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# Building Options for the Brazilian Pre-salt: A technical-economic and infrastructure analysis of offshore integration between energy generation and natural gas exploration

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ABSTRACT

The objective of this work is to evaluate the technical-economic and infrastructure aspects for the Brazilian Pre-salt natural gas use. Factors like technology maturity level, fuel and facilities costs, and electricity market are analyzed; the levelized cost of energy (LCOE) of two possibilities are calculated: (i) offshore Gas-to-Wire (GtW) and (ii) molecular natural gas outflow through the pipeline with onshore thermoelectric generation. This work also discusses the possibility of natural gas (NG) transport via liquefaction, considering the Floating Liquefied NG (FLNG) technology for national and international market. The LCOE of GtW technology is higher (67–87 US $/MWh) than onshore plants (43–69 US$/MWh) for Pre-salt area, higher than the historical energy price of Brazilian NG thermoelectric generation (44 US$/MWh), but, in general, lower than Brazilian NG energy auction price cap (84.5 US$/MWh) and lower than some values found in the literature for onshore plants (42–124 US $/MWh) abroad Brazil. FLNG technology is still new, there is no scale, few players use it, and it does not seem to be a feasible option for Pre-salt NG now. It is concluded that elements such as political uncertainties of the international natural gas market, the high $CO_2$ rate in the Pre-salt's natural gas mixture, and the difficulties in implement deep-sea infrastructure are challenging elements for the three possibilities analyzed. The Brazilian market discussion is relevant since it is a greenfield natural gas area in need of development. Thus, it is of upmost importance to implement a comprehensive energy policy to address offshore-onshore energy integration regulation and technological developments for the offshore transmission systems, and $CO_2$ content separation process.

## 1. Introduction

The transition to a world less dependent on fossil fuels places natural gas (NG) as a key element to maintain energy security and complement the intermittence of renewable generation (Economides and Wood, 2009)– (Li et al., 2021). As the demand for NG increases, its supply chain also needs to develop once the infrastructure availability is a relevant constraint to the growth of NG markets (Zhang et al., 2019). Affordability plays an important role in investment decisions and the system's construction arrangement (Hamedi et al., 2009). Countries with abundant NG reserves face the challenge of finding the best option to allocate this resource while assuring optimal production and meeting different demands flexibility. Integration between NG upstream and consumption markets has proven to enhance feasibility in the NG industry investments (Zhang et al., 2019).

Historically, countries with great NG reserves, such as Indonesia (Purwanto et al., 2016), Qatar (Chedid et al., 2007), United Arab Emirates (Kazim, 2007) and Venezuela (Khol, 1992), had the challenge of creating alternatives to exploit the NG potential since there was not enough domestic demand (Thomas and Dawe, 2003). The solution came

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from European and Asian markets since they presented a declining or none NG domestic production and a growing demand, as they were trying to replace the high carbon energy supply mix with one with lower emissions (EPE, 2017). In these regions, Liquefied Natural Gas (LNG) imports became an option to manage seasonal NG and electricity demand variations, providing higher flexibility to the energy system (Devine and Russo, 2019). NG became a strategic resource to ensure energy security as countries introduced gas-fired generation in the power sector, especially to reduce their carbon footprint (Sutrisno and Alkemade, 2020), (Devlin et al., 2016).

In the Brazilian case, renewables already represent around 86% of the installed capacity (IC) of the Brazilian National Electrical Interconnected System, out of a total of approximately 177 GW, mainly due to its hydroelectric and wind power plants, 62% and 12% respectively (ONS, 2022). Followed by natural gas (NG) and biomass power plant, with around 8% each (ONS, 2022), which offers both energy and security of supply (Paim et al., 2019). Now the expansion of the electricity mix counts on a high increase of intermittent sources such as wind, biomass and solar power plants, and the hydro capacity participation in the supply mix is declining (EPE, 2017). Environmental challenges (e.g., difficulties getting licenses) have restrained the construction of new hydro projects with large reservoirs (dos Santos et al., 2022), exposing the electricity supply to climate vulnerability. Consequently, when the rainfall season is not able to level the water reservoirs properly or during an unexpected event (e.g., demand spikes or sudden outages of large generation units), there is an urgent need for thermal power plant generation (Fernandes et al., 2008)– (Arango-Aramburo et al., 2019).

Brazil is responsible for one of the most important NG reserves discoveries in the world over the last decade, the Pre-salt area (Leal et al., 2017). The Pre-salt hydrocarbon reserves present a great opportunity to integrate the NG and power sectors as the area is near the regions with concentrated electrical power demand (southeast/coastal region of the country). The Pre-salt reservoir corresponds to a layer of oily rock composed of carbonate, under a thick layer of salt, located in the Santos and Campos basins, on the coast of the states of São Paulo, Rio de Janeiro and Espírito Santo, in the Southeast of Brazil in ultra-deep-sea region (Maués and Camargo, 2016). The Pre-salt Polygon covers approximately 149.000 km$^2$ offshore with an average distance of 300 km from the coast. The amount of oil and gas available in the Pre-salt reserves has not yet been established (Maués and Camargo, 2016), (Almeida et al., 2017). Still, despite the imprecise numbers (Goldemberg et al., 2014), it is a fact that these resources are important for the development of the Brazilian electricity grid.

The Pre-salt NG can be used to increase the share of the controllable generation with NG thermal power plants, ensuring the market's security and energy supply (Dantas et al., 2017). However, deep-sea offshore oil and gas exploration and production involves engineering challenges and require heavy investment, accompanied by the inherent uncertainty about oil and gas prices and the volume and quality of recoverable reserves, which results in in great variability in the resulting economic outcomes (Guedes and Santos, 2016).

This work evaluates the technical-economic and infrastructure aspects for the Brazilian Pre-salt natural gas use. The analyses focus on three scenarios: (i) Floating Gas-to-Wire (GtW) with offshore power transmission; (ii) NG offshore pipelines with onshore thermal power generation, and (iii) Floating Liquefied NG (FLNG) technology for national and international market.

While the offshore pipeline is a mature technology, research regarding offshore power generation from NG (GtW) are mainly focused on power-supply hubs for offshore oil and gas operations with a carbon capture process (Hetland et al., 2009)– (Nascimento Silva et al., 2020). However, for the Pre-salt case, the amount of produced gas largely exceeds the platform fuel gas requirement (EPE, 2020). Yet, existing research on offshore power plants to supply mainland electricity demand (including sub-station platforms and subsea cables) are mostly dedicated to wind farms (Firestone et al., 2018)– (Soares-Ramos et al., 2020). Thus, the current work gathers information from the individual analyses for the offshore structures - NG power generation, electrical infrastructure and floating liquefaction process - to build options for the Brazilian Pre-salt outflow and market.

The structure of this work is as follows. First, an overview of the NG industry in Brazil and its current framework is developed. Then, two of the selected cases – onshore power generation and GtW – are presented, introducing their concepts and economic valuation carried with LCOE (Levelized Cost of Energy) calculation. LCOE results are compared with national energy prices and other values found in Literature and a sensibility analysis is made. Then, the possibility of NG transport via LNG, considering FLNG technology in discussed to trade NG in the national and international market, considering technological restrictions, political conditions and natural gas prices.

The set of GtW LCOE value found in this work is higher than onshore NG power generation, but, in general, lower than Brazilian NG energy auction price cap. This result, associated with the power sector and market analysis produced throughout this work, shows that GtW technology could be seen as an energy and technological vector for offshore power grid development in Brazil, promoting the onshore-offshore energy integration and the power-hubs needed for enhancing Pre-Salt exploration. FLNG technology does not appear to be promising now for Pre-salt natural gas.

## 2. Natural gas in Brazil

The discovery of the pre-salt fields in 2006 has placed Brazil as one of the world's new largest oil and NG reserves. The domestic production of NG was approximately 126 MMm$^3$/day in 2020 and is expected to achieve 276 MMm$^3$/day in 2030 (BP, 2018). National production comes mainly from offshore fields where NG is associated with oil (EPE, 2020). Since NG demand is higher than net domestic production capacity, Brazil is also supplied by imported NG from Bolivia (30 MMm$^3$/day capacity pipeline) and LNG terminals (41 MMm$^3$/day regasification capacity) (ANP, 2019).

The Brazilian NG demand can be divided mostly between industry and electricity generation. Before 2013, NG-fired plants represented an average of 20% of total demand, while the industrial market had the largest share, with an average of 60% (MME, 2019). Due to the low levels of water in hydroelectric reservoirs, the share of NG for electricity generation is increasing and reached 46% in January 2020 (EPE, 2020), (MME, 2019), (MME, 2021). The operation of the Brazilian power generation system is established on a hydro-thermal dispatch, with hydroelectric plants operating on the baseload. Thermal power plants play a complementary role in ensuring energy security, and their NG consumption are highly variable, depending on the water reservoirs' levels (Rego et al., 2017). Electricity generation from NG plays a role of flexibility, operating only to meet the system's peak consumption (Vahl and Filho, 2015). Thus, the power sector was not seen as potential demand to absorb the growing NG production and support investments for associated gas. However, IEA, 2019, the Brazilian government launched the program New Gas Market (NGM). One of the goals of the NGM is to integrate the NG and power sectors to support the development of the Brazilian national NG reserves.

Currently, the Pre-salt NG is transported from the producing wells to the processing units through offshore pipelines. As pipelines construction requires high investments, they are usually subjected to significant economies of scale (Feijoo et al., 2018), and the large capital outlay and extensive development times might carry significant risks for investors (Spence and Kessler, 2011). In the Brazilian case, the uncertainty in the future demand is forcing the companies exploring the Brazilian pre-salt to reinject the NG production (MME, 2019), (BNDES, 2020).

## 3. Possibilities for the pre-salt natural gas

It is estimated that only the gas contained in one of the reservoirs

(Libra) is enough to double the national reserve (David, 2019). Besides the difficulty of extraction by the location in ultra-deep sea, the NG from the pre-salt is quite heterogeneous. The amount of $CO_2$ varies between 20% and 50% in the mixture (Mazza, 2016). In addition to the Libra field (approximately 45% of the volume of the gas is composed of $CO_2$), others like Jupiter and Iara also have a high $CO_2$ index (David, 2019). The NG of these fields can be used for reinjection due to the technological limitations of the treatment process (Maués and Camargo, 2016). Although the gas-oil rate (RGO) is high in Pre-salt reservoirs (Maués and Camargo, 2016), (Almeida et al., 2017), there are still many uncertainties about the amount of ideal gas to be reinjected for oil extraction productivity (Almeida et al., 2017). This is another difficulty in projecting the volume of gas that will be available in the following years. Besides, part of the gas is currently being flared, offshore natural gas flaring in responsible for more than 90% of the gas flared in Brazil (Rodrigues, 2022). Fig. 1 shows existing and future infrastructure for Pre-salt natural gas exploitation.

To reach the final consumer, NG goes through a complex production chain (Udaeta et al., 2009) and currently, the gas produced from the Pre-salt fields is treated and compressed in the FPSO and subsequently transferred to underwater pipelines (David, 2019). As discussed earlier, the power sector may become an interesting candidate to absorb the NG production due to natural gas new regulation. Thus, the authors assess two technologies aiming at electricity generation from NG. The first one considers NG transport through offshore pipelines and consumption at onshore thermal plants. The second one analyses an offshore gas-fired power plant transmitting electricity from the platform to the coast, a process known as GtW. The work also disclaims the possibility of the floating LNG technology to export NG from the Pre-salt fields. These processes are detailed in Fig. 2.

### 3.1. Natural gas transportation via offshore pipelines

Ríos-Macedo and Borraz-Sánchez (Ríos-Mercado and Borraz-Sánchez, 2015) showed that of the many types of transportation means, pipelines represent the most economical way to transport large quantities of NG and have the advantage of guaranteeing the capacity of NG flow with little maintenance and a long lifespan. Other transportation means, such as LNG, is more beneficial than pipelines only when the distance exceeds 2200 miles (Atienza-Márquez et al., 2020). Thus, NG offshore pipeline transmission has been applied on a large scale in Brazil since the first gas discoveries in the 1970s and, more recently, to the installation of Pre-salt Routes (EPE, 2020).

On the other hand, there are some challenges for the Pre-salt fields since their installation in deep sea depends on the topography of the ocean ground, and there is little flexibility to increase the pipe's capacity (David, 2019). Also, as NG resources from the Pre-salt come with large amounts of $CO_2$ and $H_2S$ it requires separating the compounds and draining them to the Floating Production Storage and Offloading (FPSO) platform, where it goes through a treatment process before transporting the gas given its corrosive effect (Mazza, 2016). This separation process is even more complex for the Pre-salt NG since it is associated with oil (Almeida et al., 2017). In the gas pipeline, the wet NG (denomination given to the gas before the processing) is compressed and sent through the offshore pipelines to the coast, where it is processed in an NG Processing Unit (NGPU) and nominated raw NG (Ríos-Mercado and Borraz-Sánchez, 2015).

The Pre-salt gas flow is defined through three pipeline routes: the Caraguatatuba route (Route 1), which started operating in 2011 and has a flow capacity of 10 $MMm^3$/day, the Cabiúnas route (Route 2), with 20 $MMm^3$/day operating since 2016, and the Maricá route (Route 3) with a capacity of 18 $MMm^3$/day which are under development (EPE, 2014). Each Route has approximately 350 km in length.

Even with the operation of these two gas pipelines routes, the injection of NG in Brazil tripled from 2010 to 2016 (Almeida et al., 2017) and currently represents more than 50% of NG production (ANP, 2020a). However, there is a limit to NG injections due to reservoirs' stability (EPE, 2019). The Brazilian Energy Research Company (EPE) indicates that all three routes will be at their maximum capacity by 2025 (EPE and "PDE, 2030, 2020), and it will be necessary to increase NG imports from Bolivia and LNG regasification to meet the country's total demand (EPE, 2014). Thus, using thermal plants to anchor the development of new pipeline infrastructure is a solution to enable the Pre-salt associated NG production.

### 3.2. Gas-to-Wire (GtW)

The GtW process consists of raw NG processing and power generation, exporting electricity to the grid. When there is an offshore NG field, GtW can be implemented along with the NG production at a floating power plant exporting electricity through subsea cables (Interlenghi et al., 2019), which is the case analyzed in this study. Although this

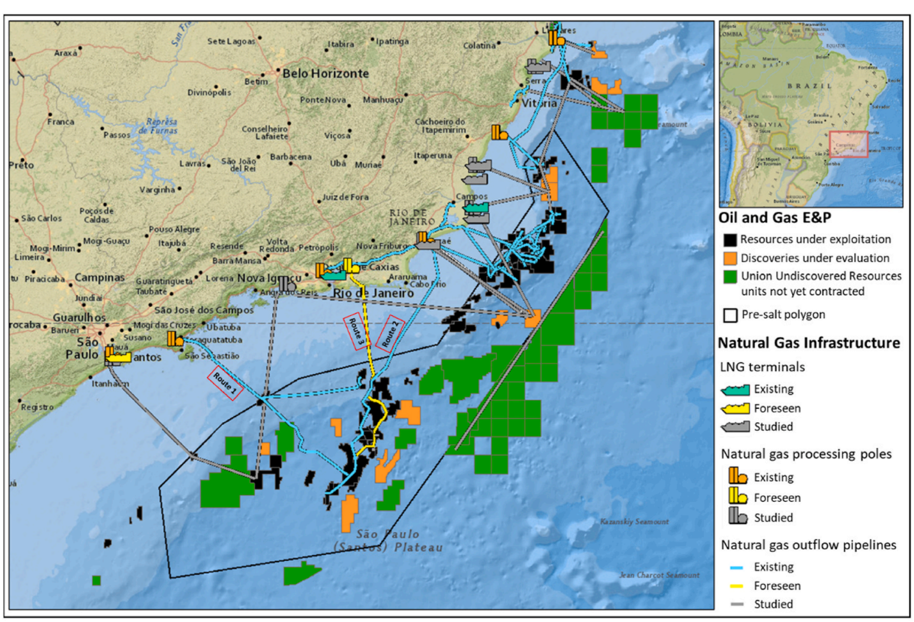


**Fig. 1.** Existing and future infrastructure for Pre-salt natural gas exploitation. Source: elaborated by the authors based on EPE (EPE, 2022).

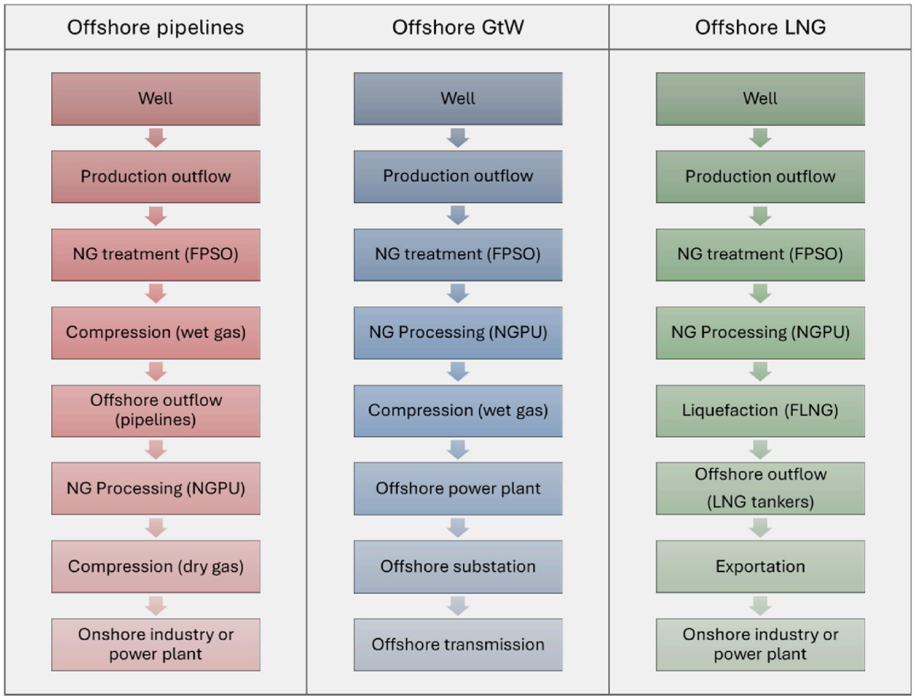


**Fig. 2.** Stages of the exploration, outflow, generation and export of NG and LNG offshore or by GtW offshore technology.

alternative avoids the offshore pipeline infrastructure, NG still must go through a treatment stage in the FPSO, since NG is mixed with $CO_2$ and $H_2S$. Then, NG must be processed in an offshore NGPU, compressed and used to generate electricity in the offshore power plant (Roussanaly et al., 2019). Afterwards, the electricity is transformed from AC to DC, enabling the transmission in High Voltage Direct Current (HVDC) (de Alegría et al., 2009)– (Itiki et al., 2017). Although the cost of offshore converter stations and other HVDC devices is high, it is still the best approach due to a transmission distance longer than 200 km (Meng et al., 2021).

NG is already used as the primary energy source of power in offshore platforms, combining technologies to achieve self-sufficiency for different energy needs, such as electricity and heat (Auld et al., 2014). Elevated costs and reduced space in the platforms have discouraged the employment of larger and more efficient offshore power plants (Nascimento Silva et al., 2020). However, rigorous environmental regulations of offshore oil and gas activities (Windén et al., 2014) and current technology development of offshore power transmission using HVDC (Windén et al., 2014) led to a renewed interest in offshore power generation approaches.

GtW projects can have positive outcomes for distant offshore oil fields with associated gas characterized by difficult processing (e.g., high $CO_2$ content) and high gas-to-oil ratio, which is the case of the Pre-salt fields. Another upside is that NG specification only needs to meet the requirements of the turbine instead of the stringent regulation for transportation via pipelines (EPE, 2020), (Interlenghi et al., 2019). Regarding electricity transmission, the offshore grid is a highly studied configuration, especially due to the development of offshore wind power in the North Sea (Kristiansen et al., 2017)– (Gorenstein Dedecca et al., 2018).

In Brazil, although GtW from offshore NG productions still faces regulatory difficulties due to the lack of policies to coordinate the electricity and gas sectors (Relva et al., 2020), this work approaches the economic feasibility of the offshore GtW technology. Both Petrobras (2017) and the Brazilian government (Pedrosa, 2016) indicate that GtW technology is one of the interests for Pre-salt NG exploitation; however, there is still no prospect of projects in this regard. On the other hand, GtW technology is currently used in onshore facilities of gas fields in the Parnaíba basin in the state of Maranhão. The Parnaíba thermoelectric complex totalizes an installed capacity of 1427 MW distributed in four power plants (Cançado, 2017), (ENEVA, 2017). Moreover, a sensibility analysis is conducted in this work to understand the NG liquefaction processes on offshore applications (FLNG) as an alternative to the Pre-salt's NG.

## 4. Economic evaluation

The economic evaluation aims at comparing the costs of an onshore thermal power plant ($TPP_{on}$) with an GtW arrangement ($TPP_{off}$), fuelled by NG from the Pre-salt. The economic feasibility of power generation is determined using the levelized cost of electricity (LCOE), which indicates the minimum price of electricity to recover total costs of the project (Eq. (1)).

$$LCOE = \frac{\sum_{t=1}^{T} \left( I_t + O\&M_t + C_t + Desc_t + E_{CO2_t} + T_{off_t} \right).(1+r)^{-t}}{\sum_{t=1}^{T} E_t.(1+r)^{-t}} \tag{1}$$

Whereas: LCOE = average lifetime levelized electricity generation cost; $I_t$ = investment in the year $t$; $O\&M_t$ = operation and maintenance total cost in the year $t$; $C_t$ = fuel cost in the year $t$; $Desc_t$ = decommissioning cost in the year $t$; $E_{CO2t}$ = carbon emission cost in the year $t$; $T_{off_t}$ = offshore electric power transmission cost in the year $t$; $E_t$ = the amount of electric production in the year $t$; T = lifetime of the system; r = discount rate.

### 4.1. Onshore versus offshore power generation

As technology costs are subject to individual plant characteristics, assumptions of each configuration were made as follows.

Both power plants are based on a combined cycle configuration. For each possibility, four cases are evaluated, changing the fuel cost. The general assumptions for both cases and fuel costs are described below and are consolidated in Table 1. Other costs assumptions are shown in Table 2 and Table 3.

**Table 1**
General assumptions and fuel price scenarios for onshore and offshore electrical power generation systems.

| Aspect | Unit | | General assumptions | | | |
|---|---|---|---|---|---|---|
| Hours | hour/day | | 24 | | | |
| Days | day/year | | 365 | | | |
| Lifespan period (t) | year | | 30 | | | |
| Discount rate (r) | % | | 10% | | | |
| Capacity fator (CF) | % | | 85% | | | |
| Electric conversion efficiency (ECE) | % | | 59% | | | |
| Installed capacity (IC) | MW | | 980 | | | |
| Distance | km | | 383 | | | |
| Aspect | Unit | Scenarios: | (i) | (ii) | (iii) | (iv) |
| Fuel price | US$/MMBtu | | 5,04 | 5,59 | 7,70 | 3,20 |

**Table 2**
Onshore and offshore facilities assumptions.

| Aspect | Unit | $TPP_{on}$ | $TPP_{off}$ |
|---|---|---|---|
| Overnight cost | US$/kWe | 958 | 1198 |
| Investment | US$/kWe | 1108 | 2124 |
| Decommissioning | % | 5% | 5% |
| $O\&M_f$ | US$/kW.year | 11.21 | 42.48 |
| $O\&M_v$ | US$/MWh | 2.70 | 2.70 |
| Fuel Cost | % | [a] | 80% of [a] |
| $CO_2$ emissions | $gCO_2eq/kWh$ | 500 | 500 |
| Emissions costs | $US\$/ton.CO_2$ | 10.45 | 10.45 |

[a] Values are presented in Table 1.

**Table 3**
Offshore electrical power transmission assumptions.

| Aspect | Unit | (i) - (iv) | |
|---|---|---|---|
| | | $TPP_{on}$ | $TPP_{off}$ |
| Investment | US$/MW.km | – | 4.000 |
| O&M | % | – | 1% |

The considered lifespan period is 30 years, assuming NG power plants expected lifetimes (Khan et al., 2020), (IEA and NEA, 2020). The 10% discount rate fits in a high-risk contracting and regulation environment (IEA and NEA, 2020), and it is commonly found in literature (U. S. EIA, 2017)– (DECC, 2012).

The adopted capacity factor is 85% (Roussanaly et al., 2019), considering the plant will have a baseload operation; that is, the plant operates continuously over extended periods to supply the base demand of the power system. The electric conversion efficiency is usually adopted at around 60% for CCGT; in this work, we assumed 59% (Leal et al., 2017), (IEA and NEA, 2015). The installed capacity (IC) of 980 MW was defined based on (IEA and NEA, 2020), and moreover, it is close to the average IC of Brazil (ANP, 2020b), (CCEE and "Leilões, 2020).

The adopted distance from the offshore plant to the coast is 383 km, based on the extension of the Route 2 pipeline (EPE, 2020).

Four fuel costs are adopted. The fuel cost is basically the match among the commodity, extraction, treatment, processing, and transportation (up to the TPP). The first three are NG Pre-salt costs defined by EPE (EPE, 2014) based on the offer price premise, that is, the minimum price that motivates the supplier to make natural gas available to the market. EPE did not consider the extraction structure CAPEX, because it is assumed that this cost is associated with the oil extraction cost. This assumption is usually used in the associated gas cost assessment. EPE also considered $CO_2$ emission rate of 20% for defining these costs. Therefore, using NG from Pre-salt with a higher $CO_2$ index may result in a higher fuel cost. The last price adopted in the scenarios is estimated by IEA and NEA (IEA and NEA, 2020) for the Americas.

The investment estimative linked to the IC for a $TPP_{on}$ is 1108 US $/kWe (IEA and NEA, 2020) and for a $TPP_{off}$ is 2124 US$/kWe (Windén et al., 2014). Investment estimative consists of overnight costs plus financing costs. The $TPP_{off}$ has an investment cost value substantially greater than the $TPP_{on}$, see Table 2. The cost of pipeline construction was not considered for $TPP_{on}$ because it would be installed on the coast and take advantage of the existing gas pipelines.

The overnight costs include mainly (i) direct construction costs plus pre-construction costs, such as site licensing; (ii) indirect costs, such as engineering and administrative costs that cannot be associated with a specific direct construction cost category; and (iii) transmission costs (IEA and NEA, 2020) and it is used in this work for the estimative of the decommissioning calculation. The adopted value for overnight cost was 958 US$/kWe for $TPP_{on}$ (IEA and NEA, 2020). In the case of $TPP_{off}$ the adopted value is 25% higher than used for $TPP_{on}$ or 1198 US$/kWe (Windén et al., 2014), (Windén et al., 2011), and it is based on the additional common value for new structures, equipment and production units (IEA and NEA, 2015). The decommissioning cost represents 5% of the overnight cost (IEA and NEA, 2020), (IEA and NEA, 2015), and it is applied after the lifespan (Table 2).

The O&M costs are divided into (a) fixed costs ($O\&M_f$) consisting of TPP operating and miscellaneous costs (PA and "Energy Market Authority, 2014), and (b) variable costs ($O\&M_v$) that cover the consumables like water, food, people and material transportation by boats and trucks and materials. $O\&M_f$ adopted for the $TPP_{on}$ was 11.21 US$/kWe. year (IEA and NEA, 2020), for the $TPP_{off}$ it is assumed to represent 2% of the investments according to (Roussanaly et al., 2019). For $O\&M_v$ it was assumed a cost of 2.70 US$/MWh (IEA and NEA, 2015) by both cases, see Table 2.

The carbon emission cost depends on the international agreements to which each country is a signatory. In Brazil, the environmental compensation cost for some electrical power facilities is equal to 0.5% of the enterprise's CAPEX (EPE, 2014). The NG power generation produces an average of 500 $gCO_2eq$ by kWh generated, see Table 2. Although there is no consensual financial value, it is considered 10.45 US$/ton. $CO_2$ (IEA and NEA, 2020).

For $TPP_{on}$ the fuel costs were defined according to Table 1. For $TPP_{off}$ it was defined as 80% of the onshore fuel cost (Jacobs, 2009) since there are no costs regarding transportation, see Table 2. On the other hand, the offshore electrical power transmission cost is added. This cost varies from 2000 to 4000 US$/MW.km (Windén et al., 2014). Because it is a system deploying in deep waters, the specific submarine cable cost has been assumed as a conservative value of 4000 US$/MW.km (Flórez-Orrego et al., 2021). This transmission technology has a low de O&M cost, and some studies assume null O&M cost (Windén et al., 2014), (Windén et al., 2011). In this study, we assumed 1% of the investment cost, see Table 3. The transmission lifespan is at least 30 years (Tee and Pesinis, 2017).

## 5. Results

The economic analysis is based on the assumptions adopted and based on the method of calculation of the LCOE in the equivalent base of US$/MWh, see Eq. (1), resulting in four scenarios of LCOE.

For all scenarios, the LCOE of $TPP_{on}$ option was lower than the LCOE of $TPP_{off}$. The $LCOE_{on}$ is an average of 21.25 US$/MWh lower than the $LCOE_{off}$. The maximum $LCOE_{off}$ was 87.47 US$/MWh for scenario (iii), and the minimum $LCOE_{on}$ was 42,88 US$/MWh for scenario (iv), see Fig. 3. This difference is due to higher investment, $O\&M_f$, and overnight costs assumed for decommissioning costs.

The LCOE calculated for both the options, $TPP_{on}$ and $TPP_{off}$, presents similar values to those found in the literature, see Table 4. For $TPP_{off}$, values found are lower than some found by other references for $TPP_{on}$, abroad Brazil. Table 4 shows the CF, lifetime and discount rate assumptions, since the comparison of different LCOE must take into consideration these critical factors, according discussed in (Loewen, 2020), (McCann, 2020).

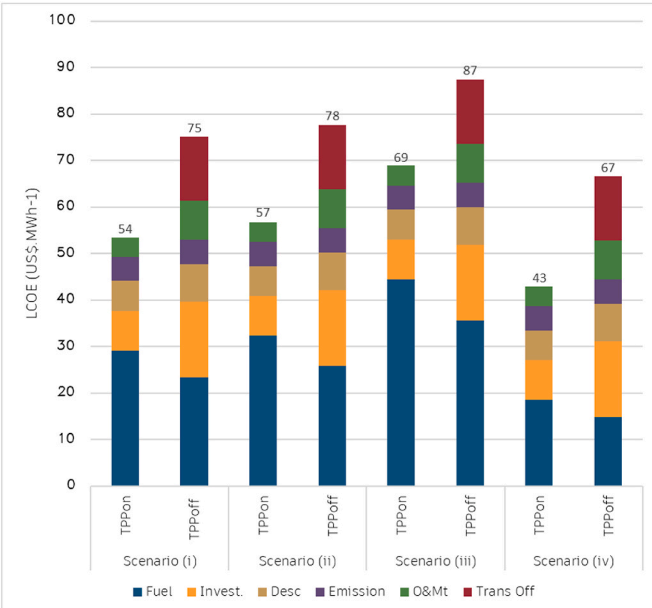


**Fig. 3.** LCOE of the four scenarios.

**Table 4**
Comparison of LCOE values for CCGT technology.

| Reference | LCOE [US $/MWh] | CF [%] | Lifetime [years] | Discount rate [%] |
|---|---|---|---|---|
| $TPP_{on}$ | 43–69 | 85 | 30 | 10 |
| $TPP_{off}$ | 67–87 | 85 | 30 | 10 |
| IEA and NEA (IEA and NEA, 2020) | 42-124 (55 for Brazil) | 85 | 30 | 10 |
| EIA/DOE (U.S. EIA, 2017) | 46–59 | 87 | 30 | 7.8 |

IEA, 2019, three NG TPP were contracted in the Brazilian new-energy auction by an average inflation-adjusted price of around 44 US$/MWh. Thus, LCOE of TPPon is consistent with the historical prices of Brazilian Auction.

IEA, 2022, a new and specific auction occurred, with the objective of contracting NG TPP in regions with little or no gas infrastructure, to expand and internalize the natural gas network in the country. In this auction, 33 TPP were registered and only 3 were contracted at the auction price cap (84.5 US$/MWh).

This auction is the result of the law that allowed the privatization of a Brazilian electricity company (Eletrobras) but determined the contracting of 8 GW of TTPs. Thus, this demonstrates a political interest in the expansion of the gas sector. Therefore, in the case of offshore GtW plants being seeing as a structuring project, as discussed in (Relva et al., 2020), a higher energy value can be admitted in favor of the development of the sector in a given region. In this condition, the offshore GtW technology could be considered a vector of technological development of the Brazilian offshore electric sector, and become feasible.

By the analysis of Fig. 3, it is evident that the fuel cost represents the largest share of the LCOE of both $TPP_{on}$ and $TPP_{off}$. in all the scenarios. The fuel cost is always higher for $TPP_{on}$, because in the case of $TPP_{off}$ there is a 20% reduction in the cost due to the discharge related to the cost of the offshore transportation of NG. But this cost reduction does not compensate for the additional offshore transmission cost.

### 5.1. Sensibility analysis of offshore transmission cost and GtW possibilities

The LCOE value for the offshore transmission system resulted in 13.85 US$/MWh. Table 5 presents the consolidated results for the offshore transmission system, based on Table 3.

Thus, maintaining the assumption that the cost of fuel is 80% at $TPP_{off}$, fuel cost may be 69,24 US$/MWh, or 11.98 US$/MMBtu, to equalize the cost of fuel in $TPP_{on}$ to the cost of fuel plus offshore transmission in $TPP_{off}$.

Furthering the cost analysis of the GtW option, the transmission cost was varied, see Fig. 4.

Assuming offshore transmission investment equal to 3000 US$/MW. km, fuel cost may be 8.98 US$/MMBtu to equalize the cost of fuel in $TPP_{on}$ to the cost of fuel plus offshore transmission in $TPP_{off}$. To offshore transmission investment equal to 2000 US$/MW.km, fuel cost may be 5.99 US$/MMBtu.

Even with the reduction of the costs of implementation and O&M of the offshore transmission, the $LCOE_{off}$ receives higher values than the $LCOE_{on}$ in all scenarios. This value allows us to exemplify that in all NG scenarios prices considered in this work, the economic viability of the $TPP_{off}$-type venture is not guaranteed without any change in the investment cost of the floating TPP, see Fig. 5.

Although GtW LCOE does not present feasible values for the current Brazilian power market, it is important to highlight that the expansion of Brazilian Pre-salt oil and gas (O&G) exploration demands power supply. Moreover, global sets of avoiding carbon emissions imply using carbon capture and storage (CCS) technologies in O&G activities. Since CCS is also an energy-intensive activity, GtW is an important technology for power hubs to supply the existing and future FPSOs with energy. Essentially, these hubs can be understood as the set of floating units (e.g. FPSOs) with GtW plants with $CO_2$ capture and storage. At the strategic level, it is necessary to determine the overall system configuration, assessing the most relevant design variables such as the number of hubs, their location and power generating capacities for the Brazilian Pre-salt area.

Besides, advances in GtW technologies - particularly regarding floating structures for power generation and offshore transmission infrastructure - can be beneficial for constructing hybrid energy hubs with the participation of offshore wind plants. This type of multiple arrangement can contribute to the distribution of costs and lower the final cost of energy.

Finally, this work considered a high capacity factor (85%) for base-load operation. In a scenario of decarbonization in which natural gas only plays a role of back-up firm capacity in the power system the LCOE can be much impacted. Tordoir (2022) has calculated that changing the capacity factor from 87% to 10% causes a more than double increase in the LCOE of NGTPP.

### 5.2. Natural gas liquefaction from the pre-salt

Different studies indicate that installing liquefaction processes on FPSOs is technically and economically feasible (Nguyen and de Oliveira Júnior, 2018), (Macangus-Gerrard, 2018). However, knowing the project's complexity and the unconsolidated technology of the offshore liquefaction process (Nguyen and de Oliveira Júnior, 2018), only a few FLNG plants are currently in operation. The first project (PFLNG SATU) was developed by Petronas and started operation in 2016 at a gas field in Malaysia. In April 2017, the unit delivered its first LNG load (Petronas). The second project (Shell Prelude FLNG) operates 475 km from the Australian coast (Offshore Technology, 2013) and is the first well-known

**Table 5**
Consolidated results of the offshore transmission system.

| t [year] | 30 |
|---|---|
| Invest. [US$/MWh] | 11.79 |
| $O\&M_t$ [US$/MWh] | 2.06 |
| LCOE [US$/MWh] | 13.85 |

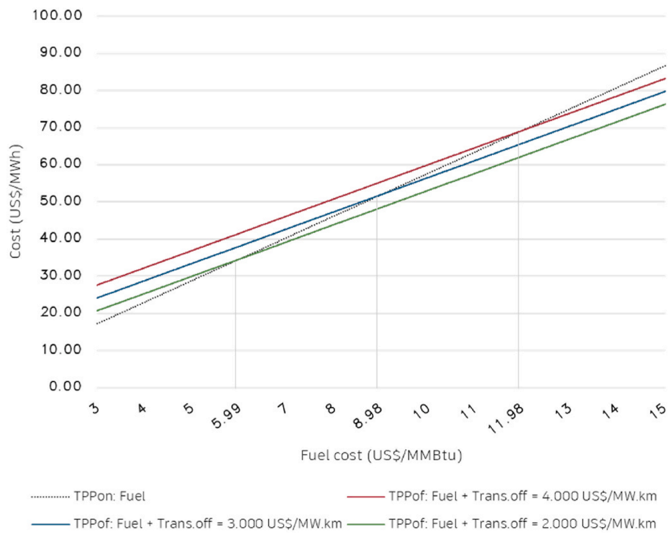


**Fig. 4.** Sensibility analysis of offshore transmission investment.

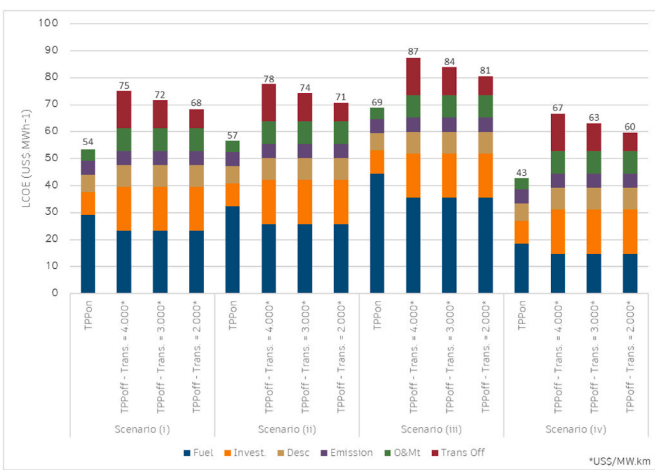


**Fig. 5.** LCOE of the four scenarios with transmission cost variation.

FLNG plant (Shell", 2017). In the past, an FLNG in Brazil was also considered by Petrobras. The company announced developing a project in the Santos basin in 2009, with a capacity of 14 MMm$^3$/day (Petrobras, 2009). However, Petrobras chose to prioritize its investments on the construction of Route 2, and the project was not carried forward (Almeida et al., 2017). IEA, 2022, Petrobras announced that it had started the operation of the FPSO Guanabara, the first definitive production system installed in the Mero field, in the Pre-salt layer of the Santos Basin. The FPSO has the capacity to process up to 180,000 barrels of oil and 12 MMm$^3$ of NG per day. However, the FPSO has gas reinjection systems, in which the production of gas with a content of 45% of carbon dioxide ($CO_2$), after its own consumption in the FPSO, is all reinjected into the deposit aiming at maintaining pressure and improving oil recovery.

NG prices have had an upward trend since 2000, but with the surge in supply coming from unconventional oil and gas resources in North America, the trend in natural gas prices has become downward in recent years. Although there is a tendency for market diversification, the demand has slowed down in recent years, and the supply increased, resulting in an oversupply and, consequently, the perspective fall of the LNG prices for the 2016–2022 horizon (Energia, 2016). But that all changed with the COVID-19 pandemic in 2020/2021 (Liu and Chen, 2022) and Russia's invasion of Ukraine IEA, 2022. The high price and tight supply environment built up during the second half of 2021 further intensified, leading to record NG prices and supply disruptions that are damaging the reputation of NG as a reliable and affordable energy source (IEA, 2022).

Moreover, the current global market comes with added competition and is becoming a more difficult task to invest. In addition, cuts in capital expenditure by the fossil energy industry and the highly uncertain outlook for NG demand due to both new LNG supply under construction and decarbonization goals (Pike, 1999) are a challenge to this international enterprise. Still, for the Pre-salt case, developing such technology for a $CO_2$ rich NG represents a bigger challenge (Spence and Kessler, 2011), and it remains one of the main reasons for the elevated reinjection (Coelho, 2019). Furthermore, the liquefaction process is energy intensive. A recent study showed that FLNG increases the total power consumption by up to 50% compared to the reinjection process (Nguyen and de Oliveira Júnior, 2018).

Thus, while Brazil may become one of the five biggest oil producers and exporters of the world (Coelho, 2019), the NG from Pre-salt still faces an unclear future, not only for exports but also for domestic demand. Conversely, the country is stimulating the expansion of LNG regasification terminals' capacity to increase flexibility and security (mainly to supply TPP), besides encouraging new gas demands to emerge near these new terminals' locations (EPE, 2021). Although regulations committed to climate change could unblock some of the bottlenecks listed previously, it will probably apply to satellite regasification facilities. The fuel shifting from diesel or oil to natural gas could offer an energetic solution to off-grid areas (e.g., rural communities or scattered geographies like Amazonas state) (Atienza-Márquez et al., 2020). Considering that there are three LNG regasification projects (two of them in the Northeast region) in the final investment decision: Gas Sul Terminal/SC, Suape/PE Terminal, and Barcarena/PA Terminal (EPE, 2014), the off-grid areas mainly located in the North and Northeast regions, will be covered within these LNG projects. Thus, the NG supply from the Pre-salt would not present the best logistics or the economic feasibility to compete with the already in development projects.

Also, with the new regulatory framework for the NG industry published in April 2021 (Brasil and Lei No 14, 2021), a cost reduction in the construction of NG pipelines in Brazil is expected due to the market opening to existing facilities, such as offshore pipelines, and sharing between Petrobras and other producers. EPE estimates an investment cost for future gas pipelines of US$ 80/m.in in comparison to the historic US$ 91/m.in average cost (EPE, 2014). EPE also investigated the cost of an FLNG unit for a 5,6 million m$^3$/d NG processing. According to the research company, the project's CAPEX would be around US$ 1,1 billion (Coelho, 2019). Knowing that Route 1 has a flow capacity of 10 million m$^3$/d with 18 in pipes and Route 3 has a flow capacity of 18 million m$^3$/d with 24 in pipes (Azevedo et al., 2014), for a 5,6 million m$^3$/d NG flow, it is possible to assume 10 in the pipeline. Considering the distance of 383 Km from the Pre-salt to the coast and the cost of US$ 80/m.in, it would take an investment of approximately US$ 306.4 million regarding the direct pipeline construction. Taking into consideration that this represents 50% of the total project cost and the other 50% contains indirect costs such as engineering costs, taxes, and contingencies (EPE, 2019), the total cost for a new NG pipeline would be US$ 612.8 million, and it could be a more profitable business to destine the NG from the Pre-salt. It is important to emphasize that this cost is only valid under the aligned assumptions. In the past, NG pipelines in Brazil cost achieved the value of US$ 340/m.in, and EPE does not discharge a cost of US$ 200/m.in. In this latter example, the total cost of the pipeline construction could be more than US$ 1,5 billion.

Furthermore, the pipeline option is only possible if a continuous domestic NG demand exists, which is not seen in Brazil (MME, 2021) (see Fig. 6). While both Bolivian and domestic NG supply the base consumption, LNG is destined to supply the variable consumption from TPP. Since 2017, the base demand has been stabilized, and without certainties of its growth, investment in new pipelines to supply the

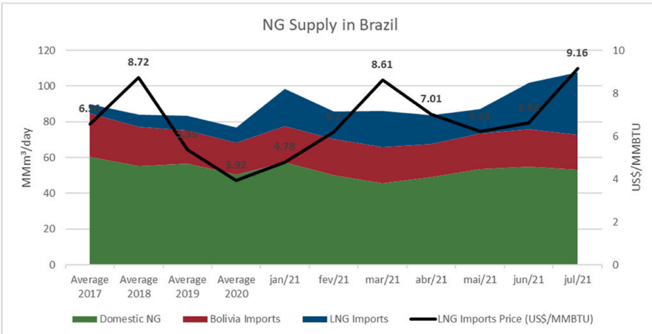


**Fig. 6.** Natural gas supply for the Brazilian market.

domestic market is not interesting for producers. Additionally, NG prices assumed earlier in this work (3.2–7.70 US$/MMBtu) are very similar to LNG import prices to the Brazilian market (see Fig. 6.). This means that investing in a solution to the LNG market could be a risk, especially if attached to long term contracts.

It is important to highlight those unexpected long-term events such as a global pandemic and the Russian invasion of Ukraine have changed the global market dynamics. Nowadays European Union, for example, is committed to speeding up the phase-out of Russian imports, which is transforming Europe's gas market (IEA, 2022). Besides, the LNG trade is expected to continue to grow over the next decade, driven primarily by the growing demand for gas in emerging Asia (China, India, and other emerging Asian countries) as they move away from coal and, outside of China, continue to industrialize (BP, 2022).

Still, given the current price of LNG, Petrobras' inability to make new investments (even more in the case of the development of new technologies), the domestic demand uncertainty, the high $CO_2$ content in the Pre-salt NG, and the non-mature level of FLNG technology, Brazil tends to increase the LNG importation rate rather than acting as a big export agent in that market and since Pre-salt is close to shore, LNG exports may be made possible by onshore processes rather than using FLNG technology.

## 6. Conclusion

Brazil is in a new era concerning producing and extracting hydrocarbons and thermoelectric use. The evaluation of the economic aspects of the NG options analyzed in this work identified methodological, technological, political, and institutional challenges, and it is possible to highlight:

(i) the difficulty in obtaining data on the cost of Pre-salt outflow works hampers the economic analysis;
(ii) improving techniques for separating $CO_2$ from NG are needed to increase the possibility of using the fuel,
(iii) this aspect, together with the unquantified amount of gas needed for reinjection to the exploitation of the oil, generate uncertainties about the amount of available fuel,
(iv) the regulatory difficulties associated with access to third parties to gas pipelines and the need to guarantee the supply of NG for thermals also hinder the economic attractiveness of these projects,
(v) GtW technology still presents high CAPEX, high system complexity, regulatory problems (due to the mandatory supply guarantee demanded today by national regulation) and technological challenges for transmission,
(vi) $TPP_{off}$ investment cost is high when compared to a $TPP_{on}$; the LCOE values (43–69 US$/MWh for $TPP_{on}$ and 67–87 US$/MWh for $TPP_{off}$) are within the range of values found in the international bibliography (42–124 US$/MWh),
(vii) the LCOE of GtW technology is higher than the historical Brazilian energy price of NG thermoelectric generation, but lower than the energy auction price cap and actual energy price of contracted TPP to be installed in regions without NG infrastructure,
(viii) even with the reduction of the cost of fuel for a $TPP_{off}$ (due to the discount of the portion of the NG outflow cost), the offshore transmission cost, depending on the depth of the site, are still high, surpassing the gain of this discount, and
(ix) LNG supply from the Pre-salt would not present the best logistics or the economic feasibility to compete with the already in LNG development projects.

Therefore, the elements of uncertainty, added to the national and international scenario of the LNG market, make the national investment in new technologies such as FLNG and offshore electric generation very unlikable now. The technical and economic difficulties in using Pre-salt natural gas highlights the need for a different energy policy, including:

(i) regulatory design of offshore energy generation and onshore-offshore energy integration,
(ii) regulatory design of offshore transmission system,
(iii) use of natural gas TPPs for baseload operation, and
(iv) incentives for technological development of offshore $CO_2$ separation process and offshore large-scale natural gas combined cycle power plants.

The evolution and investment in Research and Development (R&D) in the sector to reduce costs and improve processes can diversify the offshore NG utilization chain, which may be especially important to Pre-salt area since:

(i) the current reinjection rate of Pre-salt natural gas is high due to technological limitations,
(ii) it is necessary to develop power hubs for the energy supply of Pre-salt O&G activities,
(iii) technological development of offshore power hubs is important to accommodate new perspectives for hybrid power hubs, including offshore wind energy, and
(iv) Pre-salt is close to a high-density population onshore area where land-use pressure and energy demand are very high.

Finally, depending on the auctions and market conditions, offshore Gas-to-Wire could be seen as a technological and energy vector for the development of offshore power system in Brazil.

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