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NETWORK HOSTING CAPACITY FOR RENEWABLES: AN ECONOMIC APPROACH THROUGH BILEVEL OPTIMIZATION

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RESUMEN DE LA TESIS PARA OPTAR AL TÍTULO DE: GRADO DE MAGÍSTER EN CIENCIAS DE LA ING. MENCIÓN ELÉCTRICA Y AL TÍTULO DE INGENIERO CIVIL ELÉCTRICO
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In the context of the very large amounts of renewable generation that governments around the world are encouraging to be integrated to power systems, we introduced, for the first time, a new concept named Market Hosting Capacity (MHC). This concept attempts to determine the maximum amounts of renewable generation that can be connected to a power system in a profitable fashion.

Previous work has introduced and analyzed the renewable generation hosting capacity of electricity systems from a techno-economic perspective, considering the balancing and network challenges associated with a large-scale integration of renewables. In view of the deregulation of the electricity industry, this thesis investigates for the first time this concept from a market perspective and introduces the Market Hosting Capacity, considering the challenges of low energy prices and renewables' investment cost recovery.

To determine the MHC of a power network, a bi-level optimization model is developed, where the upper level maximizes the renewable generation capacity subject to its long-term profitability constraint and the lower level represents the market clearing process. Finally, this bi-level problem is re-formulated into a Mathematical Programming with Equilibrium Constraints (MPEC) problem and, in turn, into a Mixed Integer Linear Programing (MILP) problem.

By using this new definition and mathematical program, we demonstrate that expanding network capacity may not always drive a higher MHC. Furthermore, in some conditions, the presence of congestion may be a stronger incentive to renewables investors to act and install renewable generation capacity. In other conditions though, and depending on the power system parameters, this may change, being network expansion a more attractive option to encourage and maximize renewables penetration. To study possible scenarios, we present 3 test networks with 2, 24 and 42 busses. The latter corresponds to an equivalent representation of the Chilean electricity network, in which we study the dilemma between expanding transmission capacity to the Atacama Desert to integrate solar power sources or, instead, save these network investments, allowing proliferation of local solar power sources around Santiago.

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En el contexto del aumento significativo en generación renovable que los gobiernos en todo el mundo están alentando para ser integrados a los sistemas de energía, presentamos, por primera vez, un nuevo concepto denominado Market Hosting Capacity (MHC). Por medio de este concepto se pretende determinar las cantidades máximas de generación renovable que pueden ser conectadas a un sistema de energía de manera rentable.

Trabajos anteriores han introducido y analizado la capacidad de almacenamiento de los sistemas eléctricos para la integración de generación renovable desde una perspectiva tecno-económica, considerando el equilibrio y los desafíos de red asociados con una integración a gran escala de las energías renovables. En vista de la desregulación de la industria eléctrica, esta tesis investiga por primera vez este concepto desde una perspectiva de mercado e introduce el Market Hosting Capacity, considerando los desafíos de los bajos precios de la energía y la recuperación de los costos de inversión de las energías renovables.

Para determinar el MHC de una red eléctrica, se desarrolla un modelo de optimización de dos niveles, donde el nivel superior maximiza la capacidad de generación renovable sujeta a su restricción de rentabilidad a largo plazo y el nivel interior representa el proceso de compensación del mercado. Finalmente, este problema de dos niveles se reformula en un problema de Programación Matemática con Restricciones de Equilibrio (MPEC) y, a su vez, en un problema de Programación Lineal Entero Mixto (MILP).

Al utilizar esta nueva definición y modelo matemático, demostramos que la expansión de la capacidad de la red no siempre puede conducir a un MHC más alto. Además, en algunas condiciones, la presencia de congestiones puede ser un incentivo más fuerte para que los inversores en energías renovables actúen e instalen capacidad de generación renovable. Sin embargo, en otras condiciones, y dependiendo de los parámetros del sistema de energía, esto puede cambiar, y la expansión de la red es una opción más atractiva para fomentar y maximizar la penetración de energías renovables. Para estudiar posibles escenarios, presentamos 3 redes de prueba con 2, 24 y 42 barras. Esta última red corresponde a una representación equivalente de la red eléctrica chilena (Sistema Eléctrico nacional, a través de la que estudiamos el dilema entre la expansión de la capacidad de transmisión al Desierto de Atacama para integrar fuentes de energía solar o, en cambio, salvar estas inversiones en la red, lo que permite la proliferación de fuentes locales de energía solar en todo Santiago.

Dedication

A mis padres Paola y Guillermo.

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En primer lugar, quiero a gradecer al profesor Rodrigo Moreno por haber confiado en mí al iniciar este proyecto, por todo el apoyo y la motivación que me brindó y que permitieron sacar este trabajo adelante. Agradecer también a los profesores Dimitrios, Patricio y Francisco por sus comentarios y buena voluntad.

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Finalmente, y no menos importante, agradecer a mi familia. Agradecer a mis padres, Paola y Guillermo que han sido el pilar fundamental de todo este proceso formativo, que lo han dado todo para hacer que mis hermanos y yo tuviésemos la mejor formación posible que, evidentemente, parte por casa. Además, hicieron que nuestra única real preocupación sea el ser felices. Agradecer a mis hermanos Guillermo y Tomás que, aunque no haya una participación 100% directa, el hecho de tener a dos *partners* en quienes puedes ver el reflejo de ti mismo te hace entender que no estás solo y que, pase lo que pase, tienes en quien confiar, personas con tus mismos o más grandes objetivos. Gracias a todos ustedes por plantar los cimientos de lo que he logrado. Gracias, totales.

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Chapter 1

1 Introduction

1.1 Motivation

The increase in the share of energy from renewable sources has been a key factor in the operation and planning of electricity systems in recent years [1]. This is due to the significant benefits that these technologies present in terms of the associated reduction in pollution and CO2 emissions and the continuous decrease in their investment costs. Great efforts have been made to study both the positive and negative effects of a large increase in renewables [2], particularly solar and wind generation, in electricity systems. Within these results many countries have opted for policies that encourage the generation of renewable energy sources (RES) given its benefits in particular in terms of the reduction in CO2 emissions. In this line, at the beginning of 2017, the European Union (EU) reviewed the Renewable Energy Directive 2009/28/EC with the objective of increasing the share of renewables up to 27% by 2030, becoming the world leader in renewable energies [3]. Other regions have similar policies fostering the integration of renewables to their systems such as Denmark [4], Germany and Japan [5].

In Chile, energy policy is not far behind in terms of renewable energies. In fact, according to the new energy policy enacted in 2016 [6] at least 70% of electricity demand by 2050 must come from renewable sources, taking advantage of the country's most abundant renewable resources like solar and wind generation which can be complemented with hydroelectric developments. This represents a significant progress to the previous situation. Prior to this energy policy, many other studies were carried out in order to find the optimal penetration level of renewables under different scenarios. In [7] a study is presented where two levels of integration are assumed for RES sources, 20% and 30% by 2020. Moreover, [8] shows that under certain conditions it is technically feasible to manage a participation of around 30% of wind and solar variable sources. In terms of the interrelation between renewables integration and transmission expansion, in [9] different scenarios for the development of the generation mix are evaluated for the Central Interconnected System, concluding that an important reinforcement of the transmission system is necessary to achieve large renewables integration.

However, this large-scale integration of renewable generation introduces significant techno-economic challenges to the operation and planning of electricity systems. First of all, the inherent variability and limited predictability and controllability of renewable generation imply that conventional generators need to remain in the system and operate in an inefficient fashion (part-loaded, and with more frequent start-up and shut-down cycles) to provide the required balancing services to the system. Furthermore, integration of inverter-connected renewable generation reduces the system inertia (which is provided by the kinetic energy stored in the rotating mass of the conventional generators), which implies that imbalances between supply and demand change system frequency more rapidly, challenging the stability of the system. Finally, the large-scale connection of renewable generation to transmission and distribution grids creates certain network challenges, such as thermal congestion, increased voltage levels and increased short-circuit current levels, which threaten the security of these grids.

In this context, it was introduced the Hosting Capacity (HC) concept that aims to determine the ability of an electrical network to incorporate new consumption or production [10]. Thus, adding new production or consumption in electricity networks can affect power flow, voltage quality, short circuit currents as well as other network characteristics. In this line, there have been important progresses at the international level to determine the HC of both transmission and distribution networks. In particular, the use of this concept has been recommended by European energy regulators [11] and European network operators as a way to quantify performance in future networks. The term was first proposed by André Even and further developed by Math Bollen [12] [13], and it was initially used to determine the maximum penetration of Distributed Generation (DG) in distribution networks [14]. The objective was to quantify the impact of the DG [15] [16] [17] [18] on the quality of service in terms of voltage [19]. An important motivation is related to know how much solar [20] [21] [22] [23] or wind [24] energy can be connected to a distribution or transmission network. This, in turn, implies a concern on the part of the network operator because distributed generation can cause unacceptable network performance in terms of frequency and voltage [25]. Given the above, the concept of Hosting Capacity [26] [27] [28] became important in the EU and started to be developed by a research project of the EU, EU-DEEP, (European Distributed Energy Partnership).

TABLE 1-1: Examples of power system phenomena and related performance indices.

Phenomena	Performance Indices
Overloading from wind power	Maximum hourly value of current through transformer
Frequency variation	99% interval of 3 s average of frequency
Overvoltage from roof top solar photovoltaic cells	Highest 10 min average of voltage
Undervoltage from fast charging of electric vehicles	Lowest 10 min average of voltage
Protection mal-trip	Lowest recorded current causing interruption
Harmonics	10 min average of voltage and currents

Most of the previous studies addressed mainly technical concepts. Based on investigated phenomena, different performances indices can be selected for evaluating the hosting capacity. TABLE 1-1 summarizes different examples [29] of power system phenomena and related performances indices, different criteria have been used in the application of the concept of HC, including problems associated with overload, frequency, voltage, etc. These studies, however, have ignored the impacts of renewables on economics and markets that can also limit the amount of new generation capacity that can be connected to a network due to “price collapse”. In this context, this thesis proposes a planning tool that determines the Market Hosting Capacity, a new concept that we also introduce here, by modeling a problem that aims to find the maximum RES capacity that can be connected to an electrical system, subject to having a non-negative profit. This is done through bi-level optimization where, in the first level, we maximize capacity of RES in a given power network and, in the second level, we operate the system and clear the market following perfect competition (cost minimization) paradigm. This bi-level problem is reformulated into a mixed integer linear programming (MILP) problem.

However, apart from the above techno-economic challenges of decarbonization, the electricity industry is also facing challenges associated with its recent deregulation. This paradigm change has led to unbundling of vertically integrated monopoly utilities and the introduction of competition in the generation sector [30]. Generation investment planning is not anymore carried out by a central regulated utility aiming to minimize system costs, but relies on profit-driven decisions of self-interested generation companies, operating within a competitive electricity market. In this setting, the large-scale integration of renewable generation introduces a fundamental market challenge: given that operating costs of renewables are very low, the electricity prices are significantly reduced, threatening the recovery of their investment costs and therefore their profitability [31] [32].

1.2 Proposed Hypothesis

This thesis seeks to demonstrate that it is possible to develop a mathematical program that determines the maximum participation level of variable renewable technologies (particularly solar and wind) in any electrical power network constrained to economic feasibility from a private point of view, identifying the optimal/maximum volumes and locations of new investments in renewables in a congested network.

1.2.1 Overall Objectives

The present thesis has as a general objective:

- Propose an optimization model to identify the Network Hosting Capacity of a transmission network from an economic point of view, determining the maximum capacity to be installed of variable renewable generation, its location and technologies.

1.2.2 Specific Objectives

- Propose a new concept entitled Market Hosting Capacity (MHC) to measure the maximum amount of new renewable generation that can be connected to a given power network subject to non-negativity profit constraints from a private perspective.
- Propose the associated modelling framework to quantify the MHC of a power network through a bi-level optimization or mathematical programming with equilibrium constraints (MPEC) problem that is reformulated into a single, monolithic mixed integer linear program.
- Study the economic fundamentals of the hosting capacity concept on small and generic networks, with a particular focus on the inter-relations between the ability of a network to integrate renewables and its capacity. Also, study how the MHC may change due to the operational flexibility of the generation mix and policies to subsidize renewables.
- Demonstrate the scalability and applicability of our mathematical framework on realistic networks, in particular the Chilean one. We use our approach to determine the maximum levels of solar and wind generation that can be connected in the actual Chilean transmission network, comparing this against a potential expansion plan including an HVDC transmission line of 3000 [MW] of capacity.
- Conclude and recommend regarding the levels of maximum renewable generation capacity that can be connected in various networks with different topologies (in particular 3 cases: 2 busbars, 24 busbars and 42 busbars).

1.3 Contributions

- Propose the concept of Market Hosting Capacity as an indicator to characterize a power network.
- Develop a bilevel model that determines the maximum amount of renewables that can be connected in a profitable fashion.
- Demonstrate the inter-relationships between maximum levels of renewables that can be integrated and: (i) available transmission infrastructure, (ii) flexibility levels of existing generation technologies, (iii) subsidies.
- Exemplify the abovementioned concepts and relationships in a realistic power network like the Chilean transmission system.

To our understanding, this is the first study that addresses all of the above.

1.4 Structure of the Document

This document is structured in 5 chapters as follows. Chapter 1 motivates and introduces the research work. Chapter 2 explains the theoretical background in terms of the hosting capacity problem and the fundamentals in bi-level programming. Chapter 3 present the proposed bi-level program, its reformulated MILP model and results on two generic test systems: 2 busbar case and 24 busbar case. Chapter 4 demonstrate the applicability of the model on the actual Chilean transmission, discussing the impacts, in terms of MHC, of the proposed transmission 3000-MW HVDC link. Finally, Chapter 5 concludes and presents future research challenges.

Chapter 2

2 General Background

In this Section, we introduced the fundamental concepts and modelling principles used in this thesis, including definition of the HC concept and principles in bi-level optimization.

2.1.1 HC Definition, Performance and Maximum Limits

The incorporation of new production or consumption in a distribution and transmission network will affect the power flow quality [33], voltage quality [34] [35], short-circuit currents, location of new generation [36] [37] as well as other properties of the network. Network performance may improve or worsen for connected clients based on these indexes. Thus in [38] Hosting Capacity is defined as:

"The maximum amount of new production or consumption that can be connected without endangering the reliability or quality for other customers"

Then it is important to note that this index can be calculated both for individual locations and for larger areas, such as in the distribution network behind a HV / MV [39] transformer.

The approach to the Hosting Capacity concept [40] defines a set of performance indices that are calculated and evaluated based on the amount of new production or consumption that is incorporated into the network. Indeed, the phenomena that are studied to measure the HC can be from a new source of intermittent generation, such as installed wind energy, or new types of consumers, such as the incorporation of electric vehicles that are integrated into the consumption of a distribution network. In order to evaluate the HC, we have investigated different phenomena that allow us to define performance indexes; these indices can evaluate, for example, the quality of the supply from a technical point of view, up to certain economic parameters. Examples of different phenomena with their respective indices can be seen in TABLE 1-1.

In this way, the Hosting Capacity approach combines the adequate performance of an indicator with its acceptable limit [41]. In consequence the main challenge is based on finding a good indicator, as well as the appropriate limit.

Having the ability to measure and the knowledge to evaluate and apply certain techniques on the power system, which allow to guarantee that certain indicators are kept within acceptable limits for the new connection of loads or producers is important when determining the HC. In this way, the HC will depend to a large extent on what is perceived as an acceptable deterioration of the indicator or a certain limit.

Figure 2-1 presents an example of HC limit as the behavior of the index that is evaluated based on the new generation capacity, so the HC is not when the index begins to deteriorate but it corresponds to the unacceptable deterioration of this index.

In the example of Figure 2-1 the Hosting Capacity approach is considered a performance limit according to the increase in distributed generation of renewable energies. With the increase in DER an acceptable deterioration is defined, however when the new quantity of DER generation exceeds a certain amount, the deterioration of the indicator will exceed the acceptable limit.

Then, once one of these indexes exceeds its limit, the HC is reached. Thus, therefore, we can summarize the steps to determine the HC as [10]:

1. Choose a phenomenon and one or more performance indices.
2. Determine a suitable limit or limits.
3. Calculate the performance index or indices as a function of the generation.
4. Obtain the hosting capacity.

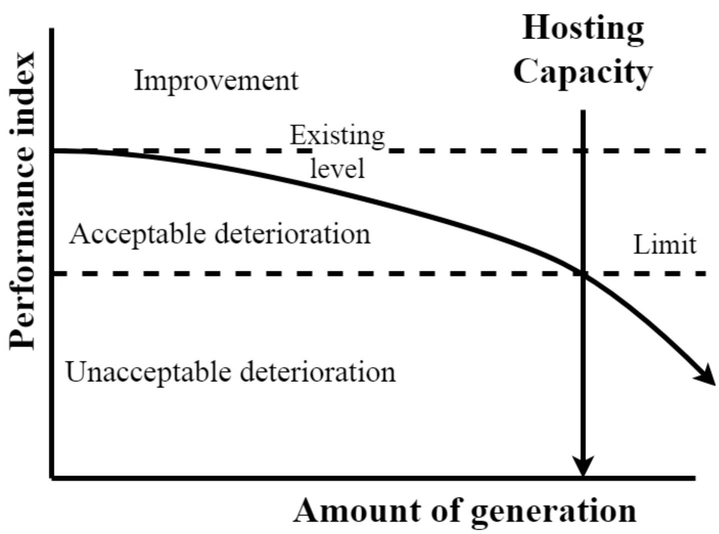

Figure 2-1: Definition of hosting capacity.

2.2 Bilevel Decomposition

If the next problem is considered [42]

$$minimize_x \ c(x) \tag{2-1}$$

$s.t$

$$h(x) \leq h_0 \tag{2-2}$$

$$g(x) \leq 0, \tag{2-3}$$

Where the function $h\ (x)$ cannot be evaluated easily, for example,

$$h_i(x) = minimum_u\ l_i(x; u); \quad \forall i \tag{2-4}$$

$s.t$

$$r_j(u) = k_j; \quad \forall j, \tag{2-5}$$

Or maybe $h\ (x)$ corresponds to the output of a complicated finite element program. It is important to emphasize that the restrictions (2-3) can be both equality and inequality constraints.

The biggest difficulty with this problem is that the restriction (2-2) cannot be easily incorporated into a standard optimization problem, so decomposition techniques are required. Since what is solved correspond to two related optimization problems, it is called bi-level decomposition. In this section we will work with the bilevel decomposition, however this type of mechanism also suggests a Benders type decomposition.

2.2.1 Bilevel Programming

If the following bi-level programming problem is considered:

$$minimize_x\ f^U(x, y^*) \tag{2-6}$$

$s.t$

$$h^U(x, y^*) = 0 \tag{2-7}$$

$$g^U(x, y^*) \leq 0 \tag{2-8}$$

$$y^* = arg\, minimize_y\ f^L(x, y) \tag{2-9}$$

$$s.t \quad h^L(x, y) = 0 \tag{2-10}$$

$$g^L(x,y) \leq 0, \tag{2-11}$$

Where the subscripts "u"and "l" indicate the upper level and the lower level respectively.

The optimization problem presented above consists of a higher level optimization problem which is associated with a lower level optimization problem. In this case the problems of the lower level consider x as a parameter and obtain in this way the optimal value of y that depends on the parameter x. For its part, the problem of higher level obtains the optimum of x using the optimal value of y calculated at the lower level of the problem.

In this way and as it is proposed, it is not possible to solve the bilevel problem. For this, one of the most common approaches is used to solve bilevel problems based on solving the non-linear problem obtained by replacing the lower level of the problem with its Karush-Kuhn-Tucker (KKT) conditions.

Thus the KKT conditions of the lower level can be expressed as:

$$\nabla_y f^L(x,y) + \lambda^T \nabla_y h^L(x,y) + \mu^T \nabla_y g^L(x,y) = 0 \tag{2-12}$$

$$\mu^T g^L(x,y) = 0 \tag{2-13}$$

$$\mu \geq 0 \tag{2-14}$$

$$h^L(x,y) = 0 \tag{2-15}$$

$$g^L(x,y) \leq 0 \tag{2-16}$$

Therefore the problem of bilevel programming can be expressed as the next monolithic non-linear programming problem.

$$minimze_{x,y}\ f^U(x,y) \tag{2-17}$$

$s.t$

$$h^U(x,y) = 0 \tag{2-18}$$

$$g^U(x,y) \leq 0 \tag{2-19}$$

$$\nabla_y f^L(x,y) + \lambda^T \nabla_y h^L(x,y) + \mu^T \nabla_y g^L(x,y) = 0 \tag{2-20}$$

$$\mu^T g^L(x,y) = 0 \quad (2\text{-}21)$$

$$\mu \geq 0 \quad (2\text{-}22)$$

$$h^L(x,y) = 0 \quad (2\text{-}23)$$

$$g^L(x,y) \leq 0 \quad (2\text{-}24)$$

It is relevant to emphasize that we use MILP to approach our problem. In our case, the non-linear expressions are treated through BigM and the strong duality theorem. In the first one a large enough constant is used to convert a non-linear constraint into four mixed integer linear constraints that are based on binary decision variables. The latter refers to using the strong duality theorem that says that, if a problem is convex, the objective functions of the primal and dual problems have the same value at the optimum, and some of the KKT conditions to obtain a linear expression of a non-linear constraint.

2.2.2 Modeling Assumptions

For clarity reasons, the main assumptions behind the proposed model are outlined below:

a) The model assumes a static planning approach and a yearly operation horizon, implying that the renewable generation capacity is maximized considering a single, future target year. The yearly operation horizon is divided into a number of representative time periods. Both investment and operating costs and revenues are calculated at the same yearly basis.
b) The considered electricity market is a pool-based energy-only market which is cleared by the market operator through the solution of a short-term social welfare maximization problem. In order to account for the effect of the transmission network, the market clearing process incorporates a DC power flow model and yields locational marginal prices (LMP) $\lambda_{i,t}$ for each node i and time period t.
c) Each conventional generation company is characterized by a different operating cost as well as different maximum output and minimum output constraints, with the latter representing the operation of must-run generation technologies.
d) The demand side is assumed inelastic.

Chapter 3

3 Theoretical Case Study

3.1 Chapter Nomenclature

Indices:

e	: Index for existing wind generating units.
g	: Index for existing thermal generating units.
hp	: Index for existing run of the river hydraulic generating units.
i	: Index for buses from 1 to I.
l	: Index for lines from 1 to L.
ns	: Index for new solar generating units.
s	: Index for existing solar generating units.
t	: Index for time periods or demand blocks running from 1 to T.

Parameters:

CV_g	: Variable cost of generating unit g.
F_l^{MAX}	: Transmission capacity of line l.
K_s	: Annuitized investment cost of new solar power unit s.
M	: Large enough constant or Big M.
P_g^{MAX}	: Maximum power output of thermal generating unit g.
P_{hp}^{MAX}	: Maximum power output of hydraulic unit hp.
$P_{t,i}^d$	: Load at bus i in time period t.
x_l	: Reactance of line l.
γ^s	: Additional payment for new solar generating units.
σ_t	: Weighting factor or duration of time period t.
ξ_e^t	: Normalized wind profile in time period t.
ξ_s^t	: Normalized solar profile in time period t.

Decision variables:

$F_{t,l}$	: Power flow through the lines l in time block demand t.
$P_{t,g}$	: Power produced by generating unit g in time block demand t.
$P_{t,hp}$	: Power produced by generating unit hp in time block demand t.
$P_{t,e}$	: Power produced by generating unit e in time block demand t.
$P_{t,s}$	: Power produced by generating unit s in time block demand t.
$P_{t,ns}$	: Power produced by generating unit ns in time block demand t.
X_i^{ns}	: Capacity investment of new solar generating unit at bus i.
$\lambda_{t,i}$	: Locational marginal price at time t on bus i.

3.2 Model Description

This work aims to find the Market Hosting Capacity of a transmission network, determining the maximum volume of renewable generation capacity that can be connected to a given network in a profitable fashion. For this purpose, we propose a generation expansion model for a target year, where we maximize renewable generation capacity subject to (in a second level) standard market clearing rules, i.e. minimum cost dispatch. The maximization of the capacity of renewable generation is also subject to a constraint that ensures non-negative profit of the new RES in the first level. The installed capacity of renewables will be determined in a node by node fashion, seeking for the best locations to maximize installed capacity of RES with non-zero profits.

The above is undertaken through bilevel optimization, where in the first level we maximize capacity of RES in a given power network and in the second level we operate the system and clear the market following perfect competition (cost minimization) paradigm.

The complete diagram of the proposed model to determine the hosting capacity can be observed in Figure 3-1Figure 3-1**¡Error! No se encuentra el origen de la referencia.**.This figure shows the bilevel structure of the model, where in the upper-level we maximize capacity of RES subject to having a positive profitability and to the lower-level problem. The lower-level problem represents the market clearing, subject to the power balance at every bus, power limits production and consumption and transmission constraints.

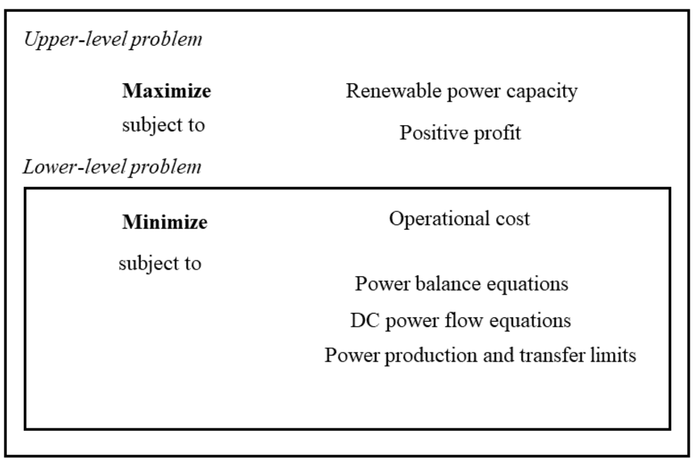

Figure 3-1: Bilevel structure of the investment model to determine the hosting capacity.

3.3 Overview of the Bilevel Investment Model

The investment decisions of renewable generation and the minimum cost dispatch are integrated through a bilevel model. The upper-level problem represents the investment decisions of the renewable power plants including volume and location at any bus. The objective of the upper-level is to maximize the amount of total installed renewable capacity in the system, subject to non-negative profitability of new plants.

The upper-level problem is subject to the problem of minimum operational cost, which is known as the second level or the lower-level problem. The objective of this level is to minimize the total dispatch cost of the system or, equivalently, maximize social welfare. The locational marginal prices (LMPs) of each bus is determined through the dual variables of the energy balance constrain in every node. Thus, while the upper-level optimizes renewable generation capacity, the lower level determines the resulting operation and LMPs. The structure of the bilevel problem is presented in Figure 3-1.

For obtaining the monolithic MPEC formulation, the lower level is replaced by its KKT conditions. The equilibrium constraints correspond to the set of KKT equations that represents the minimum cost operation. Finally, we use linearization techniques for converting the previous MPEC into a mixed-integer linear programming problem.

3.4 Model Formulation

3.4.1 Bilevel Model

The upper level objective function (3-1) corresponds to capacity expansion decisions of renewable generation. Constrain (3-2) represents the condition of non-negative profitability, that is, the revenue from energy sales at the marginal cost in the corresponding bus minus the investment cost must be positive, where $P_{t,ns}$ represent de power injected by the renewable power plant into the block demand t at bus i, γ^{s} represents additional payment for renewable generation or a certificated, K^{s} corresponds to the annual investment cost of renewable generation. LMP $\lambda_{t,i}$ is the dual variable of the energy balance constraint at bus i, time t. It is important note that the optimization model allows us to expand on any technology whose variable cost are equal to zero.

The minimization of the economic dispatch cost is represented by equation (3-3), where CV_{g} corresponds to the variable cost of thermal generation. Constraint (3-4) represents the nodal balance equation where the term $F_{t,l}$ corresponds to the flows entering or leaving note n from node $m \in L$ at time t. For transmission network, a dc linear approximation has been used. Constrain (3-5) shows the definition of the flow through the lines, where $\theta_{t,n}$ indicates the angle of the initial node and $\theta_{t,m}$ the arrival node, X_{l} corresponds to the reactance of the line. Constrains (3-7) to (3-11) indicates the flow limits through the lines as well as the maximum and minimum generation output limits.

$$Maximize \qquad \sum_{i \in I} X_i^{ns} \tag{3-1}$$

Subject to:

$$\left(\sum_{t \in T} \sigma_t \left(\sum_{i \in I} \left(\left(\lambda_{t,i} + \gamma^s \right) * P_{t,ns} \right) \right) - \sum_{i \in I} \left(K^s * X_i^{ns} \right) \right) \geq 0, \qquad \forall t, \forall i \tag{3-2}$$

$$X_i^{ns}, P_{t,ns}, \lambda_{t,i} \in argmin \{ \left(\sum_{t \in T} \sigma_t \sum_{g \in \Psi_n} P_{t,g} * CV_g \right) \tag{3-3}$$

Subject to:

$$\sum_{t \in T, g \in \Psi_n} P_{t,g} + \sum_{t \in T, hp \in \Psi_n} P_{t,hp} + \sum_{t \in T, e \in \Psi_n} P_{t,e} + \sum_{t \in T, s \in \Psi_n} P_{t,s} + \sum_{t \in T, ns \in \Psi_n} P_{t,ns} + \sum_{t \in T, l \in L} F_{t,l} = \sum_{t \in T, i \in I} P_{t,i}^d : \lambda_{t,i}, \qquad \forall i \tag{3-4}$$

$$F_{t,l} - \frac{\theta_{t,n} - \theta_{t,m}}{X_l} = 0 : \lambda_{t,i}, \qquad \forall l \in L, n \in I, m \in I \tag{3-5}$$

$$-F_l^{MAX} \leq F_{t,l} \leq F_l^{MAX} : \nu_{t,l}^{MAX}, \nu_{t,l}^{MIN}, \qquad \forall \, l \in L \tag{3-6}$$

$$0 \leq P_{t,g} \leq P_g^{MAX} : \mu_{t,g}^{MAX}, \mu_{t,g}^{MIN}, \qquad \forall g \in \Psi_n \tag{3-7}$$

$$0 \leq P_{t,hp} \leq P_{hp}^{MAX} : \mu_{t,hp}^{MAX}, \mu_{t,hp}^{MIN}, \qquad \forall hp \in \Psi_n \tag{3-8}$$

$$0 \leq P_{t,e} \leq X_e * \xi_e^t : \mu_{t,e}^{MAX}, \mu_{t,e}^{MIN}, \qquad \forall e \in \Psi_n \tag{3-9}$$

$$0 \leq P_{t,s} \leq X_s * \xi_s^t : \mu_{t,s}^{MAX}, \mu_{t,s}^{MIN}, \qquad \forall s \in \Psi_n \tag{3-10}$$

$$0 \leq P_{t,ns} \leq X_i^{ns} * \xi_{t,i}^s : \mu_{t,ns}^{MAX}, \mu_{t,ns}^{MIN}, \qquad \forall ns \in \Psi_n \tag{3-11}$$

$$\theta_{t,i} = 0 \,, \qquad i = 1 \}, \quad \forall \, t \in T, \forall \, i \in I \tag{3-12}$$

The optimization variables in the lower-level problems (3-3)-(3-12) are $\lambda_{t,i}, P_{t,g}, P_{t,hp}, P_{t,e}, P_{t,s}, P_{t,ns}, \theta_{t,n}, \nu_{t,l}^{MIN}, \nu_{t,l}^{MAX}, \mu_{t,g}^{MIN}, \mu_{t,g}^{MAX}, \mu_{t,hp}^{MIN}, \mu_{t,hp}^{MAX}, \mu_{t,e}^{MIN}, \mu_{t,e}^{MAX}$, $\mu_{t,s}^{MIN}, \mu_{t,s}^{MAX}, \mu_{t,ns}^{MIN}, \mu_{t,ns}^{MAX}$, while the optimization variables in the upper-level problem (3-1), (3-2) are X_i^{ns}.

3.4.2 MPEC

The formulation of the MPEC problem corresponding to problem (3-1)-(3-12) is stated below. It is obtained by replacing the lower-level problem by a set of constrains which are attained using the KKT conditions.

$$(3\text{-}1) – (3\text{-}2) \tag{3-13}$$

$$\sigma_t * CV_g + \mu_{t,g}^{MAX} - \mu_{t,g}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, \forall i \in I, g \in \Psi_n \tag{3-14}$$

$$\mu_{t,hp}^{MAX} - \mu_{t,hp}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, hp \in \Psi_n \tag{3-15}$$

$$\mu_{t,e}^{MAX} - \mu_{t,e}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, e \in \Psi_n \tag{3-16}$$

$$\mu_{t,s}^{MAX} - \mu_{t,s}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, s \in \Psi_n \tag{3-17}$$

$$\mu_{t,ns}^{MAX} - \mu_{t,ns}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, ns \in \Psi_n \tag{3-18}$$

$$-\lambda_{t,n} - \lambda_{t,m} + \nu_{t,l}^{MAX} - \nu_{t,l}^{MIN} - \lambda_{t,l} = 0, \qquad \forall t \in T, \forall n, \forall m \in I, g \in \Psi_n \tag{3-19}$$

$$\sum_{t,n,m} (\lambda_{t,n} - \lambda_{t,m})/X_l = 0, \qquad \forall t \in T, \forall n, \forall m \ \in I: n, m \in \Psi_n \tag{3-20}$$

$$(3-4) - (3-12) \tag{3-21}$$

$$0 \leq (F_l^{MAX} - F_{t,l}) \perp \nu_{t,l}^{MAX} \geq 0, \qquad \forall t \in T, \forall\ l \ \in L, \tag{3-22}$$

$$0 \leq (F_l^{MAX} + F_{t,l}) \perp \nu_{t,l}^{MIN} \geq 0, \qquad \forall t \in T, \forall\ l \ \in L, \tag{3-23}$$

$$0 \leq P_{t,g} \perp \mu_{t,g}^{MIN} \geq 0, \qquad \forall t \in T, \forall g \in \Psi_n \tag{3-24}$$

$$0 \leq P_{t,hp} \perp \mu_{t,hp}^{MIN} \geq 0, \qquad \forall t \in T, \forall hp \in \Psi_n \tag{3-25}$$

$$0 \leq P_{t,e} \perp \mu_{t,e}^{MIN} \geq 0, \qquad \forall t \in T, \forall e \in \Psi_n \tag{3-26}$$

$$0 \leq P_{t,s} \perp \mu_{t,s}^{MIN} \geq 0, \qquad \forall t \in T, \forall s \in \Psi_n \tag{3-27}$$

$$0 \leq P_{t,ns} \perp \mu_{t,ns}^{MIN} \geq 0, \qquad \forall t \in T, \forall ns \in \Psi_n \tag{3-28}$$

$$0 \leq (P_g^{MAX} - P_{t,g}) \perp \mu_{t,g}^{MAX} \geq 0, \qquad \forall t \in T, \forall g \in \Psi_n \tag{3-29}$$

$$0 \leq (P_{hp}^{hpMAX} - P_{t,hp}) \perp \mu_{t,hp}^{MAX} \geq 0, \qquad \forall t \in T, \forall hp \in \Psi_n \tag{3-30}$$

$$0 \leq \left(X_e * \xi_e^t - P_{t,e}\right) \perp \mu_{t,e}^{MAX} \geq 0, \qquad \forall t \in T, \forall e \in \Psi_n \tag{3-31}$$

$$0 \leq \left(X_s * \xi_s^t - P_{t,s}\right) \perp \mu_{t,s}^{MAX} \geq 0, \qquad \forall t \in T, \forall s \in \Psi_n \tag{3-32}$$

$$0 \leq \left(X_i^{ns} * \xi_{s,i}^t - P_{t,ns}\right) \perp \mu_{t,ns}^{MAX} \geq 0, \qquad \forall t \in T, \forall ns \in \Psi_n \tag{3-33}$$

The set of constraints (3-14)-(3-21) and the complementary constraints (3-22)-(3-33) are equivalent to the lower level problem (3-3)-(3-12). MPEC (3-13)-(3-33) is reformulated into a mixed integer linear programming problem as explained in the next section. It is important to note that this new problem includes all the optimization variables that appear in the problem (3-1)-(3-12) plus the binary variables used in the linearization of the complementary constrains as described in the next section.

3.4.3 Linearization

MPEC (3-13)-(3-33) includes the following nonlinearities:

1) The term $(\lambda_{t,i}) * P_{t,ns}$ in the positive profit constraint.
2) The complementarity conditions (3-22)-(3-33).

A. Complementarity linearization [43]

The complementarity condition

$$0 \leq a \perp b \geq 0 \tag{3-34}$$

$$a \geq 0, \qquad b \geq 0, \qquad a \leq \Psi * M, \qquad b \leq (1 - \Psi) * M \tag{3-35}$$

$$\Psi \epsilon \{0,1\} \tag{3-36}$$

B. Positive profit constraint linearization

The term $(\lambda_{t,i}) * P_{t,ns}$ in the non-negative profit constraint is non linear. To find a linear expression for this term, the strong duality theorem and some of de KKT equalities are used as follows.

The positive profit constraint (3-37) can be rewriting as the expression (3-38) were the first part is non-linear:

$$(\sum_{t \in T} \sigma_t (\sum_{i \in I} ((\lambda_{t,i} + \gamma^s) * P_{t,ns})) \ - \sum_{i \in I} (K^s * X_i^{ns})) \geq 0 \tag{3-37}$$

$$(\sum_{t \in T} \sigma_t (\sum_{i \in I} ((\lambda_{t,i}) * P_{t,ns})) \ + \sum_{t \in T} \sigma_t (\sum_{i \in I} ((\gamma^s) * P_{t,ns})) \tag{3-38}$$

Thus after applying the strong duality theorem to the lower level problem (3-3)-(3-12), we obtain:

$$\sum_{t\in T}\sigma_t\sum_{g}(P_{t,g}*CV_g) = -\sum_{t\in T,g\in\Psi_n}\mu_{t,g}^{MAX}*P_g^{MAX}-\sum_{t\in T,hp\in\Psi_n}\mu_{t,hp}^{MAX}*P_{hp}^{MAX} -\sum_{t\in T,e\in\Psi_n}\mu_{t,e}^{MAX}*P_e^{MAX}-\sum_{t\in T,s\in\Psi_n}\mu_{t,s}^{MAX}*P_s^{MAX} -\sum_{t\in T,ns\in\Psi_n}\mu_{t,ns}^{MAX}*P_{ns}^{MAX}-\sum_{t\in T,l\in L}\nu_{t,l}^{MIN}*F_{t,l}^{MAX}-\sum_{t\in T,l\in L}\nu_{t,l}^{MAX} *F_{t,l}^{MAX}+\sum_{t\in T,i\in I}\lambda_{t,i}*P_{t,i}^{d} \tag{3-39}$$

From (3-33):

$$\left(P_{ns}^{MAX}-P_{t,ns}\right)*\mu_{t,ns}^{MAX}=0 \rightarrow P_{ns}^{MAX}*\mu_{t,ns}^{MAX}=P_{t,ns}*\ \mu_{t,ns}^{MAX} \tag{3-40}$$

On the other hand, from (3-18):

$$\mu_{t,s}^{MAX}-\mu_{t,s}^{MIN}-\lambda_{t,i}=0 \rightarrow \lambda_{t,i}=\mu_{t,s}^{MAX}-\mu_{t,s}^{MIN} \tag{3-41}$$

Thus:

$$P_{t,ns}*\lambda_{t,i}=P_{t,ns}*\mu_{t,s}^{MAX}-P_{t,ns}*\mu_{t,s}^{MIN} \tag{3-42}$$

Finally, a linear expression for positive profit constraint can be obtained:

$$(\sum_{t\in T}\sigma_t(\sum_{i\in I}((\lambda_{t,i})*P_{t,ns}))=-\sum_{t\in T}\sigma_t\sum_{g\in\Psi_n}(P_{t,g}*CV_g)+\Upsilon_t+\sum_{t\in T,i\in I}\lambda_{t,i}*P_{t,i}^{d} \tag{3-43}$$

$$\Upsilon_t=-(\sum_{t\in T,g\in\Psi_n}\mu_{t,g}^{MAX}*P_g^{MAX}+\sum_{t\in T,hp\in\Psi_n}\mu_{t,hp}^{MAX}*P_{hp}^{MAX}+\sum_{t\in T,e\in\Psi_n}\mu_{t,e}^{MAX} *P_e^{MAX}+\sum_{t\in T,s\in\Psi_n}\mu_{t,s}^{MAX}*P_s^{MAX}+\sum_{t\in T,l\in L}\nu_{t,l}^{MIN}*F_{t,l}^{MAX} +\sum_{t\in T,l\in L}\nu_{t,l}^{MAX}*F_{t,l}^{MAX}) \tag{3-44}$$

3.4.4 Case Studies

3.4.4.1 Small-Scale Study: Illustration, Validation and Analysis over a 2-Bus Network

This section studies the impacts of maximizing renewable generation capacity on a given illustrative network's operation and nodal prices, calculating the newly-introduced market hosting capacity. We run several sensitivity analyses on network capacity, focusing on how the market hosting capacity varies. This small network also serves to illustrate and validate the model proposed in this thesis.

3.4.4.1.1 Input Data

Figure 3-2 shows the configuration of the 2-bus network with 2 thermal units, 2 solar power units, 2 demands, 2 buses and 1 line. This network is a modified version of the 2-bus Borduria (Node 1) and Syldavia (Node 2) example described in [30]. The specific data used in this paper is shown in TABLE 3-1. Note that while demand is the highest in node 2, the variable cost of thermal generation is the lowest in node 1. Also, node 1 presents the highest availability of the solar power resource.

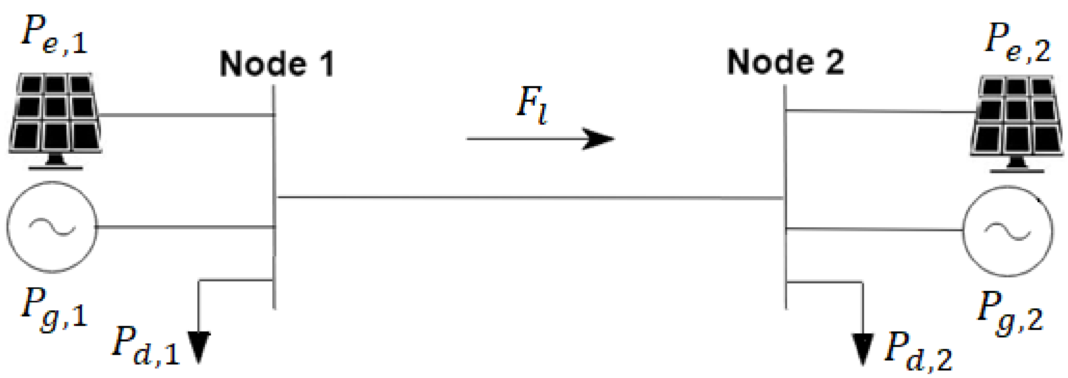

Figure 3-2: Two busbas example.

For illustrative purposes, the following results are obtained assuming a single operating condition only distributed in one hour, so both operating and investment costs are calculated accordingly. Overall, we study 2400 cases with different network capacities ranging from 0 to 1200 with a step of 0.5 MW, in which we seek to calculate, for each of them, the maximum capacity of solar power generation that can be installed in a profitable fashion.

TABLE 3-1: Input data for illustrative example.

Parameter	Node 1	Node 2
Demand [MW]	500	1500
Installed capacity of thermal generation [MW]	2000	2000
Variable cost of thermal generation [US$/MWh].	$10 * P_b + \frac{0.01}{2} * {P_b}^2$	$13 * P_s + \frac{0.02}{2} * {P_s}^2$
Normalized availability of solar power resource [p.u.].	0.28	0.15
Investment cost of renewable generation [US$/MW]	5	5

3.4.4.1.2 Results and discussion

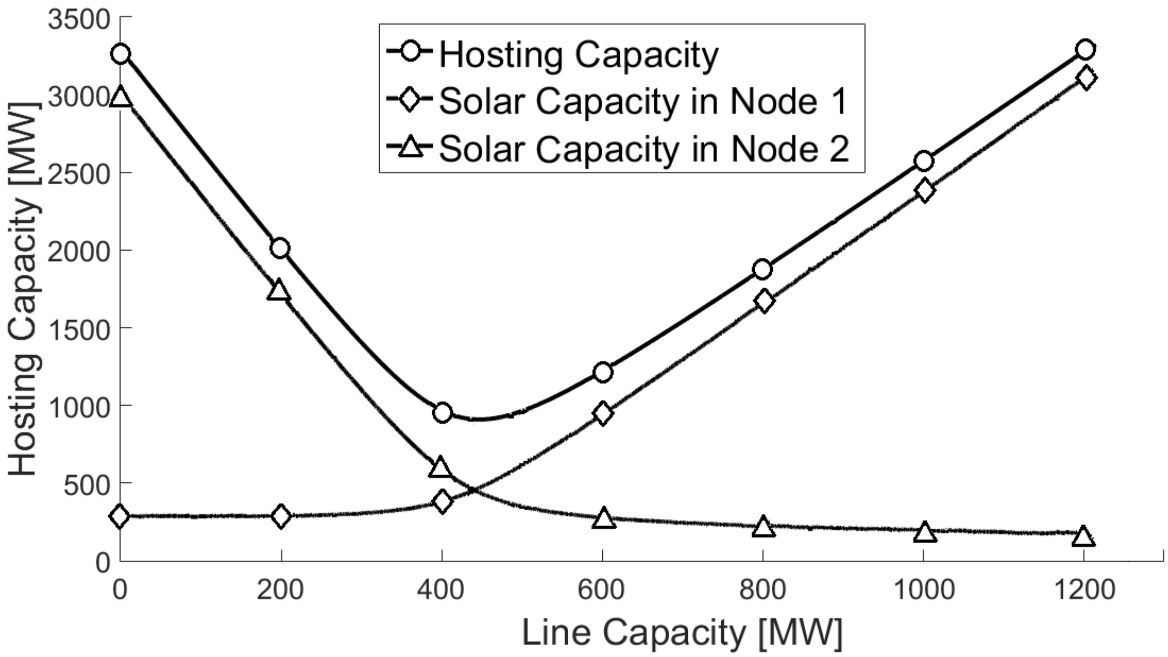

Figure 3-3:Hosting capacity vs network capacity.

Figure 3-3 shows the market hosting capacity of the 2-bus network as a function of the line capacity. Interestingly, for smaller line capacity values, the hosting capacity decreases while the line capacity increases. This counterintuitive result is so since the hosting capacity in node 2 drops disproportionally to the increase in the hosting capacity in node 1. Note that although the best solar power availability is located in node 1, prices in node 2 are higher, which presents a more attractive incentive to install higher volumes of renewable generation despite the lower availability levels of the resource. On the contrary, for larger line capacity values (above 400 MW in our case), the higher the line capacity the higher the hosting capacity. This can be explained as, naturally, the abovementioned attractiveness of node 2 disappears for higher line capacity values, where the price in node 2 drops and that in node 1 increases as illustrated in Figure 3-4, which facilitates the integration of solar power generation with higher load factors located in node 1.

The increase in the price of node 1 while the line capacity increases is due to the higher output of the low-cost thermal generator located in node 1, whose energy production can be exported to node 2 in order to minimize operational cost (see Figure 3-5). This low-cost energy produced in node 1, in turn, displaces costly energy production in node 2, reducing its price. Therefore, the increase in line capacity constantly reduces the economic attractiveness of node 2 and increases that in node 1.

All of the above demonstrate that increasing the capacity of a transmission network does not necessarily allow private investors to integrate higher volumes of renewables. On the contrary, increasing network capacity can even reduce the business opportunities for new renewable generation developments, especially in those close to the load centers and in areas with larger electricity prices.

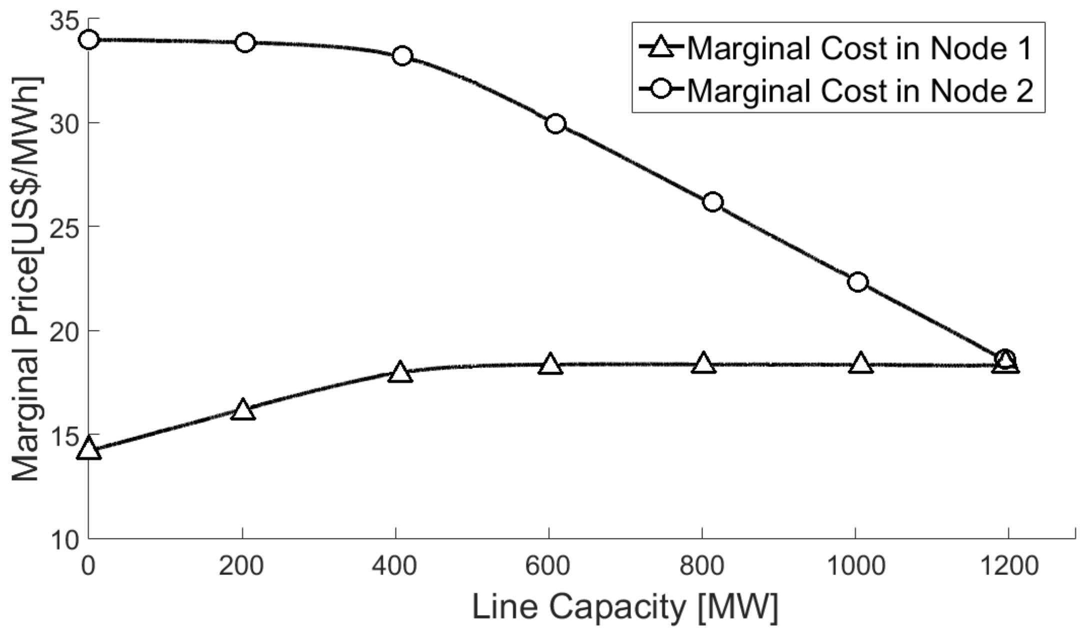

Figure 3-4: Locational marginal price vs network capacity.

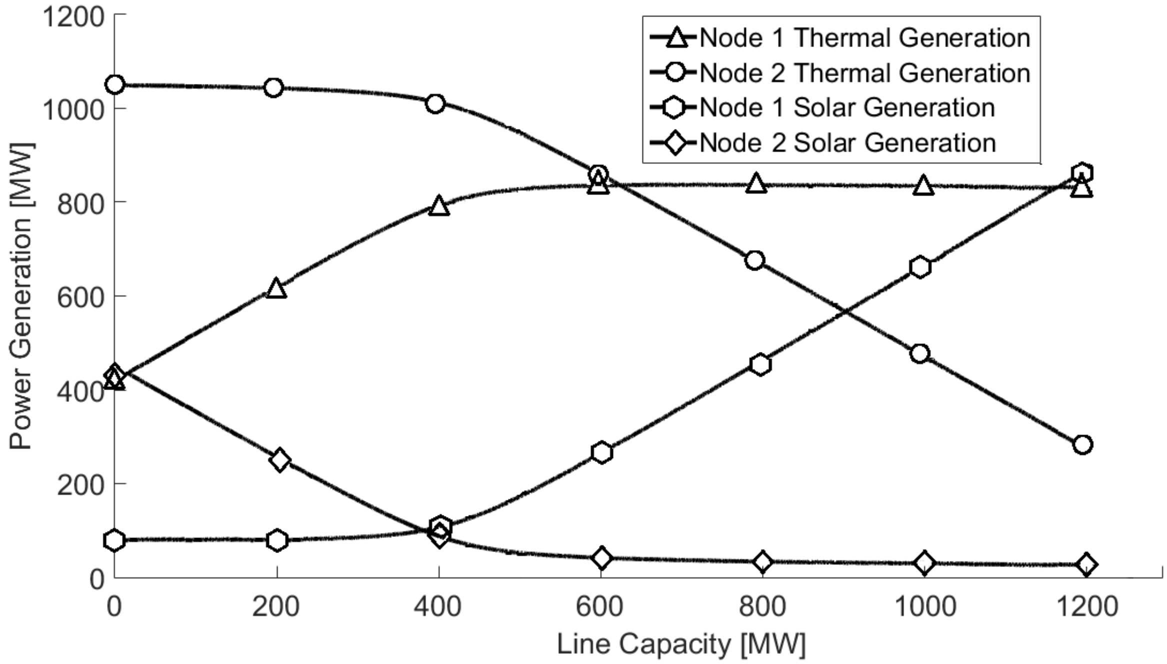

Figure 3-5:Power generation vs network capacity.

3.4.4.2 IEEE-RTS study: Analyzing the effects of network capacity, generation flexibility and subsidies on market hosting capacity

This section determines and analyzes the market hosting capacity of different network configurations, carrying out sensitivities in the capacity of the network, the flexibility of generation technologies and the potential subsidies that may exist to foster a larger penetration of renewable generation.

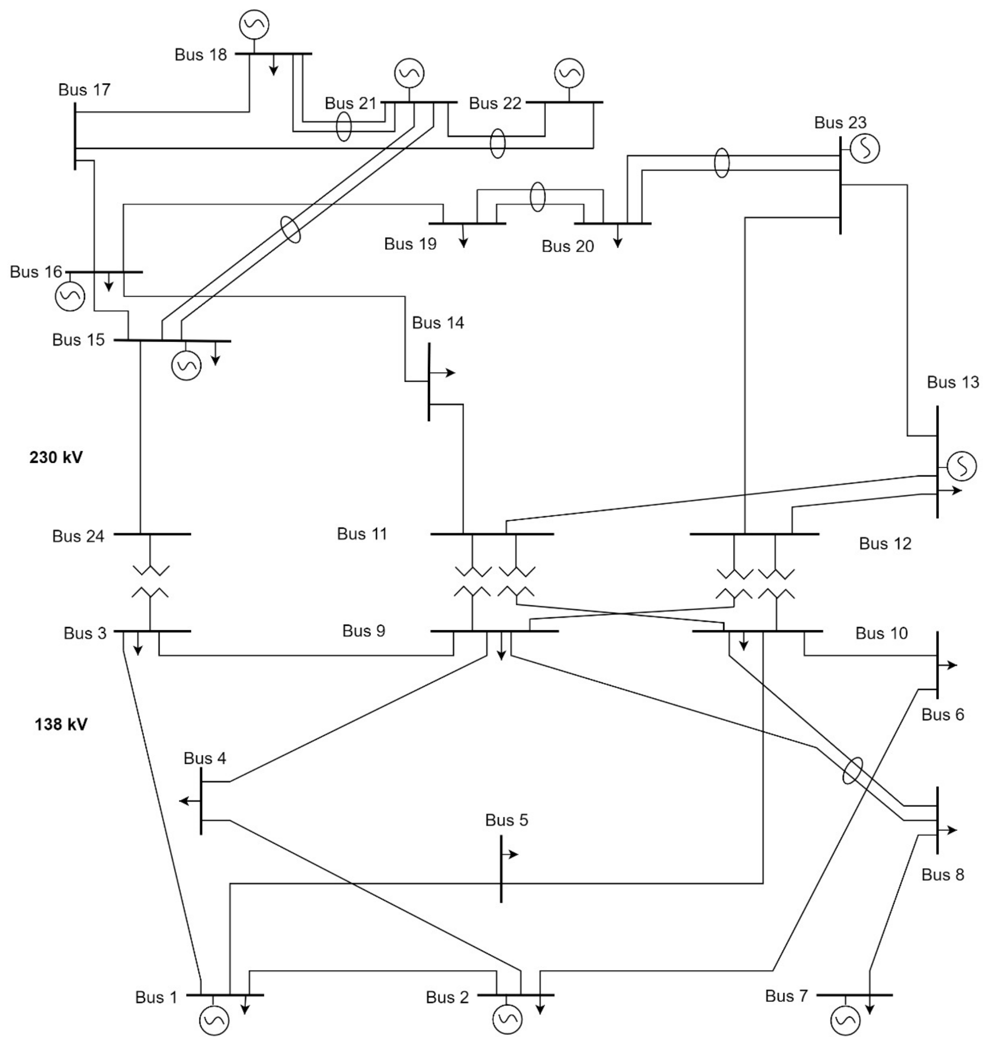

Figure 3-6: IEEE RTS System.

3.4.4.2.1 Input Data

We modified the IEEE RTS described in [44] by:

a) Original lines and transformers capacities have been reduced by 50%.
b) 20 [MW] of thermal generation for U20 type generating units.
c) 50 [MW] of thermal generation for U100 type generating units.

The IEEE-RTS network is illustrated in Figure 3-6. Note that changes a)-c) are aimed to congest the system and be able to make more reasonable analyzes, the original system has sufficient capacity to dispatch cheaper generating units that do not incentivize (in terms of LMP) the expansion of renewables. Only solar power generators can be installed in every node at an annuitized investment cost of 110000 US$/MW.yr and all nodes present the same availability profile across different time periods. To represent the multiple market clearings that occur across a year, various combinations of different demand and solar power levels can be selected through standard clustered techniques, e.g. K-Means [45]. For this particular case, we use demand and solar profiles observed in Chile, and relevant operational cost data taken from [46].

3.4.4.2.2 Case studies

We analyze 3 case studies which demonstrate how the market hosting capacity changes for:

a) 4 different network capacity levels
b) 4 different levels of flexibility in conventional generation technologies, which are varied by changing the minimum stable generation levels of conventional power plants.
c) 4 different levels of subsidies in the form of a renewables certificate.

3.4.4.2.3 Results and discussion

TABLE 3-2 shows the hosting capacity levels of various modified versions of the IEEE-RTS system when line capacities are increased by 10, 20 and 30% with respect to the base case introduced in the previous section. Interestingly, the most attractive case to maximize renewables penetration in a profitable fashion is that of minimum network capacity and this is so because of the higher LMPs present in the base case due to increased network congestion. Furthermore, an extra case study demonstrated that, in the extreme, when network capacities are very large, the hosting capacity of the network is zero. A key point in this example is that the availability and load factors of renewables are the same across the network. This makes less attractive the usual business case (absent in this case study but present in the previous 2-bus network) to expand transmission network capacity in order to access more remote but better renewable resources. In other words, network capacity expansion may impose a barrier for the development of new renewable generation in the presence of equally attractive renewable resources across a power system and this is a key result to be considered by planners and policy makers.

TABLE 3-2: Hosting capacity sensitivity to network capacity.

Case	Hosting Capacity [MW]
Original network	616.6
Original network + 10% of line capacity	524.238
Original network + 20% of line capacity	394.666
Original network + 30% of line capacity	298.68

We also analyze how operational flexibility may support higher renewables integration levels. Hence TABLE 3-3 shows the hosting capacity levels of various cases when the minimum stable generation limits of thermal units are increased by 2, 3 and 4 times with respect to the base case values for the minimum stable generations. TABLE 3-3 shows the results, demonstrating that lower levels of operational flexibility lead to smaller amounts of renewables integration in a profitable fashion. This is so since higher minimum stable generation limits increase the risk of renewables curtailments and thus decreases average energy prices.

TABLE 3-3: Hosting capacity sensitivity to operational flexibility.

Case	Hosting Capacity [MW]
Original network + minimum stable generation	508.05
Original network + 2 minimum stable generation*	372.43
Original network + 3 minimum stable generation*	269.85
Original network + 4 minimum stable generation*	171.07

Also, we study the effect of subsidies, in this case, a certificate type payment for MWh produced on top of the energy price. As expected, a higher price of this certificate increases the amount of renewables that can be integrated profitably. Interestingly, the efficiency of this subsidy in promoting renewables integration depends on network capacity. TABLE 3-4 shows that a subsidy of 12 US$/MWh can achieve more than 50% increase in hosting capacity with respect to the base case.

TABLE 3-4: Hosting capacity sensitivity to certificate prices.

Case	Hosting Capacity [MW]
Original network + 3 US$/MWh	686.71
Original network + 6 US$/MWh	771.29
Original network + 9 US$/MWh	853.63
Original network + 12 US$/MWh	958.30

Finally, it is important to mention that location of new renewables matches those nodes with higher energy prices in the base case. Bearing this in mind, in some situations (demonstrated above), it may not be beneficial to enhance network capacities for renewables as congestions will encourage further penetration of renewables due to the presence of areas with larger energy prices that can promote further capacity expansion. This finding though, and as pointed out in Section 3.4.4.1, is case specific.

Chapter 4

4 Chilean Case Study

4.1 Chapter Nomenclature

Indices:

e	: Index for existing wind generating units.
es	: Index for seasons.
g	: Index for existing thermal generating units.
h	: Index for existing hydraulic generating units.
hp	: Index for existing run of the river hydraulic generating units.
i	: Index for buses from 1 to I.
l	: Index for lines from 1 to L.
ne	: Index for new wind generating units.
ns	: Index for new solar generating units.
s	: Index for existing solar generating units.
t	: Index for time periods or demand blocks running from 1 to T.

Parameters:

CV_g	: Variable cost of generating unit g.
F_l^{MAX}	: Transmission capacity of line l.
$fp_{es,h}$	: Capacity factor of unit h at season es.
$fp_{hp,t}$	: Capacity factor of unit hp at time t.
K_e	: Annuitized investment cost of new solar power unit e.
K_s	: Annuitized investment cost of new solar power unit s.
M	: Large enough constant or Big M.
P_g^{MAX}	: Maximum power output of thermal generating unit g.
P_h^{MAX}	: Maximum power output of hydraulic unit hp.
$P_{t,i}^d$	: Load at bus i in time period t.
x_l	: Reactance of line l.
γ^s	: Additional payment for new solar generating units.
σ_t	: Weighting factor or duration of time period t.
σ_t^{es}	: Weighting factor of time demand block t, season es.
$\xi_{e,i}^t$	: Normalized wind profile in time period t at bus i.
$\xi_{s,i}^t$	: Normalized solar profile in time period t at bus i.

Decision variables:

$F_{t,l}$	: Power flow through the lines l in time block demand t.
$P_{t,g}$	: Power produced by generating unit g in time block demand t.
$P_{t,h}^h$	: Power produced by unit h in block demand t.

$P_{t,hp}$	: Power produced by generating unit hp in time block demand t.
$P_{t,e}$	: Power produced by generating unit e in time block demand t.
$P_{t,s}$	: Power produced by generating unit s in time block demand t.
$P_{t,ne}$	: Power produced by generating unit ne in time block demand t.
$P_{t,ns}$	: Power produced by generating unit ns in time block demand t.
X_i^{ne}	: Capacity investment of new wind generating unit at bus i.
X_i^{ns}	: Capacity investment of new solar generating unit at bus i.
$\lambda_{t,i}$	: Locational Marginal price at time t on bus i.

4.2 Bilevel Investment Model

The bilevel model described in section 3.2 integrates both capacity expansion decisions in renewable power plants and the operating model at minimum cost, a model that is represented by two unified optimization problems. On the other hand, the objective will always be to minimize costs and that is what should be kept in mind.

First of all, there is the first level or higher level, which represents the investment decisions of the renewable power plants. Given the characteristics of the model, they have the freedom to be located in any bus of the system. The upper level aims to maximize the share of renewable energy in the system, represented through the maximization of installed capacity subject to the overall profitability of these new generation sources being greater than or equal to zero.

As mentioned above, the main objective is to minimize costs, which is why the investment problem is nested with the operation problem at minimum cost for each demand block, which is known as the second level or lower level. The objective of this level is to realize the minimization of the economic dispatch of the system or seen in another way, the maximization of the social benefit in perfect competition. The marginal cost of each bus is obtained through the dual variables of the nodal balance equations.

Thus, the first level has as a variable the installed capacity of renewable energies, which are delivered to the second level as input parameter, so the second level that operates the system has as variable the marginal costs of the bus of the system, which are delivered to the first level as a parameter.

The optimal region of the second level or lower level is determined by the Karush-Kuhn-Tucker (KKT) conditions. Thus, after obtaining the optimal region, the upper level and the lower level represented by the conditions of KKT are taken and the resulting model corresponds to an MPEC.

The above problem corresponds to a nonlinear problem, then linearization techniques have been used to convert the MPEC model into a mixed integer linear programming model.

4.3 Model Formulation

The model of the problem is formulated through two integrated optimization problems that on the one hand, at the higher level, the planning of renewable energies is represented and, on the other hand, the lower level, the economic dispatch. The model is formulated through bi-level optimization, which is approached through an MPEC model thanks to the KKT conditions and which is finally linearized by different techniques to obtain a MILP model.

4.3.1 Bilevel Model

The optimization model used to determine the Market Hosting Capacity of the transmission network is explained below. The problem is formulated through two levels, where the first level corresponds to the maximization of capacity expansion of variable renewable energies (solar and wind) subject to positive profitability, while the second level or lower level represents the operation of the system through the economic dispatch. Thus, the problem of optimization of the lower level represents the operation of the system for each block of demand with the aim of minimizing the cost of economic dispatch, subject to nodal balance restrictions, maximum and minimum limits of generation of the units and limits of transmission. Thus, the mathematical formulation of the proposed model is presented below:

$$Maximize \qquad \sum_{i \in I} X_i^{ns} + X_i^{ne} \tag{4-1}$$

Subject to:

$$\left(\sum_{t \in T} \sigma_t \Big(\sum_{i \in I} \big(\lambda_{t,i} * P_{t,ns}\big) + \big(\lambda_{t,i} * P_{t,ne}\big)\Big) - \sum_{i \in I} \big(K^s * X_i^{ns} + K^e * X_i^{ne}\big) \right) \geq 0 \tag{4-2}$$

$$X_i^{ns}, P_{t,ns}, X_i^{ne}, P_{t,ne}, \lambda_{t,i} \in argmin \, \{ \left(\sum_{t \in T} \sigma_t \sum_{g \in \Psi_n} P_{t,g} * CV_g \right) \tag{4-3}$$

Subject to:

$$\sum_{t \in T, g \in \Psi_n} P_{t,g} + \sum_{t \in T, h \in \Psi_n} P_{t,h} + \sum_{t \in T, hp \in \Psi_n} P_{t,hp} + \sum_{t \in T, e \in \Psi_n} P_{t,e} + \sum_{t \in T, s \in \Psi_n} P_{t,s} + \sum_{t \in T, ns \in \Psi_n} P_{t,ns} + \sum_{t \in T, ne \in \Psi_n} P_{t,ne} + \sum_{t \in T, l \in L} F_{t,l} = \sum_{t \in T, i \in I} P_{t,i}^d \; : \; \lambda_{t,i} \tag{4-4}$$

$$F_{t,l} - \frac{\theta_{t,n} - \theta_{t,m}}{X_{n,m}} = 0 : \lambda_{t,i}, \qquad \forall l \in L, n \in I, m \in I \tag{4-5}$$

$$-F_l^{MAX} \leq F_{t,l} \leq F_l^{MAX} : \; \nu_{t,l}^{MAX}, \nu_{t,l}^{MIN}, \qquad \forall\, l \in L \tag{4-6}$$

$$0 \leq P_{t,g} \leq P_g^{MAX} \colon \mu_{t,g}^{MAX}, \mu_{t,g}^{MIN}, \qquad \forall\, g \in \Psi_n \tag{4-7}$$

$$0 \leq P_{t,h} \leq P_h^{MAX} \colon \mu_{t,h}^{MAX}, \mu_{t,h}^{hMIN}, \qquad \forall\, h \in \Psi_n \tag{4-8}$$

$$0 \leq P_{t,hp} \leq P_{hp}^{hMAX} \colon \mu_{t,hp}^{hMAX}, \mu_{t,hp}^{hMIN}, \qquad \forall\, hp \in \Psi_n \tag{4-9}$$

$$0 \leq P_{t,\mathrm{e}} \leq X_e * \xi_{i,e}^{t} \colon \mu_{t,e}^{MAX}, \mu_{t,e}^{MIN}, \qquad \forall\, e \in \Psi_n \tag{4-10}$$

$$0 \leq P_{t,\mathrm{s}} \leq X_s * \xi_{i,s}^{t} \colon \mu_{t,s}^{MAX}, \mu_{t,s}^{MIN}, \qquad \forall s \in \Psi_n \tag{4-11}$$

$$0 \leq P_{t,\mathrm{ns}} \leq X_i^{ns} * \xi_{t,i}^{s} \colon \mu_{t,ns}^{MAX}, \mu_{t,ns}^{MIN}, \qquad \forall\, ns \in \Psi_n \tag{4-12}$$

$$0 \leq P_{t,\mathrm{ne}} \leq X_i^{ne} * \xi_{t,i}^{e} \colon \mu_{t,ne}^{MAX}, \mu_{t,ne}^{MIN}, \qquad \forall\, ne \in \Psi_n \tag{4-13}$$

$$\sum_{t=1}^{T1} (P_{t,h} * \sigma_t) \leq P_h^{MAX} * (\sum_{t=1}^{T1} \sigma_t) * fp_{1,h} = \phi_{1,h} \colon \mu_{h,1}^{h\sigma MAX}, \qquad \forall h \in \Psi_n \tag{4-14}$$

$$\sum_{t=T1+1}^{T2} \left(P_{t,h} * \sigma_t\right) \leq P_h^{MAX} * (\sum_{t=T1+1}^{T2} \sigma_t) * fp_{2,h} = \phi_{2,h} \colon \mu_{h,2}^{h\sigma MAX}, \qquad \forall h \in \Psi_n \tag{4-15}$$

$$\sum_{t=T2+1}^{T3} \left(P_{t,h} * \sigma_t\right) \leq P_h^{MAX} * (\sum_{t=T2+1}^{T3} \sigma_t) * fp_{3,h} = \phi_{3,h} \colon \mu_{h,3}^{h\sigma MAX}, \qquad \forall h \in \Psi_n \tag{4-16}$$

$$\sum_{t=T3+1}^{T4} (P_{t,h} * \sigma_t) \leq P_h^{MAX} * (\sum_{t=T3+1}^{T4} \sigma_t) * fp_{4,h} = \phi_{4,h} \colon \mu_{h,4}^{h\sigma MAX}, \qquad \forall h \in \Psi_n \tag{4-17}$$

$$\theta_{t,i} = 0\,, \qquad i = 1\}, \quad \forall\, t \in T, \forall\, i \in I \tag{4-18}$$

The optimization variables of each lower-level problems (4-3)-(4-18) are: $\lambda_{t,i}, P_{t,g}, P_{t,h}, P_{t,hp}, P_{t,e}, P_{t,s}, P_{t,ns}, P_{t,ne}, \theta_{t,i}, \nu_{t,l}^{MIN}, \nu_{t,l}^{MAX}, \mu_{t,g}^{MIN}, \mu_{t,g}^{MAX}, \mu_{t,h}^{MIN}, \mu_{t,h}^{MAX}, \mu_{t,hp}^{MIN}, \mu_{t,hp}^{MAX}, \mu_{t,e}^{MIN}, \mu_{t,e}^{MAX}, \mu_{t,s}^{MIN}, \mu_{t,s}^{MAX}, \mu_{t,ns}^{MIN}, \mu_{t,ns}^{MAX}, \mu_{t,ne}^{MIN}, \mu_{t,ne}^{MAX}, \mu_{h,1}^{h\sigma MAX}, \mu_{h,2}^{h\sigma MAX}, \mu_{h,3}^{h\sigma MAX}, \mu_{h,4}^{h\sigma MAX}$. In addition to the optimization variables above, the upper-level problem (4-1), (4-2) includes the following optimization variables: X_i^{ns}, X_i^{ne}.

To determine the Hosting Capacity of the network, the investment in maximum renewable generation that can be connected must be determined, which is represented through the objective function (4-1) where the subscript i represents the nodes of the system and the freedom of the generation to be installed at any node. The problem of the first level is subject to the constraint (4-2) that indicates that profitability must be positive, that is, income from the sale of energy at marginal cost in the injection bus minus investment costs must be greater than or equal to zero, where $P_{t,ne}$ an $P_{t,\mathrm{ns}}$ represent the power injected by the renewable wind and solar power plants respectively in the demand block t in node i, K^e and K^s indicate the annuity of the wind and solar investment. $\lambda_{t,i}$ corresponds to the Locational Marginal Price (LMP) of bus i at time t, this is obtained through the dual variables of nodal balance constraints. In this case, the model decides how to install solar and wind energy in each node, plants with zero variable costs. Thus, both LMP and the feasible region of the optimization problem are defined by the problem of the lower level, or the problem of dispatch at minimum cost.

The second level represents the minimization of the economic dispatch cost of the system, which is represented through equation (4-3), where CV_g are the variable costs of generation of the thermal power plants. The constraint (4-4) indicates the equation of nodal balance, that is to say that the sum of the powers generated by the centrals in the node i must be equal to the demand in the node i for all block of time t, the term $F_{t,\mathrm{l}}$ corresponds to the flows entering and leaving node n from node $m \in I$. For the flows in the lines a linear approximation dc has been used, in this way equation (4-5) shows the definition of the flows in the lines, where $\theta_{t,n}$ indicates the origin node and $\theta_{t,m}$ the arrival node, X_l corresponds to the reactance of the line. The constraints (4-6) to (4-13) indicate the maximum and minimum generation limits of the system units as well as the flow limits for the lines. Restrictions (4-14) to (4-17) impose generation restrictions for reservoirs per station, thus limiting the available energy for a set of time blocks belonging to each station. Finally, equation (4-18) imposes that bus 1 corresponds to the reference bus for each block. In the model described, each of the dual variables is indicated.

4.3.2 MPEC

$$(4-1)-(4-2) \tag{4-19}$$

$$\sigma_t * CV_g + \mu_{t,g}^{MAX} - \mu_{t,g}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, \forall i \in I, g \in \Psi_n \tag{4-20}$$

$$\begin{gathered}\mu_{t,h}^{MAX} - \mu_{t,h}^{MIN} - \lambda_{t,i} + \sum_{t,h,es} \mu_{t,h,es}^{h\sigma MAX} * \sigma_t^{es} = 0, \\ \forall es \in \sigma_t^{es}, \forall t \in T, \forall\, h \in \Psi_n\end{gathered} \tag{4-21}$$

$$\mu_{t,hp}^{MAX} - \mu_{t,hp}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, hp \in \Psi_n \tag{4-22}$$

$$\mu_{t,e}^{MAX} - \mu_{t,e}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, e \in \Psi_n \tag{4-23}$$

$$\mu_{t,s}^{MAX} - \mu_{t,s}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, s \in \Psi_n \tag{4-24}$$

$$\mu_{t,ne}^{MAX} - \mu_{t,ne}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, ne \in \Psi_n \tag{4-25}$$

$$\mu_{t,ns}^{MAX} - \mu_{t,ns}^{MIN} - \lambda_{t,i} = 0, \qquad \forall t \in T, ns \in \Psi_n \tag{4-26}$$

$$-\lambda_{t,n} - \lambda_{t,m} + \nu_{t,l}^{MAX} - \nu_{t,nl}^{MIN} - \lambda_{t,l} = 0, \qquad \forall t \in T, \forall n, \forall m \in I \tag{4-27}$$

$$\sum_{t,n,m} (\lambda_{t,n} - \lambda_{t,m})/X_l = 0, \qquad \forall t \in T, \forall n, \forall m \ \in I: n, m \in I \tag{4-28}$$

$$(4-3) - (4-18) \tag{4-29}$$

$$0 \leq (F_l^{MAX} - F_{t,l}) \perp \nu_{t,l}^{MAX} \geq 0, \qquad \forall t, \forall n, \forall m \tag{4-30}$$

$$0 \leq (F_{n,m}^{MAX} + F_{t,n,m}) \perp \nu_{t,n,m}^{MIN} \geq 0, \qquad \forall t \in T, \forall\ l \ \in L, \tag{4-31}$$

$$0 \leq P_{t,g} \perp \mu_{t,g}^{MIN} \geq 0, \qquad \forall t \in T, \forall g \in \Psi_n \tag{4-32}$$

$$0 \leq P_{t,h} \perp \mu_{t,h}^{MIN} \geq 0, \qquad \forall t \in T, \forall h \in \Psi_n \tag{4-33}$$

$$0 \leq P_{t,hp} \perp \mu_{t,hp}^{MIN} \geq 0, \qquad \forall t \in T, \forall hp \in \Psi_n \tag{4-34}$$

$$0 \leq P_{t,e} \perp \mu_{t,e}^{MIN} \geq 0, \qquad \forall t \in T, \forall e \in \Psi_n \tag{4-35}$$

$$0 \leq P_{t,s} \perp \mu_{t,s}^{MIN} \geq 0, \qquad \forall t \in T, \forall s \in \Psi_n \tag{4-36}$$

$$0 \leq P_{t,ne} \perp \mu_{t,ne}^{MIN} \geq 0, \qquad \forall t \in T, \forall ne \in \Psi_n \tag{4-37}$$

$$0 \leq P_{t,ns} \perp \mu_{t,ns}^{MIN} \geq 0, \qquad \forall t \in T, \forall ns \in \Psi_n \tag{4-38}$$

$$0 \leq (P_g^{MAX} - P_{t,g}) \perp \mu_{t,g}^{MAX} \geq 0, \qquad \forall t \in T, \forall g \in \Psi_n \tag{4-39}$$

$$0 \leq (P_h^{MAX} - P_{t,h}) \perp \mu_{t,h}^{MAX} \geq 0, \qquad \forall t \in T, \forall h \in \Psi_n \tag{4-40}$$

$$0 \leq (P_{hp}^{MAX} - P_{t,hp}) \perp \mu_{t,hp}^{MAX} \geq 0, \qquad \forall t \in T, \forall hp \in \Psi_n \tag{4-41}$$

$$0 \leq \left(X_e * \xi_e^t - P_{t,e}\right) \perp \mu_{t,e}^{MAX} \geq 0, \qquad \forall t \in T, \forall e \in \Psi_n \tag{4-42}$$

$$0 \le \left(X_s * \xi_s^t - P_{t,s}\right) \perp \mu_{t,s}^{MAX} \ge 0, \qquad \forall t \in T, \forall s \in \Psi_n \tag{4-43}$$

$$0 \le \left(X_i^{ne} * \xi_{e,i}^t - P_{t,ne}\right) \perp \mu_{t,ne}^{MAX} \ge 0, \qquad \forall t \in T, \forall ne \in \Psi_n \tag{4-44}$$

$$0 \le \left(X_i^{ns} * \xi_{s,i}^t - P_{t,ns}\right) \perp \mu_{t,ns}^{MAX} \ge 0, \qquad \forall t \in T, \forall ns \in \Psi_n \tag{4-45}$$

$$0 \le \left(\sum_{t=1}^{T1} \left(P_{t,h} * \sigma_t\right) - \phi_{1,h}\right) \perp \ \mu_{h,1}^{h\sigma MAX} \ge 0 \tag{4-46}$$

$$0 \le \left(\sum_{t=T1+1}^{T2} \left(P_{t,h} * \sigma_t\right) - \phi_{2,h}\right) \perp \ \mu_{h,2}^{h\sigma MAX} \ge 0 \tag{4-47}$$

$$0 \le \left(\sum_{t=T2+1}^{T3} \left(P_{t,h} * \sigma_t\right) - \phi_{3,h}\right) \perp \ \mu_{h,3}^{h\sigma MAX} \ge 0 \tag{4-48}$$

$$0 \le \left(\sum_{t=T3+1}^{T4} \left(P_{t,h} * \sigma_t\right) - \phi_{4,h}\right) \perp \ \mu_{h,4}^{h\sigma MAX} \ge 0 \tag{4-49}$$

The lower-level problem represented by equations (4-3) - (4-18) is reformulated by means of constraints (4-19) - (4-31) and complementary constraints (4-32) - (4-49) resulting in an equivalent problem. MPEC (4-19) - (4-49) is transformed into a mixed integer linear programming problem as explained in the next section. Finally it should be mentioned that the new formulation of the problem includes both the optimization variables that appear in the problem formulated through the constraints (4-1) - (4-18) as well as the binary variables that are used in the linearization of the positive profitability constraint and complementary constraints.

4.3.3 Linearization

MPEC (4-19)-(4-49) includes the following nonlinearities:

1) The term $\left(\lambda_{t,i}\right) * P_{t,ns} + \left(\lambda_{t,i}\right) * P_{t,ne}$ in the positive profit constraint.
2) The complementarity conditions (4-32)-(4-49).

A. Complementarity linearization [40]

The complementarity condition

$$0 \le a \perp b \ge 0 \tag{4-50}$$

$$a \geq 0, \qquad b \geq 0, \qquad a \leq \Psi * M, \qquad b \leq (1 - \Psi) * M \tag{4-51}$$

$$\Psi \epsilon \{0,1\} \tag{4-52}$$

B. Positive profit constraint linearization

The term $(\lambda_{t,i}) * P_{t,ns} + (\lambda_{t,i}) * P_{t,ne}$ in the positive profit constraint. To find a linear expression for this term, the strong duality theorem and some of de KKT equalities is used.

Thus, the positive profit constraint (4-53) can be rewriting as the expression (4-54) were the first part is non-linear:

$$(\sum_{t \in T} \sigma_t (\sum_{i \in I} ((\lambda_{t,i}) * P_{t,ns} + (\lambda_{t,i}) * P_{t,ne})) \ - \sum_{i \in I} (K^s * X_i^{ns}) + (K^e * X_i^{ne})) \geq 0 \tag{4-53}$$

$$(\sum_{t \in T} \sigma_t (\sum_{i \in I} ((\lambda_{t,i}) * P_{t,ns} + (\lambda_{t,i}) * P_{t,ne})) \tag{4-54}$$

Thus after applying the strong duality theorem to the lower level problem (4-3)-(4-18), it is obtained:

$$\begin{aligned}
\sum_{t \in T} \sigma_t \sum_{g \in \Psi_n} (P_{t,g}^g * CV_g) \\
&= - \sum_{t \in T, g \in \Psi_n} \mu_{t,g}^{MAX} * P_g^{MAX} - \sum_{t \in T, h \in \Psi_n} \mu_{t,h}^{MAX} * P_h^{MAX} \\
&- \sum_{t \in T, hp \in \Psi_n} \mu_{t,hp}^{MAX} * P_{hp}^{MAX} - \sum_{t \in T, e \in \Psi_n} \mu_{t,e}^{MAX} * P_e^{MAX} \\
&- \sum_{t \in T, s \in \Psi_n} \mu_{t,s}^{MAX} * P_s^{MAX} - \sum_{t \in T, ns \in \Psi_n} \mu_{t,ns}^{MAX} * P_{ns}^{MAX} \\
&- \sum_{t \in T, ne \in \Psi_n} \mu_{t,ne}^{MAX} * P_{ne}^{MAX} - \sum_{t \in T, l \in L} \nu_{t,l}^{MIN} * F_{t,l}^{MAX} - \sum_{t \in T, l \in L} \nu_{t,l}^{MAX} \\
&* F_{t,l}^{MAX} - \sum_{h \in \Psi_n, es} \phi_{es,h} * \mu_{h,es}^{h\sigma MAX} + \sum_{t \in T, i \in I} \lambda_{t,i} * P_{t,i}^d
\end{aligned} \tag{4-55}$$

From (4-44) and (4-45)

$$(P_{ns}^{MAX} - P_{t,ns}) * \mu_{t,ns}^{MAX} = 0 \ \rightarrow P_{ns}^{MAX} * \mu_{t,ns}^{MAX} = P_{t,ns} * \ \mu_{t,ns}^{MAX} \tag{4-56}$$

$$\left(P_{ne}^{MAX} - P_{t,ne}\right) * \mu_{t,ne}^{MAX} = 0 \ \rightarrow P_{ne}^{MAX} * \mu_{t,ne}^{MAX} = P_{t,ne} * \ \mu_{t,ne}^{MAX} \tag{4-57}$$

On the other hand from (4-25) and (4-26)

$$\mu_{t,ns}^{MAX} - \mu_{t,ns}^{MIN} - \lambda_{t,i} = 0 \ \rightarrow \ \lambda_{t,i} = \mu_{t,ns}^{MAX} - \mu_{t,ns}^{MIN} \tag{4-58}$$

$$\mu_{t,ne}^{MAX} - \mu_{t,ne}^{MIN} - \lambda_{t,i} = 0 \ \rightarrow \ \lambda_{t,i} = \mu_{t,ne}^{MAX} - \mu_{t,ne}^{MIN} \tag{4-59}$$

Finally, a linear expression for positive profit constraint is obtained:

$$\begin{aligned}(\sum_{t\in T} \sigma_t (\sum_{i\in I} ((\lambda_{t,i}) * P_{t,ns} + (\lambda_{t,i}) * P_{t,ne}))\\ = -\sum_{t\in T} \sigma_t \sum_{g\in \Psi_n} (P_{t,g} * CV_g) + \Upsilon_t - \sum_{h\in \Psi_n, es} \phi_{es,h} * \mu_{h,es}^{h\sigma MAX}\\ + \sum_{t\in T,i} \lambda_{t,i} * P_{t,i}^{d}\end{aligned} \tag{4-60}$$

$$\begin{aligned}\Upsilon_t = -(\sum_{t\in T, g\in \Psi_n} \mu_{t,g}^{MAX} * P_g^{MAX} + \sum_{t\in T, h\in \Psi_n} \mu_{t,h}^{MAX} * P_h^{MAX} + \sum_{t\in T, hp\in \Psi_n} \mu_{t,hp}^{MAX}\\ * P_{hp}^{MAX} + \sum_{t\in T, e\in \Psi_n} \mu_{t,e}^{MAX} * P_e^{MAX} + \sum_{t\in T, s\in \Psi_n} \mu_{t,s}^{MAX} * P_s^{MAX}\\ + \sum_{t\in T, l\in L} \nu_{t,l}^{MIN} * F_{t,l}^{MAX} + \sum_{t\in T, l\in L} \nu_{t,l}^{MAX} * F_{t,l}^{MAX})\end{aligned} \tag{4-61}$$

4.3.4 Case Study

The objective of this section is to determine the Hosting Capacity of a real transmission network, the transmission network of the Chilean National Electrical System (SEN). As previously presented, it is not evident that an increase in the transmission capacity of the system implies an increase in the capacity of renewable energies or an increase in the HC for renewable energies, therefore two case studies have been evaluated, one base case of the current network and an expansion plan for a 3000 MW HVDC transmission line. Therefore, it is expected with this study to obtain useful information for the system planner and determine if the investment of this line is beneficial for the system or not in terms of renewables energies hosting capacity.

4.3.4.1.1 Input Data

The system considered corresponds to the simplified Chilean National Electrical System (SEN) of 42 busses, in Figure 4-1 the diagram of the system can be observed. Figure 4-1 shows the characteristics of the system, this model is 42 busses and 58 lines in its base model, the case study with which it is compared is 59 lines, HVDC line that goes from bar 4 to 29 of 3000 [MW] capacity. The number of thermal generators is 95, while the hydroelectric plants are in total 26, 10 hydraulic reservoir plants and 16 run-of-river plants. In addition, there are 13 wind power plants and 18 solar power plants (an equivalent of renewable power plants has been found by nodes). Run-of-river, wind and solar power plants have a generation profile that depends on the primary resource, and there is an additional constraint that limits the maximum energy that a hydraulic reservoir generating unit can generate in a station. The system has the freedom to install both wind and solar power plants in any node, for this the system has been divided into three zones to which different generation profiles have been assigned according to the availability of the resource. 8 representative time blocks have been simulated using the k-means algorithm [43]. For this, we have worked with 7 dimensions, demand profile and 3 generation profiles by area (north, center and south) for wind and solar generation.

The purpose of this section is to determine if the HVDC line increases the Hosting Capacity of the network. For this, 4 case studies have been simulated for two different scenarios, the first scenario corresponds to the base case, that is to say the National Electric System to 2018 that considers even the projects that are under construction and a comparison is made with the scenario with the HVDC line that goes from the north to the center, that is, the Crucero-Encuentro bus (bus 4) to the Cerro Navia bus (bus 29) in Figure 4-1. The four cases that have been simulated correspond to a sensitivity analysis in the investment annuity of the solar and wind power plants according to the projections of the Ministry of Energy of the Government of Chile, where favorable scenarios for the capacity expansion of these technologies are considered.

TABLE 4-1: Input data SEN system 42 busses.

Parameter	n°
Number of Thermal Generator	95
Number of Hydraulic Generator	26
Number of Wind Generator	13
Number of Solar Generator	18
Lines	58
Busses	42
Time Demand Blocks	8

TABLE 4-2: Renewable investment cost.

Study Case	*Solar [USD/KW]*	*Wind [USD/kW]*
Case 1	*1000*	*1300*
Case 2	*950*	*1300*
Case 3	*1000*	*1250*
Case 4	*950*	*1250*

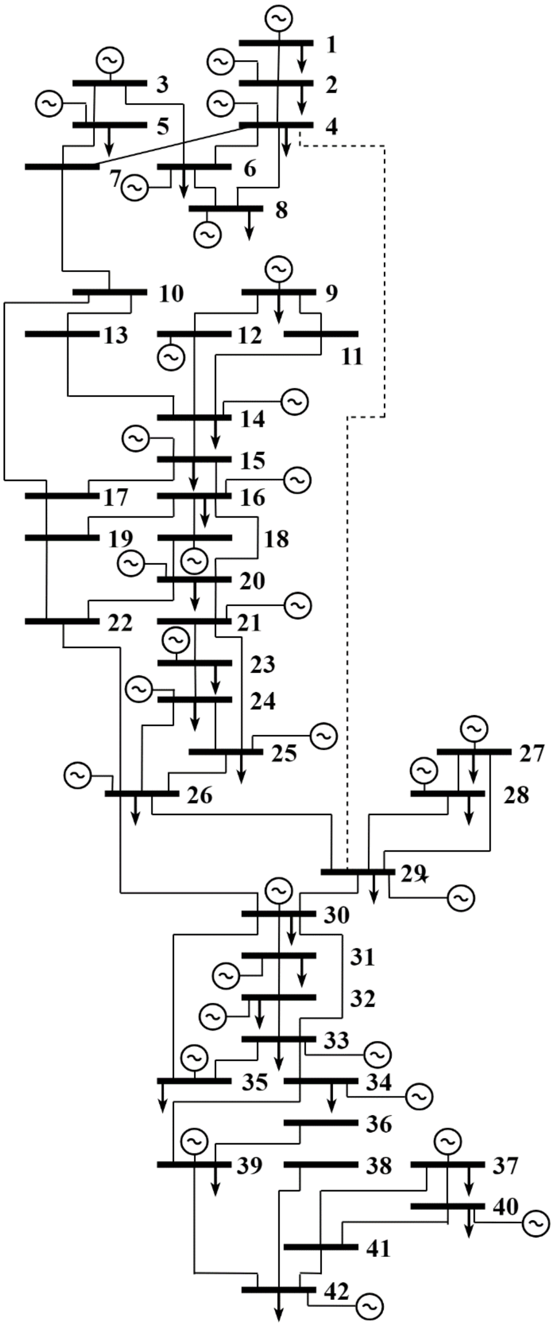

Figure 4-1:SEN 42 busses system schema.

4.3.4.1.2 Results

The results of the study are summarized in TABLE 4-3, where it can be seen that there is an increase in the Hosting Capacity when installing the HVDC line, this HC considers the sum between the investments of solar and wind technology. It can be seen that a decrease in the annual investment cost of the same amount in solar technology has a greater impact on the HC than in the wind case.

TABLE 4-3: Hosting capacity of different cases.

Study Case	HC Base Case [MW]	HC Base Case + Line HVDC [MW]
Case 1	1075.2	2925.35
Case 2	3217.41	4149.29
Case 3	1075.32	2933.85
Case 4	3217.41	4166.23

It is possible to observe from TABLE 4-3 that a decrease in the investment costs of solar technology has a higher impact on the benefits of installing the HVDC line. In this sense it can be seen that in cases where a solar investment of 1000 [USD/kW] is maintained, the HVDC line increases by a little more than 1800 MW the HC of the network, however when there is a decrease to 950 [USD/kW] the investment in solar technology, the increase is little more than 900 [MW] in the HC of the network.

From Figure 4-2 to Figure 4-4 a comparison is made between the base case, that is, how the system currently operates with respect to case 1, both in the base scenario and with the HVDC line. It can be seen that initially the share of solar and wind energy together slightly exceeds 18%, being mostly a thermal generation above 45%. However, it can be observed that when the HC of this network is determined, there is the possibility of having an increase of almost 5% more in solar energy, which allows to reduce the thermal generation to almost 40% of participation. Finally, when the HVDC line is connected, it can be observed that the total HC of the network increases to almost 31% between the existing solar and wind generation adding to the new generation, mostly solar, which reaches 12.67%. This effect allows to reduce thermal generation to 34% and a small decrease in hydraulic generation.

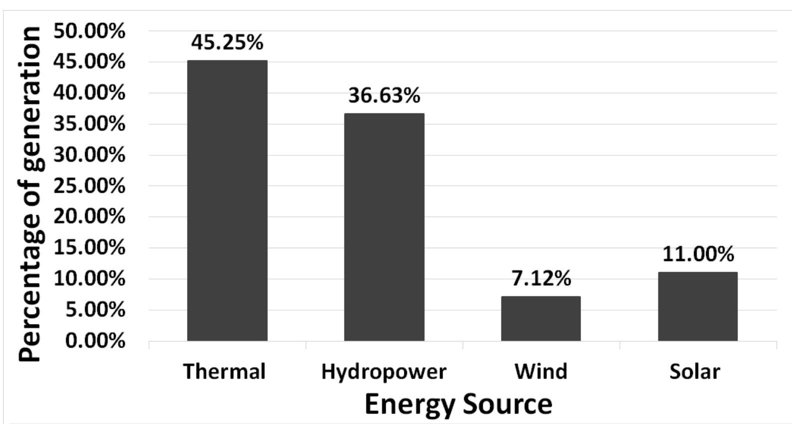

Figure 4-2:Electricity generation by energy source, base case.

Figure 4-5 to Figure 4-7 show the locational marginal prices of the system, where it is intended to compare the average of marginal costs with those of the busses where most of

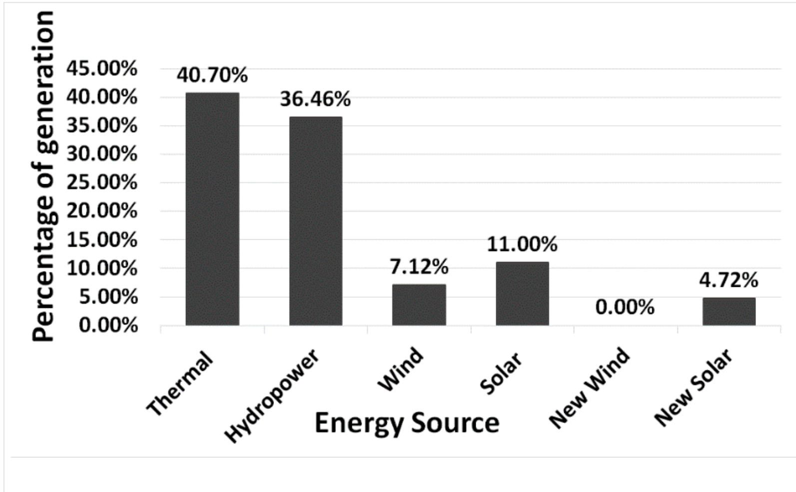

Figure 4-3: Electricity generation by energy source, HC of base case.

the solar and wind energy is installed, both in the base case and in the case of the scenario with the HVDC line. It can be seen that in the base case (Figure 4-5) there is a clear decoupling in the marginal costs, that is increased in Figure 4-6 where the HC is determined, the LMP decreases considerably with respect to the average in the busses where new is installed renewable generation, in addition the average LMP also decreases. Finally in Figure 4-7 it can be seen that the HVDC line allows for an almost perfect coupling between the average marginal costs and the marginal costs in which new renewable generation is installed, this allows observing another of the benefits that the incorporation of this line can have.

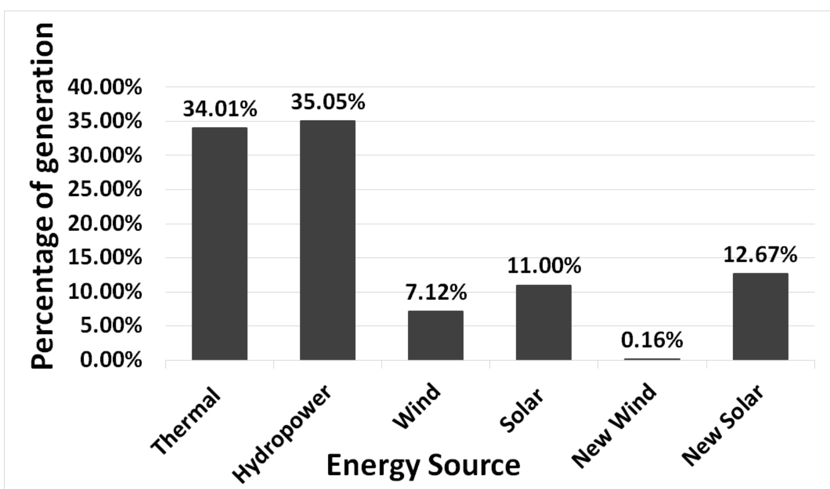

Figure 4-4: Electricity generation by energy source, HC + line HVDC.

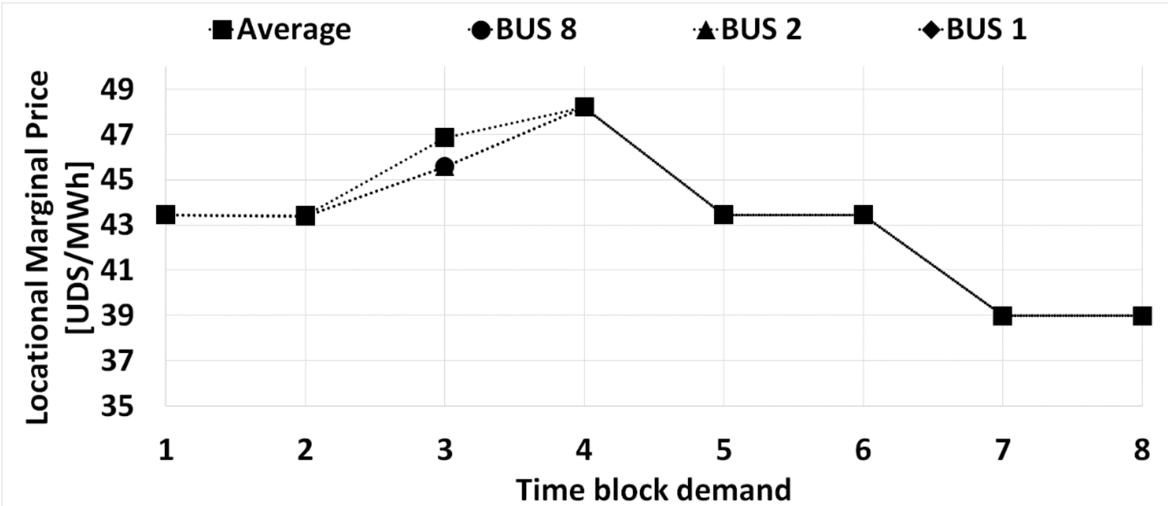

Figure 4-5: Locational marginal price base case.

4.3.4.1.3 Discussion

According to the results presented above, it can be interpreted that in the case of the Chilean Electricity System we are in the second zone of the curve of Figure 3-3 because an increase in the transmission capacity means a significant increase in the HC of the network. This is mainly due to the increase in transmission from an area with favorable primary resources (in the case of solar generation, high plant factor) to an area where the demand of the system is concentrated. In case 1 of TABLE 4-3 it can be seen that the HC of the current network is approximately 1075 [MW], where almost 100% of the new renewable generation is concentrated in nodes 1, 2 and 8, that is, in busses with high solar radiation. When installing the HVDC line there is an increase of approximately 1850 [MW] because there is a large generation that can be dispatched to the load center by this line. It is important to note that for the system it is not necessarily important to find an area with high marginal costs (which could be counterintuitive), in fact if you look at Figure 4-5 you can see that in certain time blocks, particularly block 3, busses 1, 2 and 8 are below the average of marginal costs of the system, however it is in these nodes where the new generation is concentrated, by the plant factor and the transmission and demand capacity of the area.

In case 2, that is, when the annuity of solar investment has decreased, there is an increase of more than 2000 [MW] in the HC, as in case 4, where both solar and wind investment have decreased. This shows the great effect of the decrease in investment costs of solar technology, where more than 70% is located in busses in the northern zone, that is, with high radiation. However, in cases 2 and 4 with the current network there is investment in solar technology in the southern zone, that is, with a low plant factor, in the former almost 20% of the HC is concentrated in bar 42 with approximately 655 [MW], in the second case approximately 27% of the HC is concentrated in bus 39 with approximately 875 [MW], this result shows the possibility that solar potential exists in areas with low plant factor, given that it is subject to investment costs which has not been considered to a greater extent at present. Both cases (2 and 4) increase by a little more than 900 [MW] the HC of the network when the HVDC line is installed, in both cases 100% of the new solar generation is installed in the north zone, that is to say with good plant factor. This shows that, independently of the fact that there is a considerable increase in the HC by reducing the annuity of solar investment, installing even in areas with lower plant factor, the HVDC line is beneficial in terms of the increase in the renewable HC that occurs in the network. For case 3, where the cost of investment in wind power plants has decreased, it can be seen that there is no significant effect, because due to the characteristics of the system, wind technology does not become competitive like solar technology.

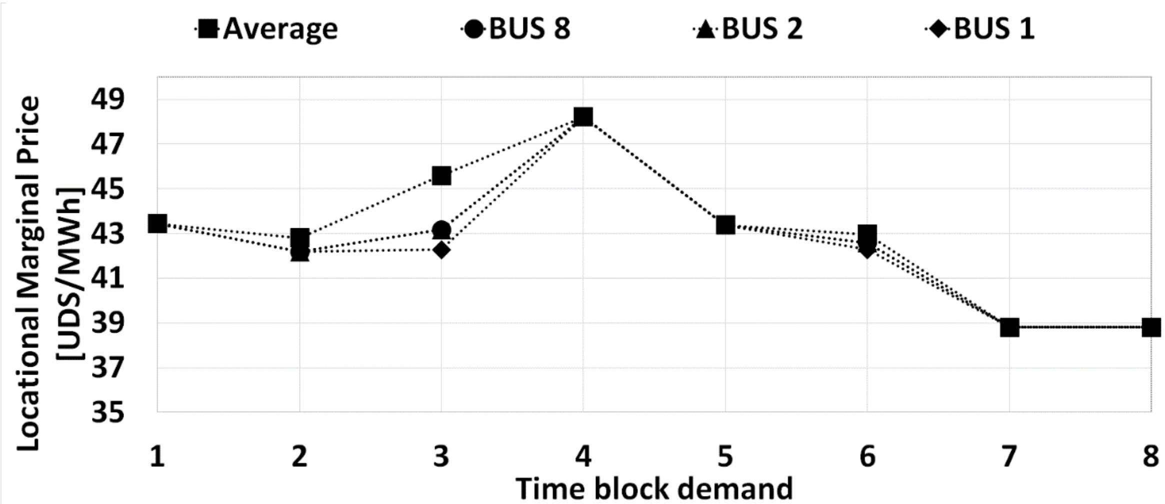

Figure 4-6: Locational marginal price base case + HC.

If you look at Figure 4-2 it can be seen that the system initially operates with little more than 18% of variable renewable energies, predominantly thermal generation, when the HC is determined it can be observed that there is an increase of 5% in solar technology, resulting in a reduction in the thermal input of almost the same proportion, this is due to the fact that the new solar power plants displace the thermal generation in the dispatch at minimum cost, maintaining almost the same hydraulic generation, in the case where the HVDC line is installed there is an increase of little more than 12.5% in solar technology, considerably reducing thermal generation. This is supported by the fact that the new solar technology is installed in busses with predominantly thermal generation, so in addition to displacement in terms of variable costs (zero for renewable generation) there is a shift in terms of utilization of the line to dispatch this technology.

Another important point to emphasize is that the new HVDC line allows integrating the system avoiding uncoupling marginal costs as seen in Figure 4-7 and unlike the base cases of Figure 4-5 and Figure 4-6, where stress in the system in terms of demand imply the appearance of decoupling in the LMP.

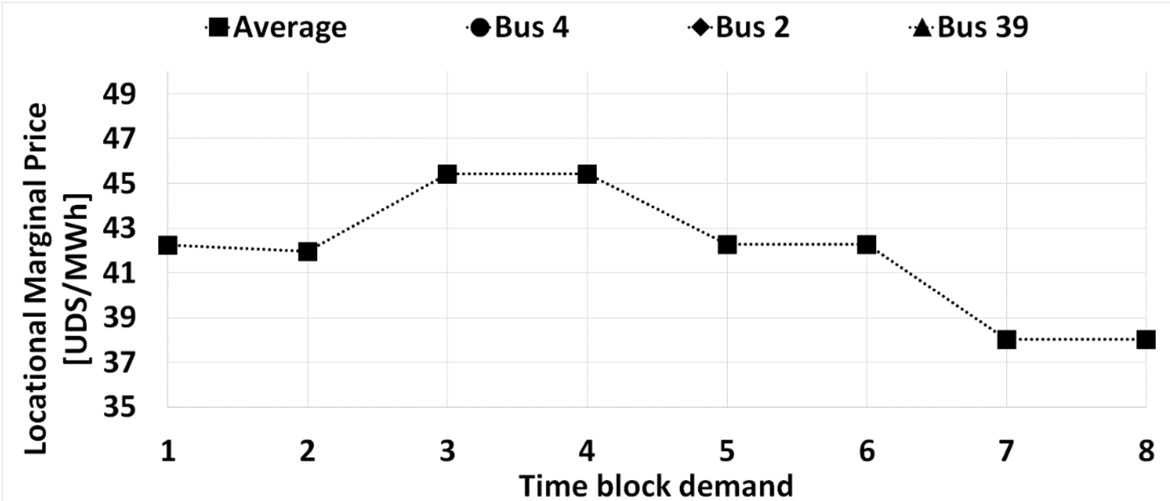

Figure 4-7: Locational marginal price base case + HC + HVDC.

Chapter 5

5 Conclusion

We introduced, for the first time, a new concept named Market Hosting Capacity (MHC) and its respective mathematical model that determines the maximum (market) amount of renewables that can be connected to a given power network. This is a new measure for hosting capacity from an economic point of view, which is useful to understand how (and if) more network capacity can effectively support higher investment in renewable generation (or not). In this context, we demonstrate that higher network capacity does not necessarily drive higher renewable generation investment since prices may drop. We also demonstrate how system flexibility and subsidies can significantly support higher levels of MHC.

We presented 2 theoretical studies on a 2 and 24 busbar system and a more practical study over a 42-busbar representation of the Chilean Electricity System. Here, we demonstrated that transmission expansion represented by the HVDC 3000 [MW] line, presents a positive impact on the MHC, allowing higher amounts of renewables to be integrated. It is also shown that with the new line it is possible to operate the system with a contribution of RES greater than 30% per year of study and that is positive in terms of energy policies.

5.1 Future Works

The previously proposed MILP optimization model has certain complications in computational terms if we want to work with more representative blocks, or with highly congested systems or planning horizons of several years, due to the significant increase in active binary variables (mixed integer problem). Therefore, it may be convenient to find another solution methodologies based on advanced algorithms or decompositions.

Another analysis that is proposed to develop is to change the objective function of the problem, having as objective the minimization of emissions, in this way investment decisions would encompass all technologies, but what is sought is to find the solution that minimizes costs and also minimizes emissions.

Correctly modeling the switching on and off of the machines is very useful for a better representation of the system, however, this would imply incorporating unit commitment constraints that, because they are not linear, cannot be directly incorporated into the second level problem, since they do of this problem a non-convex problem and, therefore, the proposed methodology cannot be applied.

Another topic of interest corresponds to the modeling of the flexibility of the system, although it is true that a case of flexibility is studied in this thesis but modeling the demand side respond or storage is a major challenge, in particular for the case of storage where a problem similar to that of the UC constraints is faced.

Finally, the multiple possible applications presented by the proposed model make it strike to study other market sectors, thus opening new study cases.

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Appendix

Name	n°	Name	n°
Tarapaca	1	Los Vilos	23
Lagunas	2	Nogales	24
Kapatur	3	Quillota	25
Crucero-Encuentro	4	Polpaico	26
Los Changos 220	5	Rapel 220	27
Laberinto-Domeyko	6	Melipilla	28
Los Changos 500	7	Cerro Navia - Lo Aguirre	29
Atacama-Mejillones	8	Alto Jahuel	30
Paposo	9	Tinguiririca	31
Cumbre 500	10	Itahue	32
Lalackama	11	Ancoa 220	33
Etaltal	12	Charrua	34
Cumbre 220	13	Colbun 220	35
Diego de Almagro	14	Cautin 500	36
Cardones	15	Puerto Montt	37
Maitencillo	16	Ciruelos 500	38
Cardones 500	17	Temuco - Cautin	39
Punta Colorada	18	Rahue	40
Maitencillo 500	19	Pichirropulli	41
Pan de Azucar	20	Valdivia - Ciruelos	42
Las Palmas	21		
Pan de Azucar 500	22		

TABLE A-0-1: Name of 42 Busses of the SEN System