ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

MASTER IN THE ELECTRIC POWER INDUSTRY

IMPACT OF AN OPTIMUM RENEWABLE PORTFOLIO STANDARD IN THE SYSTEM ADEQUACY AND ITS EFFECT ON THE WHOLESALE ELECTRICITY MARKET: DOMINICAN REPUBLIC

Author: René Báez Santana
Supervisor: Dr. Benjamin F. Hobbs

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Master's Thesis Presentation Authorization

THE STUDENT:

RENÉ BÁEZ SANTANA

....

THE SUPERVISOR

BENJAMIN F. HOBBS

Signed: Date: ...28.../ ...June.../ ...2017...

Authorization of the Master's Thesis Coordinator

Dr. Luis Olmos Camacho

Signed: .... Date: 28/ 06/ 2017

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ABSTRACT.

As in any other country, the security of electricity supply is essential to the development of Dominican Republic. With the ongoing growth of renewable energy sources of electricity in the country, its power system adequacy may be deteriorated due to the low price cap established in the wholesale market. This work proposes two methodologies based upon a linear programming model for optimizing generation investment and operations that try to solve this oncoming problem. Both methodologies measure the impact of different scenarios of renewable share, while at the same time determines a new price cap that ensures better reliability levels. These methodologies could be implemented by setting a Renewable Portfolio Standard (RPS) that resembles the best scenario of renewable share in the market according to the results. For both methodologies, an RPS of 13% with its corresponding increase in the price cap, could be consider as “optimal” or at least the preferable one, as it would result in the best improvement in reliability. This enhancement in reliability serves as a basis to remunerate renewables based on their Effective Load Carrying Capability (ELCC), which resulted in 15.2%. For any of the methodologies to work, some adjustments must be made regarding the market and regulatory design, as well as necessary improvements in the infrastructure of the power system.

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Chapter 1　Introduction and objectives

1.1 Introduction

System operators are, to some extent, responsible for maintaining system adequacy, which means ensuring that the generation mix can cover the peak demand and avoid shortages. System adequacy presents a challenge for the Dominican Republic, as the percentage of hours with non-served energy within a year are significant. The low price cap/cost of non-served energy established by the regulator may have an influence on this matter, as it does not incentivize market agents to invest in more capacity or to renew old plants that are currently performing inefficiently. It is not attractive to new investors, as well. In the end, a considerable number of hours with non-served energy during peak hours and off-peak hours are occurring and expected for upcoming years.

Nowadays, renewable energy sources (RES) represent around 3% of the energy produced in the system. However, due to the perceived risks of investing in conventional generation and incentives given to RES generation, market agents are favoring the investments on this kind of technology as the years pass. So, it is expected that higher targets of renewable generation are achieved in the not-so-distant future.

It is possible that setting a Renewable Portfolio Standard (RPS) could improve the system adequacy by reducing the hours with non-served energy in a year. Nevertheless, in theory, an aggressive RPS could instead worsen the problem of system adequacy if prices are capped, as energy prices may decrease to the point that would make fossil-fuelled generating units lose remuneration, which could motivate them to retire from the system. Nevertheless, this reduction in shortages could be translated into a new price cap/cost of non-served energy that, in theory, should be higher. This new *scarcity price* may attract new investors and motivate the actual generation agents in the market to reinvest in their facilities to improve their performance.

Establishing a higher price cap that responds to an increase in renewable energy sources, can then guarantee that system adequacy will not be harmed, while at the same time incentivizing new investments. This work aims at defining an optimal RPS, that can increase the system adequacy while attracting investment on generation.

The capacity mechanism currently in place in the Dominican Republic only remunerates conventional generation (counting hydroelectric generation). If it is ensured that the integration of more RES has a positive impact on the system's reliability, it could serve as a justification for a similar payment in the case of these technologies. Consequently, the determination of the capacity value of RES generation becomes a requirement for this remuneration. While for conventional generators the capacity value is relatively easy to calculate, it is not the case for intermittent RES generation.

For what it is read in the paragraph above, two similar methodologies have been proposed to solve the ongoing problem of the power system adequacy in the Dominican Republic, as well as to prevent the deterioration of the security of supply at a wholesale level.

1.2 Objectives

The main objective of this work is **to develop a methodology to determine the optimal RPS that would allow the increase of the price-cap/cost of non-served energy by improving the system adequacy**.

The secondary objectives of this work are to address the following questions:

- What is the importance of associating an increase in the price cap/cost of non-served energy to a defined RPS target, within the context of the Dominican power system situation?
- What is the effect of the integration of RES in the Dominican wholesale electricity market upon reliability indices, prices and the transactions involved in the market?
- Should renewable energy sources be compensated for their contribution to system adequacy?

1.3 Scope

The organization of the thesis is as follows. In the next chapter (Chapter 2), a literature survey covers the topcis of security-of-supply, reliability indices, renewable support schemes, the determination of an optimum portfolio of renewables, and capacity value.

Following in Chapter 3, a description of the current situation in the Dominican Republic is presented. A summary of how the power system and market work is given, followed by a brief explanation of the problem that this work tries to solve.

Chapter 4 describes the two methodologies that are proposed in aims of solving the problem presented in the previous chapter. The methodologies are based on a linear programming model that is also explained within this chapter, as well as the assumptions made. Afterward, the results and their analysis of the application of these methodologies to a period of four years are shown in Chapter 5.

The conclusions to this work are in Chapter 6, along with a summary of the results and findings, and recommendations for further reasearch. Finally, Chapter 7 organizes the references that supported this project, and the APPENDIX (Chapter 8).

Chapter 2 State of the Art

In this chapter, a review of the topics of system reliability, security-of-supply (and its differenc mechanisms), reliability indices, RES support schemes, optimum generation portfolios, and capacity value of RES. By discussing the relevant literature of each topic, a contribution can be made that fits into the field of enhancing the security-of-supply through renewables, taking into account its capacity value.

2.1 Concept of system reliability and security of supply

In a power system, reliability is measured by the capacity of this system to secure the supply that it demands. Reliability is one of the major drivers for the system's planning and operation, as the social and economic structure of a country depends on the security of supply of the electricity both in the short- and long-term. Because of this, reliability divides into two parts: security, and adequacy (Billinton & Allan, 1984).

A system is secure if it can endure disturbances within components of the system such as generating units or transmission lines. System adequacy refers to the matter of whether there are the necessary generating facilities as well as transmission and distribution facilities to meet the electricity demand. Adequacy is attained with a combination of different generators that may have significantly different characteristics.

As previously mentioned, a country's development depends on the security of supply. And it is one of the major drivers in decision-making in power systems alongside economic efficiency and environmental impact. To understand the problem of security of supply, it is necessary to address its four different time dimensions as first described in (Batlle, et al., 2007):

- Security, for the real-time operation and as already explained in the paragraphs above, is the ability of the system to support disturbances in its components.

- Firmness, for the short- to mid-term, to be the capability of facilities already installed in the system to respond to actual needs to meet the current load efficiently. This dimension is linked to both the technical characteristics of the generation and network facilities and their effective management in the medium-term. The remuneration of this dimension serves as an incentive to availability.

- Adequacy, for the long-term, refers to the issue of whether there are sufficient available generation and transmission capacity installed or to be installed, to meet the load in the long-term efficiently. Its remuneration encourages investment.

- Strategic expansion, for the very long-term, entails the management of resources and energy infrastructures in the very long term. This dimension usually involves the diversification of fuel provision and the generation mix. It also comprises the long-term network planning, and it is associated with energy policy.

There is an interdependency between these dimensions. The requirements for investment in generation in transmission to satisfy the demand in future years must be consistent with the needs in the short term. For example, the future generation mix required to secure the supply must be able to respond to disturbances in the grid (e.g. operating reserves). Likewise, if a country's government sets an ambitious target for intermittent renewable energy sources, it should make sure that there will be enough flexibility in the generation mix to respond to the variability of the former. Plenty examples can be provided regarding the relationship of these four dimensions.

Within the dimensions of 'security', 'firmness' and 'system adequacy' some quantifying indices can be applied to measure the degree of the power system's performance. These indices are the subject of the next subsection.

2.2 Reliability indices

The main goal of electric power system planning and operation is to provide acceptable levels of reliability at a minimum cost. To determine what an "acceptable level" is, first it is required to establish target reliability levels. The parameter that measures aspects related to the reliability of the operation of a power system is known as a reliability index. The security of supply does not only depend on the generation system but also on transmission and distribution networks, as any of them can fail under any circumstance and at any time. The reliability indices described in the next few pages measures reliability from the perspective of the generating system. In the case of generation, the most relevant aspects that must quantify the reliability indices are the number or frequency of failures, the duration, and incidence of failures.

It is fundamental to clarify that each index, deterministic or probabilistic, has strengths and weaknesses and consequently cannot individually provide a full portrayal of the generating system reliability. As mentioned previously, these reliability indices can be classified as deterministic reliability indices (2.2.1) and probabilistic reliability indices (2.2.2) as shown in (International Atomic Energy Agency, 1984).

2.2.1 Deterministic reliability indices

These indices reflect the average continuity of supply of a system and do not consider the uncertainty in the operation of the power system. Though more limited than probabilistic indices, they are frequently used because of their simple calculation and the little data required to determine them. Another characteristic is that they allow an easy comparison between systems.

Reserve margin (RM). Reserve margin measures available generation capacity over and above the yearly load requirements. Is very simple and easy to apply. However, there are limitations in not taking into account different system parameters such as generation mix, water reserves, unit sizes, technologies or forced outage rates.

The following formulations can determine the RM:

$$RM\ (MW) = Available\ Generation - Maximum\ Demand$$

$$RM\ (pu) = \frac{Available\ Generation - Maximum\ Demand}{Maximum\ Demand}$$

Largest unit (LU). This index considers the possible unavailability of the largest generator and presents an improvement over the RM by taking into account the size of the units. It is calculated from the following expression:

$$LU\ (pu) = \frac{RM\ (MW)}{Installed\ Capacity\ of\ the\ Largest\ Unit}$$

A value of LU < 1 indicates that the system will have non-served energy in case the larger unit is lost. An LU > 1 value indicates that the largest unit can be lost without having non-served energy in the system.

Dry year. This index -or criterion- is used mainly in hydro dominated systems, where the reliability is defined with respect to the required supply during a year with low hydroelectric availability. The dry year can be defined as the driest year of existing statistical data. Given the definition, the driest demand has to be satisfied.

2.2.2 Probabilistic reliability indices

In contrast to deterministic indices, probabilistic reliability indices do consider the stochasticity characteristic of power system operation. Also, they permit the quantitative assessment of system alternatives by considering parameters that influence reliability, such as the capacities of individual generating units and the forced outage rate of each unit. Thus, it is safe to say that they provide more information and of better quality.

Loss of load probability (LOLP) and Loss of load expectation (LOLE). Reflects the probability of the system not having sufficient available generating capacity to satisfy the total demand. The value of the LOLP represents an expected duration of all outages rather than the probability of these outages occurring, so, it is usually expressed as an expected value -or LOLE- e.g. 0.1 days/year.

Calculating theses indices involves combining the load profiles and the scheduled generator outages with the probability of the generating units' forced outages rates to determine the expected number of days in the year when a shortage might occur. The following formulations can determine the LOLP:

$$LOLP_{365} = \frac{LOLE}{365\ days} \quad ; \qquad LOLP_{8760} = \frac{LOLE}{8760\ hours}$$

Both calculations can be expressed in units of days per year. Nevertheless, an LOLP calculated on the basis of 365 days will always be higher than an LOLP calculated based on hourly data because it implicitly assumes that the peak load occurs during all 24 hours of the day. When comparing LOLP or LOLE, it is necessary to specify the basis of 365 Days or 8760 hours, since the values obtained are different for the same power system.

LOLP and LOLE are the most frequently used reliability indices. Nonetheless, they only provide the information that more generation is required, without specifying duration-related details and the frequency of failures, nor the incidence of the loss of load.

Probability of positive margin (POPM). Reflects the probability of satisfying the demand during the hour of maximum demand for a year with available generation. In contrast to LOLP, however, POPM is expressed as a probability of succeeding at covering demand rather than the probability of failure of doing so.

Loss of energy expectation (LOEE). Also known as Expected Energy Not Served (EENS) or Expected Unserved Energy (EUE), LOEE measures the expected energy not to be supplied per year due to generation unavailability or shortage of primary energy supply.

Loss of energy probability (LOEP). This reliability index is related to the LOEE. LOEP is defined as the probability of not supplying one kWh with available generation. It represents the ratio of the expected amount of non-served energy due to unavailable generating capacity to the total energy required for the system.

$$LOEP\ (pu) = \frac{LOEE}{Total\ Load}$$

Different from LOLP and LOLE, LOEE and LOEP measure the depth of outages since they measure the incidence of loss of load and non-served energy. Moreover, as it is expressed in per unit, it allows comparing systems of different size. Though, these indices are recommended for hydrothermal systems that have primary energy limits.

Expected loss of load (XLOL). Also known as eXpected Load Not Supplied (XLSN), this index indicates the expected magnitude of the non-served load once a failure has happened. It can be obtained through the following expressions:

$$XLOL\ (MW) = \frac{EENS\ (MWh)}{LOLE\ (hours)} = \frac{EENS\ (MWh)}{LOLP * 8760\ hours}$$

Emergency operating procedure expectation (EOPE). In some way is similar to LOLE, but is given by the number of days per year where certain emergency conditions will activate certain procedures to avoid loss of load. A list of these emergency operating procedures can be found in section 7.2.2 of (International Atomic Energy Agency, 1984).

Frequency and duration of failures (F&D). This index represents the number of expected capacity shortages events in a year and their duration. F&D indices are calculated using hourly load information.

EOPE and F&D are more realistic and meaningful than LOLP. Nevertheless, as they are hourly models the computational complexity is high, and because of this, they are hardly used in power system planning.

Effective load-carrying capability (ELCC). ELCC is an index intended to measure the contribution that an individual generator or group of generators make to overall system adequacy, and was first proposed in (Garver, 1966). For its calculation, it is necessary to define an increase of the maximum demand that can be covered with a generator of the system, maintaining a certain index of reliability constant. Another approach would be to define an improvement on the reliability index and measure the demand that needs to be covered by a generator of the system to achieve this new level in the reliability index. The calculation of the ELCC depends on the unit characteristics i.e. maximum output, forced outage rate, maintenance requirements, as well as the features of the power system in which it operates.

Firm capacity equivalent (FCE). Similar to ELCC, FCE is an index that measures the contribution of a generating unit to the system adequacy. The difference with ELCC is that it measures the impact in the reliability index by removing the generating capacity of a certain unit and that it is carried out for one specific hour. In essence, the FCE corresponds to the value of the firm power i.e. the power of an ideal generator always available, that supposes to add a generator maintaining a certain index of reliability constant.

2.3 Security-of-supply mechanisms

Based on quantified indices such as those in the previous section, central planners, system operators and regulators have assessed security-of-supply of particular systems relative to targets. If a system's performance is inadequate, it might be a signal that regulatory intervention is required. In this approach, the regulator designs a mechanism that should guarantee the security-of-supply (2.3.2 and 2.3.3). Another approach is the "energy-only markets" (2.3.1) where there is no intervention from the regulator in the hopes that the market will reach the efficient outcome by itself concerning security-of-supply. A more thorough explanation of these methods can be seen in Chapter 12 of (Pérez-Arriaga et al., 2013).

2.3.1 "Energy-only" markets

In these markets, the regulator decides not to intervene for ensuring the security-of-supply. Then, it would be expected that demand eventually learns how to manage the risk within electricity markets, e.g. signing long-term contracts and responding to prices. It is a long-term commitment from the regulator, as it cannot change its decision even when the outcome is not what was foreseen.

In theory, through the marginal principle applied in power system economics, inframarginal units should recover their fixed and variable costs. Based on this, "energy-only" markets should deliver the efficient market signals that would ensure the security of supply in the long-term. Nevertheless, due to market imperfections, this outcome may not be achieved.

Even when the regulator commits not to intervene directly on securing supply, it may take other actions. The regulator may establish long-term contracts for energy reserves in case of scarcity; give full control of the operation to the system operator when scarcity is unavoidable, which impacts on the investment recovery; or organize auctions to incentive investment when the reserve margins are too low.

Besides the political and public sensitivity of setting a high scarcity price (needed for "energy-only" markets), the fact that regulators still believe that it is required to implement actions like the ones previously mentioned shows that they do not fully trust this kind of markets when looking to guarantee system adequacy.

2.3.2 Price mechanisms

Price mechanisms are determined by a product aimed at ensuring the security of supply. It is paid to new and existing generating units, and it is usually based on their firm capacity. These mechanisms can be summarized by what is called capacity payments, and its variations.

Capacity payments. It consists of additional payments that are granted to generators using a variety of criteria. The mechanism represents a signal that stabilizes the revenues of generators, especially marginal units and/or 'peaking' units. The regulator is responsible of defining the level of additional capacity required to cover the maximum demand and establishes the price to pay for capacity. It was first introduced in Chile in 1982, and it has been used in other countries such as the U.K., Argentina, Italy, and others.

This model presents some disadvantages. If the implementation is not correctly done, it could introduce distortions in economic signals and, consequently, in the behavior of generators in the short-term market. It is also difficult to determine the volume of capacity to be remunerated for the different technologies in a mix.

2.3.3 Quantity mechanisms

When applying a quantity mechanism, the regulator defines a reliability product and a quantity, while the market determines the price. It usually takes the form of capacity markets, long-term auctions, and strategic reserves.

Capacity markets. While the regulator defines the reliability product and quantity on behalf of the demand, it does not intervene in any aspect to the determination of the price, which allows the market to react freely to the economic signals. Capacity markets have been implemented in PJM, Guatemala, NYISO, France, Western Australia, and other systems.

Within these markets, generators cannot contract or offer more than its firm supply. The firm supply may be determined by the availability of these generators when needed by the system operators. These markets can be considered as a mixture of bilateral long-term contracting and capacity payments. The latter is because a payment is made in exchange for having available capacity in the market, and because the demand is required to purchase the firm supply offered in the market.

Long-term auctions. Used in countries like Colombia and Brazil, these are auctions for long-term contracts that secure a reduction in the winner's risk exposure. It is characterized by the setting of a lag period, which gives the auction's winner time to build the units. Within this mechanism, **reliability options** can appear. In this particular type of mechanism, an auction is performed where the auctioneer (normally the regulator or the system operator) sets a relatively high strike price that works as a price cap. The accepted bids receive the premium asked by the marginal bid. Whenever the spot price exceeds the strike price/price cap during the time horizon set in the auction, the suppliers refund consumers for the difference between the spot price and the strike price. If the generation of the suppliers is below the committed capacity that was determined during the auction, a penalty is applied. A complete description of this methodology can be found n the appendix of Chapter 12 in (Pérez-Arriaga et al., 2013).

Strategic reserves. As seen in Nordic countries (Sweden, Finland, and Norway), the system operator purchases reserves for times when generation is scarce. The process to select the suppliers is done through auctions. These generators are only required to supply energy and capacity during times of scarcity. The price to be offered for this capacity is determined as well, and as being a high price, it serves as an indicator of scarcity periods.

2.4 Support schemes for renewable energy sources

Another important area of regulatory intervention in the electricity market is the promotion of renewable energy sources to address sustainability objectives. A brief description of different support schemes for RES is given in the following subsections. The possible implications of these support schemes in the Dominican Republic are also analyzed based on the general assessment made in (Batlle, et al., 2011). The two most known methodologies are first analyzed: price-based mechanisms, which are determined by the regulator or by the government; and quantity-based, which can be determined through market mechanisms, such as those presented later in Section 2.4.2. Afterward, a brief description of capacity-based mechanisms is done.

2.4.1 Price-based mechanisms

Feed-in tariff (FIT). A feed-in tariff is an energy supply policy that guarantees a certain payment to renewable energy developers for the electricity they produce. These payments are usually given as long-term contracts set over a period of 15 years and above, where the FIT is high enough, so it will ensure the long-term recovery of the costs. FIT policies have been successful mainly in Europe.

Fixing a price would eliminate the risk of exposure to the volatility of market prices which can entice new businesses and attract new investment, which is lacking in the Dominican Republic. Due to the guaranteed remuneration and low barriers to entry offered by FIT policies, the implementation of a FIT could develop the economy by creating jobs. This is important as the country suffers from significant levels of poverty and a high unemployment rate.

On the other hand, it is hard to determine the right tariff for a certain plant due to the information asymmetry between the regulator and the owner of the plant. Also, one of the major disadvantages with FIT policies in the case of the Dominican Republic is that they are subject to a high regulatory risk since they are just a regulatory instrument that is backed-up by a regulatory commitment. The government is required to allocate the incurred additional costs to electricity consumers or taxpayers. As governments and political preferences change, the probability of the regulations that govern FIT of changing is high, and it is worsened when these changes are applied retroactively.

Feed-in premium (FIP). Under a feed-in premium scheme, RES generation is normally sold on the spot market, where RES producers obtain a premium added to the market price for their electricity production; thus, FIP policies bear a resemblance to 'renewable' capacity payment. FIP can either be constant, or sliding, i.e. with variable rates or levels depending on the evolution of market prices.

It is easier to implement a fixed FIP, but there is the possibility of overcompensation when the market prices are high, and undercompensating market prices are low. Consequently, it is normal to complement a fixed FIP with a "floor" and "cap" levels either for the premium or, for the total remuneration (FIP + market price). Moreover, the FIP can be adjusted based on the market situation (sliding FIP). The market premium is calculated ex-post over a defined period, e.g. on a monthly basis, and it is based on the difference between the fixed tariff and the average electricity market price in the respective period. Technology-specific factors influence in the adjustment of the average market prices, as the prices that these different technologies obtain in the market are structurally different from the average price. For example, wind energy receives on average lower prices because more generation from this technology leads to low market prices in the corresponding. On the other hand, solar PV receives on average higher prices as PV units are generating during the day when the load is usually higher than during the late night, and early dawn, and thus, prices are higher as well. Also, a degression rate can be applied for the FIP, as well as setting a maximum remuneration level.

Some advantages from the FIT policies regarding the benefits for the economy and society may apply to FIPs, to some extent. However, investors are exposed to market prices, which would serve as a barrier to the entry of new RES producers.

Fiscal incentives. Different types of fiscal incentives that go from accelerated depreciation to tax exemptions are usually applied to complement RES support mechanisms. This kind of incentives is often used at industry and residential level to promote self-consumption.

These incentives reduce the cost of financing for the RES producers, either by accelerated depreciation or by tax exemptions. Furthermore, it is a political decision that does not traduce in an increase in the electricity tariff, when included in the state's budget. This is not necessarily an advantage as tax incentives are financed indirectly by all taxpayers, setting up a cross-subsidy between them and electricity consumers. They are therefore subject to the actual government political and economic priorities. This makes these types of incentives particularly vulnerable to regulatory risks, as the other price-based mechanisms.

As an example, Guatemala has different taxes exemptions for institutions that partake in renewable energy projects can take, such as the exemption of importing tariffs and taxes and consular charges, income taxes exemption, between others.

2.4.2 Quantity-based mechanisms

Renewable portfolio standard (RPS). A renewable portfolio standard is a regulatory order that requires the increase production of energy from renewables such as wind, solar, biomass and other non-conventional generation (National Renewable Energy Laboratory, 2017). RPS is also called 'tradable green certificates' (TGCs) or 'renewable obligations' (ROs). It does not necessarily mean a generation requirement, as it can be applied to consumers to ensure that a percentage of their electricity comes from RES. Tradable certificates are granted for every unit produced from RES and are then bought in a secondary market by those required to comply with the quota, which can be technology-specific (banding) or take account of several technologies.

RPS or TGC policies are highly well-suited with market principles and the determination of competitive energy prices while bringing a defined amount of RES generation. Furthermore, trading across different geographies systems is possible, leading to overall efficiency.

Nevertheless, RES producers are exposed to the variability of the wholesale market prices. In the case of investing more than the RES required, tradable certificates may sustain low prices. Thus, exposing participants in the TGCs market to some degree of risk. This risk can be mitigated if participants are not just subject to a quota requirement, but also bound to achieve their commitment by entering long-term contracts with RES developers. Generators tend to favor the most cost-efficient technologies in the market to comply with the RPS targets, as this policy does not discriminate between technologies.

One way to solve this problem is to grant more certificates to those less cost-efficient or applying banding.

There can be an entry barrier for new RES producers because of the possible presence of market power when a significant number of conventional generators own most of the already installed RES. It could happen that if a distribution company (which function as a retailer in the Dominican Republic) is required to meet the quota, it will favor their associates instead of acquiring this generation from new entrants. Because of the structure of the electricity market in the Dominican Republic, this would not necessarily happen, as generation is unbundled from any other activity in the sector. Setting an RPS target would bring RES generation to the Dominican Republic. Though, the difficulty with this is to determine which market agents or participants should be the ones to build the RES capacity needed to meet the standard.

To fully implement this mechanism, a tradable green certificates program must be established. The credits serve as an accounting system to verify whether generation or demand has met the target. So, to facilitate the trade, a secondary market for these certificates has to be created beside the actual electricity market. Assigning the responsible of this market would depend on the structure of the power system, and in the Dominican Republic, this task could be led by the CNE (energy regulator), with the support of the SIE (electricity regulator) and the OC (system operator, for RES metering data).

Auctions. The regulator can run an auction to set the desired renewable capacity for a given period. This certainly brings the best technical-economical offers from the participants. The winner of the bid is typically offered a long-term contract for the RES production. This is an advantage for investors since the risk is reduced; and for the government or regulator as well because it already sets the price to be paid to the RES producers, which is a major pro when compared with a FIT scheme, in this sense.

The credibility in auctions has decreased in the Dominican Republic because of recent issues regarding the non-transparency in the awarding of a new coal-fired plant. The government should work on this issue if it wants to draw the attention of actual market players and new investors for RES generation.

2.4.3 Capacity-based mechanisms

It is a relatively new RES support scheme when compared to the usual price- and quantity-based mechanisms. This mechanism aims to cover the difference between a generators's investment costs and its market revenues, that will make the project profitable, and thus, attractive to investors. It takes into account different factors. The first issue is to determine the actual payment to be done through the mechanism to recover the investments, which corresponds to the difference between the generator's total costs and the revenues that it receives through the market. Determining the market revenues can be done by defining a reference plant whose performance resembles the business activity that an efficient unit would have on the market. Secondly, the timing (ex-ante or ex-post), frequency (one-time, annually, monthly) and update (e.g. adjustment according to performance) is also settled for this payments. Finally, as there is the possibility that investors would prefer to use low-cost technology to recover the investment through this mechanism, there is the need to ask for minimum performance requirements along with the incentive. A complete analysis of the design features of this mechanism is provided in (Huntington, et al., 2016).

2.5 Defining an optimum renewable portfolio standard

A crucial question for regulators, central planners and system operators concerns the targets for security-of-supply and renewable development. These targets should be chosen, ideally, by balancing the objectives of costs, customer quality of service, emissions and other sustainability criteria, as well as other important social objectives. If the policy has a well-defined set of objectives that have been agreed upon, it can then be possible to define "optimal" or at least satisfactory levels of the targets in question.

Models that simulate the effect of any renewables support scheme may use optimization tools. The outputs of this kind of models are focused on the projected generation from renewable energy sources, their cost, and their environmental impact. In the particular case of the RPS, considering that the level of renewable energy can be subject to certain market conditions and that different combinations of RES can reach the percentage demanded by this support scheme, there could be an optimal RPS. This can be approached from the regulator's perspective or the agent's perspective. A description of some previous efforts to define optimal mixes based on RES in a generation system.

In (Muñoz, et al., 2009) a model was proposed to minimize investment risk and maximize the return of a portfolio of renewable energies within the framework of the Spanish electricity market.

In (Zhu & Fan, 2010) portfolio theory is applied to assess different scenarios, including CO_2 constrained scenarios, where the objective is to reduce the generating risk through diversification of generating technologies in China for 2020. The paper discusses China's future expansion of efficient generating portfolios that enhance energy security in the different proposed scenarios.

In (Delarue, et al., 2011), a portfolio theory model that distinguishes between installed capacity, generation, and actual instantaneous power delivery, is presented. This model associates the variability of wind power and ramp limits of conventional power plants in a way that can be included in the investment optimization.

In (Ranola, et al., 2012) an RPS model that utilizes an optimization tool which is based on an algorithm that determines the optimal generation dispatch of the current and candidate units as well as the timing of candidate generating units. A methodology (Least Cost Renewable Energy Portfolio Analysis, LCREPA) was used to identify and create possible RPS scenarios, for further analysis and comparisons between them with the objective of achieving an optimal RPS.

A fundamental ambiguity occurs in defining RES targets in a situation with multiple interest groups with conflict of objectives. So, defining an optimal RPS has at least two different perspectives: The investor's perspective, where the investor aims to reduce investment risks and maximize profits; and the regulator's (or central planner's) perspective where the objective is to maximize the social welfare. The latter one may depend on different factors, such as:

- A target for a chosen risk index related to the system security to reach a reliability standard.

- A target for a certain CO_2 constrained scenario.

After a target is achieved with renewables, another interesting matter that regulators have to evaluate is the possibility of remunerating this contribution. In the case of setting a reliability target that is met with renewables, RES can be compensated based on their capacity value. This concept is visited in the next subsection (2.6).

2.6 Capacity value and capacity credits for renewable energy sources

Capacity value measures the contribution of generators or technologies to securing the supply of demand. The contribution of conventional generation depends on the units' characteristics, such as its effective installed capacity and its Forced Outage Rate. Likewise, it has to be mechanically available by ensuring the procurement of fuel and giving the correct maintenance to prevent outages. On the other hand, intermittent RES generation depends on the availability of the natural resource, besides being mechanically available.

It has been proven that RES do have an impact on system adequacy that justifies its capacity value. Nonetheless, RES capacity value can range between 10% to 15% of nameplate for wind and 25% to 30% for solar (GE Energy, 2010), while in conventional units the capacity value comes around the 90% – 95% range, depending on the forced outage rate. Any generator that is available during high-risk (peak hours, non-served energy, high prices) periods have a very high capacity value for the system, whereas when unavailable during said periods this capacity value turns to a much lower value or even zero. Conventional generators have the advantage of only depending on their mechanical and fuel availability, and a certain failure rate, hence they have a greater chance of having a high capacity value. The case for intermittent renewable generation differs because of the high degree of uncertainty regarding the renewable resource, but when it is available, it does reduce the risk of lacking generation.

There are some concepts in literature related to the determination of the capacity value of intermittent RES generation, as for instance:

- **Effective Load Carrying Capability (ELCC)**. Already seen in 2.2.2, it is the extra demand which an additional unit can support without increasing the risk index, or a change in the risk index for a given load level. It expresses how well a unit or group of units can meet reliability conditions (Garver, 1966).

- **Comparison with the load carrying capability of a conventional plant**. This can be done by comparing the reliability impact of including the RES with the reliability impact of including a conventional capacity; or by direct comparison with the load carrying capability of a test conventional unit (Milligan & Porter, 2008).

The contribution of RES generation can be compared to the capacity of CCGTs, gas turbines, diesel generators or other conventional types of technology that are needed to get the same reliability impact. This approach is followed in this work to determine the ELCC or capacity value of the RES generation.

Many factors influence the way the ELCC is determined for RES. The main factor is the interaction of the timing of the natural resource availability and scarcity. If both solar and wind can guarantee a substantial capacity during scarcity hours, the corresponding capacity value will be relatively high. On the contrary, if the contribution is little to nil during these periods, the capacity value will turn out to be low or even zero. Therefore, if a high capacity value is expected from RES projects then is needed to follow good siting practices, state-of-the-art technology, and an efficient geographic dispersion of the wind and solar plants. Thus, to calculate the capacity value of RES, it is needed their generation profiles, load profiles, and the characteristics of the conventional generation fleet.

As explained in (Bothwell & Hobbs, 2017), some system operators are currently using methods for calculating the capacity value of RES that is inconsistent with the contribution from these technologies to system adequacy. Consequently, if the resulting capacity payment is too high, it made lead to overinvestment; and if it is too low, it could discourage the investment on RES. In this study, which considers the Electric Reliability Council of Texas (ERCOT), it was demonstrated that the most efficient generation mix resulted from basing the capacity payments on the relative marginal ability of each RES to decrease expected non-served energy. A similar approach is considered for this work.

2.7 Conclusions to the literature survey

The purpose of this survey was to review the relationship between the relevant topics exposed in this chapter. It explained how reliability indices have served as indicators to system operators and regulators to determine the performance of the power system, and justify the application of security-of-supply mechanisms when needed. Among other type of regulator intervention, RES support schemes can be found in the literature. This type of mechanisms are applied to promote investment in RES, and are helpful when regulators and central planner try to meet different type of targets through RES integration. Lastly, it was view how RES validate their capacity value by the improvement that they bring to system adequacy. The development of a policy that interrelates these subjects is the contribution of this work.

Chapter 3　Current situation in the Dominican Republic

A background of the case study is presented in this chapter. Section 3.1 gives a general description of the Dominican power system and market, by reviewing topics such as the generation mix, the wholesale markets, the capacity payments and the renewable support scheme currently in place. Section 3.2 presents how the system has been performing regarding system adequacy and summarizes the implications of applying the regulation that establishes the current price cap/non-served energy for the wholesale market.

3.1 Description of the Dominican electricity system and market

Dominican Republic (Wikipedia, 2017) occupies the eastern two-thirds of the island of Hispaniola, in the Greater Antilles archipelago in the Caribbean region. The nation of Haiti occupies the western one-third of the island. It has an area of 48,445 km^2 (land: 48,320 km^2 water: 350 km^2), with a population of over 10 million people, for a density of 197 hab./km^2.

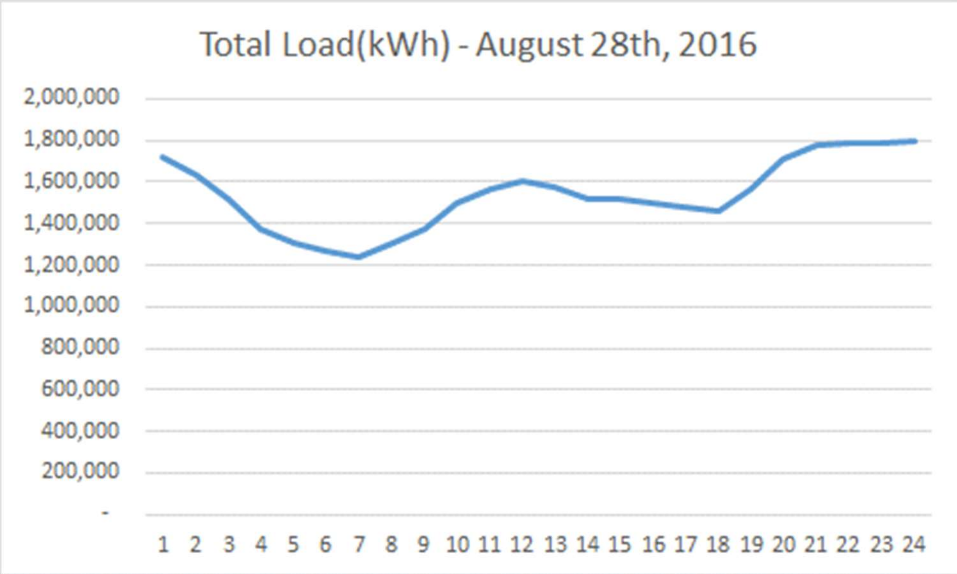
The Dominican Republic has been recognized as an exporter of coffee, sugar, and tobacco, but in recent years the service sector has surpassed agriculture as the economy's largest employer, due to growth in tourism, construction, and free trade zones. The mining industry has been playing a major role in the export market since late 2012 with extraction phase of the Pueblo Viejo Gold and Silver mine. The country suffers from marked income inequality, significant levels of poverty and a high unemployment rate (Central Intelligence Agency, 2017).

The Dominican Republic-Central America Free Trade Agreement (CAFTA-DR) entered force in July 2006, which has helped improve the investment climate and exports and reducing losses to the Asian garment industry.

According to a 2016 report from the system operator (Organismo Coordinador - OC), the annual electricity consumption was 14,893.35 GWh. For the same year, the peak demand was 2,242.89 MW, which occurred on May 20th, during the 21st period of the day. The characteristic load curve of the system illustrates that the periods of higher demand tend to be between periods 18 and 24 of the day.

The peak hours are defined ex-ante by the regulator. These are the hours between 18:00 and 22:00 of every day.

Figure 1. Characteristic load curve[1].

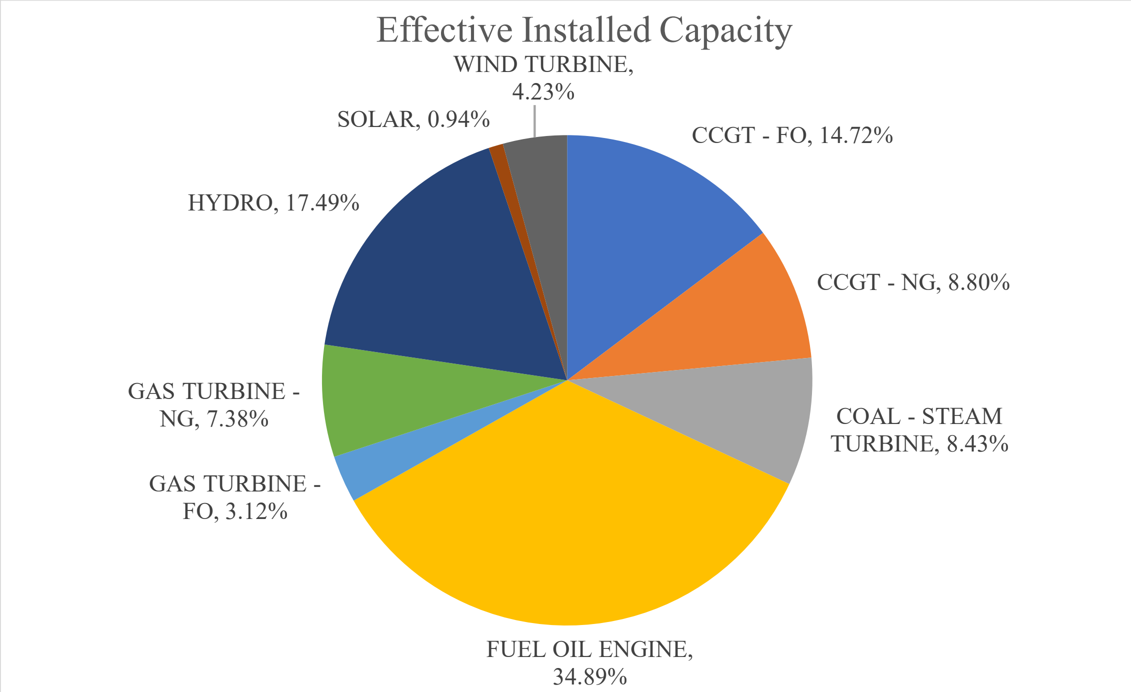


To supply electricity, Dominican Republic has an installed capacity and an effective installed capacity of 3,464.8 MW and 3,198.8 MW, respectively. Diesel engines (fuel-oil engines) dominate with 34.9%, and renewables represent 5.2% (22.7% with hydro generation).

The growth of RES generation is noticeable, considering the past few years. In 2012, the first large-scale wind farm (Los Cocos) was commissioned and started its operations with an initial 25 megawatts (MW) and later upgrading it to 77 MW. In 2016, another 49 MW of wind power entered operation (Larimar); and finally, the first solar plant (Monte Plata Solar) started its operations in the same year with 30 MW and planning to expand its capacity shortly.

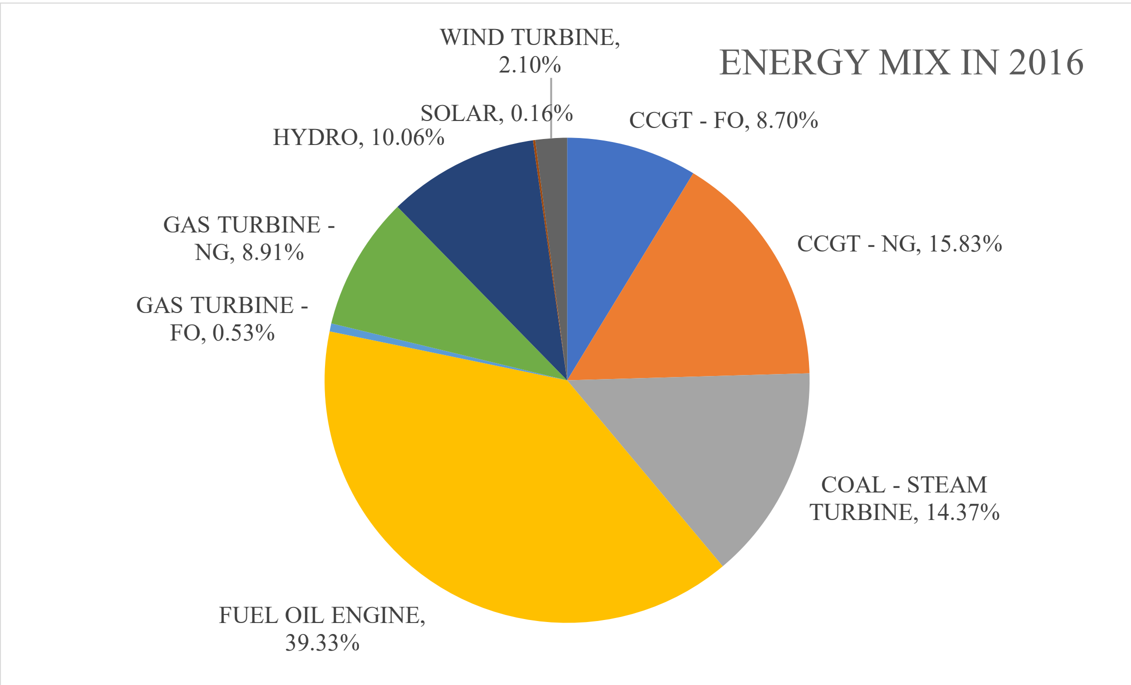
[1] The same warm tropical weather dominates in the whole country. So, it is typical to find this kind of daily load curve during the whole year. However, the shape may be different on the weekends that on the weekdays.

Figure 2. Effective installed capacity per technology as of 2016 [%].



In the energy mix, diesel engines still lead (39.3%). However, the percentage of participation changes from the effective installed capacity mix for CCGT - NG, as they come in second place for producing energy.

Figure 3. Share of the total energy per technology as of 2016 [%].



The number of participants in the power system divided by their activity in the wholesale market is shown below in Table 1.

Table 1. Number of participants in the Dominican power system.

Activity	Quantity	Definitions[2]
Generation	16	An electric company whose main objective is to operate one or several electric generation units.
Transmission	1	State-owned power company whose main purpose is to operate the interconnected System, to provide electricity transmission service throughout the national territory.
Distribution	4	The beneficiary of a concession to exploit electric distribution, whose main objective is to distribute and commercialize electric energy to customers or users of the public electric service, within its concession area.
Auto-producer	1	A company that has its own generation for their electricity consumption, regardless of their production process, which eventually, through the interconnected system, sells its power surplus (or total electric power) to third parties.
Large Consumers	78	Its monthly demand exceeds the limits established in the Article 108 of the law if it complies with the requirements recorded in the regulations.

3.1.1 Evolution of the wholesale electricity market in the Dominican Republic

Initially, all the activities of the power system where vertically integrated and managed by the Dominican Electricity Corporation (CDE) and functioning as a monopoly. The CDE was created in 1955 as a state-owned company, and granted jurisdiction and

[2] According to the definitions provided by the law: "Ley General de Electricidad 125-01".

autonomy to exercise the exclusive authority over all the power system activities in the national territory. Prior to the capitalization process, the CDE was responsible for developing the activities of generation, transmission, distribution and retailing, and the administration of the energy supply contracts with the Independent Power Producers.

With the enactment of the Law 141-97 of June 24, 1997, on the Reform and Capitalisation of Statal Companies, the power sector began a restructuring process in which five new companies were formed and capitalised with assets belonging to the property of the CDE and in which the State maintains control over 50% of the shares. Two are generation companies: EGEITABO and EGEHAINA. Three distribution companies: EDENORTE, EDEESTE, and EDESUR. All other assets, including those of the transmission and hydroelectric generation, remain under state control, through the Dominican Statal Electricity Corporations (CDEEE), former CDE.

As a result of the transformation of the Dominican electric sector initiated by the General Law of Public Company Reform No. 141-97, CDE's rights to operate the electric generation, distribution and retailing of electricity in the Dominican Republic were transferred to private companies and of mixed capital that was adjudicated after bidding processes carried out.

The liberalization of the generation activity attracts new investments and conditions are created to start a new market, while on the distribution side, a concession mechanism, which grants 40 years for the exercise of such activity, through a process of international public bidding during the development of the reform of capitalization of state-owned companies. In this order, the beneficiary distribution companies may exploit electrical works to distribute and retail the power to end users within their geographic area.

It is for this reason that electricity regulator (SIE)[3] and the National Energy Commission (CNE) were created as a decentralized body under the Ministry of Industry and Commerce (SEIC), whose purpose in General terms consisted of regulatory, promoting, and supervising functions of the electricity sector in the Dominican Republic.

[3] Official webpage of the regulator (Superintendencia de Electricidad - SIE): http://sie.gob.do/

The system and market operator (OC)[4] was created on October 29, 1998, through Resolution No. 235 of the Ministry of Industry and Commerce, to coordinate the operation of the facilities of generation, transmission and distribution companies participating in the Dominican power system.

Subsequently, the General Electricity Law No. 125-01, enacted on July 26, 2001, establishes that electricity generation, transmission, distribution and retailing companies, as well as auto-producers and cogenerators, must coordinate the operation of their facilities to provide the best service at a minimum cost. For this, they must constitute and integrate a body that coordinates the operation of generation, transmission and distribution systems, the system and market operator.

Furthermore, with the sectoral reform that led to the entry into force of the General Electricity Law No.125-01, which was enacted on July 26, 2001, the regulator became a decentralized institution of the Dominican State, with its own assets and capacity to acquire assets, exercise rights, and contract obligations.

Political interests have prevented the power industry from functioning properly, given the lack of continuity of initiatives that imply greater developments that can be achieved within a four-year government period, and considering that the State has an active participation in all the activities in the power sector. The benefits of the process that were initially considered to improve the performance of the electricity sector were questioned in 2004, initiating a process that ended up returning the three distribution companies back to the Dominican State.

[4] Official webpage of the system and market operator (Organismo Coordinador - OC): http://www.oc.org.do

Figure 4. Owned Effective Installed Capacity - December 2016

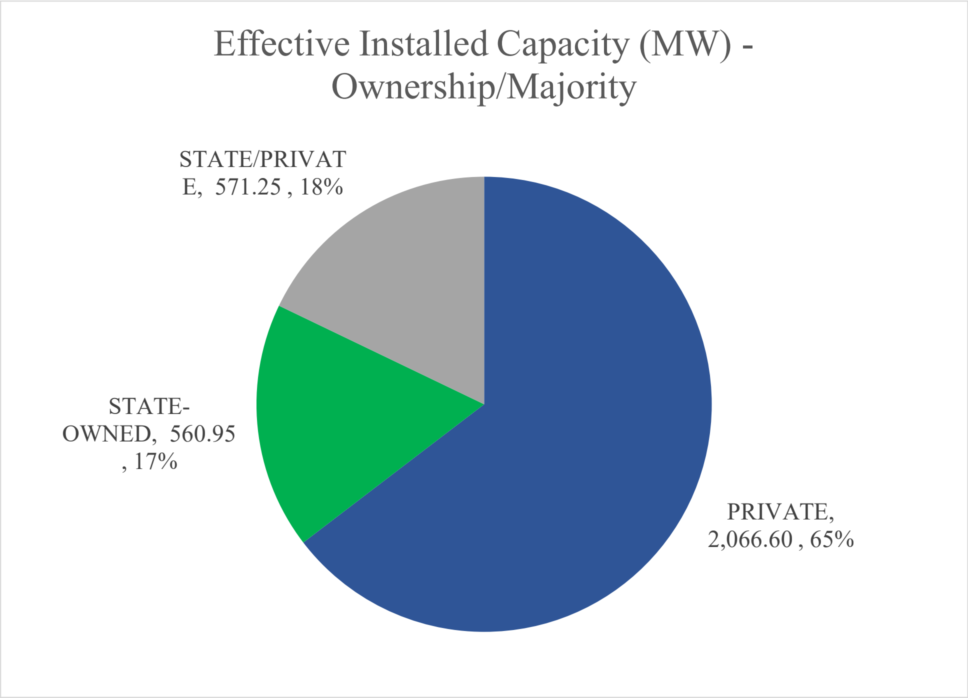
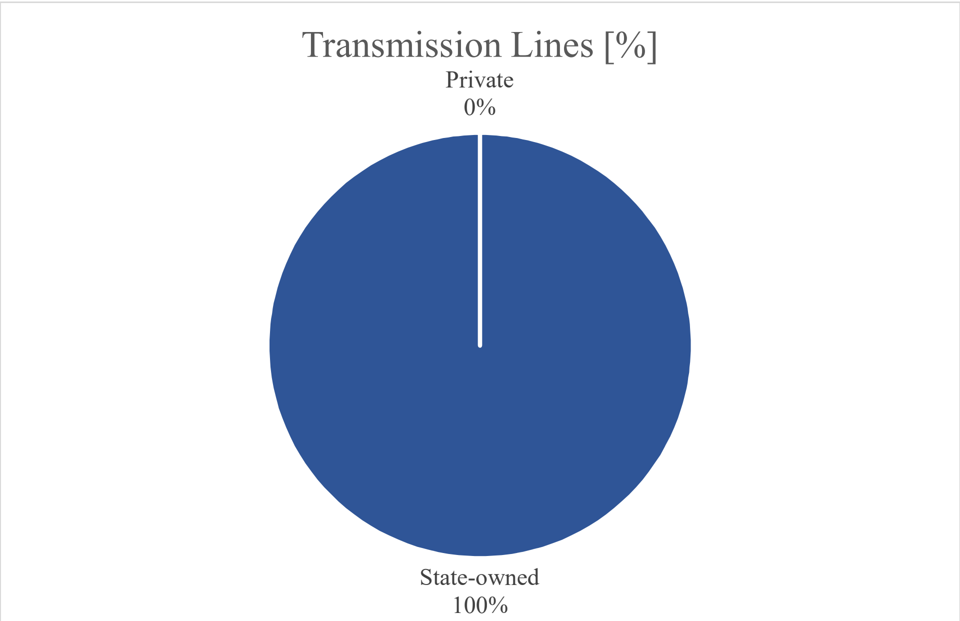


Figure 5. Owned Transmission Lines - December 2016



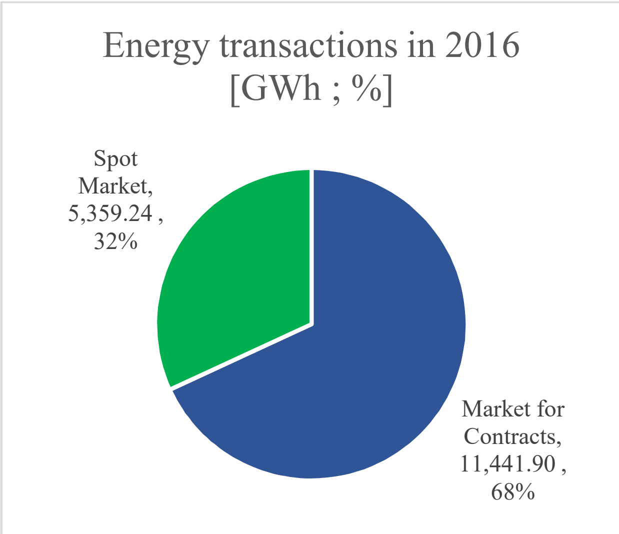
3.1.2 Generation & wholesale markets

The electricity regulation shows two types of markets where the energy is transacted: the retail market and the wholesale market (free market). It is important to note that distribution and retailing are integrated. The generation and distribution companies sell electricity at a wholesale level, which can be acquired directly from them, in the case of large consumers at a non-regulated tariff. Regulated users purchase electricity from distribution companies at a regulated tariff.

There is a market for contracts, where Generators may sell firm power and/or energy to different agents (Distributors or other Generators), and participating Large Consumers, agreeing on terms, deadlines, quantities, and prices between the parties.

There is also the spot market that functions as a trading platform, where the OC has the responsibility of commercially coordinating contracts, respecting the contractual terms by the parties, and monitoring the differences between the energy and power of the participants that result from their purchase and sale transactions and liquidating these differences as surplus or deficit in the energy spot market and in the capacity market.

Figure 6. Energy transactions in 2016



The system operator and the market operator are the same institution (OC). In a wide view, it oversees the coordination of the generators' operations and transmission lines' operations at a minimum cost, guaranteeing reliability and security of supply. It also establishes short-term market prices for power and energy transfers between generators, distributors, and large consumers, when these transactions do not correspond to contracts. Nevertheless, it coordinates those contracts commercially, as previously mentioned.

As in distribution, transmission is regulated and subject to authorization when using public domain property.

3.1.3 Spot market

According to the Electricity Act (Law 125-01 and its regulations), the spot market price is the value of the Short-Term Marginal Cost of Energy in each hour, defined as the variable cost incurred by the system for supplying an additional unit of energy considering the demand and the generation available. The Short-Term Marginal Cost corresponds to the maximum variable cost of the generating units called by economic dispatch, in the reference node or slack bus. The marginal unit is the one that has the maximum variable cost of the units that can supply the additional hour within the hour, and is the one that establishes the spot price in that hour. Generating units that operate out of the permanent regime, i.e. in transition regime, test regime or forced regime, do not participate in the determination of the spot price.

For the economic dispatch, the generators' offers are needed, so the agents submit their audited variable costs, as well as additional characteristics of the unit that are considered necessary. For hydroelectric power plants, the information needed corresponds to the generation characteristics, the level of the reservoir or energy available in the reservoir, and other characteristics described in the law.

The previous information is used for the short-term programming (weekly programming) to determine the variable costs and water value according to the results of the optimization model utilized by the OC. Subsequently, the daily program uses these previous results altogether with transmission constraints, to establish the economic dispatch that determines the spot prices.

The OC is able to modify the dispatch and carry out a re-dispatch to maintain the security of the operation of the system whenever there are severe contingencies differences between the forecasts and the real conditions. Finally, when events occurring in the Real-Time Operation lead to a temporary departure from the economic dispatch, which may change the spot prices.

3.1.4 Mechanisms for ancillary services and others

Aside from the energy market and capacity payments, other types of mechanisms or transactions that can be found at a wholesale level. There is a mechanism for the remuneration of ancillary services, considering:

1) **Spinning reserves**, which has two components: 1- a regulation reserve where a fraction of the capacity (at least 3% up to the enabled margin) of a generating unit that is synchronized to the power system is exclusively used to participate in primary frequency regulation; and 2- operating reserve, which its purpose is for the generating unit to take part in secondary regulation. Both types of reserves are remunerated by the marginal price in each hour, plus an incentive established by the regulation for this service.

2) **Forced Generation**, which is the active generation that is not under a test regime or providing another ancillary service, and presents a variable cost higher than the marginal price of the market. This may happen when a generating unit is obliged to operate outside the economic dispatch due to technical, operational, quality or reliability constraints of other generators or transmission network. The energy generated by this units is remunerated at their variable cost, and the total cost is allocated to the demand and to those agents that benefit from the application of the price cap. Likewise, generators that enter in the economic dispatch but present a variable cost that is higher than the price cap/cost of non-served energy are remunerated based on their variable cost.

3) **Compensation for deviations in the daily operating program**, any agent that deviates from the daily program shall bear a charge that translates into compensation. The total compensation to be paid will be distributed among the rest of the agents.

3.1.5 Transmission network, losses, and congestions

The transmission grid is an eminently radial transmission network with a 345 kV main line connecting the northern region with the Santo Domingo region and with 138 kV radial lines connecting the northern, southern and eastern areas with the Santo Domingo area. In addition, 69 kV lines are connecting the main distribution substations to the 138 kV grid. The Dominican Republic has no interconnection to any other power systems.

In 2016, 154 relevant events occurred. Of these 154 events, 60 correspond to generation equipment; 18 to transmission equipment involving 345/138 or 138/69 KV transformers; 23 to transmission equipment involving 345 kV, 138 kV or 69 kV transmission lines with N-1 criteria, and 53 to transmission equipment involving 345 kV, 138 kV or 69 kV transmission lines with N- 2 criteria or greater (Organismo Coordinador, 2017).

In the Dominican Republic, the electrical energy is valued at each node of the network. The energy transferred to a node is valuated at the price of the energy in the market affected by the Nodal Energy Loss Factor.

Each day, the Nodal Energy Loss Factor is calculated by the OC in the daily dispatch, using a dispatch model that represents the entire transmission system. In the case of a real-time re-dispatch operation, the nodal power losses factors will be determined in the re-dispatch.

The price of the energy that is to be affected by the Nodal Energy Loss Factor may differ from one region to another. This is due to 1- the openings of transmission lines that physically decouple from the network, or 2- due to the congestion in transmission lines. In both cases, different zonal prices may appear.

The transmission owner is remunerated through cost-of-service regulation. Each year, the regulator establishes a transmission toll based on the investment and operating costs of the transmission network, which is paid monthly mainly by the generation Agents throughout the year.

3.1.6 Capacity mechanism

There is a capacity mechanism which is related to the firm offer (firm supply) of each generating unit according to their technical characteristics, their maximum power, and availability, considering the restrictions of the plant. The firm supply is determined for fossil fuel units and hydro units. Depending on the type of technology, the methodology for obtaining the firm offer varies.

The determination of the firm supply of the generating units is carried out with the updated information in the unavailability database. At the moment of determining the injections and withdrawals of firm power for each of the Agents, the OC must consider the power commitments that have been established through contracts and the estimated maximum annual demand.

In the case of fossil-fuel units, the reduction of power in relation to the net effective installed capacity or the total unavailability of the unit comes from faults in the equipment or elements that compose this unit, and from maintenance or due to fuel limitations. For hydro units, historical inflow data is used to determine their firm supply.

The total firm supply is the amount of power needed to cover the maximum demand, which is the forecasted demand for the year given by distributors, large consumers, and the generators' self-consumption. These agents present their projection methodology, projected energy and power per hour bandwidth, and typical load curves for labor and non-labor days, weekends and holidays. With this information, the forecasted peak demand of the system is calculated. The coincident demand forecasted for each agent that appears during the peak demand is the individual firm demand of each of those agents.

The total firm supply that the set of all the thermoelectric generating units is capable of ensuring based on the unavailability database to cover the maximum demand, must guarantee a security level that ranges from ninety-five percent (95%) to ninety-eight percent (98%), starting with the value of 95%, and using the probabilistic method of convolution to determine the available power. A detailed explanation of this procedure is shown in (Domínguez G., 2013).

The difference between the total firm power of the hydroelectric units and the initial firm power of all the fossil-fuel generating units and the maximum demand of the system is calculated. This difference may be called the final residue.

If the final residue calculated is greater than zero, the security level is increased until the final residue equals to zero. If a security level of ninety-eight percent (98%) is achieved and the final residue remains greater than zero, this difference is reduced from the fossil-fuel generating unit with the highest variable generation cost, and so one with the next units until the final residue is zero. If the final residue calculated is initially less than zero, the firm supply of the fossil-fueled units will be multiplied by a common factor, so as to bring the final residue to the value of zero (0).

Therefore, the percentage of coverage of the maximum demand that a unit can offer depends on three factors: 1- Their historical unavailability during peak hours, 2- The level of security that the system can guarantee, and 3- Their variable cost.

In the two first months of the next year, the process is done again, but considering the real demand, to verify the real firm offer that the generators have for the real system demand. The difference between the results with forecasted and real demand is then calculated, setting a new balance between the creditors and debtors in the corresponding transactions.

The firm offer is valuated at what is called "Marginal Cost of Peak Capacity." The following formulation calculates this price:

$$CMPPBR_{Monthi,n} = CMPPBR_{Decn-1} \times A \times \frac{D}{D_O}$$

Being:

$$A = \left[\frac{CPI_{Monthi-1}}{CPI_{Novn-1}}\right] \text{ ; if } \left[\frac{CPI_{Monthi-1}}{CPI_{Novn-1}}\right] < 1.02$$

$$\text{A=1.02 ; if } \left[\frac{CPI_{Monthi-1}}{CPI_{Novn-1}}\right] > 1.02$$

Where:

$CMPPBR_{Monthi,n}$: Price (RD\$[5]/kW-month) of Peak Capacity in month 'i' and year 'n.'

[5] RD$ is the Dominican currency (Dominican "pesos").

$CMPPBR_{Dec n-1}$: Price (RD$/kW-month) of Peak Capacity in December of the previous year, which is fixed every four years by the regulator.

$CPI_{Month i-1}$: Consumer Price Index of the U.S.A. “All cities, all items” of the previous month.

$CPI_{Nov n-1}$: Consumer Price Index of the U.S.A. “All cities, all items” in the month of November of the past year.

D : Average exchange rate of for the American dollar corresponding to the previous month in the official market, according to Central Bank of the Dominican Republic.

D_O : Average exchange rate of for the American dollar corresponding to the month of November of the previous year, according to Central Bank of the Dominican Republic.

3.1.7 Renewable support scheme

The Dominican Republic has enacted laws to incentivize the investment in renewable energy projects based on the country’s renewable energy potential. The Act No.57-07 and its regulation enacts the rules for renewable incentives. The law has helped mitigate the investor’s risk regarding the high investments in this technologies. The main objectives of this Act are:

- Increasing the country's energy diversity in terms of self-sufficiency, provided that non-conventional resources are more viable than conventional ones.
- Reducing dependence on imported fossil fuels.
- Stimulating private investment for RES projects.
- Mitigating the negative environmental impacts of fossil fuel energy operations;
- Promoting community social investment in renewable energy projects;

Nevertheless, the government has interfered with this law’s incentives. In 2012, the government enacted the Law No. 253-12 on strengthening the state's fiscal sustainability where some of the incentives were cut or reduced. In the following table the original incentives and the changes done by Law No. 253-12 are explained:

Table 2. Incentives for RES in the Dominican Republic.

Incentive	Description according to Law 57-07	Changes through Law 253-12
Exemption from importing tariffs and taxes	Consular charges and duties on the importation of machinery and equipment used exclusively for the generation of energy in the area where renewable energy projects are located. They are also exempt from all taxes to the final sale. This incentive is valid during the period of pre-investment and construction, which will not exceed 10 years.	No changes.
Exemption from income taxes	Generators are exempt from income taxes that derive from the generation and sale of electricity from renewable energy sources. The installers are exempt from the income tax derived from the installation of equipment with a minimum of 35% of the value that will be produced in the Dominican Republic. The exemption is applicable for 10 years, until the year 2020.	Changes: Eliminated.
Exemption from Tax on the Transfer of Industrialized Goods and Services (ITBIS)	100% exemption from ITBIS for projects based on renewable energy, a value-added tax applicable to the transfer and import of most products, and most services (the current tariff is 18%).	No changes.
Low external financing interest rate	The external financing interest rate payment for renewable energy projects is limited to 5%.	No changes.

Incentive	Description according to Law 57-07	Changes through Law 253-12
Tax credit for self-generators	Owners of the renewable energy technology equipment have an exemption on their incomes up to 75% of the equipment costs.	Changes: Reduced to 40% of the equipment cost.
Low-interest loans for community projects	Subsidies and loans to finance up to 75% of the cost of equipment for small-scale installations (<500 kW) developed by communities or social organizations.	Changes: Incentives for social and cultural institutions were eliminated
Feed-in premium	Stipulates a premium to be paid on top of the wholesale electricity price for energy produced from renewable energy resources. This would be applied over a 10-year period through 2018.	No changes.

Besides the interference that the government has had over these incentives, some barriers remain. One of the main barriers is the bureaucracy around governmental procedures to obtain a concession and to have access to certain benefits from this law, even though they have been improving. The second major concern, and at this time a barrier, is the uncertainty regarding the implementation of the feed-in premium.

3.2 Presentation of the problem

The problem that this work is trying to solve is the prevention of the reduction in system adequacy due to the low price cap while having an increase in RES generation. In 3.2.1, the current situation regarding scarcity at the wholesale level is analyzed, and afterward, 3.2.2 assess the problem of the price cap/cost non-served energy.

3.2.1 Non-served energy at wholesale level

Maintaining the power system's reliability in all its dimensions presents a challenge for the Dominican Republic. Scarcity at the wholesale level is a reality and, according to the statistics from the system operator, the hours with non-served energy have been significant over the years.

Figure 7. Hours with non-served energy at the wholesale level (2010-2016).

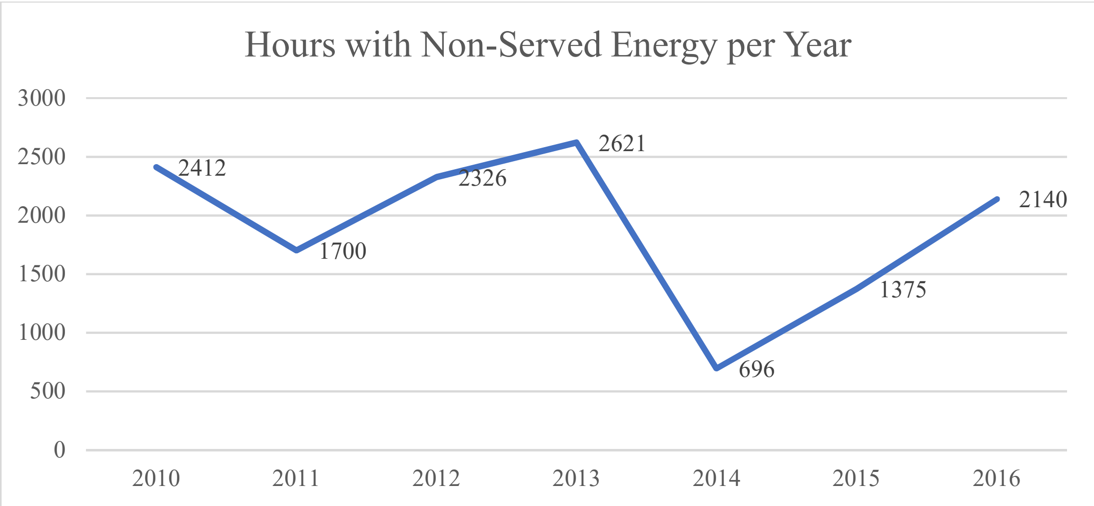


Figure 7 shows the number of hours with non-served energy. This scarcity can happen due to two main factors. The first one is the lack of available capacity to supply the demand at certain times, and the second one is the unreliability of the transmission system due to its configuration being eminently radial. The former one is the focus of this work.

Within the scope of lack of generation, the volume of non-served energy is subject to numerous factors, such as the generation mix, its installed capacity, and the units' availability. The installed capacity of hydro reservoir generation is not significant in the Dominican Republic, but its operation tends to be optimal for the benefit of the system.

As mentioned previously, having sufficient available generation capacity diminishes the reliability risk. The Dominican regulation requires available generation capacity during "peak hours." "Peak hours" are defined ex-ante for every year, and are established as the period between 18:00 and 22:00[6]. It is important to highlight that the availability during these "peak hours" is the one considered for determining the firm offer/supply of fossil-

[6] System operator's Rule OC-51-2003.

fuel generators. This definition may be based on the fact that the system operator wants to guarantee that all generation is available during the periods of high demand according to the typical load curve when the system is at the greatest risk of not meeting demand.

The availability of fossil-fuel generators is calculated considering the forced mechanical unavailability and programmed unavailability due to maintenance. The forced unavailability rate of these units corresponds to the failure statistic of the last ten (10) years. In the case of units that do not have ten (10) years of statistics, a reference value of forced unavailability rate is adopted to complete the ten (10) years, considering national and international statistics for units of the same type.

Indexes calculated for the fossil fuel units are found in the reports from the OC. Figure 8 classifies the average availability factor per technology, as of December 2016. It is noticeable the low availability shown by both combined cycles and gas turbines that use fuel oil.

Figure 8. Average availability factor per technology[7] [%].

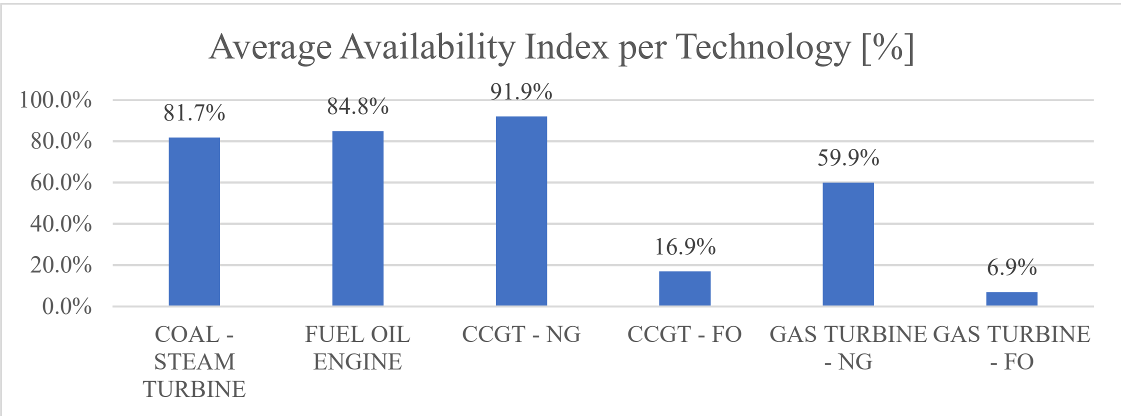
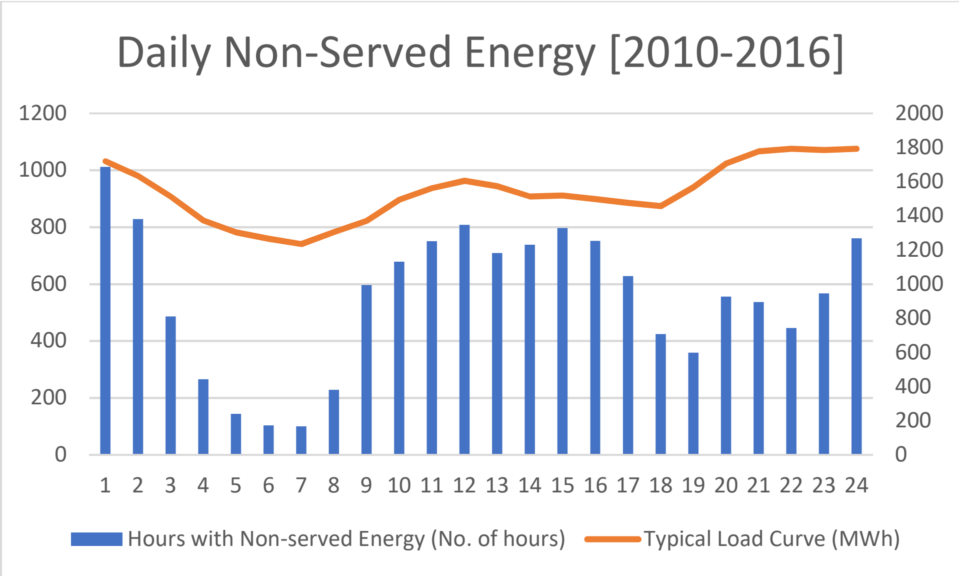


Figure 9 shows a typical load curve in contrast with a number of hours where there was non-served energy during the day for the period 2010-2016. The clear majority of periods with non-served energy appear out of the defined "peak hours." It could be said that setting a certain period as "peak hours" where unavailability is considered for the determination of the firm offer/supply, may implicitly force fossil-fuel units to declare availability only during "peak hours" for specific scenarios, e.g. generators would always prefer to program their maintenance outside of the period from 18:00 to 22:00. Therefore,

[7] Based on the unavailability during "peak hours".

the probability of some units setting maintenance at the same time or having maintenance periods that overlap, is higher.

Figure 9. Typical load curve and daily non-served energy.



3.2.2 Price Cap and Cost of Non-Served Energy

The Cost of Non-Served Energy (CNSE) is defined by the law as "*the cost incurred by users, for not having energy and having to obtain it from alternative sources; or the economic loss resulting from the lack of production and sale of goods and services and the loss of welfare due to a decrease in the quality of life in the case of the residential sector*". It is established by the regulator every year, and it is also defined as the price cap of the wholesale market.

The formula applied to calculate the price cap/cost of non-served energy is the following one:

$$CMET_{month\ i,\ \ year\ n} = CMET_0 * \left(0.40 * \frac{CPI_{month\ i-2}}{CPI_{Marc\ \ 2001}} + \ 0.60 * \frac{PFO\#6_{mont\ \ i-1}}{PFO\#6_{base}}\right)$$

Where:

$CMET_0$ = Base value of the CNSE/Price cap since July 2012 = US$56.375/MWh;

$CPI_{month\ i-2}$ = Consumer Price Index of the United States of America "All Cities, All Items", two months before the calculated one.

$CPI_{March\ 2001}$ = Consumer Price Index of the United States of America "All Cities, All Items", March 2001 = 176.2.

$PFO\#6_{month\ i-1}$ = Platt's prices for Fuel Oil #6, 3% Sulfur, USA Gulf COAST, for the month i-1, calculated as the average of the mean of the daily minimum and maximum values published the previous month.

$PFO\#6_{month\ i-1}$ = Platt's base price for Fuel Oil #6, 3% Sulfur = US$17/barrel.

Given that the demand is totally unresponsive to market prices in the Dominican Republic, the regulator may find the need to establish a price cap, as it sometimes becomes complicated to differentiate if the scarcity is produced because of lack of available generation or because of generators exercising market power. Though, this can be used as an argument to address the necessity of more competition instead of intervening the market.

During situations where there is scarcity, the market price rises above marginal operating costs of the generating units. Within these periods, all units operating in the merit-order are remunerated at this price which should contribute to the recovery of their fixed costs. This is questionable, as the cost of non-served energy/price cap is too low (even below some of the already installed units), the reality may be that these units are not recovering their fixed costs.

With the number of hours with non-served energy and a suitable cost of non-served energy, it should be enough to attract the needed investments. If the price is well below, it may drive to existing 'peaking' units to exit the system with a high probability of not being substituted; or discourage the reinvestments on the current installed capacity. This would increase the scarcity, and decrease the systems's flexibility.

It has to be taken into consideration that setting a low price cap aggravates the problem of the "missing money." This issue brings the intention of the regulator to intervene the market, once again, by introducing a capacity mechanism to secure the supply in coming years. Therefore, it could be argued that the capacity payments that conventional generators receive in the Dominican Republic, should be enough to recover fixed costs. However, in 3.1.6 it is seen that the remuneration of capacity is based on availability, which corresponds to ‘firmness,' and not necessarily to ‘adequacy’ which would entice investments.

Additionally, the increasing RES generation in the market can worsen the problem of adequacy. With a higher share of RES generation, the hours during which conventional generators produce are reduced. Even when conventional generation contributes to supply demand during periods of low RES generation, it has become a risky investment in the Dominican Republic, as revenues depend on fewer hours of operation, and on a low price cap to help recover capital costs. Consequently, there is the possibility that the system will fail to deliver enough capacity to meet demand in the future.

In the context of the Dominican Republic, raising the price cap is a sensitive political issue. Even so, it is a matter that needs to be addressed due to the foreseen increase in RES generation. Hence, to solve this issue, two methods are proposed in the next chapter.

Chapter 4 Proposed methodologies

This chapter presents two similar methodologies to solve the issues that Chapter 3 describes. These methodologies are based on a linear programming model (4.1) for optimizing generation investment and operations. With this model, the impact of different scenarios of renewable share can be measured, while at the same time determines a new price cap that ensures better reliability levels. Nevertheless, the approach to determining the price cap/cost of non-served energy is what distinct both methodologies.

The first methodology (4.5.1) is explained step by step with the help of screening curves. As the second methodology is similar to the first one, only the differences are shown when the description is done for the second methodology (4.5.2). The data sources and assumptions for the model are detailed within this chapter as well.

4.1 Model

A mathematical model for combined energy-capacity-renewable credit markets was provided by the Department of Environmental Health & Engineering at The Johns Hopkins University (Bothwell & Hobbs, 2017). The model was adapted to GAMS modeling language, and it has been developed as to include unit commitment constraints.

The model optimizes a minimizing function as a linear program using CPLEX solver in GAMS. The period from 2013 to 2016 (*H*) is simulated for determining the hourly energy market. For this model, the following units are considered:

- One (1) coal steam turbine.
- One (1) CCGT powered by natural gas.
- One (1) gas turbine powered by natural gas.
- One (1) diesel engine.
- One (1) CCGT powered by fuel oil.
- One (1) gas turbine powered by fuel oil.
- Two (2) wind generators located in different sites.
- Two (2) solar PV generators located in different sites.

Notation: Sets

p Set of hourly periods ($p \in H$).

g Set of generators.

F Set of fossil-fueled generators ($F \in g$).

W Set of wind generators ($W \in g$).

S Set of solar PV generators ($S \in g$).

y Set of years (for yearly RPS calculations).

Notation: Parameters

DM_p	Demand in period 'p' [MW].
RPS_y	State-mandated fraction of generation from renewables for a year [%].
FC_g	Fixed costs of generator 'g' [$/MW].
VC_g	Variable cost of generator 'g' ($F \in g$) [$/MWh].
SU_g	Start-up cost of generator 'g' ($F \in g$) [$/MW].
PC	Price cap / Cost of non-served energy [$/MWh].
$QMIN_g$	Minimum output capacity as a fraction of the total capacity [%].
RU_g	Upward ramp capacity as a fraction of the total capacity [%].
RD_g	Downward ramp capacity as a fraction of the total capacity [%].
FOR_g	Forced outage rate of generator 'g' ($F \in g$) [%].
AF_g	Annual availability factor of generator 'g' ($F \in g$) [%].
$AVAIL_{p,g}$	Renewable generation hourly availability ($W, S \in g$) [%].

Notation: Variables

x_g	Installed capacity of each technology including fossil fuel generators ($g \in F$), and wind ($g \in W$) and solar ($g \in S$) locations [MW].
$e_{p,g}$	Hourly dispatch of energy for each generator 'g' during period 'p' [MWh].
$pmin_{p,g}$	Hourly dispatch of minimum output energy for each generator 'g' during period 'p' ($F \in g$) [MWh].
$e1_{p,g}$	Hourly dispatch of energy above minimum output for each generator 'g' during period 'p' ($F \in g$) [MWh].
nse_p	Non-served energy for every period 'p' [MWh].
$suc_{p,g}$	Start-up capacity for each generator 'g' ($F \in g$) during hour 'p', which corresponds to the minimum output.

The optimal values of these variables are given by minimizing the objective (1) below, subject to the specified market and generating constraints. The investment costs [$/MW/year], variable costs, start-up costs and price cap are represented by FC_g, VC_g, SU_g and PC, respectively.

$$\boldsymbol{MIN}\ (\$/\boldsymbol{year}) = \sum_{g\in G}[\boldsymbol{FC_g} * \boldsymbol{x_g}] + \left(\frac{\mathbf{8760}}{|\boldsymbol{H}|}\right) * \sum_{p\in H, g\in F}[\boldsymbol{VC_g} * \boldsymbol{e_{p,g}} + \boldsymbol{SU_g} * \boldsymbol{suc_g}] + \sum_p[\boldsymbol{PC} * \boldsymbol{nse_p}] \qquad (1)^8$$

Subject to:

$$\sum_g e_{p,g} + nse_p = DM_p \qquad \forall p \qquad (2)$$

$$\sum_{p,g\in(W,S)} e_{p,g} = \sum_{p\in H} DM_p * RPS_y \qquad \forall y \qquad (3)$$

$$\frac{pmin_{p,g}}{QMIN_{p,g}} \leq x_g * (1 - FOR_g) \qquad \forall g \in F; p \qquad (4)$$

$$e1_{pg} \leq (\frac{1}{QMIN_g} - 1) * pmin_{p,g} \qquad \forall g \in F; p \qquad (5)$$

$$e_{p,g} \leq x_g * AVAIL_{p,g} \qquad \forall g \in W, S; p \qquad (6)$$

$$\sum_p e_{p,g} \leq x_g * AF_g * |H| \qquad \forall g \in F \qquad (7)$$

$$pmin_{p,g} \leq pmin_{p-1,g} + suc_{p,g} \qquad \forall g \in F; p \qquad (8)$$

$$e_{p,g} = pmin_{p,g} + e1_{p,g} \qquad \forall g \in F; p \qquad (9)$$

$$e1_{p,g} - e1_{p-1,g} \leq \left(pmin_{p-1,g}/QMIN_g\right) * RU_g \qquad \forall g \in F; p \qquad (10)$$

$$e1_{p-1,g} - e1_{p,g} \leq \left(pmin_{p,g}/QMIN_g\right) * RD_g \qquad \forall g \in F; p \qquad (11)$$

It is also considered that all variables are nonnegative. In detail:

- (2) establishes hourly energy balances between supply and demand;
- (3) ensures sufficient renewable energy to meet the defined renewable portfolio standard (RPS);
- (4) relates $pmin_{p,g}$ to the total capacity x_g;
- (5) relates $pmin_{p,g}$ to the generation above the minimum output $e1_{p,g}$;

[8] The objective function is set to calculate an annualized cost. Nevertheless, the part of the cost that corresponds to the non-served energy, is calculated for the whole period. To get the annualized fixed and variable costs of the mix, it is needed to substract the total non-served energy cost.

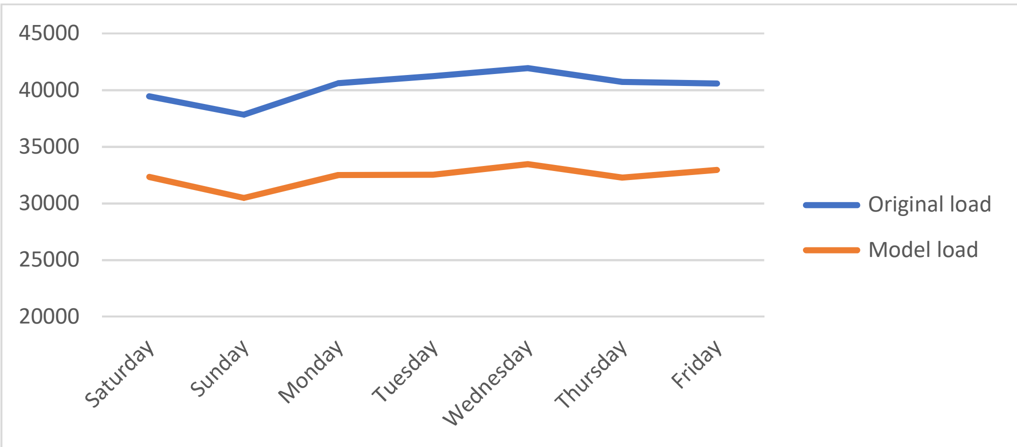
– (6) defines generation of wind/solar as equal to each generator's hourly availability ($AVAIL_g$), which depends on wind or sun conditions;
– (7) upper bound on yearly fossil generation based on an annual availability factor (AF) to account for maintenance;
– (8) relates $pmin_{p,g}$ to the start-up capacity $suc_{p,g}$;
– (9) indicates that the hourly total energy is equal to the minimum stable load plus the energy above the minimum stable load;
– (10) and (11) are ramping constraints. These formulations ensure that $e1_{p,g}$ is zero in the first period after start-up from $pmin_{p,g}$= 0. It is also ensured that $e1_{p,g}$ is zero the period before shut-down[9].

4.2 Assumptions and simplifications in the model

This Section describes the main assumptions made for the case study:

1) The hydroelectric generation and the generation from generators used exclusively for reactive compensation were subtracted from the actual load, as well as the production from RES already installed. An example of this effect is presented in Figure 10.

Figure 10. Original load/Model load: December 3rd (Saturday) - 9th (Friday).



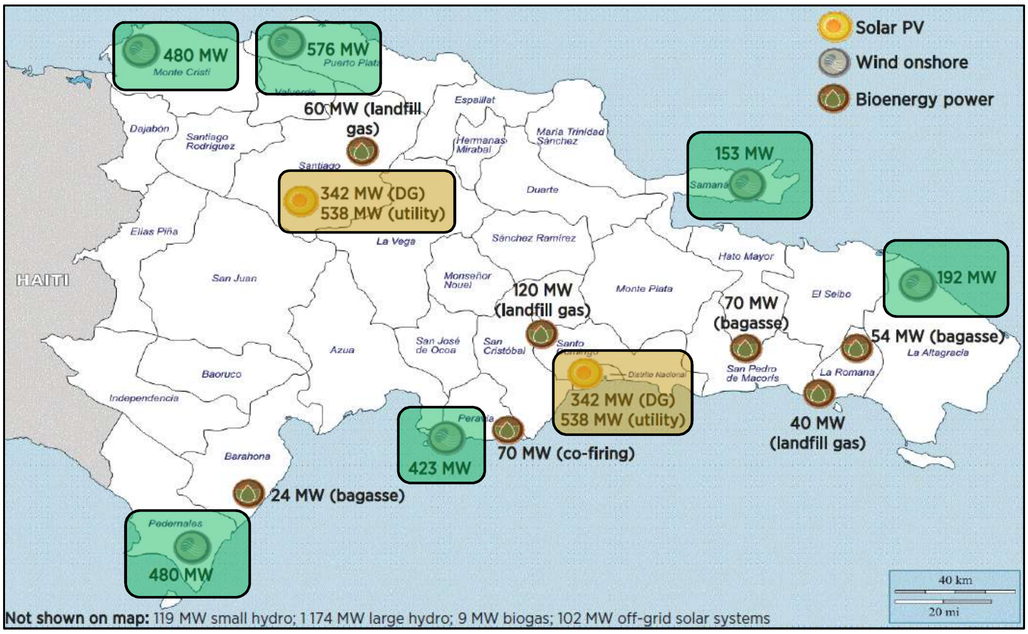
[9] Ramping constraint were included in the model. However, due to the fact that the fossil-fueled units can reach maximum output within the hour, it was not necessary to model them along with the rest of contraints.

2) Different conventional units can operate with fuel oil or natural gas. Nonetheless, as there is an agent that is vertically integrated with the natural gas supply, its units are the only ones considered as the users of natural gas. This is the reason why there is a differentiation between the CCGTs and OCGTs taken into account for the modeling. Currently, because of their low variable costs when compared to fuel oil units, these units operate as base units along with coal steam turbines.

3) As the modeling rests on the assumption that due to the current low price cap, the interest to invest relies on RES generation, the decision over the effective installed capacity of conventional generation is upper-bounded to the actual effective installed capacity in the market.

4) An upper bound was set for each wind and solar locations. This was done considering a study from the IRENA and the CNE (IRENA, 2016). In the study, an estimated of 2.3 GW of wind generation and 1.1 GW of solar could be installed by 2030. This served as a basis to estimate an installed capacity by 2020, which resulted in **660 MW** of wind and **308 MW** of solar, to be divided equally in two different sites for each technology.

Figure 11. Estimated RES Installed Capacity by 2030 - IRENA and CNE



5) The treatment of solar and wind curtailments have not been taken into account in this work.

6) It is assumed that are no transmission constraints ("copper sheet" analysis) for the case study. Therefore, the capacity value of generators, in general, is not penalized due to transmission constraints.

7) The increasing RES share requires available and flexible capacity as reserves. This flexible capacity guarantees the generation–demand balance regardless of the stochasticity from RES generation. Considering that there is currently plenty of flexible capacity from fossil-fueled units in addition to that from hydro reservoirs, constraints related to reserves were not included in the model. Nonetheless, it is recommended to add this constraint to scenarios with very high shares of renewables.

4.3 Determination of the samples

Initially, the numbers of hours to be included in the model was ten years. However, due to computational limitations, this period was reduced to four years. For intermittent generation is difficult to determine the samples needed to assess its capacity value. In (Hasche, et al., 2011), a 10-year wind data set for the Republic of Ireland was used to calculate the ELCC for wind. In the conclusions, they determined that with a minimum of four years of data, the deviations are within 10% of the long-term capacity value. Hence, a data sample of four years can be considered as a good base for the calculations.

4.4 Data sources

To test the model and the methodologies, it is needed to compute four years of hourly data (2013-2016). All the data tables are within the APPENDIX. The following information was provided by the OC:

- **Hourly demand (DM_p).**
- **Variable costs for fossil-fueled generators (VC_g).**

- The actual minimum stable load of the fossil-fueled generators needed to calculate the **minimum output capacity as a fraction of the total capacity ($QMIN_g$)**.
- **Price cap/cost of non-served energy (PC)**.
- The effective installed capacity of the generation mix.
- Hourly generation from the generation mix.

Start-up costs (SU_g) and **ramps (RU_g, RD_g)** for the fossil-fueled generators were taken from (European Commission Artelys, 2016).

Fixed costs per generator (FC_g). To determine the annualized fixed costs, the Levelized Cost of Energy (LCOE) according to different reports [(Lazard, 2014), (U.S. Energy Information Agency, 2015)] was considered. With the LCOE, the fixed costs are calculated through the following formula:

$$FC\ (\$/MW/year) = [LCC + FOM + TI] * CF * 8760\ h$$

Where:

LCC → Levelized Capital Cost [$/MWh].
FOM → Fixed Operation & Maintenance [$/MWh].
TI → Transmission Investment [$/MWh].
CF → Capacity Factor [%].

Forced Outage Rate (FOR_g). Long-term historical data sets exist for fossil-fuel generation availability that allows reasonably good characterization of key performance metrics in the Dominican wholesale electricity market. Nevertheless, the FORs used in the model were obtained from the Generating Availability Data System (GADS) reports from the North American Electric Reliability Corporation (NERC). Given the high unavailability of some of the technologies that are installed in the country, it does not seem reasonable to use the local data for determining future investment decisions.

Availability Factor (AF_g). The availability factor to account for maintenance of fossil-fueled generators was also gotten from the GADS reports.

Solar and wind profiles ($AVAIL_{p,g}$). For the intermittent generation, four years of hourly profiles were considered. Data for the Dominican Republic could not be found. Thus, a simple adaptation of hourly profiles from different regions in Germany[10] was made. First, the data was normalized:

$$ND_{r,i} = \frac{OD_{r,i}}{\sum_i^n OD_{r,i}/n} \qquad ; \qquad \forall\, r$$

Where:

$ND_{r,i}$ → Normalized data on hour 'i' for profile type 'r'.

$OD_{r,i}$ → Original data on hour 'i' for profile type 'r'.

n → Total number of samples.

Afterward, the results from normalizing the data were multiplied by the estimated capacity factor of the four different locations for generation that are considered for the model (two wind sites, two solar sites). The capacity factor assumed for wind and solar generation was 30% and 20%, respectively, based on information from Annex 3 in (IRENA, 2016).

However, when looking at the peaks of the different profiles, they were either much higher or lower than 1. Consequently, a nonlinear transformation was applied to the previously normalized data:

$$NND_{r,i} = \frac{{ND_{r,i}}^{\beta}}{\overline{ND_{r,i}}} \qquad ; \qquad \forall\, r$$

Where:

$NND_{r,i}$ → New normalized data on hour 'i' for profile type 'r'.

$\overline{ND_{r,i}}$ → Maximum value in the vector of the previous normalized data on hour 'i' for profile type 'r'.

β → Power to which the previously normalized data is raised. The β was determined using the 'goal seek' function from Excel.

[10] This data was provided by the Energy Research Centre of the Netherlands.

Following this process, it was possible to obtain peak values for the capacity factors that would range from 0.89 to 1 in different profiles, while maintaining the average capacity factor of 30% and 20% for wind and solar generation, respectively.

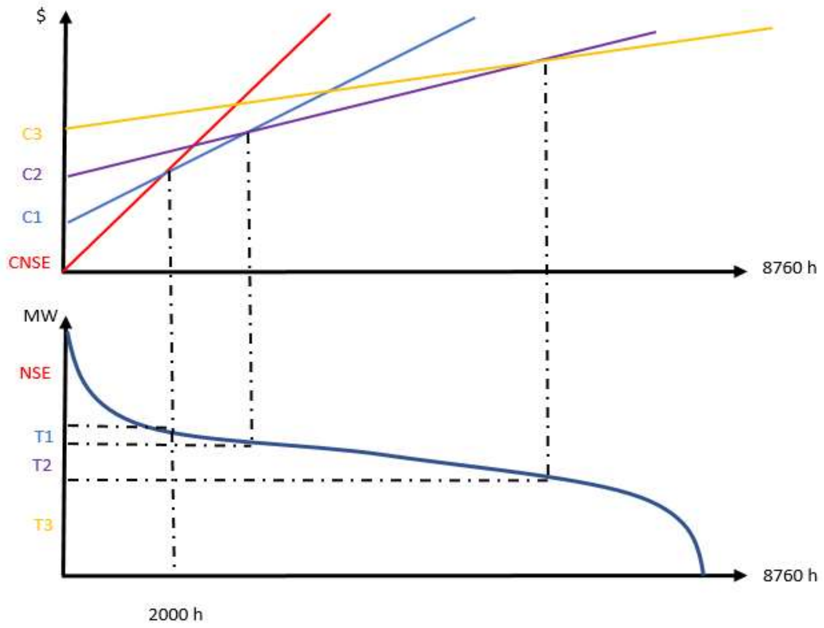
4.5 Methodologies

The issue explained in chapter 3 can be approached in two ways, 'Methodology A' (MetA) and 'Methodology B' (MetB). Both methodologies use the model explained in 0, in four different stages or steps. The difference between the both is the determination of the price cap. This price cap depends on the generation mix determined to meet a certain reliability level. For this, the first methodology uses only conventional generation, whereas the second one uses both conventional and RES generation. The following subsections explain the methodologies by going through its different stages.

4.5.1 Methodology A (MetA)

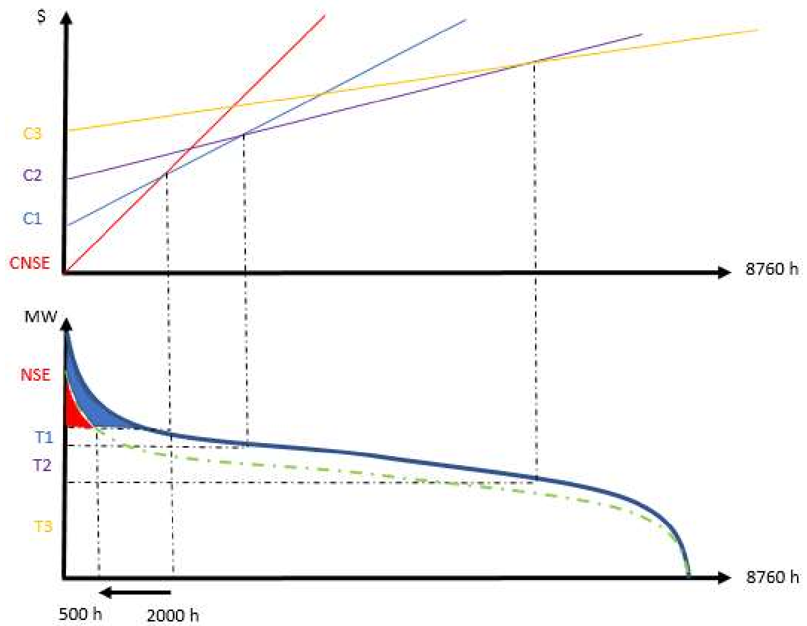
First Stage. The 'Base Case' is defined. The fossil-fueled is upper-bounded by the effective installed capacity in the system. This stage determines the effect of the price cap/cost of non-served energy in the effective installed capacity and the operation of these units. Also, the result for hours with non-served energy and the amount of non-served energy (NSE) is given. A representation of this stage is shown using screening curves in Figure 12. The resulting fossil-fueled generation mix is considered for the following stage.

Figure 12. First Stage – MetA.



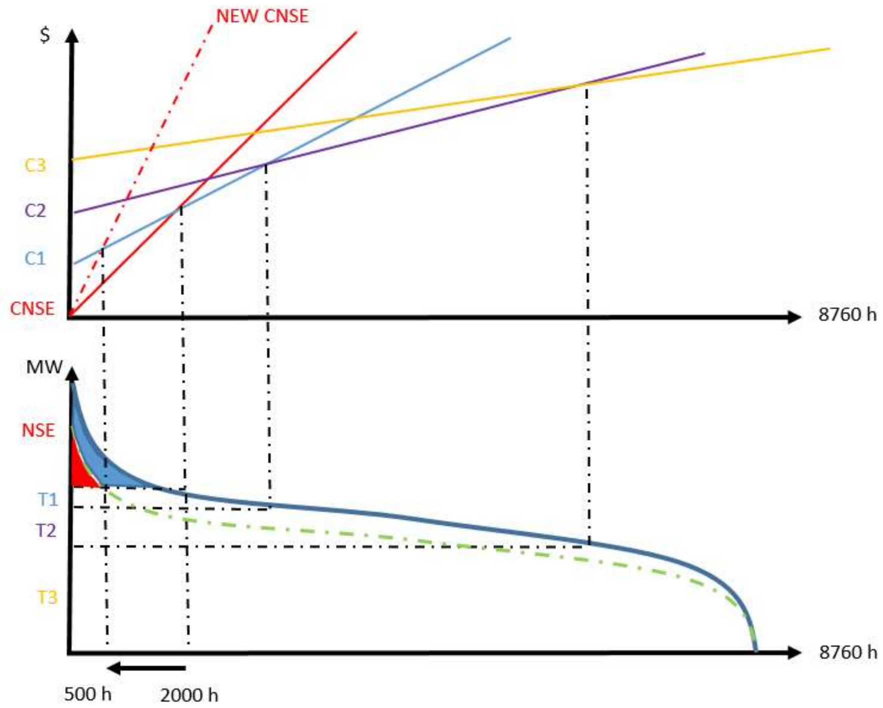
Second Stage. The resulting fossil-fueled generation mix is fixed, and the effect of setting an RPS in system adequacy is measured by the reduction of the hours with non-served energy and the non-served energy itself with respect to the 'Base Case.' The effect on the demand curve is shown by the green dotted line beneath the actual load curve in Figure 13. The objective of this stage is to determined the resulting non-served energy, which is given by the red area in the same figure.

Figure 13. Second Stage - MetA.



Third Stage. It can be said that this effect can be brought into the 'Base Case' by increasing the price cap/cost of non-served energy in the First Stage, as Figure 14 shows.

Figure 14. Third Stage - MetA [1/2].



There are two objectives in this stage. The first one is to obtain the new price cap/cost of non-served energy. The 'Base Case' is now limited to the resulting NSE of the Second Stage, and to transpose this into the model, a new input and a new constraint are considered in the model, as well as a modification of the objective function is done:

$$MIN\ (\$/year) = \sum_{g \in G}[FC_g * x_g] + \left(\frac{8760}{|H|}\right) * \sum_{p \in H, g \in F}[VC_g * e_{p,g} + SU_g * suc_g] (1)$$

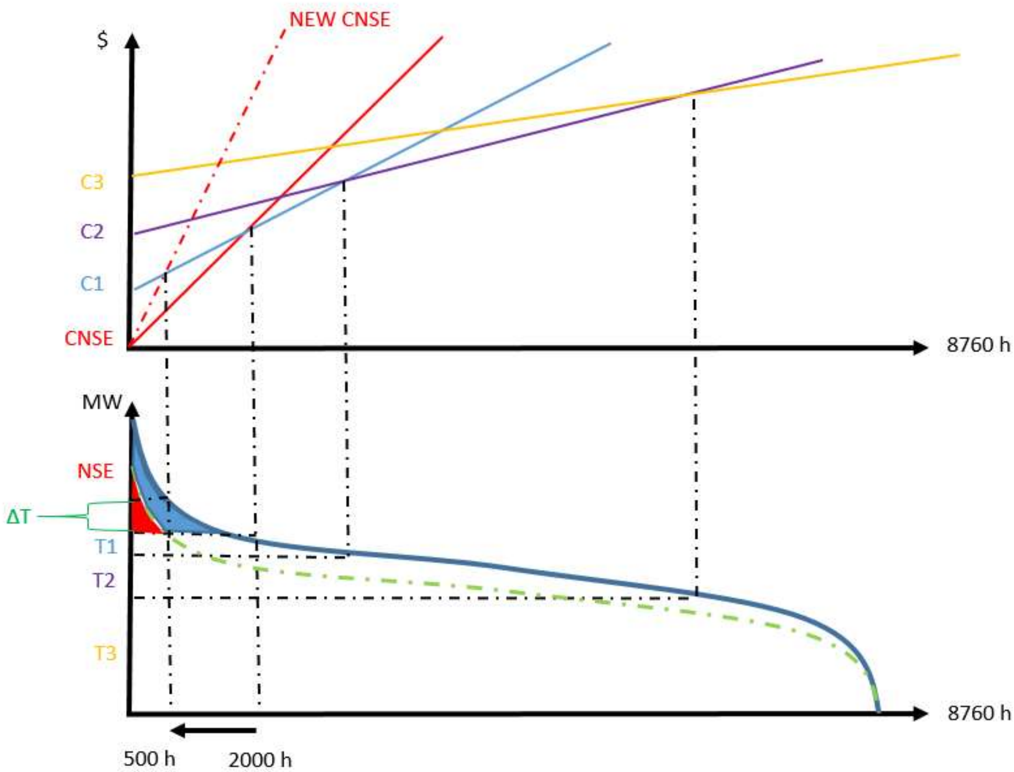
New constraint:

$$\sum_g nse_p \leq NSE_{2nd.\ Stage} \quad (12)$$

The shadow price of this constraint gives the new price cap/cost for the non-served energy, which is associated with the defined RPS target.

The second objective is to obtain the ELCC corresponding to the share of intermittent generation. In the 'Base Case,' the system is modeled without considering the intermittent generation. The fossil-fueled generation mix is adjusted to meet the same level of reliability as in the Second Stage. This adjustment presents an increment in the mix of the 'Base Case' (represented as ΔT in Figure 15), which can be considered as the ELCC or Capacity Value of the share of renewables. Consequently, renewables could be remunerated for this improvement on system adequacy.

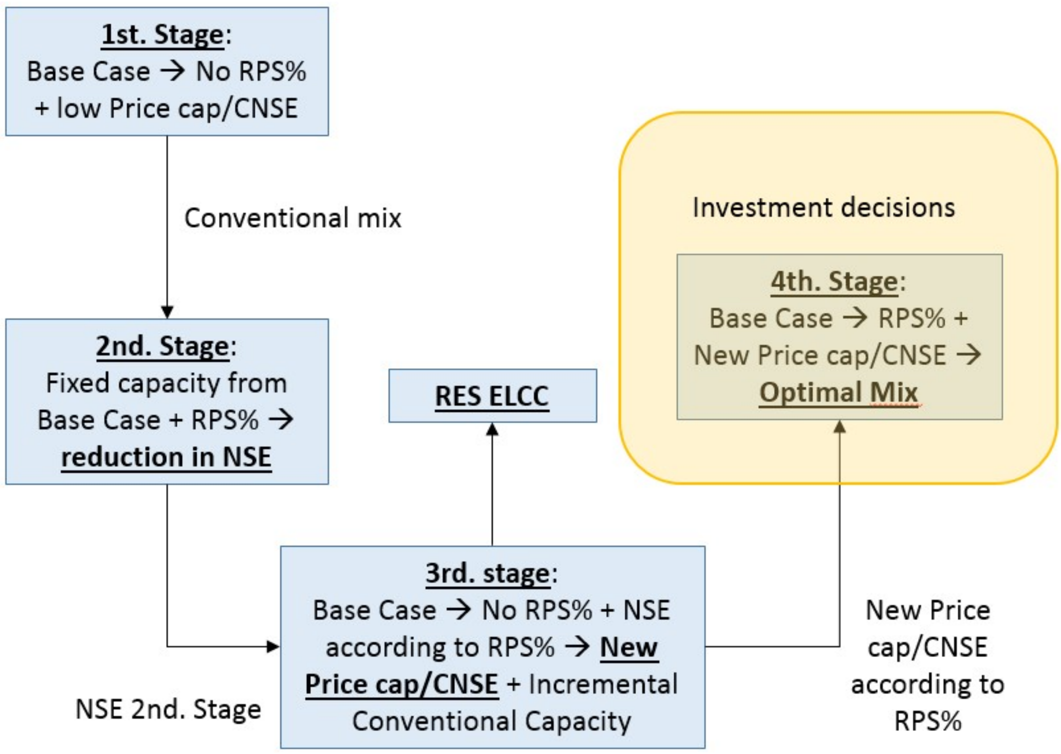
Figure 15. Third Stage - MetA [2/2].



Fourth Stage. Now that a reference price cap/cost of non-served energy is calculated in the previous stage, the same procedure as in the First Stage takes place. The difference is that a share of renewables is defined, and a higher price cap/cost of non-served energy is applied. This would result in an optimal mix that includes both conventional and non-conventional generation.

The implications of this methodology are explained in 5.4. In summary, Methodology A can be explained by Figure 16.

Figure 16. Summary of Methodology A (MetA).



4.5.2 Methodology B (MetB)

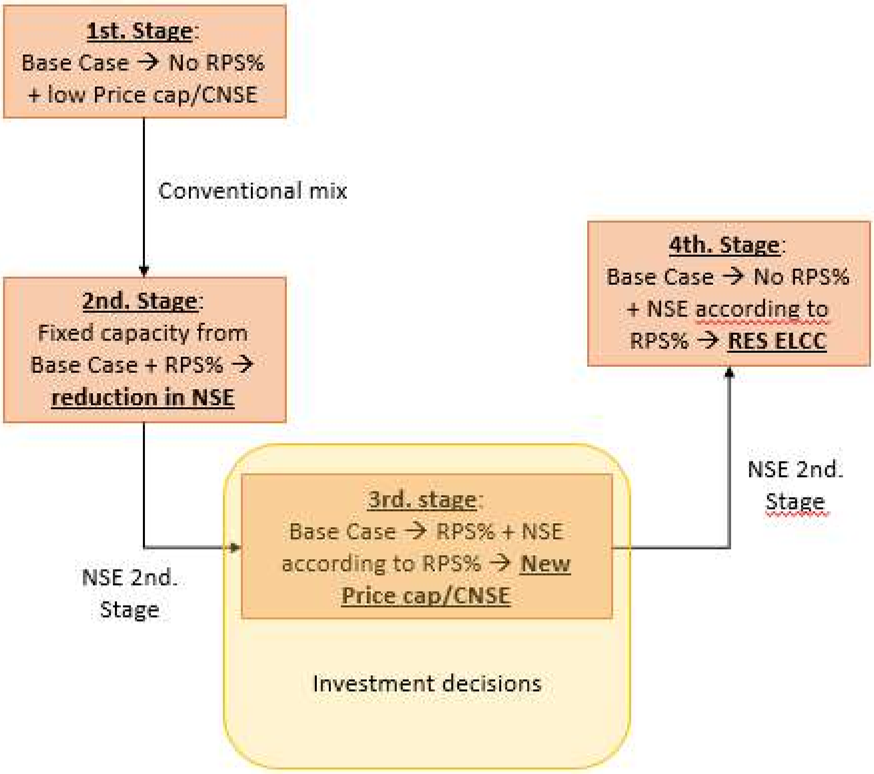
Similar to MetA, the **First** and **Second** stages have the same objectives in MetB. The differences appear in the Third Stage.

Third Stage. The optimal mix is achieved by letting the model determine it based on the NSE from the Second Stage. As in MetA, the dual variable of the new constraint would give a new price cap/cost of non-served energy.

Fourth Stage. Like in the second objective of the Third Stage of MetA, the ELCC corresponding to the share of intermittent generation is calculated. In the 'Base Case,' the system is modeled without taking into account the non-conventional generation.

Methodology B can be summarized by Figure 17.

Figure 17. Summary of Methodology B (MetB).



Chapter 5　Results and analysis

This chapter presents the results of each step of the methodologies. The 'Base Case' and the non-served energy for different scenarios are presented in 5.1 and 5.2, respectively. 5.3 shows the results of calculation of the ELCC of the total share of renewables according to both methodologies. As methodologies differ starting with the calculation of the price cap, the results for both methodologies are presented by making a comparison between both from Section 5.4 onwards.

The results justify the importance of associating an increase of the price cap a defined RPS target, as keeping the low price cap would lead to a deterioration of system reliability as the renewable share increases. Based upon an assessment done within this chapter, an "optimal" RPS can be determined by a scenario comparison, and based on the reliability improvement, these results serve as a basis to set a remuneration for the capacity value of RES. Likewise, the results help in letting the viewer analyze what the possible outcome of different commercial transactions in the wholesale market could be when implementing an RPS along with a higher price cap.

5.1 Base Case

The first run of the model provides the total hours with scarcity for the given period, as well as the total non-served energy.

- Non-served energy (NSE) = ***92,344 MWh***.
- Hours with non-served energy (HNSE) = ***1756 hours***.

Table 3 presents a comparison between the conventional generation installed as of 2016 in the Dominican Republic, and the result of the First Stage, where the 'Base Case' is defined.

Table 3. Actual Mix & Base Case.

	Effective Installed Capacity (MW)	
Technology	Actual Mix	Base Case
COALST	268.4	268.4
CCGTNG	280.6	280.6
GASTNG	236.0	236.0
FUOENG	1109.1	1014.8
CCGTFO	469.7	234.0
GASTFO	99.5	0.0
Total	**2463.2**	**2033.8**

The meaning of these first results is that it would be cheaper to have scarcity than to have the same level of actual conventional generation.

5.2 Reduced non-served energy

According to the Second Stage, the conventional capacity from the 'Base Case' is fixed, and different RPS targets are tested with the model. Each target presents a reduction in both the NSE and HNSE (Table 4).

Table 4. Reduced NSE and HNSE by RPS.

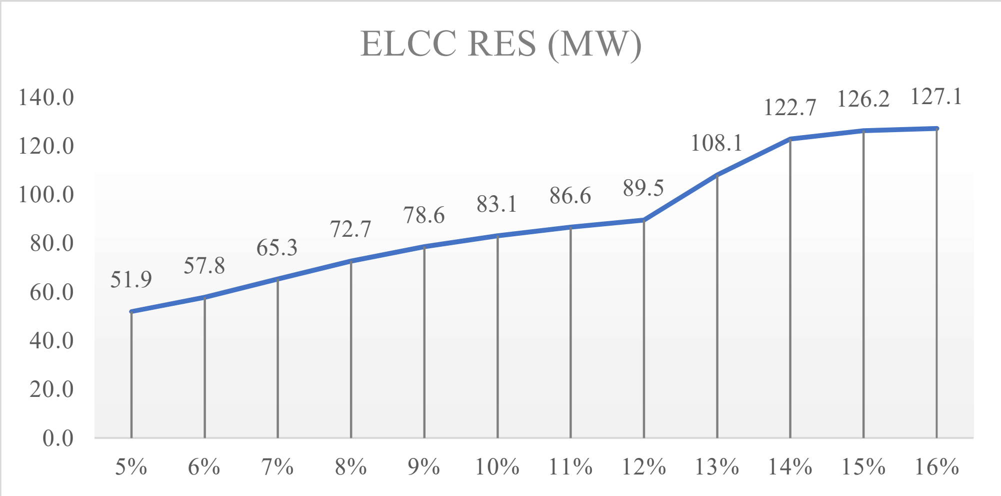
RPS	Non-served Energy (MWh)	Hours with non-served energy (h)	Total RES (MW)
0%	92,344	1,756	0.0
5%	34,202	751	254.1
6%	29,999	674	304.9
7%	25,223	589	358.7
8%	21,036	508	415.2
9%	18,119	452	471.8
10%	16,103	395	528.3
11%	14,687	362	584.9
12%	13,606	335	641.4
13%	8,041	229	706.0
14%	5,034	133	774.4
15%	4,476	105	843.5
16%	4,332	100	913.3
≥17%	**Unfeasible**		

The model is applied to different scenarios with a defined RPS target. The starting point is an $RPS_{5\%}$. It is relevant to note that the model reaches infeasibility when the RPS target is 17% or higher. This is due to the upper bound defined in 4.2.

5.3 Effective Load Carrying Capability (ELCC) of RES

The result for the ELCC in both methodologies is shown in Figure 18. As expected, for a greater share of renewables, a higher ELCC is expected due to the improvement in system adequacy. What is important to notice is that the graph becomes steeper for an $RPS_{13\%}$. This can be interpreted as the highest improvement in the contribution of an RPS to system adequacy with respect to the previous.

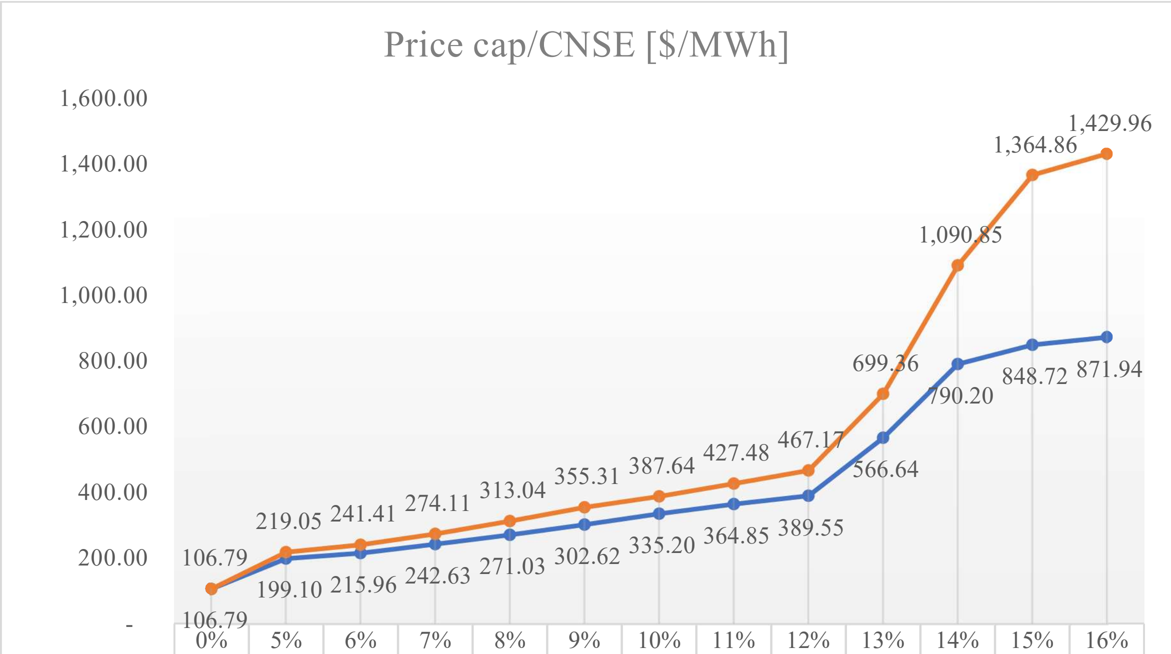
Figure 18. ELCC for the RES according to both methodologies.



5.4 New Price cap/Cost of non-served energy (CNSE)

The different approaches that MetA and MetB present regarding the determination of the price cap, produce different results. The reasoning behind this is that it costs more to reach the same level of reliability with both conventional and RES (MetB) than only considering conventional (MetA). Hence, the effect on the objective function of increasing the right-hand side of equation (12) by one additional unit, happens to be greater in MetB than in MetA.

Table 5. Price cap/cost of non-served energy (CNSE) according to MetA and MetB.

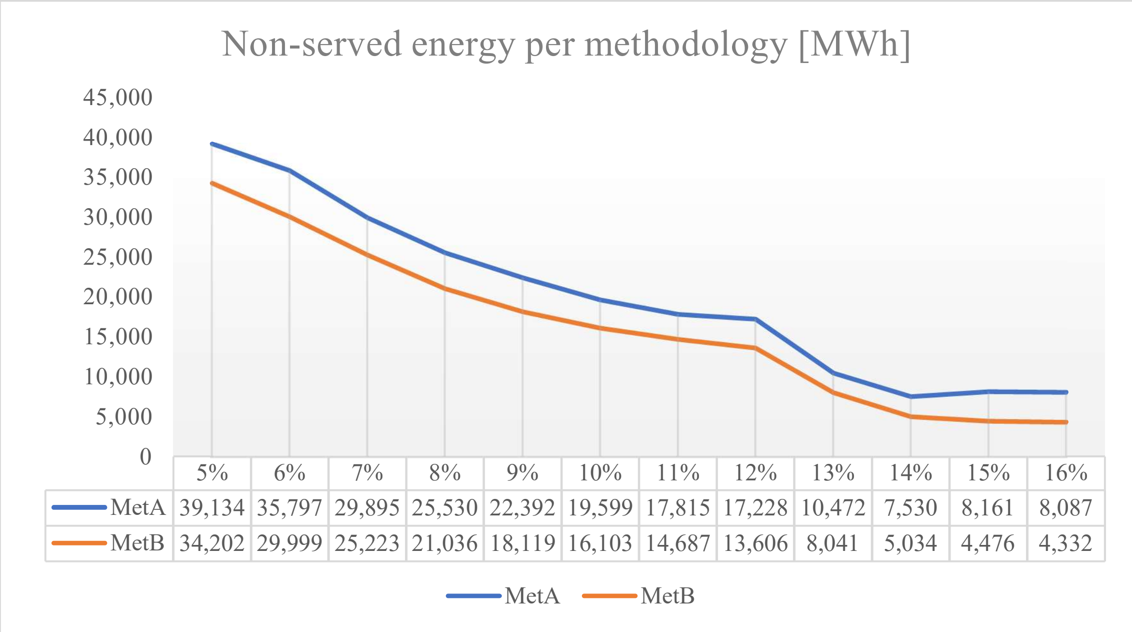


	0%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%
MetA	106.7	199.1	215.9	242.6	271.0	302.6	335.2	364.8	389.5	566.6	790.2	848.7	871.9
MetB	106.7	219.0	241.4	274.1	313.0	355.3	387.6	427.4	467.1	699.3	1,090	1,364	1,429

5.5 Resulting non-served energy for each methodology

As the price caps differ between the two approaches, it is expected that the effect on system adequacy is different as well. Given that the price cap in MetB is higher than in MetA, the scarcity is less. Curiously, the NSE starts to rise after $RPS_{14\%}$ in MetA, whereas in MetB keeps decreasing, although at a less steep pace (Figure 19). It would have to be asked if it would make sense to increase the RPS target and, therefore, the price cap, to have a small improvement in system adequacy.

Figure 19. NSE according to MetA and MetB.



5.6 Average non-served power

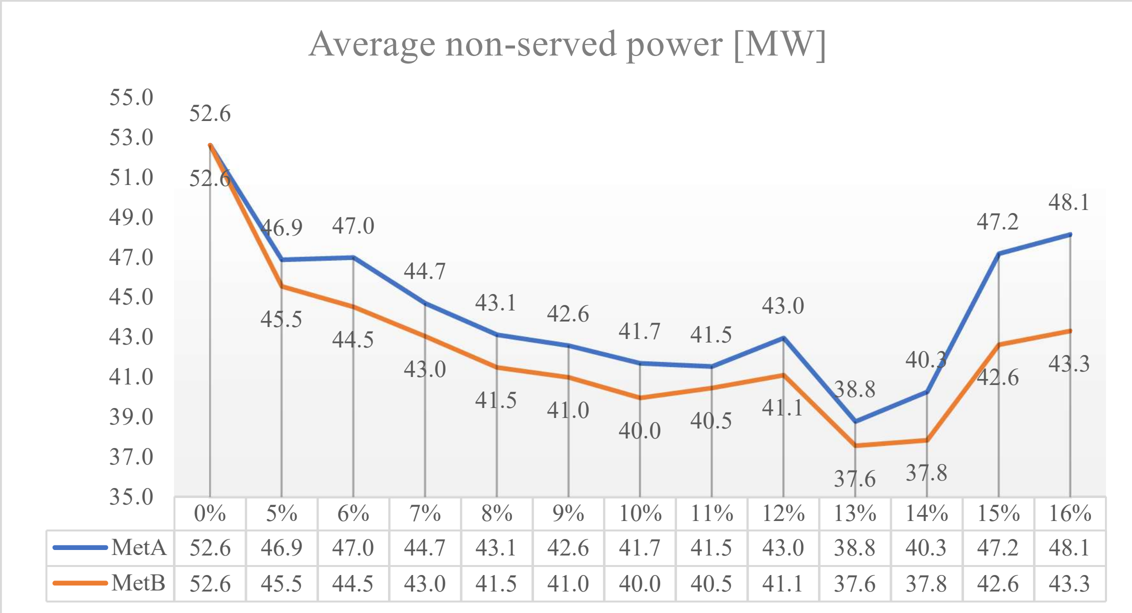
Following the logic of previous results, a decision is made to determine what is the best contribution to system adequacy that a combination RPS% - Price cap can have. A similar approach as in 7.3.3 of (Billinton & Allan, 1984), regarding load- and energy-oriented indices is made. In this reference an average energy not supplied (AENS) is presented as:

$$AENS = \frac{total\ nonserved\ energy}{total\ number\ of\ customers\ served}$$

For the purpose of analyzing results, a similar index is used. In this index, the total non-served energy is divided by the total hours with non-served energy:

$$Average\ nonserved\ power\ (AVP) = \frac{\sum_p nse_p}{\sum_p hnse_p}$$

Figure 20. Average non-served power according to MetA and MetB.



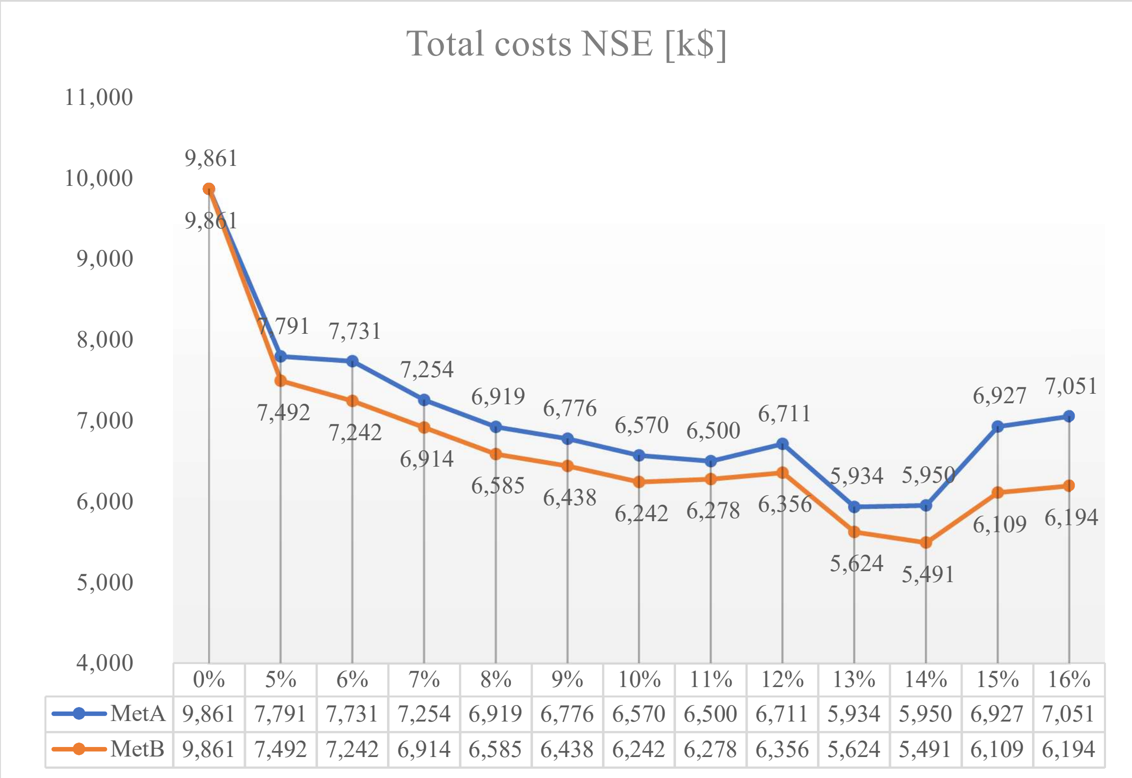
	0%	5%	6%	7%	8%	9%	10%	11%	12%	13%	14%	15%	16%
MetA	52.6	46.9	47.0	44.7	43.1	42.6	41.7	41.5	43.0	38.8	40.3	47.2	48.1
MetB	52.6	45.5	44.5	43.0	41.5	41.0	40.0	40.5	41.1	37.6	37.8	42.6	43.3

In both methodologies, the lowest AVP was provided by $RPS_{13\%}$ and its corresponding price cap (Figure 20). What is important to notice is that after $RPS_{13\%}$, the index begins to rise again. This can be due to two reasons. The first one is that after $RPS_{13\%}$, the reduction in the HNSE is more significant than the decrease in the NSE. The second one is that the NSE is increasing, as it happened in MetA.

5.7 Total cost of non-served energy

The impact of setting an RPS% target and a higher price cap can be assessed by the effect on the reduction of the total costs caused by scarcity in the system (Figure 21), which is nothing more than the product of the total NSE multiplied by the price cap/CNSE.

Figure 21. Total costs of NSE according to MetA and MetB.



The lowest NSE total cost was given by $RPS_{13\%}$ and $RPS_{14\%}$ in MetA and MetB, respectively. It is interesting to note that in MetA, both the AVP and the total cost of NSE are at the lowest point when the target is $RPS_{13\%}$, whereas, in MetB, the lowest total cost of non-served energy is given by $RPS_{14\%}$. Nonetheless, it is safe to say that the best contribution regarding this indices is provided between $RPS_{13\%}$ and $RPS_{14\%}$ in both methodologies.

Either of these measures -or both- can be used to evaluate the contribution to system adequacy of an RPS and a corresponding increase in the price cap, as both measures are positively correlated (0.90 and 0.96 of correlation coefficient for MetA and MetB, respectively).

5.8 Optimal mix

The optimal mix was determined for each RPS% - Price cap scenario. Because of the different price cap, the installed capacity of the resulting mix in MetA and MetB, differ.

Figure 22. Installed capacity (conventionals and RES) for MetA.

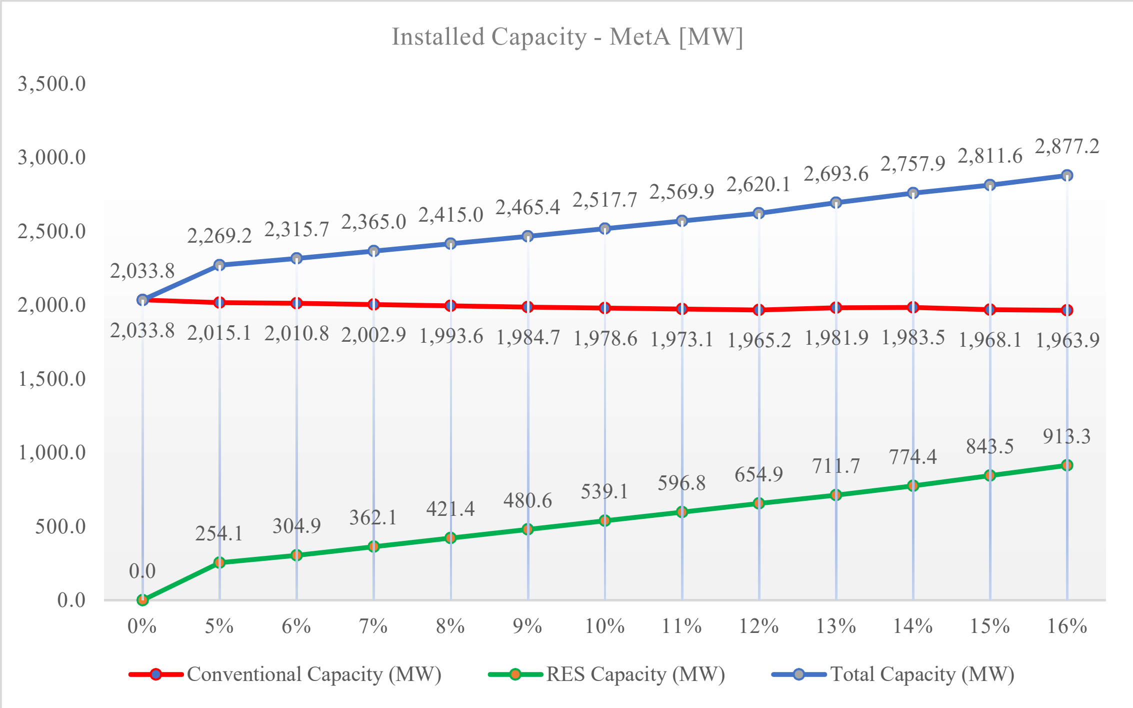
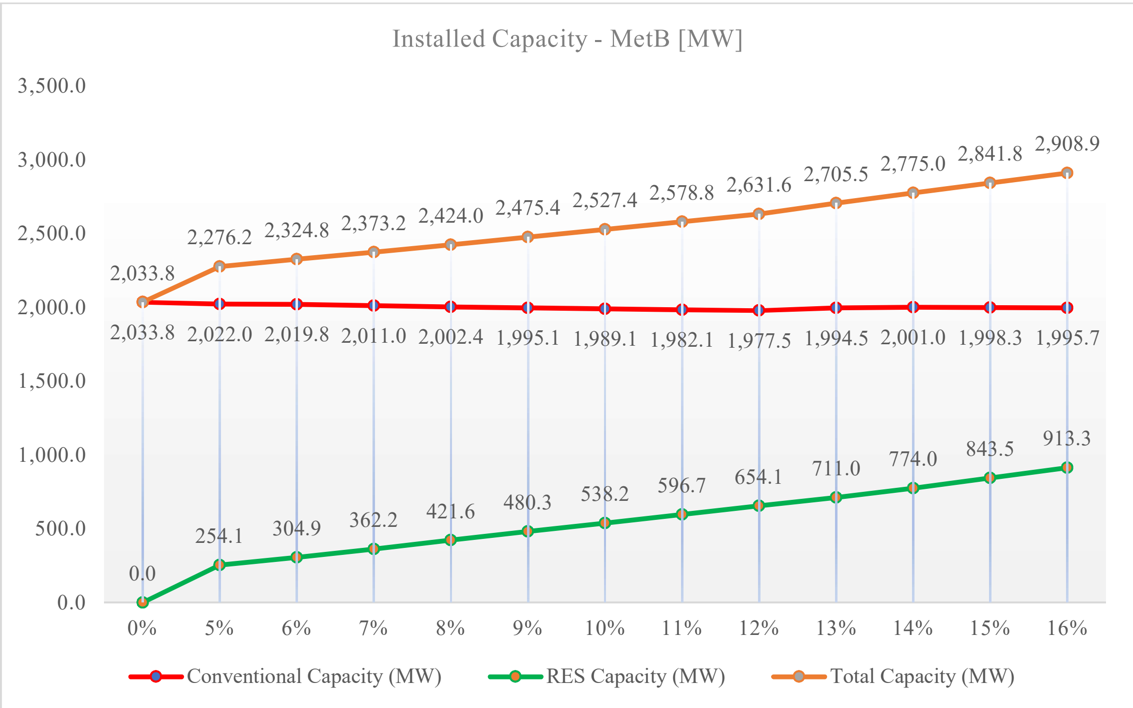
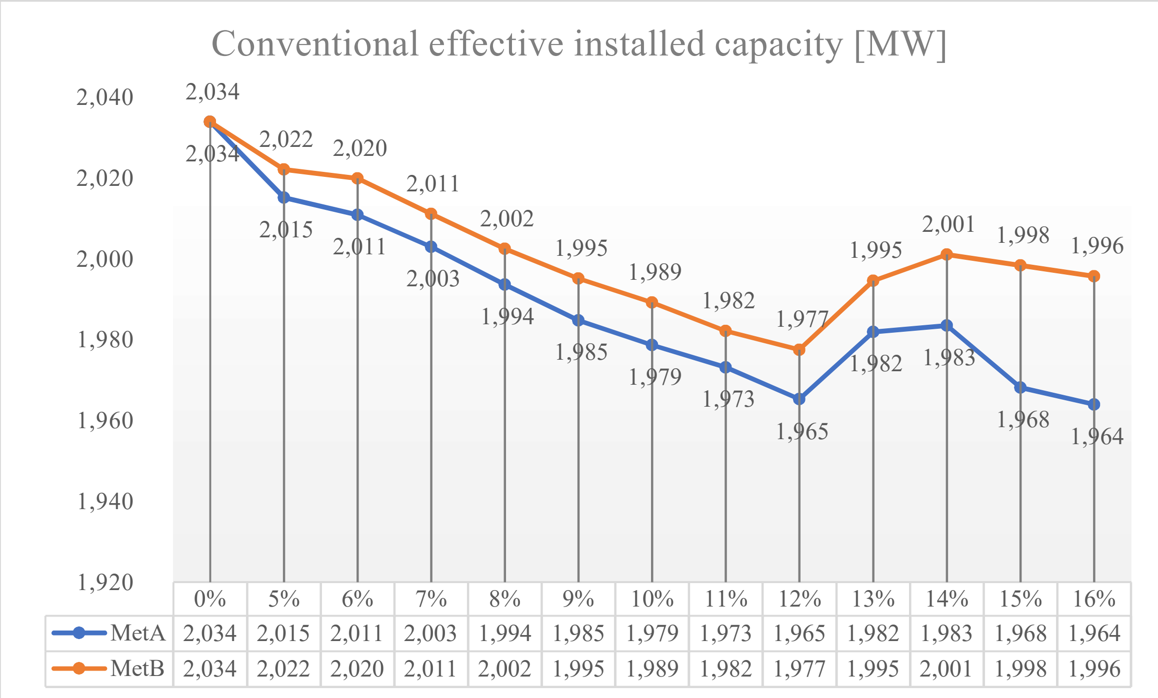


Figure 23. Installed capacity (conventionals and RES) for MetB.



As it can be seen in both illustrations, there is little to no difference in the resulting installed capacity of the RES. The differences appear when comparing the effective installed capacity that corresponds to the conventional generation (Figure 24).

Figure 24. Installed capacity of conventional generation (MetA and MetB).



It can be seen how the conventional capacity is reducing as the share of renewables is increasing. However, when the target is $RPS_{13\%}$ and $RPS_{14\%}$, the capacity is increased with respect to previous targets. This is because of the considerable impact that these targets have regarding system adequacy, which reflects in a much higher price cap. It can be interpreted that a consequence of this much higher price cap, the decision to install more conventional generation in order to have available generation to cover more demand. Under the same logic, it would be expected that the conventional capacity would keep increasing, but as the renewable share increases ($RPS_{15\%}$ and onwards), there is no more room for improvement in the system adequacy with conventional generation. Thus, the conventional capacity starts to decline again.

5.9 Which is the optimal RPS?

As explained in 2.5, an optimal RPS can be defined through different approaches. This work is focused on the impact that setting a particular RPS target would have in system adequacy, with respect to the resulting average non-served power and the total cost of the non-served energy. It is important to notice that setting an RPS target is accompanied by an increase in the price cap, so, the definition of this optimal RPS is conditioned by said price cap. Table 6 shows what would be the optimal RPS and its corresponding price cap, according to MetA.

Table 6. Optimal RPS according to MetA.

RPS	New Price Cap/CNSE [$/MWh]	NSE [MWh]	HSNE [hours]	Average Non-Served Power [MW]	Total cost of NSE [k$]
0%	106.79	92,344	1,756	52.6	9,861.4
5%	199.10	39,134	835	46.9	7,791.4
6%	215.96	35,797	762	47.0	7,730.7
7%	242.63	29,895	669	44.7	7,253.6
8%	271.03	25,530	592	43.1	6,919.4
9%	302.62	22,392	526	42.6	6,776.4
10%	335.20	19,599	470	41.7	6,569.5
11%	364.85	17,815	429	41.5	6,499.8
12%	389.55	17,228	401	43.0	6,711.1
13%	**566.64**	**10,472**	**270**	**38.8**	**5,933.9**
14%	790.20	7,530	187	40.3	5,950.4
15%	848.72	8,161	173	47.2	6,926.5
16%	871.94	8,087	168	48.1	7,050.9

The resulting generation mix according to this RPS% and price cap, is compared with the 'Base Case' in Table 7.

Table 7. Effective installed capacity according to $RPS_{13\%}$ - MetA.

Effective Installed Capacity [MW]		
Technology	Base Case	MetA - RPS13%
COAL - STEAM TURBINE	268.4	268.4
CCGT - NG	280.6	280.6
GAS TURBINE - NG	236.0	236.0
FUEL OIL ENGINE	1014.8	781.5
CCGT - FO	234.0	415.4
GAS TURBINE - FO	0.0	0.0
WIND SITE 1	0.0	302.9
WIND SITE 2	0.0	330.0
SOLAR SITE 1	0.0	78.8
SOLAR SITE 2	0.0	0.0
Total	**2,033.8**	**2,693.6**

There is no change in the base load generators, as their capacity had reached the defined upper-bound. Nonetheless, a change in the peaking units (FUEL OIL ENGINE and

CCGT – FO) can be appreciated. FUEL OIL ENGINE presents a lower variable cost than that of GAS TURBINE – FO. However, its fixed costs are higher. The fact that the Forced Outage Rate for the FUEL OIL ENGINE is higher than for the CCGT-FO has to be considered, as it does influence. Therefore, when the price cap is increased, the model finds that is more economically efficient to invest in more GAS TURBINE – FO than in FUEL OIL ENGINE.

In the case of MetB, the determination of the optimal RPS is not as clear as in MetA. $RPS_{13\%}$ would give the lowest AVP, whereas $RPS_{14\%}$ would give the lowest total cost of the NSE.

Table 8. Optimal RPS according to MetB.

RPS	New Price Cap/CNSE [$/MWh]	NSE [MWh]	Average Non-Served Power [MW]	Total cost of NSE [k$]
0%	106.79	92,344	52.6	9,861.4
5%	219.05	34,202	45.5	7,491.9
6%	241.41	29,999	44.5	7,242.1
7%	274.11	25,223	43.0	6,913.8
8%	313.04	21,036	41.5	6,584.9
9%	355.31	18,119	41.0	6,437.9
10%	387.64	16,103	40.0	6,242.0
11%	427.48	14,687	40.5	6,278.3
12%	467.17	13,606	41.1	6,356.3
13%	**699.36**	**8,041**	**37.6**	5,623.5
14%	**1,090.85**	**5,034**	37.8	**5,491.4**
15%	1,364.86	4,476	42.6	6,109.1
16%	1,429.96	4,332	43.3	6,194.4

The decision over which one to implement could rest over the assessment of other issues. It can be discussed that is acceptable to have an $RPS_{14\%}$ as it is the target that has the lowest NSE cost and reduces CO_2 emissions between the two. Or a counterargument can be that having an extremely high price cap is not socially or politically well seen, hence, an $RPS_{13\%}$ would seem more suitable.

Assuming the $RPS_{13\%}$ is the preferred one, the resulting optimal mix would be the following one:

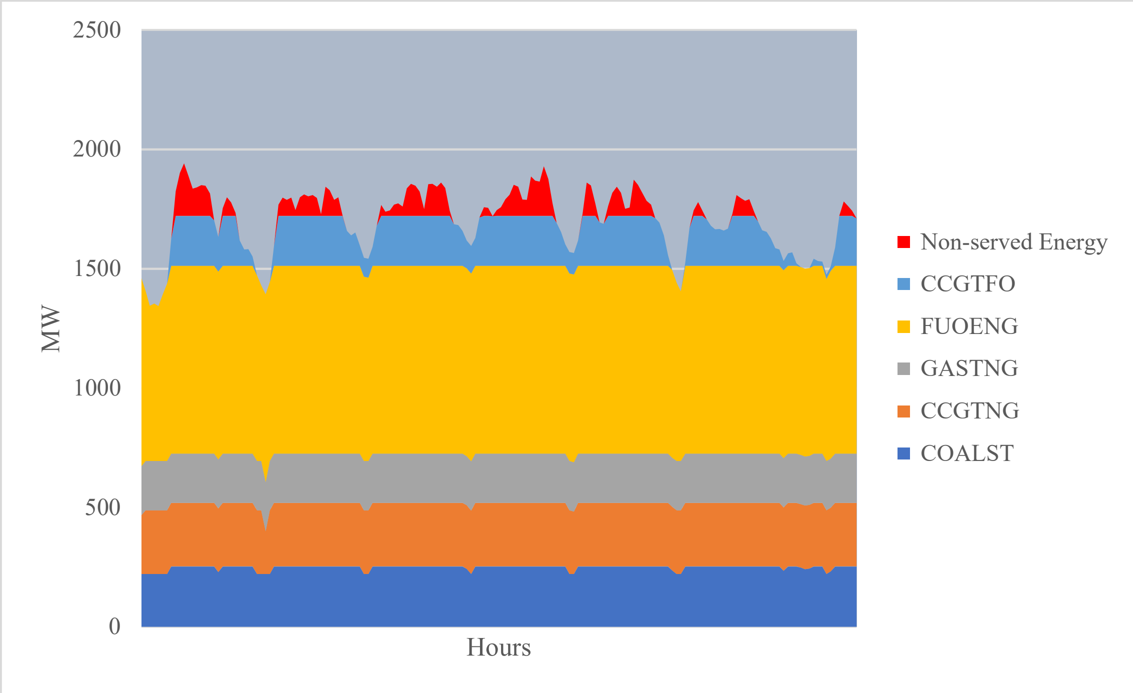
Table 9. Effective installed capacity according to $RPS_{13\%}$ - MetB.

Effective Installed Capacity [MW]		
Technology	Base Case	MetB - RPS13%
COAL - STEAM TURBINE	268.4	268.4
CCGT - NG	280.6	280.6
GAS TURBINE - NG	236.0	236.0
FUEL OIL ENGINE	1014.8	782.1
CCGT - FO	234.0	417.3
GAS TURBINE - FO	0.0	10.2
WIND SITE 1	0.0	306.3
WIND SITE 2	0.0	330.0
SOLAR SITE 1	0.0	74.7
SOLAR SITE 2	0.0	0.0
Total	**2,033.8**	**2,705.5**

5.10 Impact on system adequacy

In the previous topics, it has been able to see the impact on the long-term reliability. It is also interesting to see the impact on a shorter time-scale. For this, the results for the week from May 16th to 22nd of 2016 is considered. The result for the 'Base Case' shows that this week presents 90 hours were there was scarcity, which accounts for a total of 7.3 GWh. The resulting dispatch is provided in Figure 25.

Figure 25. May 16th – 22nd – Base Case.



When increasing the share of renewables as well as the price cap in this scenario, the following results are given for both methodologies A and B, assuming an $RPS_{13\%}$:

Methodology	NSE (GWh)	HNSE (hours)
Methodology A	0.95	25
Methodology B	0.72	22

Figure 26. May 16th - 22nd – MetA ($RPS_{13\%}$).

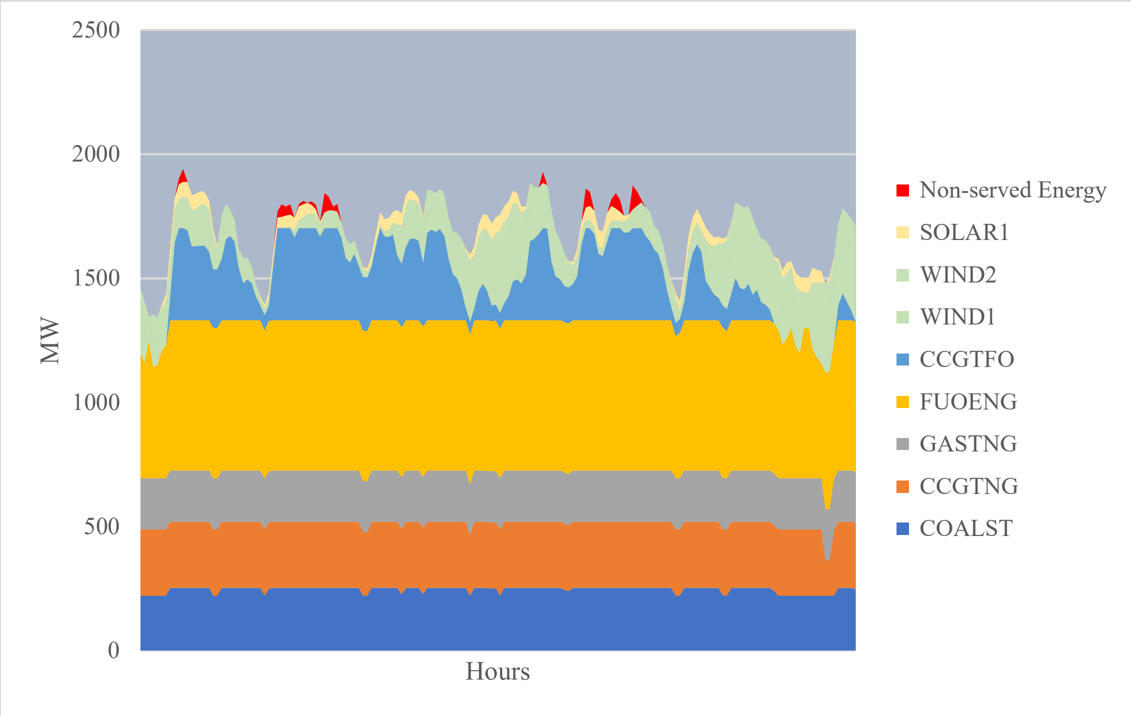
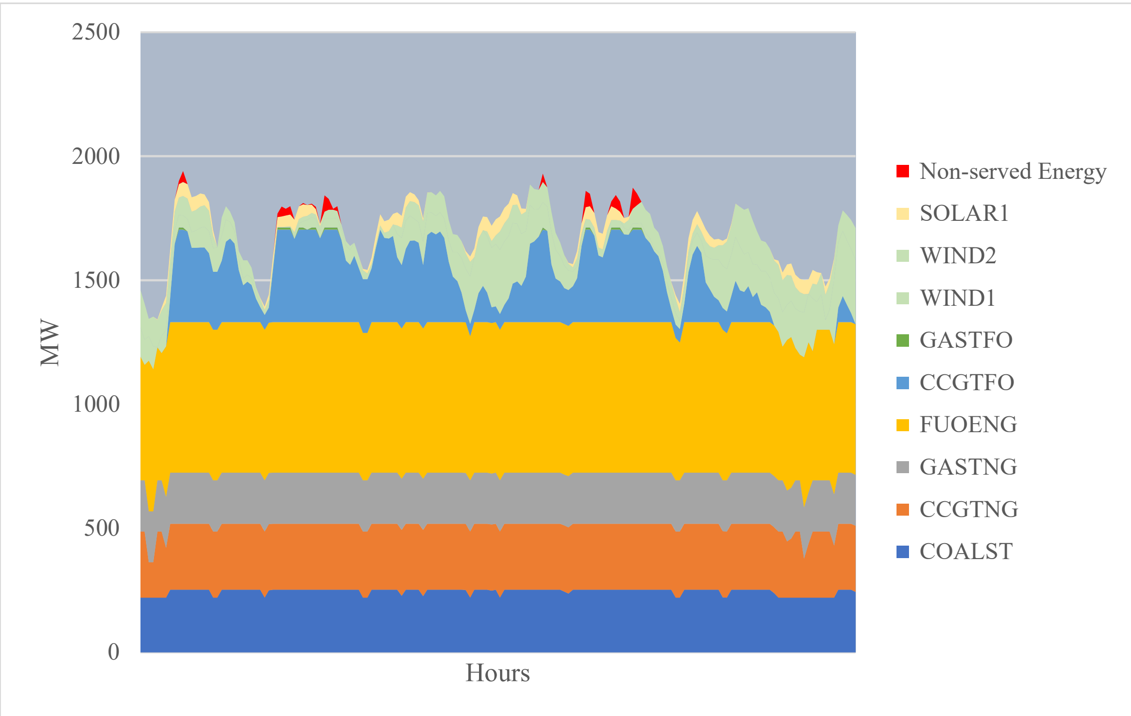
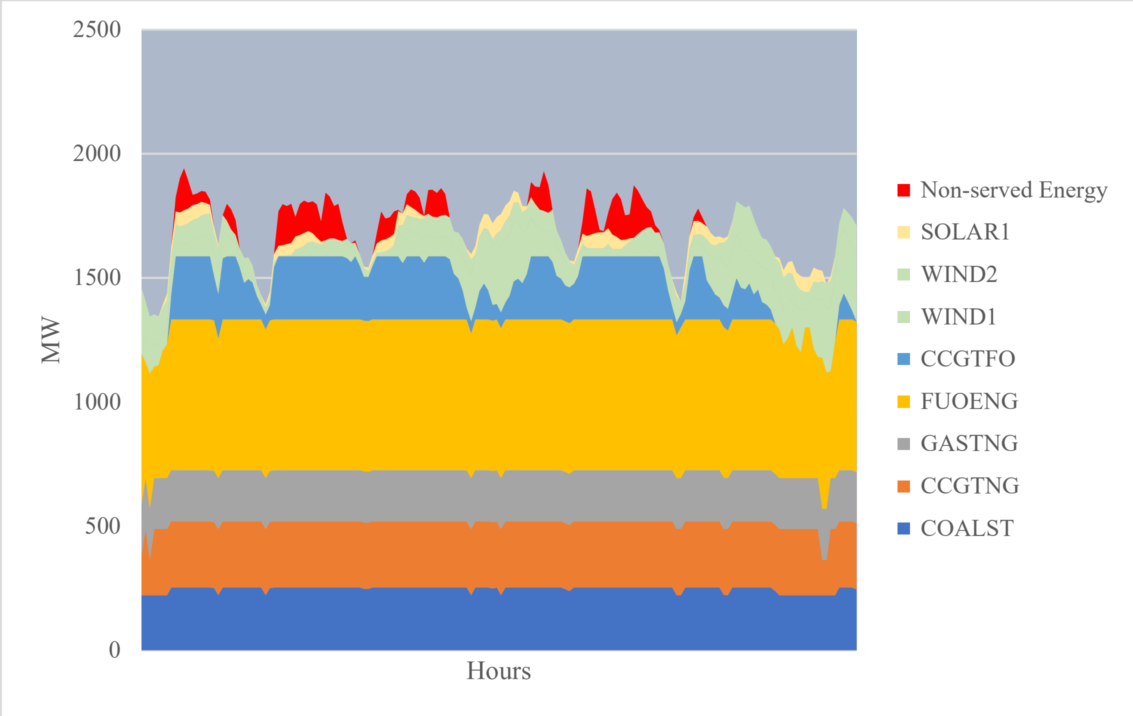


Figure 27. May 16th - 22nd – MetB ($RPS_{13\%}$).



From the previous two figures, is evident that the reliability has improved. Although, it is not only because of the growth in the RES share, as the increase of the price cap makes this possible. If the same price cap is left, there will be little to no improvement in system adequacy, as we increase the share of renewables. The model can provide results that support this claim as can be seen in Figure 28.

Figure 28. May 16th - 22nd – Low price cap and RPS13%.



Comparing with the 'Base Case' there has been a small improvement regarding scarcity, as the scarcity periods have gone from 90 to 71 hours, and the non-served energy is reduced from the initial 7.3 GWh to 6.7 GWh. However, when looking at the whole period (2013-2016), there is a decrease in reliability according to Table 10.

Table 10. Base case and low price cap - and RPS13% scenario comparison.

	Hours with non-served energy	Non-served energy [MWh]
(a) Base Case	1752	92,344
(b) Low price cap - RPS13%	1756	110,716
Difference (a) - (b)	-4	-18,372

Hence, even with a relatively not so aggressive RPS, it is possible to increase scarcity within the system if the price cap is not rised.

5.11 *Effect on the wholesale market transactions*

The first effect that is thought of is the reduced market prices when RES are brought on to the market to operate. Of course, RES present higher investment costs than conventional generation which is translated to more costs for the consumer, but the market prices are decreased over time because of the less usage of conventional generation, which present a much higher variable cost. In a system with marginal pricing, as it is the Dominican market, renewables can reduce the demand for conventional generation, changing the marginal unit in the system, and thus, reducing the marginal cost.

As it has been mentioned, the application of this methodologies comes with an increment on the price cap. So, as the price cap is lifted considerably, the remuneration of inframarginal generators would no be limited to a price cap that is lower than other units' variable costs. In this sense, the procedure for the compensation of forced generation (3.1.4) should be modified, as there would not be needed to compensate economic-dispatched generators that used to have a variable cost higher than the price cap.

Another effect that can be taken into account is in the overall capacity payments. Firstly, based on their capacity value demonstrated by determined the ELCC, the RES could receive the same payments. Although to be consistent with this decision, some considerations have to be made regarding the actual procedure for the remuneration of the capacity. In 3.1.6, it is explained that this capacity payment is based on the firm supply that the conventional generation can offer to the system peak demand. If a similar logic is followed as in (Bothwell & Hobbs, 2017) regarding the peak-shifting caused by the RES, it may result in a reduction of the conventional capacity that is to be remunerated.

Figure 29. Peak-shifting for 2015 - MetB (RPS$_{13\%}$).

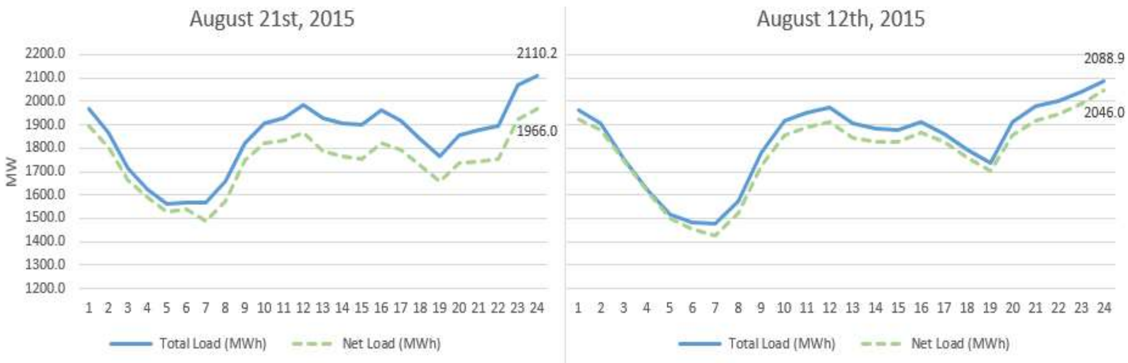


Figure 29, shows the hypothetical effect that RES would have in the determination of the peak demand. Considering the result of the mix in MetB, the installed capacity for wind is 636.3 MW which provides most of the RES generation. The curves on the left show the peak demand day (August 21st) for the system in 2015. During the hourly peak demand, as there is no solar at that time of the day (hour 24), only wind is contributing 144.2 MW or 22.7% of its installed capacity. The scenario is much different when looking at August 12th. In this date, the curves on the right show that the contribution of wind during the peak hour (again, hour 24) is less with only 42.9 MW or 6.7% of its installed capacity. Consequently, with the considered target of RPS$_{13\%}$, the annual net load peak occurs on August 12th, instead of August 21st. The effect that wind has is the reduction of the system peak by 64.2 MW -from 2,110.2 MW to 2,046.0 MW-, which means that the firm supply that conventional generation can offer is reduced. This last scenario would require not only the forecasted and real demand, but the forecasted and real wind and solar generation.

5.12 Remunerating the capacity value of solar and wind

The ELCC for both solar and wind is determined altogether. A proposal to set the monthly capacity payments corresponding to solar and wind can rely on their actual generation and the ELCC. Considering the resulting ELCC of 108.1 MW with RPS$_{13\%}$ for both technologies, this capacity can be divided pro rata of their energy within the month.

Table 11. RES generation and capacity value 2016 - MetB (RPS13%).

Month	Generation [MWh]			Capacity Value [MW]		
	Wind site 1	Wind site 2	Solar site 1	Wind site 1	Wind site 2	Solar site 1
January	72,372	100,033	3,664	44.4	61.4	2.2
February	76,439	80,278	5,867	50.8	53.4	3.9
March	79,337	67,973	10,941	54.2	46.4	7.5
April	47,549	60,945	14,185	41.9	53.7	12.5
May	47,705	47,765	15,197	46.6	46.7	14.8
June	58,500	48,902	14,836	51.7	43.2	13.1
July	43,713	53,453	15,977	41.8	51.1	15.3
August	54,730	65,882	15,163	43.6	52.5	12.1
September	80,954	72,501	12,250	52.8	47.3	8.0
October	81,977	69,478	9,571	55.0	46.6	6.4
November	63,315	65,564	5,288	51.0	52.8	4.3
December	70,123	59,954	4,109	56.5	48.3	3.3

The capacity value shown in the three columns to the right in Table 11 are the base on which these technologies would receive their capacity payments. Assuming the price set by the regulator to remunerate the capacity ($8,770.10/MW-month) as of the month of December 2016, the remuneration for RES capacity is determined in Table 12.

Table 12. Capacity remuneration of RES for 2016 - MetB (RPS13%).

Month	Remuneration [USD$]		
	WIND SITE 1	WIND SITE 2	SOLAR SITE 1
January	389,687.84	538,630.33	19,730.13
February	445,726.33	468,112.65	34,209.32
March	475,292.34	407,212.12	65,543.84
April	367,453.89	470,971.42	109,622.99
May	408,675.37	409,183.12	130,189.80
June	453,712.02	379,273.52	115,062.77
July	366,283.06	447,893.98	133,871.26
August	382,149.12	460,023.37	105,875.81
September	463,161.59	414,798.40	70,088.31
October	482,642.20	409,054.97	56,351.13
November	447,392.32	463,291.03	37,364.94
December	495,429.23	423,587.08	29,031.99

5.13 Summary of results

In Methodology A, the resulting price cap is lower than in Methodology B. This is due to the fact that the former considers only conventional generation to reach a certain reliability criteria when determining the price cap, and the latter one considers both conventional and RES generation to meet the same criteria. As intermittent generation presents variability and a relatively low capacity value when compared to conventional, it is more costly for the system to reach the same level of reliability when considering RES.

Furthermore, for a given set of data of hourly demand, and wind and solar hourly profiles, both methodologies give similar results regarding the optimal mix and the optimal RPS target. This RPS target along with its corresponding price cap, guarantee an enhancement in system adequacy, which can validate the capacity value of RES and, therefore, its compensation for this added value.

Considering the assumptions made in the case study, an $RPS_{13\%}$ could be regarded as the "optimal." The outcome is an ELCC of 15.2% [Equivalent conventional generation (108.1 MW) / RES installed capacity (711.0 MW)].

A benefit from the results of these methodologies is that it defines the location and the quantity of RES capacity to install well-known in advance, which serves as a basis for the transmission investment planning.

Chapter 6　Conclusions

6.1 Basic conclusions

Renewable Energy Sources do have an impact on system adequacy. This is represented as a capacity value that, although it is not as high as in conventional generators, does contribute to system reliability. The decision of remunerating this contribution rests on the State or regulator of the Dominican Republic, who is interested on incentivizing the investment on this kind of technologies, but aware of the effects that it would have in the actual wholesale market transactions and considering that this increase in the share of renewables could eventually deteriorate system reliability. The latter happens when the market presents a relatively low price cap, as it is the case of the Dominican Republic.

The remuneration for the capacity value of RES generation could replace any support mechanism that is currently in force (feed-in premium). Nevertheless, even if this remuneration secures future revenues for market agents, it doesn't necessarily mean that it would cover its fixed (investments) costs in the long run. Firstly, because of the tendency of electricity prices to decline when these technologies are operating, and secondly, because of their low capacity value (e.g. Table 13). Therefore, the capacity remuneration mechanism, in the case of these RES, could be complemented with the current tax incentives, with aims of reducing the high capital investments that these technologies require.

Table 13. ELCC of RES – Calculated for MetB (RPS13%) [%][11].

Month	ELCC [%]		
	WIND SITE 1	WIND SITE 2	SOLAR SITE 1
January	14.5%	18.6%	3.0%
February	16.6%	16.2%	5.2%
March	17.7%	14.1%	10.0%
April	13.7%	16.3%	16.7%
May	15.2%	14.1%	19.9%
June	16.9%	13.1%	17.6%
July	13.6%	15.5%	20.4%
August	14.2%	15.9%	16.2%
September	17.2%	14.3%	10.7%
October	18.0%	14.1%	8.6%
November	16.7%	16.0%	5.7%
December	18.4%	14.6%	4.4%

The methodologies proposed in this work could be implemented with the objective of promoting investment in conventional and RES generation, by linking a RES target to a price cap. The results would then give an idea to the regulator and market players on what would be the optimal mix that would secure the supply of the future demand.

As they are methodologies that have been based on solving a particular problem of a country, it may not be suitable for other regions or countries. However, it would be interesting to test both methodologies in the context of a similar power system and market.

6.2 Discussion

This Section describes the relevance of these results to the Dominican Republic situation, and the implications of applying any of the two methodologies, as well as some issues that need to be solved before executing any of them.

Initially, it is recommended to apply Methodology B (MetB). Methodology A (MetA) dismisses the effect that the share of renewables would have in the determination of the

[11] These percentages are given by dividing the results of the capacity value [MW] in Table 11 by the resulting installed capacity of each technology.

price cap, so, it is more coherent to rely on MetB. The issue with MetB is that the price cap is higher than in MetA, and from a political or social perspective it may not be as well received as the price cap from MetA. Another benefit from MetB is that it is the one that guarantees the best level of reliability between both methodologies for the same RPS target.

Normally, setting an RPS is requiring that a minimum share of the demand is supplied by RES. Due to the situation in the Dominican Republic regarding the reliability of its system and the current low price cap, the increase in the share of renewables must be overseen with care. Hence, for what has been analyzed in this work, when defining an RPS target for the Dominican Republic, it is best to follow that specific percentage of production from RES. As the methodologies give the installed capacity needed to reach that specific target based on the solar and wind profiles, the regulator could base its mandate on requiring market agents to install the necessary RES capacity to reach the desired target for a period of time.

The generation activity is liberalized in the Dominican Republic. So, setting limits on the RES capacity to be built in the system may not be very well seen by its market players. Nevertheless, due to the imperfections that exist nowadays in the market, regulatory intervention is needed up to some extent. Even though, it is true that a great deal of the market inefficiencies has been caused by the different rules established by the regulator. In this sense, it has to be said that what it is looked for with the objectives of this work is to propose solutions to amend these rules, in order to complement the wholesale market, so it ensures security of supply. This can be included in the debate of needing or not needing regulatory intervention for the security of supply, as read in 12.1.1 of (Pérez-Arriaga et al., 2013).

Even when there is a limit on market agents regarding the RES capacity to be installed for a certain period, the installed capacity for these technologies can be brought onto the system and the market through auctions, which represents a competitive environment.

Concerning the investments on conventional generation, the results of these methodologies give an idea of what technologies are needed, which would then give an idea to the regulator and market players on what is the necessary conventional generation that would finally result if a decision is made with regards to the mandated RES generation.

Some issues need to be solved before applying these methodologies. As the generation that is producing during times of scarcity is going to be remunerated at a very high price, it is required that the scarcity caused by transmission outages is kept to a minimum possible. In the case of the Dominican Republic, it requires both a high investment in transmission infrastructure and a thoroughly planned transmission operation.

Similarly, there has to be a redefinition of the criteria that define 'peak hours.' As it is analyzed in 3.2.1, most periods where scarcity appears are out of the 'peak hours'. If the capacity payments of conventional generators are based on the remuneration of availability of the generators, it means that they should be available when the system needs them the most, i.e. when there is scarcity. Therefore, it is necessary to redefine the 'peak hours' as the hours where there is scarcity. This complementary measure would incentivize conventional generators to schedule better their programmed outages (e.g. maintenance), which comes as necessary when guaranteeing security of supply. In this regard, the unavailability that would be considered in the calculation of the firm offer of the conventional generators, would be that unavailability of those generators during periods where the market price would be equal to the price cap/cost of non-served energy.

Lastly, it is important to notice that the price cap is indexed to the price of the fuel oil (3.2.2). Consequently, to implement these methodologies, the increase should be made on the base price cap (US$56.375/MWh), and keep the same indexation formula.

For what has been explained briefly in this last two Sections, it can be said that the questions presented in 1.2 have been answered. Thus, The objectives of this work were reached. Two methodologies are proposed to solve the existent and future reliability problems in the Dominican Republic. Both justify the link between the growth of renewables and an increase of the price cap.

6.3 Recommendations for further research

A series of recommendations can be done with regards to the methodology, its implementation and the assessment of its results such as:

- **Developing a more robust model**. Even when a good data set of demand and wind and solar profiles was used (four years of hourly-data), a longer period is always better to use, e.g. 10 years. This would entail a more robust model and more computational requirements, in order to get more accurate results. Within this development, it can be assessed the possibility of including stochasticity. Although, using a considerable sample as in the case study (35,064 hours for load and RES profiles) or even a greater sample, could give satisfactory results even when a deterministic model as the proposed in this work is used to determine a probabilistic index.

- **Including hydroelectric generation in the modeling**. Dominican Republic has approximately 560 MW of hydro effective installed capacity, from which 90% of this capacity corresponds to hydro reservoirs, and the rest to run-of-the-river hydro plants, and no pumping units. The model does no consider any investment decisions with respect to hydro generation, so, the feasibility of including this decision in the model could be assessed.

- **Analyzing the impact on market prices**. As an estimated generation dispatch is gotten, there is also a way to estimate the market prices. For the case of the Dominican sector, it is not necessarily the shadow prices that result from the demand balance equation. There is what can be considered an uplift, as the market price is given by the most expensive generator that has available generation at the moment.

- **Including environmental impacts**. The approach followed by the proposed methodologies is focused on improving system reliability. Nevertheless, RES also have a positive impact on the environment. The influence of the increase of RES generation on emissions reduction could be included in the methodologies. Although, there are no mandatory targets for a reduction of emissions in the

Dominican Republic, setting a target for emissions could have an effect on the overall results if included on the methodologies.

- **Transmission investments**. The model could be adapted to include the decision over the necessary transmission investments. It already provides the location and the capacity to be installed. Thus, they can serve as inputs for the transmission investment decisions.

- **Running more scenarios**. It is of most importance to test various scenarios for different demand profiles, as well as solar and wind profiles. In the case study, both methodologies resulted in similar outcomes with regards to determining the "optimal" RPS. Nevertheless, it cannot yet be denied that this could be different in other specific demand scenarios, or with other wind and solar profiles.

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Chapter 8　APPENDIX

8.1 *Support data for determining fixed costs*[12] .

Table 1. Estimated levelized cost of electricity (LCOE) for new generation resources, 2019

	U.S. Average LCOE (2012 $/MWh) for Plants Entering Service in 2019							
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Subsidy[1]**	**Total LCOE including Subsidy**
Dispatchable Technologies								
Conventional Coal	85	60.0	4.2	30.3	1.2	95.6		
Integrated Coal-Gasification Combined Cycle (IGCC)	85	76.1	6.9	31.7	1.2	115.9		
IGCC with CCS	85	97.8	9.8	38.6	1.2	147.4		
Natural Gas-fired								
Conventional combined Cycle	87	14.3	1.7	49.1	1.2	66.3		
Advanced Combined Cycle	87	15.7	2.0	45.5	1.2	64.4		
Advanced CC with CCS	87	30.3	4.2	55.6	1.2	91.3		
Conventional Combustion Turbine	30	40.2	2.8	82.0	3.4	128.4		
Advanced Combustion Turbine	30	27.3	2.7	70.3	3.4	103.8		
Advanced Nuclear	90	71.4	11.8	11.8	1.1	96.1	-10.0	86.1
Geothermal	92	34.2	12.2	0.0	1.4	47.9	-3.4	44.5
Biomass	83	47.4	14.5	39.5	1.2	102.6		
Non-Dispatchable Technologies								
Wind	35	64.1	13.0	0.0	3.2	80.3		
Wind – Offshore	37	175.4	22.8	0.0	5.8	204.1		
Solar PV[2]	25	114.5	11.4	0.0	4.1	130.0	-11.5	118.6
Solar Thermal	20	195.0	42.1	0.0	6.0	243.1	-19.5	223.6
Hydroelectric[3]	53	72.0	4.1	6.4	2.0	84.5		

[12] U.S. Energy Information Agency and Lazard.

U.S. Average Levelized Costs (2013 $/MWh) for Plants Entering Service in 2020[1]

Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System LCOE	Subsidy[2]	Total LCOE including Subsidy
Dispatchable Technologies								
Conventional Coal	85	56.8	4.2	29.5	1.1	91.7		
Advanced Coal	85	69.1	6.9	28.4	1.1	105.5		
Advanced Coal with CCS	85	84.9	9.8	31.8	1.2	127.6		
Natural Gas-fired								
Conventional Combined Cycle	87	13.7	1.7	66.0	1.2	82.6		
Advanced Combined Cycle	87	14.3	2.0	61.9	1.2	79.3		
Advanced CC with CCS	87	25.8	4.2	75.2	1.2	106.3		
Conventional Combustion Turbine	30	38.4	2.8	110.3	3.4	154.9		
Advanced Combustion Turbine	30	24.1	2.7	88.4	3.4	118.6		
Advanced Nuclear	90	62.5	11.8	13.5	1.1	88.9		
Geothermal	94	38.2	21.2	0.0	1.4	60.8	-3.8	56.9
Biomass	83	43.0	14.5	34.8	1.2	93.5		
Non-Dispatchable Technologies								
Wind	35	58.9	13.0	0.0	3.1	75.1		
Wind – Offshore	38	147.4	22.5	0.0	5.7	175.6		
Solar PV[3]	25	101.8	11.4	0.0	4.1	117.3	-10.2	107.1
Solar Thermal	20	165.6	42.1	0.0	5.9	213.6	-16.6	197.1
Hydroelectric[4]	52	76.1	4.4	7.3	2.0	89.9		

Source: World Bank, IHS Waterborne LNG, Department of Energy of South Africa, Sydney and Brisbane Hub Trading Prices and Lazard estimates.

(a) Low end assumes a solar fixed-tilt utility-scale system with per watt capital costs of $1.50. High end assumes a solar rooftop C&I system with per watt capital costs of $3.00. Solar projects assume capacity factors of 26% – 28% for Australia, 25% – 27% for Brazil, 23% – 25% for India, 27% – 29% for South Africa, 15% – 17% for Japan and 13% – 15% for Northern Europe. Equity IRRs of 12% are assumed for Australia, Japan and Northern Europe and 18% for Brazil, India and South Africa; assumes cost of debt of 8% for Australia, Japan and Northern Europe, 14.5% for Brazil, 13% for India and 11.5% for South Africa.

(b) Assumes natural gas prices of $7 for Australia, $16 for Brazil, $15 for India, $15 for South Africa, $17 for Japan and $10 for Northern Europe (all in U.S.$ per MMBtu). Assumes a capacity factor of 10%.

(c) Diesel assumes high end capacity factor of 30% representing intermittent utilization and low end capacity factor of 95% representing baseload utilization, O&M cost of $15 per KW/year, heat rate of 10,000 Btu/KWh and total capital costs of $500 to $800 per KW of capacity. Assumes diesel prices of $5.80 for Australia, $4.30 for Brazil, $4.00 for India, $4.65 for South Africa, $5.40 for Japan and $7.40 for Northern Europe (all in U.S.$ per gallon).

7 | LAZARD

8.2 Support data for ramping constraints and start-up costs[13].

Parameters \ Type of unit	Minimal generation level (% of Pmax)	Positive load gradient (% of Pmax)	Negative load gradient (% of Pmax)	Starting cost (€/MW)	Off-state minimal duration (h)[4]	Efficiency (%) @Pmin/@Pmax
OCGT - prevailing	50%	8%/min	8%/min	30	<1	27% / 36%
OCGT- state of the art	40%	12%/min	12%/min	21	<1	32% / 42%
Oil fired	50%	8%/min	8%/min	30	1	26% / 35%
CCGT - oldest	50%	2%/min	5%/min	45	2	40 / 49%
CCGT - prevailing	50%	2%/min	5%/min	41	2	48% / 57%
CCGT – state of the art	40%	4%/min	5%/min	33	2	52% / 61%
Hard Coal Power Plant – prevailing	40%	2%/min	5%/min	65	6	36% / 42%
Hard Coal Power Plant – state of the art	25%	4%/min	5%/min	50	4	41% / 46%
Lignite Power Plant – prevailing	50%	2%/min	5%/min	25	6	34% / 38%
Lignite Power Plant – state of the art	50%	2%/min	5%/min	25	4	38% / 42%
Nuclear Power Plant	40%	5%/min 7% Rmax	5%/min 7% Rmax	24	No off-state modelled	7,4€/MWh
Hydro turbine (lakes and PHS)	60%[5]	Not constrained	Not constrained	0	<1	90%[6]
Biomass steam turbine	20%	4%/min	5%/min	36	1	33% / 36%

Table 1 - Technological data

[13] METIS project - (European Commission Artelys, 2016)

8.3 Conventional mix data.

Plant	Fuel Type	Technology	Technology-GAMS	Installed Capacity
HAINA TG	FUEL # 2	Turbinas a Gas	GASTFO	100
BARAHONA CARBON	COAL	Turbinas a Vapor	COALST	45.6
SULTANA DEL ESTE	FUEL # 6	Motor combustión interna	FUOENG	85
QUISQUEYA 2	FUEL # 6	Motor combustión interna	FUOENG	215
ITABO 1	COAL	Turbinas a Vapor	COALST	128
ITABO 2	COAL	Turbinas a Vapor	COALST	132
CESPM 1	FUEL # 2	Ciclo Combinado	CCGTFO	100
CESPM 2	FUEL # 2	Ciclo Combinado	CCGTFO	100
CESPM 3	FUEL # 2	Ciclo Combinado	CCGTFO	100
PIMENTEL 1	FUEL # 6	Motor combustión interna	FUOENG	31.6
PIMENTEL 2	FUEL # 6	Motor combustión interna	FUOENG	28
PIMENTEL 3	GAS Y FUEL #6	Motor combustión interna	FUOENG	51.6
ESTRELLA DEL MAR 2	GAS Y FUEL #6	Motor combustión interna	FUOENG	108
PALAMARA	FUEL # 6	Motor combustión interna	FUOENG	107
LA VEGA	FUEL # 6	Motor combustión interna	FUOENG	92
CEPP 1	FUEL # 6	Motor combustión interna	FUOENG	18.7
CEPP 2	FUEL # 6	Motor combustión interna	FUOENG	58.1
LOS MINA 5	GAS	Turbinas a Gas	GASTNG	118
LOS MINA 6	GAS	Turbinas a Gas	GASTNG	118
AES ANDRES	GAS	Ciclo Combinado	CCGTNG	319
MONTE RIO	FUEL # 6	Motor combustión interna	FUOENG	100.1
METALDOM	FUEL # 6	Motor combustión interna	FUOENG	42
INCA KM22	FUEL # 6	Motor combustión interna	FUOENG	14.2
BERSAL	FUEL # 6	Motor combustión interna	FUOENG	25.2
LOS ORIGENES	FUEL # 6 y GAS	Motor combustión interna	FUOENG	60.69
SAN FELIPE	FUEL # 6 Y #2	Ciclo Combinado	CCGTFO	185
QUISQUEYA 1	FUEL # 6	Motor combustión interna	FUOENG	215

Plant	Effective Capacity LV	Losses	Effective Capacity HV	Minimum Output	VC (RD$/MWh)	VC (US$/MWh)
HAINA TG	99.8	0.35	99.45	60.00	11,416.20	244.36
BARAHONA CARBON	42.4	0.05	42.35	41.00	1,898.32	40.63
SULTANA DEL ESTE	66.8	0.34	66.46	34.00	3,240.76	69.37
QUISQUEYA 2	220.9	4.16	216.74	66.00	3,172.82	67.91
ITABO 1	117	0.43	116.57	94.00	1,301.44	27.86
ITABO 2	110	0.49	109.51	100.00	1,196.66	25.61
CESPM 1	96.3	0.35	95.95	65.00	4,146.13	88.75
CESPM 2	98.4	0.35	98.05	65.00	3,830.27	81.99
CESPM 3	99.6	0.35	99.25	65.00	3,889.99	83.26
PIMENTEL 1	30.8	0.09	30.71	7.90	3,364.74	72.02
PIMENTEL 2	27.5	0.07	27.43	7.00	3,302.44	70.69
PIMENTEL 3	50.4	0.11	50.29	17.06	3,162.18	67.69
ESTRELLA DEL MAR 2	108.6	0.34	108.26	49.00	2,631.82	56.33
PALAMARA	103	0.14	102.86	21.20	3,513.25	75.20
LA VEGA	87.5	0.34	87.16	13.85	3,421.58	73.24
CEPP 1	16.2	0.03	16.17	4.48	3,602.33	77.11
CEPP 2	49	0.06	48.94	11.00	3,436.49	73.56
LOS MINA 5	118	0	118.00	60.00	2,463.35	52.73
LOS MINA 6	118	0	118.00	60.00	2,562.01	54.84
AES ANDRES	281.3	0.73	280.57	150.00	1,719.65	36.81
MONTE RIO	96.6	0.17	96.43	45.00	3,294.08	70.51
METALDOM	40.7	0.12	40.58	10.50	3,326.48	71.20
INCA KM22	14.2	0.03	14.17	1.57	3,415.95	73.12
BERSAL	23.9	0.08	23.82	6.00	3,520.55	75.36
LOS ORIGENES	57.3	0.27	57.03	14.00	3,160.22	67.64
SAN FELIPE	176.4	0	176.40	132.00	4,395.63	94.09
QUISQUEYA 1	122	0	122.00	122.00	3,172.82	67.91

8.4 *GAMS sets, scalars and parameters.*

```
SETS

p
/p1*p35064/
g                    Generators
/
COALST
CCGTNG
GASTNG
FUOENG
CCGTFO
GASTFO
WIND1
WIND2
SOLAR1
SOLAR2
/
year
/
2013
2014
2015
2016
/
```

```
SETS
t(g)                 Thermal Generators (Fossil)
/
COALST
CCGTNG
GASTNG
FUOENG
CCGTFO
GASTFO
/
w(g)                 Wind Generation
/
WIND1
WIND2
/
s(g)                 Solar Generation
/
SOLAR1
SOLAR2
/
```

```
SCALARS
pc                   non-served energy cost (US$ per MWh)
/
106.79
/
RPS                  Renewable Portfolio Standard
/
0.1
/
```

PARAMETERS					
fc(g)	**Annualized Investment cost for generator g [US$ per MW per year]**				
/		Cap.Fac(%)	LvCapCost	FxO&M	Tx Inv
COALST	486223.8	85%	60	4.2	1.1
CCGTNG	131084.64	87%	14.3	1.7	1.2
GASTNG	121939.2	30%	40.2	2.8	3.4
FUOENG	157680	30%	57.1	1.7	1.2
CCGTFO	131084.64	87%	14.3	1.7	1.2
GASTFO	121939.2	30%	40.2	2.8	3.4
WIND1	197100	30%	58.9	13	3.1
WIND2	197100	30%	58.9	13	3.1
SOLAR1	205509.6	20%	101.8	11.4	4.1
SOLAR2	205509.6	20%	101.8	11.4	4.1
/					
vc(g)	**Variable cost for generator g [US$ per MWh]**				
/					
COALST	31.37				
CCGTNG	36.81				
GASTNG	53.78				
FUOENG	70.55				
CCGTFO	87.02				
GASTFO	244.36				
/					

```
PARAMETERS
su(g)          Start-up cost for generator g [US$ per MW]
/
COALST         65.00
CCGTNG         41.00
GASTNG         30.00
FUOENG         30.00
CCGTFO         41.00
GASTFO         30.00
/


FORate(g)      Forced outage rate
/
COALST         0.059
CCGTNG         0.0505
GASTNG         0.1282
FUOENG         0.2244
CCGTFO         0.1079
GASTFO         0.1079
/

AF(g)          Availability factor due to maintenance
/
COALST         0.8621
CCGTNG         0.8909
GASTNG         0.8651
FUOENG         0.9436
CCGTFO         0.8525
GASTFO         0.8525
/
```

PARAMETERS

ru(g)	**Upward ramp of thermal groups [proportion of maximum capacity - % per hour]**
/	
COALST	1.20
CCGTNG	1.20
GASTNG	4.80
FUOENG	4.80
CCGTFO	4.80
GASTFO	4.80
/	
rd(g)	**Downward ramp of thermal groups [proportion of maximum capacity - % per hour]**
/	
COALST	3.00
CCGTNG	3.00
GASTNG	4.80
FUOENG	4.80
CCGTFO	4.80
GASTFO	4.80
/	

PARAMETERS

xmax(g)	**Maximum effective installed capacity of g [MW]**
/	
COALST	268.4
CCGTNG	280.6
GASTNG	236.0
FUOENG	1109.1
CCGTFO	469.7
GASTFO	99.5
WIND1	330.0
WIND2	330.0
SOLAR1	154.0
SOLAR2	154.0
/	
eminp(g)	**Proportion minimum output of generator g [MW]**
/	
COALST	0.875
CCGTNG	0.535
GASTNG	0.508
FUOENG	0.388
CCGTFO	0.696
GASTFO	0.603
/	

PARAMETERS	
d(p)	**Demand of the system in period p [MW]**
/	
p1	1277.166007
p2	1328.54428
p3	1257.49146
p4	1200.492749
p5	1177.548906
p6	1160.030097
p7	1130.185837
p8	1044.718724
p9	1024.363386
p10	1100.117994
p11	1162.687397
p12	1200.300075
p13	1178.985022
p14	1155.663581
p15	1120.509276
p16	1100.091391
p17	1066.455399
p18	1086.94679
p19	1189.180727
p20	1287.389897
p21	1282.958617
p22	1242.409774
p23	1179.214993
p24	1110.749175
	***
p35041	1397.935676
p35042	1287.695982
p35043	1163.054174
p35044	1079.048838
p35045	1035.733824
p35046	1002.116992
p35047	994.8628693
p35048	959.9819274
p35049	1045.361923
p35050	1150.690909
p35051	1223.387829
p35052	1262.045338
p35053	1386.003393
p35054	1357.137206
p35055	1342.947661
p35056	1341.870232
p35057	1282.939255
p35058	1230.420846
p35059	1330.864019
p35060	1386.475885
p35061	1300.860997
p35062	1226.297911
p35063	1180.504673
p35064	1114.890439
/	

PARAMETERS	
solp1(p)	**solar profile 1**
/	
p1	0.00
p2	0.00
p3	0.00
p4	0.00
p5	0.00
p6	0.00
p7	0.00
p8	0.00
p9	0.19
p10	0.36
p11	0.44
p12	0.41
p13	0.37
p14	0.26
p15	0.11
p16	0.02
p17	0.00
p18	0.00
p19	0.00
p20	0.00
p21	0.00
p22	0.00
p23	0.00
p24	0.00
	***
p35041	0.00
p35042	0.00
p35043	0.00
p35044	0.00
p35045	0.00
p35046	0.00
p35047	0.00
p35048	0.00
p35049	0.06
p35050	0.12
p35051	0.14
p35052	0.14
p35053	0.17
p35054	0.12
p35055	0.05
p35056	0.00
p35057	0.00
p35058	0.00
p35059	0.00
p35060	0.00
p35061	0.00
p35062	0.00
p35063	0.00
p35064	0.00
/	

PARAMETERS	
solp2(p)	**solar profile 2**
/	
p1	0.00
p2	0.00
p3	0.00
p4	0.00
p5	0.00
p6	0.00
p7	0.00
p8	0.00
p9	0.02
p10	0.08
p11	0.08
p12	0.09
p13	0.08
p14	0.06
p15	0.02
p16	0.00
p17	0.00
p18	0.00
p19	0.00
p20	0.00
p21	0.00
p22	0.00
p23	0.00
p24	0.00
	***
p35041	0.00
p35042	0.00
p35043	0.00
p35044	0.00
p35045	0.00
p35046	0.00
p35047	0.00
p35048	0.00
p35049	0.00
p35050	0.03
p35051	0.06
p35052	0.08
p35053	0.09
p35054	0.07
p35055	0.03
p35056	0.00
p35057	0.00
p35058	0.00
p35059	0.00
p35060	0.00
p35061	0.00
p35062	0.00
p35063	0.00
p35064	0.00
/	

PARAMETERS	
windp1(p)	**wind profile 1**
/	
p1	0.38
p2	0.44
p3	0.50
p4	0.59
p5	0.68
p6	0.78
p7	0.83
p8	0.86
p9	0.86
p10	0.87
p11	0.87
p12	0.87
p13	0.86
p14	0.86
p15	0.83
p16	0.82
p17	0.81
p18	0.78
p19	0.79
p20	0.76
p21	0.68
p22	0.62
p23	0.55
p24	0.51

***

p35041	0.78
p35042	0.73
p35043	0.67
p35044	0.59
p35045	0.48
p35046	0.36
p35047	0.32
p35048	0.29
p35049	0.29
p35050	0.30
p35051	0.27
p35052	0.23
p35053	0.23
p35054	0.14
p35055	0.10
p35056	0.09
p35057	0.08
p35058	0.07
p35059	0.08
p35060	0.06
p35061	0.05
p35062	0.05
p35063	0.04
p35064	0.03
/	

PARAMETERS	
windp2(p)	**wind profile 2**
/	
p1	0.49
p2	0.60
p3	0.64
p4	0.66
p5	0.65
p6	0.64
p7	0.59
p8	0.52
p9	0.51
p10	0.51
p11	0.52
p12	0.53
p13	0.52
p14	0.53
p15	0.56
p16	0.62
p17	0.66
p18	0.68
p19	0.62
p20	0.63
p21	0.61
p22	0.59
p23	0.60
p24	0.62
	***
p35041	0.45
p35042	0.44
p35043	0.44
p35044	0.45
p35045	0.45
p35046	0.45
p35047	0.45
p35048	0.43
p35049	0.41
p35050	0.41
p35051	0.45
p35052	0.47
p35053	0.43
p35054	0.44
p35055	0.42
p35056	0.44
p35057	0.47
p35058	0.49
p35059	0.52
p35060	0.52
p35061	0.53
p35062	0.55
p35063	0.55
p35064	0.54
/	