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OPTIMAL TAKE-OR-PAY LNG SUPPLY FOR HYDROTHERMAL ELECTRICITY SYSTEMS

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RESUMEN DE LA TESIS PARA OPTAR AL GRADO DE:
MAGÍSTER EN CIENCIAS DE LA INGENIERÍA
MENCIÓN ELÉCTRICA
Y AL TITULO DE: INGENIERO CIVIL ELÉCTRICO.
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SUMINISTRO ÓPTIMO DE GNL CON CONTRATOS TAKE-OR-PAY PARA SISTEMAS HIDROTÉRMICOS

Importar gas natural licuado (GNL) a través de contratos Take-or-Pay (ToP) para la generación de electricidad en sistemas hidrotérmicos es una tarea compleja ya que la demanda de gas es altamente incierta dada la variabilidad de las condiciones hídricas. Esto es agravado por la dificultad de transar *ex-post* los excedentes/déficits de GNL en un mercado secundario (p. ej. cuando el GNL importado no basta para satisfacer la demanda en condiciones hídricas húmedas), el cual es, muchas veces, muy reducido.

En este contexto, la presente tesis propone un modelo de optimización estocástica de minimización de costos y aversión al riesgo que permite determinar portafolios óptimos de contratos de suministro de GNL para el sistema eléctrico nacional (desde la perspectiva del planificador social). Este portafolio incluye contratos con varios grados de flexibilidad e interacciones con el mercado spot. A través de varios casos de estudio basados en el principal Sistema eléctrico Chileno (*SIC*) se conluyó lo siguiente:

(i) es óptimo, desde una perspectiva neutral al riesgo, importar GNL para una condición hídrica “promedio”. Esto implica que el GNL contratado (a través de contratos ToP) no será suficiente en condiciones hídricas secas donde se necesitarán centrales más costosas (p. ej. unidades diésel) para suplir la demanda eléctrica, mientras que en condiciones húmedas las centrales a gas desplazarán generación menos costosa (p. ej. unidades a carbón).

(ii) es óptimo, desde una perspectiva de aversión al riesgo, importar GNL para una condición hídrica “seca”. Esto implica que el planificador social aumentará las importaciones de GNL para proteger al sistema de sobrecostos operacionales en condiciones secas. Esta decisión sistémica es fundamentalmente diferente a la tomada por compañías de generación en un ambiente de mercado, quienes se protegen del riesgo disminuyendo las importaciones de GNL.

(iii) contratos ToP con cláusulas flexibles pueden soportar un aumento en los volúmenes importados de GNL acompañado de una reducción de costos operacionales del sistema.

(iv) los requerimientos óptimos de GNL para el SIC son cercanos a 6 TWh por año, lo cual es casi el doble de los 3.47 TWh que se importan actualmente. Este monto (6 TWh) puede aumentarse si (i) el planificador social fuera averso al riesgo, protegiendo a los consumidores de sobrecostos producidos por sequías, y/o (ii) se modelaran contratos más flexibles.

(v) aumentar los volúmenes importados de GNL a 6 TWh por año (desde los 3.47 TWh actuales) disminuirá los costos esperados del sistema en un 4.1% y reducirá los pagos de la demanda en un 32.1%. Esta reducción desproporcionada en los pagos de la demanda es debido a que parte del excedente del productor es transferido al consumidor gracias a una disminución de los costos marginales del sistema.

(vi) es posible diseñar un mecanismo de pago (i.e. *price uplifts*) donde la demanda cubra parcialmente los costos fijos de los generadores (cuando los precios spot no cubran los costos de GNL) de manera de compartir eficientemente entre el riesgo generadores y demanda. Esto sería beneficioso para ambos ya que estarían en una mejor posición económica que la actual.

A pesar que los casos de estudio están enfocados en el mercado chileno, creemos que esto es de interés para otros sistemas hidrotérmicos de América Latina y África, que enfrentan (o lo harán en el futuro cercano) problemas similares asociados al suministro de GNL. Por lo tanto esta investigación puede ser crítica para entender los costos y beneficios de las decisiones relacionadas con la importación de GNL y, de esta manera, sostener un desarrollo y una operación de sistemas eléctricos más eficiente y segura. Este trabajo es, a su vez, oportuno y puede servir para aprovechar los bajos precios en el mercado internacional del GNL que se observan actualmente.

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Importing liquefied natural gas (LNG) through take-or-pay (ToP) contracts for electricity generation is significantly challenging in hydrothermal systems since gas demand from the electricity sector is highly uncertain due to the historical volatile behavior associated with hydro conditions. This is compounded by the difficulties to undertake *ex-post* trading of surpluses/shortfalls of LNG in a secondary market (e.g. when LNG imported does not suffice during dryer hydro conditions), which is –in many cases– significantly limited.

In this context, this thesis proposes a cost-minimization, risk-averse stochastic optimization model that allows us to find optimum portfolios of LNG supply contracts for the national power system (from the social planner's perspective). This portfolio includes contracts with various degrees of flexibility and interactions with the spot market. Through several case studies based on the Chilean power system, we found that:

(i) it is optimal, from a risk-neutral, cost-minimization perspective, to import natural gas for an "average" hydro condition. This implies that contracted natural gas (through ToP contracts) will not suffice under dryer conditions where more costly plants (e.g. diesel units) will be needed to supply electricity demand and that gas plants will displace less costly plants (e.g. coal units) during wetter hydro conditions.

(ii) it is optimal, from a risk-averse, cost-minimization perspective, to import natural gas for a "dryer" hydro condition. This implies that a social planner will increase LNG imports in order to hedge the system against operational cost spikes during dry conditions. This system-wide decision is fundamentally different to that taken in a market environment where generation companies (e.g. gas plant owners) tend to hedge risk exposure by under-importing LNG.

(iii) flexible clauses in ToP contracts can support increased LNG import volumes and a reduction in system operating costs.

(iv) optimal LNG system requirements for the Chilean main electricity system are circa 6 TWh per year which is almost twice the amount of 3.47 TWh that is currently being imported. This amount (6 TWh per year) can be increased if (i) the social planner were risk averse to protect consumers against higher costs driven by droughts, and/or (ii) more flexible contracts are modelled.

(v) increasing the import volumes to 6 TWh per year (from current 3.47 TWh) will decrease expected system costs by 4.1% and reduce demand payments by 32.1%. This disproportional reduction in demand payments is observed since part of producer's surplus is transferred to the consumer's surplus as system marginal costs decrease.

(vi) it is possible to design a payment mechanism (i.e. price uplifts) where demand can partially cover gas generators' fixed costs (when spot prices cannot cover LNG costs) so as to efficiently share risks between gas generators and demand, and this will be beneficial for both since they will be in a better economical position compared to current situation.

Although the case studies in this thesis are focused on the Chilean market, we believe that this is of interest to further hydrothermal systems in Latin America and Africa, which face (or will face in the near future) similar problems associated with LNG supply. Hence this research can be critical to understand the costs and benefits of various decisions associated with LNG imports and thus support a more efficient and risk-free operation and development of future electricity systems. This framework is also timely and can serve to take advantage of the present lower prices in the international LNG market.

A mis padres

y a mis abuelos

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GLOSSARY

ToP	Take-or-Pay
Take-or-Pay Generator	Generator with LNG supply with Take-or-Pay contracts
M$	Million US Dollar
mmBtu	Million British Thermal Units
SIC	Sistema Interconectado Central (Central Interconnected System)
SING	Sistema Interconectado del Norte Grande (Great North Interconnected System)

SETS

Ω_G	Set of Generators
$\Omega_{G(gnl)}$	Set of Generators with LNG supply
$\Omega_{G(n)}$	Set of Generators connected to the electrical node n
Ω_{ToP}	Set of Take-or-Pay Contracts
$\Omega_{ToP(gt)}$	Set of Take-or-Pay Contracts with delivery point in the Gas Tank gt
Ω_{Spot}	Set of Spot Contracts
Ω_{Tank}	Set of Gas Tanks (regasification terminal)
Ω_N	Set of Gas Nodes
Ω_{GC}	Set of Gas Connections (Pipelines)
$\Omega_{GC(gt)}$	Set of Gas Connections with initial node in Gas Tank gt
$\Omega_{GC(n^+)}$	Set of Gas Connections with initial node in Gas Node n
$\Omega_{GC(n^-)}$	Set of Gas Connections with terminal node in Gas Node n
$\Omega_{GC(g)}$	Set of Gas Connections with terminal node in Generator g
Ω_S	Set of Scenarios (Hydrological)
Ω_T	Set of Stages (Time period)
$\Omega_{B(t)}$	Set of Blocks of Stage t
Ω_D	Set of Dams
Ω_L	Set of Transmission Lines
Ω_N	Set of Electrical Nodes
$\Omega_{L(n^+)}$	Set of Transmission Lines with initial node in Electrical Node n
$\Omega_{L(n^-)}$	Set of Transmission Lines with terminal node in Electrical Node n
$\Omega_{HC(g/d^+)}$	Set of Hydro Connections that end at Hydro generator g or Dam d
$\Omega_{HC(g/d^-)}$	Set of Hydro Connections that start at Hydro generator g or Dam d

ELEMENTS	
g	Generator
c	Gas Contract (Take-or-Pay or Spot)
gt	Gas Tank
n	Gas Node
gc	Gas Connection
s	Scenario
t	Stage
b	Block
n	Electrical Node
l	Transmission line
$n^{+}(l)$	Initial node of line l
$n^{-}(l)$	Terminal node of line l
d	Dam
hc	Hydro connection
$hc^{+}(g/d)$	Hydro connection with ending point at generator g or dam d
$hc^{-}(g/d)$	Hydro connection with starting point at generator g or dam d

PARAMETERS	
h_g	Heat Rate of Generator g [m^3/MWh]
$pmax_g$	Max Power of Generator g [MW]
β_g	Variable Cost of Generator g [US$/MW]
γ_c^{ToP}	Price of Take-or-Pay Contract c [US$/$m^3$]
β_c^{ToP}	Equivalent price of Take-or-Pay Contract c [US$/MWh]
γ_c^{Spot}	Price of Spot Contract c [US$/$m^3$]
β_c^{Spot}	Equivalent Price of Spot Contract c [US$/MWh]
$vmin_{gt/d}$	Minimum Volume of Gas Tank gt or Dam d
$vmax_{gt/d}$	Maximum Volume of Gas Tank gt or Dam d
$vini_{gt/d}$	Initial Volume of Gas Tank gt or Dam d
$vfin_{gt/d}$	Final Volume of Gas Tank gt or Dam d
Y_c	Minimum Volume fraction of Take-or-Pay Contract c [0 to 1]
X_c	Penalization fraction of Take-or-Pay Contract c [0 to 1]
ρ_s	Probability of Scenario s
Δ_t	Duration of Stage (time period) t [h]
$\Delta_{t,b}$	Duration of Block b, of Stage t [h]
E_c	Contracted Energy [MWh]
α	C-VaR confidence level [0 to 1]
ω	Risk Aversion of System Operator [0 a 1]
r_l	Resistance of Transmission Line l [Ohm]
x_l	Reactance of Transmission Line l [Ohm]
$pfmax_l$	Maximum transfer capacity of Transmission Line l [MW]
$Dem_{n,s,t,b}$	Load at node n [MW]
$Af_{hc,s,t,b}$	Affluent of hydro connection hc, at Scenario s, Stage t, Block b [m^3/s]
η_g	Efficiency of Hydro generator g [MW/(m^3/s)]
$K_d, K1_d$	Polinomial factors for filtrated flow approximation of dam d [m^3/s], [1/s]

η_g	Efficiency of Hydro generator g [MW/(m^3/s)]
VARIABLES	
$P_{g,s,t,b}$	Generated Power by Generator g, at Scenario s, Stage t, Block b [MW]
V_c^{ToP}	LNG Contracted Volume with Take-or-Pay Contract c [m^3]
$V_{c,s,t}^{Spot}$	LNG Contracted Volume at Spot Market c, at Scenario s, Stage t [m^3]
$D_{c,s,t}$	LNG Delivered Volume of Take-or-Pay Contract c, at Scenario s, Stage t [m^3]
$V_{gt,s,t,b}$	Volume of Gas Tank gt at Scenario s, Stage t, Block b [m^3]
$F_{gc,t,b,s}$	Gas Flow through Gas Connection gc, at Scenario s, Stage t, Block b [m^3/h]
V^+	Auxiliary variable for Minimum Volume Take-or-Pay Contract formulation
C_s	System cost (operational + LNG supply) at Scenario s
VaR	Auxiliary Variable (Value at Risk) for C-VaR formulation
$CVaR$	Auxiliary Variable (C-VaR) for C-VaR formulation
Z_s	Auxiliary Variable (associated to Scenario s) for C-VaR formulation
$pf_{l,s,t,b}$	Power flow through Transmission Line l [MW]
$Loss_{l,s,t,b}$	Transmission Losses in Transmission Line l [MW]
$\theta_{n,s,t,b}$	Angle of electrical node n [rad]
$QT_{hc^-(g),s,t,b}$	Turbined flow at generator g [m^3/s]
$QS_{hc^-(g),s,t,b}$	Spilled flow at generator g [m^3/s]
$QR_{hc^-(d),s,t,b}$	Released flow of dam d [m^3/s]
$QF_{hc^-(d),s,t,b}$	Filtrated flow of dam d [m^3/s]
$QOvf_{hc^-(d),s,t,b}$	Overflow of dam d [m^3/s]
$QE_{hc,s,tb}$	Extracted flow of dam d [m^3/s]
$Vol_{d,s,t}$	Stored volume at dam d [m^3]

1 INTRODUCTION

1.1 Motivation

1.1.1 The situation in Chile

Since the beginning of the decade high electricity costs have presented significant challenges for Chile. Moreover, a report published by Centro de Estudios Públicos (2014) that analyzed quantitatively the economic effect of sustained raises in the electricity costs, pointed out that such effects are "a serious constraint to the country's growth and development" [1].

The Chilean Government has explicitly acknowledged this situation and its Agenda de Energía, published in 2014, centered the focus on "the reduction of electricity prices, improving competition and diversification of the energy market". Among the measures, the *promotion of the use of LNG in the electrical power generation instead of diesel* was envisaged as a key action [2].

In this context, the Energy Centre of the Physical and Mathematical Sciences Faculty of the University of Chile (CE-FCFM) developed the study "Economic Analysis of the Electrical Dispatch of Generators with LNG Take-or-Pay Supply Contracts" [3]. This study demonstrated that there are two major sources of inefficiencies in the Chilean power market with respect to the LNG generation:

1) Problems in the system operation with Take-or-Pay supply contracts when using the declared variable cost scheme, which fundamentally ignores fixed costs.
2) Under-utilization of the generation capacities of Natural Gas (NG) fired generators, as shown in Figure 1, which constantly generate power through diesel.

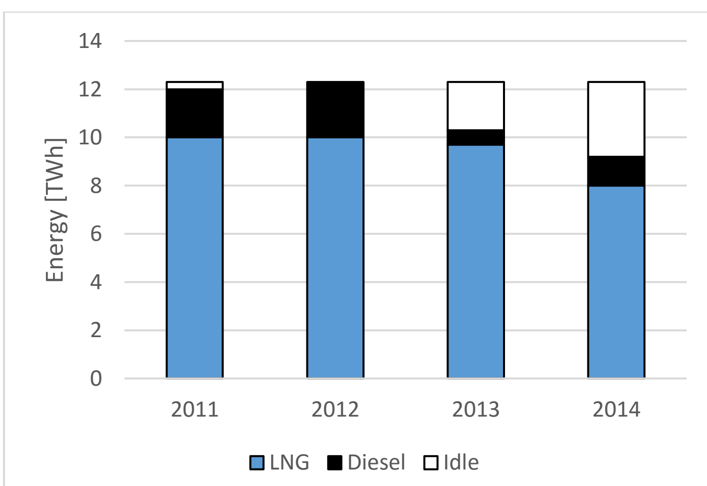

Figure 1: Annual generated and idle energy [TWh] (with respect to 2012) by the dual-fuel generators of the Chilean Interconnected Central System *[3]*.

This thesis contributes to the second point above and develops a stochastic optimization model to determine actual **global, system requirements** of LNG for the electricity system. This is a challenging task, considering the variability of LNG demand due to the **hydrological uncertainty** that undergo hydro-thermal power systems like that in Chile. Furthermore, the proposed methodology determines an **optimal portfolio** of LNG supply through Take-or-Pay contracts with various degrees of flexibility along with the LNG requirements for the power system, allowing us to analyze the trade-offs between prices and flexibility in Take-or-Pay contracts (long-term take-or-pay contracts can provide more stable prices at the expense of supply flexibility).

1.1.2 The situation in the world

Chile's situation is particular due to the energy dependency of the country, as it lacks fossil fuel resources, and its remote and isolated condition that compounds the possibility of a liquid secondary market where to trade surpluses or shortfalls of natural gas. Nonetheless, interest in the aforementioned problem is not confined to Chile. We believe that the problems studied in this thesis are of interest to further Latin American and Sub-Saharan African power systems:

Latin America:

Latin American power systems are predominantly hydrothermal and face significant uncertainty in its hydroelectricity generation, which is exposed to extreme events such as El Niño and La Niña. Recent droughts have put great stress in electricity systems, such as in Brazil (2015) [4], Colombia (2015-2016) [5], Panama (2013) [6] and Costa Rica (2015) [7], rising electricity prices and even forcing energy conservation measures to avoid blackouts.

Moreover, several countries have important gas generation capacities but are net importers of natural gas for their electricity systems, or will be in the near future. Argentina, Colombia, Brazil, and Central America's *Mercado Eléctrico Regional* have LNG regasification terminals or projects being commissioned in the upcoming years, with long-term supply contracts already signed.

Sub-Saharan Africa

Sub-Saharan electricity systems are facing significant challenges that come from underdevelopment. Its main problem is the low electrification rates: over 50% of the population lacks access to electricity, which is a huge constraint to its social and economic development. In particular, the region faces challenges in developing and maintaining infrastructure (generation and transmission), assuring supply reliability, reducing high electricity tariffs and establishing regulatory frameworks [8] [9].

Total grid-connected installed capacity is only 90 GW, with 46 GW only in South Africa. 45% of the region's generation capacity is coal-based, mainly located in South Africa, 22% hydro, 17% oil and 14% natural gas, located mainly in Nigeria.

Hydropower accounts for one-fifth of today's power supply in Sub-Saharan Africa, but less than 10% of the estimated technical potential has been utilized. With greater regional cooperation new projects have arisen in Democratic Republic of Congo, Ethiopia and Mozambique, which are expected to reduce the share of oil-fired power [9].

Natural gas production is on the rise in the region, as more efficient practices are being implemented to reduce gas flaring, and exploration has led to many oil and gas reserves to be found. Nearly 30% of the world natural gas discoveries in the last 5 years have been made in Africa. Major gas producers in the region are West African countries of Nigeria and Angola, both of them exporters of LNG, with new LNG export projects appearing East Coast countries such as Mozambique and Tanzania [9].

Domestic natural gas markets are virtually nonexistent in many countries, and there are efforts in countries that produce NG, such as Mozambique and Tanzania, to promote them. Among those countries, it is of particular interest to us the case of Ghana, who will be the first country of the region to install a LNG regasification facility to supply part of its power plants [10], and who may be confronted to the problems studied in this thesis.

1.2 Objectives

1.2.1 General Objective

- The implementation of a risk-averse stochastic optimization model to determine the optimal portfolio of LNG supply contracts for the power system along with the system's LNG requirements.

1.2.2 Specific Objectives

- Study of the State-of-the-Art in Take-or-Pay contract in electricity systems.
- Determination of LNG requirements and associated optimal portfolio of contracts for the national electricity system.
- Analyze the current LNG import situation in Chile.

1.3 Scope

Given the proposed objectives, this research is focused on modeling LNG supply contracts for the medium and long-term. Therefore, Take-or-Pay contracts with various levels of flexibility were carefully modeled. Technical details in the electricity model were captured through DC, linearized power flow approximation, with linearized transmission losses. The hydro system uses an advanced model of multiple reservoirs and generators. Regarding the gas system, the model includes LNG storage capability constraints and LNG inflows (i.e.

LNG shipping) associated with ToP contracts. Further technical constraints associated with gas transport were neglected. Importantly, we assume that NG surplus (i.e. volumes that are not used in electricity dispatch) cannot be re-sold or used for other ends and this attempts to capture the isolated condition of the country.

Several hydrological conditions were used to capture uncertainty. Hydrological uncertainty was identified as main driver for NG demand, disregarding other factors such as fuel price variability.

Two networks were used in our analysis: (i) a small-scale study was carried out to validate the model and analyze the main trends that drive contract decision, and (ii) a large-scale study was carried out to study the current situation in Chile. In particular, our studies were focused on global LNG requirements and optimal supply portfolio with various available contracts, including purchases from the spot market.

1.4 Contributions

The main contribution of this thesis is the **systemic approach** to LNG supply decision by the development a stochastic optimization model to determine actual **global system requirements** of LNG for the electricity system. This is a challenging task, considering the variability of LNG demand due to the hydrological uncertainty that undergo hydro-thermal power systems like that in Chile. This systemic approach has not yet been fully addressed in the literature.

Second, the proposed methodology determines an **optimal portfolio** of LNG supply through Take-or-Pay contracts with various degrees of **flexibility**. Similar studies have used combinatorics or simulation methodologies, where contract flexibility would be very difficult to study. By modeling flexible contracts directly into the optimization model, our methodology allows us to study its effects on contract decision and system operation.

Third, the methodology includes a **risk-aversion** measure from a system-wide perspective in the contract decision model, which can be fundamentally different that the one from a generators perspective under current regulatory and market framework.

Finally, this thesis presents real case studies based on the Chilean main electricity system where actual effects of LNG supply through Take-or-Pay contracts are demonstrated. The conclusions obtained from this work are applicable to other hydrothermal electricity systems, such as those in Latin America and Africa.

1.5 Content

This document is structured as follows. Chapter 2 develops the theoretical background, which includes a review of LNG technology and market, covering the current situation in Chile and other countries in Latin America and Sub-Saharan Africa, and a survey of the state-of-the-art research in power market operation with Take-or-Pay contracts and portfolio optimization.

Chapter 3 explains in detail the proposed optimization model.

Chapter 4 shows results of a small-scale study used to validate the model and demonstrates its main features.

Chapter 5 presents the application of the proposed model in a large-scale electricity system representative of the Chilean main electricity system.

Finally, Chapter 6 concludes and identifies our future work.

2 THEORETICAL BACKGROUND

2.1 What is LNG?

Liquefied Natural Gas (LNG) is natural gas that has been condensed into liquid state for ease of storage and transportation. Liquefaction of natural gas can reduce its volume 600 times, and to achieve this gas is cooled to approximately -162 °C.

Like oil and coal, natural gas (NG) is a fossil fuel. This gaseous hydrocarbon is found in underground reservoirs. It can be produced alone (non-associated gas) by extraction in isolated natural gas fields, or as a by-product of oil extraction (associated gas). Additionally, it can be found in certain coal beds and in shale layers, where the gas is trapped in sedimentary rocks. Since the beginning of 2000s, shale gas has become one of the most important sources of natural gas in Canada and the United States.

Natural gas is composed mainly by methane (CH_4) and is used for domestic purposes, (such as cooking and heating), industrial ones (such as the turbine propulsion, heating, incineration and being the primary ingredient for many products such as plastic and fertilizers), electricity generation, and other ends like transportation and aviation [11].

Electricity generation with natural gas is done through the use of cogeneration, gas turbines and steam turbines. Gas turbines and steam turbines can be combined in a combined-cycle generator (CCGT) to achieve higher efficiencies. Natural gas fired generators are well suited to work as peak-load power plants and in tandem with variable generation such as wind and solar, for its high ramp rates.

Natural gas has also a high rate of hydrogen per molecule, which makes it one of the hydrocarbons with least CO_2 emissions per unit of energy produced, and thus one of the cleanest fossil sources of energy, as shown in Figure 2.

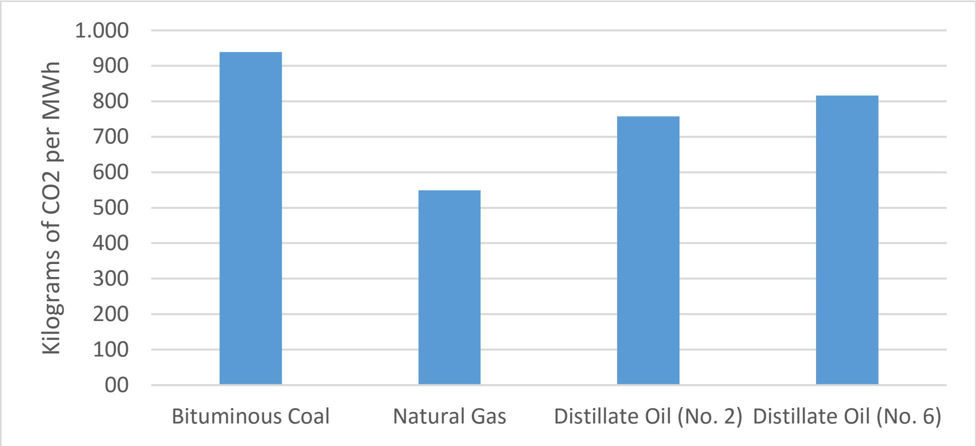

Figure 2: Kilograms of CO_2 emissions per MWh of electrical generation. *[12]*

Natural gas has to be transported from production sites to consumption regions, which can be far apart. Because of its low density, gas is not easily transported by vehicle and thus this is usually done by pipelines. However, over larger distances pipeline transportation becomes economically impractical (over around 1300 km for offshore transportation and

3500 km for onshore transportation [13]) and hence LNG is produced and transported via specially designed cryogenic carriers over sea.

2.1.1 LNG supply chain

There is a complex supply chain for LNG to reach its final customers. It can be roughly divided into six stages, each with its own market agents and regulations (Figure 3).

Figure 3: LNG supply chain

2.1.1.1 Exploration and Production

Exploration is the process of locating natural gas deposits. It is done by geologists and geophysicists who use a set of techniques to examine the structure of the earth and determine areas where it is more likely to find natural gas deposits. Among these techniques, that of onshore and offshore seismology is widely used to analyze the earth layers and determine the existence of NG deposits. To do this, artificial seismic waves are produced, using seismic trucks that produce vibrations on the floor (onshore seismology) or ships with large air guns (offshore seismology).

Extraction is done by drilling wells deep into Earth's crust to reach the natural gas or oil deposits. Different techniques are required depending on the kind of deposit where the natural gas is found, whether it is onshore or offshore, or whether it is found as associated or as non-associated gas. For example, shale gas exploitation requires hydraulic fracturing, where the porous shale rock is fractured by injecting highly pressurized liquid to create paths for the natural gas to flow out from the deposit.

After extraction is done, commercial natural gas, which is around 82% methane, has to be produced. Impurities such as water vapor, hydrogen sulfide (H_2S) and other hydrocarbons that can be obtained as by-products of natural gas (like ethane, propane or butane) are extracted from natural gas in processing plants, usually near the extraction sites. Several chemical processes are carried to achieve a "pipeline quality" natural gas.

Exploration, extraction and processing of natural gas is often carried by multinational oil and gas companies such as BP, Total, Shell or Gazprom.

2.1.1.2 Liquefaction

Production of LNG is undertaken in liquefaction plants where water vapor, CO_2 and other impurities are removed to reach a gas that is over 95% methane. Next, the purified gas is condensed by freezing it to -162 °C. Strict safety measures are required in this process to minimize risks of gas ignition.

Currently there are 35 liquefaction terminals in operation around the world [14].

2.1.1.3 Maritime Transportation

Transport of LNG is done through specially designed tank ships called LNG carriers. These ships have store LNG in reinforced tanks to prevent leaks. LNG is highly flammable and leaks are the main risks of LNG transportation and storage.

Tanks also work as giant thermoses, keeping the low temperature required for the LNG to remain in liquid state. Nevertheless, insulation is not perfect and a small amount of LNG boils during the trip. In a typical 20-day voyage, between 2 to 6 % of the LNG may be lost [15]. Carriers use the boiled LNG they transport for their own propulsion, usually in a mixture with oil. A schematic of one of these ships is shown in Figure 4.

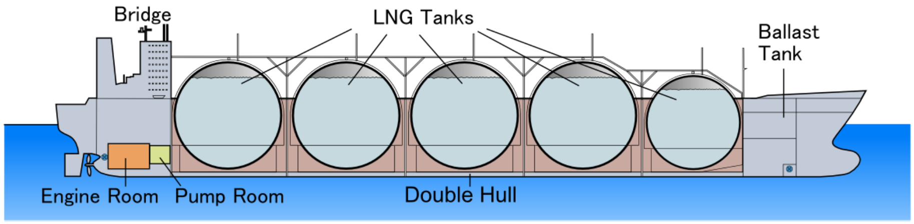

Figure 4: Schematic view of a LNG carrier (side view) *[16]*

As of end-2014, there were 373 LNG carriers in operation with over 100 to be delivered until 2017 [17].

2.1.1.4 Regasification

LNG has to be reconverted into gas to be used, which is done in regasification terminals. LNG carriers dock in these ports and are unloaded of their cargo, which is stored into onshore LNG tanks. Next, LNG is pumped to the regasification plant where it is vaporized to be injected to the gas transport and distribution networks.

One of the technologies used for vaporization of LNG is the Open Rack Vaporizer (OVR), where sea water is used to heat the LNG. The Submerged Combustion Vaporizer (SCV) is another type of vaporization technology, where pipes carrying LNG are submerged into demineralized water heated by natural gas combustion.

In the last decade, a new alternative to onshore regasification plants appeared with the Floating Storage and Regasification Units (FSRU). FSRU are LNG carriers reconverted to act as regasification plants anchored in open sea and they can be economically attractive since they accelerate commissioning of LNG projects, needing less infrastructure and reducing environmental impact. There are companies that provide charter FSRU, such as Excelerate who has 9 FSRU that can provide between 14 to 22 Mm^3/day of regasified natural gas [18].

Currently there are 111 regasification terminals in operation around the world, including 12 FSRU [14].

2.1.1.5 Transport and Distribution

Similar to the electricity system, there is a transport system and local distribution system. Transport of regasified natural gas is done through large pipelines which connect suppliers (LNG terminals, for example) with distribution companies and large industrial customers.

On the other hand, distribution companies supply medium and small consumers, such as the residential and commercial sector. Distribution can be done through a small-diameter pipeline grid, or alternative methods where no pipeline grid is built, such as truck delivery.

Transport and distribution of natural gas have to compress the natural gas to pressurize it and make it flow through the pipes. This is done in compression stations, which in large transmission grids have to be located at most 65 to 170 km apart [19].

2.1.2 Market Considerations

LNG trade started in the 60's and it developed as a local market. The Pacific basin market grew rapidly as countries like Japan and South Korea lacked energy resources and needed to import LNG. On the other hand, the Atlantic basin market had a slow growth in the 80's and beginning of the 90's due to the availability of local resources and a well-developed pipeline network, from Canada to Mexico in North America and from Russia to Spain in Europe.

As global demand for natural gas rose in the 90's and new technologies emerged, costs were reduced along the value chain, expanding LNG trading through various countries that started to export/import LNG. A spot and short-term market emerged rapidly, growing from less than 5% of traded volumes in 2000 to 27% in 2014 [17].

LNG exporters are mainly African and Asian countries, like Nigeria, Algeria, Malaysia, Indonesia and Qatar (who solely represents about one third of global supply). Nevertheless, new development in coal-bed and shale gas extraction are changing the perspectives, with US and Australia's natural gas production growing rapidly.

LNG market perspectives are favorable, as new liquefaction and regasification projects are being developed. Global supply capacities will increase up to 30% by 2018, most of which is already sold in forward contracts [20].

2.1.2.1 LNG Supply Contracts

LNG projects are capital-intensive, for instance, an export facility costs circa $10 billion. Historically LNG trade has been undertaken via long-term contracts, usually between 20 to 25 years, named Sales & Purchase Agreements (SPA). SPAs stipulate the terms and structures for pricing and the different mechanisms to ensure compliance and spread risk among the participants.

Among these clauses, we find the Take-or-Pay clause. It stipulate that a percentage of the price has to be paid whether the product is taken or not. These clauses are very common in the energy sector, particularly in the natural gas trade (through pipelines or LNG). They provide a mechanism to allocate risks among the participants of the supply chain, with the supplier assuming the *price risk* and the consumer the *quantity risk*[1] [21], and to guarantee return on investments of the expensive infrastructure.

Over the years different mechanisms or clauses have appeared to add flexibility to the strict Take-or-Pay contract. Minimum Take-or-Pay volumes are usually established in the SPAs, which can be monthly or yearly. Reported yearly minimum volumes range from 60 to 90% of the contracted volume [21] [22].

Another common clause is the Make-Up, which establishes that the compromised product that has not been consumed can be utilized in future periods. Similarly, the Carry Forward clause establishes that the product that has been consumed over the compromised level can be considered as credit for the next period.

SPAs can include maritime transport, where the seller is responsible for maritime transport (Delivery Ex Ship, DES). When maritime transport is not included in the SPA the buyer is responsible for the LNG transportation (Free-on-Board, FOB), thus the buyer needs to have its own ships or subcontract transport with independent carriers.

Long-term contracts have also pre-agreed destinations and cargo diversion is not permitted unless previously accorded between buyer and seller. Cargo diversion can be useful when the buyer does not need the product, cannot receive it for technical reasons (for example unavailable storage or regasification capacity), or when it is attractive for economic reasons (for example to sell LNG in another market to a profit). In the latter, profit may be shared between buyer and seller.

LNG is usually traded in energy units like British Thermal Units (commonly in million Btu or mmBtu). Pricing of LNG is set in the SPA and it differs from market to market. Gas prices are indexed to an indicator that could be Hub linked, like the LNG price at the Henry Hub market in the USA, or Oil linked, as in the Asian market and most of Europe, where it is linked to the Brent barrel. Formulas of indexed prices take the form shown in (1), where A is a constant base price, B a gradient and X the indexation.

$$GasPrice = A + BX \tag{1}$$

Also the pricing formula can have an S-Curve function to limit risk taken by both parties, as it sets a lower and upper bound for the contract price when the indexed indicator differs greatly form that expected [23].

2.1.2.2 Examples

The vast majority of upcoming liquefaction capacity is sold forward in long-term contracts. US projects of Sabine Pass and Corpus Christi (Texas), near Henry Hub, have their capacities already contracted through 20 years contracts with rights to be extended for 10 more years. Reported prices for these SPA are around 3-3.5 \$/mmBtu for the fixed fees (parameter A in (1)) and 115-120%HH (this means 115 to 120% of the Henry Hub LNG price)

[1] In principle, suppliers have more information on production costs and have greater scope to respond to market price changes, therefore they assume a *price risk* (with respect to the market prices and their production costs) by setting a sale price on the SPA. On the other hand buyers have more information on potential demand and can initiate strategies to stimulate demand, therefore they assume a *quantity risk* by compromising a product quantity to be payed whether delivered or not.

[18]. These are FOB prices, which means that regasification and transport (maritime and pipeline) costs are not taken in account.

Maritime transport can be contracted in long-term or charter for the short-term/spot market. Long term contracts can be assimilated as a fixed cost, with reported prices of 1-2 $/mmBtu for Brazil and Chile (Concepción) [18]. On the other hand, charter fees are established in $/day and they change as vessel demand and supply varies, from 40,000 to 160,000 $/day as reported in the last 3 years [17]. For a round-trip voyage of 28 days, it amounts to 0.3-2 $/mmBtu [23].

The regasification process is usually engaged in long term contracts with Take-or-Pay clauses for onshore or offshore terminals. Average charter rates per day of FSRU units contracted for 15 years are equivalent to 0.5 to 1 $/mmBtu [18]. For onshore terminals, regasification and commercialization tariff for Quintero terminal is between 1.22 and 1.6 $/mmBtu [24], for 10 to 20 year contracts, and for Mejillones terminal is between 1.85 and 2.01 $/mmBtu for 10 to 20 year contracts [25]. Finally, transportation costs are around 0.3 $/mmBtu [3].

2.2 LNG in Hydrothermal Electricity Systems

LNG supply poses various problems to hydrothermal electricity system operation and planning. Hydrothermal systems suffer from inherently variability in its hydropower generation due to the uncertainty of rainfalls. For example, droughts can put great stress into the electricity system as hydro generation can be severely reduced, forcing generation by thermal plants, while high rainfall seasons can have significantly lower needs of thermal generation.

Long-term Take-or-Pay contracts are a way to secure attractive and more stable prices, shielding the consumer from the variability of the spot market, but they lack the flexibility in supply that is required by the high hydrological variability of hydrothermal systems. Thus, there is a trade-off between less costly long-term Take-or-Pay contracts, less flexible and more harmful to the hydrothermal optimization, and a more costly, yet more flexible and beneficial to the hydro optimization, short-term or spot contract. Therefore, there is an optimal portfolio for LNG supply consisting in a mix of long-term, short-term and spot contracts.

Currently gas prices are the lowest in the decade, driven by slow demand growth and the arrival of new producers to the market, namely USA and Australia, with prices expected to rise in the upcoming years (see Figure 5) [26] [27]. This trend might encourage generators to establish long-term supply agreements with current low gas prices, as it has been seen, for example, in Chile, with new deals signed by generators to increase imports [28], and Brazil, with a shifting strategy from short to long term supply contracts for new import capacity [29].

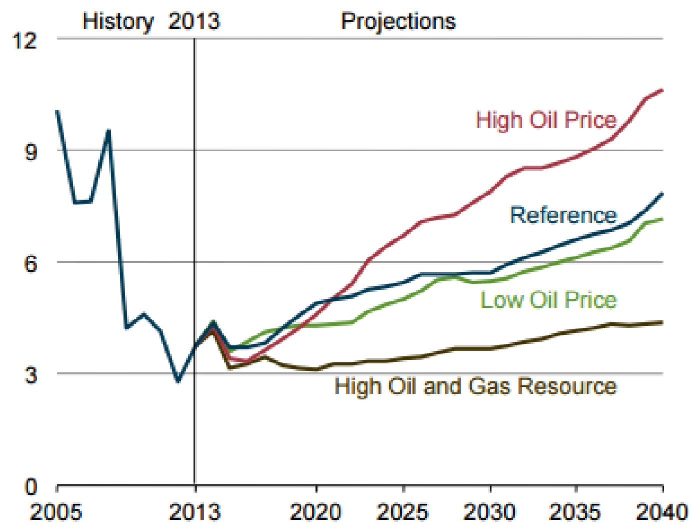

Figure 5: Average Henry Hub spot prices for natural gas in four cases, 2005-40 (2013 US$/mmBtu) *[27]*

2.2.1 The Chilean case

In the 90's there was a boom in the construction of natural gas (NG) fired power plants in Chile, stimulated by cheap NG importation from Argentina. This led to important gas generation capacities, both in the *Central Interconnected System* (SIC, 2822 MW of NG generation capacity) and in the *Great North Interconnected System* (SING, 1441 MW of NG generation capacity), as shown in Figure 11 [30].

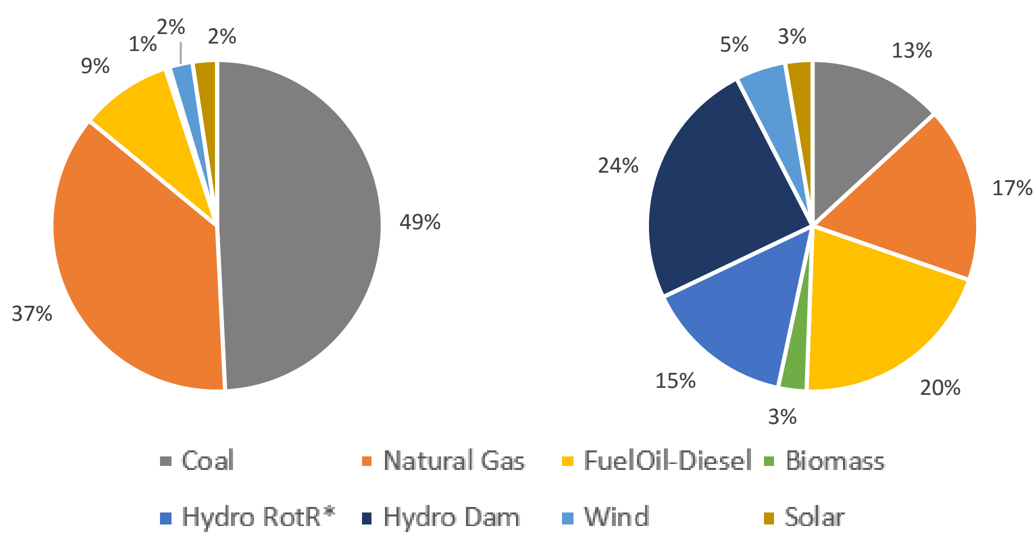

Figure 6: Percentages of net installed capacity per generation technology, as of November 2015, in the SING (left) and SIC (right). *Run-of-the-river

After the Argentinean crisis of 2004 where the NG exports to Chile were heavily limited, new alternatives for NG supply were searched. In this context, the Chilean Government decided the construction of regasification terminals of LNG in order to have strong, independent and affordable supply sources. This would give the country more independence in energy terms as various international suppliers of LNG could participate [31].

In 2009 the LNG terminal in Quintero began its operation, supplying NG demand in the Chilean central zone. This terminal has a shared property among various companies such as ENAP S.A., METROGAS S.A., ENDESA S.A. and BG Group. Currently, there is no open access and only these companies can use the terminal.

Furthermore, in 2010 the LNG terminal in Mejillones began its operation supplying NG demand in the North of Chile, mainly for power generation and the mining sector. This terminal has a shared property among GDF Suez and CODELCO.

In a context where the electricity sector was deeply stressed, the Chilean Government introduced its Agenda de Energía, published in 2014, where one of the identified challenges was the reduction of electricity prices, improving competition and diversification of the energy market. To reach this goal, one of the identified actions was the "*promotion of the use of LNG in the electrical power generation instead of diesel"* [2]. Among the measures proposed we can find:

- 1.1 MMm3/day of LNG supply to generation companies without LNG contracts (AES Gener & Colbún) for 10 years. This is supplied by ENAP (one of the members of Quintero consortium) and is equivalent to 240 MW of steady generation.
- The construction of a third regasification terminal in Penco Lirquén, Concepción bay, expected by 2017.
- The enhancement of the regasification capacity of Quintero Terminal from 15 MMm3/day to 20 MMm3/day. It should be noted that this terminal has a very high utilization rate (91% on 2013 compared to a 33% of all world terminals [32]) driven by the high NG demand of the Chile's central zone.
- The development of a new regulatory framework to adequate electricity system operation (Centro de Despacho de Control de Carga, CDEC) and recognize constraints from gas sector and its Take-or-Pay contracts.

In this context, it is not clear which are the actual requirements of LNG from the electricity sector and this thesis is an attempt to clarify this question, including the stochastic nature of gas demand from the electricity sector, which is highly dependent on hydro conditions.

2.2.2 Other countries situation

We believe that the problems that Chile is currently facing may be of interest to further power systems in Latin America, such as Argentina, Colombia, Brazil and Central America, and Sub-Saharan Africa, such as Ghana. All these systems have important hydro generation capacities exposed to volatile rainfall conditions, and are net importers of natural gas for their power systems (or will be in the near future).

Argentina:

Argentinean power system has important hydroelectric and gas-fired generation facilities, accounting for a 33% and 42% if installed capacity respectively [33].

Natural gas is the primary source of energy in Argentina accounting for over 50% of electricity generation in 2014 [34]. Natural gas is also widely used in industrial and residential sectors. Argentina is an important gas producer with the world's second-largest shale gas reserves [35]. Nonetheless, lack of investment due to government policy has made them a net importer of natural gas, primarily from Bolivia and from its two LNG regasification terminals [36]. This trend is reversing as increasing domestic production has displaced part of the imports since 2015, but the country will remain a net importer in the following years [37].

Colombia:

Colombian power system depends mainly in hydro (70%) and natural gas (9.9%) generation [38]. Also, Colombia is a gas producer with fields in the northern Caribbean Region and in the Eastern Plains Region. Gas production supplies its small domestic market dominated by power generation, as residential demand is weak [39], and since 2007 Colombia has been exporting natural gas to Venezuela.

Nonetheless, gas production is declining and deficits are expected by 2018. To address this a LNG regasification terminal in the Caribbean coast is being developed by a consortium of thermal generators (Grupo Térmico) and it is expected to begin operations by end 2016, with another project in the Pacific coast expected by 2021. These projects aim to assure gas supply and lower the risk of scarcity during extreme weather events [40].

Currently Colombian gas generators can subscribe take-or-pay supply contracts in the bulk national gas market and liquidity in the secondary market is limited due to the predominance of power generators in the gas market [39].

Brazil:

Brazil's power system, the largest in Latin America, is highly dependent on hydroelectric generation, accounting for 64.8% of its installed capacity, and important natural gas generation facilities exists, accounting for 8.9% of installed capacity [41].

Brazil is a major natural gas producer with the second largest reserves in South America, mainly located in the pre-salt layers off-shore Rio de Janeiro. NG demand is supplied by its indigenous production, pipeline imports from Bolivia and through three LNG regasification terminals. State-owned Petrobras has the monopoly on NG production, Bolivian imports and owns the 3 LNG terminals. Also, it owns most of the NG-fired plants in the country [42]. In addition, two privately owned LNG terminals and associated power plants are expected to enter the market by 2017 [43].

Petrobras' supply has been made by rigid short-term Take-or-Pay contracts, and in recent dry seasons (2012-2013) the company had had to resource to expensive spot LNG to meet demand of its gas-fired plants [42]. On the other hand, private LNG terminals will be supplied by 25-year long-term Take-or-Pay contracts [43].

Central America:

Central America countries[2] have established a regional electricity market, the *Mercado Eléctrico Regional* (MER), which started operations in 2013. These countries form an interconnected electricity system where predominant sources for generation are hydro (42% of installed capacity) and diesel-fuel oil (37% of installed capacity) [44].

Currently there is no natural gas market in Central America, since there is no indigenous production or import infrastructure (neither gas pipelines nor regasification terminals). Hence, there is no natural gas-fueled electricity generation. This situation is meant to change as several efforts to bring natural gas to the region have been made. In 2014, Central America governments signed an accord to promote energy integration, in which one of the foreseen actions was the introduction of NG to the region [45]. Since then, several projects have arisen, such as:

- A pipeline from Mexico that would supply with NG to Guatemala, Honduras and El Salvador and is expected to be completed by 2019 [46],
- The Costa Norte LNG regasification terminal and power plant in Panama [47], expected operational by 2018, and for which a 10-year supply contract with ENGIE has already being signed [48],
- The Ajacutla LNG regasification terminal and power plant in El Salvador, expected to begin its operations in 2018, and for which a tender process to sign a 20-year supply contract has already being launched [49].

Since future NG supply is likely to be made by long-term Take-or-Pay contracts and due to the hydrological preponderance on the MER generation capacity (and its inherent variability), in the upcoming years this system is likely to be confronted to the same problems that Chile is currently facing.

Ghana:

Ghana is a developing country in sub-Saharan Africa. Its electricity system is composed by hydroelectric plants (56% of its installed capacity) and dual-fuel plants (gas-diesel or gas-fuel oil) (43% of its installed capacity) [50].

Ghana is a small oil and gas producer. Its gas production is used for domestic power generation and it does not suffice to cover its rising demand. In addition, Ghana imports gas from Nigeria through the West African Gas Pipeline, whose operation has proven to be unreliable. This has forced Ghana to the use of heavy fuels for power generation by its dual-fuel plants [51]. To address this situation Ghana has signed for a LNG floating regasification

[2] The countries that signed the Marco Treaty on 2000, which founded the MER, are Panamá, Costa Rica, Nicaragua, Honduras, El Salvador and Guatemala.

terminal (FSRU) scheduled to begin its operations by end 2016 [10]. There is a long-term contract signed with Shell to supply, using the FSRU facility, a 125 MW gas-fired plant, increased to 1300 MW within five years [52].

Ghana’s developing electricity system will face many challenges, including significant reliability of supply in the near future [53], and the need to assess an optimal portfolio natural gas supply might arise in the following years.

2.3 State-of-the-Art Research

We divided the state-of-the-art research in LNG contacts into two groups:

- Operation of the electricity system given a set of natural gas constraints
- Portfolio optimization of Natural Gas supply contracts

Finally, a brief review of portfolio theory and risk measures is detailed.

2.3.1 Operation with Natural Gas constraints

Interest on power system operation with natural gas constraints is fairly recent, mainly in Brazil and North America. These researches focus on operation or scheduling of the power system to minimize costs, or of a single generation unit to maximize its profit, with a fixed set of NG contracts constraints. Therefore, there is no portfolio optimization of supply contracts.

Several studies have centered on the power system operation and scheduling with natural gas constraints that come from transmission and distribution networks. Modelling the dynamics of NG distribution is a challenging task as pressure and flow through pipes follow non-linear constraints, and the following researches have put their effort into it. In Ref. [54] authors propose a dispatch model for the electricity system with constraints for the gas transport model. In Ref. [55], authors use the concept of *energy hubs,* points where the NG and electricity infrastructure couple, to formulate a distributed optimal power flow for the NG and electricity networks. In Ref. [56], authors propose a Security-Constrained Unit Commitment with NG transmission constraints. In Ref. [57] effects that contingencies in NG infrastructure have on the power system was studied. Reference [58] presented an analysis framework for dynamic scheduling of NG and electricity systems. Simulations were carried out from none to full coordination between systems, and from a static (the current NG grid operation paradigm) to a dynamic scheduling of NG infrastructure, which enabled a performance assessment of the different levels of coordination.

Other studies, such as Ref. [59], have focused on the effects of NG infrastructure on systems with high penetration of renewable sources like wind. Main findings are that the high and fast ramp ability of gas-fired plants make them an ideal complementary resource for variable renewable generation. In particular, authors of Ref. [59] found that technical constraints from the NG infrastructure can produce load shedding in electricity systems with high penetration levels of renewable resources. In these cases, additional gas storage facilities may be able to mitigate these effects.

It is especially interesting for this thesis the study of Ref. [60]. In this study authors examine the effects of natural gas infrastructure in hydrothermal systems, with study cases in the context of the long-term economic dispatch of Chile power network. Authors found limitations in the NG transport infrastructure reduce the consumed fuel for a set of hydrological scenarios and increase the marginal and operational costs of the system. Therefore, future operational costs are underestimated when fuel transportation and availability are ignored, affecting the short-term scheduling of reservoir power plants. Also, the expansion and development of the power system might be distorted as wrong price signals are sent to market participants.

In a similar effort, the study of Ref. [61] analyzed the effects of gas supply and transmission constraints in long-term stochastic hydrothermal scheduling. This reference took the

Brazilian hydrothermal system as a case study, where results showed that a hydro-scheduling model blind to future gas supply and transmissions constraints would deplete reservoirs faster on the basis of the availability of future gas-fired generation, which may not occur, jeopardizing the system's reliability. Therefore, authors proposed an integrated electricity-gas modelling for hydro-thermal markets, whose results showed a significant raise on electricity marginal cost when taking in account gas constraints, as the previous study [60] showed.

Finally, other studies have focused its modeling in other areas. In Ref. [62] authors propose a short-term scheduling of the power system with supply of coal and NG through Take-or-Pay contracts, and in Ref. [63], authors propose a joint Gas-Electricity Expansion model, that minimizes investment and operational costs of the NG and electricity system.

All the previous studies have put in evidence the impact of NG infrastructure, such as transmission and storage, and the need for a joint optimization in the operation and scheduling of electricity and NG infrastructure. This is necessary not only for the economic benefits that arise from higher coordination, but also for the electricity system security under high stress conditions.

Other trend of studies searches the optimal scheduling of a generation unit, in order to maximize its profit. Reference [22] optimizes the scheduling and maintenance of a thermal plant with a fixed fuel supply through Take-or-Pay contracts. This study models several contract clauses, such as monthly and annual Take-or-Pay volumes and make-up clauses and takes in account electricity price uncertainty.

2.3.2 Portfolio Optimization of Natural Gas supply contracts

Natural gas portfolio optimization is a problem that arose in the 80s and 90s with the liberalization of electricity and gas transmission systems and there has been a worldwide interest. We can find studies that are centered on local gas distribution utilities or generation companies.

For the first case, reference [64] presents a methodology for portfolio optimization of NG supply contracts for a local distribution company, by minimizing total supply costs. Contracts were modelled by a Take-or-Pay rate (minimum share of the contracted demand to be delivered), a commodity price (price of each unit of gas) and a charge price (price of the peak demand of the contract). Here, uncertainty comes from fluctuations on demand (dependent on weather conditions). In reference [65] authors present a portfolio optimization of NG supply through ToP contracts, modelling contracts similarly to reference [64], but for trading enterprises. In this study they maximize the expected profit of the trading company.

For the latter, reference [66] presents a risk-constrained profit-maximization model of an Electric Utility Company (EUC), where uncertainty comes from demand. It models the EUC risk preference with a quadratic function, thus obtaining a nonlinear problem. In reference [67], portfolio optimization of NG supply is carried out for a generation company participating in a short term electricity market. In this study two types of NG supply contracts were modelled: baseline (as a constant output for the 24-hour period simulation) and intraday (a constant output for a specific set of hours), and companies had access to the spot market to buy or sell NG. Uncertainty came from both electricity and gas spot prices and risk is evaluated *ex-post*. On the other hand [68] presents a risk-constrained fuel cost minimization model for a gas turbine. It includes long-term fixed contracts and short-term purchases, considers uncertainty on electricity demand and short-term prices of natural gas and uses C-VaR as a risk measure.

A review of the state-of-the-art research at a world-wide scale has shown that there are no studies focused on NG requirements at a national level, which may be relevant for regulators and policy makers. Only recent studies in Chile have focused on this matter: first of all the CE-FCFM study [3] demonstrated the inefficiencies present in the current Chilean system operation, where Take-or-Pay contracts constraints are neglected. Additionally, this study evidenced an underutilization of NG generation capacity, and showed that increasing the import levels through Take-or-Pay contracts, from 3.48 TWh to 4.36 TWh per year, could reduce the expected system costs by 6%.

In a similar effort, a study carried out by the CDEC-SIC proposed a methodology to determine the LNG requirements for the power system through Take-or-Pay contracts [69]. It estimates the total cost function of the power system by simulating its 5-year operation with different levels of Take-or-Pay LNG supply. It analyzed risk of each LNG level *ex post* by comparing results to the current "base" import situation. From a risk-neutral cost-minimization perspective, they found that it is optimal to increase the import levels of LNG by the equivalent of one CCGT plant operating continuously from the months of January to August, from the current base situation of 2 CCGT plants operating continuously. This is equivalent to an increase from 3.3 GWh to 4.4 GWh of yearly NG generation. Our proposed model offers an optimization rather than a simulation based method to determine optimal gas volumes for the power system, including contracts with various degrees of flexibility that would be very difficult to be studied in a combinatorics, simulation basis.

2.3.3 Risk Management and Portfolio Theory through C-VaR

Risk management is a practice that seeks to identify, prioritize and assess risks in an environment with uncertainty.

Portfolio Theory is a method that tries to maximize the expected return of a set of assets for a given amount of risk taken, by selecting the proportions of the different assets. Portfolio theory is widely used for risk management, as it allows to evaluate decisions and investments. Its study originated in 1952 when Henry Markowitz introduced the notion of risk measure (a numerical indicator that allows a characterization of risk) of a portfolio using the variance of return. Since then several risk measures have been developed, amongst which are:

- **Variance:** It is an indicator of the dispersion of the return distribution function and it is commonly used when assuming normally distributed returns. It does not give a good representation of tails (worst outcomes).
- **Value-at-Risk (VaR):** for a given confidence level $\alpha \in [0,1]$, the Value-at-Risk is the largest return η ensuring that the probability of obtaining lower profits than η is $1-\alpha$. It provides a value for the $(1-\alpha)$ worst case, but it gives no information on the tail of the return distribution beyond this point. See Figure 7.
- **Conditional-Value-at-Risk (C-VaR):** for a given confidence level $\alpha \in [0,1]$, the C-VaR is the expected value of the $(1-\alpha)$ quantile of the profit distribution. It is similar to the VaR but it provides information on the tail of the distribution function. It

represents the average loss of the worst $(1-\alpha)\%$ scenarios (see Figure 7). Usual confidence levels (α) are 90%, 95% and 99%.

C-VaR has many useful mathematical properties. C-VaR is a coherent and averse risk measure (See [70] and [71]), but more importantly it is superior for optimization modelling than other risk measures. C-VaR is a convex function with respect to the confidence level α, even with discrete distributions, and it preserves convexity of the distribution function. As proven by the work of Rockafellar & Uryasev (2000) [72], C-VaR can be expressed as a **linear minimization formula**, therefore easily included in a mixed integer linear optimization problem (MILP). Finally, it can give information on the tail of the distribution function, which is particularly useful when presented to fat-tailed distribution. A drawback is that it needs a more accurate tail modelling or a larger sample size to get a stable and reliable value than, for example, VaR.

C-VaR is used in finance as a complementary risk measure of VaR. Also, its good optimization properties have made C-VaR widely used in problems pertaining electricity markets.

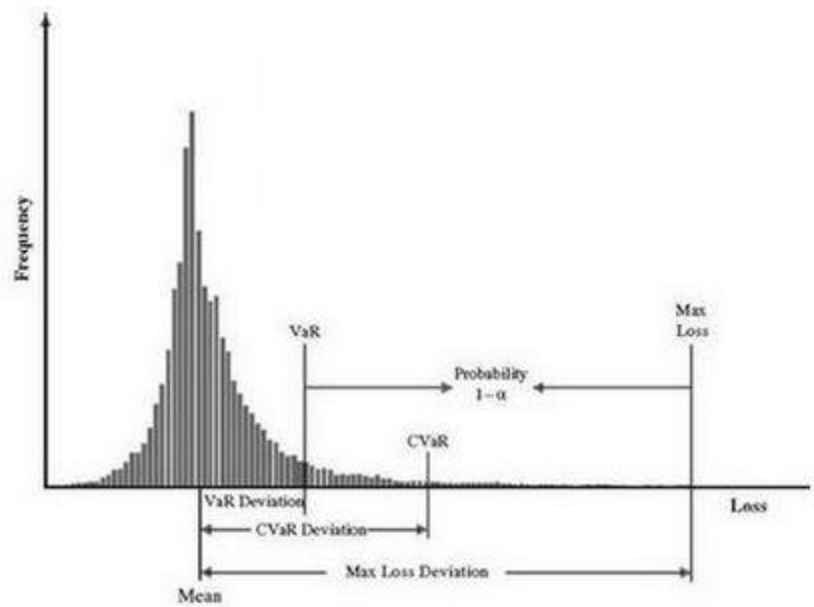

Figure 7: Loss probability distribution. C-VaR and VaR at α confidence level are represented *[70]*.

3.1 General overview

The proposed two stage stochastic optimization model determines in its first stage the LNG contract portfolio decision which is then evaluated in a second stage where electricity operation is optimized across various scenarios with different hydrological conditions. In this framework, ToP contracts are modeled through a contracted volume, a price, a delivery regime (or gas "inflows") and a delivery point in the gas network where there is a tank of limited capacity. Volumes of imported LNG can be increased by purchasing extra gas in the spot market and gas is delivered to CCGT power plants through a gas network which is modelled through a simplified *transport model*. Electricity network, on the other hand, is modeled through linearized, DC power flow equations, considering different locations of generation infrastructure and thus the presence of multiple reservoirs that can store water to manage electricity production. The aforementioned representation is sufficient to capture the availability of NG for the electricity dispatch and coordination of its usage with further hydrothermal generation infrastructure. This is illustrated in Figure 8.

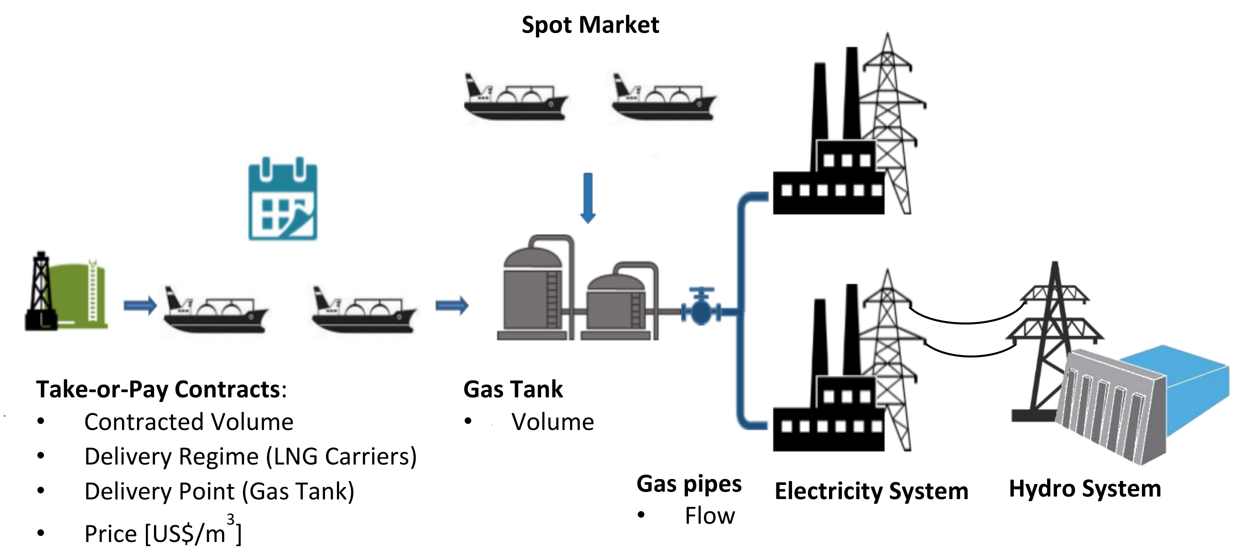

Figure 8: Diagram of the implemented model.

Minimize the expected operational cost **considering LNG supply contract costs**
Subject to: • Generation-demand nodal balance • Transmission grid constraints • Transmission losses • Dams/inflows constraints • Run-of-the-river constraints • **Gas tanks & gas network constraints** • **Gas supply contracts constraints**
Decision Variables: • Generator's Dispatch (for each time period/scenario) • **LNG volume per contract**

Figure 9: Implemented Optimization model, where the usual hydrothermal economic dispatch formulation is shown in black and additions from the gas world are shown in brown.

The proposed optimization model was implemented in AMEBA, which is a computational platform for energy systems optimization and analytics [73].

Next, we present the full mathematical formulation.

3.2 Mathematical formulation

3.2.1 Strict Take-or-Pay Contract formulation

The model optimizes the operation costs of the electrical power system together with LNG supply costs given by the long-term Take-or-Pay contracts and the short-term Spot LNG purchases over the simulation horizon, as shown in equation (2). In this formulation Take-or-Pay contract decision is a first-stage, here and now type of decision. Short-term spot market purchases, in contrasts, are second-stage decisions so they can be optimized in every realized scenario. We consider that ToP contracts have only a fixed (rather than variable) cost.

$$of = \min \sum_{s\in\Omega_s}\left(\sum_{t\in\Omega_T}\sum_{b\in\Omega_{B(s)}}\sum_{g\in\Omega_G} P_{g,s,t,b}\cdot\beta_g + \sum_{t\in\Omega_T} V_{s,t}^{Spot}\cdot\gamma^{Spot}\right)\cdot\rho_s + \sum_{c\in\Omega_{ToP}} V_c^{ToP}\cdot\gamma_c^{ToP} \tag{2}$$

Electrical constraints:

Equation (3) shows the nodal balance between generated powers, inward and outward power flows, transmission losses and load. Equation (4) enforces Kirchhoff's law for DC-power flow, Eq. (5) constraints power flow to the line maximum transfer capacity. Eq. (6) shows the linearized transmission losses, where $\mathrm{abs}()$ is the absolute value of the power flow. Finally, Eq. (7) limits power generation by the generator's maximum output, and Eq. (8) limits generation by renewable sources (wind or solar) by the availability of resources.

$$\sum_{g\in G(n)} P_{g,s,t,b} + \sum_{l\in L(n-)} pf_{l,s,t,b} = Dem_{n,s,t,b} + \sum_{l\in L(n+)} pf_{l,s,t,b} + \sum_{l\in L(n)} \frac{Loss_{l,s,t,b}}{2} \tag{3}$$

$$\forall n \in \Omega_N;\;\; s \in \Omega_s;\;\; t \in \Omega_T;\;\;\; b \in \Omega_{B(t)}$$

$$pf_{l,s,t,b} = \frac{\theta_{n+(l),s,t,b} - \theta_{n-(l),s,t,b}}{x_l} \tag{4}$$

$$\forall l \in \Omega_L;\;\; s \in \Omega_s;\;\;\; t \in \Omega_T;\;\;\;\; b \in \Omega_{B(t)}$$

$$-pfmax_l \leq pf_{l,s,t,b} \leq pfmax_l \tag{5}$$

$$\forall l \in \Omega_L;\;\; s \in \Omega_s;\;\;\; t \in \Omega_T;\;\;\;\; b \in \Omega_{B(t)}$$

$$Loss_{l,s,t,b} = r_l \cdot pfmax_l \cdot abs(pf_{l,s,b,t}) \tag{6}$$

$$\forall l \in \Omega_L;\;\; s \in \Omega_s;\;\;\; t \in \Omega_T;\;\;\;\; b \in \Omega_{B(t)}$$

$$P_{g,s,t,b} \leq Pmax_g \tag{7}$$

$$\forall g \in \Omega_G;\;\; s \in \Omega_s;\;\;\; t \in \Omega_T;\;\;\;\; b \in \Omega_{B(t)}$$

$$P_{g,s,t,b} \leq P_{g,s,t,b}^{Available} \tag{8}$$

$$\forall g \in \Omega_{G(solar/wind)};\;\; s \in \Omega_s;\;\;\; t \in \Omega_T;\;\;\;\; b \in \Omega_{B(t)}$$

Hydro constraints:

Constraints for the management of reservoirs and hydro generators are the following: Eq. (9) relates generated power to turbined flow on generators, (10) equals hydro generators' turbined flow to input flows (affluents, dam releases, filtrations and overflows, and turbined and spilled flows from other generators). Eq. (11) defines a total extracted flow for dams for each period and Eq. (12) maintains dam volume consistent with extractions from one time period to the next. Eq. (13) enforces a linear relation between the filtrated flow on a dam and its volume and Eq. (14) maintains stored volume within dam capabilities.

$$P_{g,s,t,b} = \eta_g \cdot QT_{hc(g),s,t,b} \tag{9}$$

$$\forall g \in \Omega_{G(hydro)};\; s \in \Omega_s;\;\;\; t \in \Omega_T;\;\;\;\; b \in \Omega_{B(t)}$$

$$QT_{hc(g),s,t,b} + QS_{hc(g),s,t,b} = \sum_{hc\in\Omega_{HC(g^+)}} Af_{hc,s,t,b} + QR_{hc,s,t,b} + QF_{hc,s,t,b} + QOvf_{hc,s,t,b} + QT_{hc,s,t,b} + QS_{hc,s,t,b} \tag{10}$$

$$\forall g \in \Omega_{G(hydro)};\; s \in \Omega_s;\;\;\; t \in \Omega_T;\;\;\;\; b \in \Omega_{B(t)}$$

$$QE_{d,s,t,b} = QF_{hc(d^-),s,t,b} + QR_{hc(d^-),s,t,b} - \sum_{hc\in\Omega_{HC(d^+)}} Af_{hc,s,t,b} + QF_{hc,s,t,b} + QOvf_{hc,s,t,b} + QT_{hc,s,t,b} + QS_{hc,s,t,b} \tag{11}$$

$$\forall d \in \Omega_D;\; s \in \Omega_s;\;\;\; t \in \Omega_T;\;\;\;\; b \in \Omega_{B(t)}$$

$$Vol_{d,s,t} = Vol_{d,s,t-1} - \sum_{b \in B(t)} 3600 \cdot \Delta_{t,b} \cdot (QOvf_{hc^{-}(d),s,t,b} + QE_{d,s,t,b}) \tag{12}$$

$$\forall d \in \Omega_D;\ s \in \Omega_s;\quad t \in \Omega_T$$

$$QF_{hc^{-}(d),s,t,b} = K1_d + K2_d \cdot Vol_{d,s,t} \tag{13}$$

$$\forall d \in \Omega_D;\ s \in \Omega_s;\quad t \in \Omega_T;\quad b \in \Omega_{B(t)}$$

$$vmin_d \leq Vol_{d,s,t} \leq vmax_d \tag{14}$$

$$\forall d \in \Omega_D;\ s \in \Omega_s;\quad t \in \Omega_T$$

Gas constraints:

Additionally, the optimization problem is constrained by the following equations, consistent with the modelling of gas elements (tanks and pipelines): Eq. (15) enforces that delivered LNG should not exceed the contracted LNG volume. Eq. (16) maintains the stored gas levels consistent with inputs and outputs from one time period to the next. Eq. (17) keeps the stored levels of gas within capability of the tank. Constraints (18) and (19) model the simplified transport model of the gas network.

$$\sum_{t \in \Omega_T} d_{c,s,t} \leq V_c^{Top} \tag{15}$$

$$\forall c \in \Omega_{ToP};\, s \in \Omega_S$$

$$V_{gt,s,t} - V_{gt,s,(t-1)} = \sum_{c \in \Omega_{ToP(gt)}} d_{c,s,t} + V_{s,t}^{Spot} - \sum_{gc \in \Omega_{GC(gt)}} \sum_{b \in \Omega_{B(t)}} F_{gc,s,t,b} \cdot \Delta_{\mathrm{t,b}} \tag{16}$$

$$\forall gt \in \Omega_{GT};\, s \in \Omega_S;\ t \in \Omega_T$$

$$vmin_{gt} \leq V_{gt,s,t} \leq vmax_{gt} \tag{17}$$

$$\forall gt \in \Omega_{GT};\, s \in \Omega_S;\ t \in \Omega_T$$

$$\sum_{gc \in \Omega_{GC(n^{+})}} F_{gc,s,t,b} = \sum_{gc \in \Omega_{GC(n^{-})}} F_{gc,s,t,b} \tag{18}$$

$$\forall n \in GN;\, s \in \Omega_S;\, t \in \Omega_T;\, b \in \Omega_{B(t)}$$

$$P_{g,s,t,b} \cdot h_g = F_{gc(g),s,t,b} \tag{19}$$

$$\forall g \in \Omega_{G(lng)};\ s \in \Omega_S;\, t \in \Omega_T;\, b \in \Omega_{B(t)}$$

3.2.2 Flexible Take-or-Pay Contracts

The cost structure of LNG can be very complex, as each stage of the LNG supply chain may require a supply contract with different levels of flexibility in their Take-or-Pay clauses. To address this we modeled two types of flexible contracts through the following parameters: minimum volume and presence of penalizations. These two types of contracts are explained next.

Minimum Volume Take-or-Pay Contract

Minimum volume contracts are common, not only in LNG supply but also in pipeline NG supply [21]. These contracts establish that a certain minimum volume should be payed even if this is not required or delivered to the consumer. Typical minimum volumes are between 60% and 90% of the total contracted volume. Actual deliveries of LNG can vary between this minimum volume and the contracted volume without penalizations to the consumer.

The mathematical implementation of this type of contract was carried out through the parameter Y that represents the fraction of take-or-pay volume over the total volume. This value lies within the range of $[0,1]$, where 0 represents a fully flexible contract and 1 represents an inflexible Take-or-Pay contract.

An auxiliary variable was needed to its implementation, V_s^+, which represents the delivered LNG volume over the minimum take-or-pay volume in the scenario s, as shown in Figure 10.

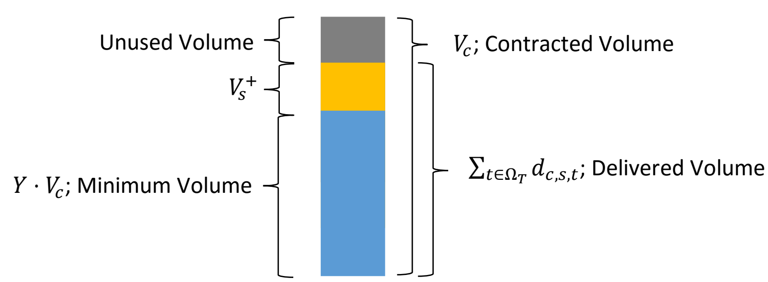

Figure 10: Diagram of a Take-or-Pay contract with Minimum Volume and its variables.

The Take-or-Pay term of the objective function is modified to include these types of contracts, as shown in equation (20). This formulation classifies the cost of the Take or Pay contract in a fixed cost independent of the hydrological scenario (minimum Take-or-Pay volume) and a variable cost that depends on the actual utilization of the LNG contract, and thus on the hydrological scenario.

$$of = \min \begin{array}{l} \sum_{s\in\Omega_s}\left(\sum_{t\in\Omega_T}\sum_{b\in\Omega_{B(s)}}\sum_{g\in\Omega_G} P_{g,s,t,b}\cdot\beta_g + \sum_{t\in\Omega_T} V_{s,t}^{Spot}\cdot\gamma^{Spot}\right)\cdot\rho_s + \\ \sum_{s\in\Omega_S}\left(\sum_{c\in\Omega_{ToP}} V_{c,s}^{+}\cdot\gamma_c^{ToP}\right)\cdot\rho_s + \sum_{c\in\Omega_{ToP}} Y_c\cdot V_c^{ToP}\cdot\gamma_c^{ToP} \end{array} \quad (20)$$

Also, constraint (15) is modified as shown in (21):

$$V_{c,s}^{+} + Y_c \cdot V_c^{ToP} \geq \sum_{t \in \Omega_T} d_{c,s,t} \tag{21}$$

- **Penalization Take-or-Pay Contract.**

The penalization contract refers to the classical definition of a Take-or-Pay contract, where the consumer has to pay the supplier a penalty for the volume he does not take. It can also be a representation of a local secondary market, were surpluses of natural gas can be sold there with a loss (penalization), or of a complex cost structure with fixed (Take-or-Pay) and variable terms (for example a fixed LNG cost with flexible regasification contracts).

The mathematical implementation of this type of contract was made by means of the penalization parameter X, that represents the fraction of the total price that the consumer has to pay for non-delivered LNG. This value lies within the range of $[0,1]$, where 0 represents a fully flexible contract (no penalizations) and 1 represents an inflexible Take-or-Pay contract.

Implementation of this contract requires to modify the objective function, as shown in Equation (22). This formulation also classifies the contract cost in a fixed cost and a variable cost.

$$of = \min \begin{array}{c} \displaystyle\sum_{s \in \Omega_s} \left(\sum_{t \in \Omega_T} \sum_{b \in \Omega_{B(s)}} \sum_{g \in \Omega_G} P_{g,s,t,b} \cdot \beta_g + \sum_{t \in \Omega_T} V_{s,t}^{Spot} \cdot \gamma^{Spot} \right) \cdot \rho_s + \\ \displaystyle\sum_{s \in \Omega_S} \left(\sum_{t \in \Omega_T} \sum_{c \in \Omega_{ToP}} d_{c,s,t} \cdot \gamma_c^{ToP} \, (1 - X_c) \right) \cdot \rho_s + \sum_{c \in \Omega_{ToP}} X_c \cdot V_c^{ToP} \cdot \gamma_c^{ToP} \end{array} \tag{22}$$

3.2.3 General formulation

The aforementioned two types of contract formulations were merged into a single model, where any contract with a combination of penalizations (X) and minimum volume (Y) can be formulated. The general objective function is shown in (23). The first term is the power system operating cost, the second term is the cost of LNG purchased in the spot market (in the very short term), the third term is the penalization for underutilized LNG volume, and the final terms are the costs (fixed and variable) associated to the delivered LNG.

$$of = \min \begin{array}{c} \displaystyle\sum_{s \in \Omega_s} \left(\sum_{t \in \Omega_T} \sum_{b \in \Omega_{B(s)}} \sum_{g \in \Omega_G} P_{g,s,t,b} \cdot \beta_g + \sum_{t \in \Omega_T} V_{s,t}^{Spot} \cdot \gamma^{Spot} \right) \cdot \rho_s + \\ \displaystyle\sum_{s \in \Omega_S} \left(\sum_{c \in \Omega_{ToP}} \left(V_c^{ToP} (1 - Y_c) - V_{c,s}^{+} \right) \cdot \gamma_c^{ToP} \cdot X_c \right) \cdot \rho_s + \\ \displaystyle\sum_{s \in \Omega_S} \left(\sum_{c \in \Omega_{ToP}} V_{c,s}^{+} \cdot \gamma_c^{ToP} \right) \cdot \rho_s + \sum_{c \in \Omega_{ToP}} Y_c \cdot V_c^{ToP} \cdot \gamma_c^{ToP} \end{array} \tag{23}$$

3.2.4 Risk Aversion (C-VaR)

We can model risk-aversion in the contract portfolio decision. For this reason a risk-driven optimization problem was formulated, by means of the Conditional Value-at-Risk (C-VaR) calculated to the percentile α. The model, therefore, minimizes a linear combination of the expected system cost, and the C-VaR of system costs, which is given by the $(1-\alpha)$% worst scenarios.

A weighting factor ω ($\omega \in [0,1]$) was used as a risk-aversion measure of the system planner, where $\omega = 0$ means a risk-neutral planner and $\omega = 1$ a fully risk-averse planner. This is shown in the risk averse objective function (of_{risk}) in (24), where of is the risk neutral objective function detailed in (23).

$$of_{risk} = (\mathbf{1} - \boldsymbol{\omega}) \cdot of + \boldsymbol{\omega} \cdot CVaR \tag{24}$$

This formulation is subjected to the following constraints: (25) defines the total system cost per scenario s; and (26), (27) and (28) are the linear formulation of the C-VaR as derived in the pioneer paper by Rockafellar & Uryasev [72].

$$C_s = \begin{array}{c} \sum_{t\in\Omega_T} \sum_{b\in\Omega_{B(s)}} \sum_{g\in\Omega_G} P_{g,s,t,b} \cdot \beta_g + \sum_{t\in\Omega_T} V_{s,t}^{Spot} \cdot \gamma^{Spot} + \\ \sum_{c\in\Omega_{ToP}} \left(V_c^{ToP}(1-Y_c) - V_{c,s}^{+}\right) \cdot \gamma_c^{ToP} \cdot X_c + \\ \sum_{c\in\Omega_{ToP}} V_{c,s}^{+} \cdot \gamma_c^{ToP} + \sum_{c\in\Omega_{ToP}} Y_c \cdot V_c^{ToP} \cdot \gamma_c^{ToP} \end{array} \tag{25}$$

$$Z_s \geq C_s - VaR \tag{26}$$

$$Z_s \geq 0 \tag{27}$$

$$VaR + \frac{1}{1-\alpha} \sum_{s\in\Omega_S} Z_s \cdot \rho_s \leq CVaR \tag{28}$$

4 STUDY CASE: SMALL SCALE SYSTEM

A small scale study was proposed to act as a proof of concept and to put in evidence the fundamental principles in optimal LNG import volume and portfolio selection. Only risk-neutral simulations were run in this section.

4.1 Description of the Case Study

4.1.1 The Electrical System

A Case Study based on a simplified version of the Chilean main electricity system is implemented. It is composed of 16 generators that represent different technologies, all connected to a single node, as detailed in Table 1. There are eight Fuel-Oil and four Diesel generators with increasing variable costs to emulate the system reality.

Generator Type	Capacity [MW]	Variable Cost [$/MWh]
Coal	2000	50
NG	2000	0
Fuel-Oil (8)	2000 (8x250)	110-145
Diesel (4)	1000 (4x250)	200-215
Dam	3000	0
Run-of-River	2000	0

Table 1: Generators of the small scale Case Study

The simulation horizon is one year, which is divided in four equal stages, each one with two blocks: a peak load block and a low load block, of the same duration. That amounts a total annual consumption of 52.56 TWh.

Stage	Block	Duration [h]	Demand [MW]
1,2,3,4	1	1095	4500
1,2,3,4	2	1095	7500

Table 2: Block duration and demand

4.1.2 Hydrological Scenarios

Three hydrological scenarios were used: a dry, a medium and a wet scenario, all with constant inflows and the same probability of occurrence.

Scenario	ρ_s	Inflow [p.u.]	Annual Dam Energy [TWh]	Annual Run-of-River Energy [TWh]
Dry	0.33	0.35	9.198	6.132
Medium	0.34	0.50	13.140	8.760
Wet	0.33	0.65	17.082	11.380

Table 3: Characteristics of hydrological scenarios: probability of occurrence, inflows and available energy.

4.1.3 Take-or-Pay Contracts

A Gas Tank with a Gas Connection to the gas power plant was modeled. An inflexible Take-or-Pay Contract ($X = Y = 1$) and a Spot Market to top-up gas during dry conditions were modelled, and its prices are shown in Table 4.

Gas Contract	Price [$/MWh]
Take-or-Pay	80
Spot	160

Table 4: Available LNG Contracts

4.2 Results

Several studies were carried out so as to illustrate different features of the model and the optimal decision. Results are presented in four main sub-sections, each of them focusing on different aspects of LNG contract decision:

- Proof of concept: Optimal LNG Volume.
    - Effects of Take-or-Pay contracts on the electric power system.
- Profit of Take-or-Pay generators.
    - Analysis of incentives of generators regarding LNG import decision.
- Contract Flexibility.
    - Effects of flexibility in LNG contract decision and use.
- Portfolio Optimization.
    - Analysis of key parameters in portfolio decision making.

4.2.1 Proof of concept: Optimal LNG Volume

The definition of an optimal LNG import volume is not straightforward, as demand depends strongly on hydrological conditions. A simulation without Take-or-Pay constraints was made, to exhibit different LNG requirements according to the hydrological scenario (in these simulations Natural Gas is modelled similarly to any other fossil fuel, e.g. Diesel). Total generated energy per technology is shown in Figure 11, and generation per block/scenario can be found in Appendix II. It can be seen that LNG usage varies from a 0.95 capacity factor of the LNG power plant in dry scenarios, to a 0.375 in wet scenarios. Therefore, it is not clear **how much LNG should be imported** for the electric power system.

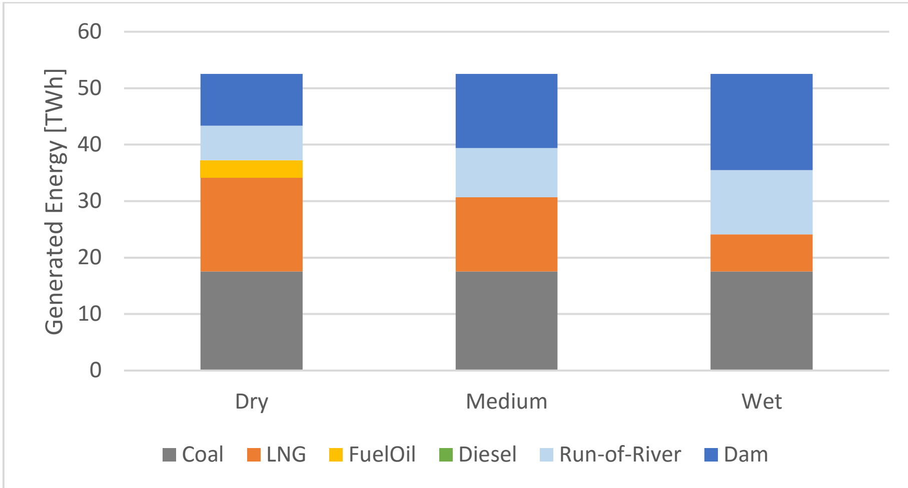

Figure 11: Deterministic annual power generation per scenario without Take-or-Pay constraints [TWh].

Dry	Medium	Wet
0.95	0.75	0.375

Table 5: Capacity factor of the LNG generator per scenario, without Take-or-Pay constraints

Results of a risk-neutral simulation considering constraints associated with Take-or-Pay contracts show an optimal volume of **13.14 TWh** (or a LNG capacity factor of 0.75 p.u) which is exactly the LNG requirements for the medium scenario. However, in dry scenarios, the available LNG volume is less than what the system requires, and thus more costly generation (e.g. fuel-oil generation) is needed to meet demand. On the other hand, in wet scenarios available LNG volume is higher that the system requirements and thus it displaces less costly generation (e.g. coal generation) (Figure 12).

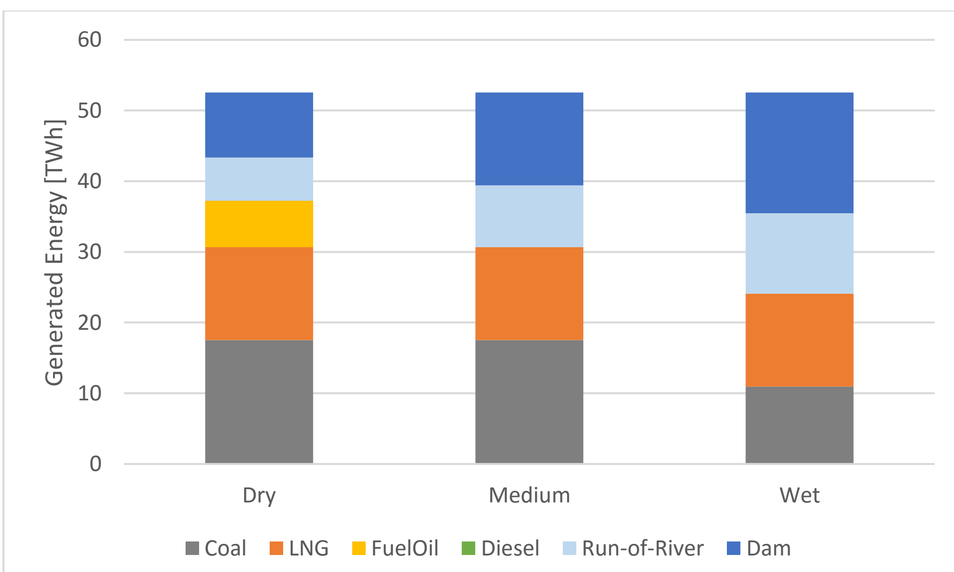

Figure 12: Annual energy generation per scenario with optimal Take-or-Pay Contract [TWh]

Take-or-Pay clauses in LNG supply have important economic impact. As shown in Figure 13, it increases system costs by 5% in average, with a higher regret[3] in wet scenarios reaching 12%.

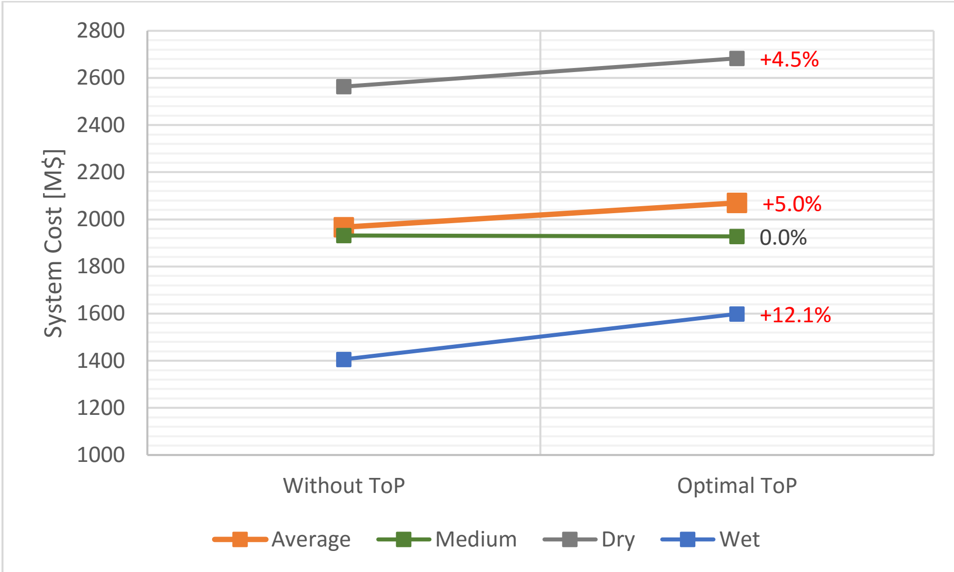

Figure 13: Total average and per scenario system cost [M$]. Labels indicate extra costs for each scenario [%].

A sensitivity study was carried to prove the optimality of the solution with variations of the LNG volume equal to +5% and -5%. Results are shown in Table 6, where we can see that importing more LNG, even though it is useful for dry scenarios, increases costs in medium and wet scenarios where more coal generation is displaced in favor of the more costly LNG generation. On the contrary, lowering LNG volumes produces extra costs in medium and dry scenarios, where more costly generation (fuel-oil) has to supply the deficit of LNG.

Case	ToP LNG Volume [TWh]	System Cost per Scenario [M$]			Average System Cost [M$]
		Dry	Medium	Wet	
-5%	12.48	2712.75	1947.34	1578.99	2079.69
Optimal Volume	13.14	2683.18	1927.63	1598.70	2069.84
5%	13.80	2656.90	1947.28	1618.41	2074.20

Table 6: Average System Cost and Cost per scenario with Take-or-Pay LNG supply

[3] Regret is defined the lost opportunity when an alternative course of action would have resulted in a more favorable outcome. In this case, regret is the extra cost incurred, upon realization of a scenario, by taking a decision under uncertainty (LNG contracting) with respect to the best (deterministic, perfect information) action.

4.2.2 Profit of Take-or-Pay generators

Generation companies are responsible for managing their fuel supply. Since most NG fired generators are dual-fuel power plants, they can use diesel to continue operating even when there is no LNG available. Chilean regulation does not oblige generators to comply with a specific volume of NG supply, therefore the imported volume of LNG is taken by generation companies which are also LNG importers. To analyze the incentives that affect the LNG import decision carried by generators, profits of Take-or-Pay generators were studied.

A sensitivity of +5% and -5% of the optimal volume was made, and profit was computed as follows: we subtracted the cost of the LNG supply to the energy sold by the Take-or-Pay generator at the system's marginal price. Results are shown in Table 7.

To understand how profit works with Take-or-Pay contracts, we analyze it by scenarios:

Case	ToP LNG Volume [TWh]	Profit per Scenario [M$]			Average Profit [M$]
		Dry	Medium	Wet	
-5%	12.48	561.74	374.49	-374.49	187.25
Optimal Volume	13.14	525.60	0.00	-394.20	43.80
5%	13.80	551.88	-412.53	-413.91	-91.52

Table 7: Profit of LNG generator per scenario with Take-or-Pay LNG supply

- In dry scenarios the imported LNG volume is less than the system requirements, then Fuel-Oil generation compensates for the deficit in LNG and this technology sets the marginal price. That way, LNG generators sell their energy at a positive profit. Decreasing LNG imports can force an increase in marginal prices, as a more costly unit may be forced to be dispatched, increasing the ToP generator's profit. This is the case in the -5% sensitivity.
- In wet scenarios LNG generation displaces less costly coal generation, and thus this technology sets the system marginal price. This situation produces a loss in LNG generators, given by the difference between coal and LNG variable costs. Therefore, decreasing LNG import volumes convey a reduction of LNG generator's losses.
- In medium scenarios where LNG volume corresponds to the system requirements, this technology sets the marginal price and so there is no profit for LNG generators. Decreasing LNG import volumes forces Fuel-Oil generation to produce electricity, increasing the system marginal price and thus increasing LNG profit. In contrast, increasing LNG imports reduces coal generation and sets the system marginal price at a lower level, producing losses to LNG generators.

  In summary, being V_c^{ToP} the contracted volume in Take-or-Pay contracts, V_s^* the optimal LNG requirement and λ_s the marginal price for scenario s:

$$\text{If } V_c^{ToP} < V_s^* \rightarrow \lambda_s = \beta_{fueloil}$$
$$\text{If } V_c^{ToP} > V_s^* \rightarrow \lambda_s = \beta_{coal}$$

Results indicate that LNG generators responsible for their fuel supply can be motivated to reduce their LNG import volume in order to maximize their profit. Decreasing LNG imports also reduces their exposure to adverse hydrological scenarios (wet ones), as losses are limited.

4.2.2.1 LNG Generators' Optimal Volume

An analysis was made to find the optimal LNG volume from the generators' point of view. For doing so, a simplified simulation system was used, where only one aggregated Fuel-Oil and one Diesel generator exist (instead of 8 and 4 respectively with incremental variable costs), as shown in Table 8.

Generator Type	Capacity [MW]	Variable Cost [$/MWh]
Coal	2000	50
LNG	2000	0
Fuel-Oil	2000	110
Diesel	1000	200
Dam	3000	0
Run-of-River	2000	0

Table 8: Capacity and Variable costs of available generators.

We studied various ranges of LNG import volumes, from 0 to 1 p.u. of the capacity factor of the LNG generator, and profit was computed as previously stated. Expected profit and profit per scenario can be found in Figure 14, where we find 5 ranges or intervals that are detailed below.

A. LNG available volume is low and system's marginal price is given by fuel-oil in Medium and Wet scenarios, and by diesel in Dry scenarios. Profit per MWh generated is high.
B. LNG available volume is low (less than dry scenario's need) and and system's marginal price is given by fuel-oil in all scenarios. Profit per MWh generated is high.
C. LNG available volume is higher than the needs in the wet scenario, and thus marginal price is given by coal, producing losses for the LNG generator. In other scenarios LNG volume is less than system requirements, so marginal price is given by fuel-oil.
D. LNG volume is higher than the needs in the dry and medium scenarios, and thus marginal price is given by coal, producing losses for the LNG generator. In the wet scenario marginal price is still given by fuel-oil.
E. LNG volume is higher than system requirements for all scenarios, producing losses in wet and medium scenarios, and slightly positive profit in the dry scenario where fuel-oil generation is always needed in peak-load hours.

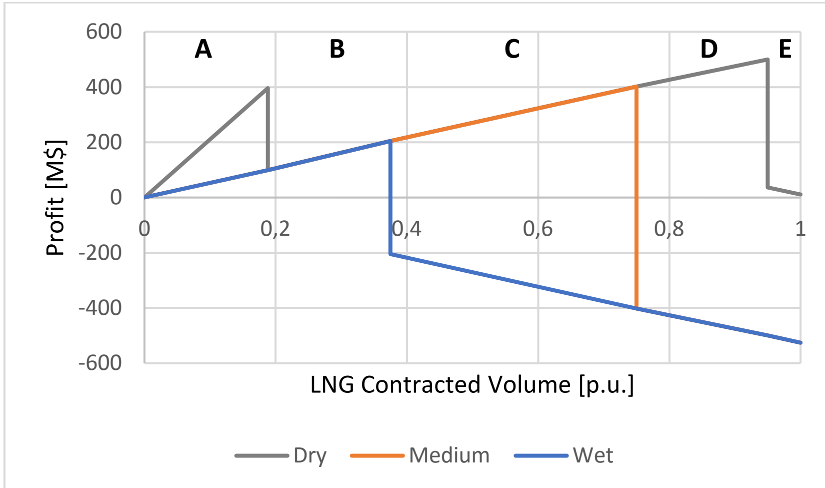

Figure 14: Profit of LNG generator per scenario as a function of the imported LNG volume.

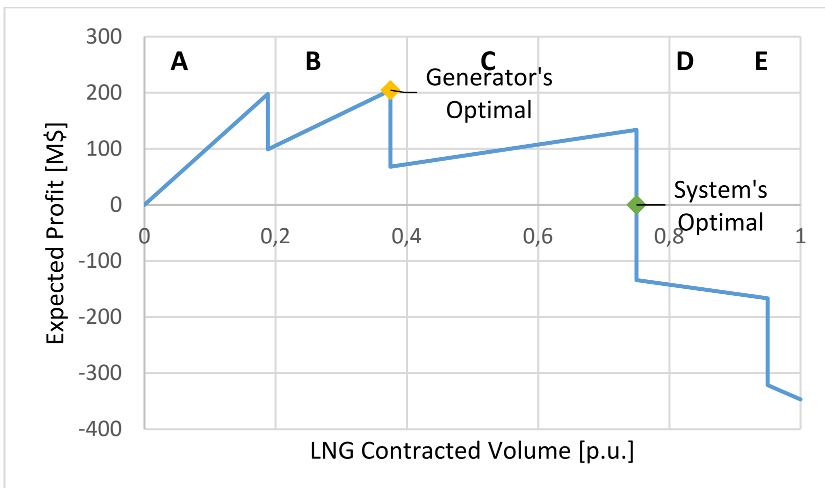

Figure 15: Expected profit of LNG generator as a function of the imported LNG volume.

As seen if Figure 15, the LNG volume that maximizes generator's profit differs from the system's optimal volume. Hence, interests of the social planner or regulator and generators are not aligned, which can cause inefficiencies in the electricity market given the fact that generators are responsible for their own fuel supply. This effect can be exacerbated as generation companies are often owners of a portfolio of generators, with various technologies represented. Figure 16 shows the marginal profit (in $/MWh) for different technologies as LNG import volume varies.

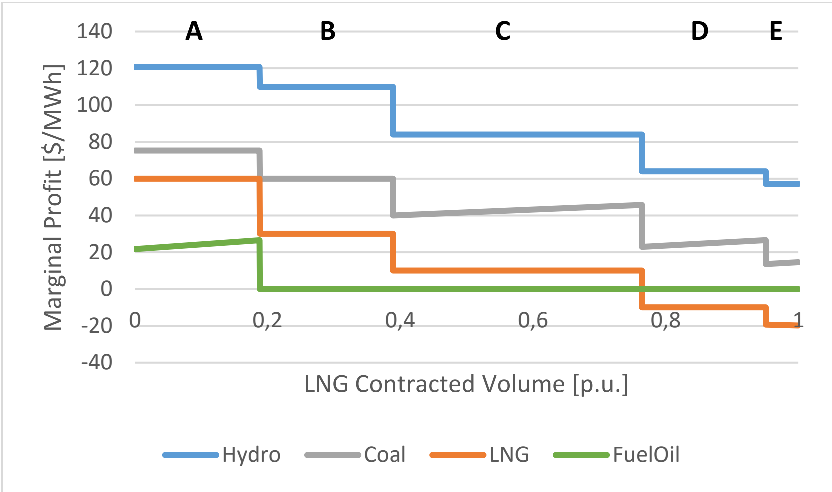

Figure 16: Marginal profit [$/MWh] per technology as a function of the imported LNG volume.

4.2.3 Contract Flexibility

In this section, we studied the effects of contract flexibility on system cost and contract volume decision. Studies where carried out by modifying the flexibility parameter (X or Y) from 0 (fully flexible) to 1 (fully inflexible) of the available LNG contract. The only LNG available contract has a price of 80 [$/MWh] and the system is the same as in the previous studies.

4.2.3.1 Minimum volume contract

Given a flexible LNG contract, a minimum volume will allow the system to use different quantities of LNG according to the hydrological scenario, in a given range. This is shown in Figure 17.

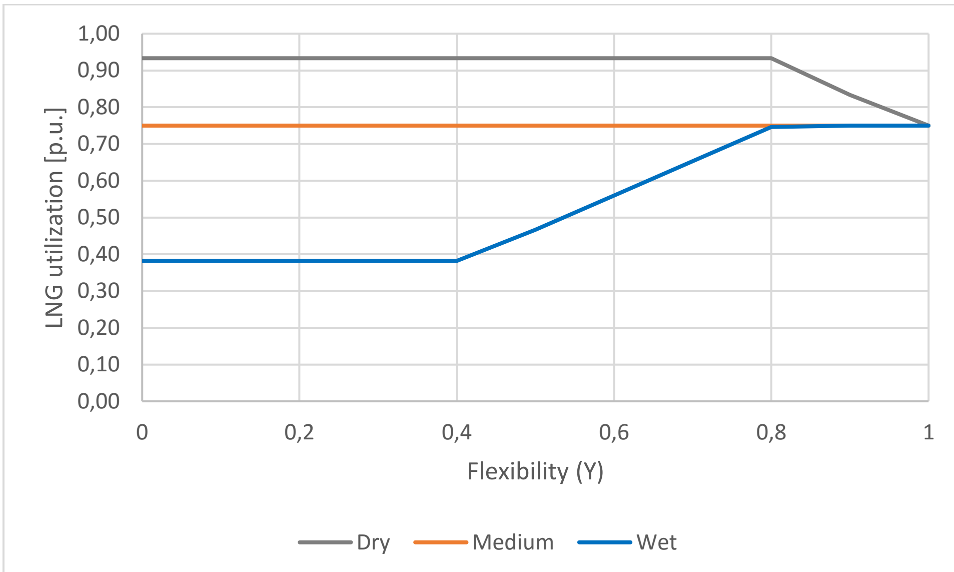

Figure 17: LNG utilization per scenario as LNG contract flexibility varies (Y, minimum volume)

As flexibility increases the range in which LNG utilization can move also increases, allowing the system to reach optimal levels of LNG utilization for each scenario. For minimum volumes under 0.4 [p.u.] there is no change in LNG utilization, as the optimal levels are already attained.

Increasing contract flexibility also reduces expected system costs by 4.9%, as less fuel-oil generation is needed in dry scenarios and less coal generation is displaced in wet scenarios, as shown in Figure 18.

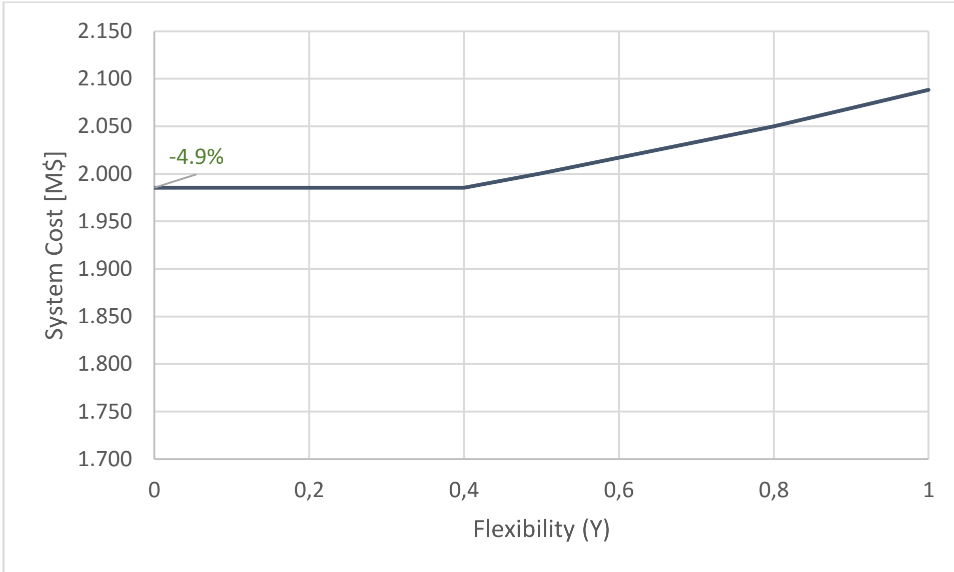

Figure 18: System expected cost as LNG contract flexibility varies (Y, minimum volume). Label indicates cost reduction by the fully flexible contract ($Y = 0$) with respect to the fully inflexible contract ($Y = 1$).

4.2.3.2 Penalization contract

Increasing flexibility in Take-or-Pay contracts with penalizations will not automatically improve system performance, and this is fundamentally different from what we observed in the study carried out with minimum volume contracts. In fact, if penalizations are too important the LNG contract will act as a fully inflexible contract. In Figure 19 LNG utilization as flexibility increases (decreasing penalizations) is illustrated, and 3 ranges can be found.

A. Penalizations are too large, it is not economically efficient to underutilize the LNG already bought.
B. LNG utilization is reduced in wet scenarios. This implies that less costly coal generation is not displaced by LNG generation, but a penalization has to be paid. The flexibility threshold is given by the point where the *variable cost* (as exposed in 0) of the LNG is less than that of coal, as shown in equation (29). In this case, the flexibility threshold for wet scenarios is $X = 0{,}375$

$$\begin{gathered} \beta_{LNG}^{*} \cdot (1 - X) \leq \beta_{coal} \\ X \leq 1 - \frac{\beta_{coal}}{\beta_{LNG}} \end{gathered} \tag{29}$$

C. LNG imports are increased in order to reduce fuel-oil generation in dry scenarios The setback of this action is that penalizations has to be paid in medium and wet scenarios for the LNG volumes that are not used. Therefore, a flexibility threshold for dry scenarios can be derived, as seen in equation (30), and it reflects the point where the benefits of displacing fuel-oil generation in dry scenarios (right side of the equation) are greater than the penalizations that have to be paid in wet and medium scenarios (left side of the equation). In this case, the flexibility threshold for dry scenarios is $X = 0{,}184$.

$$
\begin{gathered}
\left(\beta_{fueloil} - \beta_{LNG}\right) \cdot \rho_{dry} \geq X \cdot \beta_{LNG} \cdot \left(1 - \rho_{dry}\right) \\
X \leq \frac{\left(\beta_{fueloil} - \beta_{LNG}\right) \cdot \rho_{dry}}{\beta_{LNG} \cdot \left(1 - \rho_{dry}\right)}
\end{gathered}
\tag{30}
$$

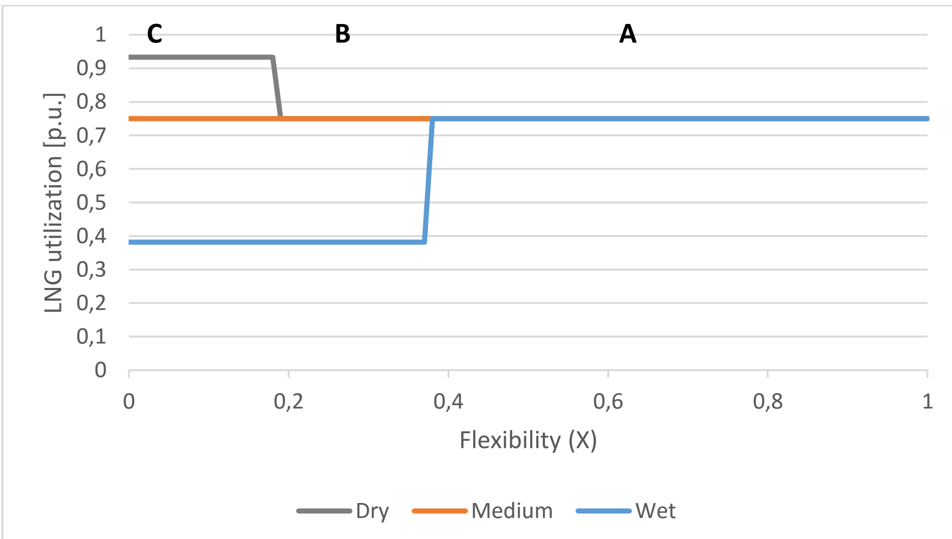

Figure 19: LNG utilization per scenario as LNG contract flexibility varies (X, penalization)

LNG utilization differs strongly depending on the type and flexibility of the contract. On one hand, a contract with minimum volume will always generate a range of maneuver that can be exploited by the system operator, allowing him to use different volumes of LNG according to the hydrological scenario.

On the other hand, a contract with penalizations can prove to be unattractive if penalties are too high, and it will be equivalent to a fully inflexible Take-or-Pay contract. Therefore, low penalties are necessary to benefit from the flexibility of the contract (under ~40%).

Finally, it is important to mention that this study was carried out from a systemic point of view, so the decision of whether or not paying a penalty and reducing LNG import does not take into account impacts on individual generator’s benefits.

4.2.4 Contract Portfolios

Having stated the fundamentals of Take-or-Pay contract decision and the effects of flexibility on it, we proceeded to study optimal portfolios of LNG supply. This sections aims to analyze how contract price and flexibility affects selection when given a set of available LNG supply contracts to choose from.

Studies were carried out using three available contracts with different levels of flexibility: one fully inflexible Take-or-Pay and two other flexible contracts (of the same type of flexibility).

4.2.4.1 Portfolio with minimum volume contracts

As seen in section 4.2.1, when presented to an inflexible Take-or-Pay contract the optimal volume of LNG is consistent with the requirements of the medium scenario. When presented to a flexible contract, the system planner has to take a decision: he can continue to use the less costly inflexible contract, or he can arrange a supply with the flexible contracts in order to adapt its imports in extreme scenarios.

Three cases were studied, named A, B and C, with different prices for the flexible contracts. Prices for each contract in each case are shown in Table 9. Results of contract decision and ex-post LNG utilization per scenario are shown in Figure 20.

Available Contracts	Min. Vol. (Υ) [p.u.]	Contract Price [$/MWh]		
		Case A	Case B	Case C
ToP	1	80	80	80
Flex1	0.6	90	85	85
Flex2	0.2	110	110	88

Table 9: Minimum Volume [p.u.] and price [$/MWh] of available contracts for the three cases studied.

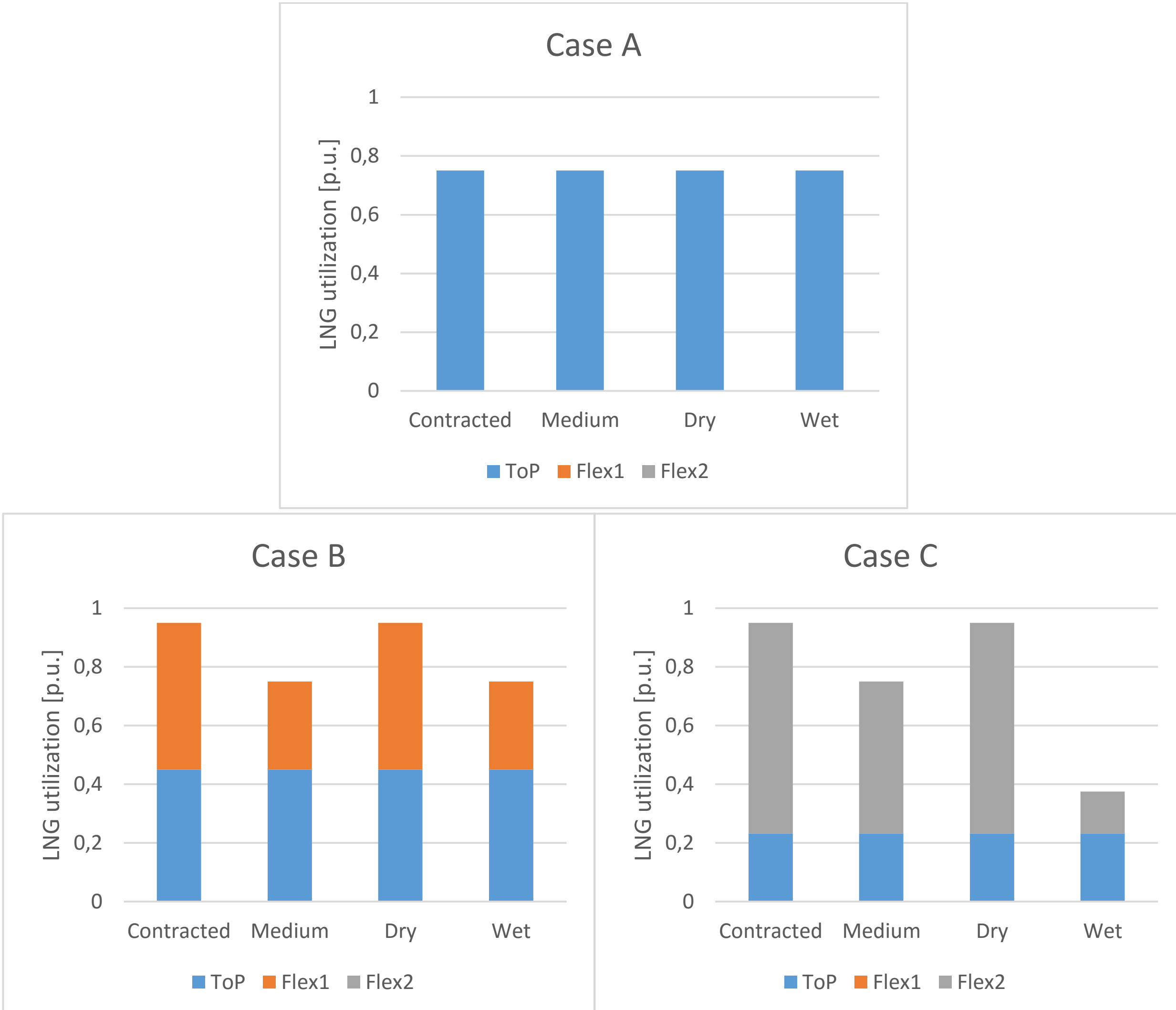

Figure 20: Contracted LNG volume and LNG utilization per scenario for minimum volume contracts.

We analyzed each case separately:

In case A, price of flexible contracts is too high, therefore they are economically inefficient. Only the inflexible contract is selected to supply the whole demand even though this causes inefficiencies in extreme scenarios.

In case B, LNG demand is supplied by a combination of a base-load contract (*ToP* contract) and a flexible contract (*Flex1* contract). A fraction of the contracted volume in the Flex1 contract is delivered in all the scenarios, corresponding to its minimum volume clause, and the remaining is delivered only in dry scenarios.

In this case selecting the flexible contract presents more benefits than extra costs to the system. Benefits come from displacing more costly generation in dry scenarios (e.g. fuel-oil generation) and extra cost come from having to pay LNG at a higher price in all scenarios, as there is a minimum volume to respect, with respect to the ToP contract. This is shown in equation (31), where benefits are in the left side of the inequality and extra costs in the right side. From the mentioned equation a price threshold for dry scenarios can be derived for the flexible contract (dependent on its flexibility and variable costs of alternative sources), as seen in equation (32). Under this threshold the flexible contract becomes economically efficient to supply LNG in dry scenarios.

$$(1-Y)\cdot\left[\beta_{fueloil}-\beta_{Flex}\right]\cdot\rho_{dry}\geq\ Y\cdot[\beta_{Flex}-\beta_{ToP}] \tag{31}$$

$$\beta_{Flex}\leq\frac{\beta_{ToP}\cdot Y+\beta_{fueloil}\cdot(1-Y)\cdot\rho_{dry}}{Y+(1-Y)\cdot\rho_{dry}} \tag{32}$$

In case C, LNG demand is supplied by a combination of a base-load contract (*ToP* contract) and a flexible contract (*Flex2* contract). A fraction of the contracted volume in the Flex2 contract is delivered in all the scenarios, corresponding to its minimum volume clause, and the remaining is delivered in medium or dry scenarios, according to its requirements.

In this case selecting the flexible contract presents more benefits than extra costs to the system. Benefits come from using less costly generation (e.g. coal generation) instead of LNG in wet scenarios, and extra cost come from having to pay LNG at a higher price in all scenarios, with respect to the ToP contract. This is shown in equation (33), where benefits are in the left side of the inequality and extra costs in the right side. From the mentioned equation a price threshold for dry scenarios can be derived for the flexible contract, as seen in equation (34). Under this threshold the flexible contract becomes economically efficient to reduce its deliveries in wet scenarios.

$$(1-Y)\cdot[\beta_{ToP}-\beta_{coal}]\cdot\rho_{wet}\geq[\beta_{Flex}-\beta_{ToP}]\cdot((1-\rho_{wet})+Y\ \cdot\rho_{wet}) \tag{33}$$

$$\beta_{Flex}\leq\frac{\beta_{ToP}-\beta_{coal}\cdot(1-Y)\cdot\rho_{wet}}{(1-\rho_{wet})+Y\cdot\rho_{wet}} \tag{34}$$

In Figure 21, the available contracts for each case and the aforementioned thresholds are shown. In Case A, both flexible contracts are above the thresholds and therefore inefficient. In Case B, contract *Flex1* is under the dry threshold, therefore economically efficient to supply LNG in dry scenarios. Finally, in Case C, contract *Flex2* is under both thresholds, therefore economically efficient to supply LNG for dry and wet scenarios.

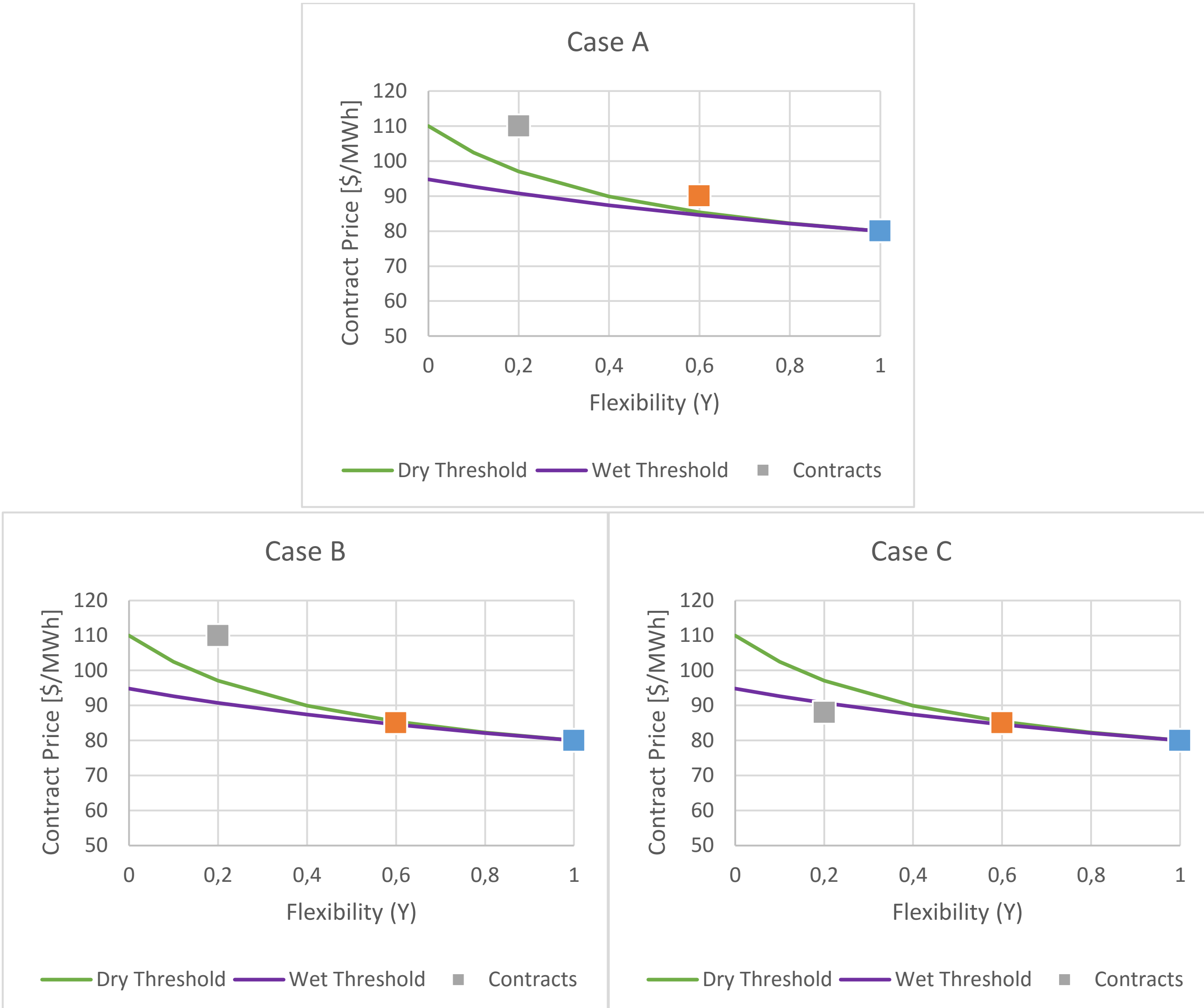

Figure 21: Price of available contracts and efficiency thresholds for minimum volume contracts. The three studied cases are shown

4.2.4.2 Portfolios with penalization contracts

Similar to the case with the minimum volume contracts, the system planner might have to choose between an inflexible Take-or-Pay contract and a flexible one. To analyze this situation, three cases were studied, named A, B and C, with different prices for the flexible contracts. Prices for each contract in each case are shown in Table 10. Results of contract decision and ex-post LNG utilization per scenario are shown in Figure 22.

Contract	Min. Vol. (Υ) [p.u.]	Contract Price [$/MWh]		
		Case A	Case B	Case C
ToP	1	80	80	80
Flex1	0.3	85	82	82
Flex2	0.1	105	105	91

Table 10: Contracted LNG volume and LNG utilization per scenario for minimum volume contracts.

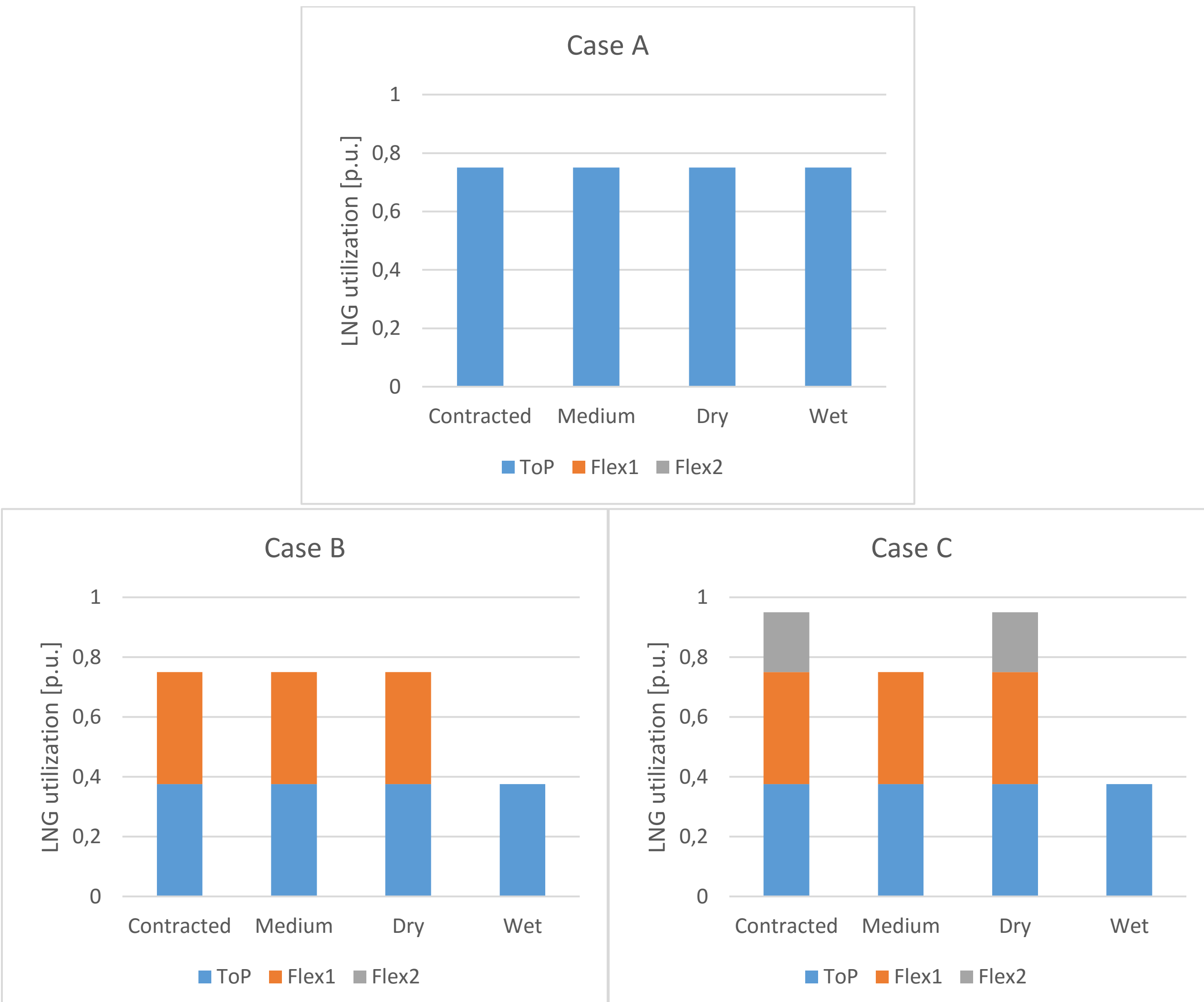

Figure 22: Contracted LNG volume and LNG utilization per scenario for penalization contracts.

Similarly to the previous case, we analyzed each case by separated:

In case A, price of flexible contracts is too high therefore they are economically inefficient. Only the inflexible contract is selected to supply the whole demand even though this causes inefficiencies in extreme scenarios.

In case B, LNG demand is supplied by a combination of a base-load contract (*ToP* contract) and a flexible contract (*Flex1* contract). In this case the flexible contract is used to decrease LNG generation on wet scenarios enabling production with less costly technologies (e.g. coal generation), but paying a penalization for the undelivered volume. As there is no minimum volume constraint the totality of the contracted LNG can be not delivered in wet scenarios.

Similarly to the study with minimum volume contract, benefits come from increasing less costly generation in wet scenarios and extra cost come from the extra price payed for LNG in medium and dry scenarios, plus the penalizations payed for the undelivered volume in wet scenarios, as stated in equation (35). A price threshold can be derived for the utilization of the penalization contract in wet scenarios, equation (36). Under this threshold the penalization contract becomes economically efficient to reduce its deliveries in wet scenarios.

$$[\beta_{ToP} - \beta_{coal}] \cdot \rho_{wet} \geq \ [\beta_{Flex} - \beta_{ToP}] \cdot (1 - \rho_{wet}) + X \cdot \beta_{Flex} \cdot \rho_{wet} \tag{35}$$

$$\beta_{Flex} \leq \frac{\beta_{ToP} - \beta_{coal} \cdot \rho_{wet}}{1 - \rho_{wet} \cdot (1 - X)} \tag{36}$$

In case C, LNG demand is supplied by a combination of a base-load contract (*ToP* contract) and both flexible contracts (*Flex1* and *Flex2* contract). In this case one contract is used to reduce LNG consumption in wet scenarios, by means of a penalization, as in Case B, and the other is used to increase consumption in dry scenarios, but paying a penalization in medium and wet scenarios.

The flexible contract that is used to increase LNG consumption in dry scenarios (*Flex2*) produces benefits to the system by displacing more costly generation in dry scenarios. On the other hand it have the extra costs of penalizations in medium and wet scenarios, where LNG is not consumed, and the extra price at which LNG is bought in dry scenarios (Equation (37)). A price threshold can be derived for the utilization of the penalization contract in dry scenarios, shown in equation (38). Under this threshold the penalization contract becomes economically efficient to be used only in dry scenarios.

$$\left[\beta_{fueloil} - \beta_{Flex}\right] \cdot \rho_{dry} \geq \ [\beta_{Flex} - \beta_{ToP}] \cdot \rho_{dry} + X \cdot \beta_{Flex} \cdot (1 - \rho_{dry}) \tag{37}$$

$$\beta_{Flex} \leq \frac{\beta_{ToP} - \beta_{coal} \cdot \rho_{wet}}{\rho_{dry} + X \cdot (1 - \rho_{dry})} \tag{38}$$

In Figure 21, the available contracts for each case and the aforementioned thresholds are shown. In Case A, both flexible contracts are above the thresholds and therefore economically inefficient. In Case B, contract *Flex1* is under the wet threshold, therefore economically efficient to be not delivered and pay the penalization in wet scenarios. Finally, in Case C, contract *Flex2* is under the dry threshold, but not under the wet threshold, therefore economically efficient to supply LNG only for dry scenarios.

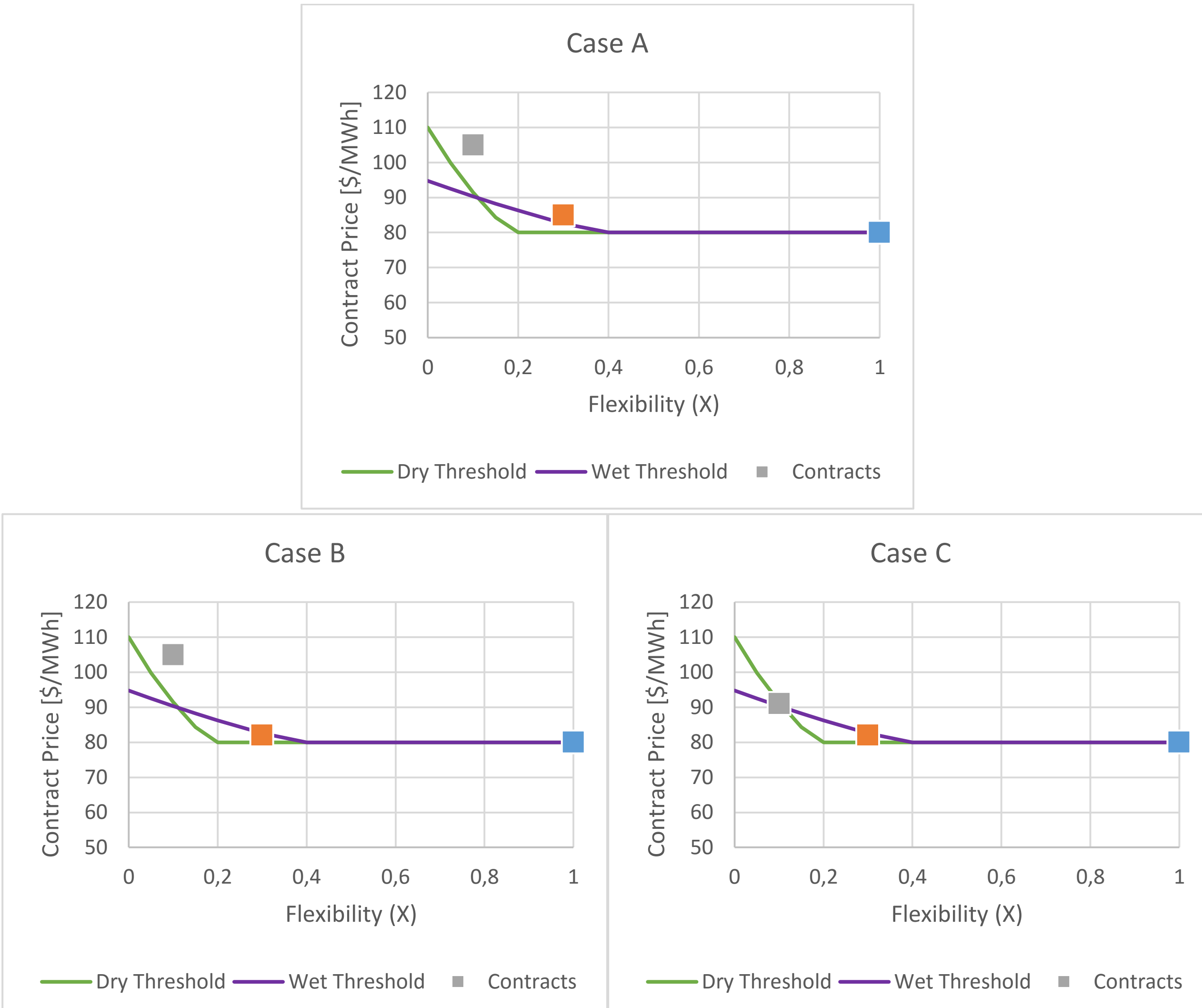

Figure 23: Price of available contracts and efficiency thresholds penalization contracts. The three studied cases are shown

4.2.4.3 Analysis on contract portfolios

Studies demonstrated that an optimal portfolio of LNG supply can be determined by using the proposed model. Depending on the available contracts, a Take-or-Pay contract will be selected for a base LNG demand and flexible contracts will be selected for extreme hydrological scenarios. Flexible contracts can therefore support increased import LNG volumes or reduction of actual consumption in extreme scenarios while providing a reduction in system costs.

Contracted volume and posterior usage will depend on the type of flexibility of the available contracts. Minimum volume contracts main advantage is that they provide a range within which LNG intake can vary without paying a penalization, but nevertheless they require a fraction of it to be used over all scenarios, displacing the inflexible Take-or-Pay contract in the base demand. As the minimum volume increases (less flexibility), more base demand will be supplied by it, increasing the contract costs. Therefore, the threshold price at which it becomes economically efficient decreases as flexibility decreases.

On the other hand, penalization contracts do not restrict usage per scenario. As a consequence, the whole contracted volume can be rejected by paying a penalization, as seen in Figure 22. Also, as seen in 4.2.3.2, large penalizations (over 40% for this case) make this type of contract inefficient for the system operation. This effect restricts the attractive contracts to only those with low penalizations.

5 STUDY CASE: LARGE SCALE SYSTEM

Studies were carried out in a large scale system. It was a representation of the Chilean *Interconnected Central System (SIC)*, a hydrothermal power network. The objective was to analyze the current import situation in Chile and to evaluate the optimal LNG supply portfolio through several contract options.

5.1 Description of the study case

5.1.1 The system

The electricity network is consistent with the Chilean SIC based on the Nodal Price Report of April 2015 [74]. It is a linear system with 6 nodes (Figure 24) and the transfer limits of the lines are shown in Table 11.

Line	Max Transfer [MW]
North – North Central	388.7
North Central – Central	255.9
Central – South Central A	2806
South Central A – South Central C	1506.8
South Central C – South	764.1

Table 11: Maximum transfer capacity of lines [MW]

The generation park consist of 101 units that represent clusters per node of generators with the same technology and similar variable costs, up to April 2015. The available capacity per node/technology is shown in Table 12 and the number of units per technology in Table 13. For the detailed list of generators and its parameters see Appendix II.

It can be seen that LNG generation is concentrated in the Central node, where the most important demand is located, and in the North node. The south region is strong in hydro generation and the North and North Central regions have predominantly thermal and solar/wind generation.

Node	Solar	Wind	Biomass	FuelOil/Diesel	Coal	R-o-t-r*	Dam	GNL
North	371	99	-	365	-	-	-	338
North Central	129	598	-	359	393	33	-	-
Central	4	18	46	45	756	1145	810	2212
South Central A	-	-	33	83	-	82	917	-
South Central C	-	43	280	484	860	134	2173	-
South	-	36	101	242	-	293	163	-

Table 12: Available generation capacity [MW] per technology and node. * Run-of-the-river

Technology	Number of Units
Solar	7
Biomass	26
Wind	5
FuelOil	21
Coal	7
Run-of-the-river	9
Dam	20
GNL	6
TOTAL	**101**

Table 13: Number of generation units per technology.

The hydro system is composed of 29 generation units, 20 of which are dependent on 8 dams and 9 are run-of-the-river generators. The hydro structure of inflows, dams and generation units is a complex one and it is divided in 5 basins. A diagram of the hydro system is shown in Figure 25.

Finally, two gas tanks were modeled, one representing the regasification terminal of Quintero, supplying LNG to the Central node generators (Nehuenco, Nueva Renca, Quintero and San Isidro), and one representing the regasification terminal of Mejillones, supplying LNG to the North node generator of Tal-Tal. Their storage capacities where augmented in order to conduct the studies without the technical limitations of the gas regasification process, and are not representative of real storage capacities.

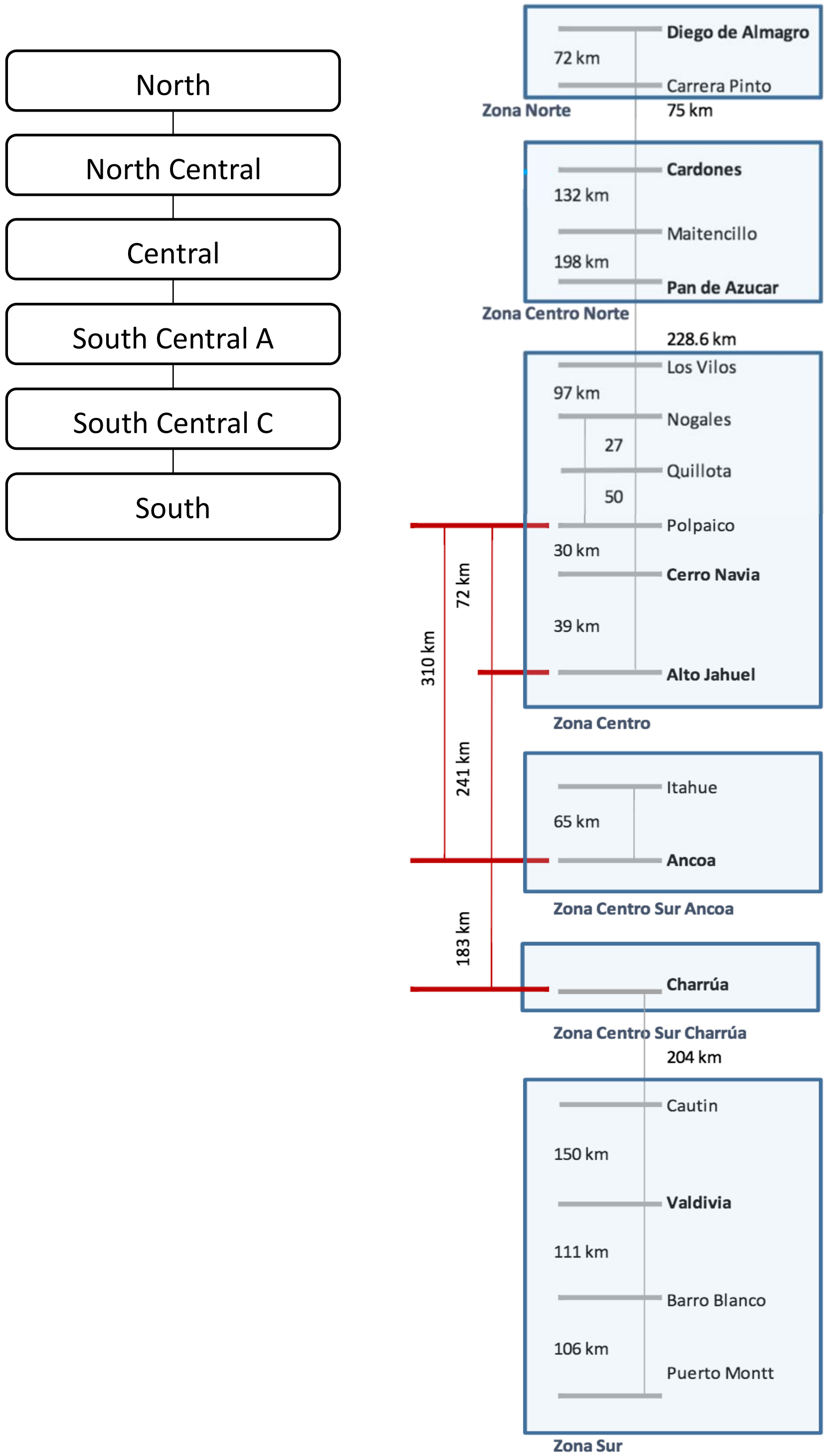

Figure 24: Nodal electricity system (left) and its correspondence to the actual network.

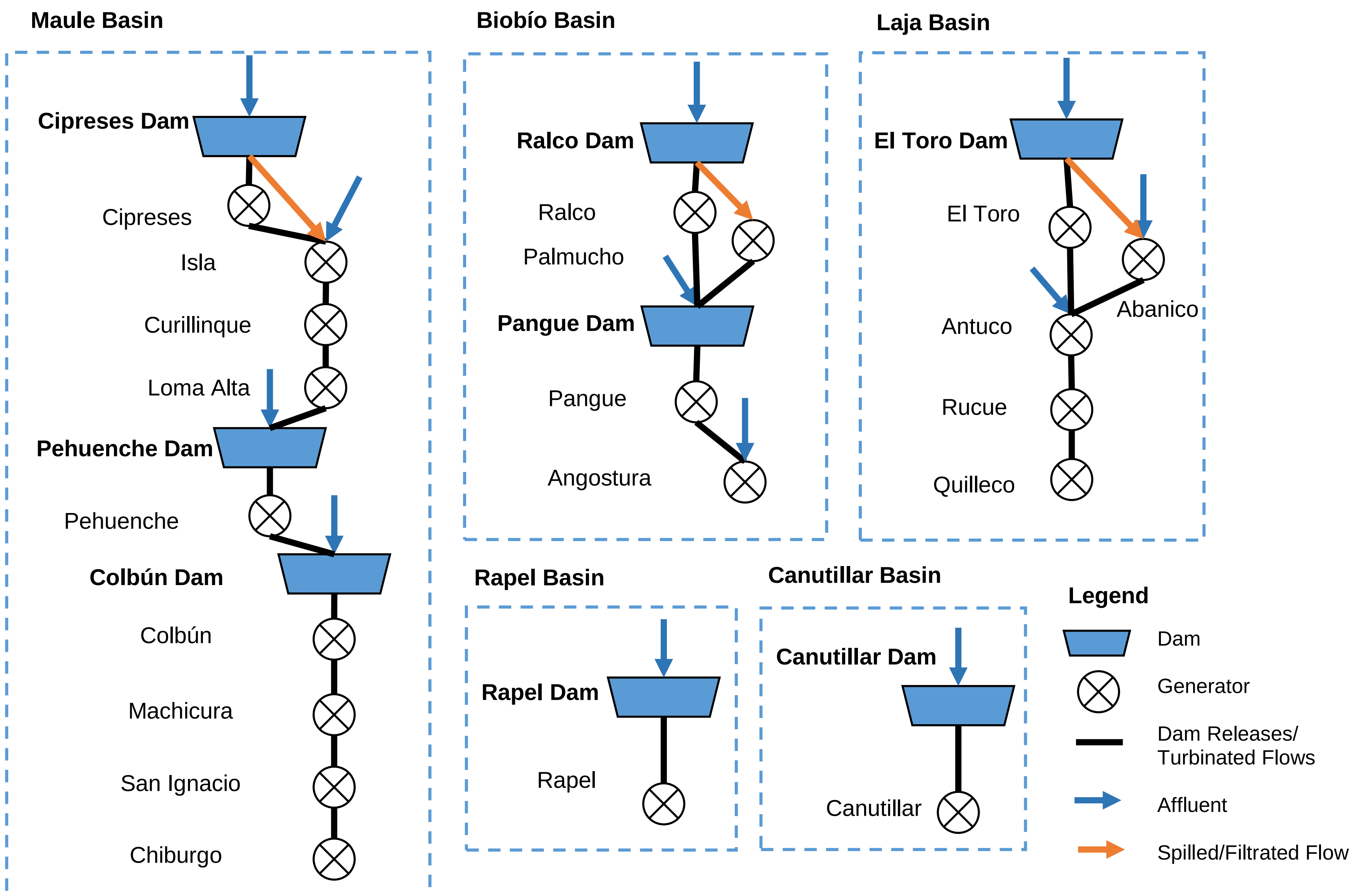

Figure 25: Hydro system divided in its 5 basins.

5.1.2 Hydrological scenarios

54 hydrological scenarios acted as input to the model, that corresponded to the historical hydrological years recorded in Chile since 1961, and which are used in the planning of the system operation and investment by the CDEC-SIC.

5.1.3 Available Contracts

Several studies were carried with different sets of available LNG contracts, allowing us to analyze the trade-offs between contract price and flexibility. The basic spot, flexible and Take-or-Pay contracts used are shown in Table 14. As a comparison, variable cost of coal generation is around 40-50 [$/MWh] and FuelOil/Diesel generation over 180 [$/MWh] (see Appendix II for variable cost per unit).

Contract	Minimum Volume (Y)	Penalizations (X)	Price [$/MWh]
Take-or-Pay	1	1	80
Flex Minimum Volume	0.8	0	85
Flex Penalizations	0	0.2	85
Spot	-	-	180

Table 14: Available LNG contracts for the large scale system study.

5.1.4 Simulation options

Simulations were carried out with a horizon of 1 year, set in year 2015. The simulation period was divided into two-week stages (26 time stages in total) and 5 blocks per stage. Additionally the problem was formulated as two-stage optimization problem, with the first stage acting as a common node and then the 54 hydrological scenarios running independently from the second stage, as seen in Figure 26.

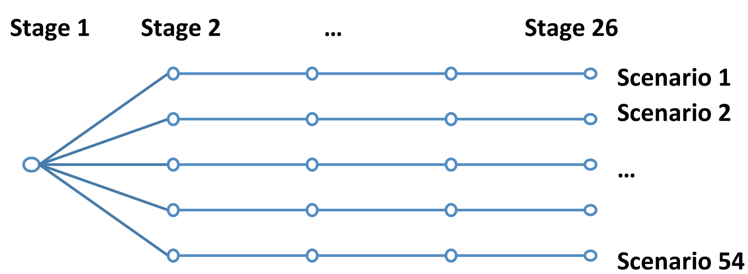

Figure 26: Scenario tree of the stochastic optimization problem

Wind and solar generation was obtained via a time series based on historical wind and solar generation.

Dam volume at the end of the simulation period was constrained to be equal or higher than the initial volume. This means that there is no inter-year regulation of the dam volume, since there is no future cost associated with it.

The optimization problem was solved in the Leftraru cluster of the National Laboratory of High Performance Computing (NLHPC).

5.2 Results

Several studies were carried, and results are presented in four main sub-sections, each of them focusing in different aspects of LNG contract decision and independent from each other:

- **Optimal LNG Portfolio**.
  - Systemic requirements of LNG through various type of contracts.
- **Transmission effects on LNG contract decision.**
  - Analysis on the effects of the electricity grid on LNG import decision.
- **Current import situation versus optimal situation**
  - Analysis and comparison of the current LNG import situation with the optimal case from the systemic, generator's and demand's point of view.
- **Risk Aversion**
  - Analysis of introducing risk notions in the LNG contract decision process.

5.2.1 Resolution Time

The whole simulation process consist in four sequential tasks: preprocessing the input data, formulating the LP problem, solving the optimization problem and computing and writing the results. The whole process takes around 30 minutes in the Leftraru cluster (Figure 27), which demonstrate the complexity of the undertaken problem.

Resolution time is high since the optimization problem is solved in a one-shot way, without the use of any decomposition scheme, such as Stochastic Dual Dynamic Programming (SDDP). Computational effort will significantly increase with the problem size, hindering the applicability of the proposed methodology to larger or more detailed systems. Also, hydrothermal systems with high storage capacity of reservoirs may need a longer planning horizon since they can have inter-year regulation capacity, such as the Brazilian where the planning horizon is at least 3 years. Therefore, the implementation of a decomposition algorithm, such as SDDP, is a key step for this methodology to be used in further analysis.

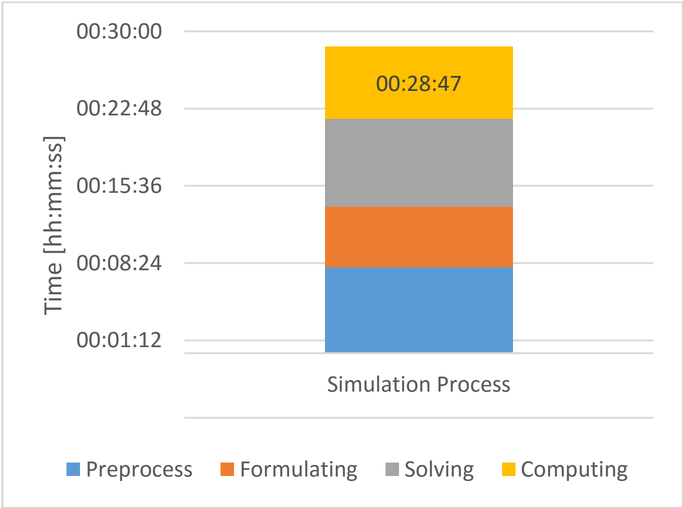

Figure 27: Resolution time per task of the large scale system.

5.2.2 Optimal LNG portfolio

The objective of this study is to analyze the system requirements of LNG and how optimal portfolio decision changes as different contracts are available. First, an ideal case is studied without LNG supply constraints. Next, four sets of available contracts are studied:

- First, only with a Take-or-Pay contract;
- Second, a Take-or-Pay contract with access to the spot market (only to buy LNG).
- Third, a Take-or-Pay contract, access to the spot Market and a minimum volume flexible contract;
- And fourth, a Take-or-Pay contract, Spot Market and a penalization flexible contract.

5.2.2.1 Ideal Case

A simulation without LNG supply constraints was carried out in order to determine the system requirements of LNG according to the hydrological scenario. Results of average and per scenario annual generation are shown in Figure 28 and Figure 29 respectively. In Figure 29 Biomass, Solar and Wind generation were grouped into Non-Conventional Renewable Energy (NCRE) generation and run-of-the-river and dam generation were grouped into Hydro generation. Additionally, LNG generation per scenario is detailed in Figure 30.

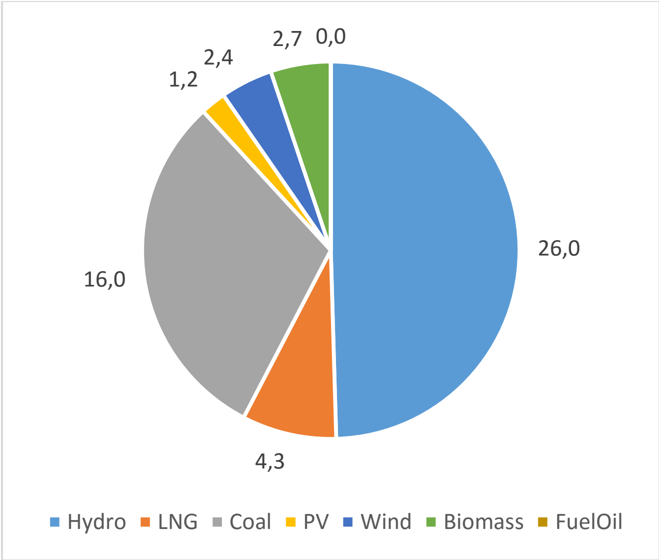

Figure 28: Average annual generation per technology without LNG supply constraints [TWh]

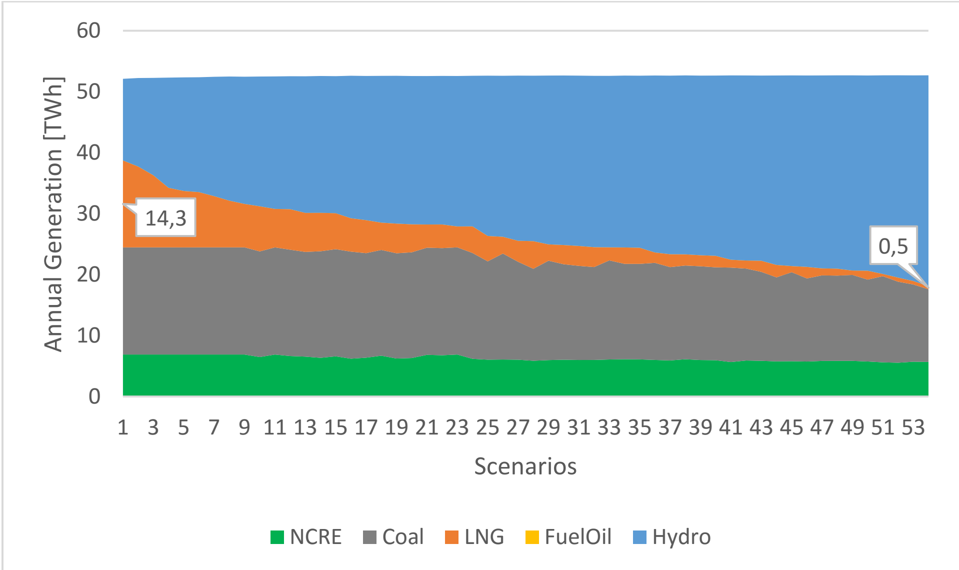

Figure 29: Annual generation per hydrological scenario [TWh] without LNG supply constraints. Scenarios are ordered from the driest (left) to the wettest (right). Labels indicate LNG generation in TWh at the extreme scenarios.

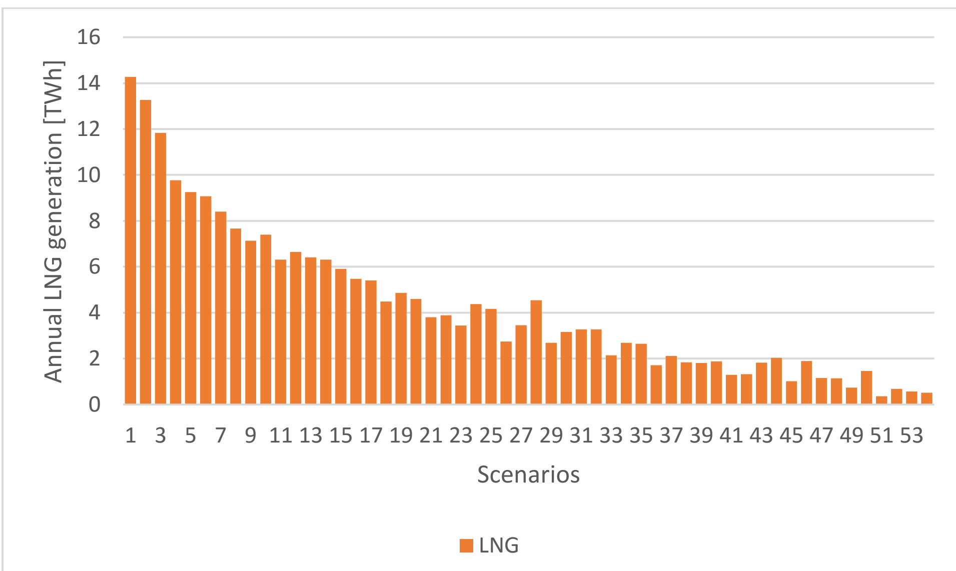

Figure 30: Annual LNG generation per scenario, without gas supply constraints. Scenarios are ordered from the driest (left) to the wettest (right).

Results show the preponderance of hydro generation in the Chilean power system, as almost half of the average generation is by hydro sources. Therefore the system is extremely dependent of the hydrological conditions and it is the LNG generation that compensates this variation, since coal generation remains mostly a base load technology. Also, hydrological scenarios are complex phenomenon since there are no two identical cases. Scenarios can have similar total hydro generation (in annual TWh) but LNG generation can differ greatly, as seen in scenarios 25 to 28.

Another important point is that there exist sufficient installed capacity to meet demand even in the driest scenarios without using fuel-oil/diesel generation. LNG facilities are sufficient if there were always available natural gas to fire them.

Even though NCRE generation amounts only to 10% of total annual generation, as of 2015, it is expected to grow significantly in the upcoming years. As of 2016 there were 2866 MW of NCRE installed capacity in the whole country, with 2692 MW under construction and over 18900 MW in projects with environmental approval [75]. This will bring significant challenges to the system operation, including LNG contract decision and operation. This subject is, however, out of the scope of this thesis

5.2.2.2 Take-or-Pay Contract

A simulation with only a Take-or-Pay contract was made (without access to the Spot market or any flexible contracts available).

Contract decision is a difficult one considering the variability of LNG requirements. As shown in Figure 29, annual LNG needs vary between 14.2 and 0.5 TWh, with an average of 4.3 TWh. When presented to an inflexible Take-or-Pay contract, what would be the optimal LNG import? Figure 31 and Figure 32 show the average and per scenario annual generation with an optimal Take-or-Pay contract.

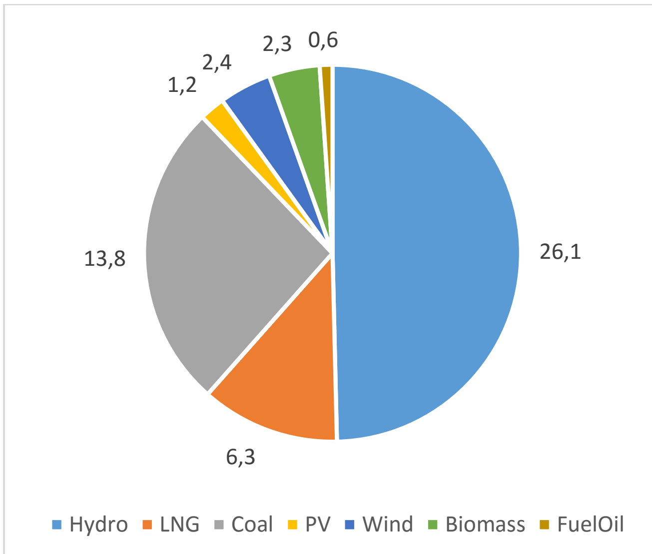

Figure 31: Average annual generation per technology with a LNG Take-or-Pay contract [TWh]

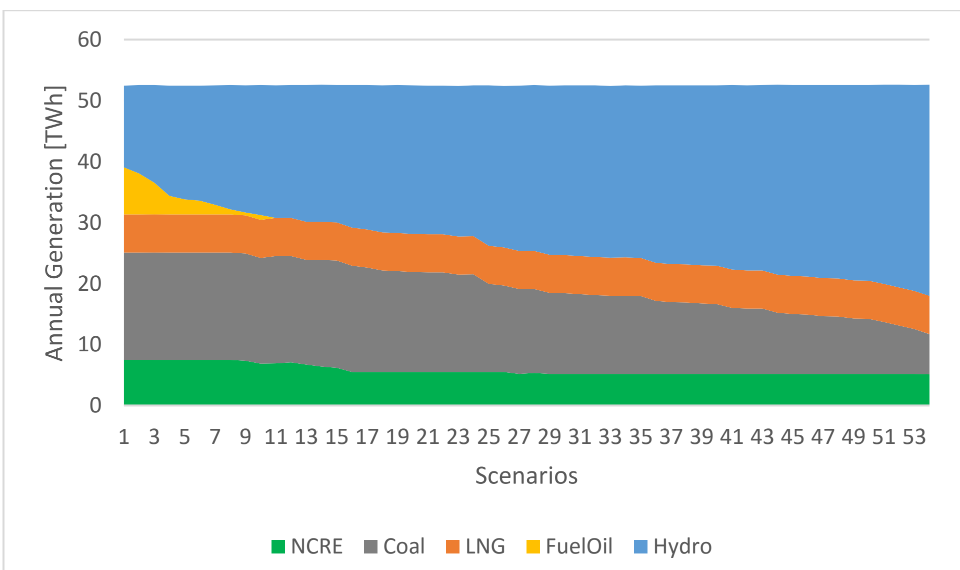

Figure 32: Annual generation per hydrological scenario [TWh] with a LNG Take-or-Pay contract. Scenarios are ordered from the driest (left) to the wettest (right).

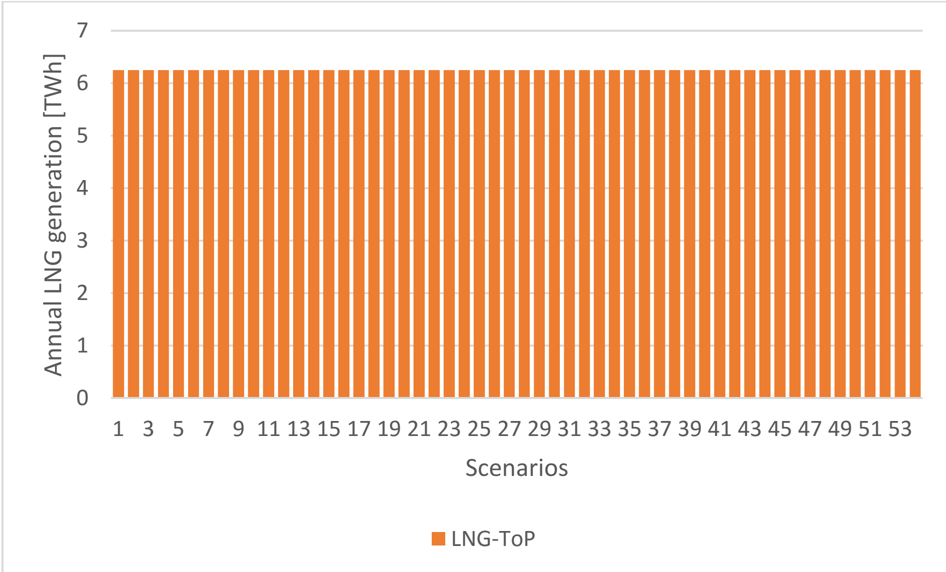

Figure 33: Annual LNG generation per scenario, with a Take-or-Pay contract. Scenarios are ordered from the driest (left) to the wettest (right).

The contracted equivalent energy (6.3 TWh per year) is more than the average LNG production in the ideal case (4.3 TWh per year). This happens because fuel-oil generation is much more costly than LNG generation, making the price differential between fuel-oil and LNG much bigger than that of LNG to coal. Thus, dry scenarios have a much bigger weight in the optimization's objective function than wet ones, increasing LNG supply.

The side effect of Take-or-Pay contract constraints is that LNG generation is constant throughout scenarios. This provokes that in dry scenarios (left side of Figure 32) more costly (i.e. fuel-oil) generation has to be used to meet demand and in wet scenarios (right side of Figure 32) less costly (i.e. coal) generation is displaced in favor of LNG generation.

5.2.2.3 Take-or-Pay Contract and Spot Market

Results of simulation carried out with a Take-or-Pay contract and access to the spot market are shown in Figure 34, Figure 35, and Figure 36. It should be noted that there was no limitations to LNG imports though the spot market, assuming a liquid, though more costly, market.

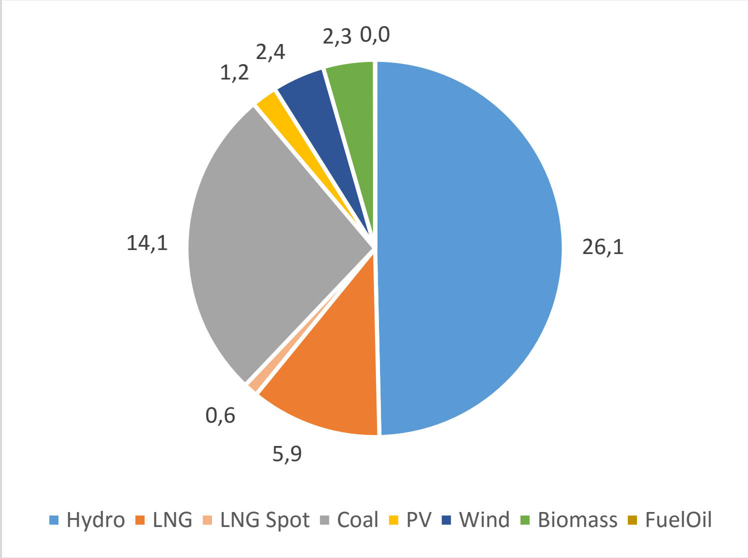

Figure 34: Average annual generation per technology with LNG Take-or-Pay contracts and Spot market [TWh]

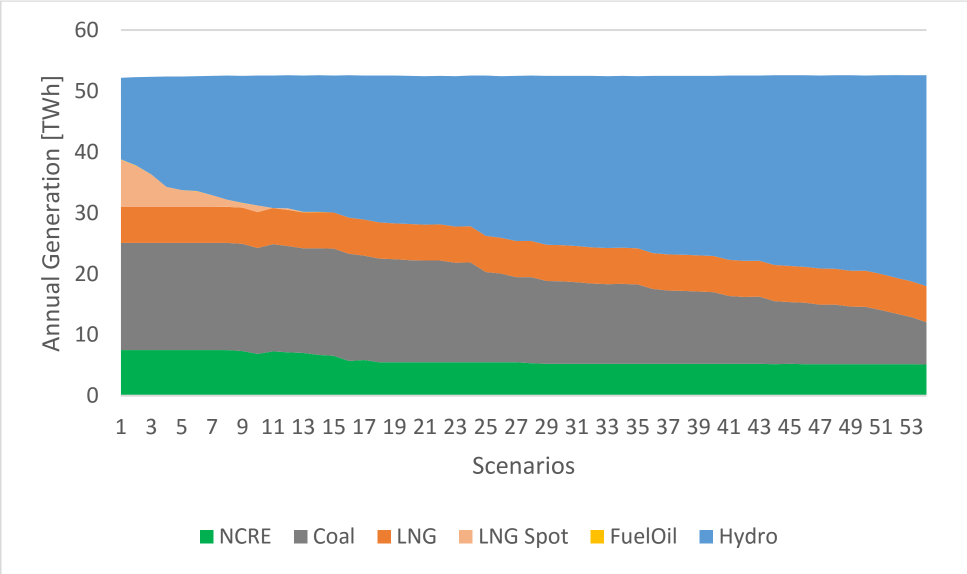

Figure 35: Annual generation per hydrological scenario [TWh] with a LNG Take-or-Pay contract and a Spot market. Scenarios are ordered from the driest (left) to the wettest (right).

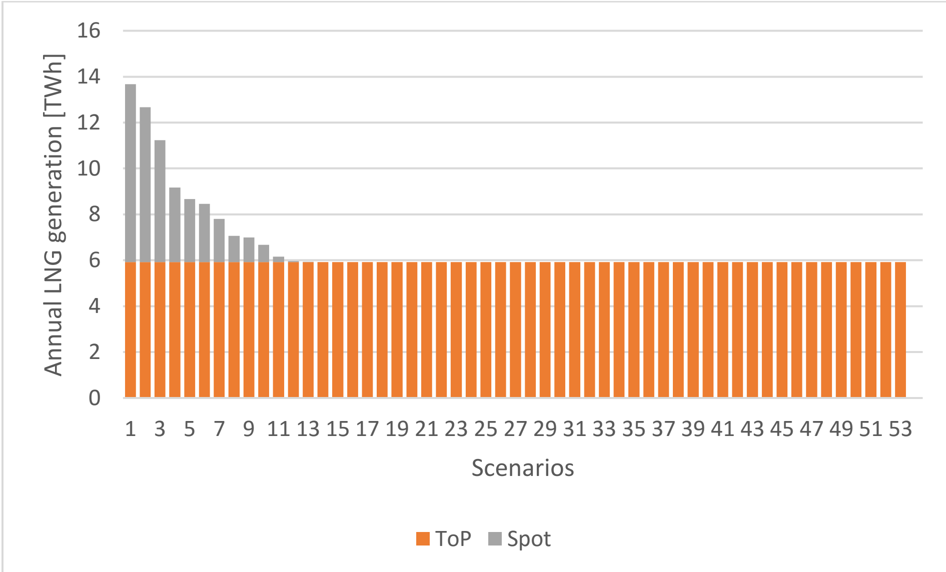

Figure 36: Annual LNG generation per scenario, with a Take-or-Pay contract and access to the Spot market. Scenarios are ordered from the driest (left) to the wettest (right).

When confronted to a rigid Take-or-Pay contract with the possibility of buying extra LNG from a more costly Spot market, the system will choose a base load of Take-or-Pay LNG and will use the Spot market in the extreme scenarios. In this case the spot market is only requested in 11 of the driest scenarios.

Access to the LNG spot market allows a reduction of fuel-oil generation to almost zero, since spot LNG is less costly than most fuel-oil generation. Also, as spot buys limit the cost of dry scenarios (fuel-oil generation over 180 $/MWh is not used), the Take-or-Pay contracted energy is reduced, though in a little amount (see Figure 34 and Figure 35).

A sensitivity study was carried, varying the Spot price from 80 to 180 [$/MWh]. Results show that contracted Take-or-Pay volumes are very sensitive to the Spot price (Figure 37). As the spot market becomes less costly, the inflexible Take-or-Pay contract loses attractiveness to the system planner and its contracted volume decreases. When the price of the Spot market is 130 [$/MWh], the contracted volume attains only 4.32 TWh per year.

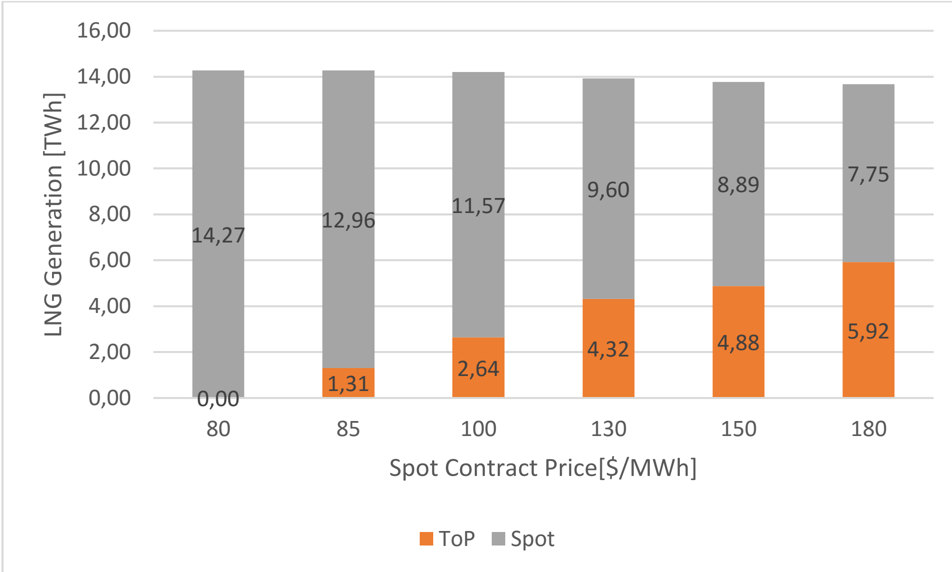

Figure 37: LNG generation [TWh] in the worst hydrological scenario as the LNG Spot price varies.

5.2.2.4 Minimum Volume Contract

This simulation was carried out with a Take-or-Pay and a minimum volume flexible (Y=0.8) contract available, with access to the Spot market. Results are shown in Figure 38, Figure 39 and Figure 40.

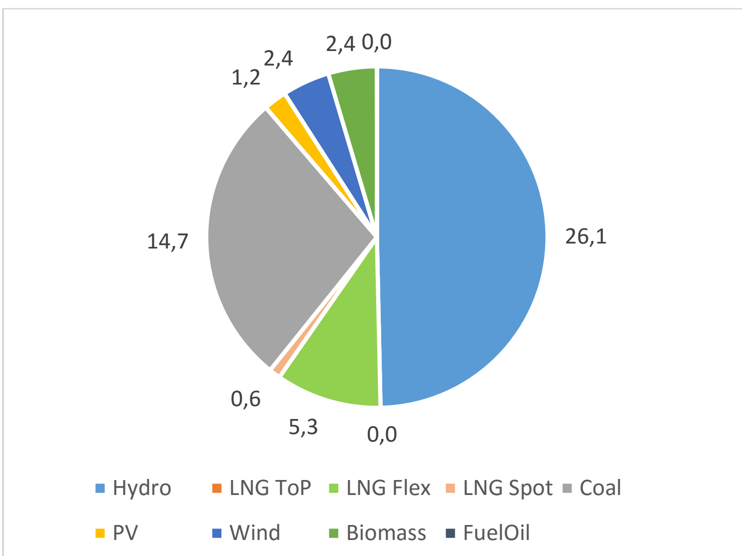

Figure 38: Average annual generation per technology with a LNG Take-or-Pay contract, a minimum volume contract and Spot market [TWh]

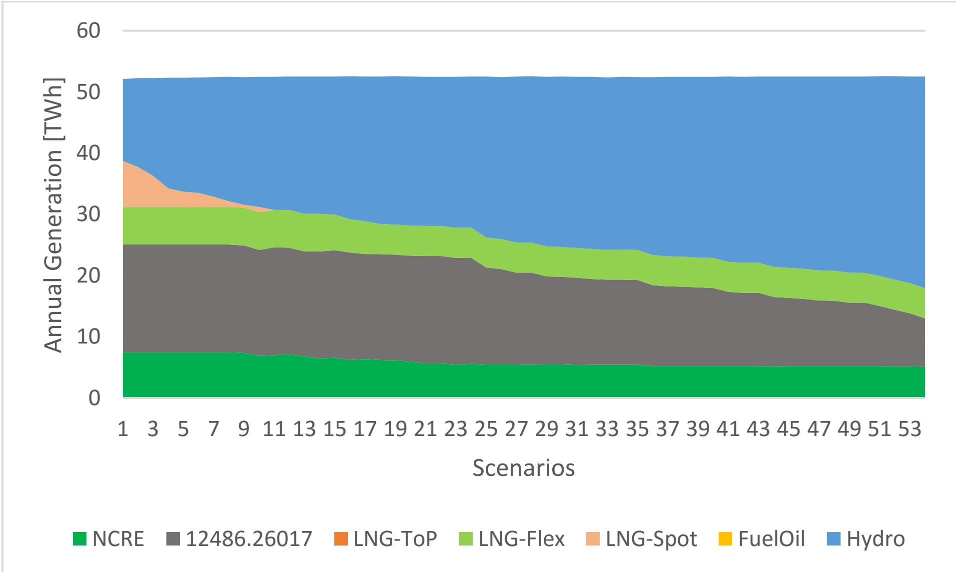

Figure 39: Annual generation per hydrological scenario [TWh] with a LNG Take-or-Pay contract, a minimum volume contract and a Spot market. Scenarios are ordered from the driest (left) to the wettest (right).

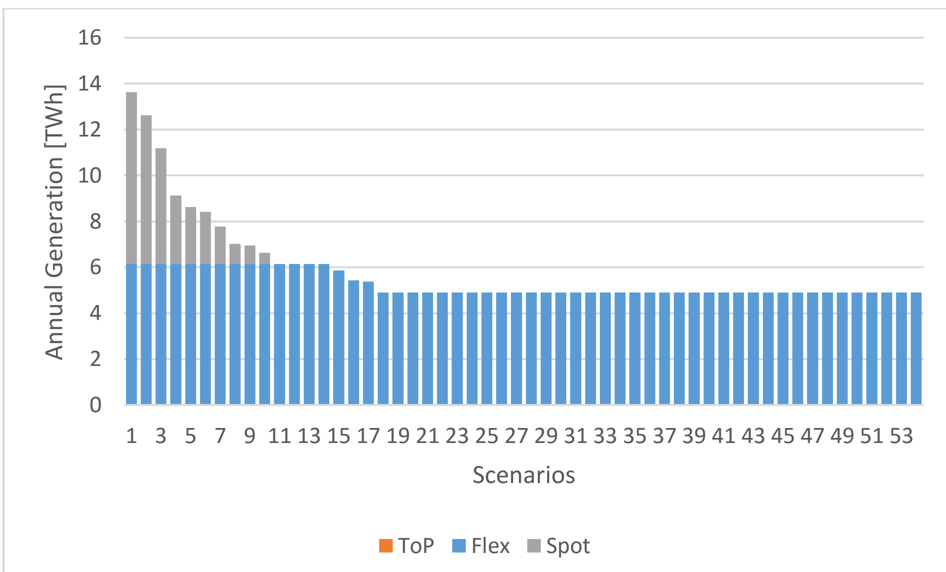

Figure 40: Annual LNG generation per scenario, with a Take-or-Pay contract, a 0.8 p.u. Minimum Volume contract and a spot market. Scenarios are ordered from the driest (left) to the wettest (right).

In this case the whole LNG supply is engaged with the minimum volume contract, dismissing the less costly Take-or-Pay contract. The spot market is used in 10 of the driest scenarios.

The flexible contract has in itself a base load (the minimum volume), which replaces the need of a base-load Take-or-Pay contract. The flexible contract allows the system planner to modify the intake of LNG according to the hydrological scenario, but the range in which it can vary is limited to only 20% of the contracted volume (1.2 TWh). This cap in flexibility allows the system to support only a minor increase in LNG contracted volumes (from 5.9 to 6.1 TWh)

5.2.2.5 Penalization Contract

This simulation was carried out with a Take-or-Pay contract and a penalization flexible (X=0.2) contract available, with access to the Spot market. Results are shown in Figure 41, Figure 42 and Figure 43.

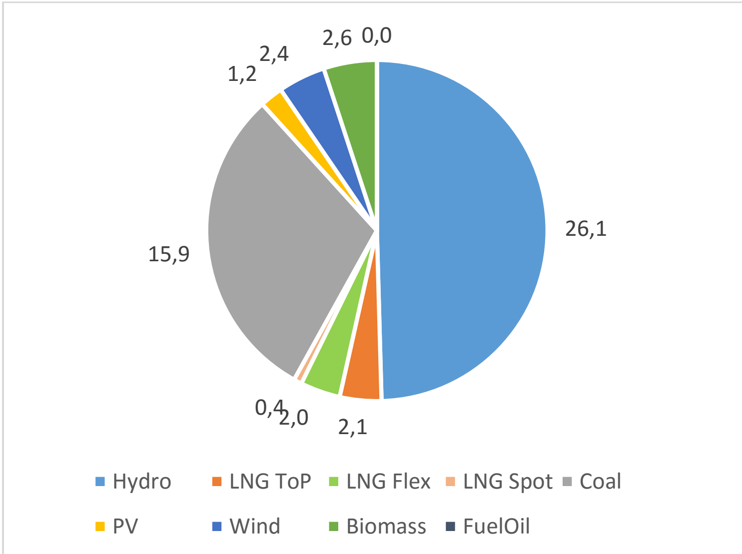

Figure 41: Average annual generation per technology with a LNG Take-or-Pay contract, a penalization contract and Spot market [TWh]

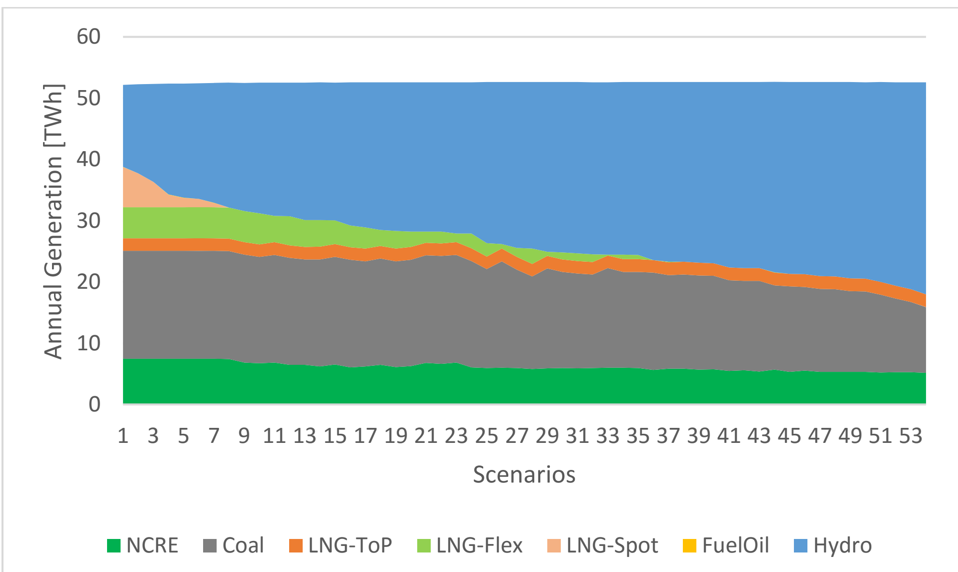

Figure 42: Annual generation per hydrological scenario [TWh] with a LNG Take-or-Pay contract, a penalization contract and a Spot market. Scenarios are ordered from the driest (left) to the wettest (right).

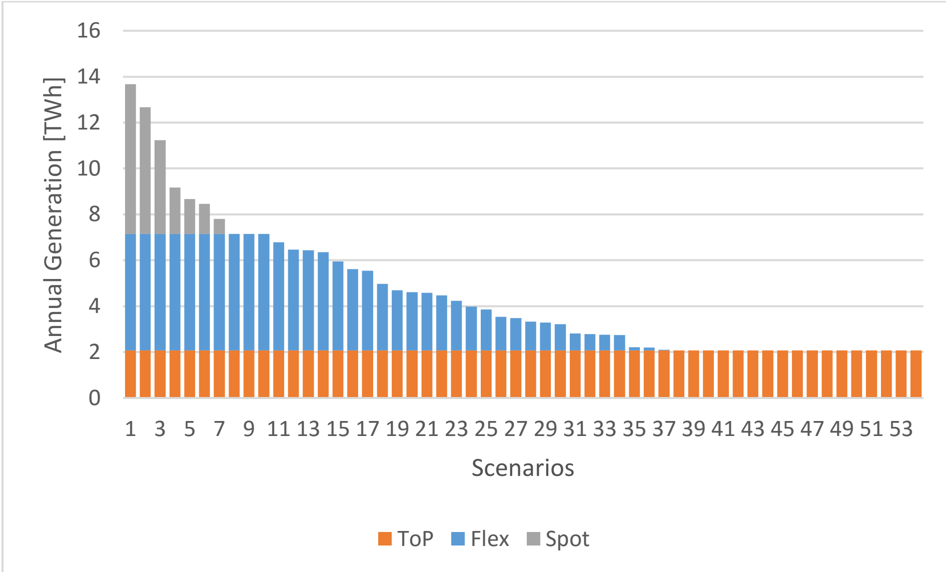

Figure 43: Annual LNG generation per scenario with a Take-or-Pay contract, a 0.2 p.u. penalization contract and a spot market. Scenarios are ordered from the driest (left) to the wettest (right).

An optimal portfolio of LNG supply contracts is determined with a Take-or-Pay contract providing the base LNG supply and the flexible contract and spot market providing the LNG needed for the extreme scenarios. In this case the penalization contract allows a wide range to regulate the LNG import volume, of 5 TWh per year, in contrast to the minimum volume contract which allows only a small margin for regulation of the LNG volume. Increased flexibility supports an increase in LNG contracted volume, reaching 7,1 TWh per year.

The penalization contract allows the system to reduce LNG imports in wet scenarios to produce power with coal instead of more costly LNG. This is economically efficient because the penalization (17 $/MWh) is smaller than the variable cost differential between coal and LNG (30 to 40 $/MWh).

However, in hydrothermal systems with reservoirs capable of inter-year regulation like the one in study, the flexible LNG could be used to displace *this year* hydro generation to save water for *next year*, instead of paying the penalization. To analyze this phenomenon a simulation must be made with a longer horizon, for example 2 years, or with future costs associated to dam stored volumes. We choose the first option, and a simulation was carried out with a 2 year horizon and 162 independent hydrological scenarios. This represents the available 54 hydrological scenarios for the first year and three hydrological scenarios for the second year (dry, medium and wet). All other parameters (demand, generators, available LNG contracts) are equal to the 1 year-horizon studies, and results are shown in Figure 44 and Table 15.

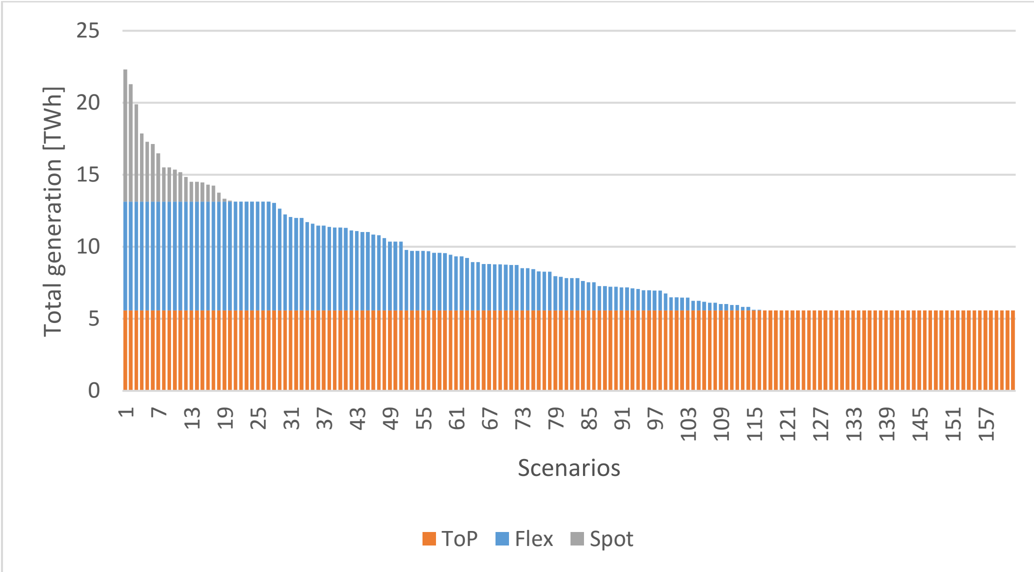

Figure 44: Total 2-year LNG generation per scenario with a Take-or-Pay contract, a X=0.2 penalization contract and a spot market. Scenarios are ordered from the driest (left) to the wettest (right).

Simulation Horizon	Take-or-Pay	Penalization	Total
1 year	2.1	5.1	7.2
2 years	2.8	3.8	6.7

Table 15: Annual Contracted LNG Energy [TWh] according to the simulation horizon.

Results show that as operational flexibility increases (with the capability of inter-year regulation by hydro reservoirs), **more base-load LNG can be accommodated** into the system via the Take-or-Pay contracts. Therefore, flexibility in LNG supply is less required, reducing the contracted volume of the Flexible contract by a 25%. Even so, the penalization contract remains as the largest contract engaged, providing capacity of LNG regulation to the system.

Sensitivity studies on contract flexibility and price were carried, for both the minimum volume and penalization flexible contracts, and results are shown Appendix III.

5.2.2.6 System Cost Comparison

Results show that LNG import decision is a complex one. System requirements are highly dependent on the hydrological scenario and they can oscillate in an extreme wide range. Decision is also highly dependent on the available contracts, since the optimal Take-or-Pay commitment vary significantly if there are flexible contracts available and it may turn in an all-or-nothing decision (either I choose to contract all the requirements with one contract or with the other).

However, this problem has to be analyzed with costs in perspective as it can exhibit the risks incurred by the system. Expected total system costs for the five studied cases are shown in Figure 45.

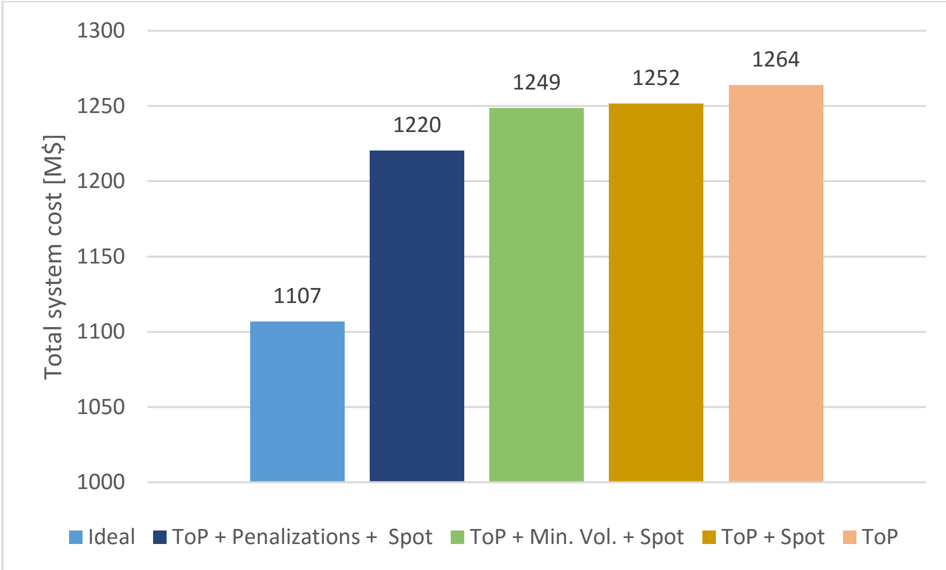

Figure 45: Expected total system costs [M$]

Results show that Take-or-Pay constraints increase system costs by over a 10% (157 M$) from an ideal case (without LNG constraints). This amount can be reduced as more flexibility is available for the system planner, such as access to the spot market or the availability of a flexible contract.

Cost savings produced by the minimum volume contract are small (only 3 M$) because (i) the regulation range in which LNG can fluctuate is small, and (ii) the base-load LNG (given by its minimum volume) is more costly, as this contract completely replaces the Take-or-Pay contract.

On the other hand the penalization contract allows a bigger cost reduction, as its regulation range is higher (5 TWh) and it does not replace the base-load Take-or-Pay contract entirely. Benefits produced by the penalization contract are higher, despite of having to pay a penalization when the LNG is refused.

5.2.2.7 Comments on water spillage

Water spillage (or reservoir overflow) was analyzed for all contract cases, to study if an excess of Take-or-Pay LNG could provoke spillages in wet scenarios.

Results show that there were only water spillages in the smaller reservoirs of Rapel and Ralco, in 28 and 14 of the 54 scenarios respectively. These spillages are not due to Take-or-Pay purchases made in advance but to excessive inflows into these reservoirs (with turbines generating power at their maximum output), and they are identical for all the studied cases, with and without Take-or-Pay constraints. In the studied cases there was always thermal generation (i.e. coal) that could be displaced in favor of natural gas generation when there was excess of gas (i.e. LNG with Take-or-Pay clauses in wet scenarios, see Figure 32). Hence, the system was not confronted to a situation where it could no longer accommodate all the NG and hydro generation. Nevertheless, the system may be forced to spill water from its reservoirs or vent/lose the excess of natural gas if system storage capacity does not suffices.

5.2.3 Effects of Transmission on LNG contract decision

The objective of this study was to analyze the effects that the electricity grid has on LNG import decision. Results of a simulation with the grid previously described were compared to a simulation with the power transfer limits enhanced, so there were no transmission constraints in the system. This study was carried out with only the Take-or-Pay contract available.

Results of transmission constraints in the electricity network and Take-or-Pay contracted energy are shown in Table 16 and Table 17 respectively.

Line	Transmission constraints	
	North-South	South-North
North - North Central	0%	0%
North Central - Central	19%	0%
Central - South Central A	0%	**41%**
South Central A - South Central C	0%	0%
South Central C - South	0%	0%

Table 16: Occurrence of transmission constraints per line for the base case.

Case	Take-or-Pay Contracted Energy [TWh]
With transmission limits	6.253
Without transmission limits	5.354

Table 17: Take-or-Pay contracted energy [TWh] with and without transmission limits.

Transmission losses account for 3% of the total generated energy (1.5 TWh of losses over 52 TWh of total production). On the other hand transmission constraints occur mostly on the Central-South Central A line, always in the south-to-north direction. This happens mostly in wet scenarios where hydro generation located in the South Central A and South Central C buses needs to be evacuated to the load center, in this case the Central bus.

When freed of transfer constraints, the contracted Take-or-Pay LNG volume decreases, as shown in Table 17. This happens because hydro generation is no longer constrained to reach the load center and thus it can reduce the generated power by more costly energy sources such as LNG.

This result shows the importance of modelling the grid in "optimal LNG volume" studies. The oversight of the grid or a misrepresentation of it can produce inaccurate results, in this case by over a 14%.

Moreover, this result shows that transmission investment can have significant effects on the LNG requirements. Investment can reduce LNG requirements as it allows less costly generation to reach the load centers and thus reduce the LNG generation. It may be of interest in the upcoming years as significant renewable projects will arrive into the system and line congestions may limit the transfer of competitive generation.

5.2.4 Current Import Situation versus Optimal Situation

This study was conducted to analyze and compare the current LNG import situation with the optimal one found through the optimization problem. Only the Take-or-Pay contract was considered available, and its contracted volume was fixed for the two cases in study to the values shown in Table 18. It should be noted that the system operation is optimal for both cases, which means that usage of available LNG is optimized. This is in contrast to the study carried out by the CE-FCFM [3], where they evaluated impacts of taking into account fuel availability constraints in a sub-optimal system operation.

Case	Contracted LNG Energy [TWh]
Optimal LNG	6.253
Current LNG	3.476

Table 18: Contracted LNG for the two studied cases. Optimal LNG refers to the volume found through the optimization problem, while Current LNG refers to the volume currently being imported through Take-or-Pay contracts.

Results are shown next:

System-wide perspective:

In Table 19, system costs results for both cases are shown. As seen in the small scale case study (Section 4.2.1), increasing imported LNG to an optimal volume will reduce system costs. This represents an expected benefit of 4.1% (54M$) from the current situation. This is exacerbated in the more costly scenarios (dry ones), where the LNG requirements are higher and therefore a reduction of LNG imports will increase even more the system costs (by over 300 M$).

Case	Min Cost	Expected Cost	Max Cost
Optimal LNG	832	1264	2725
Current LNG	732	1318	3150

Table 19: System costs according to the import situation. Min cost is the average of the three scenarios with smaller costs and max cost is the average cost of the worst three scenarios.

Gas Generators' Perspective

In Figure 46 total profit of the LNG generators per scenario for both cases is shown[4]. Similar as the results exposed in 0, decreasing LNG imports can be beneficial for the generators as it can increase their expected profit. We can identify three zones according to the hydrological condition:

A. Drier scenarios (where electricity prices are high) where increasing the imported LNG presents benefits to the generators since they sell more energy at a high price.
B. Medium scenarios where increasing LNG imports reduces profit of NG generators, passing from profitability to operating at a loss.
C. Wet scenarios (where electricity prices does not suffice to cover operating costs) where increasing LNG imports increases NG generators' loses, since they sell more energy at a lower price.

In average, even though in the driest scenarios importing more LNG can be beneficial for generators, since they sell more energy, this is counteracted by the fact that it decreases the number of scenarios in which the LNG generators make a profit. Also, increasing LNG imports increments risk exposure of NG generators to adverse scenarios (wet ones from this perspective). Results prove that system (or the social planner) and generators' interests of are not necessarily aligned, which can cause inefficiencies in the electricity market and damage to the consumers.

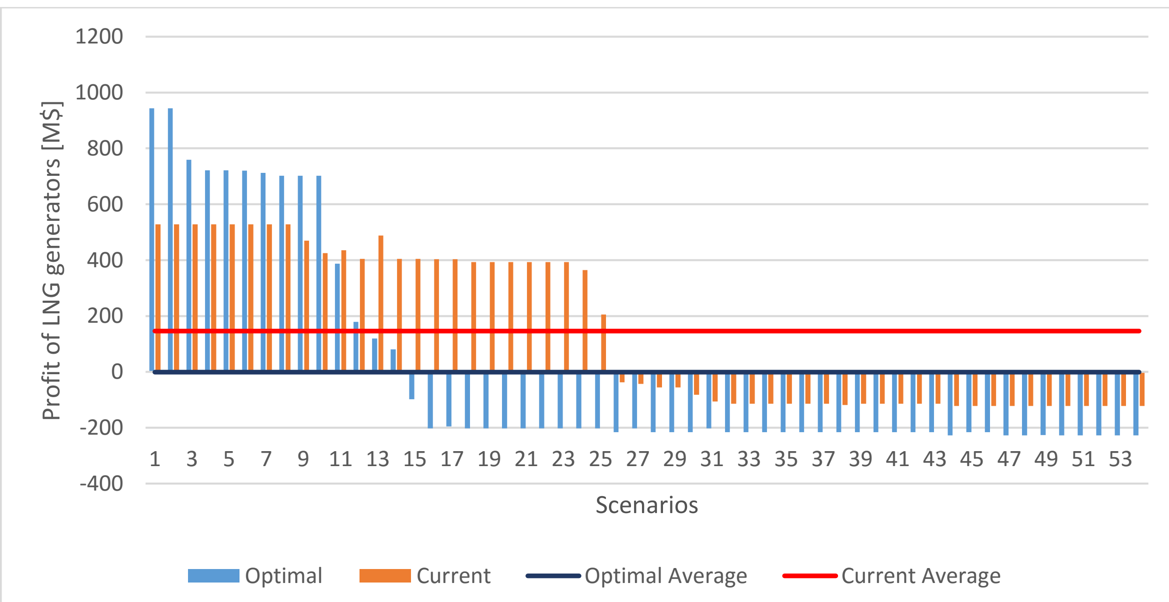

Figure 46: Total profit of the LNG generators per scenario for the optimal and the current LNG import situations. Average profit for each case is computed.

[4] Total profit was computed as the sum of profits (revenues of selling energy at the spot price minus operational costs given by the cost of the ToP contract) for all LNG generators in the system (Nehuenco, San Isidro, Quintero, Nueva Renca and Tal Tal).

Additionally, two indicators were computed, shown in Table 20. First; the average or expected profit, shown also in Figure 46, and second; the compensated profit, or average profit without losses (scenarios where the LNG generators lose money are counted as zero profit), which represents a payment mechanism that would partially compensate NG generators to cover operating costs in scenarios where selling energy at spot prices does not suffice.

Case	Average Profit [M$]	Average Compensated Profit [M$]
Optimal LNG	-1.05	155.44
Current LNG	146.04	203.54

Table 20: Average profit and average profit without losses for the optimal and current LNG import situations [M$]

Even though for both indicators under-importing is more beneficial for NG generators, it should be noted that if the compensatory mechanism is implemented requiring to import an optimal volume of LNG, it would be advantageous for generators since their profit would increase in 9.4 M$ in average from the current situation.

As seen in the small scale study case (Section 4.2.2), under-importing LNG can drive up the marginal prices of electricity, forcing the entrance of more costly generation. Figure 47 shows the average marginal price at the Central bus (where most of the LNG generators are located), per scenario. Between scenarios 3 to 30, sub-importing LNG drives up the marginal cost, which means that even though LNG generators will be selling less energy it will be sold at a higher price. This could have a higher impact as generation companies have a portfolio of generators and profit made by selling energy with gas generators can be negligible next to the one made by a hydro or coal generator selling their energy at marginal price.

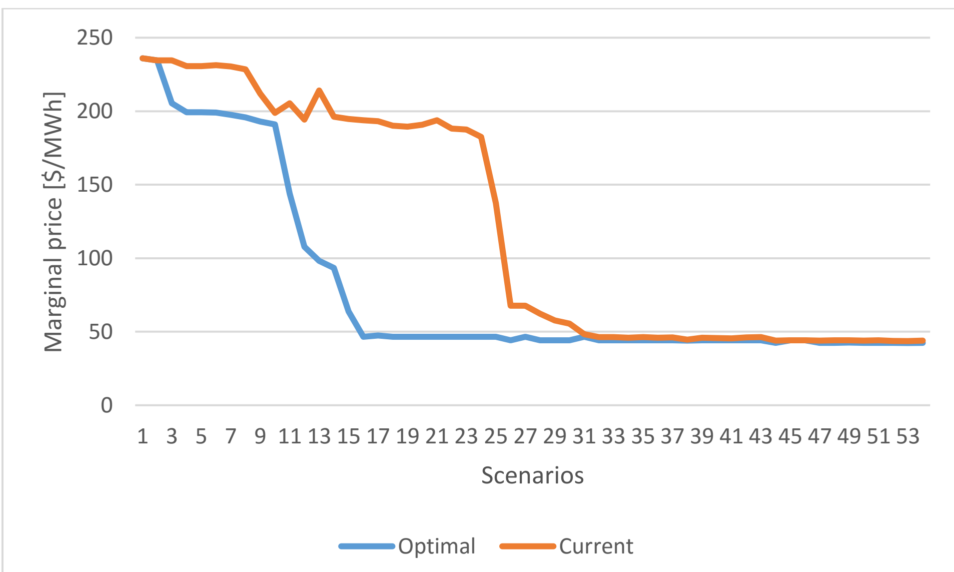

Figure 47: Average marginal price at Central bus per scenario. Hydrological Scenarios are ordered from the driest (left) to the wettest (right).

Demand perspective:

The decrease in marginal prices that is observed in Figure 47 can have significant impacts on demand payments. Results of annual payments for a demand fully exposed to electricity spot prices are shown in Figure 48. Two indicators where computed, shown in Table 21. First, the average demand payment, and second the average demand payments plus compensations, which refers to the aforementioned complementary payment mechanism where demand would compensate part of the NG generators' operating costs when electricity spot prices do not suffice to cover them.

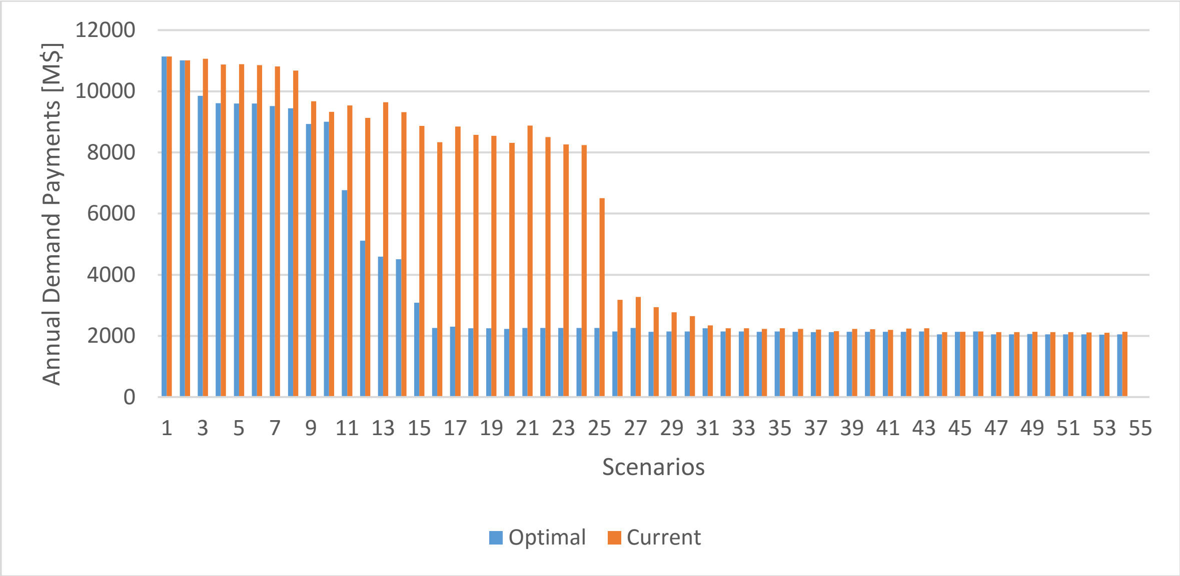

Figure 48: Annual demand payments [M$] per scenario for the optimal and the current LNG import situations. Hydrological Scenarios are ordered from the driest (left) to the wettest (right).

Case	Average Demand Payment [M$]	Average Demand Payments + LNG Compensations [M$]
Optimal LNG	3811.36	3967.85
Current LNG	5611.65	5669.15

Table 21: Annual average demand payment and average demand payments plus LNG compensations.

Increasing LNG imports through ToP contracts to an optimal volume can reduce demand payments in over 1800 M$, equivalent to a 32.1% reduction, given by the decrease in electricity spot prices. The disproportionate reduction of demand payments with respect to system costs is due to a transfer of generators' surplus to consumers' surplus through the reduction of electricity prices.

Implementing the aforementioned compensatory mechanism, where demand partially covers NG generators' operating costs in wet scenarios, would represent an extra payment of only 154 M$ in average, if an optimal volume of LNG were imported. This amount is easily covered by the reduction in demand payments. This mechanism would be beneficial for both NG generators and consumers since they would be in a better economical position compared to the current situation.

5.2.5 Risk Aversion

Agents in electricity markets are risk-averse, which can include social or system planners. The objective of this study was to analyze the LNG contract decision as risk, from the systemic point of view, is accounted for in the evaluation process.

For the execution of this study only the Take-or-Pay contract and the Spot market were considered as available, and *Conditional Value-at-Risk* at the 94.4% confidence level was used as a risk measure, which represents the average cost of the three worst scenarios. The risk-aversion of the system operator (ω) parameter was swept from 0 (risk-neutral) to 1 (extremely risk-averse) and LNG contract decision and system cost was analyzed.

Results of contracted energy through ToP contracts as risk-aversion varies are shown in Figure 49. As risk-aversion of the system planner increases, so does Take-or-Pay contract volume. Being risk-averse from the systemic point-of-view means that the *system costs* of the worst scenarios have a larger impact on the decisions. Therefore, the system operator increases LNG imports to reduce more costly generation and consequently system costs in dry scenarios. This action is fundamentally different of the one taken by a LNG generator, who reduces LNG imports to hedge from wet scenarios.

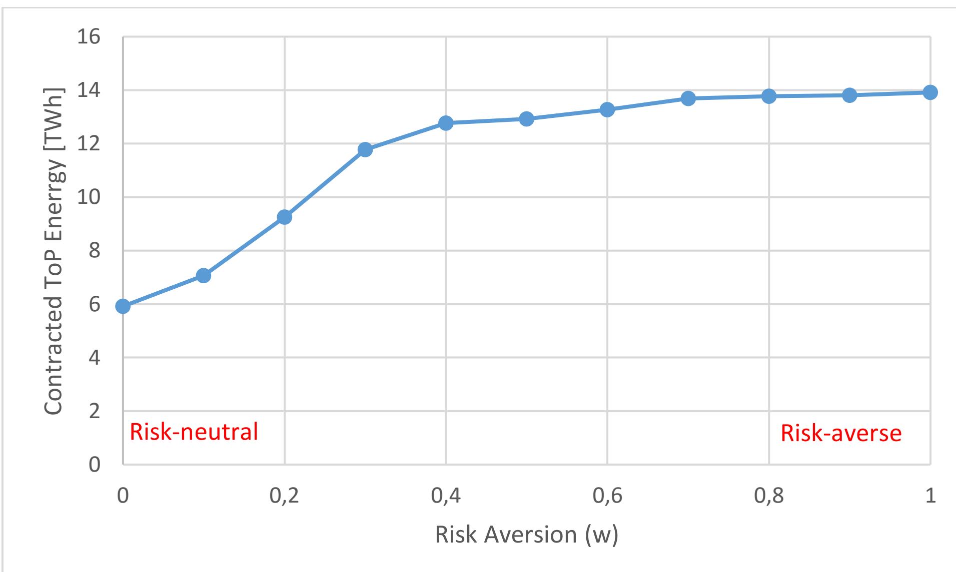

Figure 49: Contracted LNG energy [TWh] through Take-or-Pay contracts as the risk aversion of the system operator increases.

A Pareto frontier of efficient solutions can be determined (Figure 50) where the trade-offs between expected system costs and risk can be assessed and the feasible and infeasible solution regions made explicit. A risk-neutral decision has a poor performance in the worst scenarios but a better performance in average, on the other hand a risk-averse decision increases expected cost by 195 M$ but can save over 665 M$ in the worst scenarios.

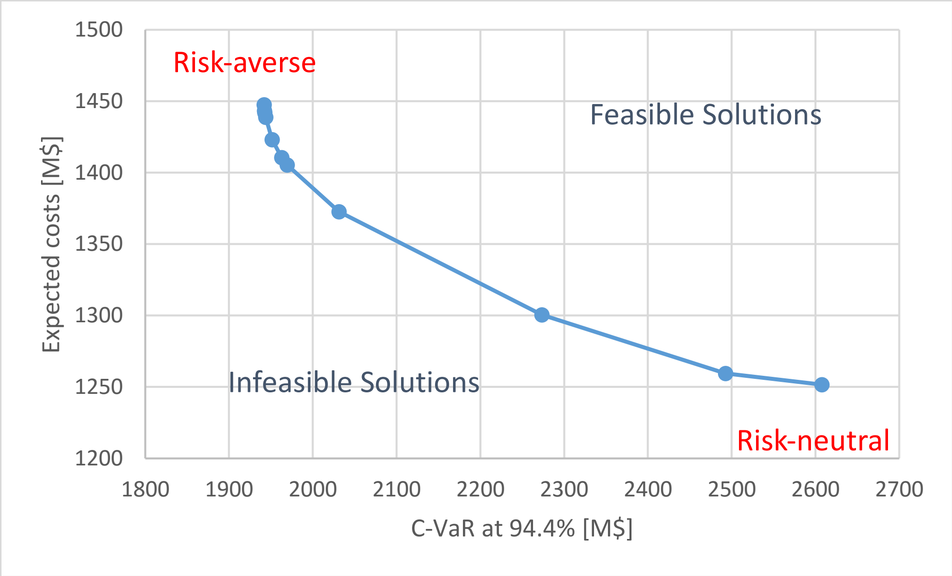

Figure 50: Pareto frontier between the expected system costs and the incurred risk (C-VaR).

The same exercise can be made mapping the system cost as a function of the contracted LNG energy through Take-or-Pay LNG (Figure 51). Increasing the contracted LNG energy (and the risk aversion) entails an increment in the expected costs (in 15.6%) but a greater cost reduction in riskier scenarios. In general, the volatility of the system costs is reduced as the Take-or-Pay energy increases.

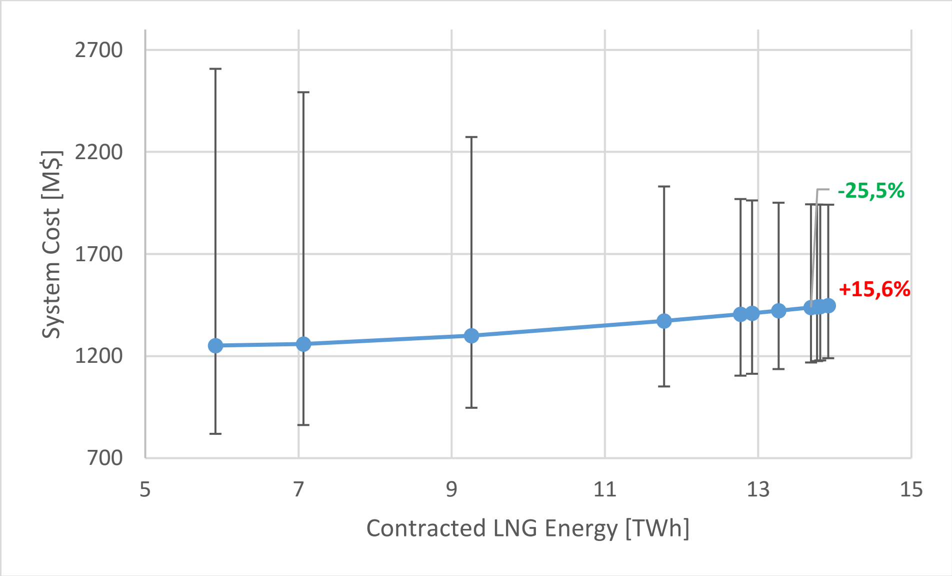

Figure 51: Expected system costs according to the contracted LNG energy in Take-or-Pay contracts. Error bars show the minimum and maximum costs for the three best and worst (C-VaR) scenarios. Labels show the difference (in %) of average system cost (red) and worst-case scenario system costs (green) between the risk-neutral and risk averse case.

6 CONCLUSIONS AND FURTHER WORK

6.1 Conclusions

Importing liquefied natural gas (LNG) through take-or-pay (ToP) contracts for electricity generation is significantly challenging in hydrothermal systems since gas demand from the electricity sector is highly uncertain due to the historical volatile behavior associated with hydro conditions. This is compounded by the difficulties to undertake ex-post trading of surpluses/shortfalls of LNG in a secondary market, which is –in many cases– significantly limited.

Although the problem of electricity system operation with ToP contracts has been already addressed in the literature, we found that there is no research focused on the need for natural gas from a systemic point of view which may be of interest of regulators and policy makers. Therefore, we proposed a risk-averse stochastic optimization model that allows us to find an optimal portfolio of LNG supply contracts for the national power system (from a social planner perspective). The model co-optimizes the LNG contract decision with the power system operation and the LNG portfolio includes contracts with various degrees of flexibility and interactions with the spot market.

The model was tested in a small scale study case where the fundamental principles that govern the LNG supply contract decision were exhibited. They were corroborated in a large scale study system representing the Chilean main electricity system.

Our main findings are:

(i) it is optimal, from a risk-neutral, cost-minimization perspective, to import natural gas through Take-or-Pay contracts for an "average" hydro condition. This implies that contracted natural gas will not suffice under dryer conditions where more costly plants (e.g. diesel units) will be needed to supply electricity demand and that gas plants will displace less costly plants (e.g. coal units) during wetter hydro conditions.

(i) it is optimal, from a risk-averse, cost-minimization perspective, to import natural gas for a "dryer" hydro condition and this implies that a social planner will increase volumes of LNG imports (with respect to risk-neutral levels) in order to hedge the system against operational cost spikes during dry conditions. This system-wide decision is fundamentally different to that taken in a market environment where generation companies (e.g. gas plant owners) tend to hedge risk exposure by under-importing LNG in order to ensure that natural gas is actually used in the generation dispatch.

(ii) flexible clauses in ToP contracts (that allows power plants to use lesser gas than that contracted) can support increased LNG import volumes and a reduction in system operating costs.

(iii) risk-neutral optimal LNG system requirements for the Chilean main national electricity system are circa 6 TWh per year, which is almost twice the amount of 3.47 TWh that is currently being imported. Furthermore, this amount can be significant increased if (i) the social planner were risk averse to protect consumers against higher costs driven by droughts, and/or (ii) more flexible contracts are modelled.

(iv) Increasing the import volumes to 6 TWh per year (from current 3.47) will decrease expected system costs by 4.1% and reduce demand payments by 32.1%. This disproportional reduction in demand payments is observed since part of producer's surplus is transferred to the consumer's surplus as system marginal costs decrease (here we assumed that demand is fully exposed to spot prices).

(v) It is possible to design a payment mechanism (i.e price uplifts) where demand can partially cover the cost of ToP contracts associated with natural gas units during wet hydrological conditions (when spot prices cannot cover LNG costs) so as to efficiently share risks between gas generators and demand, and this would be beneficial for both since they would be in a better economical position compared to current situation.

Although the case studies in this thesis are focused on the Chilean market, we believe that this is of interest to further Latin American hydrothermal systems such as those in Argentina, Colombia, Brazil and Central America, and developing systems in Sub-Saharan Africa such as that in Ghana, which face (or will face in the near future) similar problems associated with LNG supply. Hence this research can be critical to understand the cost and benefits of various decisions associated with LNG imports and thus support a more efficient and risk-free operation and development of electricity systems. This framework is also timely and can serve to take advantage of the present lower prices in the international LNG market.

6.2 Further Work

We have identified multiple ways to continue this investigation. We have grouped them in decomposition scheme implementation, model improvements, simulation analysis, and market design:

Decomposition scheme implementation: This refers to the development and implementation of a decomposition algorithm, such as SDDP, to solve the optimization problem. This technique will allow us to overcome the computational limitations of the proposed methodology and for it to be run over larger and more detailed systems.

Model improvements: This includes all new constraints and parameters that can be included to the model to obtain more realistic solutions.

- Different horizons for LNG contract duration. For example having the choice of short-term contracts (1 or 2 years) versus long-term contracts (5 years or more).
- Regasification capacities of terminals. LNG terminals have a maximum amount of LNG that can be injected to the gas system, usually in [m^3/day]. This has an impact on how much gas can actually be delivered to NG generation during periods of high demand.
- Delivery constraints, such as minimum/maximum volume per stage and *Ship Commitment*.
- Other gas loads and gas transmission constraints. The regasification terminals and the pipeline system is used to supply NG to other consumers, such as residential and industrial ones, besides power plants. The review of the state-of-the-art showed

that gas transmission congestion can have significant impact on system operation during periods of high demand.

Simulation Analysis: This refers to other aspects that needs to be studied, carrying additional simulations.

- LNG Spot price volatility. Uncertainty does not only come from the hydrological scenarios, it also comes from the fuel prices (LNG and other fuels) in the spot market. In this case, long-term contracts can provide more stable prices at the expense of supply flexibility.
- Longer horizons of study. This can incorporate effects of new gas and power projects entering the market.
- Effects of electricity supply contracts. Generators can sign long term electricity supply contracts, and this can have an impact on their optimal strategy towards LNG purchasing.
- Simulations with the model improvements.

Market design & Policy: Our research showed that LNG market imposes important constraints to the electricity market and that volumes of imported LNG should be increased at a national level. In this context, reference [3] shows alternative market arrangements that can be used to increase the participation of natural gas plants in the national electricity market.

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II.I Generation per stage/block

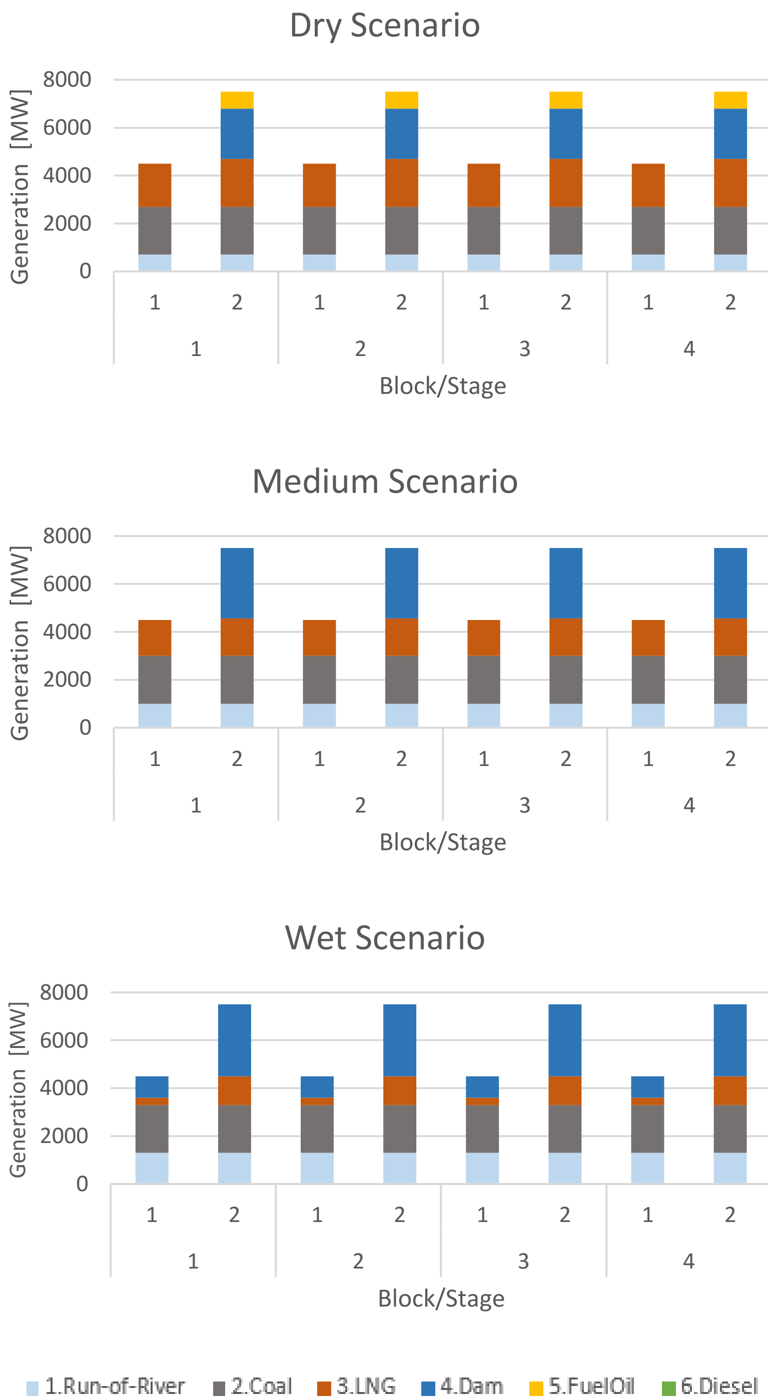

Figure 52: Generation per Stage/Block and per Scenario without Take-or-Pay Constraints. [MW]

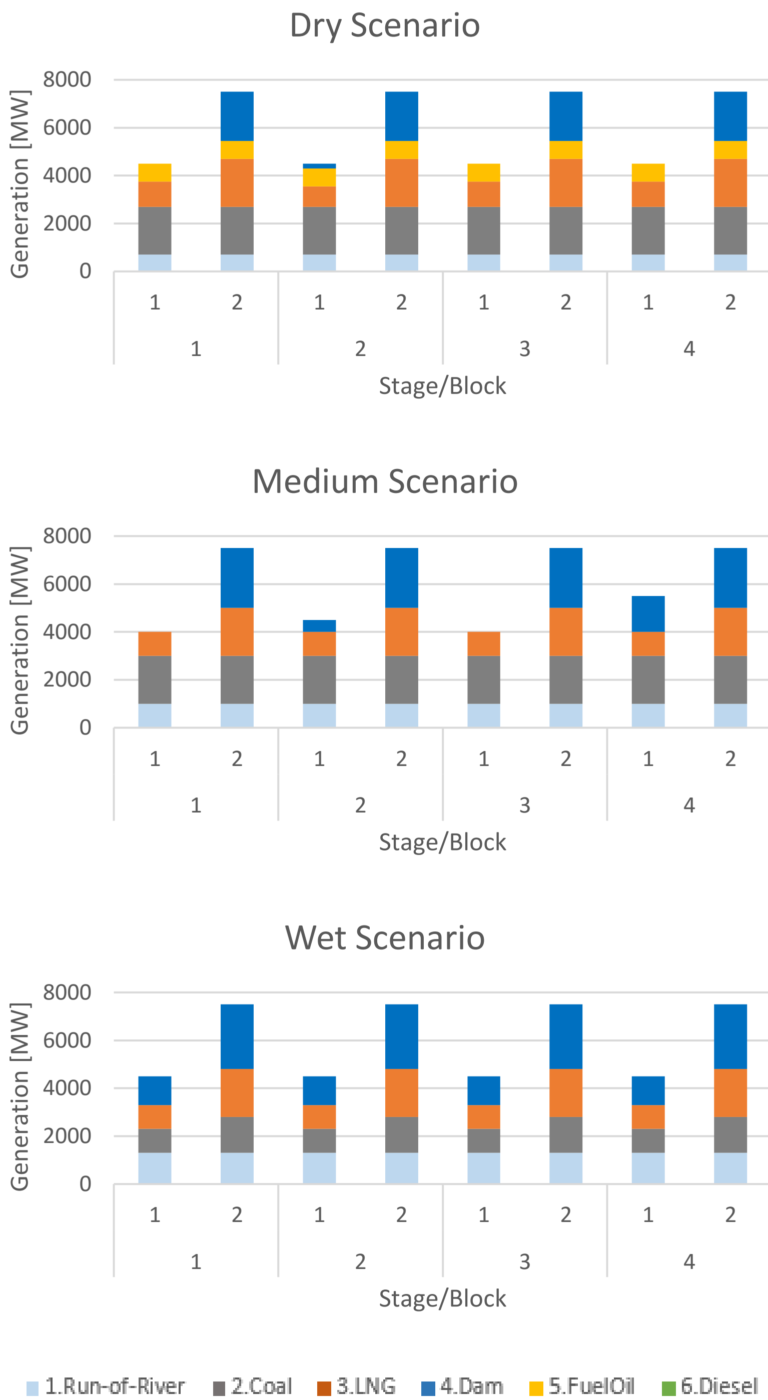

Figure 53: Generation per Stage/Block and per Scenario Optimal Take-or-Pay Contract. [MW]

APPENDIX II: LARGE SCALE SYSTEM GENERATORS

The following table presents the generators used in the large scale simulations. **Pmax** is the installed capacity of the generator, **FOR** is the forced outage rate that represents the average time the generator is unavailable due to maintenance or outages, and the **Available Pmax** is the result of $Pmax \cdot FOR$.

Generator	Type	Node	Pmax [MW]	F.O.R.	Available Pmax [MW]	Variable Cost [$/MWh]
Eq_Biomass_C	Biomass	Central	35	0.07	32	16.4
Eq_Biomass_C2	Biomass	Central	14	0.07	13	53.4
Eq_Biomasa_S1	Biomass	South	13	0.07	12	50.8
Eq_Biomasa_S2	Biomass	South	22	0.07	20	60.0
Eq_Biomasa_S3	Biomass	South	9	0.07	8	62.5
Eq_BiomOtros-LicorNegro_S	Biomass	South	61	0.07	57	64.2
Eq_Biomasa_S4	Biomass	South	4	0.07	4	73.1
Eq_Biomasa-LicorNegro_SCA	Biomass	South Central A	6	0.07	6	10.5
Eq_Biomass_SCA1	Biomass	South Central A	6	0.07	6	16.0
Eq_Biomass_SCA2	Biomass	South Central A	10	0.07	9	38.0
Eq_Biomass_SCA3	Biomass	South Central A	6	0.07	6	45.0
Eq_BiomOtros-LicorNegro_SCA	Biomass	South Central A	8	0.07	7	89.5
Eq_DesechosForestales_SCC1	Biomass	South Central C	4	0.07	4	0.0
Eq_LicorNegro_1_SCC	Biomass	South Central C	37	0.07	34	0.0
Eq_Petcoke_1_SCC	Biomass	South Central C	54	0.07	50	3.9
Eq_BiomOtros-PetroleoN6_SCC1	Biomass	South Central C	21	0.07	19	34.3
Eq_Biomass_SCC2	Biomass	South Central C	27	0.07	25	38.5
Eq_Biomass_SCC1	Biomass	South Central C	36	0.07	33	42.5
Eq_Biomass_SCC3	Biomass	South Central C	30	0.07	27	52.7
Eq_DesechosForestales_SCC2	Biomass	South Central C	8	0.07	7	55.0
Eq_BiomOtros-PetroleoN6_SCC2	Biomass	South Central C	11	0.07	10	59.8
Eq_Biomasa-LicorNegro_SCC1	Biomass	South Central C	39	0.07	36	102.8
Eq_BiomOtros-PetroleoN6_SCC3	Biomass	South Central C	11	0.07	10	130.2
Eq_PetroleoN6_1_SIC_SCC	Biomass	South Central C	10	0.07	9	131.9
Eq_Biomass_SCC4	Biomass	South Central C	11	0.07	10	152.2
Eq_BiomOtros-PetroleoN6_SCC4	Biomass	South Central C	4	0.07	4	189.1
Eq_Coal_C1	Coal	Central	491	0.07	457	42.5
Eq_Coal_C2	Coal	Central	322	0.07	299	45.5
Eq_Coal_NC1	Coal	North Central	137	0.07	128	33.8
Eq_Coal_NC2	Coal	North Central	286	0.07	266	37.5

Eq_Coal_SCC2	Coal	South Central C	139	0.07	129	36.8
Eq_Coal_SCC1	Coal	South Central C	321	0.07	299	38.6
Eq_Coal_SCC3	Coal	South Central C	464	0.07	432	50.4
Chiburgo	Dam	Central	19	0.04	19	0.0
Colbun	Dam	Central	376	0.04	361	0.0
Machicura	Dam	Central	97	0.03	94	0.0
Rapel	Dam	Central	350	0.04	336	0.0
Canutillar	Dam	South	169	0.03	163	0.0
Cipreses	Dam	South Central A	105	0.05	100	0.0
Curillinque	Dam	South Central A	89	0.04	85	0.0
Isla	Dam	South Central A	68	0.03	66	0.0
LomaAlta	Dam	South Central A	38	0.04	36	0.0
Pehuenche	Dam	South Central A	457	0.05	436	0.0
Rucue	Dam	South Central A	169	0.06	158	0.0
SanIgnacio	Dam	South Central A	37	0.04	35	0.0
Abanico	Dam	South Central C	136	0.02	133	0.0
Antuco	Dam	South Central C	320	0.04	307	0.0
ElToro	Dam	South Central C	368	0.04	352	0.0
Palmucho	Dam	South Central C	32	0.07	30	0.0
Pangue	Dam	South Central C	472	0.04	453	0.0
Quilleco	Dam	South Central C	70	0.04	67	0.0
Ralco	Dam	South Central C	539	0.02	529	0.0
Angostura	Dam	South Central C	316	0.04	302	0.0
Eq_Diesel_C1	FuelOil/Diesel	Central	56	0.51	27	285.3
Eq_Diesel_C2	FuelOil/Diesel	Central	19	0.07	17	396.5
Eq_Diesel_N1	FuelOil/Diesel	North	220	0.09	201	180.7
Eq_Diesel_N2	FuelOil/Diesel	North	55	0.08	50	248.6
Eq_Diesel_N3	FuelOil/Diesel	North	55	0.06	51	294.7
Eq_Diesel_N4	FuelOil/Diesel	North	69	0.09	63	328.0
Eq_IFO-180_CN1	FuelOil/Diesel	North Central	17	0.07	16	134.6
Eq_Diesel_NC1	FuelOil/Diesel	North Central	234	0.06	220	179.6
Eq_Diesel_NC2	FuelOil/Diesel	North Central	14	0.09	13	189.7
Eq_Diesel_NC3	FuelOil/Diesel	North Central	81	0.09	74	232.3
Eq_IFO-180_CN2	FuelOil/Diesel	North Central	58	0.36	37	239.2
Eq_Diesel_S1	FuelOil/Diesel	South	94	0.09	86	182.4
Eq_Diesel_S2	FuelOil/Diesel	South	23	0.09	21	194.5
Eq_Diesel_S4	FuelOil/Diesel	South	112	0.08	103	204.3
Eq_Diesel_S3	FuelOil/Diesel	South	36	0.09	33	213.8
Eq_IFO-180_SCA	FuelOil/Diesel	South Central A	14	0.05	13	115.4
Eq_Diesel_SCA1	FuelOil/Diesel	South Central A	60	0.06	56	184.6
Eq_Diesel_SCA2	FuelOil/Diesel	South Central A	15	0.09	14	240.3
Eq_PetroleoDiesel_SCC1	FuelOil/Diesel	South Central C	290	0.07	268	170.6

Eq_PetroleoDiesel_SCC2	FuelOil/Diesel	South Central C	76	0.09	70	285.0
Eq_PetroleoDiesel_SCC3	FuelOil/Diesel	South Central C	160	0.09	146	358.4
SanIsidro	LNG	Central	742	0.04	710	0.0
Candelaria	LNG	Central	254	0.06	239	0.0
Nuehuenco	LNG	Central	745	0.06	700	0.0
Quintero	LNG	Central	257	0.06	242	0.0
NuevaRenca	LNG	Central	342	0.06	321	0.0
TalTal	LNG	North	360	0.06	338	0.0
Eq_MiniHidro_C	Run-of-the-river	Central	48	0.00	48	0.0
Eq_ROTR_C	Run-of-the-river	Central	1097	0.00	1097	0.0
Eq_MiniHidro_NC	Run-of-the-river	North Central	33	0.00	33	0.0
Eq_ROTR_S	Run-of-the-river	South	178	0.00	178	0.0
Eq_MiniHidro_S	Run-of-the-river	South	115	0.00	115	0.0
Eq_ROTR_SCA	Run-of-the-river	South Central A	25	0.00	25	0.0
Eq_MiniHidro_SCA	Run-of-the-river	South Central A	57	0.00	57	0.0
Eq_ROTR_SCC	Run-of-the-river	South Central C	126	0.00	126	0.0
Eq_MiniHidro_SCC	Run-of-the-river	South Central C	8	0.00	8	0.0
Eq_Solar_C	Solar	Central	4	0.00	4	0.0
Eq_Solar_N	Solar	North	244	0.00	244	0.0
El Pilar Los Amarillos	Solar	North	3	0.00	3	0.0
Lalackama Etapa II	Solar	North	16	0.00	16	0.0
Conejo Etapa I	Solar	North	108	0.00	108	0.0
Eq_Solar_NC	Solar	North Central	93	0.00	93	0.0
Luz del Norte Etapa I	Solar	North Central	36	0.00	36	0.0
Eq_Wind_C	Wind	Central	18	0.00	18	0.0
Eq_Wind_N	Wind	North	99	0.00	99	0.0
Eq_Wind_NC	Wind	North Central	598	0.00	598	0.0
Eq_Wind_S	Wind	South	36	0.00	36	0.0
Eq_Wind_SCC	Wind	South Central C	43	0.00	43	0.0

APPENDIX III: SENSITIVITY STUDY ON THE LARGE SCALE SYSTEM

Sensitivity studies were carried for the flexible contracts, extending what is exposed in 5.2.2. Results are shown in the following sub-sections.

III.I Sensitivity on the Minimum Volume Contract

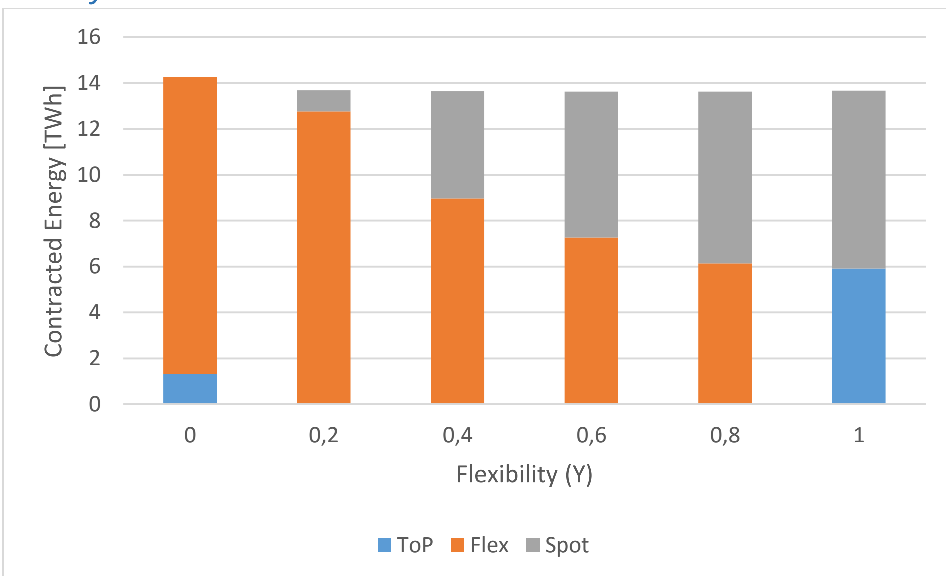

Figure 54: Contracted energy as the contract flexibility (minimum volume) varies. Energy showed for the driest scenario, with a Take-or-Pay contract, a minimum volume contract ($\beta = 85\$/MWh$) and a spot market available.

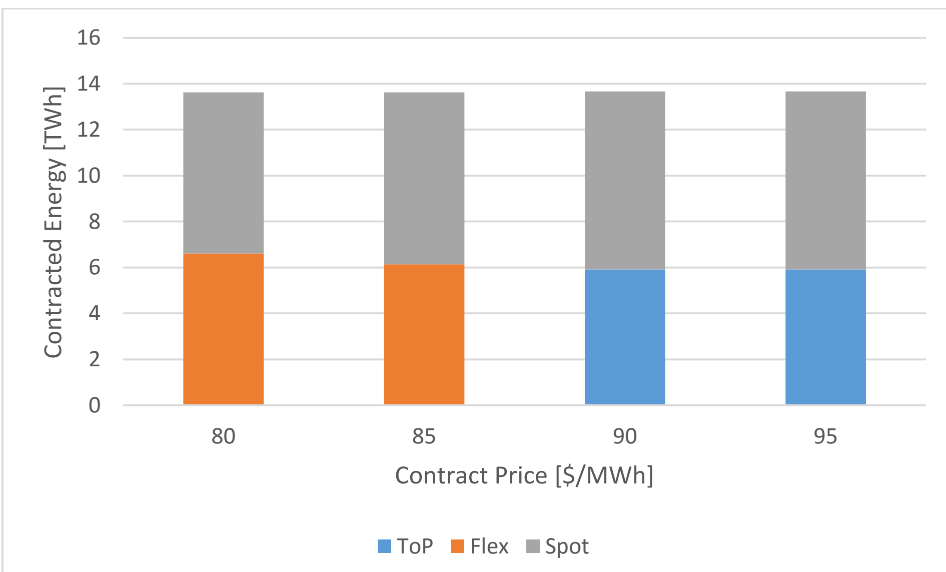

Figure 55: Contracted energy as the contract price (of the minimum volume contract) varies. Energy showed for the driest scenario, with a Take-or-Pay contract, a minimum volume contract ($Y = 0.8$) and a spot market available.

III.II Sensitivity on the Penalization Contract

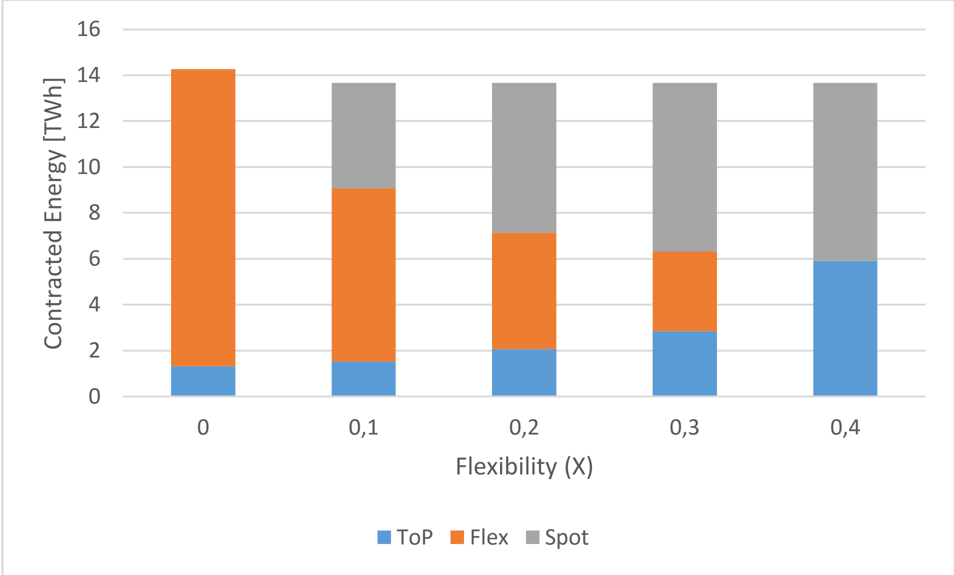

Figure 56: Contracted energy as the contract flexibility (penalization) varies. Energy showed for the driest scenario, with a Take-or-Pay contract, a penalization contract ($\beta = 85\$/MWh$) and a spot market available.

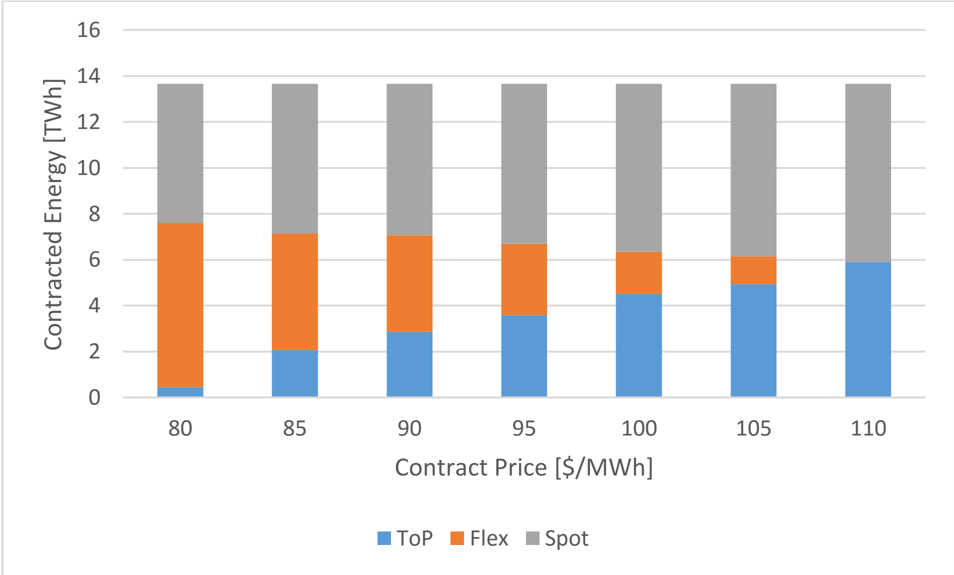

Figure 57: Contracted energy as the contract price (of the penalization contract) varies. Energy showed for the driest scenario, with a Take-or-Pay contract, a penalization contract ($X = 0.2$) and a spot market available.