Pontifícia Universidade Católica
do Rio de Janeiro

Larissa de Oliveira Resende

Assessing the value of natural gas underground storage in the Brazilian system: a Stochastic Dual Dynamic Programming approach

Tese de Doutorado

Thesis presented to the Programa de Pós–graduação em Engenharia de Produção of PUC-Rio in partial fulfillment of the requirements for the degree of Doutor em Engenharia de Produção.

Advisor : Prof. Davi Michel Valladão
Co-advisor: Dr. Bernardo Vieira Bezerra

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Prof. Davi Michel Valladão
Advisor
Departamento de Engenharia Industrial – PUC-Rio

Dr. Bernardo Vieira Bezerra
Co-advisor
PSR – Consultoria

Prof. Alexandre Street de Aguiar
Departamento de Engenharia Elétrica – PUC-Rio

Dr. Bruno da Costa Flach
IBM Research – Brazil

Prof. Bruno Fanzeres dos Santos
Departamento de Engenharia Industrial – PUC-Rio

Prof. Edmar Luiz Fagundes de Almeida
Instituto de Economia – UFRJ

Dr. Rafael Kelman
PSR – Consultoria

Rio de Janeiro, May the 6th, 2019

Larissa de Oliveira Resende

Senior Gas Supply Analyst at Comgás. Master in Economics Applied by the Federal University of Juiz de Fora. Graduated in Economic Sciences from the Federal University of Juiz de Fora.

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To my parents, for their support
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Abstract

Resende, Larissa de Oliveira; Valladão, Davi Michel (Advisor); Bezerra, Bernardo Vieira (Co-Advisor). **Assessing the value of natural gas underground storage in the Brazilian system: a Stochastic Dual Dynamic Programming approach**. Rio de Janeiro, 2019. 78p. Tese de doutorado – Departamento de Engenharia Industrial, Pontifícia Universidade Católica do Rio de Janeiro.

The current scenario of the Brazilian natural gas industry is characterized by low maturity and dynamism of the market.The stochastic behavior of Brazilian demand for natural gas, added to its associated market price volatility, motivates the usage of underground storage due to supply flexibility and protection against price fluctuations. However, the existing literature lacks a more robust analytical tool to support a quantitative analysis of the benefits that the UNGS activity could provide to the natural gas industry. In this thesis, we propose a stochastic dynamic programming model for long/medium term planning to determine the supply optimal policy together with the possibility of storing gas. A markovian model characterizes thermoelectric demand while market price is represented by a stagewise independent stochastic process. The proposed model is efficiently solved using the Stochastic Dual Dynamic Programming algorithm for the Brazilian case study considering realistic data for the actual gas network and electric power system. For an exogenous but meaningful choice of underground storage location and size, we observe the operational and economic benefits of the provided storage flexibility. Additionally, comparing the OPEX and CAPEX costs of investments in storage infrastructure in depleted fields and salt caverns with the savings provided by storage in the supply operation, it is possible to observe the economic benefit of storage. The proposed framework provides an important quantitative support for discussion about Underground Natural Gas Storage infrastructure pricing and business models.

Keywords

Underground Natural Gas Storage; Natural Gas Supply; Stochastic Dual Dynamic Programming; Decision under Uncertainty;

Resumo

Resende, Larissa de Oliveira; Valladão, Davi Michel; Bezerra, Bernardo Vieira. **Estimando o valor do armazenamento subterrâneo de gás natural no sistema brasileiro: uma abordagem de programação dinâmica dual estocástica**. Rio de Janeiro, 2019. 78p. Tese de Doutorado – Departamento de Engenharia Industrial, Pontifícia Universidade Católica do Rio de Janeiro.

O cenário atual da indústria de gás natural brasileira é caracterizado por baixa maturidade e dinamismo de mercado. O comportamento estocástico da demanda por gás, somado volatilidade do preço de mercado do GNL, motiva a utilização de estocagem subterrânea como forma de inserir flexibilidade no suprimento, além de promover proteção contra flutuação no preço. No entanto, a literatura existente carece de uma uma ferramenta analítica mais robusta para apoiar uma análise quantitativa dos benefícios que a atividade UNGS poderia proporcionar à indústria de gás natural. Nesta tese, propomos um modelo de programação dinâmica estocástica para planejamento de longo/médio prazo, a fim de determinar a política ótima de fornecimento juntamente com a possibilidade de armazenamento de gás. Um modelo markoviano caracteriza a demanda termoelétrica, enquanto o preço de GNL é representado por um processo estocástico temporalmente independente. O modelo proposto é eficientemente resolvido usando o algoritmo de programação dinâmica dual estocástica para o estudo de caso brasileiro, considerando dados dos setores de gás e setor elétrico. Para uma escolha exógena, mas significativa, da localização e tamanho do armazenamento subterrâneo, observamos os benefícios operacionais e econômicos da flexibilidade que esta atividade poderia proporcionar. Além disso, comparando os custos de OPEX e CAPEX de investimentos em infraestrutura de armazenamento em campos depletados e cavernas de sal com as economias proporcionadas pelo armazenamento na operação de fornecimento, é possível observar o benefício econômico da atividade de estocagem. A estrutura proposta fornece suporte quantitativo importante para discussões sobre precificação de infraestrutura e modelo de negócios para Armazenamento Subterrâneo de Gás Natural.

Palavras-chave

Programação dinâmica dual estocástica; Decisão sob incerteza; Estocagem subterrânea de gás natural; Suprimento de gás natural.

Table of contents

List of figures

List of tables

List of Abreviations

AND – Abridged Nested Decomposition
ANP – National Petroleum, Natural Gas and Biofuel Agency
CADE - Administrative Council for Economic Defense
CONFAZ – National Council for Treasury Policy
CPI – Consumer Price Index
CUPPS – Convergent Cutting-Plane and Partial-Sampling
CVaR – Conditional Value at Risk
EPE – Energy Research Company
FERC – Federal Energy Regulatory Commission
DCF – Discounted Cash Flow
GASBOL – Bolivia-Brazil gas pipeline
GASENE – Southeast-Northeast Integration Gas Pipeline
GUS – System Usage Gas
ICB – Cost Benefit Index
LNG – Liquefied Natural Gas
ONS – Brazilian Electric Power System Operator
PLD – Settlement Price of Differences
PDE – Decennial Energy Expansion Plan
S – Southern
SE/MW – Southeastern/Mid-Western
SDDP – Stochastic Dual Dynamic Programming
SIN – National Integrated System
SSE – Sum of the Square Errors
TR – Regasification Terminals
UNGS – Underground Natural Gas Storage
UPGN – Natural-Gas Processing Unit
US – United States

1
Introduction

The current scenario of the Brazilian natural gas industry is characterized by an extreme concentration of supply and demand, in addition to the low maturity and dynamism of the market.

The domestic supply is predominantly produced by gas fields operated by Petrobras, who is also the only importer of natural gas, either via the Bolivian gas pipeline or via Liquefied Natural Gas (LNG). Moreover, the whole infrastructure productive chain was built and operated by the state company, which remains dominant across all segments of the natural gas sector.

In addition to the large concentration of demand for natural gas in the industrial and thermoelectric sectors, decisions to dispatch thermoelectric plants are taken based on an electric generation model at the lowest cost with relevant dependence on hydrological conditions, making thermoelectric demand for gas a stochastic quantity with high volatility.

The importance of coordinated planning between the electricity and natural gas sectors has already been explored in the literature, as in the study (77), which presents a mathematical programming problem for optimal operation planning and coordinated expansion of electric power and natural gas systems in order to ensure a reliable energy supply.

The article (62) reviews factors at the intersection of electricity and natural gas markets and operations, and present ways to address the risks. Additionally, (75) proposes a novel mixed-integer linear programming (MILP) formulation that couples power and gas networks taking into account the gas traveling velocity and compressibility, where the model accounts for the gas adequacy needed to assure the power system reliability in the short term.

Given that a large part of the domestic gas production comes from fields associated with oil production where a flexible gas production management is economically and technically infeasible, LNG acts as the primary source of supply flexibility to satisfy thermoelectric demand. As LNG purchases are made in the spot market, their prices show strong volatility related to international market conditions.

To mitigate this exposure to price volatility, it is proposed that the gas trader is able to sell flexible contracts to the industrial sector, that can be interrupted in case of an increase of thermal generation, as observed by (48), where the determination of the optimal price for this type of contract was one of the objective of her study.

Considering that Petrobras positions itself as the only natural gas supplier in the Brazilian market, its commitment to divestment in the sector[1] introduces a new challenge of sharing risks and responsibilities among the other agents, where the importance of adopting flexibility tools arises, not only to ensure system security and balancing requirements but also greater price stability.

Due to its essential role in other countries, mainly in North America and Europe, the underground natural gas storage (UNGS) is considered a possible way of inserting flexibility in the supply chain of this energy source in Brazil (see (3, 5, 6, 16, 17, 39, 50)). However, there is a lack of quantitative study and economic analysis to support UNGS business models.

In order to assess the potential economic value that UNGS activity would have for the Brazilian electricity sector, we can mention the pioneering works of (29, 16), in addition to the study recently developed by EPE (57), both using the discounted cash flow (DCF) method, with favorable results regarding UNGS activity.

The work (29) sought to assess the potential economic value for the electricity sector of having UNGS facilities, and the study (16) estimates the economic value for a thermoelectric plant by participating in a New Energy Auction associated with a UNGS. The study (57) analyzes the technical and economic feasibility of a specific UNGS project. It also promotes a simulation of storage in the Brazilian gas pipeline network, using thermofluid-hydraulic simulations.

Recently, (50), a paper developed by the author and associated with this thesis, identifies the barriers to the development of UNGS in Brazil, and evaluates potential applications that such activity could have in the natural gas and electric sectors in Brazil. Given the restructuring of the Brazilian natural gas market, this thesis develops an analytical tool to assess the operational and economic benefits of the UNGS in the Brazilian context.

In particular, the gas storage activity poses an additional challenge on the development of a proper analytical tool, since it creates a temporal coupling between the decision taken in the present and the future supply conditions. Considering the stochastic behavior of gas demand and LNG price, we argue that stochastic dynamic programming techniques suitably represents the actual

[1]For more details see the Petrobras's commitment negotiated through the signing of a commitment term (54) with the Administrative Council for Economic Defense (CADE).

decision-making process. For large-scale problem solving, state-space sampling-based decomposition methods are used, such as SDDP (8), which is also suitable for a discrete Markov dependent stochastic process, besides being particularly useful in solving a dynamic stochastic allocation problem.

In this regard, this thesis presents a long/medium-term planning model based on a Markov chained SDDP to obtain monthly decisions on natural gas amounts to be purchased from each available supply, considering the underground gas storage. The application of this model to the Brazilian gas sector is also presented, where monthly decisions are obtained for each of the subsystems that make up the integrated gas grid. The uncertain variables are the thermoelectric demand for natural gas and the LNG price. A time consistent CVaR-based risk measure is considered in the construction of the objective function as a risk aversion mechanism (see (46)).

This thesis's main contributions are: (i) the development of a long/medium term planning model based on the SDDP methodology to obtain monthly decisions on natural gas amounts to be purchased from each available supply, considering the underground gas storage activity (ii) the use of a Markov chain to approximate the dynamics of the thermoelectric gas demand, determined from an optimal policy of the power system operation planning problem; (iii) to promote integration between gas purchasing decisions and thermoelectric dispatch decisions; (iv) to illustrate the operational and economic benefits of the storage activity to the Brazilian gas industry, from a numerical exercise; (v) to provide an analytical tool that allows an interested agent to assess the impact that specific storage structures would have on the market, supporting the development of a business plan - not only in the Brazilian market but also in other countries where supply flexibility could improve operational flow and financial costs; (vi) to suggest a model for the development of underground gas storage activity in the Brazilian gas market.

This thesis is structured as follows. Section 2 presents the literature and background review, including technical issues about UNGS, in addition to the challenges and market opportunities to UNGS activity in Brazil[2]. Section 3 presents the proposed framework, including the model, aspects of its implementation, and scenario generation. Section 4 presents the case study assumptions. Section 5 presents empirical results and preliminary proposal for the development of UNGS in Brazil. Finally, Section 6 covers the conclusion and suggestions for future research.

[2]The content of Section 2 is associated with a conference paper developed by the author.

2
Literature and Background Review

2.1
Underground Natural Gas Storage

According to (59), UNGS is nothing more than the transfer of gas produced from one source reservoir to another reservoir, usually closer to the consumer market. It is also defined, according to (60), as an efficient process that aims to adapt the constant supply of natural gas to the changing demands of the markets, which depend on various factors such as climate, season and economic advantages obtained by controlling the volume of gas offered. For (61), storage capacity is the fastest and safest alternative to promote flexibility for short-term needs.

In addition to being an efficient instrument of supply flexibility, allowing supply to be adapted to erratic demand variations, storage can be managed of such a way as to obtain advantages in fluctuating gas prices, increasing supply during periods of higher appreciation or guaranteeing liquidity (see (5)).

Moreover, according to (5), UNGS can also allow for better import contracts or even reduce these contracts, as the presence of storage facilities makes it more flexible and more efficient to meet domestic demands. Besides, in the case of oil-associated gas fields, UNGS provides the required flexibility for thermal power to accommodate the oil production curve.

The first underground natural gas storage was completed in 1915 in Welland Country, Canada, followed by the construction of the first United States (US) facility in 1916 for geological storage of natural gas. Since then, given the rising use of natural gas, potential sites for UNGS are increasingly explored, especially in the US. The high share of storage net withdrawals on natural gas production in the US proves the importance of UNGS for this market. Between 2002 and 2012, net withdrawals of natural gas storage in the US accounted for about 50% of the country's net gas production oftentimes (see (63)).

The main agents that own and operate the underground storage facilities are transmission system operators or owner, distribution companies, and independent storage service providers. However, as can be seen from the (59) report, these storage facility owners operate the UNGS but do not necessarily own the stored natural gas, working as service providers. Clients of such service can be shippers, local distribution companies, suppliers, or natural gas final consumers.

An interesting example of how this process works can be seen in (59), which is that if a carrier relies heavily on underground storage to facilitate load balancing and system supply management on its long-distance transmission lines, Federal Energy Regulatory Commission (FERC) regulations allow shipping companies to reserve part of their storage capacity for this purpose, and most of their storage capacity is rented to other industry participants.

There are different ways of storing gas, such as LNG tanking, pipeline line-pack gas inventory (see (75, 62)), and interruptible gas supply contracts (see study (48)). Underground storage are also possible and can be developed in depleted fields, aquifers or salt caverns. The choice of storage type depends mainly on the available geological structures and the purpose of the storage, which may have high storage capacity for seasonal operation or low to ensure high delivery rates in the event of peak demand. In Brazil, it is also possible to make use of virtual reservoirs, since there is idle storage capacity in the reservoirs of the hydro power plants already installed in the National Integrated System (SIN), although there are conceptual and regulatory obstacles to the practical application of this mechanism (see study (77)).

Each type of storage has its physical characteristics - porosity, permeability, gas holding capacity - and economical - site preparation and maintenance costs, injection/withdrawal rates and number of cycles - which underpin its suitability for specific applications. However, according to (59), two critical features of an outstanding underground storage reservoir are its ability to hold natural gas for future use, called useful gas, and the rate at which gas storage can be removed, that is the delivery fee. The different types of underground natural gas storage facilities can be analyzed in Figure 2.1.

The total volume of gas in a storage is made up of two distinct parts, the base gas, which cannot be fully recovered, remaining in the reservoir to maintain adequate pressure to ensure gas delivery rates, and useful gas, which is the gas that can be removed to meet demand.

According to data from (63), while the useful gas storage capacity at Salt Caverns in the US in 2015 was 13,980 Mm^3, this volume in Aquifers and Depleted Fields was 12,800 Mm^3 and 109,080 Mm^3, respectively. The percentage of usable gas storage capacity over total storage capacity in this period was 70% in Salt Caverns, 31% in Aquifers and 54% in Depleted Fields.

While injection and withdrawal rates are a function of the reservoir's

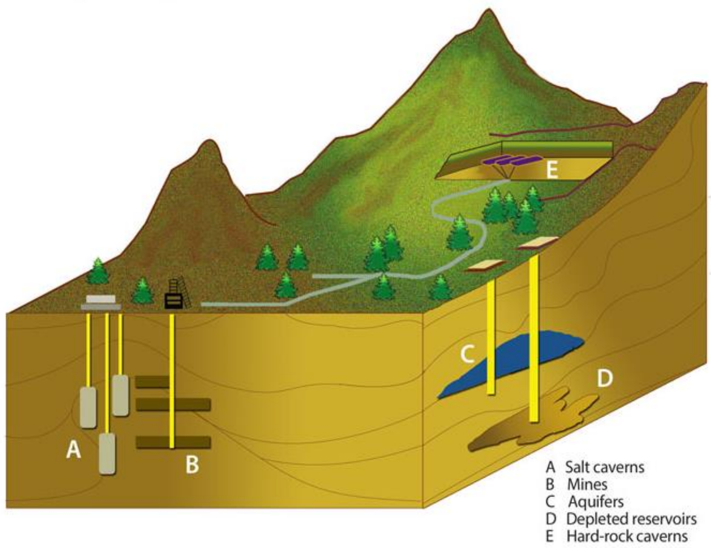

Figure 2.1: Types Of Underground Natural Gas Storage Facilities - Source: (59) report

internal pressure, which in turn depends on how full the reservoir is, the correlation between stored volume and withdrawal/injection flow is nonlinear. For practical applications, as observed by (3), it is usually considered that the flows are constant for a certain amount of gas stored.

Although there are other types of underground natural gas storage structures, such as deactivated mines and rocky caves, their use is less significant and, therefore, we do not address them in this work.

2.1.1 Depleted Fields

Storage in depleted oil and gas fields, where productive or economic life is at or near the end, is the simplest and most common form of geological storage, as relevant geological knowledge is already acquired during the exploration and reservoir production. Also, existing wells, collection system, and pipeline connections can be reused. Of the three types of underground storage, depleted fields on average are the cheapest and easiest to develop, operate, and maintain (see (64)).

It is the geographic and geological factors that determine whether or not a depleted field will be a suitable storage facility. According to (64), while geographically the reservoirs should be relatively close to the consuming regions, the transmission and distribution infrastructures, geologically, the formations of the depleted fields must have high permeability and porosity. While porosity determines the amount of natural gas that can be stored, permeability promotes the removal and injection rates of the base gas, which requires further seismic analysis, considering that the level of permeability needed is higher than that required for production activity.

According to (65), for reservoirs that do not have adequate porosity and permeability, artificial methods can be applied, such as producing fractures in order to create new pathways for fluid flow.

In order to maintain pressure in this type of reservoir, although around 50% of the natural gas in the formation should be kept as base gas, if these reservoirs are already filled with natural gas and hydrocarbons, they do not require injection of what will become physically irrecoverable gas, since this gas already exists in the formation (see (64)). However, when compared to other types of storage, as discussed by (3), these structures allow a smaller number of injection and withdrawal cycles, usually one injection/withdrawal cycle per year, being mainly used for seasonal supplies.

2.1.2
Salt Caverns

The use of salt caverns for natural gas storage provides high withdrawal and injection rates over useful gas capacity, with the need for relatively low base gas. According to the (59), caverns construction is more costly than depleted field conversions when measured based on dollars per thousand cubic feet of usable gas capacity, although the ability to perform multiple withdrawal and injection cycles reduce the cost per unit per thousand cubic feet of gas injected and withdrawn each year.

As can be seen in (66), the need for salt caverns base gas is between 20% and 30% of the total gas capacity, and it is possible to perform about 10 or 12 useful gas cycles per year.

This formation is well suited for natural gas storage, allowing little loss of injected gas, in addition to being resistant to reservoir degradation.

Although salt caverns are typically much smaller than depleted reservoirs and aquifers, which also have a lower delivery capacity, natural gas stored in a salt caverns can be removed more quickly, and caverns can be replenished with natural gas, faster than any other type of storage facility (see (64)). Besides there is the advantage of process monitoring, because occupied area is considerably smaller.

According to (3), due to the volatility observed in natural gas demand in Brazil, mainly in thermoelectric demand, salt caverns seem to be the most suitable structures for use in the country, as they have greater flexibility among the types of storage. Salt caverns can be quickly started, and gas withdrawal is very useful in emergencies or during unexpected short-term increases of demand [1].

2.1.3 Aquifers

Permeable and underground rock formations that act as natural water reservoirs, known as aquifers, if covered by impermeable rock, can be refurbished and used as natural gas storage facilities. Delivery rates can be leveraged if there is an active water flow that sustains reservoir pressure during its injection and withdrawal cycles. This leverage allows more cycles per year than the depleted fields (see (3)). Given that large urban centers typically develop close to freshwater concentrations, this type of storage has a prime location close to the market (3).

According to (59), although aquifer geology is similar to depleted fields and allows for high natural gas delivery rates, its use for natural gas storage generally requires more base gas and allows less flexibility in injection and withdrawal. As can be seen from (66), aquifer base gas requirements range from 50% to 80%, making your investment high.

According to (64), developing an aquifer for storing natural gas is more expensive and requiring a significant amount of time, as its geological features are not as well known as depleted fields. Thus development time can be up to four years, which is more than twice the time required for reservoir development in depleted fields(see (64)). Thus, these types of installations are generally only used in areas where there are no depleted fields nearby.

Reference (64) points out that these formations do not have the same natural gas retention capabilities as depleted reservoirs, which means that part of the natural gas that is injected escapes formation, and must be collected and extracted by collecting wells. This generates high environmental restrictions seeking to reduce the possibility of freshwater contamination. For this reason, this type of underground storage will not be analyzed in this study.

2.2 Underground Natural Gas Storage in Brazil: challenges and market opportunities

As in much of the world, the Brazilian natural gas industry was developed through the action of a large state-owned company, Petrobras, which exercises

[1]According to (64), salt caverns can quickly start gas flowing (injection or withdrawal) within one hour of notification.

a dominant position in all segments of the supply chain. Due to the stochastic variability of the thermoelectric gas dispatch, so far Petrobras has been in charge of the flexibility of the country natural gas supply. This company has positioned itself as the only natural gas supplier gas in the Brazilian market.

Given the need to adapt the activities of the natural gas sector to the new market that is being proposed and to reduce Petrobras's participation in various segments of the chain, the Brazilian government launched the Gas to Grow initiative, now renamed as New Gas Market. This initiative aims openness, modernization, and increased competition on that market (see (49)); as illustrated by the Figure 2.2.

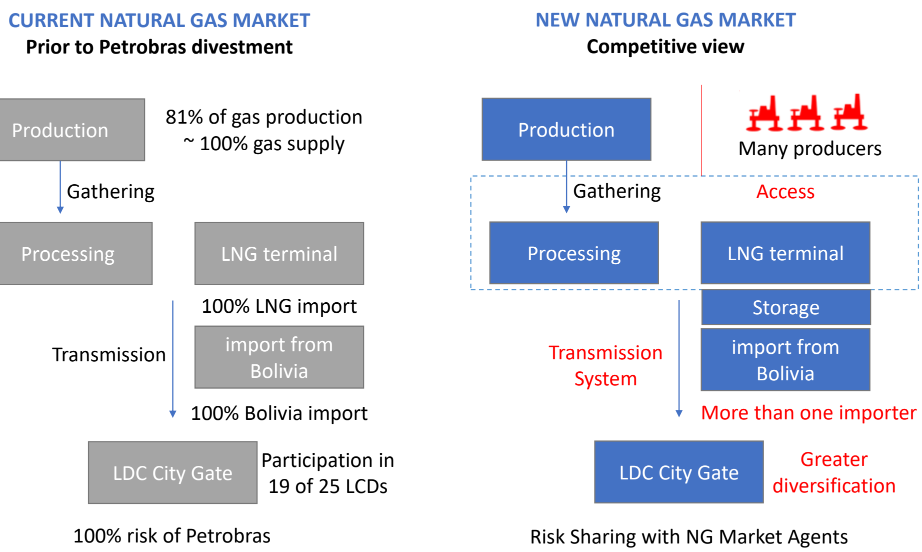

Figure 2.2: Vision of Transformations of the Natural Gas Industry in Brazil in Gas to Grow - Source: Adapted from (49)

In this context, UNGS emerges as a potential alternative to insert operating flexibility into the system, without the need to reduce the production flow of natural gas fields associated with oil production, allowing an integrated optimization in the Brazilian market, where the balance between supply and demand can be obtained most efficiently.

Given this scenario and several studies in the literature indicating benefits that this activity may provide to the energy sector (see (29, 16, 3, 39)), we developed a study that promoted a diagnosis on the barriers to the development of UNGS in Brazil, as well as the identification and evaluation of potential applications that such activity could have in the natural gas sector and the

Brazilian electric sector if implemented. It will be presented in parts in this chapter (see fully in (50)).

2.2.1 Challenges and Barriers to UNGS Implementation in Brazil

The market price signal is recognized as a powerful tool for allowing supply and demand flexibility alternatives in the natural gas sector to be deployed alone by market participants (29). Currently the pricing of natural gas in Brazil (both domestic and imported from Bolivia) is not related to the country supply and demand. Thetefore, under the current market structure UNGS would not be viable. It is clear that the new regulation needs to be prepared to enable UNGS to thrive as a competitive industry.

Moreover, the study (29) highlights the difficulty of estimating the volume of natural gas demand to be stored in UNGS facilities in countries without severe winters and with a predominance of hydroelectric generation, which makes any business model unfeasible and, consequently, the implementation UNGS facilities, as in Brazil, where the thermal demand for natural gas is admittedly volatile.

In this sense, given the need for predictability of demand for natural gas to enable flexibility mechanisms, it is essential to adopt measures to encourage more integrated planning between the natural gas industry and electricity, in order to promote greater convergence, among them, creating better predictability conditions that, by generating natural gas price signals, would provide greater competitiveness in the implementation of flexibility mechanisms such as UNGS.

At this point, it is of utmost importance to conduct a more robust study that provides the industry with an analysis of the benefits that the UNGS activity could provide to the natural gas industry, as well as signaling the required volume of gas and withdrawal flow in these structures, meet peak demand, minimizing the risk of lack of supply and providing reduction and higher stability of energy costs for the country. This is the gap this thesis proposes to fill.

Given the existence of few gas pipeline routes in the country, which makes it difficult to commercialize gas at physical points, the implementation of virtual hubs becomes relevant in Brazil as a way of generating liquidity and simplifying the network. This is in line with government initiative to replace the current charging model for natural gas transportation service with the entry and exit capacity contracting model (see (51)).

Without the need to link to a specific gas facility or any physical pipeline connection, virtual hubs are characterized by balancing gas deliveries through electronic platforms, where administrative services are also provided that facilitate movement and transfer of gas custody between shippers and traders.

Thus, as in mature markets, UNGS facilities are an essential support tool for hubs, enabling and facilitating the creation of a broad portfolio of services that can be offered, including the physical coverage of short-term balance of delivery needs versus shippers' received access to commercialization of virtual gas based on virtual platforms, as well as provision of custody transfer service between the parties (buyer and seller).

Its possible to observe barriers to the development of UNGS activity since Gas Law (52). As determined by Law N. 11.909 / 2009, the exercise of UNGS activity is subject to concession of use, preceded by competitive bidding, pursuant to Law N. 8.666 / 1993 (General Procurement Law (53)), where the exploitation shall be at the risk and expense of the concessionaire.

Given the inconsistency between the need to proof the minimum qualification requirements for project execution, with high level of detail, already in the preliminary qualification phase and the shortage of prior information, not even for the definition of the storage capacity, made unfeasible the development of storage activity in the country.

The lack of competitiveness in the natural gas supply, resulting mainly from the absence of compulsory access to the production gathering pipeline and natural-gas processing unit (UPGNs), added to the large concentration of decision making power to purchase gas from few buyers, puts a barrier to the Fentry of new agents, discouraging the development of the natural gas market and, consequently, of UNGS.

One of the measures that could bring agents on a level playing field and stimulate the development of UNGS would be the application of the essential facilities doctrine[2], which enables access to LNG pipelines, UPGNs and regasification terminals, and complete unbundling, avoiding the practice of self dealing and conflict of interest, as this would prevent producer participation in distributors.

Regarding the actions to promote competition established by CNPE, under the New Gas Market, as well as Petrobras's commitment negotiated through the signing of a commitment term ((54)) with the Administrative Council for Economic Defense (CADE), it is expected that there will be an effective promotion of negotiated third party access to essential facilities.

In relation to regulatory barriers, it is important to mention the challenge

[2]The Essential Facilities Doctrine states that the owner of an infrastructure deemed essential is required to provide access to that facility at a "reasonable" price (see (49)).

of the tax legislation in the sector, regarding the unlinking of the physical flow of gas through pipelines and its replacement by the contractual flow for the application of the tax in the circulation of goods and services, the ICMS.

The change in systematic has been proposed because gas is a fungible good and there is no way to ensure that the gas molecule that came out of the physical origin of the gas will be the one delivered to the original purchaser. This flexibility also allows producers to make commercial strategies that bring more efficiency to their operations, as well as being an important step towards enabling UNGS service provision.

In this sense, the National Council for Treasury Policy (CONFAZ) published the SINIEF Adjustment No. 03/2018, which changes the basis of calculation of physical flow to contractual flow, suitable for a fungible product and continuous flow operation (for more detail see (55)).

2.2.2
Potential Applications of Storage in Brazil

The electric power industry in Brazil since its origination has been characterized by the widespread predominance of the water source. The presence of large reservoirs able to regulate energy production over time, as well as the high correlation between the storage capacity and the load to be served, providing an operating regime capable of living comfortably with the natural variation in the energy regime, rain on a multiannual scale.

Thus, the base generation of the system was performed by hydroelectric plants, and the participation of other sources had an additional role and limited to sporadic situations, in periods of reduced hydraulicity. The growing difficulties for the construction of new hydroelectric projects with significant reservoirs have been changing the generation mix profile and expanding the space for gas penetration as a controllable source, capable of bringing safety and predictability to the system.

More recently, the pursuit of diversification of the electrical mix and the need to meet environmental requirements has led to the penetration of uncontrollable sources such as wind and solar. These sources are characterized by low operating costs, but pose significant challenges to system operation, resulting from intermittent and unpredictable production. This generates large variability in dispatch and requires high flexibility of the generator park, which must be able to timely compensate for sudden variations in order to promote instantaneous adjustment between supply and demand.

Besides, to meeting peak system demand, which was naturally satisfied by the expansion of the hydropower source, required technological alternatives such as flexible, rapid-start thermals, for which planning has been considering as candidate plants those with variable costs compatible with natural gas (see (40)). It is also essential to analyze UNGS's contribution to the viability of thermal generation operating at the base and releasing the hydroelectric complex with existing reservoirs to meet the system's flexibility needs.

The more seasonal trend of hydropower supply coupled with the expected intense penetration of intermittent generation sources (solar and wind) led Energy Research Company (EPE) to estimate a need for a significant expansion of LNG-powered rapid start thermoelectric generation.

The seasonality observed in this hydrological regime brings the opportunity to evaluate the viability of UNGS as an alternative to LNG, in order to favor the consideration of thermoelectric demand in guaranteeing the physical flow for the oil associated gas production. At this point, in addition to reducing the dependence on LNG imports in the spot market, which is much higher than the price of long-term contracts, the possibility of monetizing pre-salt gas would bring significant benefits to the country.

Pre-salt auction rounds promise to put into operation several production units, which, in addition to the platform revitalization program announced by Petrobras in the Santos and Campos basin reservoirs, will contribute significantly to the increase in natural gas supplied. As these are associated oil and gas fields, with the possibility of anchoring these investments in thermoelectric projects, it is quite feasible to think about the usefulness that UNGSs would have in storing production, as it would allow producers to defend themselves against seasonality gas demand, reducing flaring and reinjection needs, which makes us believe that UNGS can be extremely important in enabling the production of these fields.

Reflecting on even more significant losses, if gas reinjection is not technically justifiable and commercial exploitation is not feasible, operators will not be able to develop the field (56). However, with burning and reinjection restrictions, some tools can be used for the flow of this gas that can unlock its commercial potentials, such as storage, direct introduction of gas into the gas supply network and storage liquefaction in appropriate compartments and vessels.

In Brazil, with no storage facilities, gas is currently produced and sent through the pipeline network to gas treatment units to be specified and distributed. Thus, in the case of the impossibility of direct flow to the network, especially with the expectation of large production volumes to come, if the UNGS activity were implemented, the production would not have to be interrupted, avoiding immeasurable financial losses.

Firstly, it should be noted that the deployment of LNG regasification terminals in Brazil sought to serve the natural gas market in the thermoelectric segment, given that this segment does not have a well defined seasonal natural gas demand behavior, being more characterized due to its randomness, due to the character of thermoelectric generation complementary to the national hydroelectric generation. Thus, the potential applicability of UNGS could be as a tool of additional flexibility the supply-side LNG importation, seeking to act in an articulated manner, allowing a lower dependence on the highly volatile spot market prices of energy from the international market.

The subject has been the object of research (see the works (29)) that argue that UNGS could represent for the electricity sector a new energy storage capacity, similar to the storage of hydroelectric reservoirs. This integration would occur in order to increase the thermal dispatch flexibility for the system, considering a trade-off between LNG import versus UNGS supply, concerning the gas supply cost for thermal dispatch.

In order to assess the potential economic value that UNGS activity would have for the Brazilian electricity sector, we can mention the pioneering works of (29) and (16), in addition to the study recently developed by EPE (57), both using the discounted cash flow (DCF) method, with favorable results regarding UNGS activity.

The works (29) sought to assess the potential economic value for the electricity sector of having UNGS facilities, where it was considered that Brazilian Electric Power System Operator (ONS) would trade-off between LNG imports versus UNGS gas withdrawals during reservoir periods and unfavorable rainfall - and consequently high Settlement Price of Differences (PLD) - and, in the opposite situation, that ONS would request the injection of natural gas into UNGS, backed by existing thermal contracts.

Another study (16) estimated the economic value for a thermoelectric plant by participating in a New Energy Auction associated with a UNGS, comparing the increase in underground storage costs versus the benefit in the Cost-Benefit Index (ICB) of a thermal resulting from the flexibilization brought stocking in some scenarios.

Finally, through case studies encompassing the possibility of LNG price arbitrage, sale of natural gas to thermal power plants and peak-shaving to natural gas producers, the study (57) analyzes the technical and economic feasibility of a specific UNGS project, it also promotes a simulation of stocking in the Brazilian gas pipeline network, using thermofluid-hydraulic simulations.

Having exposed the potential applications of UNGS in Brazil, it is considered that the potential candidates for the use of UNGS installation services are producers, importers, distributors, natural gas carriers, large energy consumers, natural gas-fired thermoelectric plants and government for energy security purposes.

In this context, in contrast to the emergence of additional fixed costs and the increased risk to potential users, Table 2.1 presents the advantages they could have with the use of this activity.

UNGS Users	Benefits
natural gas producers	operational flexibility in function to their supply contracts
natural gas importers, distributors, thermo-electric plants, and big consumers	possibility of reducing costs with your supply contracts (take or pay and ship or pay)
government	energy security
gas traders	possibility to create custom products and possibility of reducing costs with your supply contracts
carriers and transporting gas	possibility to create custom and system balancing services

Table 2.1: Advantages of using UNGS by potential user

Thus, as in mature markets, virtual hubs combined with UNGS facilities would provide a focal point for spot market transactions, and gas trading that combined would provide greater price discovery opportunities (see (58)). The availability of pricing information in hubs and access to other buyers and sellers in these hubs would also help reduce price risk exposure for the various natural gas chain agents, including end customers.

3
Proposed Framework

Given the restructuring of the Brazilian natural gas market and the need to develop an analytical methodology to analyze the potential UNGS benefits for the gas industry, this work assesses the operational and economic benefits that the storage activity could provide to the Brazilian gas industry, from a numerical perspective. We provide an analytical tool to assess the operational and economic impact of specific underground storage structures. We also provide managerial insights over volume and flow needed to suit the market's needs.

Considering that the implementation of the gas storage activity creates a temporal coupling between the present and the future supply resources, the decision process becomes dynamic. We argue that stochastic dynamic programming techniques suitable to represent the problem considering the stochastic behavior of gas demand and LNG prices. However, as highlighted by (8), the use of standard (Stochastic) Dynamic Programming techniques requires the discretization of the state space, which leads to an exponential increase of the computational effort with the number of state variables. Thus, for large-scale problem solving, state-space sampling-based decomposition methods such as Stochastic Dual Dynamic Programming (SDDP) are more efficient. In particular, the SDDP framework is suitable for a discrete Markov dependent stochastic process. In contrast to traditional SDP, SDDP is capable of generating an actual policy, i.e., decision rule for any uncertainty realization (see (8)), without the need of any external interpolation.

The SDDP originated in the electric power sector (8) and remains the method used in the studies of medium and long-term planning of the operation of hydro-thermal operation planning (11, 18, 19, 20). Some improvements have already been made in the method, and its applications extrapolated the electric sector. In (21, 22, 24, 11), it is emphasized that the SDDP framework is also suitable for a discrete Markov dependent stochastic process, which is particularly useful in solving a dynamic stochastic allocation problem.

In this regard, this thesis presents a long/medium-term planning model based on a Markov-chained SDDP to obtain monthly decisions on natural gas amounts to be purchased from each available supply, considering the underground gas storage. The uncertain variables are the thermoelectric demand for natural gas and the LNG price. We assume temporal independence for the LNG price, where the model adopts a discrete distribution, while thermoelectric demand is considered a discrete Markov state process in the SDDP structure to capture its temporal dependence.

We assume CVaR-based time-consistent risk measure as a risk aversion mechanism, where the objective function is composed of a recursive formulation from a convex combination of expected value and Conditional Value at Risk (CVaR) (see (23, 22)). Following (23), the goal of a risk-averse approach is to avoid high-cost scenarios under any possible realization of the stochastic process.

3.1 The Dynamic Stochastic Programming Model

3.1.1 Notation

Let us define notation for sets, coefficients, uncertain factors, and decision variables as follows. For didactic purposes, we denote sets with calligraphic fonts, matrices as bold capital letters, vectors as bold letters and scalar coefficient with regular fonts.

Sets:

$\mathcal{J}_t$: Set of j Markov state indexes for period t;
$\mathcal{K}_{t+1}$: Set of k Markov state indexes for period *t+1*;
$\mathcal{I}$: Set of i supply indexes;
$\mathcal{R}$: Set of r, l, and m regions indexes;
$\mathcal{T}$: Set of t periods indexes;
$\mathcal{S}_t$: Set of s indexes associated to scenarios of a Markov state for period t, where $\mathcal{S}_t = \{\mathcal{S}_{k,t}\}_{k \in \mathcal{K}_t}$ for Markov state k;

Coefficients:

β: Discounting factor;
α: CVaR significance level;
λ: CVaR weight in the objective function;
$\boldsymbol{c}_{i,t}$: Vector of natural gas price for each supply source i, and period t, where $\boldsymbol{c}_{i,t} = \{c_{r,i,t}\}_{r \in \mathcal{R}}$ for region r in $US\$/Mm^3$;
$\boldsymbol{g}$: Vector of gas storage cost $\forall t \in \mathcal{T}$ period, where $\boldsymbol{g} = \{g_r\}_{r \in \mathcal{R}}$ for region r in $US\$/Mm^3$;

q^{-}: Cost of natural gas supply deficit for all period t and region r in $US\$/Mm^3$;
q^{+}: Cost with "spilled" natural gas for all period t and region r in $US\$/Mm^3$;
$P_{a,b}$: Probability of transition between the Markov states $a \in \mathcal{K}_t$, in t, and $b \in \mathcal{K}_{t+1}$, in $t+1$;
$\boldsymbol{z}_t$: Vector of non-thermoelectric demands for gas for period t, where $\boldsymbol{z}_t = \{z_{r,t}\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\overline{\boldsymbol{x}}_{i,t}, \underline{\boldsymbol{x}}_{i,t}$: Vectors of upper and lower limits to the natural gas supply for source i and for period t, where $\overline{\boldsymbol{x}}_{i,t} = \{\overline{x}_{r,i,t}\}_{r\in\mathcal{R}}$ and $\underline{\boldsymbol{x}}_{i,t} = \left\{\underline{x}_{r,i,t}\right\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\overline{\boldsymbol{u}}_t, \underline{\boldsymbol{u}}_t$: Vectors of upper and lower limits to the LNG supply for period t, where $\overline{\boldsymbol{u}}_{i,t} = \{\overline{u}_{r,i,t}\}_{r\in\mathcal{R}}$ and $\underline{\boldsymbol{u}}_{i,t} = \left\{\underline{u}_{r,i,t}\right\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\overline{\boldsymbol{v}}, \underline{\boldsymbol{v}}$: Vectors of upper and lower limits to the gas stored $\forall t \in \mathcal{T}$ period, where $\overline{\boldsymbol{v}} = \{\overline{v}_r\}_{r\in\mathcal{R}}$ and $\underline{\boldsymbol{v}} = \{\underline{v}_r\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\overline{\boldsymbol{w}}_t, \underline{\boldsymbol{w}}_t$: Vectors of upper and lower limits for withdrawal of gas storage for period t, where $\overline{\boldsymbol{w}}_t = \{\overline{w}_{r,t}\}_{r\in\mathcal{R}}$ and $\underline{\boldsymbol{w}}_t = \left\{\underline{w}_{r,t}\right\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\overline{\boldsymbol{y}}_t, \underline{\boldsymbol{y}}_t$: Vectors of upper and lower limits for injection of gas into storage for period t, where $\overline{\boldsymbol{y}}_t = \left\{\overline{y}_{r,t}\right\}_{r\in\mathcal{R}}$ and $\underline{\boldsymbol{y}}_t = \left\{\underline{y}_{r,t}\right\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\overline{\boldsymbol{f}}_{m,l}, \underline{\boldsymbol{f}}_{m,l}$: Vectors of upper and lower limits, respectively, of natural gas flows between m and l regions, where $m, l \in \mathcal{R}$ in Mm^3, throughout the t period;
h: Gas loss in the compressors by the gas withdrawal (injection) process from (at) the storage, in Mm^3.

<u>Uncertain factors</u>:
$\boldsymbol{d}_t$: Vector of thermoelectric demand for period t, where $\boldsymbol{d}_t = \{d_{r,k,s,t}\}_{r\in\mathcal{R},s\in\mathcal{S},k\in\mathcal{K}_t}$ for region r, scenario s, and Markov state k in Mm^3;
$\boldsymbol{p}_t$: LNG supply prices for period t, where $\boldsymbol{p}_t = p_t\mathbf{1}$ and $\mathbf{1}$ is a vector of ones with length $|\mathcal{R}|$.

<u>Decision Variables</u>:
$\boldsymbol{v}_t$: Vector of natural gas stored at the end of period t, where $\boldsymbol{v}_t = \{v_{r,t}\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\boldsymbol{x}_{i,t}$: Vector of natural gas supply for source i and for period t, where $\boldsymbol{x}_{i,t} = \{x_{i,r,t}\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\boldsymbol{u}_t$: Vector of LNG supply for period t, where $\boldsymbol{u}_t = \{u_{r,t}\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\boldsymbol{o}^{-}{}_t$: Deficit natural gas supply for period t, where $\boldsymbol{o}^{-}{}_t = \{o^{-}{}_{r,t}\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\boldsymbol{o}^{+}{}_t$: "Spillage" natural gas for period t, where $\boldsymbol{o}^{+}{}_t = \{o^{+}{}_{r,t}\}_{r\in\mathcal{R}}$ for region r in Mm^3;

$\boldsymbol{w}_t$: Vector of gas extracted from storages, accounted at the withdrawal point, for period t, where $\boldsymbol{w}_t = \{w_{r,t}\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\boldsymbol{y}_t$: Vector of gas injected into storages, accounted at the injection point,for period t, where $\boldsymbol{y}_t = \{y_{r,t}\}_{r\in\mathcal{R}}$ for region r in Mm^3;
$\boldsymbol{\pi}_t$: Vector of dual variables associated to the first constraint of the equation (3-1) for period t, where $\boldsymbol{\pi}_t = \{\pi_{r,t}\}_{r\in\mathcal{R}}$ for region r;
$f_{m,l,t}$: gas flow, in Mm^3, from region m to region l, at a particular period t, where $\boldsymbol{f}^{FROM}_{m,t} = \{f_{m,l,t}\}_{l\in\mathcal{R}}$; $\boldsymbol{f}^{TO}_{l,t} = \{f_{m,l,t}\}_{m\in\mathcal{R}}$.

3.1.2 Model Formulation

For each period $t\in\mathcal{T}$ and Markov state $j\in\mathcal{J}_t$, the problem of minimizing the cost of the natural gas supply system in Brazil, with the implementation of the storage activity, has its formulation presented from equation (3-1) to (3-10).

$$Q_t^j(\boldsymbol{v}_{t-1}, \boldsymbol{d}_t, p_t) =$$

$$\begin{aligned} \underset{\boldsymbol{x}_t,\boldsymbol{u}_t,\boldsymbol{v}_t,o^-{}_t,o^+{}_t,\boldsymbol{w}_t,\boldsymbol{y}_t,\boldsymbol{f}_t}{\text{Minimize}} \quad & \sum_{i\in\mathcal{I}} \boldsymbol{c}_{i,t}^\top \boldsymbol{x}_{i,t} + p_t \mathbf{1}^\top \boldsymbol{u}_t + \boldsymbol{g}^\top \boldsymbol{v}_t + q^- \left(\mathbf{1}^\top \boldsymbol{o}_t^-\right) + q^+ \left(\mathbf{1}^\top \boldsymbol{o}_t^+\right) \\ & + \beta \sum_{k\in\mathcal{K}_{t+1}} P_{j,k}, \mathcal{Q}_{t+1}^k(\boldsymbol{v}_t) \end{aligned} \tag{3-1}$$

subject to

$$\boldsymbol{v}_t - \boldsymbol{y}_t + \boldsymbol{w}_t + h(\boldsymbol{w}_t - \boldsymbol{y}_t) = \boldsymbol{v}_{t-1} \qquad : \boldsymbol{\pi}_j \tag{3-2}$$

$$\boldsymbol{w}_t - \boldsymbol{y}_t + \sum_{i\in\mathcal{I}} \boldsymbol{x}_{i,t} + \boldsymbol{u}_t + \boldsymbol{f}^{TO}_{l,t} - \boldsymbol{f}^{FROM}_{m,t} = \boldsymbol{d}_t + \boldsymbol{z}_t + \boldsymbol{o}_t^+ - \boldsymbol{o}_t^- \tag{3-3}$$

$$\underline{\boldsymbol{w}}_t \leq \boldsymbol{w}_t \leq \overline{\boldsymbol{w}}_t \tag{3-4}$$

$$\underline{\boldsymbol{y}}_t \leq \boldsymbol{y}_t \leq \overline{\boldsymbol{y}}_t \tag{3-5}$$

$$\underline{\boldsymbol{x}}_{i,t} \leq \boldsymbol{x}_{i,t} \leq \overline{\boldsymbol{x}}_{i,t} \qquad \forall i \in \mathcal{I} \tag{3-6}$$

$$\underline{\boldsymbol{u}}_t \leq \boldsymbol{u}_t \leq \overline{\boldsymbol{u}}_t \tag{3-7}$$

$$\underline{\boldsymbol{v}} \leq \boldsymbol{v}_t \leq \overline{\boldsymbol{v}} \tag{3-8}$$

$$\underline{f}_{m,l} \leq f_{m,l,t} \leq \overline{f}_{m,l} \qquad \forall m, l \in \mathcal{R}, m \neq l, \tag{3-9}$$

where:

$$\mathcal{Q}^k_{t+1}(\boldsymbol{v}_t) = (1-\lambda)\ \mathbb{E}[Q_{k,t+1}(\boldsymbol{v}_t, \tilde{\boldsymbol{d}}_{t+1}, \tilde{p}_{t+1}) \mid K_{t+1} = k] \\ + \lambda\ CVaR_\alpha[Q_{k,t+1}(\boldsymbol{v}_t, \tilde{\boldsymbol{d}}_{t+1}, \tilde{p}_{t+1}) \mid K_{t+1} = k] \tag{3-10}$$

The objective function of problem (3-1) minimizes the risk-adjusted present-value supply cost of the natural gas system. The first part of this function represents the immediate cost of supply, consisting of the sum, by region, of the natural gas acquisition costs of different supply sources ($\sum_{i\in\mathcal{I}} \boldsymbol{c}_{i,t}^\top \boldsymbol{x}_{i,t}$), LNG ($p_t \mathbf{1}^\top \boldsymbol{u}_t$), storage cost of the purchased gas ($\boldsymbol{g}^\top \boldsymbol{v}_t$), cost with gas supply deficit $q^-\left(\mathbf{1}^\top \boldsymbol{o}_t^-\right)$ and with "spilled" natural gas $q^+\left(\mathbf{1}^\top \boldsymbol{o}_t^+\right)$ is the future cost expressed as a function of the storage at t given the Markov state k. As presented by equation (3-10), this function is composed of the convex combination of the expected value of the future cost function and the CVaR of that function (see (31, 22)).

The set of constraints represented by the set of equations from (3-2) to (3-9) has an equation per region in the problem, as all constraints are vectors. The constraint (3-2) represents the storage balance of $\mathcal{R}$ regions, where, in each region, the volume stored at the end of the current period ($\boldsymbol{v}_t$) is equal to the amount stored in the previous period ($\boldsymbol{v}_{t-1}$) plus the liquid gas injection in the reservoir ($\boldsymbol{y}_t - \boldsymbol{w}_t$) minus the losses related to the consumption of compressors for gas withdrawn or injected process ($h(\boldsymbol{w}_t + \boldsymbol{y}_t)$) [1].

The constraint (3-3) presents the balance between supply and demand for natural gas for each of the considered regions, where the sum of net gas withdrawal from the reservoir ($\boldsymbol{w}_t - \boldsymbol{y}_t$), the natural gas and LNG acquired from the supply sources ($\sum_{i\in I} \boldsymbol{x}_{i,t} + \boldsymbol{u}_t$), and the net gas flow from other regions ($\boldsymbol{f}_{l,t}^{TO} - \boldsymbol{f}_{m,t}^{FROM}$)[2] must be equal to the demand for natural gas ($\boldsymbol{d}_t + \boldsymbol{z}_t$), balanced by slack variables, with spilled gas minus deficit gas supply (${\boldsymbol{o}^+}_t - {\boldsymbol{o}^-}_t$), where the thermoelectric demand is associated with the set $s \in \mathcal{S}_t$ of the Markov state $j \in \mathcal{J}_t$.

From constraint (3-4) to (3-9) comprise the lower and upper limits of the decision variables: (3-4) and (3-5) constraint address the flow limit vectors for gas withdrawal and injection at the storage respectively, over the t period; the (3-6) and (3-7) ones represent the capacity limits of the different supply sources and LNG for each region, over t; the constraint (3-8) shows the gas volume limits stored for each regions along t; the last one (3-9) addresses the gas flow limits between regions over t.

[1]When gas is withdrawn (injected) from (at) the storage, the stock is emptied (filled) into an upper (lower) amount than the one actually delivered (withdrawn) to the system $\boldsymbol{w}_{r,t}$ ($\boldsymbol{y}_{r,t}$), since part of the gas is consumed in the compressors (3).

[2]Although $\boldsymbol{f}_{l,t}^{TO}$ and $\boldsymbol{f}_{m,t}^{FROM}$ have been created to simplify the notation of the model, relating all incoming and outgoing gas flow, respectively, the primary variable is $f_{m,l,t}$.

The thermoelectric demand is represented as a Markovian process. Each Markov state $k \in \mathcal{K}_{t+1}$, in the *t+1* period, is conditioned to a Markov state $j \in \mathcal{J}_t$, from the previous period. The probabilities of the transitions that can occur from period t to the *t+1* period are described by a transition matrix P_t.

3.1.3 Solution method: Markov-chained SDDP

This thesis focuses on the SDDP algorithm, which iteratively constructs the future cost function, using Bender cuts (see (43, 8)). The SDDP is a sampling-based algorithm that does not need the explicit representation of the whole scenario tree and therefore presents a lower computational burden (24). The basic algorithm assumes temporal independence of the stochastic process, which implies a single future cost function for each decision stage. However, there are ways to treat a stochastic variable with a Markov dependency to enable its use in the SDDP method, as can be seen in (22, 24, 11). The set of future cost functions and their associated problems provide an operation policy, i.e., a set of optimal decisions for each period and scenarios considered.

In particular, we substitute the *true* (continuously distributed) problem by its sample average approximation (SAA). Given that the cost-to-go function $\mathcal{Q}_{t+1}^k$ is unknown even for a discrete probability distribution, we replace it by an outer approximation, from now on denoted by $\hat{\mathcal{Q}}_{t+1}^k$. More objectively, in (3-1), we replace $\mathcal{Q}_{t+1}^k$ by $\hat{\mathcal{Q}}_{t+1}^k$ to define the outer-approximation subproblem $\hat{Q}_t^j(\boldsymbol{v}_{t-1}, \boldsymbol{d}_t, p_t)$.

Given a set S_j of equally probable uncertainty realizations, randomly generated following the conditional probability distribution given the current Markov state k, we can represent the cost-to-go function (3-10) as the weighted average

$$\hat{\mathcal{Q}}_t^j(\boldsymbol{v}_{t-1}) = \sum_{s \in S_j} p_{s|j}(\lambda) \left[\hat{Q}_{j,t}\Big(\boldsymbol{v}_{t-1}, \tilde{\boldsymbol{d}}_t(s), \tilde{p}_t(s)\Big) \right] \tag{3-11}$$

where the weights $p_{s|k}(\lambda) = (1-\lambda)\,|S_k|^{-1} + \lambda\,\delta_{s|k}^*$ comprises a convex combination of the conditional probability distributions $|S_k|^{-1}$ and the optimal solution

$$\delta_{s|j}^* \in \arg\max_{\delta \geq 0} \left\{ \sum_{s \in S} \delta_s \left[Q_{j,t}\Big(\boldsymbol{v}_{t-1}, \tilde{\boldsymbol{d}}_t(s), \tilde{p}_t(s)\Big) \right] \;\middle|\; \begin{array}{l} (1-\alpha)\,|S|\,\delta_s \leq 1, \forall s \in S_j, \\ \sum_{s \in S} \delta_s = 1 \end{array} \right\} \tag{3-12}$$

of the dual representation of CVaR.

For a given trial point $\hat{\mathbf{v}}_{t-1}$, a linear approximation

$$l(\boldsymbol{v}_t) = \hat{\mathcal{Q}}_t^j(\hat{\boldsymbol{v}}_t) + \Big(\textstyle\sum_{s \in S_j} p_{s|j}(\lambda)\ \boldsymbol{\pi}_j(s)\Big)\,(\boldsymbol{v}_t - \hat{\boldsymbol{v}}_t) \tag{3-13}$$

is computed, where $\boldsymbol{\pi}_j(s)$ is the dual variable in (3-2) associated with the uncertainty realization $s \in S_j$. Then, for each SDDP iteration we update for each stage the outer approximation

$$\hat{\mathcal{Q}}_t^j(\boldsymbol{v}_{t-1}) \leftarrow \max\Big(\hat{\mathcal{Q}}_t^j(\boldsymbol{v}_{t-1}), l(\mathbf{v}_t)\Big). \tag{3-14}$$

For competition purposes the pseudo-code for the SDDP algorithm is given in AppendixA, where N is a sequence of node-state pairs (for more detail see (4)).

3.2 Stochastic model and scenario generation

3.2.1 Thermoelectric demand scenarios

The Brazilian hydrothermal operation problem consists of generating electricity consistent with expected demand at a minimal cost. Based on the thermoelectric technical data received and possible hydrological scenarios, Monte Carlo simulations are used to iteratively construct a cost-to-go function for the system, see (32). At this point, the marginal cost of operation is uncovered from the cost of generating an additional unit of load from the last thermal unit dispatched.

Thus, based on the different scenarios considered and associated optimum policy, the stochastic model establishes a generation schedule that describes which power plants should be dispatched and the associated generation goal in order to achieve the least-cost operation of the whole system taking into account uncertainties on future inflows and load levels.

Although the generation of a particular thermoelectric unit usually has a binary characteristic (full dispatched or not dispatched at all), which would be well represented by a discrete model, the variable of interest of the proposed model is thermoelectric gas demand for each subsystem as a whole. To approximate the behavior of a group of units (subsystem), we propose the use of a Markov process where, conditioned to each Markov state, we define a multivariate probability distribution of the gas demand for each particular subsystem.

The multivariate distribution of the demand (vector) $\boldsymbol{d}_t$ depends only on t and the current state of the Markov state, from now on denoted as the random variable K_t with the support set $\mathcal{K}_t$. This method allows for modeling different "states" of the system and implies that conditionally on each given state of the Markov chain, the underlying stochastic process $\boldsymbol{d}_t$ follows equation (3-15) (see (22, 24, 11)).

$$
\begin{aligned}
&P(\widetilde{\boldsymbol{d}}_t \in A, \widetilde{\boldsymbol{d}}_{t+1} \in B \,|\, K_t = j, K_{t+1} = k) = \\
&\quad P(\widetilde{\boldsymbol{d}}_t \in A \,|\, K_t = j)\; P(\widetilde{\boldsymbol{d}}_{t+1} \in B \,|\, K_{t+1} = k), \quad \forall j \in \mathcal{K}_t,\; k \in \mathcal{K}_{t+1}
\end{aligned}
\tag{3-15}
$$

3.2.2 LNG Price

LNG acts as the primary source of gas supply flexibility in the Brazilian market, having prices heavily dependent on international market conditions, historically presenting relevant volatility. Therefore, we consider a stochastic LNG price in the proposed framework.

Though oil indexation has played a decisive role in the early stage development of the natural gas industry, given to the failure to reflect gas market fundamentals, the transition to hub-based pricing has been well advanced in northwest Europe and North America (see (67)).

As stated in (67, 68), in view of North America gas prices reflect gas supply-demand balances through gas-on-gas competition while European prices are linked both to oil prices and hub prices, there are substantial gaps in prices between the most significant hub-based spot prices in North America and Europe, and oil-indexed long-term contract prices in East Asia due to high oil prices.

The growing supply of LNG, which can physically be directed to the highest value market, makes contractual arrangements are also more flexible, where spot and flexible LNG purchases are increasingly used to cover part of peak gas demand, giving buyers greater flexibility regarding shipping costs and the ability to exploit profit opportunities through arbitrage (see (69))

In practice, as highlighted by (69) LNG costs vary considerably mainly as a function of capacity, particularly the number of trains in liquefaction plants and shipping distance, which has resulted in a more flexible approach to and a more comprehensive range of pricing is emerging in the LNG industry. Thus, suppliers are adopting different pricing policies according to the buyers' market.

As an increasing share of LNG is traded under short-term contracts with spot shipments being diverted to markets offering the highest returns (netback), relative natural gas prices, as well as LNG transportation costs, are essential determinants of LNG price (see (70)).

According to (71), the enhancement of the role of gas for energy needs coverage and the increased gas transactions of international have determined elevated pressure on prices and increased volatility where in a current context there are four areas of formation of natural gas prices that follow different dynamics and record various levels.

With the enhancing global competition, the forecast of the future movement of the natural gas price becomes, therefore, more and more critical. In this context, though many papers exist implementing Artificial Neural Networks (ANN) or other statistical methods, i.e. Box-Jenkins (BJ), autoregressive integrated moving average (ARIMA) or generalized autoregressive conditional heteroscedasticity (GARCH) for forecasting electricity-related time series, publications in the domain of natural gas market-oriented forecasts are sparse, as observe (72).

One of the few works is the early paper of (73), who try to predict natural gas spot price movements for the US market analyzing trader positions published in the U.S. Commodity Futures Trading Commission (CFTC) Commitment of Traders Report, and another research paper published by (74), who analyses monthly forward products (futures) using linear regression (LR), GARCH models, and multilayer perceptron (MLP).

In the study developed by (3), which sought to size the capacity of natural gas storage under LNG demand and price uncertainty, due to the problematic representation of LNG price dynamics, it was decided to treat it through a robust. Also, the author highlights the complexity of the LNG purchasing process is dynamic, with multiple stages, where this dynamic is simplified by the consideration of a security criterion that establishes a minimum volume of LNG to be purchased, being the (76) technique adopted to address LNG price uncertainty.

In addition to the publications in the domain of natural gas market-oriented forecasts are sparse, making it difficult to evaluate the performance of alternative models, the LNG is purchased in the Brazilian gas sector the in the spot market from several suppliers, where different pricing policies formation are adopted, following different dynamics and record various levels, resulting in historically volatile prices.

It is possible to observe that the first papers that deal with this issue choose for the spot price process the geometric Brownian motion (36), see (30) work, which addresses the problem of valuation of options written on oil.

However, according to (15), during the nineties, energy commodity price trajectories did not exhibit the feature of prices growing on average, where the geometric Brownian motion did not seem the best representation anymore. Then, several authors proposed instead that prices of commodities are best modeled by mean-reverting processes (see (14, 13, 12)), which has more economic logic than the geometric Brownian for commodities and interest rates.

According to (10), mean-reverting processes are Markov process where the sign and intensity of the drift are dependent on the current price, which reverts to a market level equilibrium level which we typically assume is the long-term mean price. Also, given that mean-reverting processes are not as simple to approximate by a probability lattice with binomial, methods employing Monte Carlo simulation and discrete trinomial trees (9) have been developed for modeling these processes (see (10)).

In addition to the lack of publications in the domain of natural gas market-oriented forecasts, the LNG is purchased in the Brazilian gas sector in the spot market from several suppliers, where different pricing policies formation are adopted. Based on the literature recognition that a mean-reverting processes best model prices of commodities (see (14, 13, 12)), in addition to the limitations of the optimization algorithm used (47), the model will assume a discrete-time approach to model LNG price uncertainty, where we will approach a mean-reverting stochastic process by a log-normally distribution.

Therefore, due to the limitations of the optimization algorithm used (47), where we assume stagewise independence to deal with LNG price uncertainty, the model will assume a discrete-time approach to consider a mean-reverting stochastic process.

Then, independently of thermoelectric demand, we simulated a LNG price scenario following a log-normal distribution. The discrete price distribution will be estimated from Monte Carlo simulation of the $ln(p_t(s))$ following the distribution presented by (3-16).

$$\ln(p_t(s)) \sim \mathcal{N}(\mu, \sigma^2) \tag{3-16}$$

4
Case Study Assumptions

In order to generate insights into the potential benefit of the natural gas storage activity for Brazil, we apply the proposed model to obtain the country's optimal natural gas supply policy for a 60-month horizon ($\mathcal{T}$=1,2,...,60), considering the geographic regions connected by gas transmission network ($\mathcal{R}$=SE/MW, S, NE).

We consider the following supply sources: i) domestic production; ii) import through the Bolivia-Brazil gas pipeline, GASBOL; iii) import of LNG; and iv) fuel deficit (an artificial source of supply to ensure a relative complete recourse model). The following cases were considered: "With Storage", with consideration of generic storage; "Depleted Fields" and "Salt Caverns", with specific storage; and no possibility of storage, called “No Storage", as it occurs in the current situation.

For all simulated cases, we consider the following CVaR parameters: significance level $\alpha = 0.5$ and weight in the objective function $\lambda = 0.5$. The discount factor (β) used was 0.993, equivalent to a discount rate of 8.5% per year, which was the Selic[1] rate at the time the research was conducted to reflect the preference ratio of money spent over time.

We present the input data of the model as follows.

4.1
Gas Storage Data

For the simulations that considered the possibility of gas storage, we considered the existence of a generic underground reservoir in each geographic region analyzed. As there is no underground reservoir in Brazil and the literature lacks robust analyzes that bring data that could be applied to the Brazilian case, such as storage capacity and the rate of withdrawal and injection of underground reservoirs, the storage data disclosed in the studies (37, 39) were used, where industry experts are consulted for greater adherence to the study.

Given that this study initially seeks to identify the need for storage in the integrated natural gas system, and understanding the high variability in

[1]The Selic is the base interest rate of the Brazilian economy.

relation to storage capacity (between 20.0 and 110.0 Mm^3 for Salt Caverns and 50.0 and 4200.0 Mm^3 for Depleted Fields, according to (39)), we consider the value of 300.0 Mm^3 of gas storage capacity per subsystem.

In order to determine the maximum monthly withdrawal and injection rate in the storage structures, the study (39) indicates an average daily withdrawal flow in European reservoirs of 5.0% of the useful gas in salt caverns and 2.5% of the useful gas in depleted fields. We consider for the case of "With Storage", which considers generic storage, a daily gas withdrawal capacity of the generic reservoirs of 3.75% of the useful gas volume. Since the periodicity worked in the proposed modeling is monthly, and the injection and withdrawal capacity presented in the literature is daily, we convert the data to a monthly frequency.

Withdrawal and injection rates are a function of the reservoir internal pressure, so the fuller the reservoir, the greater its internal pressure and therefore the easier it will be to withdraw the gas and the more harder to inject it. Although the relation between volume and flow is not linear, for practical application it is usual to consider it constant for a certain amount of stored gas (see (3)). Thus, considering a constant withdrawal rate over a month, if 3.75% of the volume stored in the period is withdrawn daily, after 30 days, 68.2% of the initially stored period will be withdrawn.

Therefore, we assume that the maximum withdrawal capacity per period is 68.2% of the initial storage gas volume. Similarly, considering the rates for each type of infrastructure, as a limit of withdrawal, we assume a rate of 53.2% and 78.5% of the initial gas volume for the cases of "Depleted Fields" and "Salt Caverns", respectively.

In the injection process, according to (39), as a general and simplifying assumption, injection rates are equivalent to 50.0% of the withdrawal rates. Then, we consider a daily gas injection capacity of the generic reservoirs of 1.87% of available capacity for the "With Storage" case. With a reverse logic, since the fuller the reservoir, the harder it will be to inject gas, if 1.87% of available storage capacity is injected daily, at the end of 30 days 43.3% of available gas storage capacity at the beginning of the period will be injected. Therefore, the model assumes that the maximum injection capacity per period is 43.3% of available storage capacity at the beginning of the period. Finally, for the cases of "Depleted Fields" and "Salt Caverns", we will work with a limit of injection of 31.4% and 53.2% of available storage capacity, respectively.

To consider gas consumption by compressors in the process of injecting and withdrawing gas from storage, a loss of 1% of the gas moved will be considered (see (3)).

The literature on underground storage shows that storage costs are specific to each type and vary widely depending on natural factors, market factors, proximity to transmission infrastructure, and environmental issues, where the main factors influencing unit costs are the volume of the storage facility and the maximum withdrawal capacity (16).

The study (37) carried out a benchmark to assess and compare the tariffs of underground gas storage services of companies that offer this type of service in the most important European countries. Their results revealed different underlying trends linked to the economic structure of tariffs - regulated and negotiated - and the technical characteristics of storage - where a first trend shows equal tariffs, regardless of the type of storage, and another shows the application of differentiated tariffs, where prices access to salt caverns storage services are, on average, higher than depleted fields.

The determination of the storage service tariff is highly complex. Understanding the factors affecting the value of natural gas storage is essential both for optimum planning of investments and for the operation of existing facilities (38). Since the valuation of gas storage is not the object of this study, we assume in the first part of our study that the storage cost is equal to the average tariff charged in the countries analyzed by (37). Updating this value to 2018, according to the consumer price index (CPI) of France, was reached a rate of US$ 7,124.0 per million cubic meters of gas stored per month[2].

In the second part of the case study, where we analyze the storage benefit confronting the savings provided by storage in meeting gas demand with the associated OPEX and CAPEX, the considered storage cost are equal to the variable operating cost, based on data from (39), which, adjusted for inflation for 2018, i.e., equal to US$ 465.00 per million cubic meters of gas stored per month. We characterize differing storage types ("depleted fields" and "salt caverns") by their investment costs, withdrawal/injection capacity and, therefore, fixed operational cost.

For the CAPEX, we consider the international average of investment in underground natural gas storage, published in (39) and adjusted according to the CPI of France[3]. In particular, the CAPEX reaches US$ 52,146.0 per million cubic meters of gas useful in storage in depleted fields and $ 764,806.0 per million cubic meters of useful gas in salt caverns. For the OPEX cost, the value considered is the one related to the annual cost of fixed operation, also based on the same study and corrected at the price of 2018, in the order of

[2]The storage service cost is computed in relation to the total volume stored at the end of the t period, as presented by equation (3-1), shown in Section 3.

[3]The choice of the French CPI to update European costs is due to country relevance in this activity.

US$ 743,508.0 per million cubic meters per day, using the availability daily maximum[4].

Figure 4.1 illustrates the decision problem for the "With Storage" case.

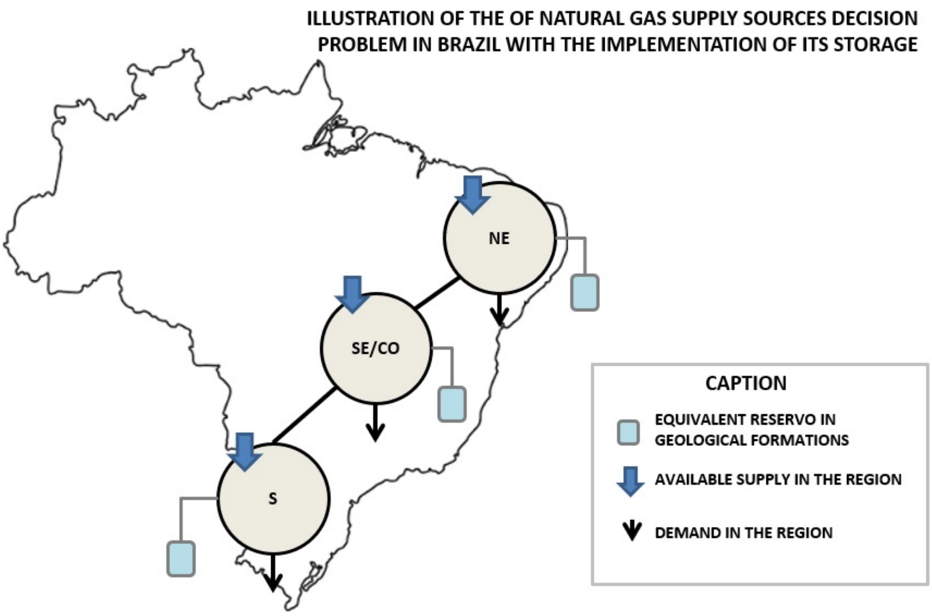

Figure 4.1: Decision Problem of the Natural Gas Supply

4.2 Capacity to supply gas to the Brazilian market

Table 4.1 depicts the considered values for the capacity of each supply source of natural gas to supply the Brazilian market via integrated mesh.

The primary source of natural gas supply in Brazil is the gas domestically produced, extracted from the producing fields whether associated or not with oil production. This source has the supply capacity to the market directly limited to the capacity of extracting, processing, transmission, and distribution (25).

Thus, the maximum domestic gas supply capacity, per period, was considered equal to the potential supply of this source in the interconnected grid, provided for in the Decennial Energy Expansion Plan (PDE) 2026 (40). The historical proportions of production in the integrated system, between January 2010 and April 2017, were considered for the disaggregation between

[4]Thus, in the case of a reservoir with withdrawal availability of 8.4 Mm^3/day, and a fixed operating cost of US$ 743,508.0 per Mm^3/day, the annual cost would be US$ 6.25 million. Therefore, in the case of a reservoir with withdrawal availability of 8.4 Mm^3/day, and a fixed operating cost of US$ 743,508.0 per Mm^3/day, the annual cost would be US$ 6.25 million.

		Capacity (Mm^3/day)			
		Maximum		**Minimum**	
Supply Type	**Year**	**SE/MW**	**NE**	**SE/MW**	**NE**
Domestic	2018	39.7	8.5	27.8	6.0
	2019	40.7	8.7	28.5	6.1
	2020	40.2	8.6	28.1	6.0
	2021	39.4	8.4	27.6	5.9
	2022	41.1	8.8	28.8	6.2
Bolivian	2018 to 2021	30	0	24	0
	2022 to 2021	20	0	16	0
LNG	2018 to 2022	20	21	0	0
Deficit	2018 to 2022	∞	∞	0	0

Table 4.1: Maximum Capacity of Natural Gas Supply (Mm^3/day)

the producing regions, Southeastern/Mid-Western (SE/MW) and NE (27, 35). The minimum assumed purchase limit is related to the take-or-pay clause, of 70% of the maximum volume per period, according to estimates of experts consulted.

Besides gas fields operated by Petrobras predominantly produce the domestic supply, this state company is the only importer of the gas, either via the Bolivia-Brazil gas pipeline (GASBOL) or via LNG.

Brazilian SE/MW subsystem is the entry point of Bolivian gas. A connection between SE/MW and South (S) allows a daily flow of gas up to 12.6 Mm^3 [5] (45).

We consider the potential supply of GASBOL specified on the PDE 2026 as the Bolivian gas supply maximum limit. The minimum assumed purchase limit is the same current percentage of the total volume contracted, subject to a take-or-pay clause, of 80% of the maximum volume per period (26, 27).

Regarding LNG, only spot market purchases are considered[6].The upper limit of this source is considered as its potential supply in PDE 2026 for the integrated network during the analysis horizon, which is concentrated in three regasification terminals (TR): the TR of Guanabara Bay in the SE/MW region, and the TR of the Pecem and Bahia in the NE region[7].

[5] One of the natural gas import contracts between Bolivia and Brazil matures in December 2019 and the state is expected to renegotiate its contract with a volume about half the current value, where the rest of GASBOL's capacity can be negotiated between the other agents of the gas market and Bolivia, subject to certain conditions, as an effective Bolivian production capacity. Also, there is the possibility of a variation in the contracted percentage subject to the take-or-pay clause. However, this study considers the contractual structure in force regarding a take-or-pay clause.

[6] By 2015, about 80% of the total imported LNG volume was purchased on the spot market.

[7] Although the TR of Sergipe and Açu Port are expected to be in operation until 2022, it is not known when these infrastructures are connected to the interconnected network.

If it is not possible to meet all of the gas demand with the supply of gas available, either by current period purchases or storage gas consumption, it will be considered that the thermoelectric demand surplus will be met by alternative energy sources, prioritizing the supply to non-thermal demand. In this case, a "gas deficit" cost will be considered for each unsupplied gas molecule. The deficit variable will always be greater than or equal to zero

4.3 Gas Demand

In addition to the large concentration of gas supply, the demand for natural gas is highly concentrated in the industrial and thermoelectric sectors, where the lack of integration between the electric and natural gas sectors makes domestic demand challenging to predict.

As shown by (28), given that thermal plant dispatch decisions are made based on a cost-of-power generation model, in a scenario where all thermal plants are dispatched simultaneously, total gas consumption would be very close to the gas demand of all non-thermoelectric segment. On the other hand, if the hydroelectric system is in an abundant rainy period, all the demand for electricity would have the potential to be met without the need for thermoelectric dispatch (see (28)).

As described in the previous chapter, to approximate the behavior of a group of units (subsystem), we propose the use of a Markov process where, conditioned to the Markov state, we define a multivariate probability distribution of the gas demand for that particular subsystem.

Thus, the sets of possible thermoelectric demand scenarios represent conditional probability distributions for each Markov state. Given that the thermoelectric dispatch and, consequently, the thermoelectric demand for gas, originates from the operational decision model of the electricity sector, where Monte Carlo simulations of the affluence, in the same Markov state are processed, the same probability of occurrence will be considered for each scenario. That is, a single Markov state is associated with a set of thermoelectric demand realizations with the same probability of occurrence that characterize the state.

Thus, for example, when a Markov state $k = 3$ is visited, it is linked to a set of scenarios equally probable. From this set, a scenario is randomly drawn to represent the thermoelectric demand that characterizes that state.

Based on Newave's results released in January 2018, 2,000 monthly natural gas demand scenarios are generated for the period from January 2018 to December 2022. Each scenario is a set of thermoelectric demands for each of the Brazilian regions in the R sets.

In order to disaggregate the thermoelectric demand scenarios in different Markov states, for each period, the k-means (33) algorithm was used. K-Means is a clustering method that, by setting the chosen number of clusters (or groups), the method partitions the observations between the groups so that the distance between each observation belonging to the clusters and the respective group centroid is smaller. Centroids are calculated as the average of the values of each attribute of each observation that belongs to this centroid. The iterative process follows the following steps: i) calculation of centroids based on the initially allocated observations; ii) generation of distance matrix between each observation and the centroids; iii) reallocation of observations in clusters according to their distance from the centroid of the group; iv) calculation of the new centroids for each cluster; v) the steps are repeated until convergence.

Then, based on the 2000 sets, per period, the K-means algorithm was used to part them into clusters (or Markov states).In order to determine the ideal number of Markov clusters, k-means was performed by varying the total number of states considered, from 2 to 20. Based on the sum of the square errors (SSE) of each alternative analyzed, the number of clusters selected was that, by increasing the number of states in one unit, the reduction in SSE was lower than a tolerance level of 10% (see (34)).

Based on the Markov states defined by the resulting k-means groups, a transition probability matrix was created for each period, which determines the probability of moving from the states of one period, for each state belonging to the next period.

To each new iteration (in the forward steps), the model will re-sample the stochastic variable, following the transition probability matrix. For the visited state, a scenario belonging to this state is considered. Each demand scenario corresponds to three individual demand realizations, one for each region.

On the other hand, the non-electric demand for natural gas is related to the level of economic activity observed at a given moment and is less relevant - than the electric power demand - to explain the volatility of the total demand for natural gas (3).

In this study, the non-thermoelectric demand considered is the one specified on the PDE 2026 for Brazil, where the historical proportion of the subsystems was used to make the regional breakdown (jan./2010 and apr./2017). Figure 4.2, 4.3 and 4.4 show the average values of the thermoelectric demand scenarios, as well as their percentiles of 5 and 95, based on the 2,000 monthly natural gas demand scenarios generated by Newave and considered in this case study, besides the non-thermoelectric demand per gas for each of the subsystems. As can be seen, there is no thermoelectric demand in the South.

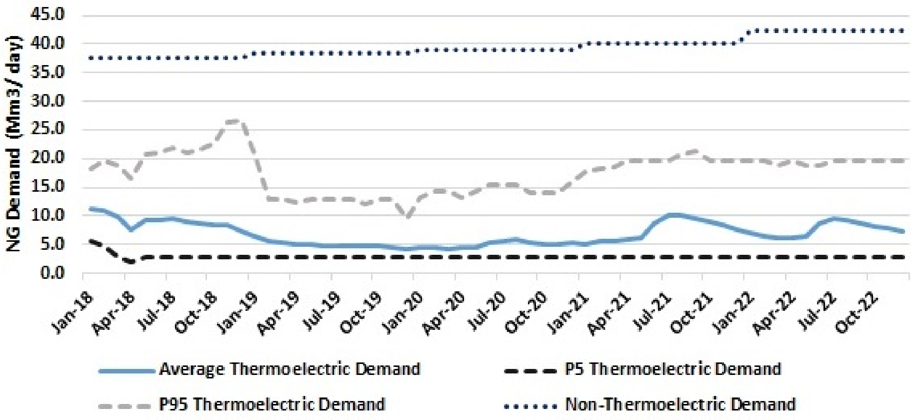

Figure 4.2: Natural Gas Demand / Southeast

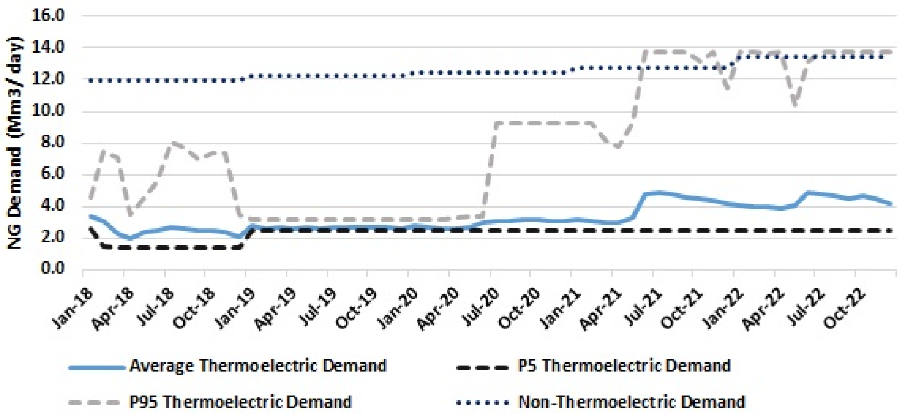

Figure 4.3: Natural Gas Demand / Northeast

4.4 Supply Price

The price of the domestic natural gas supply is considered as the average value of the probable range of prices of the source molecule, specified on the PDE 2026 for each year of analysis[8].

For the price of Bolivian gas, based on the adjustment logic regarding the portion of the price related to the natural gas molecule in the current contracts, the portion of the price for the gas molecule traded in the quarter immediately prior to the start of the projection is readjusted, taking into account 50% of

[8]This price excludes ICMS and PIS/COFINS taxes, transmission and distribution margin.

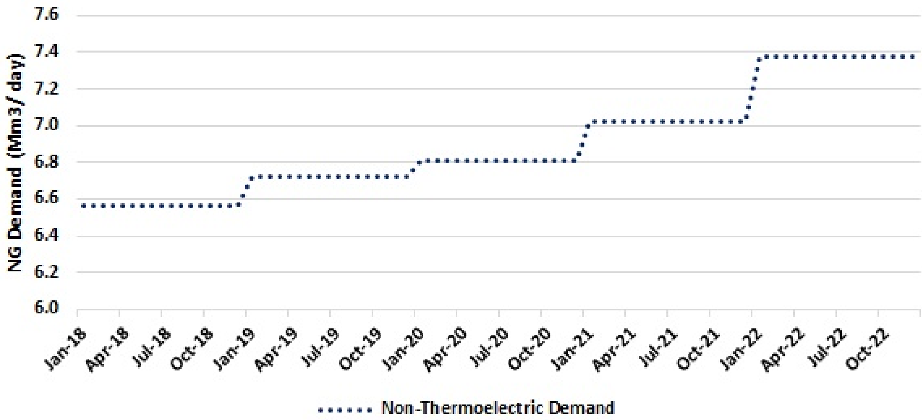

Figure 4.4: Natural Gas Demand / South

the current price and 50% of the Brent oil price change[9], also specified on the PDE 2026. This readjustment was made quarterly over the projection period. After the price adjustment of the imported gas for every projection horizon, the average was calculated for each year of analysis.

Graph 4.5 shows the average value of the domestic and Bolivian gas price scenarios.

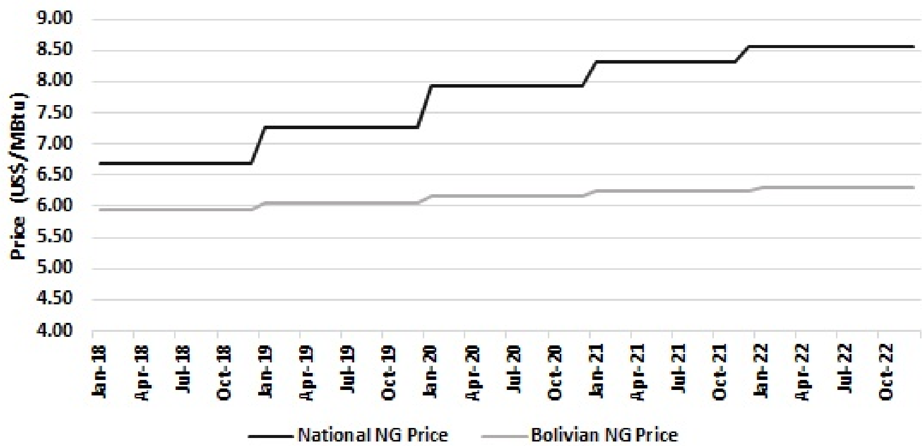

Figure 4.5: Price of Domestic and Bolivian Natural Gas

Since a large part of the domestic gas production comes from fields associated with oil production, LNG acts as the primary source of supply flexibility for thermoelectric in order to keep the balance between supply and demand for gas. Although LNG purchases may occur in the spot market and through long-term contracts, the spot market for LNG in the Brazilian market

[9]In current contracts, this adjustment is made considering the price variation of a list of fuel oils. In the present thesis, in order to simplify the price adjustment methodology, the Brent price variation, from which this list of oils is derived, was used.

almost always refers to the supply or redirection of load under a long-term contract, being carried out in a timely manner, according to internal needs and external market conditions, where LNG price has relevant volatility and historically high import costs (for more details see (2)).

Since imports are made only by Petrobras, at the time of writing of this study, it is difficult to obtain information on the prices of long-term contracts practiced in Brazil, due to its commercial strategy.

In addition to the lack of publications in the domain of natural gas market-oriented to forecasts LNG price, this gas' source is purchased in the Brazilian in the spot market from several suppliers, where different pricing policies formation are adopted. Based on the literature recognition that a mean-reverting process best models prices of commodities (see (14, 13, 12)), in addition to the limitations of the optimization algorithm used (47), we assume a stagewise independent model for LNG price uncertainty given by a log-normally distribution.

Then, to each thermoelectric demand scenario, conditioned to each Markov state, we independently simulate a LNG price scenario following a log-normal distribution. The price distribution presented by equation (3-16) is estimated, where μ is the natural logarithm of the expected LNG price for the year, according to PDE 2026 and σ is the standard deviation of the natural logarithm of historical LNG prices.

The log of prices is used since it is generally assumed that commodity prices are log-normally distributed and these values cannot be negative ((10). According to (7), log-normal distributions are usually characterized in terms of the log-transformed variable, using as parameters the expected value, or mean, of its distribution, and the standard deviation. This characterization can be advantageous as, by definition, log-normal distributions are symmetrical again at the log level.

For the deficit, the cost considered will be 10% above the deficit cost used in the electric power sector's operating problem, which is R$ 4,650/MWh, reaching US$ 209/MBtu of power generation not supplied by the energy sector.

4.5 Flow between Regions

Given the lack of prediction of new gas pipelines on the PDE 2026 connecting the subsystems of the interconnected system during the analyzed horizon, as only the Southeast-Northeast Integration Gas Pipeline (GASENE) is considered, with a maximum capacity to transport 20.0 Mm^3/day between the SE/MW and NE regions, and GASBOL, connecting the SE/MW and S regions, with a maximum capacity of 12.5 Mm^3/day; the flow between these regions being allowed and limited to that amount.

5
Empirical Results

We implemented the proposed model using the open-source library, SDDP.jl, built by Oscar Dowson to solve multistage stochastic optimization problems using the SDDP algorithm (42). The SDDP.jl library is built on JuMP, an algebraic modeling language in Julia.

To soften the influence of simulated horizon closing conditions, a static period of 5 years after the end of the analysis horizon was considered, only to avoid "end effects".

Based on the developed tool, we first obtain the optimal policy for the "With Storage" case, in which the stopping criterion is the stabilization of the lower-bound value over the iterations (43, 44) [1]. Figure 5.1 shows the evolution of the SDDP's lower limit throughout 150 iterations, for the 120 periods (60 periods of analysis and 60 static periods for the elimination of "end effects"). As can it can be noticed, from the 75th iteration, the expected total cost stability is observed with variations of less than 0.003%.

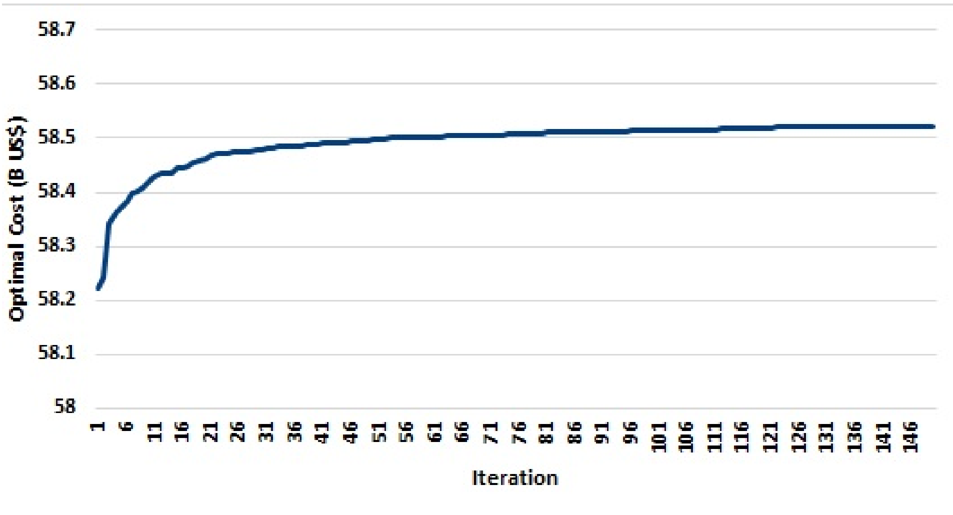

Figure 5.1: Lower Cost for the Optimal Value throughout the 150 Iterations

Based on the SDDP Future Cost Functions, the developed model is used

[1]Since the use of the recursive CVaR nested in the model formulation prevents the stopping criterion from being tested by means of the difference between the values of the lower limit and the upper limit for the optimal value, the criterion used was the stabilization of the lower limit to the optimal value.

to analyze the natural gas supply and storage decision policy based on the simulation of 1,000 scenarios of LNG price and natural gas demand, reassessed from the set of possible scenarios constructed and considered initially.

In order to compare the operational benefit of storage to the Brazilian integrated system fairly, we obtain the optimal policy for the "No Storage" case, using the same scenarios of thermoelectric demand and LNG price used in the case "With Storage" both in the optimization and definition phase of the optimal gas supply policy, and in the simulation phase of the calculated policy.

Finally, we analyze the economic benefit of underground storage. The savings provided by storage in meeting the demand for gas is confronted with the OPEX and CAPEX costs of these investments. To this end, we obtain the optimal policy considering specific storage infrastructures: "Depleted Fields" case and "Salt Caverns" case. For comparison purposes, we use the same set of simulated scenarios from previous cases.

The results observed from the optimization and simulation of the cases shown are presented below.

5.1 Storage as Source of Flexibility in the Operation

To evaluate the model we randomly generate 1,000 uncertainty realizations (Markov states, thermoelectric demand volumes, and LNG prices) to simulate the optimal policy for the "No Storage" and "With Storage" cases over the 60-period horizon.

Let us denote "High Demand" any scenario whose thermoelectric demand is above the 70th percentile of demand for each given period. Similarly, let us denote "High LNG Price" any scenario where the LNG price is above the 70th percentile of price distribution for each given period. As can be seen in Table 5.1, given "High Demand" and "High LNG Price", in 56% of the time there is LNG acquisition (with high cost) in the "No Storage" case, with an average total volume purchased of 1,056.6 Mm^3 per year. On the other hand, in the "With Storage" case, the LNG purchase only occurred in 29% of the occurrences, representing a total volume purchased of 438.8 Mm^3 per year under these unfavorable price conditions.

Now, let's categorize as "Low LNG Price", any scenario where the LNG price is below the 10th percentile of the price distribution for each given period. Then, in periods where thermal demand is high under competitive 3 price conditions ("Low LNG Price"), the volume of LNG purchase was 1.535.2 Mm^3 per year in the "With Storage" case, either for immediate supply or for storage,

	"High LNG Price"		"Low LNG Price"	
	"With Storage"	"No Storage"	"With Storage"	"No Storage"
Purchase Occurrence (%)	29%	56%	99%	100%
Annual Average Volume (Mm^3)	452.1	1,056.6	1,535.2	993.2

Table 5.1: Price Effect on LNG Purchases Given "High Demand" Scenario

whereas in the case where there is no possibility of storage this acquisition was 993.2 Mm^3 in the annual average, only to meet the demand.

Let's categorize as "Low Demand" any scenario where the thermoelectric demand is below the 10th percentile of thermoelectric demand distribution for each given period. Analyzing the statistics presented in the table 5.2, given "Low Demand" and "Low LNG Price": on the one hand in the "No Storage" case there is an average annual volume purchased of $71.2 Mm^3$ per year, in the case of "With storage" the average volume acquired per year is considerably higher, at 199.1 Mm^3, indicating more significant use of competitive gas, either for immediate consumption or storage.

	"High LNG Price"		"Low LNG Price"	
	"With Storage"	"No Storage"	"With Storage"	"No Storage"
Purchase Occurrence (%)	0%	0%	70%	81%
Annual Average Volume (Mm^3)	0	0	184.2	71.2

Table 5.2: Price Effect on LNG Purchases Given "Low Demand" Scenario

In Table 5.3, we present the flow of gas injection and withdrawal from storage given "High Demand". Given also "High LNG Price", the probability of occurrence of gas withdrawal above 50% of the flow capacity to meet demand is 60%. Given "Low LNG Price", the occurrence of gas injection at storage above the 50% injection limit is 50%. These results illustrate that the possibility of storage enables the system to reduce its exposure to high prices by choosing to use stored gas, while at competitive LNG prices, system agents can gain economic advantages by not only meeting current demand, but also storage the fuel.

We depict the results for "Low Demand" scenarios in Table 5.4. Given "High LNG Price", the utilization above 50% of the gas Withdrawal from

	"High LNG Price"	"Low LNG Price"
Injection Occurrence Greater than 50% of Injection Capacity (%)	0%	52%
Withdrawal Occurrence Greater than 50% of Withdrawal Capacity	60%	1%

Table 5.3: Price Effect on Storage Utilization Given "High Demand" Scenario

storage occurred in 30% of the cases. Given "Low LNG Price"s, gas injection is above 50% of the flow capacity by 30%.

	"High LNG Price"	"Low LNG Price"
Injection Occurrence Greater than 50% of Injection Capacity (%)	0%	30%
Withdrawal Occurrence Greater than 50% of Withdrawal Capacity	33%	16%

Table 5.4: Price Effect on Storage Utilization Given "Low Demand" Scenario

The LNG purchase to meet demand in the "No Storage" case is strongly dependent on the current international price. On the other hand, for the "With Storage" case, the model rather use stored gas instead of buying LNG at unfavorable pricing conditions, i.e., the model chooses not to buy LNG, using gas stored in storage to meet peak demand, what provides greater flexibility in the supply decisions.

Analyzing the volume of stored gas, summarized by the average and percentiles in Figure 5.2, it is possible to note a quite frequent use of storage, especially from the year 2021[2], when the total volume stored in the un-

[2]Based on the 2,000 monthly natural gas demand scenarios generated by Newave, the level of gas thermoelectric dispatch increases considerably in the Northeast subsystem from June/21.

derground storage infrastructures distributed throughout the interconnected system reaches, on average, usage exceeds 300 Mm³ in all periods. In cases belonging to the 95th, this use above 600 Mm³.

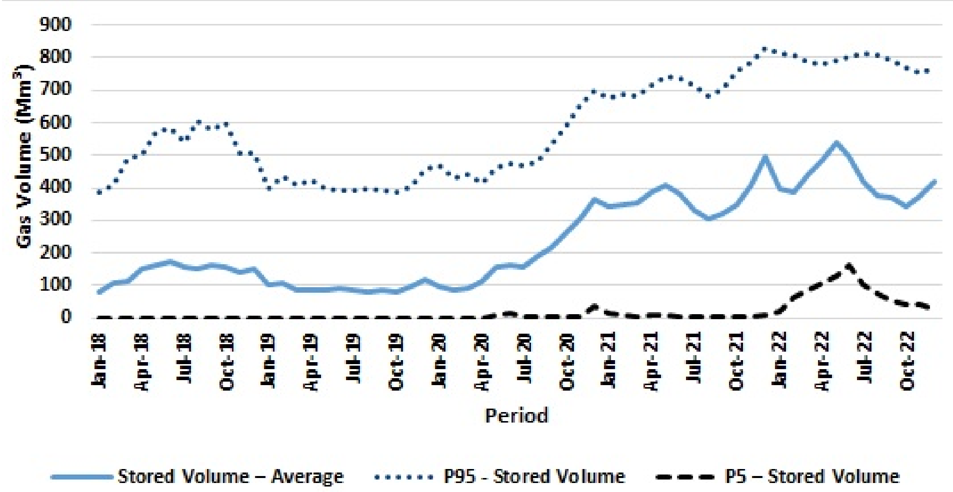

Figure 5.2: Storage Capacity Usage in the Interconnected Network

In the analyzed case, since the price of Bolivian gas is, most of the time, the lowest compared to the other supply sources, and since there is a possibility of storage, it is possible to observe that in 80% of simulations there is purchase greater than 90% of Bolivian supply capacity for the country, either for immediate use or for injection in storage.

The flexibility that the storage activity can provide in LNG purchase decisions is reinforced by comparing the two analyzed cases, "No Storage" and "With Storage". As can be seen from Figure 5.3, during periods where the LNG price was below the Bolivian gas price, storage allowed for a 74% increase in the volume of LNG purchased, from an annual LNG purchase of 332 Mm^3 to 580 Mm^3. In relation to LNG purchases when it is above domestic gas prices, storage allowed it to be reduced by 26% from a total annual volume of 434 Mm^3 to 323 Mm^3. When we analyze at reductions in LNG purchases in scenarios where prices were above US$ 12.0/MBtu and US$ 16.00/MBtu, the reductions were 62%.

5.2
Storage as a Source of Price Regulation

Figures 5.4 and 5.5 compare two analyzed cases, "No Storage" and "With Storage", in the matter the marginal cost of meeting the demand for natural gas for the SE/MW regions, i..e, the optimal dual variable associated with

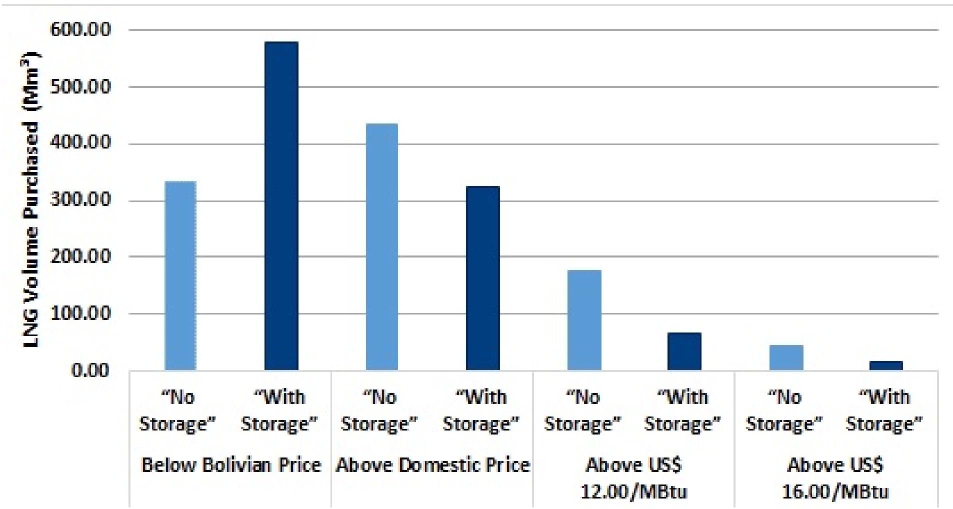

Figure 5.3: LNG Volume Acquired by Year, by Price Scenario

supply-demand constraint, in addition to the monthly percentage variation in the marginal cost of gas, respectively.

It is possible to observe, especially from the year 2021, where there is a higher use of the storage, that the storage activity provides not only lower levels of the cost of supplying the demand for an additional gas molecule but also higher stability in this marginal cost of gas. The case without storage demonstrates susceptible to price spikes, which brings greater instability to the market as a whole.

At this point, it is essential to note that the storage could act as a vital tool for regularizing natural gas prices in the market, as observed in (41), supporting the physical balance of gas in the short-term market. Figures 5.4 and 5.5 compare two analyzed cases, "No Storage" and "With Storage", in the matter the marginal cost of meeting the demand for natural gas for the SE/MW regions, i.e, the optimal dual variable associated with supply-demand constraint, in addition to the monthly percentage variation in the marginal cost of gas, respectively. This statements can also be extended to the S and NE regions, as can be observed in the AppendixB and AppendixC.

5.3 Economic Benefit of the Storage

To assess the economic benefit of the storage we compare OPEX[3] and CAPEX[4] costs of investments in storage infrastructure in depleted fields and in

[3]Given that variable operating costs are incorporated into the model as stocking cost, OPEX took into account the fixed operating costs presented in the previous chapter.

[4]To annualize the cost of capital investment, a 30-year amortization period was considered, which is reasonable for capital intensive investments in infrastructure.

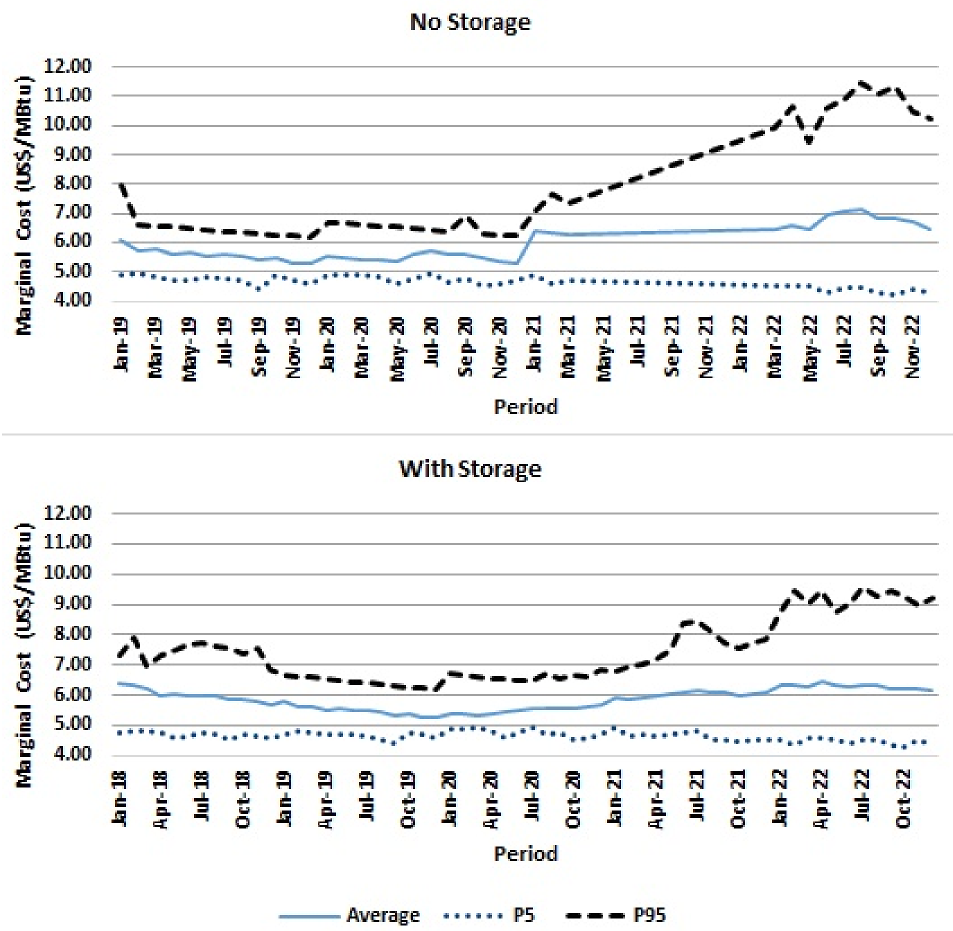

Figure 5.4: Marginal cost of gas demand supply - SE/MW

salt caverns, with the savings provided by the storage in the supply operation for different useful gas capacities.

To estimate the savings provided by the storage, we simulate (for the same uncertainty realizations of previous cases) the optimal policy for specific storage infrastructures and capacities. Thus, the total gas supply cost for the "No Storage" case is compared to the costs in each of the specific cases analyzed over the 60-period horizon.

The attributes that differentiate the “Depleted Fields" case from the “Salt Caverns" case are the withdrawal and injection flow in the storage and the investment cost. Moreover, while in the case “With storage ” average storage tariff is considered as the cost of storage, in the cases that will be analyzed in this subsection, in order to assess the economic benefit, only the variable operating cost was considered in the simulations as the cost of the storage service. All the data considered from these cases are presented in the previous subsection.

Table 5.5 presents the different results for the “Depleted Fields" case,

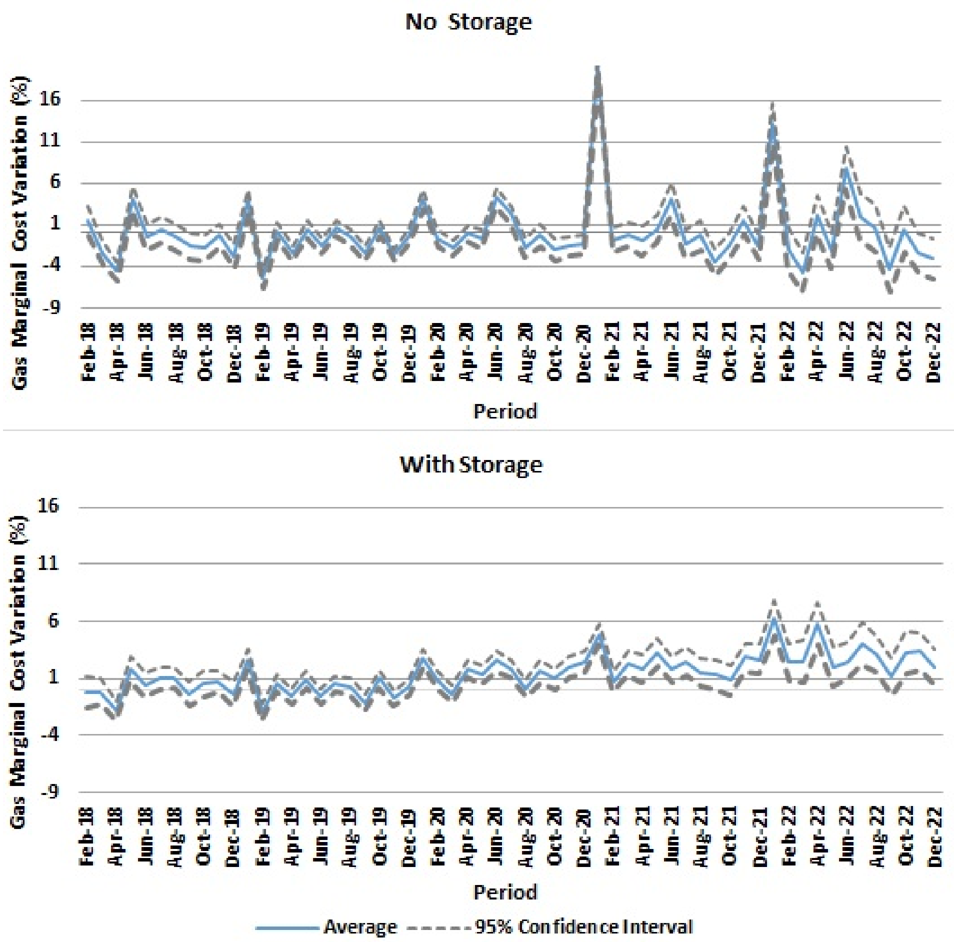

Figure 5.5: Monthly Variation of the Marginal Cost of Supply to the Natural Gas Demand- SE/MW

considering a total installed storage capacity between 600 and 1,500 Mm³ distributed over the Brazilian subsystems. For a total installed capacity of 1,200 Mm³ an annual economic benefit of US$ 16.7 million is found.

In terms of annual economic benefit per installed capacity and annual economic benefit per total CAPEX, it can be seen that the "Depleted Field" investment option that maximizes these returns is the smallest analyzed capacity of 600 Mm^3 total in the subsystem, which results in US$ 0.024 million per Mm^3 and rate of 0.47, respectively.

Looking at figure 5.6, we observe that there is an optimum capacity between 1.125 and 1.200 Mm that maximizes the economic benefit of storage activity for the Brazilian gas industry, that is, providing more significant savings for the gas supply. On the other hand, the economic benefit to installed capacity ratio tends to decrease as storage size increases.

Table 5.6 presents the results for the “Salt Caverns" case, considering a total installed storage capacity between 100 and 600 Mm³ distributed over the

Total Storage Capacity (Mm^3)	600	900	1,050	1,125	1,200	1,500
Annual Savings in Cost of Meeting Demand (million US$)	28.8	34.7	38.0	39.6	41.1	46.4
OPEX (millions US$ per year)	11.2	16.7	19.5	20.9	22.3	27.9
CAPEX (millions US$ per year)	1.0	1.6	1.8	2.0	2.1	2.6
Annual Storage Benefit (million US$)	14.6	16.4	16.6	16.7	16.7	15.9
Annual Storage Benefit per Installed Capacity (million US$/$Mm^3$)	0.024	0.018	0.016	0.015	0.014	0.011
Annual Storage Benefit per Total CAPEX	0.47	0.35	0.30	0.29	0.27	0.20

Table 5.5: Economic Benefit in "Depleted Fields" over Installed Storage Capacity

Brazilian subsystems. For a total installed capacity of 300 Mm³ an annual economic benefit of US$ 4.7 million is found, considerably less than the maximum benefit found in the "Depleted Fields" case.

Regarding to annual economic benefit per installed capacity and annual economic benefit per total CAPEX, it can be seen that the "Salt Caverns" investment option that maximizes these returns is the smallest analyzed capacity of 100 Mm^3 total in the subsystem, which results in US$ 0.032 million per Mm^3 and rate of 0.42, respectively.

Analyzing Figure 5.7, we observe that there is an optimum capacity between 150 and 300 Mm that maximizes the economic benefit of storage activity for the Brazilian gas industry, that is, providing more significant savings for the gas supply. On the other hand, the economic benefit to installed capacity ratio tends to decrease as storage size increases.

Then, in order to analyze the sensitivity of the storage benefit to the degree of risk aversion associated with the operation policy, this was optimized

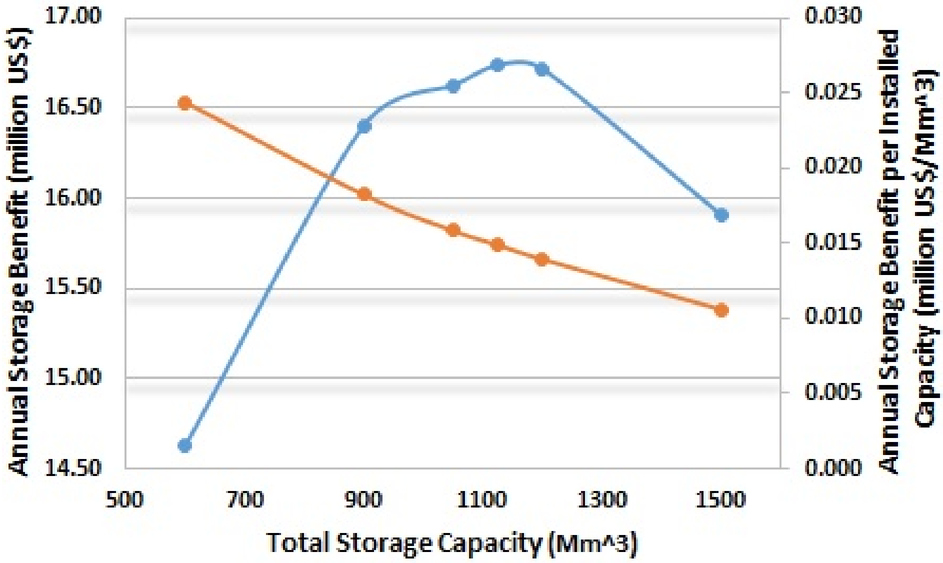

Figure 5.6: Economic Benefit per Installed Capacity for the "Depleted Fields" case

considering lower risk aversion levels, the lambda parameter in 0.1 and 0.7, considering a storage capacity of 1,200 Mm^3 in depleted fields. Therefore, we observe that the benefit of storage is reduced as the degree of risk aversion of the operational policy increases, as can be seen in Table 5.7.

Due to the fact that risk aversion considers a higher weight for scenarios where supply conditions are more expensive, the higher the level of risk aversion, the greater the signaling for the model to bear storage costs, protecting itself, and ensuring flexible supply conditions even in the worst case scenarios of thermoelectric demand and LNG pricing. That is, the higher the level of investor risk aversion, the greater the willingness to invest in a "premium" that guarantees less costly supply conditions even in the worst-case scenarios.

That is, even considering a highly risk-averse investor, the saving that gas storage provides outweighs both investment and operating costs, in addition to the "insurance" costs for worst-case scenarios, resulting in a benefit of US$ 13 million a year.

5.4 Preliminary Business Model

This section brings a preliminary proposal of how it could take place to develop underground gas storage activity in the Brazilian gas market.

Given that investment in UNGS is capital intensive and with the relevant associated risk inherent mainly to the unpredictability of thermoelectric demand, and in view of the government's recognition of the importance of un-

Total Storage Capacity (Mm^3)	**100**	**150**	**300**	**450**	**600**
Annual Savings in Cost of Meeting Demand (million US$)	9.5	13.5	23.5	31.2	37.8
OPEX (millions US$ per year)	3.7	5.6	11.2	14.9	22.3
CAPEX (millions US$ per year)	2.5	3.8	7.6	10.2	15.3
Annual Storage Benefit (million US$)	3.2	4.1	4.7	3.0	0.2
Annual Storage Benefit per Installed Capacity (million US$/$Mm^3$)	0.032	0.027	0.016	0.007	0.0004
Annual Storage Benefit per Total CAPEX	0.042	0.036	0.020	0.009	0.001

Table 5.6: Economic Benefit in "Salt Caverns" over Installed Storage Capacity

derground gas storage activity for market development (see (49)), we propose that the development of gas stocking activity take place under the governmental initiative.

Following a Public Bidding Round process for qualifying and evaluating potential investors interested in the storage project, the energy sector government agents invest their best efforts in the technical and geological study phase for the location determination of the infrastructure, in partnership with the winning investor candidate. With these results, an economic study of the project would be performed, which proposes the use of the analytical tool developed here, incorporating the necessary technical details, coupled with the operation model of the electricity sector, in order to increase the level of predictability of the model.

Then, after defining the most beneficial project in order to reduce the cost of gas supply and optimize the security of supply, the process of contracting firm gas storage capacity would take place through a Public Hiring Round, coordinated by the regulator agent, in the Brazilian case, the ANP, where

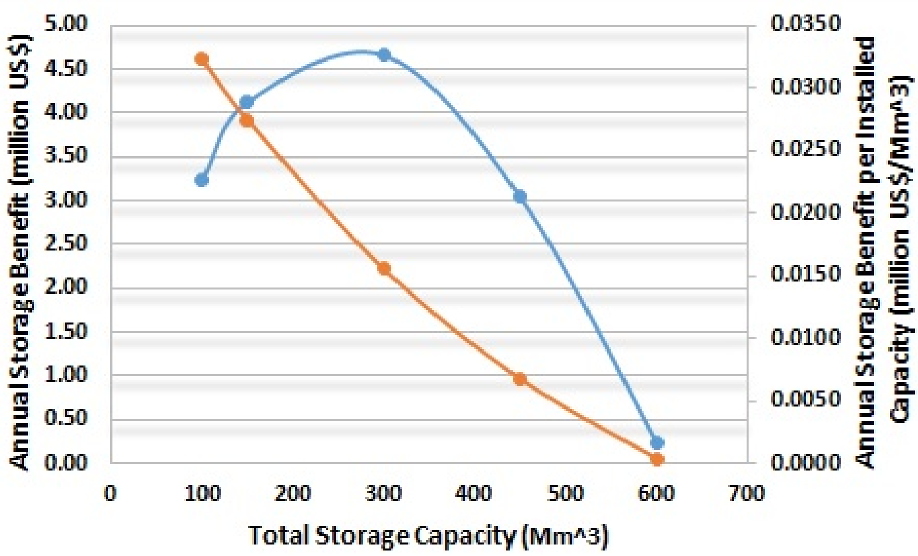

Figure 5.7: Economic Benefit per Installed Capacity for the "Salt Caverns" case

agents interested in hiring storage capacity would qualify and sign five-year contracts, with rights and obligations previously determined in this process.

Given that the change in storage level is a necessary flexibility inherent to the system, so as not to leave the fixed costs of the storage capacity to the investor, it would be prudent for the storage capacity contractor to bear the related cost, not only its expectation of average use, but its need for flexibility, where the right of use, and also of partial or full assignment to another agent, would be guaranteed in contract, as long as the new agent has at least the same conditions of financial guarantee of the principal.

Defined the required capacity to be contracted, it is proposes that the contracting agent has fixed monthly costs, which aim to fund the investment, fixed operating costs and return of the investor. A variable cost related to the actual utilization of contracted capacity, on a daily basis, would be add, aiming to remunerate variable operating costs. In addition, from the whole volume of injected and withdrawn gas would be deducted the System Usage Gas (GUS), which refers to the gas consumed by compressors in the process of gas injecting and withdrawal from storage, about 1% of the gas moved.

The beginning of the investment would occur after the signing of the contracts, which would have as a precedent condition for validity the requirements, provided in the Public Hiring Round Notice. Starting in the second half of the first year of operation, annual rounds would take place to offer capacity for five years ahead, where capacity offered for the first four years would be limited to the remaining capacities and for the fifth year for total storage capacity. It is believed that this mechanism would not only make the

Risk Aversion Level	$\lambda = 0.1$, $\alpha = 0.5$	$\lambda = 0.3$, $\alpha = 0.5$	$\lambda = 0.5$, $\alpha = 0.5$	$\lambda = 0.7$, $\alpha = 0.5$
Annual Savings in Cost of Meeting Demand (million US$)	47.7	44.9	41.1	37.4
OPEX (millions US$ per year)	22.3			
CAPEX (millions US$ per year)	2.1			
Annual Storage Benefit (million US$)	23.3	20.6	16.7	13.0

Table 5.7: Risk Aversion Level Storage Benefit Sensitivity Analysis - capacity of 1,200 Mm^3 in depleted fields

stockholders more secure and predictable in their investments but could also signal to the regulatory agent and the market they need to expand installed storage capacity as when demand in Public Hiring Round began to outstrip supply.

Processing the proposal based on the optimal storage indicated in the case study conducted here, it is proposed to invest in storage in depleted fields, with a total useful capacity of 1,200 Mm^3 distributed in the Brazilian interconnected system, with technical structure and investment in compressors that allows a gas withdrawal flow at a rate of 2.5% of stored stored gas.

In a simplified way, when projecting a cash flow where in the first year the total capital investment of US$ 62.5 million is disbursed, and over 30 years of useful life the asset obtains revenue equal to the annual savings provided to the interconnected gas system, in the amount of US$ 41.1 million, in addition to consider a fixed operating cost of US$ 22.3 million, not considering tax impact, amortization of the asset, and nor financial leverage, if we consider a 30% discount rate, the net present value of the project would still be positive. Compared to other investments in the energy sector, such as electricity generation projects (1), the expected return on storage investment is attractive, given the assumptions used here.

Synthesizing the tariff proposal, would be offered via Public Procurement Round total storage capacity equal to the average storage utilization in the 60 analyzed periods, which was equal to 800 Mm^3, plus the fixed flexibility costs related to the incremental capacity of 400 Mm^3. That is, the agent concerned would contract a particular volume of capacity and be entitled to the flexibility of up to 50%, additionally disbursing only the variable cost related to the volume of gas storage during the month.

Table 5.8 presents the cost structure of the storage service for each contracted capacity level. As can be seen, an agent interested in contracting of 100 Mm^3 of storage capacity, and a flexibility to store up to 150 Mm^3, would have a fixed monthly cost of US$ 0.43 million and a variable cost of $US\$$ 465.00 for each million cubic meters stocked over the month or, converting to million british thermal units (MBtu), variable cost of $US\$$ 0.0125 for million british thermal units storage over a month.

Contracted Storage Capacity (Mm^3)	50	100	400	800
Flexibility (Mm^3)	25	50	200	400
Monthly Fixed Cost (million US$)	0.21	0.43	1.71	3.43
Monthly Variable Cost (US$/$Mm^3$/month)	465.00			

Table 5.8: Storage Cost Structure for Case Study

Thinking of a combined-cycle natural gas thermoelectric of 1.0 gigawatt of installed capacity, which consumes $4Mm^3$ per day, and is dispatched for six months throughout the year, would result in a total of 720 Mm^3 per year. If contract a volume of 100 Mm^3 reflects the need for this thermoelectric plant, we may think that, in terms of fixed cost, the storage cost would result in an additional cost of US$ 0.19 per million British thermal units which, in conjunction with the ability to purchase competitively priced LNG could increase the competitiveness of the project.

6 Conclusions

Given the significant potential volume of pre-salt gas coming into production in the next years, associated with oil production, and given that Petrobras will no longer assume the role as the only guarantor of gas in the country, considering its divestment initiative in the gas sector, there is the need to insert tools aimed at flexibility and guarantee of energy security in Brazil.

In this thesis, presented here in parts, the author aimed to promote the diagnosis of the obstacles to the development of UNGS in Brazil, in addition to identifying and evaluating the potential applications that such activity could have in the Brazilian natural gas and electricity sectors. The diagnosis made and the positive results that the initial economic studies have presented in the literature indicated the need for a more robust analytical tool to support the sector with a quantitative analysis of the benefits that the UNGS activity could provide to the natural gas industry.

A stochastic dynamic programming model was developed for the mid/long term planning of the minimum cost gas supply under operational, inventory, and market constraints. The model determines the optimal policy of each type of supply together with the possibility of storing gas in different structures of storage, in order to supply the demand for natural gas.

The solution methodology used is SDDP, where the developed mathematical model considered the natural gas thermoelectric demand and LNG price as stochastic variables. In this point, the thesis's first main contribution was the development of a long/medium term planning model based on the SDDP methodology to obtain monthly decisions on natural gas amounts to be purchased from each available supply, considering the underground gas storage activity.

Although the temporal independence in the LNG price variable is assumed, having the model to adopt a discrete distribution, a discrete Markov state process was assumed in the SDDP structure to capture the temporal dependence of the thermoelectric demand. The use of a Markov chain to approximate the dynamics of the thermoelectric demand was the thesis's second main contribution.

Based on the 2,000 set of thermoelectric demand scenarios generated from official electric power sector planning model, Newave, the K-means algorithm was used to part them into Markov states. This itegration between gas purchasing decisions and thermoelectric dispatch decisions resulting from the electric sector planning model was the thesis's third main contribution.

Also, in order to consider a level of risk aversion in the optimization process, a time-consistent CVaR-based dynamic risk measure is considered in the construction of the objective function.

In order to assess the benefit that the natural gas storage activity would have for the Brazilian system, consisting of the thesis's fourth main contribution, the optimal policy for the supply of natural gas in the Brazilian market is analyzed for a period of 60 months using data regarding the Brazilian gas and electric power sectors, considering the possibility of gas storage in underground reservoirs distributed in the different geographic regions of the country.

The application of the model in "With Storage" and "Without Storage" cases allowed us to conclude that the possibility of storage enables the system to reduce its exposure to high prices by choosing to use stored gas, while at competitive LNG prices, system agents can gain economic advantages by not only meeting current demand but also storing the fuel.

A significant level of storage usage is observed throughout the period of analysis, especially since 2021. Still, a high percentage of Bolivian gas purchases are observed when compared to the maximum supply capacity, either for immediate use or storage, since the price of Bolivian gas is, most of the time, the lowest compared to the other supply sources.

It is worth mentioning that, currently, the country has chosen to import a level that is relatively lower than the maximum capacity of the contracts, prioritizing the use of domestically produced gas, associated mainly with oil production, which makes management difficult. At this point, by introducing operational flexibility into the system, storage would allow the optimization of the system, without the need to reduce the production flow of the natural gas fields, which would be extremely important for the country face to the expected increase in production of gas in the pre-salt areas.

Comparing the cases with and without storage, it is observed that the use of storage provides not only lower levels of the marginal cost of meeting the demand but also higher stability in this marginal cost of gas. That is, the storage could act as a tool for regularizing natural gas prices in the market.

Comparing the OPEX and CAPEX costs of investments in storage infrastructure in depleted fields and salt caverns with the savings provided by storage in the supply operation, it is possible to observe the economic benefit of storage. The analysis does not exhaust all the possibilities and combinations of storage that the model could simulate, but it can be explored to support the decision about an optimum capacity that maximizes the economic benefit of storage activity for a specific gas market, that is, providing more considerable savings for the gas supply.

Also, in observing the sensitivity of the storage benefit to the degree of risk aversion of the operational policy, it was possible to observe that even considering a highly risk-averse investor, the economy that gas storage provides outweighs the costs.

Finally, consisting of the thesis's fifth main contribution, the study suggests a preliminary proposal of how the development of underground gas storage activity could take place in the Brazilian gas market. Given that the investment is capital intensive and with the considerable associated risk inherent mainly in the unpredictability of thermoelectric demand, it is proposed that the development of gas storage activity take place under the governmental initiative, where a process of Public Bidding Round followed by Public Hiring Round could be explored.

Therefore, it is possible to conclude that the underground natural gas storage is important for Brazil, allowing to mitigate the dependence of LNG prices in the international market, supporting the physical balance of gas in the short-term market, providing regularization of energetic prices in the country, in addition to promoting energy security, since the country is dependent on gas imports.

Given the significant impact that the level of thermoelectric demand has on the policy of gas supply decisions, we stress here the importance of greater integration between the operating models of the electricity sector and the gas sector.

Considering the simplifications of the model, given that the model considers no delay between the time when LNG is purchased, and it is available for consumption, where this delay can even exceed 30 days, the potential benefit of storage activity is expected to be even higher than that estimated in this study.

Furthermore, this study is aimed at analyzing the energy dynamics of natural gas and therefore, no restrictions on time dispatch nor the nonlinear dynamics of pipeline constraints were considered. Thus, it is believed that short-term benefits also exist, on top of those found.

Regarding future studies, it is proposed that, based on the modeling developed here, technical and logistic constraints be incorporated into the model, conditioned to the analysis of potential specific regions where gas storage infrastructures can be made possible. Besides, the business model under government initiative for the development of the activity could be explored too.

In addition, the model of operation developed could be implemented to determinate an expansion planning, where it would be possible to give the optimum locational signal for the implantation of the first storage facilities, as well as the type of structure and its useful gas, optimal withdrawal and injection capacities to meet the country's need.

Therefore concluding with the thesis's sixth main contribution, it is believed that the model developed here can be used as an analytical tool, allowing an interested agent to assess the impact that specific storage structures would have on the market, supporting the development of a business plan - not only in the Brazilian market but also in other countries where supply flexibility could improve operational flow and financial costs.

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Appendices

A
Pseudo-code for the SDDP Algorithm

set iter $= 0$
while iter $\leq max_iteration$
do
  Forward Pass
  set $\boldsymbol{v} = \boldsymbol{v}_0, \mathcal{N} = [\ ]$
  sample *j* from $\mathcal{J}_t$ according to the transition matrix $\mathcal{P}_t$
  while $t < \mathcal{T}$ **do**
    sample $(\boldsymbol{d}_t^j, p_t^j)$
    solve $Q_t^j(\boldsymbol{v}, \boldsymbol{d}_t, p_t)$
    append $(j, \boldsymbol{v}_t^j)$ to the list $\mathcal{N}$
    set $\boldsymbol{v} = \boldsymbol{v}_t^j$
   sample new *j* from $\mathcal{K}_{t+1}$ according to the transition matrix $\mathcal{P}_t$
  end
  Backward Pass
  for$(j, \boldsymbol{v}_t^j)$ in reverse $(\mathcal{N})$**do**
   for $j \in \mathcal{K}_{t+1}$ **do**
    for $(\boldsymbol{d}_t^j, p_t^j)$ to all $j \in \mathcal{K}$**do**
     solve $Q_t^j(\boldsymbol{v}, \boldsymbol{d}_t, p_t)$
     set $Q_t^j(iter)(\boldsymbol{d}_t, p_t)$ to the optimal objective value
     set $(\boldsymbol{\pi})^j_{t,\boldsymbol{d}_t^j,p_t^j}$ (iter) to the value of $\boldsymbol{\pi}^j$ in the optimal solution
    end
   end
   compute $l(\boldsymbol{v}_t^j)$
   update $\hat{\mathcal{Q}}_t^j(\boldsymbol{v}_{t-1})$ as in (3-14)
  end
  increment K
end

B
Marginal cost of gas demand supply

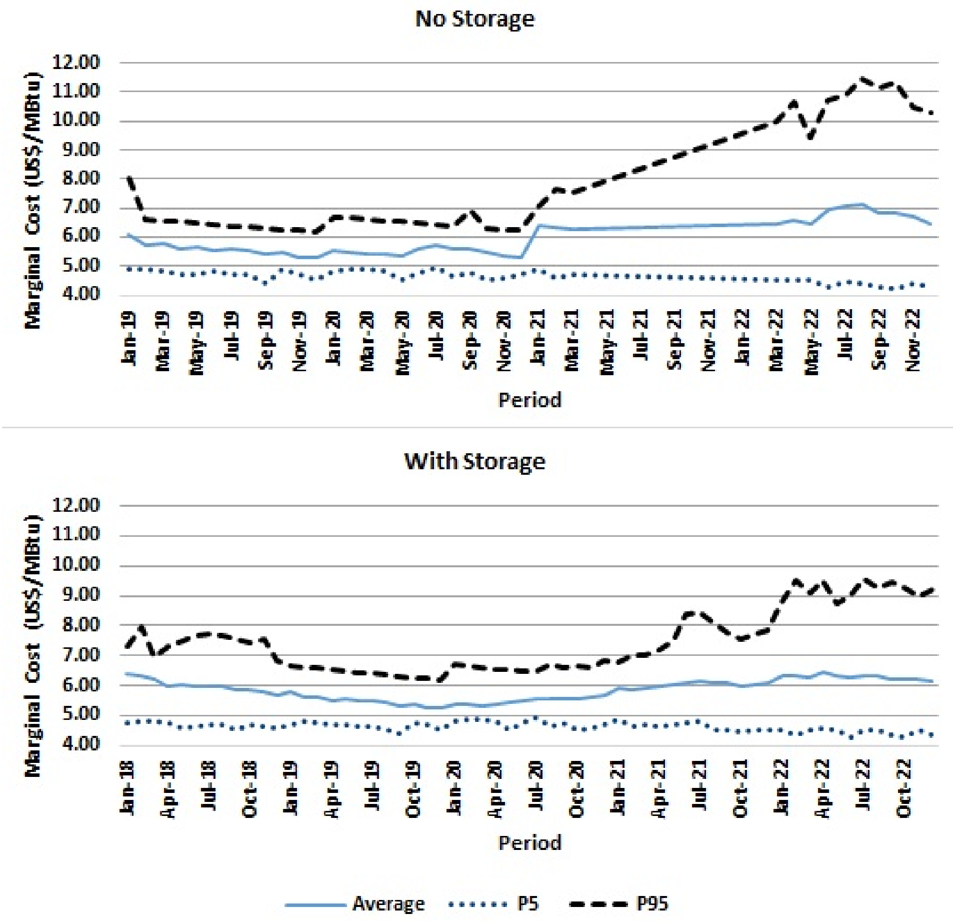

Figure B.1: Marginal cost of gas demand supply - South

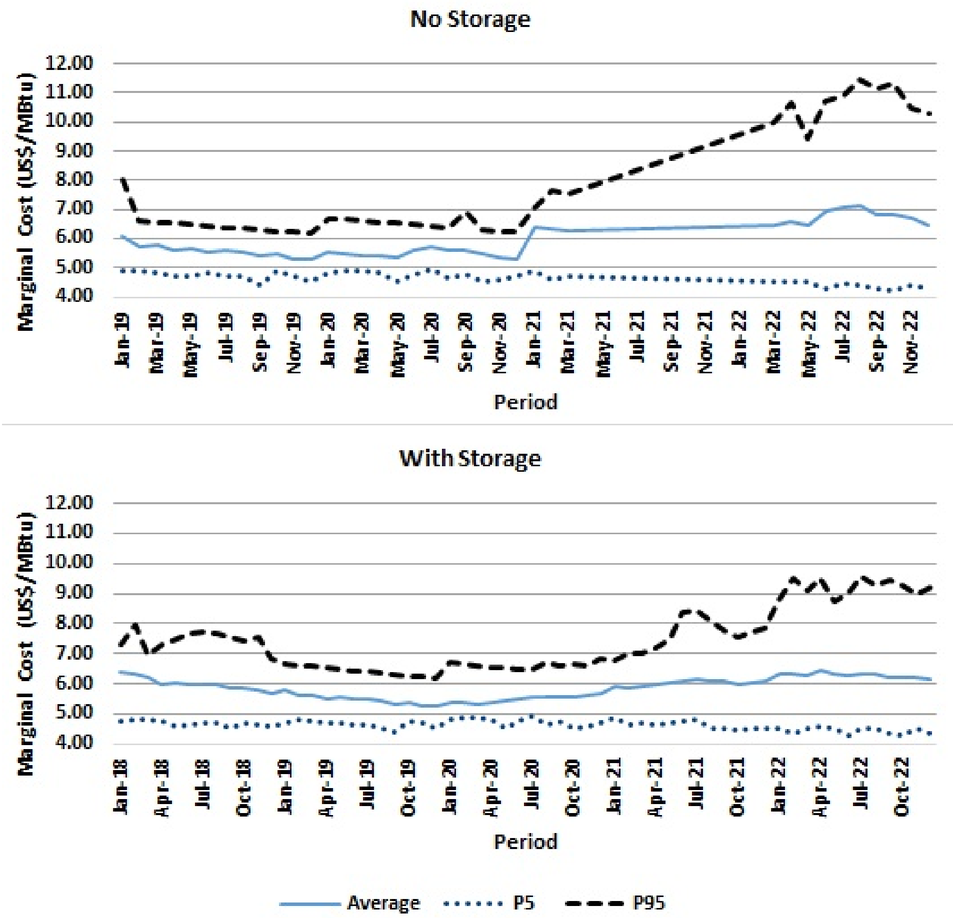

Figure B.2: Marginal cost of gas demand supply - Northeast

C
Variation of the Marginal Cost of Supply to the Natural Gas Demand

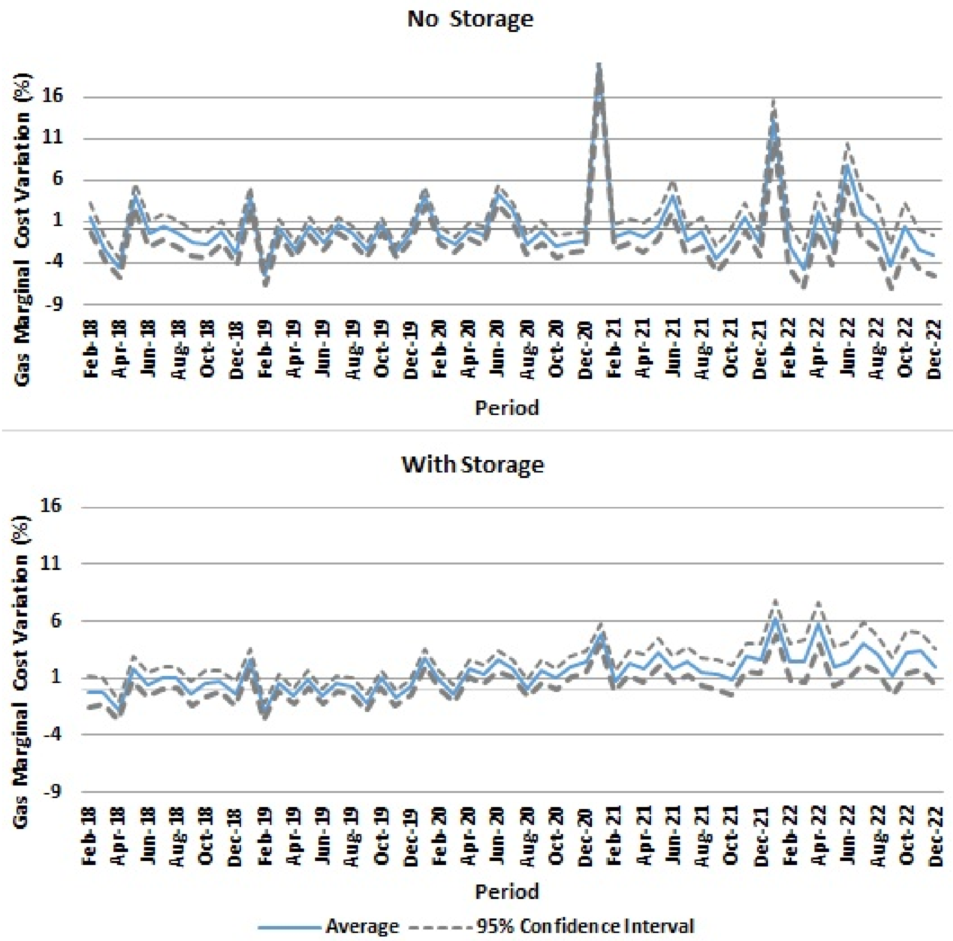

Figure C.1: Monthly Variation of the Marginal Cost of Supply to the Natural Gas Demand - South

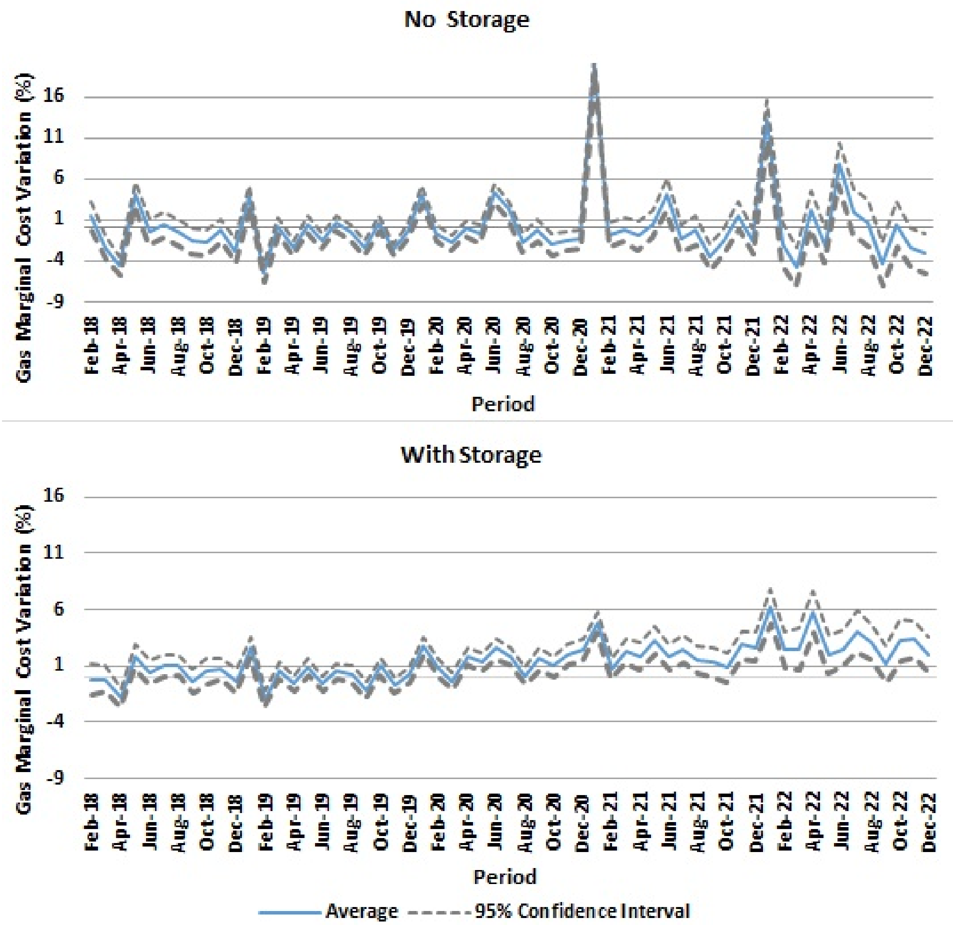

Figure C.2: Monthly Variation of the Marginal Cost of Supply to the Natural Gas Demand - Northeast