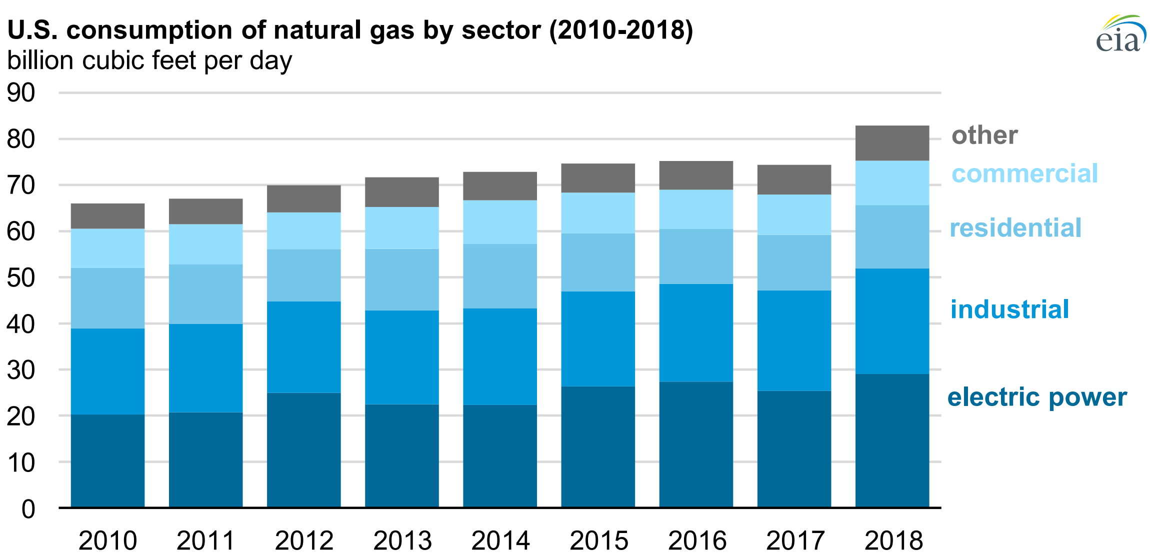

Fig. 2. U.S. Consumption of Natural Gas By Sector (2010 - 2018) (EIA 2019f)

2.4 Natural Gas Production: After a test well has been analyzed, and positive results regarding the amount of reserves and economic potential; production wells can be drilled. Natural gas wells, much like oil wells, can be drilled vertically or horizontally into the hydrocarbon-bearing rocks. After the wells have been drilled and completed, natural gas can be produced from the reservoir.

After natural gas has been produced and brought to the surface from the reservoir, it then must be processed, which is covered in the next section.

2.5 Natural Gas Processing: Natural gas processing is a complex process that is designed to rid the produced natural gas of various impurities such as heavier hydrocarbon, water, CO_2, H_2S, sand, etc. The processed natural gas would then be used for sale, transportation, or disposal. Natural gas used by the end consumer is much different that the natural gas produced at the wellhead. While it is less complicated than processing of crude oil, processing of natural gas is equally as important before it is used by the consumers. The two most common and important ones are acid gas removal and dehydration, which will be covered in this section. **Fig. 3** shows the basic flow diagram for processing natural from the wellhead.

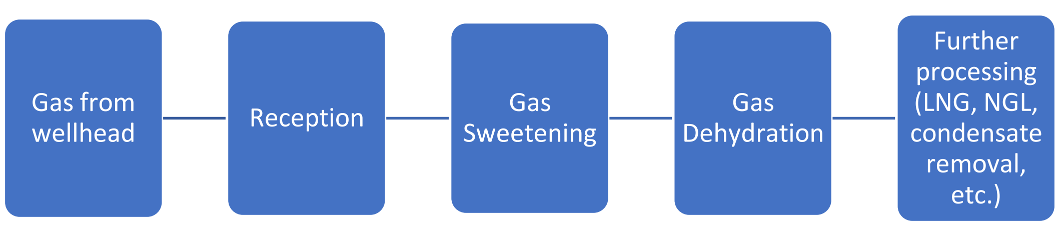

Fig. 3. Basic Gas Processing Diagram

The first step in gas processing is called sweetening. Produced natural gas can sometimes contain acid gas. Acid gas is a generic term to describe gases such as hydrogen sulfide and carbon dioxide. This kind of gas can corrode the piping and components of the processing equipment and must be removed. Many natural gas streams contain hydrogen sulfide (H_2S) in various concentration. Gases containing H_2S are classified as "sour" while gases free from H_2S are called "sweet". Removal of H_2S is usually accompanied by removal of CO_2. The most common process to remove these acid gases is called amine sweetening. In this process, the gas stream passes through the amine vessel, where it flows and intersect a lean amine solution. When the two streams meet, the amine solution absorbs the acid gas. The sweetened gas stream then exit the vessel while the used amine solution is regenerated in order to be reused. **Fig. 4** from GPSA Data Book shows the schematic of the amine sweetening process

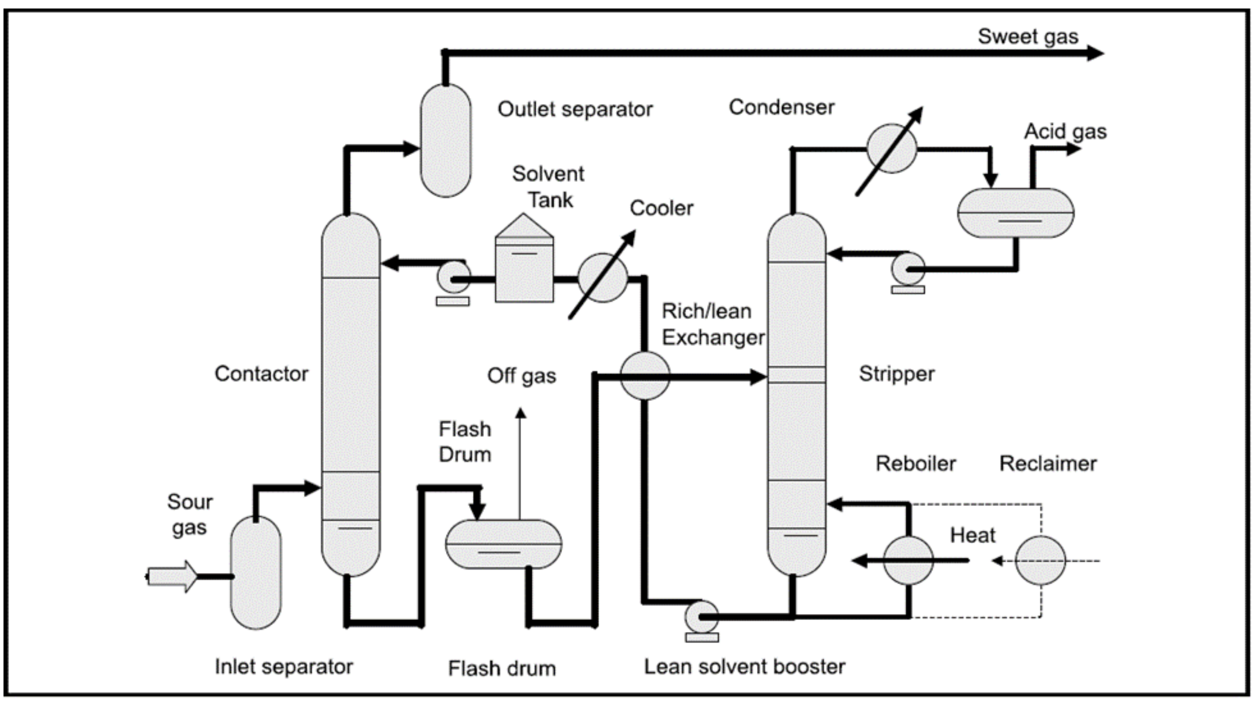

Fig. 4. Amine Sweetening Process Diagram

After removing acid gas, the gas stream must be dehydrated, to be free of water. Water is one of the most, if not the most, prevalent contaminants in a natural gas stream. It can exist as either liquid or vapor form. Water can bring several undesirable effects. It can combine with hydrocarbon and other molecules in the right pressure and temperature to form hydrates, which can block pipes and equipment. Water can also combine with the acid gas mentioned above and cause corrosion in the components of the equipment. Therefore, water must be removed in order to meet specification of the consumers, as well as prevent hydrates and corrosion. One common process for removing water in gas streams is glycol dehydration. The feed gas stream is fed into the glycol contactor, in which it flows counter-currently with a lean glycol stream. The glycol stream removes water via absorption, and the rich glycol mixture exits the vessel, to be regenerated and reuse. **Fig. 5** from GPSA shows a typical glycol dehydration flow diagram.

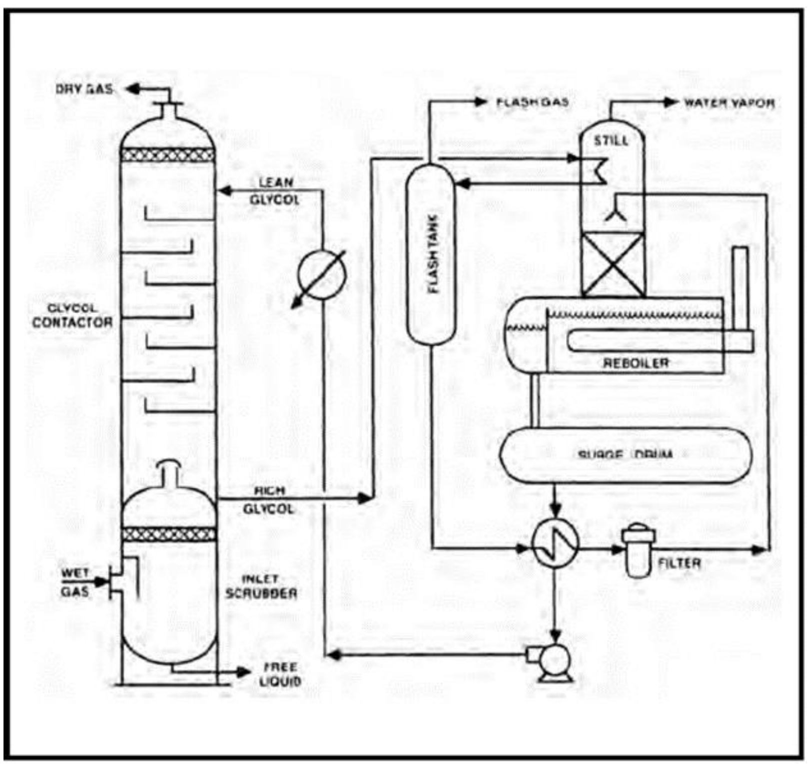

Fig. 5. Glycol Dehydration Process Diagram

Depending on the composition of the natural gas, some additional processing to remove the heavier components like propane, butane, etc. may be required. These heavier components may condense when going through compressor stations and reduce a pipeline's capacity. They may be fractionated and marketed as "pure" components, or they may be combined and sold as natural gas liquids mix commonly known as NGL. This will add to the economic value of the product, as the value of NGL are higher than that of natural gas.

After going through the processing steps mentioned in the section above; natural gas can be liquefied.

2.6 Natural Gas Liquefaction

The process for liquefaction of natural gas utilizes a refrigerant agent. This agent is compressed, cooled, condensed, and depressurized through the Joule-Thomson effect. The refrigerant is then used to cool the feed gas down to -260°F. This is the temperature at which methane, the main constituent of natural gas, liquefies. Also, at this temperature, all the other hydrocarbons in the natural gas will be in liquid form. In this form, natural gas has a volume of $1/600^{th}$ of the volume of its gaseous form, this will be beneficial in transportation, storage, etc.

There are three main types of liquefaction methods: cascade, mixed refrigerant, and expansion cycles. Most often, liquefaction processes make use of one, or a combination of these cycles. Some examples of combination cycles are pure-component cascade cycle, propane-precooled mixed-refrigerant cycle, dual mixed-refrigerant cycle, single mixed-refrigerant cycle, mixed-fluid cascade process, etc. (Vink 1998)

Fig. 6 below, from ConocoPhillips, shows a simplified version of their Darwin LNG plant[4]

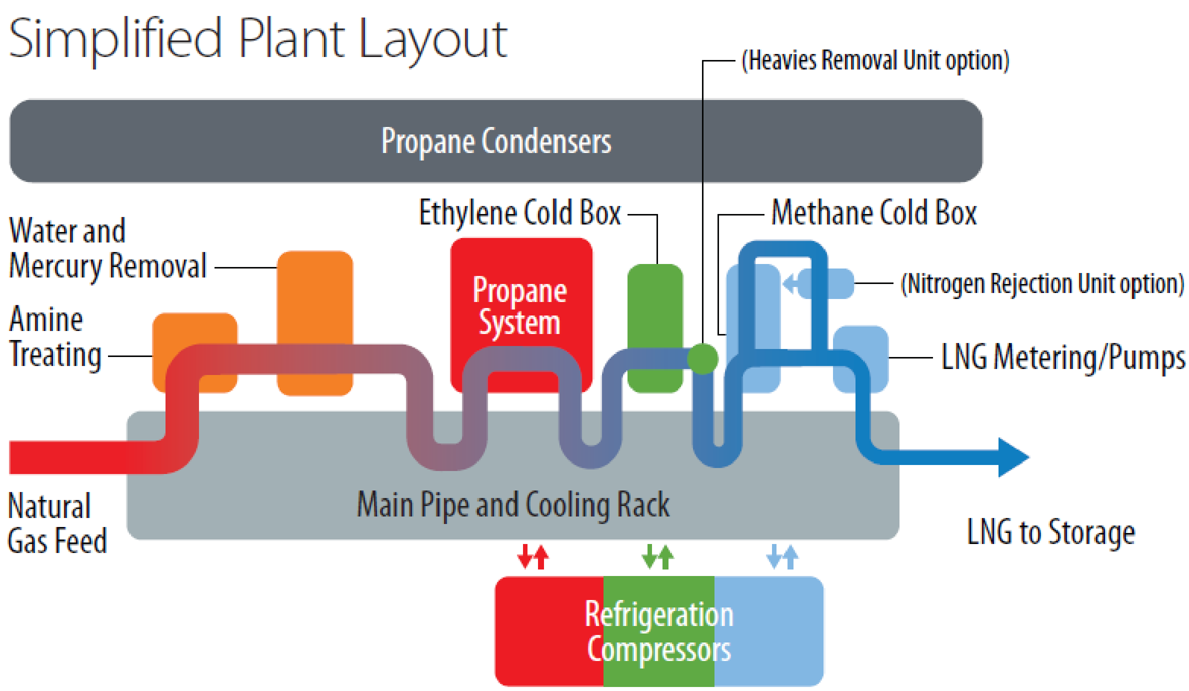

Fig. 6. Simplified LNG Plant

As mentioned in the introduction, natural gas is limited in supply, and it is also unevenly distributed around the world. Per basic economic, if supply is more than demand, then the excess natural gas must be stored for future use, as to avoid unnecessary loss. If demand is more than supply at a given location, then natural gas must be transported to that location from an exporting hub. Storing and transporting natural gas comes at a cost; but, with LNG, that cost can be reduced.

2.7 Gas-to-Liquids

Gas to liquids (or GTL) is a refining process that take natural gas, or other gaseous hydrocarbon, and turn them into long-chain hydrocarbon such as gasoline, or diesel. These products are also odorless and colorless; as well as contain almost no impurities (such as sulfur,

[4] http://lnglicensing.conocophillips.com/what-we-do/lng-technology/optimized-cascade-process/

aromatics, etc.). Generally, the Fischer-Tropsch (FT) technique is the most used in GTL facilities[5]. The FT process is a combination of chemical reactions that converts natural gas, mostly methane, into a mixture of carbon dioxide, hydrogen, and carbon monoxide. This mixture is then processed to remove any contaminations (such as sulfur, water, etc) and then recombine to form longer hydrocarbon, in liquid forms. **Fig. 7** (EIA 2014) shows the FT process diagram. According to the same report, there are currently five GTL plants operating globally. Shell controls two in Malaysia, one in Qatar; Sasol operates one in South Africa, and Qatar is where the fifth one resides, a joint venture between Sasol and Chevron. In the US, there are three proposed plants: Lake Charles, Louisiana; Karns City, Pennsylvania; and Ashtabula, Ohio.

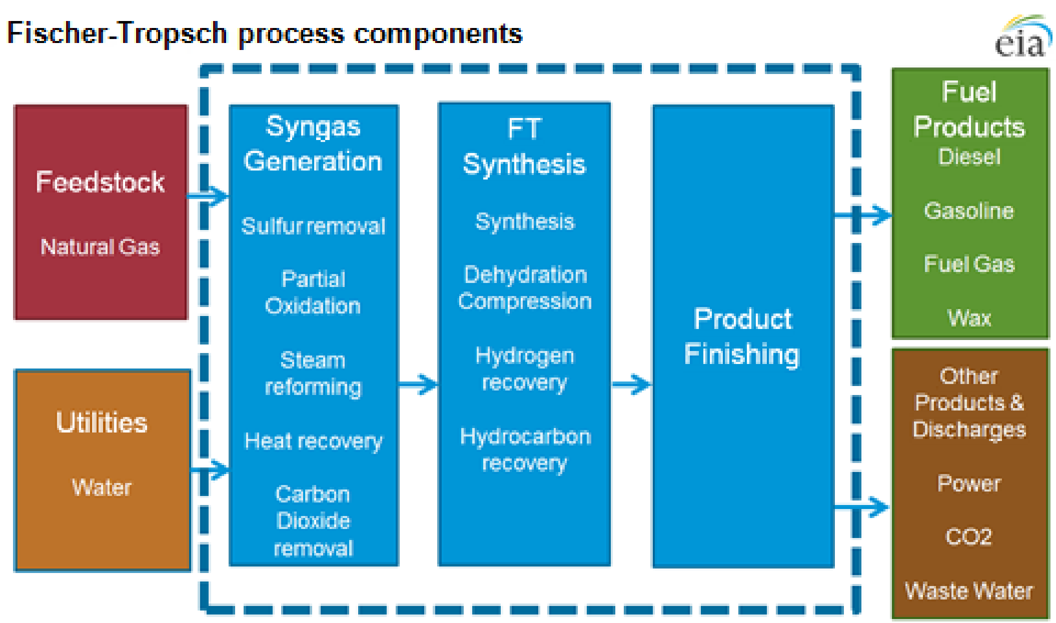

Fig. 7. Fischer-Tropsch Process Diagram (EIA 2014)

2.8 Natural Gas Liquids

As mentioned in the Gas Processing section; Natural Gas Liquids are heavier hydrocarbon that are associated with a natural gas stream. There are many uses for NGLs, spanning nearly all sectors of the economy. NGLs are used as inputs for petrochemical plants, burned for space heat and cooking, and blended into vehicle fuel. Higher crude oil prices have contributed to increased NGL prices and, in turn, provided incentives to drill in liquids-rich resources with significant NGL content. **Table 2** shown below (EIA 2012), shows typical usage for some common types of NGLs, ranging from C2 to C6+

NGL component	**Usage**
Ethane	Plastic production, petrochemical feedstock
Propane	Residential and commercial heating
Butane	Petrochemical feedstock
Isobutane	Refinery feedstock
Pentane	Natural gasoline
Pentane plus	Blending with vehicle fuel

Table 2. NGL Usage (EIA 2012)

2.9 Natural Gas and LNG Market:

US: The US's natural gas market accounts for 25% of the global natural gas consumption, and 85% that of North America (Tusiani 2007) In February 2016, Cheniere Energy, an LNG company headquartered in Houston, TX, became the first US company to export this commodity[5]. Additionally, in 2018, the company also signed a 25-year agreement with Taiwan's CPC Corp to supply LNG at a rate of 2 million tonnes per year, staring in 2021. The deal is estimated at $25 billion[6]

Global: The global market for LNG is always growing, Tunisia, 2007, said the industry had nearly doubled in size each decade from 1970 to 2000. In 1975, LNG only accounted for 10% of total cross border trade; but in 2005, this number has grown to be more than a quarter of international gas trade. This growth, according to Tunisia, has been driven by the decreasing capital of the LNG chain, strong demand for gas, as well as abundant reserves. Moreover, 293.1 metric tonne of LNG were traded globally in 2017, which is an increase of 35.2 MT compared to 2016 (IGU 2018).

The demand for energy is always growing, and LNG has certainly been the answer for this ever-growing rise. About one hundred million m^3 of new LNG supply is expected to be commissioned between 2018 and 2023; with most of it coming out of the US and Australia (IEA 2019)

[5]https://www.houstonchronicle.com/business/energy/article/Cheniere-Energy-kicks-of-production-at-Corpus-13396963.php
[6]https://www.reuters.com/article/us-cheniere-energy-taiwan/cheniere-signs-25-year-lng-sales-deal-with-taiwans-cpc-idUSKBN1KW03E

3. Stranded Gas:

Stranded gas resources area gas that is essentially being wasted or left unused. In an oil well, some associated gas can sometimes be categorized as stranded due to it being economically wasted. However, this research looks at stranded gas on a field and reserve scale. By this definition, a stranded gas reserve is a gas reserve that has been discovered but cannot be produced due to either physical or economic reason. About 40 to 60% of the world's proven gas reserve lies in stranded fields (Chabrielle 2002). A gas reserve can be considered stranded if:

- The reserve might be too remote from a market, making construction of pipeline to transport the gas too expensive.
- The reserve is located in a region where the market is already to saturated with natural gas, and the cost of exporting this gas is excessive.
- The reserve might be too deep to drill, or is located beneath an obstruction, thus making it costly to reach and produce.

While there is technology being developed to physically reach stranded gas reservoirs; for economically stranded reserve, floating liquefied natural gas (FLNG) is a likely candidate for development. In 2001, the World LNG/GTL Review stated that approximately 450 Tcf of natural gas stranded in fields with capacity of more than 50 BCF, can be produced and processed for less than $0.5/MMBTU (Zeus Development Inc.)

3.1 Some location of stranded gas

According to a study published in 2013 by the US Geological Survey, stranded gas outside of North America accounts for about 2, 612 TCF, and **Fig. 8** (Attanasi and Freeman 2013) shows the distribution of this gas. Looking at the graph, one can see that Russia take the lead with 33%; followed by Southeast Asia and Oceania, 17%; the Middle East, 12%; and central Asia, 12%. Of this 2, 612 TCF, about 60% is onshore, and the rest offshore.

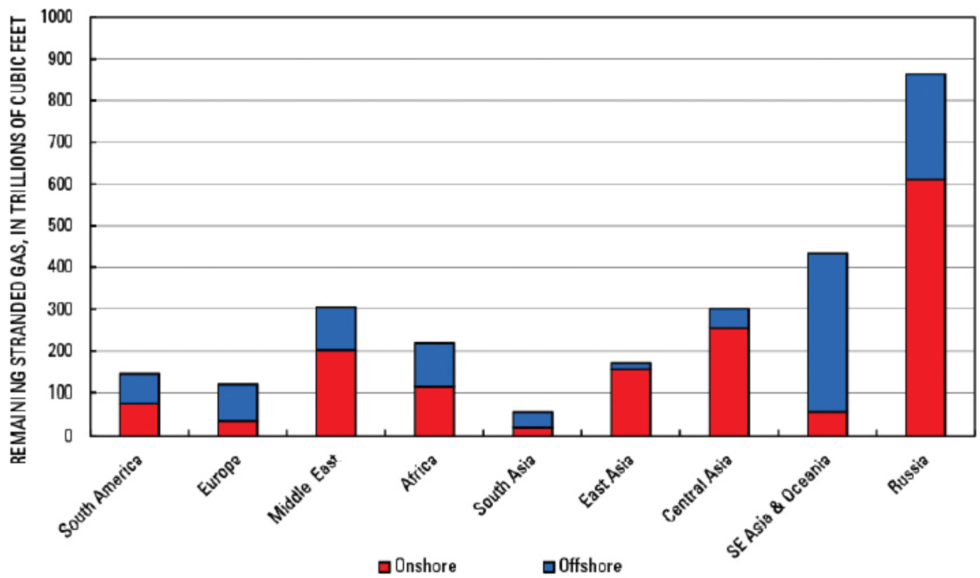

Fig. 8. Distribution of Stranded Gas Outside of North America (Attanasi and Freeman 2013)

4. Floating Liquefied Natural Gas

4.1 What is FLNG?

Floating liquefied natural gas (FLNG) is an offshore processing facility designed to process and liquefy a natural gas feed stream from a reserve for the purpose of transporting to a market in need via carrier ships. FLNG has been touted as the technology that can unlock natural gas reserves that may once have been stranded. As stated, natural gas demand is always growing; and FLNG will certain help meet this growth. Offshore fields are often the location of many natural gas resources, but due to geographical, technical, and economic limitations; these fields are often difficult to develop. FLNG can be the answer to overcome these challenges.

4.2 FLNG Challenges: Moving LNG production offshore presents a set of obstacles. These challenges can be categorized into sizing, operational optimization, and environmental safety. Solutions to these issues will be needed to bring FLNG from theory to safe, efficient practice.

The first challenge for FLNG is sizing. Every element of a typical LNG plant will have to be able to fit into a much smaller area, while maintaining appropriate levels of safety (Chiu 2006) A typical LNG plant would require anywhere between 25 to 250 acres of land (Durr 2007) and building an FLNG of this size is impractical. The largest FLNG currently, Shell’s Prelude, is only 1600 ft long and 243 ft wide, which would cover an area of only 8 acres. Therefore, all the equipment of an LNG plant must be fitted on an area about a quarter of its size.

Another issue to consider is disposal of byproducts and wastes. As with any other hydrocarbon production, when LNG processing is moved offshore, this become a more complicated scenario. The simplest way to dispose of these byproducts (sulfur, carbon dioxide, water) is to feed them to the ocean. However, this practice raises environmental concerns. The oceanic environment must be protected from substantial human involvement. Therefore, the disposed products must be strictly held to standards before they are released. Doing this may cause an increase in operational expenses in order to meet with environmental standards.

4.3 FLNG Around the World:

Since FLNG is a relatively new development, many major oil and gas companies are still in the process of researching and developing their own vessels. However, the world's first major development of FLNG is the Prelude FLNG Project based offshore Western Australia in Browse Basin, which was announced by Royal Dutch Shell in May 2011, and began construction in October 2012[7]

In Asia, Petronas's first FLNG, the "PFLNG SATU" produced and delivered its first LNG cargo from the "Kanowit" gas field offshore Bintulu, Sarawak, Malaysia on 1 April 2017. This LNG cargo was loaded on the carrier Serri Camellia and made its way to the Asian market.[8]

In 2020, Africa's first FLNG project will come online in the form of the Fortuna FLNG owned by a joint venture between Ophir Energy and Golar LNG producing around 2.2 mmtpa of gas in Equatorial Guinea.[9]

[7] https://www.shell.com/about-us/major-projects/prelude-flng.html
[8] https://www.lngworldnews.com/malaysias-petronas-in-flng-first/
[9] https://www.naturalgasworld.com/the-rise-of-flng-ngw-magazine-53962

4.4 FLNG Pricing and a Closer Look at Prelude

Due to FLNG being a relatively new development, there hasn't been many pricing models readily available. For the purpose of this paper, Shell's Prelude project will be the basis for pricing of FLNG. Prelude costs averaged out to be about $14 billion[10], which will be used as the costs for the FLNG scenario in the economic analysis section.

The Prelude FLNG, based in Browse Basin, Australia, is the world's largest FLNG vessel, and the biggest offshore facility of any kind. The vessel lies at 488m long (1600 ft) and 74m wide (243 ft); this means the facility's deck is longer than four soccer fields put end to end; and its liquid storage capacity is the equivalent of 175 Olympic-sized swimming pools (Shell Global 2019)

Fig. 9 below (Shell Australia 2019) shows the technical component of Prelude's subsea infrastructure. The number indicates:

1. Anchor chains to secure the facility to the seafloor
2. Risers and flowlines for transfer of LNG product
3. Subsea system including wellheads, Christmas trees, production manifolds, etc.
4. Power lines

[10] https://www.ft.com/content/fa529dd8-832f-11e7-94e2-c5b903247afd

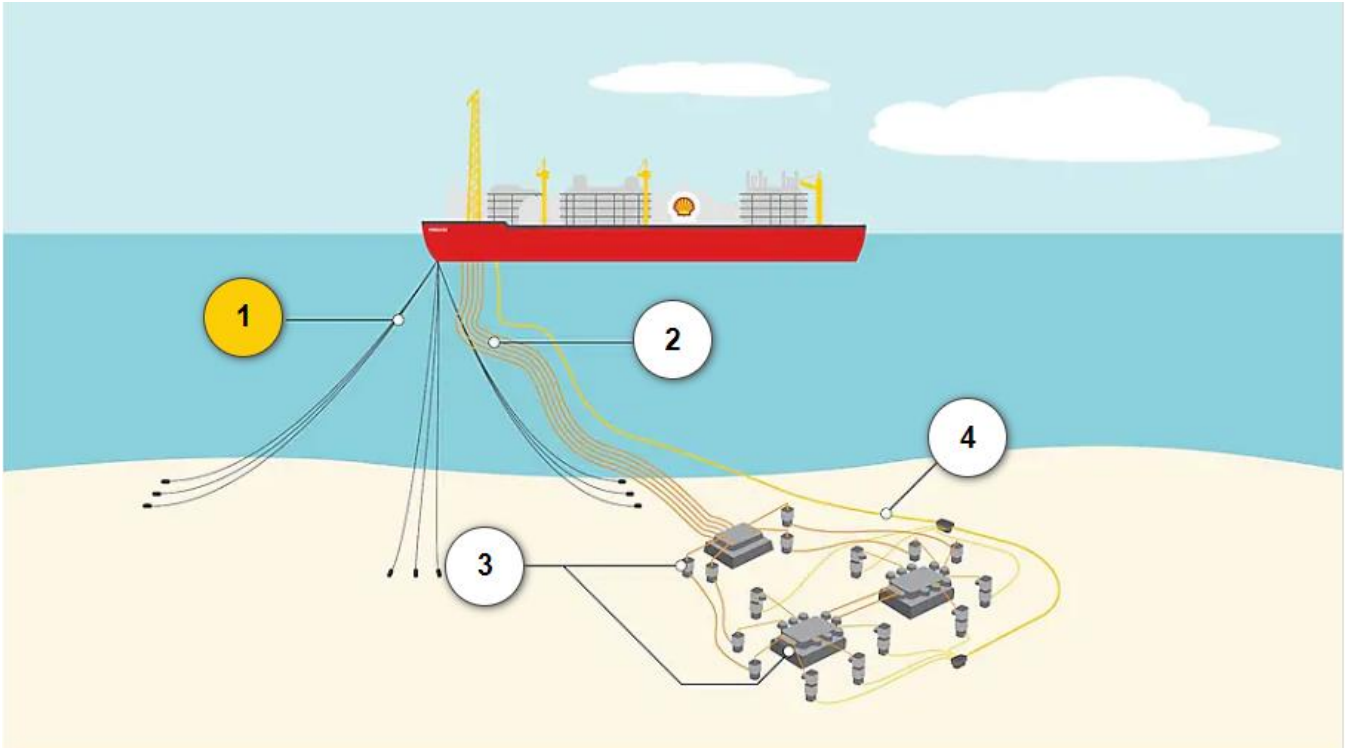

Fig. 9. Prelude's Technical Components (Shell Australia 2019)

5. Pipeline and its Usage

The pipeline is the most convenient method of transporting gas. The gas can travel to multiple destinations at the same time, as the pipelines are fixed). In the US, about 70% of petroleum products are transported via pipeline. 23% are from oil tanks and water barges. Trucks account for 4%, and rail 3% (Conca 2014)

5.1 Issues: There are many issues that can be encountered when using pipeline as the means of transporting natural gas.

The first challenge to overcome is formation of hydrates. A hydrate is a physical combination of water and other small molecules to produce a solid which has an “ice-like” appearance but possesses a different structure than ice (GPSA 2014). Their formation in gas and/or NGL systems can plug pipeline, equipment and instruments, therefore inhibiting flow of gas. Hydrate blocking is time consuming and costly. It can form in any location where a free gas, water, and the appropriate temperature and pressure exist in the production, transportation and processing of natural gases (Bahubali et al. 2009)

The formation of hydrates can be suppressed and prevented via a number of methods. All of these methods utilize the idea of controlling temperature, pressure, and removal of water.

The second issue facing pipelines is corrosion. It can be defined as the deterioration of metals due to reaction with their environment. These reactions can be internal or external. For the case of pipeline, both internal and external are applicable. The three main types of corrosion are: chemical, electrochemical, and microbial.

There are a few ways to mitigate corrosion in a pipeline. Corrosion inhibitors could be used. This is a compound that, when added to a fluid, can decrease the rate of corrosion of a metal. The fluid composition, temperature, flow regime, can affect the effectiveness of this substance. When used within the correct condition, a corrosion inhibitor can achieve high efficiency (El-Haddad 2019). Another method is to use anti-corrosive paint (a paint with anti-corrosive pigment such as lead chromate, zinc chromate, etc.) to protect the surface of the pipeline. This method can be combined with building the pipeline out of corrosion resistant alloys. The pricing of each method will determine the best choice for any situation.

5.2 Pricing:

Kaiser, 2017, estimated that the average costs for an offshore gas pipeline was \$3.1 million/mile. For this project, the baseline distance between the gas reservoir and onshore equipment is 100 miles, making the cost of construction for the pipeline \$310 million.

5.3 Gas to LNG plant

The first scenario involving the pipeline is transporting the produced gas from the wellhead to an onshore LNG plant. The economics of this would include the cost to build the pipeline; the cost of the LNG plant (construction and operating cost, \$550/mpta, similar to the cost of the Sabine Pass Train 1 to 4 LNG facility, Songhurst 2018); as well as upstream costs (\$2/MSCF, assumed).

5.4 Gas to Wire

Another option for monetizing stranded gas is gas to wire (or gas to power) where the gas is transported to a power plant, and fed into gas turbine, in order to generate electricity as the product. The most common method of generating power from gas is using gas turbine generators. The amount of power available from a fixed quantity of feed gas depends on several factors including the type of turbine, mode of operation, and transmission system. This thesis won't go into the discussion of all these parameters, as it is not the focus of the research.

This monetization method would be helpful in West African countries, and the assumed scenario of gas-to-wire for this research will be in Nigeria. For the purpose of this report, the overnight capital cost for a natural gas power plant is $952/KW (conventional gas/oil combine cycle) (EIA 2019e). However, considering the amount of gas that will be converted to power, this would not be a viable scenario. Instead, for this paper, the power plant would have already been constructed, and the project will pay 0.001% ($0.00958/KWH) of the overnight capital costs in order to use this plant, as well as constructing the pipeline ($3.1 million/mile) to bring the gas onshore, and any operational and maintenance costs ($3.61/MWH, EIA 2019e) This scenario would be useful for development in West African country, this report chooses the scenario of development in Nigeria. **Fig. 10** (Fullwood 2019) shows the different categories of electricity generation in many African countries.

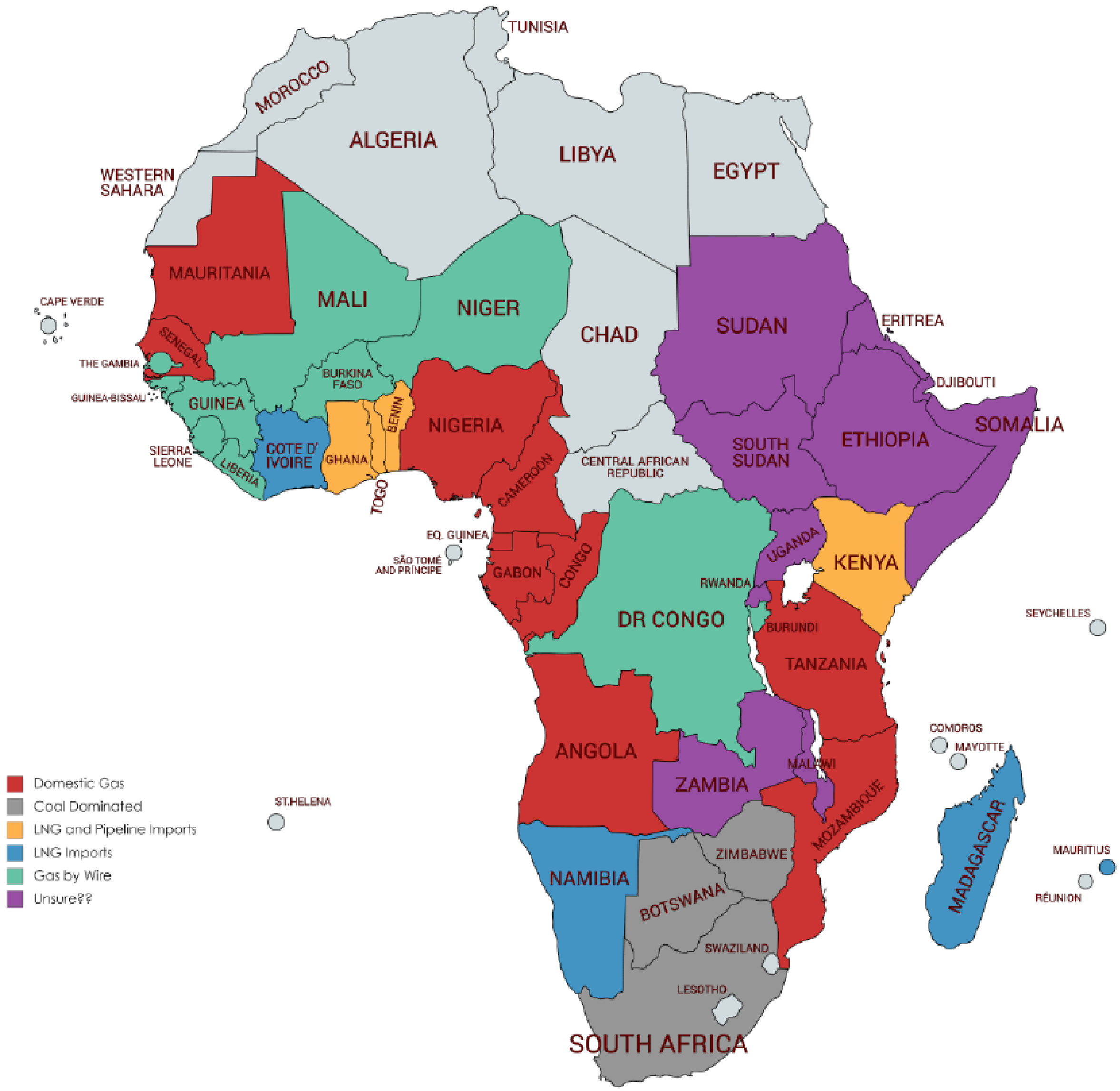

Fig. 10. African Countries Electricity Generation by Category (Fullwood 2019)

From looking at the map, Nigeria is located on the Western shore of Africa, and is currently one of the largest oil-and-gas producers on the continents. It would be a good candidate for the gas-to-wire opportunity.

6. Economic Comparison

6.1 Setup of Calculations: In order to determine the best development technology for this stranded gas fields; Monte Carlo simulations and sensitivity analysis were used. Each scenario has a set of factors that are put under consideration. In total, there are 6 scenarios; 2 for FLNG (a and b), 2 for pipeline transportation to an onshore LNG plant (c and d), and 2 for Gas-to-Wire (e and f). For cases 1 and 2, the factors being considered are price of LNG, discount rate, condensate-to-gas ratio (CGR), initial production rate (qi), hyperbolic decline constant (b), and initial decline rate at t=0 (di). In appendix A, some basic discussion of decline curve will be provided. For cases 3 and 4, all the factors above will be considered, along with distance to the onshore LNG plant. For cases 5 and 6, the factors are different, they are discount rate, natural gas price (for Nigeria), electricity price (for Nigeria), share of capital expense (in %), CGR, distance to the onshore power plant, b, and di. All of these factors will be used in the sensitivity analysis to gauge their effects on a scenario's net present value (NPV). **Table 3** below shows the value for the baseline of the analysis.

LNG Price	$5/MSCF
Natural Gas Price	$3.08/MMBTU
Electricity Price	$0.25/kWh
Qi	5 BCF/D
B	0.8
Di	0.27
CGR	30 bbl/MSCF
Distance to Shore	100 miles
Share of CAPEX	0.001%

Table 3. Sensitivity Analysis Parameters

The setup for analysis is as follow. The production follows a typical hyperbolic decline curve, while assuming a typical decline parameter to be b = 0.27 and di = 0.8. Before undergoing the depletion flow regime, the gas field will have 2 scenarios of plateau, constant production: 5 years and 10 years. **Fig. 11 and 12** shows this production curve. The x-axis show the cumulative time, in months, and the y-axis shows the monthly production rate, in BSCF/month. The initial plateau rate is 5 BSCF/day, or 152 BSCF/month. Additionally, condensate will be produced for the first 5 years of the project, at a ratio of 30 bbls/MMSCF. The total life of the project for all scenarios is 16 years (202 months), which is slightly lower than the expected life of Shell’s Prelude FLNG (Shell Global)

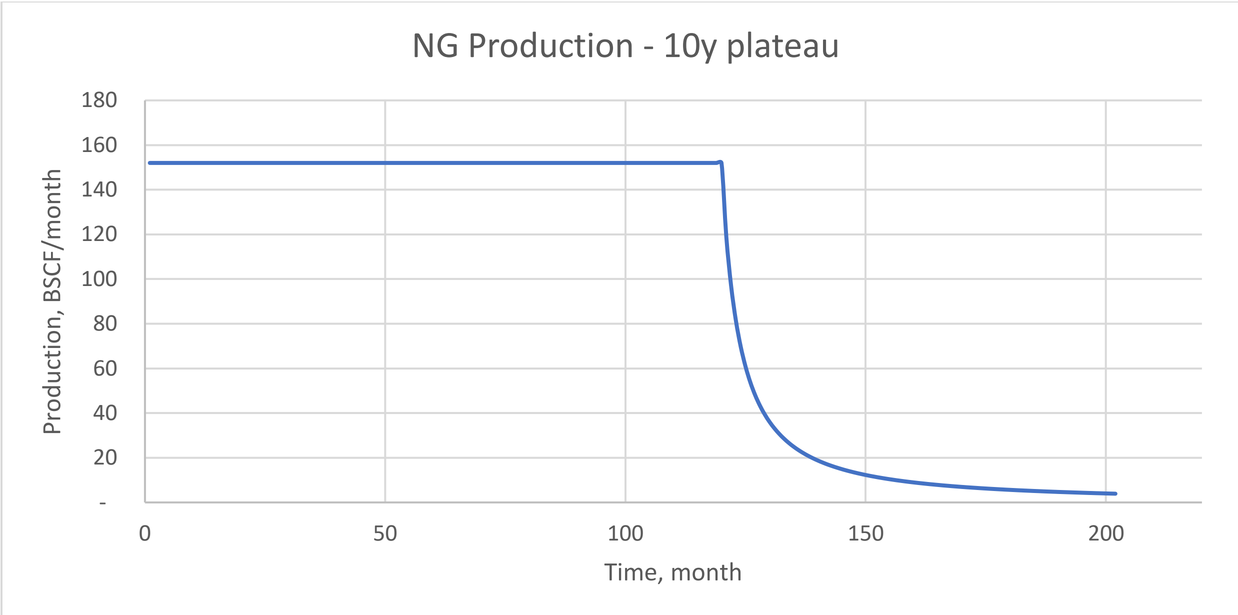

Fig. 11. 10 Year Plateau Production Curve

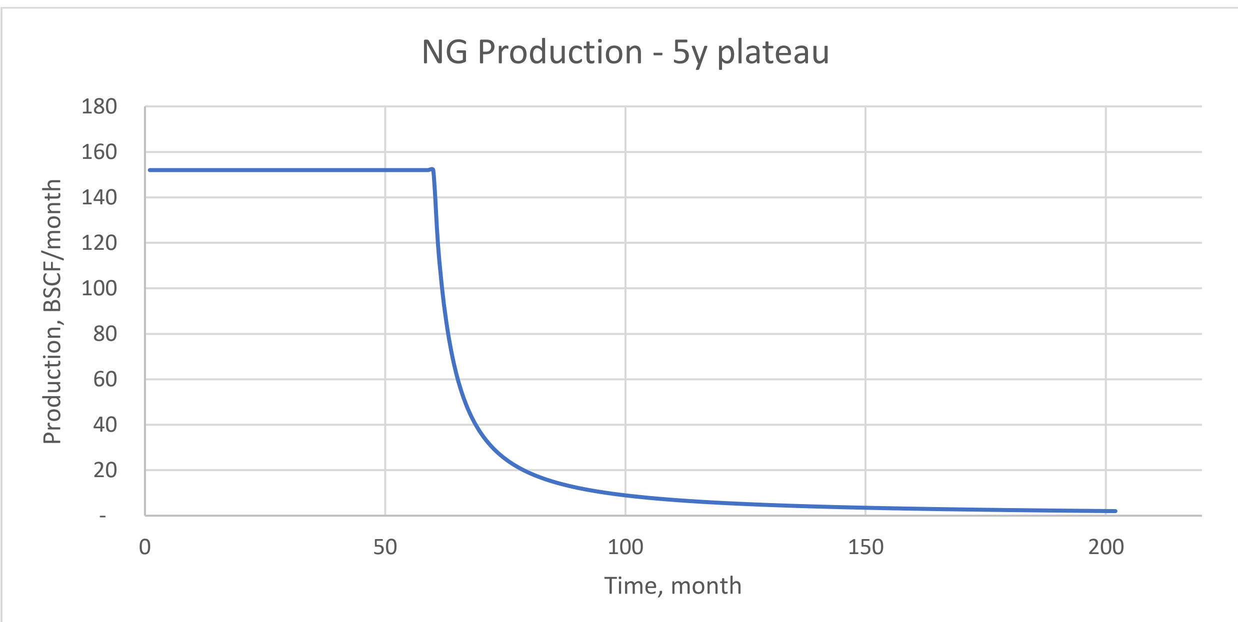

Fig. 12. 5 Year Plateau Production Curve

In order to obtain the NPV for each scenario; the initial cost need to be calculated.

For FLNG; this includes the cost of the FLNG vessel, $14 billion, which is the average cost for the Prelude FLNG, at an LNG capacity of 3.6 MTPA; an assumed upstream cost of $2/MSCF, a fixed, one-time, operational expense of $10 million. However, since the field is also producing condensate, that amount of hydrocarbon will be sold for profit for an assumed price of $40/bbl, and will be taken into account for the initial cost. This initial cost comes out to be $3.37 billion

For pipeline to LNG plant, this cost consists of the costs for the pipeline ($3.1 million/mile, as mentioned above), cost to build the LNG plant ($550/mtpa), the upstream, operational expense, and profit from condensate sale are the same as the FLNG case. This cost comes out to be $8.93 billion

For the last case, gas to power, cash flow will be calculated slightly differently. The cost includes pipeline, the percentage of overnight capital expense that is spent (0.001%), and operational and maintenance costs ($3.61/Mwh, EIA 2019e). Additionally, for this case, the gas price will be that of Nigeria's, which turned out to be $3.08/MMBTU (Fulwood 2019). This gas price will be used to calculate potential loss due to the power plant's efficiency, which is 40%. For cash flow, the gas flow rate will be converted from MSCF to MMBTU, and then multiply with an assumed electricity price of $0.25/kWh. Finally, instead of considering the cost to construct a power plant, this report makes the assumption that a subsidy from the government was granted, and only 0.0001% of the overnight capital cost for a power plant ($952/KW, as stated above) will be paid. After this calculation, the total cost comes out to be $58.13 billion if the plateau time is 10 years, $26.19 billion if the plateau time is 5 years. All of the costs mentioned in this paragraph was shown in Table 3 above.

Table 4 shows the initial cost calculated for each scenario.

Utilization Scenario	**Initial costs, in billions**
FLNG, 10-year plateau	$3.37
FLNG, 5-year plateau	$3.37
Pipeline to LNG plant, 10-year plateau	$8.93
Pipeline to LNG plant, 5-year plateau	$8.93
Gas to Wire, 10-year plateau	$58.13
Gas to Wire, 5-year plateau	$26.19

Table 4. Initial Costs for Each Scenario.

In Microsoft Excel, the NPV function can be used to easily calculate a scenario's net present value after an initial investment, the cash flow, and a discount rate have been defined. The project's nominal net present value is presented in **Table 5**.

Utilization Scenario	**NPV, in billions**
FLNG, 10-year plateau	$11.8
FLNG, 5-year plateau	$11.2
Pipeline to LNG plant, 10-year plateau	$6.2
Pipeline to LNG plant, 5-year plateau	$5.7
Gas to Wire, 10-year plateau	$34
Gas to Wire, 5-year plateau	$62.4

Table 5. Nominal NPV For Each Scenario

Interestingly, for Gas to Wire, a shorter plateau time yielded a larger NPV, as can be seen above. This could be due to less gas be converted into power, hence less capital and maintenance spending, as well as less gas being lost, which also means less money loss.

6.2 Sensitivity analysis

Sensitivity analysis is a model that determines how a target variable is affected by changes made to the input variable. Both the target and the input (or dependent and independent variable) are analyzed under a given set of assumptions. Normally, input variables are independent; therefore, for this report, it is assumed that all input variables are independent from each other, even thought they might not be in real life applications. For example, the 2 decline curve parameters, b and di, are usually dependent on each other; LNG price and discount rate could also be dependent. For this report, the model in question is the project's NPV for all its different cases. By doing sensitivity analysis, the importance of different uncertain parameters can be found, and from there, a decision can be made on whether to pursue the project for each scenario.

The sensitivity analysis is done by changing the uncertainty factors by 20% both ways. These factors are mentioned in part 6.1 Setup of Calculations. For each scenario, 9 data point were obtained, with the baseline being 100%, the other 8 data points being 80%, 85%, 90%, 95%, 105%, 110%, 115%, and 120% of the base parameters, which have been mentioned at the part above. From these 9 data points, the main 3 that are taken into consideration are 80%, 100%, and 120%. These values are then plotted on a tornado chart, to determine the sensitivity of each parameter on the NPV of each case.

A tornado chart is a special type of bar chart that is commonly used in sensitivity analysis. Each bar indicate the sensitivity of each variable being considered. This variable is modeled as having a range of uncertainties while the rest are held at baseline value. The process is repeated for all uncertain variable, and the plot is created. The variables are ordered so that the most sensitive parameter appear on top, the second most sensitive right below, and so on. The chart gets its name from the fact that the finished chart resemble a tornado.

Table 6 shows an overview of the 6 cases to be discussed.

Case Number	**Utilization Scenario**
1	FLNG, 10-year plateau
2	FLNG, 5-year plateau
3	Pipeline to LNG plant, 10-year plateau
4	Pipeline to LNG plant, 5-year plateau
5	Gas to Wire, 10-year plateau
6	Gas to Wire, 5-year plateau

Table 6. Summary of All Cases

6. 2a Case 1, FLNG, plateau of 10 years: The baseline was the NPV calculated at the above section, and from there, 20% was added or taken away, to determine the sensitivity of each parameter to the NPV. Values were then plotted on a tornado chart, for better visualization. Looking at the chart, it's clear that the initial rate has the biggest impact on NPV. When qi changes by 20% (both increase and decrease), NPV changed by $5.16 billion. The second strongest factor is the interest rate, with a decrease of $2.51 billion for a 6% rate, and increase of $3.7 billion for a 4% rate. **Table 7** shows the change in NPV, and **Fig. 13** shows the tornado chart for this scenario.

Percentage	b	di	CGR	LNG price	Discount rate	qi
80	$11.80	$11.80	$9.61	$8.76	$15.49	$6.64
100	$11.80	$11.80	$11.80	$11.80	$11.80	$11.80
120	$11.80	$11.80	$13.99	$14.83	$9.29	$16.96
Value in billion dollars						

Table 7. NPV Change for Case 1.

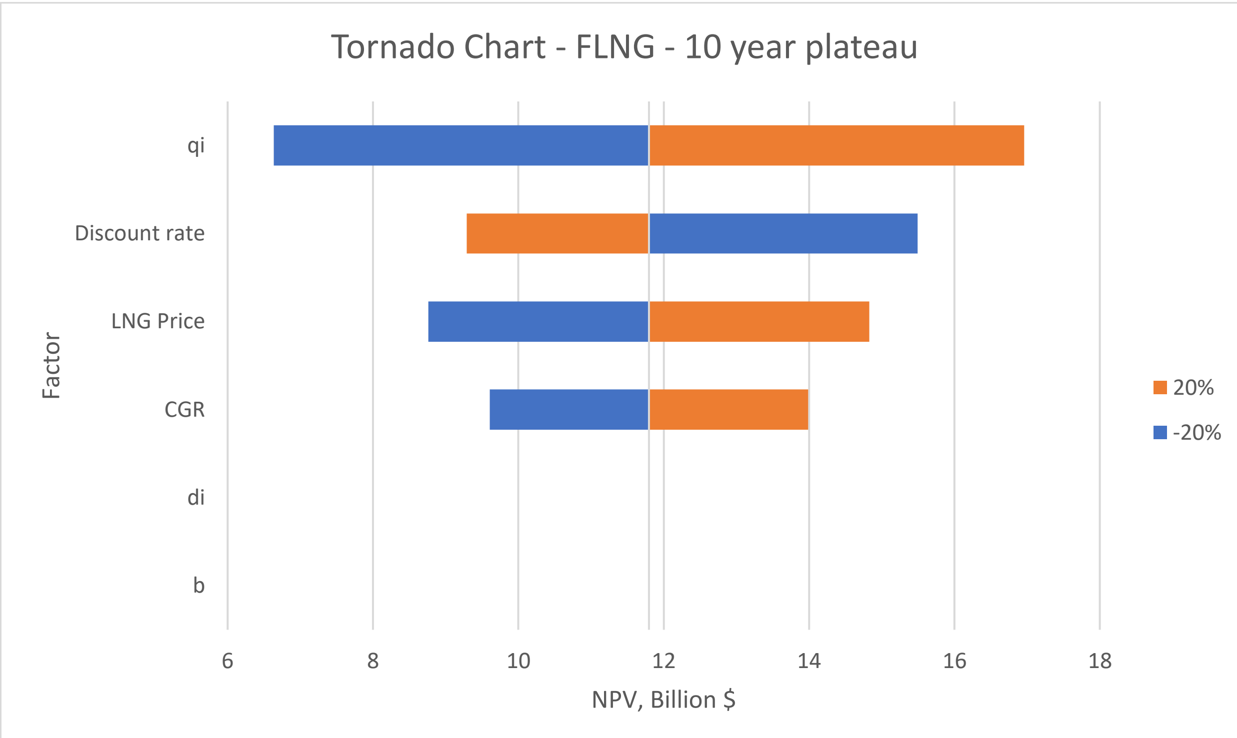

Fig. 13. Tornado Chart for Case 1

6. 2b Case 2, FLNG, plateau of 5 years: The baseline was the NPV calculated at the above section, and from there, 20% was added or taken away, to determine the sensitivity of each parameter to the NPV. Values were then plotted on a tornado chart, for better visualization. Looking at the chart, it’s clear that the initial rate has the biggest impact on NPV. When qi changes by 20% (both increase and decrease), NPV changed by $5 billion. The second strongest factor is the interest rate, with a decrease of $2.2 billion for a 6% rate, and increase of $3 billion for a 4% rate. **Table 8** shows the change in NPV, and **Fig. 14** shows the tornado chart for this scenario.

Percentage	di	b	CGR	LNG price	Discount Rate	qi
80	$11.24	$11.19	$9.02	$8.29	$14.20	$6.17
100	$11.21	$11.21	$11.21	$11.21	$11.21	$11.21
120	$11.19	$11.23	$13.40	$14.13	$9.01	$16.26
Value in billion dollars						

Table 8. NPV Change for Case 2

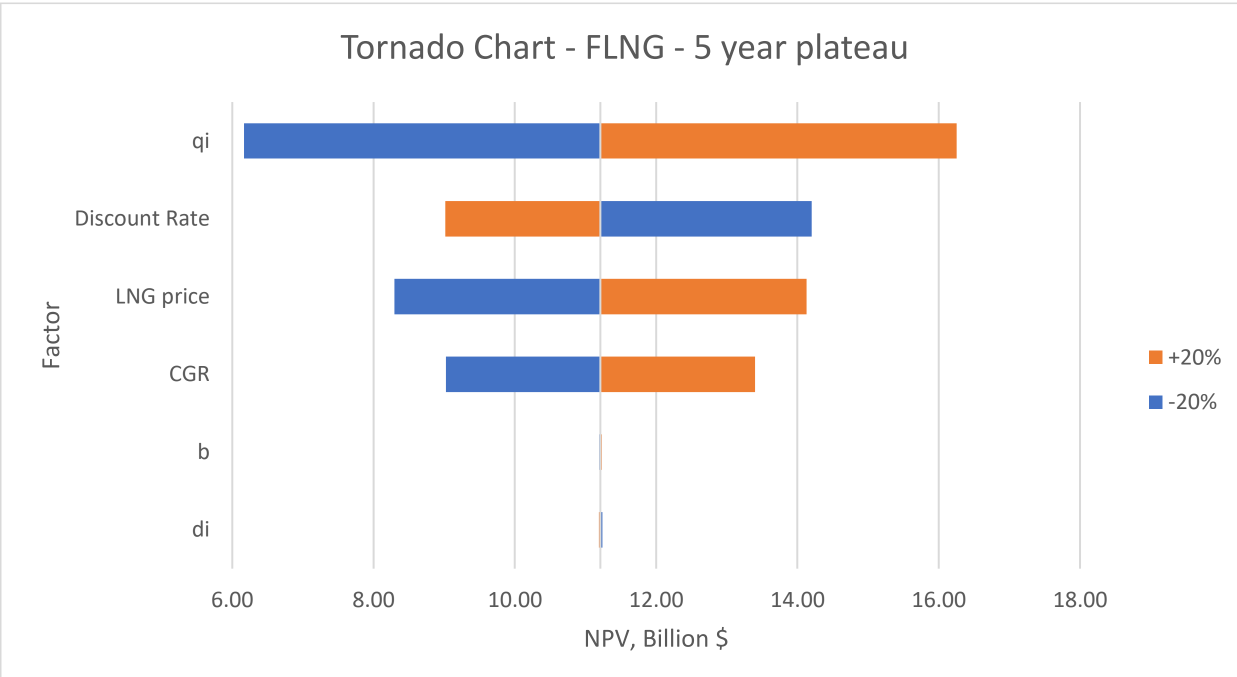

Fig. 14. Tornado Chart for Case 2

6.2c Case 3, pipeline to LNG plant, plateau of 10 years: The baseline was the NPV calculated at the above section, and from there, 20% was added or taken away, to determine the sensitivity of each parameter to the NPV. Values were then plotted on a tornado chart, for better visualization. Looking at the chart, it's clear that the initial rate has the biggest impact on NPV. When qi changes by 20% (both increase and decrease), NPV changed by $5.1 billion. The second strongest factor is the interest rate, with a decrease of $2.51 billion for a 6% rate, and increase of $3.7 billion for a 4% rate. **Table 9** shows the change in NPV, and **Fig. 15** shows the tornado chart for this scenario.

Percentage	b	di	Distance to shore	CGR	LNG Price	Discount rate	qi
80	$6.24	$6.24	$6.30	$4.05	$3.20	$9.93	$1.08
100	$6.24	$6.24	$6.24	$6.24	$6.24	$6.24	$6.24
120	$6.24	$6.24	$6.17	$8.43	$9.27	$3.73	$11.40
Value in billion dollars							

Table 9. NPV Change for Case 3

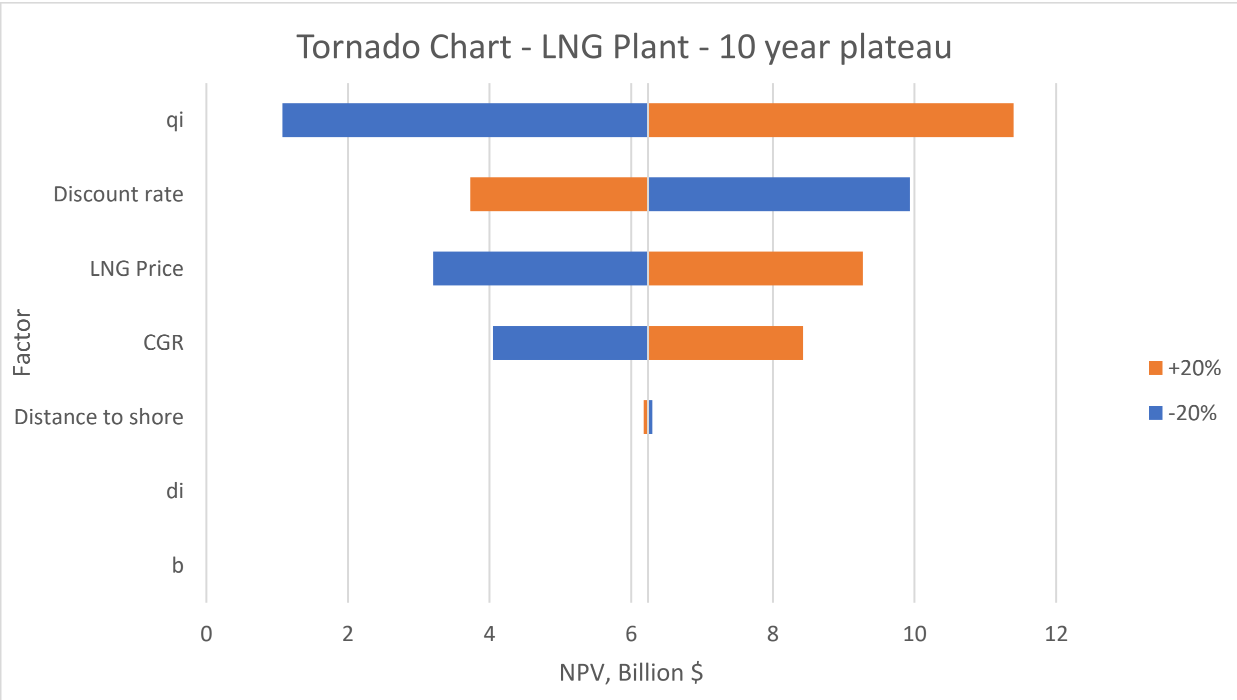

Fig. 15. Tornado Chart for Case 3

6.2d Case 4, pipeline to LNG plant, plateau of 5 years: The baseline was the NPV calculated at the above section, and from there, 20% was added or taken away, to determine the sensitivity of each parameter to the NPV. Values were then plotted on a tornado chart, for better visualization. Looking at the chart, it's clear that the initial rate has the biggest impact on NPV. When qi changes by 20% (both increase and decrease), NPV changed by $5 billion. The second strongest factor is the interest rate, with a decrease of $2.2 billion for a 6% rate, and increase of $3 billion for a 4% rate. **Table 10** shows the change in NPV, and **Fig. 16** shows the tornado chart for this scenario.

Percentage	Di	b	Distance to Shore	CGR	LNG Price	Discount rate	qi
80	$5.68	$5.63	$5.71	$3.46	$2.74	$8.64	$0.61
100	$5.65	$5.65	$5.65	$5.65	$5.65	$5.65	$5.65
120	$5.63	$5.67	$5.59	$7.84	$8.57	$3.45	$10.70
Value in billion dollars							

Table 10. NPV Change for Case 4

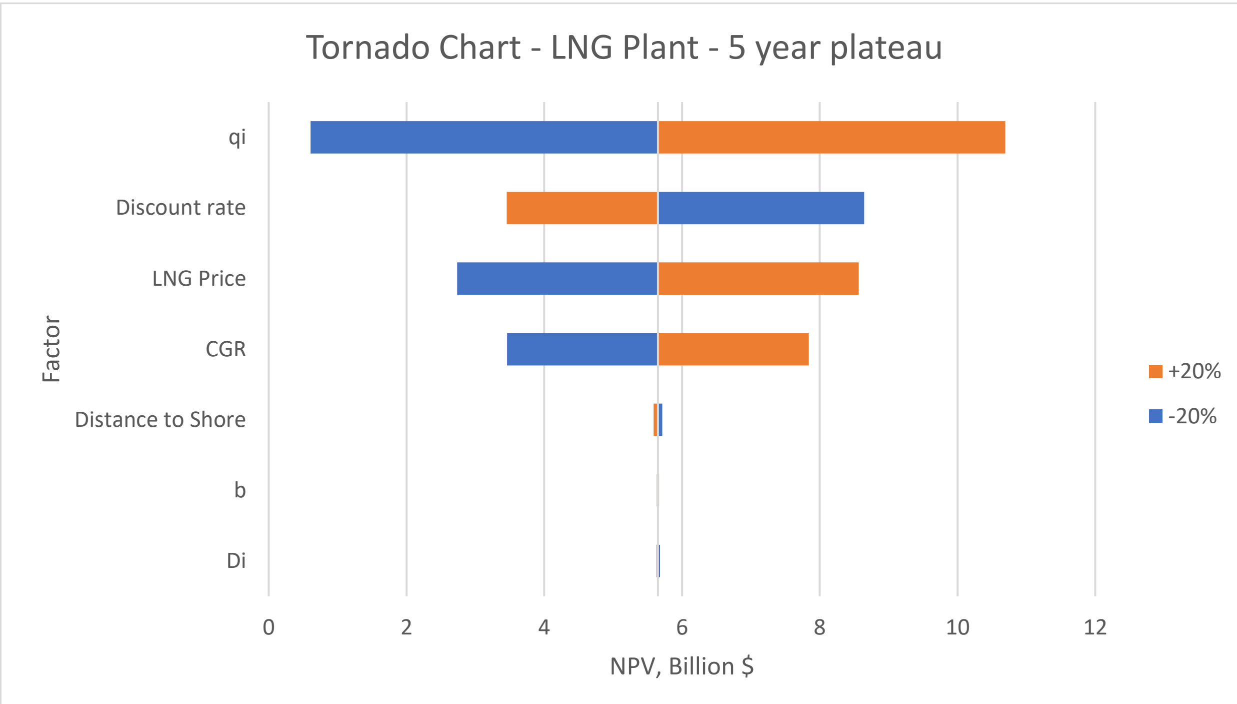

Fig. 16. Tornado Chart for Case 4

6.2e Case 5, gas-to-wire, plateau of 10 years: The baseline was the NPV calculated at the above section, and from there, 20% was added or taken away, to determine the sensitivity of each parameter to the NPV. Values were then plotted on a tornado chart, for better visualization. Looking at the chart, it's clear that interest has the biggest impact on NPV. When interest rate decrease from 5% to 4% (a 20% decrease) NPV increased by $22.4 billion; when it increases to 6% (a 20% increase) NPV dropped by $15.2 billion. The second strongest factor is electricity price, with a change of $18.42 billion for a change of 20% in price ($0.2 and $0.3). **Table 11** shows the change in NPV, and **Fig. 17** shows the tornado chart for this scenario.

Percentage	Distance to Shore	Di	b	CGR	Capital Spending	qi	Gas Price	Electricity Price	Discount Rate
80	$34.03	$33.01	$34.79	$31.78	$38.53	$27.11	$41.48	$15.55	$56.42
100	$33.97	$33.97	$33.97	$33.97	$33.97	$33.97	$33.97	$33.97	$33.97
120	$33.90	$34.64	$33.11	$36.15	$29.40	$40.82	$26.45	$52.39	$18.73
Values in billion dollars									

Table 11. NPV Change for Case 5

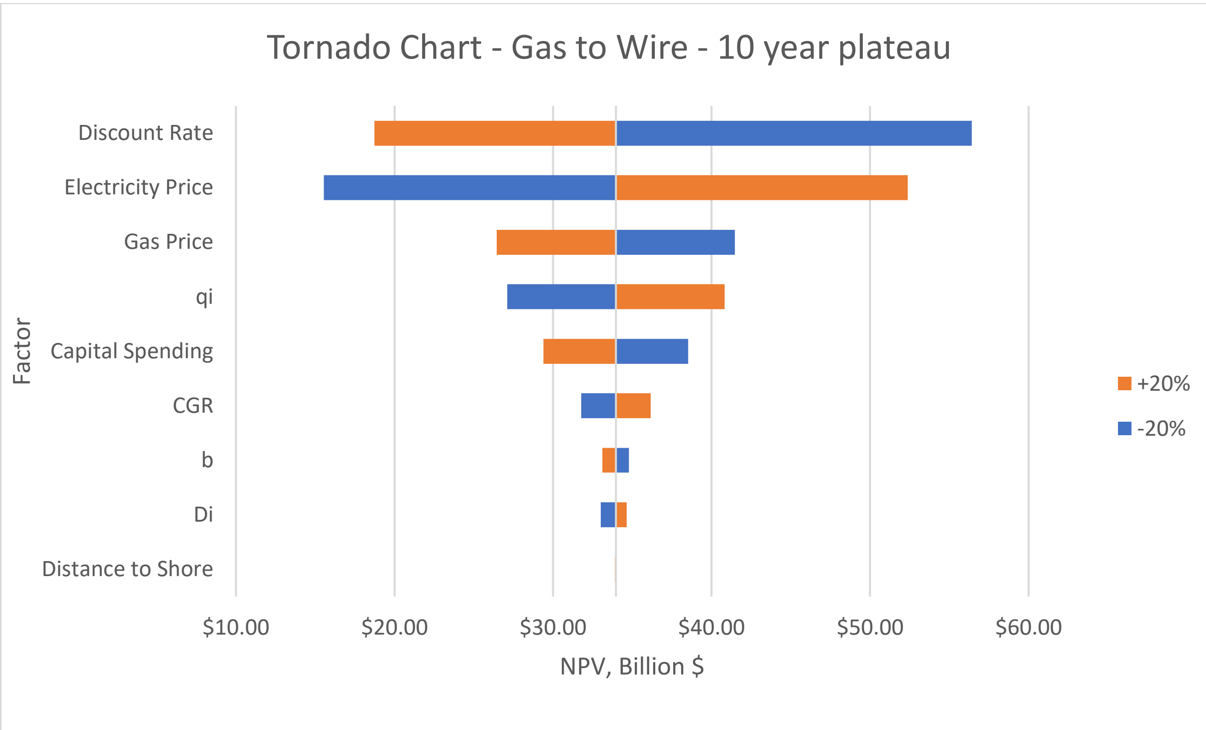

Fig. 17. Tornado Chart for Case 5

6.2f Case 6, gas-to-wire, plateau of 5 years: The baseline was the NPV calculated at the above section, and from there, 20% was added or taken away, to determine the sensitivity of each parameter to the NPV. Values were then plotted on a tornado chart, for better visualization. Looking at the chart, it's clear that interest has the biggest impact on NPV. When interest rate decrease from 5% to 4% (a 20% decrease) NPV increased by $18.17 billion; when it increases to 6% (a 20% increase) NPV dropped by $13.34 billion. The second strongest factor is electricity price, with a change of $17.71 billion for a change of 20% in price ($0.2 and $0.3). **Table 12** shows the change in NPV, and **Fig. 18** shows the tornado chart for this scenario.

Percentage	Distance to Shore	Di	b	CGR	Capital Spending	Gas Price	qi	Electricity Price	Discount Rate
80	$62.42	$61.58	$63.08	$60.17	$64.80	$66.38	$49.82	$44.65	$80.52
100	$62.36	$62.36	$62.36	$62.36	$62.36	$62.36	$62.36	$62.36	$62.36
120	$62.29	$62.91	$61.60	$64.55	$59.91	$58.33	$74.89	$80.06	$49.02
Values in billion dollars									

Table 12. NPV Change for Case 6

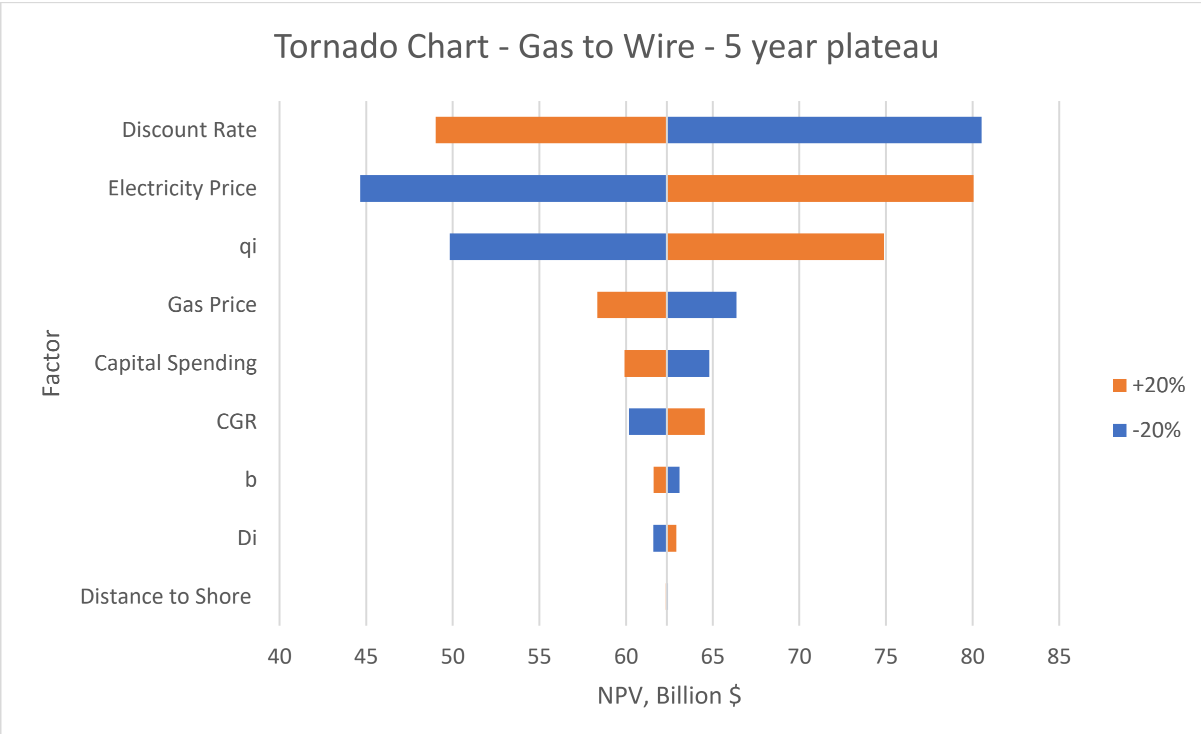

Fig. 18. Tornado Chart for Case 6

6.3 Observation and Discussion:

Looking at the results from the analysis above; a trend can be observed for the cases involving FLNG and LNG plant. For the 4 cases, a through d, initial production rate (qi) is observed to have the most effect on the net present value of each case. This means that the size and life of the gas field will be the most important parameter when developing any LNG-related process. Also, discount rate is the 2nd most dominant factor in those 4 cases. It is, however, the most dominant factor for both gas-to-wire scenarios. Discount rate would affect the present value of each month's cash flow. This would mean that the project would benefit best from a low interest rate, which might be difficult to obtain as there are many factors that can affect the interest rate. Some of these include inflation, global interest and exchange rate, economic growth rate, etc. Determining a specific factor would be beyond the scope of this research.

Prices is also a strong factor for all cases. LNG price for case 1 through 4, and electricity price for case 5 and 6, are the 3rd and 2nd most dominant factors, respectively. Additionally, natural gas price is the 4th most sensitive parameter for both gas-to-wire cases. These factors would affect the future value of the cashflow. For natural gas (and by extension, LNG), price is mainly driven by supply and demand.

On the supply side, production, imports, exports, storage amount, all affect it. Rising supply would decrease prices, and vice versa. On the demand sides, factors like weather (temperature), economics, oil prices, will affect demands for natural gas. Low temperatures increase heating demand, while hot temperatures necessitate cooling demand; both of which will affect the demand for natural gas. Economic conditions can also influence demand for natural gas, for example, for manufacturers. Finally, demand may be moderated by petroleum fuel prices, which may be an economical substitute for natural gas for power generators, industrial manufacturers, etc. Unlike supply, higher demand tends to lead to higher prices, while lower demand can lead to lower prices.

The price of electricity isn't driven by only supply and demand, but rather, a combination of factors. These include fuel types (coal is inexpensive, while natural gas is more costly,) maintaining and operating power plants as well as transmission and distribution lines, weather conditions, government regulations, seasons, location, to name a few.

It should be noted that, for the gas-to-wire cases, the capital expenses being considering is the overnight capital expense, defined as the cost to construct a power plant overnight, which is not realistic, and would explain the high value. Moreover, the model is created under the assumption that the Nigerian government is providing the power plant, or, at the very least, undertaking the majority of the cost to build the power plant. If this subsidy did not exist, then this scenario should not be pursued. In order to have a more accurate model, capital expense for power plant in West Africa should be used. Additionally, due to time constraint, an assumed electricity price was used, instead of the current price of electricity in Nigeria.

With all these consideration in mind, an informed decision can be made whether a scenario can be pursued; and in the next section; a basic development plan will be provided.

7. Development Plan:

Assuming the exploration phase is successful, and a suitable gas reservoir has been found; these steps should be taken. The size of the reservoir can be determined using an exploratory well, after which a model of the reservoir can be created. Moreover, by using information from related fields, the best suited decline curve parameters can be attributed to the reservoir (b and di). With these parameters, the expected production life span of the reservoir can be determined.

Combining the previous knowledge with the results from the sensitivity analysis from chapter 6, a development plan can be created. Generally, this plan can consist of several things:

- The number of wells to be drilled to best optimize production
- The completion technique for the wells drilled in the reservoir
- The recovery technique to produce natural gas from said wells
- The type and cost of processing equipment, such as separators, compressor, dehydration columns, sweetening columns, etc.

After hydrocarbon has been produced and process, the appropriate utilization for the processed LNG can be determined. This can be done by taking into account factors such as discount rate, LNG price, etc. These factors are dependent on the location of the field. If the project is in the West African shore, and the cost of building a power plant does not fall on the operator, then the gas-to-wire scenario would prove to be most profitable. However, if the subsidy is not obtained, but discount rate is low (such as Qatar, with a current 4.5% discount rate, Qatar Central Bank, 2019); then FLNG would be the most appropriate monetization strategy. **Fig. 19** below shows a basic flow chart for a development plan of an offshore stranded gas field.

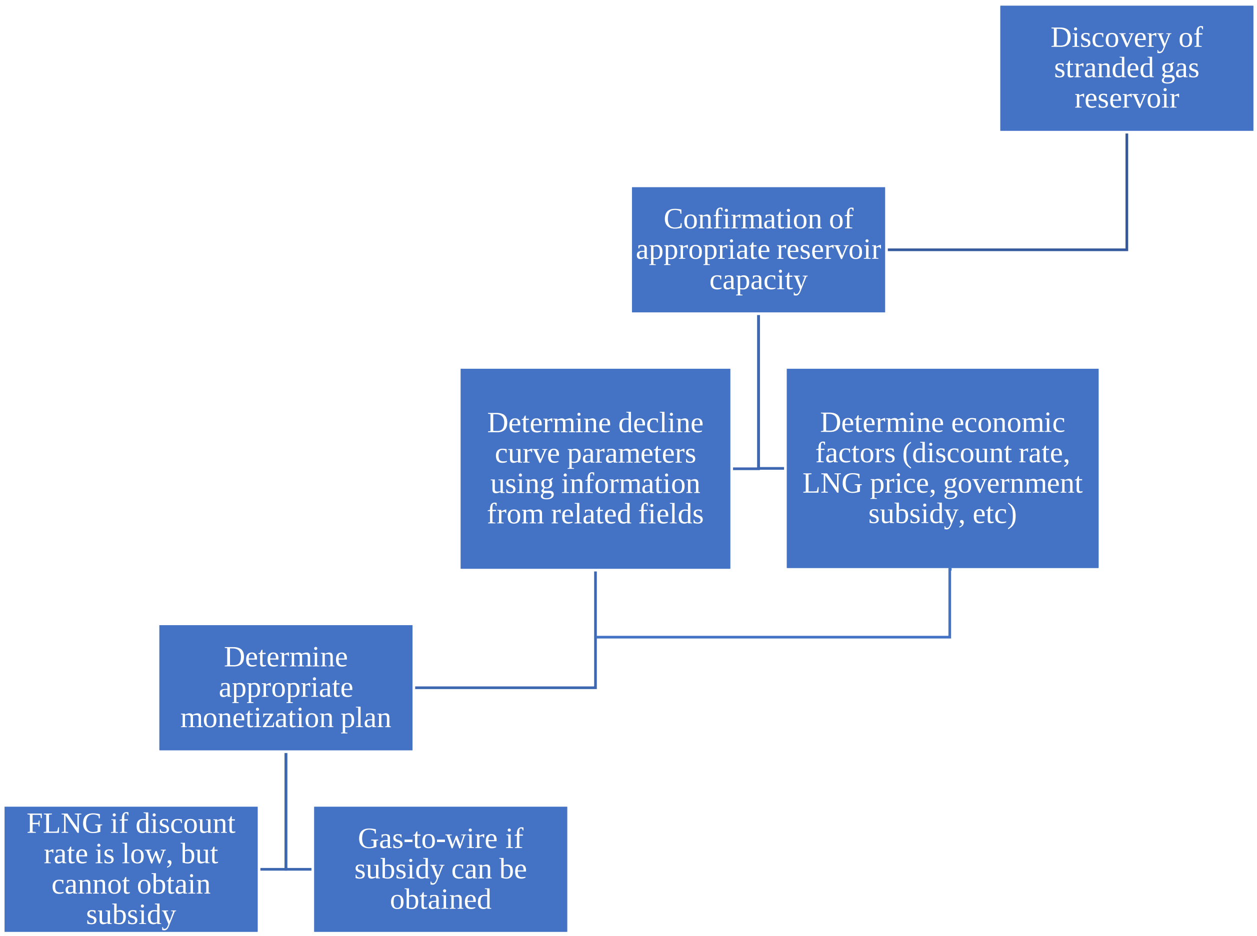

Fig. 19. Basic Stranded Gas Field Development Flow Chart

8. Future Work:

While this project has covered a lot of ground, there is certainly room for more detailed analysis. Another option to consider regarding FLNG is the possibility of long-term lease of an FLNG vessel. Leased FLNG vessel would be smaller, 2 to 3 MTPA compared to Shell's Prelude's almost 4 MPTA capacity. Some companies have expressed interest in building FLNG ships for lease, such as Teekay, SBM Offshore, and BW Offshore (Houwer et. al 2014) Leasing such a vessel would decrease the burden of capital expense in lieu of constructing one own's FLNG vessel.

Another issue to consider is a change in condensate production. In this project, condensate was produced for only 5 years, then the rate dropped to 0 bbls/MMSCF. For another, more realistic scenario, CGR could be lowered to 50% of the initial rate, after 5 years; meaning that CGR will be 30 bbls/MSCF for the first 5 years of the project, then it will become 15 bbls/MSCF for the rest of the life of the project. If this change were to be implemented in all scenarios, the change would affect the initial cost of each case, and therefore would change NPV. Shown now is case 2, but with this change implemented. The extra profit would be $1.03 billion from the new condensate production; **Table 13** shows the comparison of this modification

Case	**NPV, in billions**
Case 2, unmodified	$11.21
Case 2, CGR dropping to half after 5 years	$12.24

Table 13. NPV Comparison for Case 2, Modified CGR

A third point to be brought up, was that distance to the onshore LNG plant for case 6c and 6d was 100 miles for the baseline. This number was picked based on the distance from the FLNG Prelude to the nearest onshore platform, which was 125 miles. With this distance, the effect of the parameter was not very noticeable on the tornado charts, and the NPV for the 2 cases weren't that much lower than that when using FLNG. Due to this reason, 3 modified scenarios for case 4 is presented below, with every parameter remaining the same, except the distance, which has been increased to 250, 500, and 1000 miles for the base line. **Table 14 through 16** and **Fig. 20 through 22** shows the NPV change and tornado chart for these cases

Percentage	b	di	Distance to shore	CGR	LNG Price	Discount rate	qi
80	5.771	5.773	5.927	3.583	2.738	9.469	0.610
100	5.772	5.772	5.772	5.772	5.772	5.772	5.772
120	5.773	5.771	5.617	7.961	8.805	3.263	10.933
Value in billion dollars							

Table 14. NPV Change for Case 4, 250 Miles

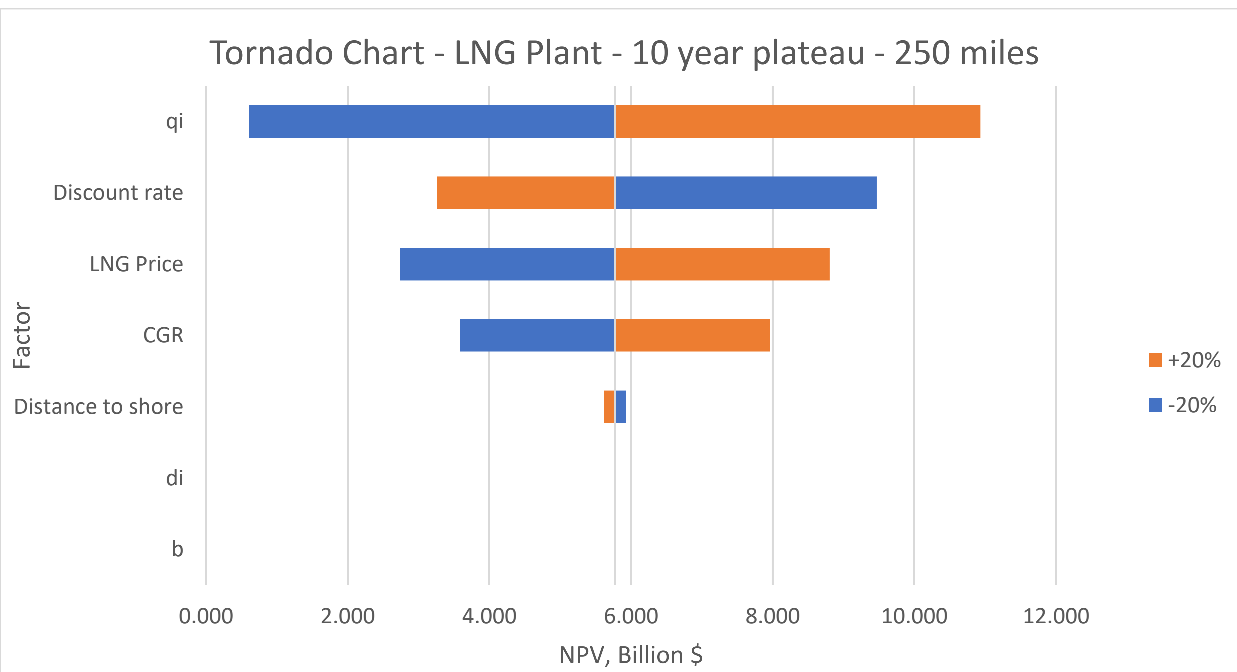

Fig. 20. Tornado Chart for Case 4, 250 Miles

Percentage	b	di	Distance to shore	CGR	LNG Price	Discount rate	qi
80	4.996	4.998	5.307	2.808	1.963	8.694	-0.165
100	4.997	4.997	4.997	4.997	4.997	4.997	4.997
120	4.998	4.996	4.687	7.186	8.030	2.488	10.158
Values in billion dollars							

Table 15. NPV Change for Case 4, 500 Miles

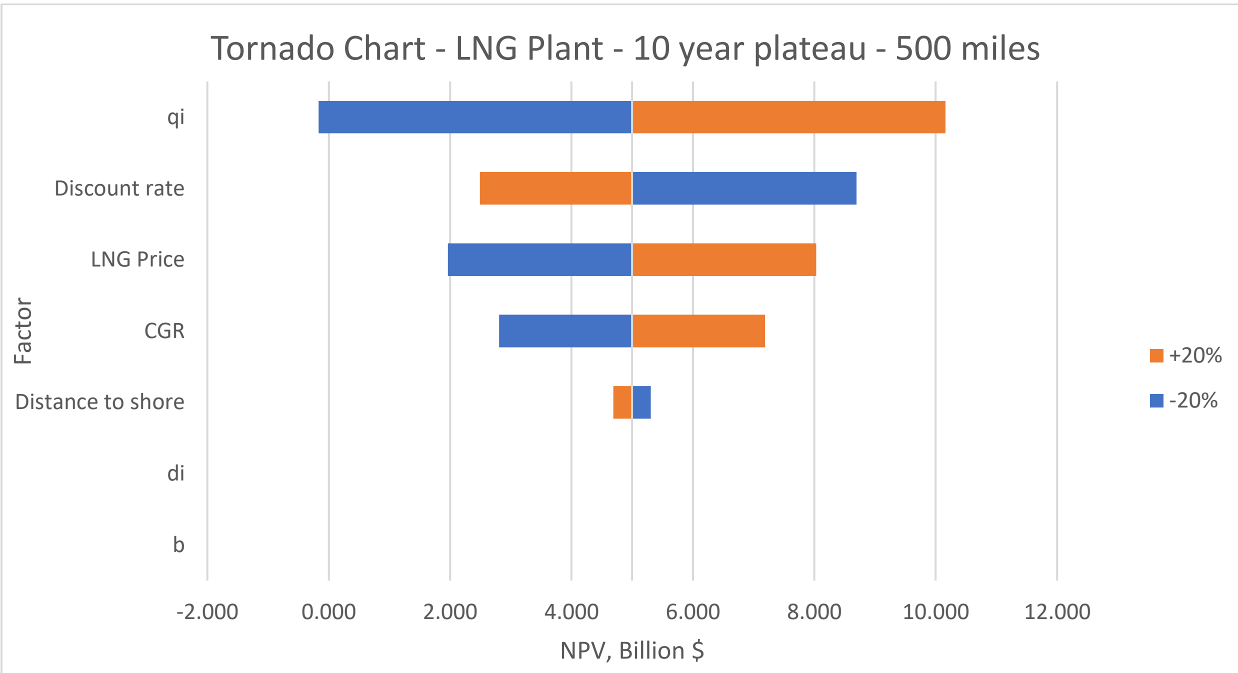

Fig. 21. Tornado Chart for Case 4, 500 Miles

Percentage	b	di	Distance to shore	CGR	LNG Price	Discount rate	qi
80	3.446	3.448	4.067	1.258	0.413	7.144	-1.715
100	3.447	3.447	3.447	3.447	3.447	3.447	3.447
120	3.448	3.446	2.827	5.636	6.480	0.938	8.608
Values in billion dollars							

Table 16. NPV Change for Case 4, 1000 Miles

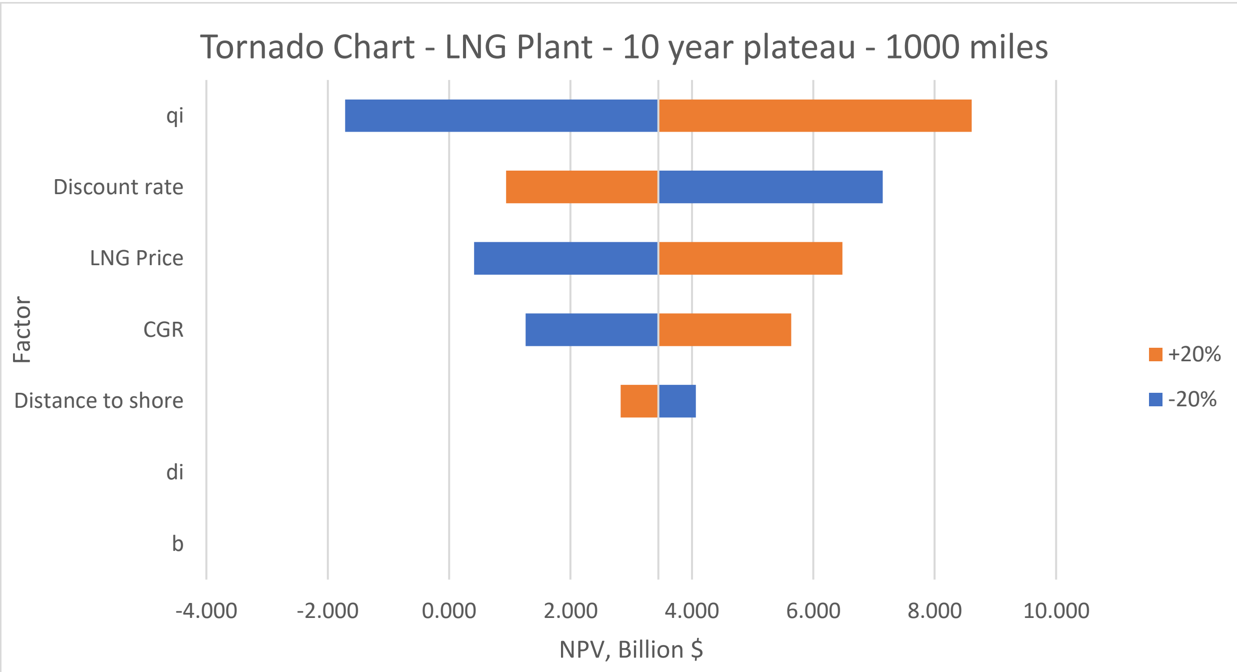

Fig. 22 Tornado Chart for Case 4, 1000 Miles

As the chart and values show, increasing the distance to shore will decrease the NPV, but make the effect of this parameter on NPV more pronounced; however, it does not change the order of importance of the rest of the parameters. Moreover, increasing the distance, and decreasing the initial production rate (qi) could lead to a negative NPV, as shown by the values for the 500- and 1000-mile scenarios. This means that, the longer the distance to shore is, the more likely that FLNG will be the better alternative.

9. Conclusion:

With so much potential stranded gas still left in the world, finding a suitable utilization method is crucial. As a result of the sensitivity analysis, a development flowchart was created. Additionally, this research shows that, the longer the distance to shore is, the more attractive FLNG will be. As the calculation in chapter 6 shows, if the distance to shore is 100 miles +/- 20%, then the NPV for the FLNG scenarios will be about twice that of the corresponding LNG plant scenario. However, if the distance were to increase to 250 miles, then FLNG becomes the clear winner; as shown in chapter 7. However, it should be noted this report consider the case of building an LNG plant and a pipeline from the ground up, hence the advantage of FLNG. If there were a subsidy for said plant, then going with pipeline transportation maybe be the better option.

For both FLNG and pipeline to an LNG plant cases, initial production rate has the biggest impact on the NPV. Therefore, this project, if chosen to go with an LNG-related development, would benefit best from a large gas field. It was also found that, CGR, while having an effect on NPV, was not as sensitive as other parameters such as interest rate and LNG price. With that being said, the most attractive option would be Gas to Wire, if the project can secure subsidy from the government of a West African country (Nigeria, for this report.) If the government cannot subsidize the project, then FLNG would be the most effective utilization option.

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Appendix

A. Overview of Decline Curve Analysis

Decline curve analysis (DCA) is a reservoir engineering technique that extrapolates trends in production using existing data from producing oil and gas wells. By fitting a line through the production history, the expected estimated ultimate recovery (EUR) of a well can be determined. It should be noted that, in DCA, there is an assumption that whatever causes controlled the trend of a curve in the past will continue to affect that trend in the future.

There are 3 main types of decline curve: hyperbolic, exponential, and harmonic. Each has its own governing equation.

Hyperbolic:

$$q = \frac{q_i}{(1 + bd_i t)^{\frac{1}{b}}}$$

With:

q: current production rate

q_i: initial production rate

d_i: nominal decline rate, at t = 0

t: cumulative time since start of production

b: hyperbolic decline constant (0<b<1)

Exponential: a special case of hyperbolic decline where b = 0

$$q = q_i e^{-dt}$$

Harmonic: a special case of hyperbolic decline where b = 1

$$q = \frac{q_i}{(1 + d_i t)}$$

It should be noted that, if production has not reached a stabilized phase, DCA may not be able to create reliable results.