Abstract: This paper proposes a set of indicators to quantify the impact of conventional thermal generating unit cycling on its non-fuel variable costs (NFVC) due to generation mix changes in the system. A novel iterative cost adjustment framework is developed to evaluate the proposed indicators in order to assess the impacts of increasing installation of renewable resources on operation costs of the thermal units. The proposed framework allows private investors to estimate NFVC using a minimum level of information without a full knowledge of the system parameters. Additionally, the proposed framework is kept generic, which supports the NFVC adjustment for the conventional thermal units in a changing market environment. The impact of accelerated solar photovoltaic penetration on cycling and operational costs of existing thermal power plants in the Chilean power system is assessed using the indicators and methodology developed. The results suggest that natural gas driven peaking power plants are more susceptible to experiencing increased NFVC from solar photovoltaic growth than coal fired base load power plants.

Keywords: thermal generator; solar photovoltaic; operation costs; unit commitment; generator ageing; cycling

1. Introduction

Generation resources in modern power systems are composed of capacity and energy resources due to the introduction of renewable energy conversion technologies to reduce the environmental stresses created by conventional fossil fueled power plants [1]. Capacity resources in the power system are those generation plants which can be dispatched to meet the demand for power and energy simultaneously [2]. Although the energy resources can deliver a certain amount of energy over a period, the interim instantaneous power level is not guaranteed. Hence, the capacity resources are essential to support the energy resources in maintaining the supply adequacy of the system.

Nowadays, wind turbines and solar photovoltaics (PV) are the renewable energy technologies with largest growth rates, accounting up to 487 and 303 GW of installed capacity worldwide by the end of 2016, respectively [3]. It is expected that both energy resources will continue to grow significantly within the electric power systems in upcoming years. Nevertheless, although renewable energy is a low greenhouse emission alternative for electricity generation, its integration affects the operation of the remaining conventional generators (capacity resources) on the power system, due to their variability and uncertainty [4]. Several studies have shown that variable renewable generation such as wind and solar photovoltaic (PV) may cause an increase of the so called conventional generators cycling: start-stop, operation at partial load, ramping and load following [5–7]. The usual measures for
cycling are EHS (Equivalent Hot Start), EOH (Equivalent Operating Hours), Cycling rate and EFOR (Equivalent Forced Outage Rate) [5,7–9], and plant capacity factor [6]. The methodology proposed in [7] can estimate increasing start-up costs of base load units due to increasing wind penetration. In [6], an investigation is carried out to assess the impact of wind penetration on capacity factor and start-up cost of thermal plants which represent capital investment and variable fuel costs. Escalation in the operating and maintenance (O&M) cost of the thermal generators fleet is observed due to the frequent cycling operations [5]. Although the possible increase in the O&M costs components are presented in [5], change in these costs for a particular type of thermal unit cannot be predicted without prior information regarding the expected operation of the unit in the system environment.

In general, thermal operating cost can be divided in three main categories: (1) fuel start-up costs: (2) energy production costs: and (3) operation and maintenance costs (O&M), as shown in Figure 1. In particular, O&M costs are composed of two components: (i) a fixed part that includes minor periodic maintenances, wages, property taxes, facility fees, insurances and overheads; and (ii) a variable component related to periodic replacements, major overhaul maintenances and repairs that are triggered after meeting certain operating conditions (e.g., certain number of starts, equivalent operating hours, firing hours or a combined approach between number of starts and operating hours) [9]. All three of these components of thermal operating costs are affected by the cycling frequency of their operation, which is directly related to the penetration scales of variable energy resources such as wind and solar power [5,8,10,11].

Cycling operation performed by conventional generators makes internal components, such as boilers, steam lines, turbine, and auxiliary components, go through thermal and pressure stresses, which may cause damage. The level of damage produced depends on several characteristics that are particular for each generator and technology [12]. Hence, the cycling operation of conventional generators leads to frequent maintenance activities which impose higher O&M costs for the plant owner. Maintenance costs due to escalated wear and tear of the machines affects the variable component of the O&M costs of conventional power plants defined as the non-fuel variable costs (NFVC) due to the increase in frequency of major overhauls [9]. In power markets with mandatory pool structures, such as Chile, Peru, and Panama, the frequent cycling effects are reflected explicitly in an increase of the linear component of variable costs (associated with NFVC as depicted from Figure 1). On the other hand, in power markets with non-mandatory pool structure (e.g., power exchanges in Europe, NordPool, etc.) these effects are reflected implicitly on the prices offered.

The marginal generation costs of conventional thermal power plants directly depend on the thermal operation costs, which are functions of fixed costs and variable costs. Therefore, with the presence of significant renewables-based generation systems in the power system, marginal generation costs of conventional thermal units will depend on both fuel costs and variable energy resource penetration level. This phenomenon brings uncertainty for conventional power plant operation,
planning, and investment decisions. Thus, in order to stay competitive in the electricity market, utilities need a better understanding of the nature of their variable costs and cycling operation consequences under this foreseen, more variable scenario [13,14].

In recent years, a considerable number of studies have assessed the impact of renewable generation penetration on power systems. In particular, effects of wind and solar PV over remaining conventional generators in the power system are highlighted in [5,7,11]. Additionally, several studies have aimed to quantify the impacts of cycling operation in thermal generators [8,10]. In general, these studies have used methodologies that require intensive use of historical data and models to estimate the additional costs of cycling operation. On the other hand, complex studies are required to endogenize this problem and tackle it from a perspective of centralized planning.

Approximated financial assessments are often required by the private and/or public investors and system operators to analyze the performance of thermal power plants in an uncertain future market environment. A detailed study for such assessment requires a large number of complex market simulations based on technical and market data, including a detailed assessment of thermal plants costs, particularly the O&M component, which is normally nonpublic. However, an accurate study may not be necessary nor efficient for screening purpose, and to realize inside mechanism for future energy cost in the market. Hence, a framework that permits an approximate and efficient assessment of the financial impacts of future market structure on the thermal power plant operation with the minimum amount of system information is desired.

The information requirement depends on the type of analysis, simulation tool used, market structure, and system operation strategy. The conventional generation dispatch scheduling requires specific and exact system data, such as the detailed and specific information of financial and thermal model of individual generating units, transmission network operation principles, high resolution demand, weather data, and so on. However, for screening purposes, decision makers require approximated values with less detailed information about the system parameters. Therefore, the minimum information required to estimate approximated change in non-fuel variable costs (NFVC) using the proposed methodology for a mandatory pool-based energy market are operating cost, ramp rates and capacity of a sample generating unit from each cluster, size and number of generating units in the system, data of additional maintenance requirements for units from each generation technology or cluster, basic market operation principles, topology and line capacity of transmission network, and forecasted weather and demand data.

Based on the aforementioned context, this paper aims to present a novel and practical methodology to analyze and quantify the impacts of renewable energy penetration on conventional generators’ variable operation costs. The methodology developed can capture the numerical impact on NFVC due to cycling of thermal power plants. The NFVC is adjusted using iterative technique based on the cycling operation record of thermal power plants. Clustering of generation unit families is proposed to reduce the volume of system level information requirement for the impact assessment. The proposed framework can be adopted in different energy markets, such as mandatory and non-mandatory pool structures, with the appropriate market simulation tool for the corresponding market. One of the important features of the method developed is the requirement for the minimum amount of system information to estimate the impact on operation costs. The framework and analysis is illustrated from the perspective of an investor in new thermal power plants, but the key findings of the present study are also relevant for decisions makers like system operators and policy makers.

This paper is organized as follows: Section 2 presents a brief review on thermal plant cycling and description of the indicators to analyze and quantify cycling operation effects over thermal generators proposed by the study. Section 3 details the proposed methodology. Section 4 exposes the case study characteristics. Section 5 presents the obtained results. Finally, Section 6 summarizes the conclusions and future work.
2. Quantification of Cycling

Conventional generation plants are dispatched by the system operator in order to keep the load-generation balance at the minimum cost while complying with the security standards. Due to zero variable cost and clean energy, wind and solar PV generation usually reduce energy generation from conventional thermal generation plants which are expensive and causing environmental pollutions. In absence of renewable energy resources, the conventional plants are operated to follow the variability in electricity demand, scheduled and emergency outage of the network components. However, due to the uncertainty in availability of wind and solar PV generation, the thermal generators experience additional variability in operation and are forced to go through increased cycling. The increased cycling of conventional thermal power plants due to renewable energy resources includes operations like frequent shut down and start up events, variations in loading, ramping up and down, and operation at partial load [5,7].

The escalated cycling operations of thermal power plants raises the operating costs including variable fuel costs [10]. Additionally, the equipment of the thermal generators experience creep, fatigue, erosion wear, vibration and other related phenomena incurring more frequent maintenance requirements [12]. According to [8] there are several key drivers that cause the cycling related maintenance activities and associated costs to vary among different units such as:

(a) Maintenance related activities,
(b) Equipment design and manufacturer,
(c) Vintage of technology,
(d) Turbine design and pressure,
(e) Fuel type and quality,
(f) MW capacity,
(g) Age,
(h) Time between an off and on cycle,
(i) Plant configuration, size, economies of scale, and scope.

Therefore, increasing the level of cycling will cause the thermal power plant to experience higher variable operating expenditure not only in fuel but also in the O&M costs. The impact on the variable fuel costs of such plants due to the integration of variable generation systems based on renewable resources and cycling operations is presented and analyzed in [10]. However, the influences of cycling operation due to increasing penetration of renewable resources in the power systems on the hidden variable O&M costs is not quantified and analyzed explicitly in relevant studies. For example, in [8,12] the large variations in cycling and related costs for a wide range of thermal power plants are presented. However, the model of variable O&M costs due to cycling cannot be found in the existing reported literature. In electricity markets with mandatory pool structures the costs associated with major overhauls of conventional units are directly related to the non-fuel variable cost component of the thermal operational costs. Hence, the variable O&M costs of a thermal power plant due to cycling operations from increasing penetration of renewable resources in the grid requires precise evaluation.

The maintenance activities of a thermal power plant are generally conducted on a regular basis after a certain number of operating hours, unless an emergency outage is experienced (this includes partial or complete overhauls at specified periods, oil changes, lubrication, equipment adjustments). Therefore, the impact of thermal power plant cycling on its variable O&M costs is to be modeled using the operating hour approach. The aging and maintenance requirement of a thermal power plant depends on the number of start events, operating hours and ramping up/down, which result from the cycling operation mode. Based on the state of the art in this subject, to analyze and quantify cycling operation effects over thermal generators, the present study proposes Equivalent Operating Hours (EOH) as the indicator.

Equivalent Operating Hours (EOH) is frequently used for some power plant manufacturers to quantify the equivalent wear of a specific generation unit for a given operation mode, measured...
in terms of the number of operating hours (or firing hours, understood as the sustained hours of operation) start-up and load following events. The proposed EOH definition for a thermal power plant is a linear weighted average of the operational indicators: number of starts (NS), operating hours (OH) and load following operations (LF) as shown in (1).

\[ EOH = \alpha \times NS + \beta \times OH + \gamma \times LF \]  

(1)

where, \( \alpha \), \( \beta \) and \( \gamma \) are the weighing factors to estimate EOH and depend on each generation unit type, but also depends on the maintenance conditions agreed with the plant manufacturer [9]. The weighting factors \( \alpha \), \( \beta \) and \( \gamma \) convert the NS, OH and LF to equivalent operating hours for maintenance purposes and their values can be estimated from historical data or experience in thermal unit operation. For example, \( \alpha \) represents the hours of operation which produces equivalent thermal stress and wears experienced by the thermal unit from each start-up process. The operational indicators NS, OH and LF are expressed using (2) to (7) as presented:

a. Number of starts: Number of times that one specific thermal generator is turned ‘ON’ during the analyzed time frame. NS is estimated using (2) and (3) as follows.

\[ NS = \sum_{t=2}^{T} Z_t \]  

(2)

\[ Z_t = \begin{cases} 
1, & \text{for } X_{t-1} = 0 \cap X_t > 0 \\
0, & \text{otherwise}
\end{cases} \]  

(3)

where, \( X_t \) is the output power of a thermal generator during time \( t \) and the analyzed time frame is \( T \). \( Z_t \) is the integer variable to indicate start of a thermal unit as shown in (3).

b. Operating hours: Number of hours that one specific thermal generator is ‘ON’ during the analyzed time frame. OH can be estimated using (4) and (5) as follows.

\[ OH = \sum_{t=1}^{T} W_t \]  

(4)

\[ W_t = \begin{cases} 
1, & \text{if } X_t > 0 \\
0, & \text{otherwise}
\end{cases} \]  

(5)

where, \( W_t \) is the integer variable to indicate that a thermal unit is in operation as shown in (5).

c. Load following: Variations on the output power of one specific thermal generator between two consecutive instants (expressed as percentage). Moreover, the related ancillary service is the instantaneous following of system load, including picking up load ramp between scheduling steps and maintaining the frequency of electricity within the required tolerance. The expressions for computing LF are presented in (6) and (7).

\[ LF = \sum_{t=1}^{T} LF_t \]  

(6)

\[ LF_t = \frac{|X_{t+1} - X_t|}{P_{\text{max}} - P_{\text{min}}} \times 100\% \quad t \in [1, T - 1] \]  

(7)

where, \( P_{\text{max}} \) and \( P_{\text{min}} \) are the maximum and minimum allowed output power level of the thermal generator.
3. Proposed Methodology

Operational data of the plant, scenario of renewable penetration scenarios, and indicators are endogenous to the cycling impact assessment of thermal generation plants due to the increasing penetration of renewable resources in power system. Hence, an iterative framework is proposed to generate the required data and indicators for assessing the impact as discussed in the following subsection. The distinguished features of the developed algorithm are as follows:

- Utilization of less detailed information, such as individual generating units parameters for operating costs, but with realistic results.
- Permits the use of any market operation simulating tool that is suitable for the structure of the market under analysis.
- To allow a systematic analysis for the type of technologies rather than one specific project.

3.1. Estimation of Indicators

A general flow diagram of the proposed methodology is presented in Figure 2. In the first place, it is initiated by gathering all necessary data and system information related to the power system to be simulated, such as: generation mix, generation variable costs, hydrology, demand, technical parameters of units, renewable hourly profiles, among others. With this information, the definition of a reference year scenario is established. This scenario can be defined based on projections developed by the system operator, regulator or a specific interest group.

Additionally, since it is desired to assess the related effects of wind and solar PV penetration levels and thermal power plants’ O&M costs, it is essential to define different scenarios with various penetration levels that reflect alternative expectations. Usually, expert criteria of decision takers are used for the scenario definitions. It is important to note that the variation in other relevant system parameters, like interconnections, topological changes, fuel prices, and so on, should be treated consistently as a parallel study. In this case, more than one reference scenario should be considered.

![Figure 2](image_url)

Figure 2. Steps in the proposed methodology.
In the following step, all scenarios are simulated independently using Yearly Simulation Tool [15] which provides the dispatched levels of the individual generator in the system. A centralized cost minimization approach in the Unit Commitment (UC) program is proposed for the Yearly Simulation Tool in case of mandatory pool structure-based market structure. The conventional generation unit scheduling tool for a different energy market can also be adopted as the Yearly Simulation Tool. Alternatively, a more sophisticated market simulation tool for the whole year can be used in this step (i.e., application of complex optimization techniques along with detailed market operation requirements). A finer time step and sophisticated market simulation tool will improve the accuracy of the result at the cost of the simulation time requirement. For example, the application of sequential Monte Carlo Simulations and UC tool with stochastic optimization technique will give more accurate operation of the units in the system. The Yearly Simulation Tool provides the operational data for the next step to estimate the indicators and costs.

It is important to note that before running the Yearly Simulation Tool (i.e., \( \text{itt} = 1 \), where \( \text{itt} \) refers to iteration number), an assumption on fuel and non-fuel variable costs of the conventional unit park is made. After the operation of the power plants is simulated in the first iteration (\( \text{itt} = 1 \)), verification of previous assumption is performed. This analysis could, for instance, require that the linear component of the variable cost of a combined cycle plant is changed from \( X \) to \( Y \) USD/MWh. It is possible when the resulting operating pattern deviates from initial assumption (i.e., assumption made in \( \text{itt} - 1 \)). Such variations in generation costs and hence the energy offered price may have impact on the unit commitment decision. Therefore, the energy price or cost model in the Yearly Simulation Tool is to be adjusted accordingly. If adjustment in cycling parameters is required, a new yearly simulation of the corresponding scenario should be carried out (i.e., \( \text{itt} = \text{itt} + 1 \) and \( \text{itt} > 1 \)) as shown in Figure 2. This iteration is integrated into the methodology in order to mimic what would happen in real market operation. It is likely that the cost of the generation will be adjusted by the unit owners once the cycling pattern changes from what was assumed first, which will therefore impact the market clearing outcome. This market condition is adopted by using the proposed iterative adjustment of the parameters for the yearly simulation.

Once the simulation of all scenarios for the target years is performed, an evaluation of various indicators (detailed in Section 2) is carried on for further analysis. Finally, based on the evaluation of each indicator (\( NS, OH, LF, EOH \)), several analyses are performed to estimate the impact of renewable variable generation in the expected generation costs of conventional units. The results constitute the basis for a risk analysis carried out by decision takers.

3.2. Clustering of Power Plants

The indicators obtained from simulations are analyzed in order to assess the cycling impact of increasing renewable energy resources on the operation costs of thermal power plants. Although the analysis can be performed for an individual generation unit in the system, the definition of clusters for different base technologies is suggested to reduce the computational burden and requirement for detailed information. There could be a number of ways form clusters such as based on the technologies, fuels, locations, capacities, among others. One of the convenient options for clustering could be fuel type; for instance, coal and natural gas plants can form two different clusters for the purpose of operation cost variation investigation. The additional benefit of clustering the plants is that less information is required for the desired initial assessment. Analysis considering each individual plant will require specific data of all the power plants in the systems and it is extremely challenging to manage such data for the plants with new technologies. Therefore, generalized conclusions regarding the impact on the system operation can be achieved with reasonable accuracy by applying clustering method. The indicators (\( NS, OH, \) and \( LF \)) defined for each unit can be re-calculated for each cluster. These results are then fed in the new calculation of \( EOH \) for each cluster.
3.3. Non-Fuel Variable Cost Assessment

Additional indicators are required to be evaluated for assessing the cycling impact of increasing renewable energy resources on the operation costs of thermal power plants. It is apparent from (1) that the computation of $EOH$ involves $NS$, $OH$, and $LF$, along with the weighing factors $\alpha$, $\beta$ and $\gamma$. On the other hand, $\alpha$, $\beta$ and $\gamma$ parameters depend on the characteristics of each unit and contractual agreements with manufacturers, which usually correspond to non-public available data. Therefore, a sensitivity analysis for the parameters $\alpha$, $\beta$ and $\gamma$ is suggested as described in Section 4.3.

Once all indicators and all sensitivities for each cluster are calculated, a systematic analysis of the results is proposed. In relation to the analysis to be performed, it is essential to count with an approximation of the total amount of equivalent operating hours to reach one complete major overhaul cycle, as well as the total costs associated to these major overhauls. Given this, the non-fuel variable costs ($NFVC$) for each unit in a given scenario, are calculated as:

$$NFVC = \frac{MO_{cost}}{EOH} \cdot \frac{EOH}{AE}$$

(8)

where, $MO_{cost}$ is the major overhaul costs that should be incurred after reaching a number of operating hours $EOH$. $AE$ is the annual energy generated by the unit or cluster, and the $EOH$ is the estimation of the equivalent operating hours that is consistent with $AE$ and the operating profile, which is estimated using Equation (1). It is important to note that due to $MO_{cost}$, $EOH$, and $EOH$, the value of $NFVC$ in (8) is highly dependent on the type and size of thermal power plants. This is because major overhaul costs $MO_{cost}$ for different types of thermal plant vary largely, for example, overhaul costs for a steam turbine unit is much higher than that of the gas turbine unit. The dispatch and start of the generating units in a system depends on the fuel cost, plant type, and size. $EOH$ and $AE$ of thermal unit depend on the unit commitment and dispatch of the unit in the system.

With the available $NFVC$ for each scenario, it is possible to compare the variations in $NFVC$ with respect to the reference scenario. The change in $NFVC$ for $ith$ scenario $S_i$ with respect to the reference scenario $S_1$ is calculated using (9).

$$\Delta NFVC_{S_i} = NFVC_{S_i} - NFVC_{S_1}$$

(9)

where $\Delta NFVC_{S_i}$ is the change in non-fuel variable costs of a thermal unit in the $ith$ scenario with respect to its own $NFVC$ in the reference scenario expressed in monetary unit per energy unit (USD/MWh).

Investors, plant owners and system planners are interested to know how much the $NFVC$ changes each year or with penetration level of renewable resources in the system. Since the commissioning of different renewable based power plants are completed at different time, it is practical to present the change in $NFVC$ with respect to variable penetration levels of renewable energy resources. For this purpose, the $\Delta NFVC_{S_i}$ can be normalized by a factor of 100 MW of variable renewable energy installed capacity over the additional renewable energy installed capacity between $S_i$ and $S_1$. The expression for estimating normalized $NFVC$ can be obtained from (10).

$$\Delta NFVC_{Rate} = \Delta NFVC_{S_i} ÷ 100MW_P$$

(10)

The generalized single value of $\Delta NFVC_{Rate}$ can be obtained from the slope of the line drawn between various $NFVC$ with respect to the installed capacity of variable renewable power plants in different scenarios as shown in Figure 3 using a linear regression approach. The $\Delta NFVC_{Rate}$ is the slope of the line drawn through the points of $\Delta NFVC$ vs. installed capacity of variable renewable resources in the system. For this example of Figure 3, solar PV penetration level is presented as additional generation capacity to the reference scenario (S1). The linear approximation in this case indicates that normalized $NFVC$ incremental rate is 0.068 USD/MWh for each additional MW installed solar PV generation capacity.
The proposed method for incremental rate of NFVC estimation considers a linear relationship between incremental NFVC and additional PV installation. A nonlinear function of additional PV installed capacity could represent the rate of NFVC increment model with higher accuracy. Hence, depending on the sophistication level, the function $\Delta NFVC_{Rate}$ can be adjusted.

4. Case Study

The proposed methodology, along with the indicators, are applied to the Chilean power system to investigate the impact on the operation costs of thermal power plants of increasing solar PV penetration.

4.1. System Information

Up to 2016 the Chilean power system consisted of two major independent power systems: SIC and SING, with 53,603 and 17,710 GWh of energy demand, respectively. As of June 2017, to meet the demand of SIC and SING have an installed generation capacity of 17.605 and 5.505 GW, respectively [16]. The composition of the generation mix in the two major Chilean power systems is presented in Table 1. From careful attention to Table 1 it can be observed that the main fossil fuel-based generation technologies are of steam, gas, and combined cycle turbines. An accelerated increase in the penetration of solar and wind energy has been experienced during the last five years. Coal-based steam turbines are used as the base load generators and gas turbines and diesel engines are mostly used to support intermediate load variations and peak load. Hence, variation in demand can be well served by the system with cycling of fast responding thermal power plants. The two systems are expected to be fully interconnected by 2019 [17]. The Chilean power system has the following characteristics:

1. Longitudinal structure.
2. Mandatory pool-based energy market.
3. Government target to achieve 20% energy penetration of non-conventional renewable generation by 2025.
4. Principally hydro-thermal power system.
5. Possession of Atacama Desert with significant solar radiation potential.

To reach the target for energy from renewable resources by 2025, the government policy has considered development of large scale solar PV and wind-based energy generation technologies in the Chilean power system. The targets for solar and wind-based electricity generation capacity to be achieved by 2025 are 4357 MW and 2978 MW, respectively [17].

![Figure 3. Variation of $\Delta NFVC$ with solar photovoltaics (PV) penetration.](image-url)
Table 1. Generation mix of Chilean Power Systems in 2017.

| Technology    | Installed Capacity (MW) |
|---------------|-------------------------|
|               | SING | SJC | Total |
| Coal          | 2419 | 2364 | 4783  |
| Natural gas   | 1912 | 2959 | 4871  |
| Diesel        | 184  | 2656 | 2840  |
| Solar         | 516  | 1272 | 1788  |
| Wind          | 201  | 1214 | 1415  |
| Biomass       | -    | 410  | 410   |
| Hydro         | 17   | 6656 | 6673  |
| Biogas        | -    | 60   | 60    |
| Geothermal    | 24   | -    | 24    |
| Others        | 232  | 14   | 246   |
| **System Total** | 5505 | 17,605 | 23,110 |

4.2. Scenario Generation

The Chilean power system is going through a number of changes, including building interconnections, replacing generation technologies and commissioning new power plants. To harmonize with Chilean actual renewable regulation and relatively stable generation mix, it is decided to set the planned system generation mix in 2025 as reference year. Since there is uncertainty about the future market parameters that drive the operating conditions of thermal power units, the purpose of ‘scenario’ definition is to capture the possibilities where the uncertain parameters may rely. For instance, a ‘reference scenario (S1)’ regarding the level of renewables integration could be set according to current system/market political targets, while alternative scenarios (S2–S5) could be defined with increasing renewable generation penetration levels in the system. The system information corresponds to the reference year can be found in [17] published by the regulator (National Energy Commission). Additionally, plentiful national resources and current market conditions of solar technologies indicate that their development beyond the minimum target level of 20% by 2025 can be expected. Hence we have opted to examine different solar PV penetration levels over the reference year and for the purpose 4 possible scenarios are developed with additional solar PV installed capacity of 1200 MW, 2400 MW, 3000 MW and 3600 MW as shown in Figure 4.

Figure 4. Scenarios with various levels of solar PV penetration.
4.3. Sensitivity Matrix for Weighting Factors

The proposed indicator for assessing the thermal power plant cycling impact on the operational costs $EOH$ is estimated from the operational indicators $NS$, $OH$ and $LF$ along with the weighting factors $\alpha$, $\beta$ and $\gamma$, as shown in Equation (1). The exact values of these weighting factors, along with the $MO_{\text{costs}}$ and $EOH$ could be obtained directly from the plant owner or manufacturer. However, this is information that is not publicly available. Since the weighting factors are essential for the assessment of cycling impacts, there are a few steps to follow for the estimation of these factors:

1. Public operational information: Detailed information of the current and past operation regime of the power plants ($AE$, $NS$, $OH$ and $LF$) as well as $NFVC$ during consecutive periods of plants overhaul maintenances are normally available in the ISO public information systems.

2. Revise specialized literature: In addition to the operational data, the specialized literature for information of typical values for $EOH$ and $MO_{\text{costs}}$ should be obtained. Alternatively, if possible, these values could be obtained directly from manufacturers of plant owners. Information from insurance companies and international benchmarks can be used to verify the above information.

The relationship between the known operating regime and overhaul costs and $EOH$ is obtained combining Equations (1) and (8), leaving a linear function of $\alpha$, $\beta$ and $\gamma$. Therefore, the parameters could be obtained by a Least Squares fitting procedure. Alternatively, an additional assumption on how the weighting factors are related could be taken. For instance, it is seen that the component $\alpha$ related to start-up process is more important than $\beta$ related to firing hours, as the start-up process further accelerates the need for maintenance. In [9] authors discuss how for different CCGT operating regimes, the ratio of start-up to firing hours goes from 16 to 200.

Thus, applying these weighting factor estimation steps, in the Base Case, the values of $\alpha$, $\beta$ and $\gamma$ are approximated to 150, 1.5 and 0, respectively. These values are obtained for a case of a unit with $P_{\text{max}} = 350$ MW, Capacity factor = 0.75, $NS = 12$, $NFVC = 7$ USD/MWh with a contractual agreement for overhaul of $MO_{\text{costs}} = 175$ million US dollars, $EOH = 125$ thousand hours, and in consideration of a ratio of start-up to operating hours of 100.

Regarding the previous discussion about how these parameters are essential and their estimation is a key aspect of the methodology presented, a sensitivity analysis is conducted in this study to observe how the uncertainty in the determination of the weighting factors impacts on the operational costs of the thermal plants and the overall results. The sensitivity matrix for the weighting factors $\alpha$, $\beta$ and $\gamma$ is presented in Table 2.

| Case | $\alpha$ | $\beta$ | $\gamma$ |
|------|----------|---------|----------|
| Base | 150      | 1.50    | 0.0      |
| $\alpha$−1 | 100  | 1.50    | 0.0      |
| $\alpha$−2 | 175  | 1.50    | 0.0      |
| $\alpha$−3 | 200  | 1.50    | 0.0      |
| $\beta$−1 | 150 | 1.25    | 0.0      |
| $\beta$−2 | 150 | 1.75    | 0.0      |
| $\beta$−3 | 150 | 2.00    | 0.0      |
| $\gamma$−1 | 150 | 1.50    | 7.5      |
| $\gamma$−2 | 150 | 1.50    | 15       |
| $\gamma$−3 | 150 | 1.50    | 22.5     |

The reason to select 0 for the weighting factor of load following indicator in Base Case is the lack of available experimental data to show the impact of $LF$ on the aging of the thermal power plants. The subsequent cases have the variation of weighting factors around the values of those parameters in
Base Case. It is also to be noted in the analysis, only $LF > |60\%|$ are considered in $EOH$ calculation considering its impact.

4.4. Simulation Tool

The dispatch model considers a single node model dispatch without transmission restrictions to obtain the operation of thermal generators in the Chilean power system. The available power generation from the renewable resources is forecasted from the historical data. In the unit commitment program, the thermal generators are scheduled to supply net demand, that is, the total predicted demand less the generation output from renewable based resources.

The operation simulations considered an hourly time resolution, to harmonize with the time resolution used by Chilean power system operators. The considered temporal length of operation simulations is chosen to be one year to capture the solar PV and hydroelectric generation seasonality. The UC model is based on mixed integer programming and solved for the entire year using a two-stage rolling planning methodology, suitable for operation planning of hydrothermal systems [18]. These tools are part of the Ameba cloud-based simulation platform [15].

To capture the seasonal variability in electricity demand and solar generation output, time series data of the year is used in this study. The Solar Energy Explorer provides a data base of solar resource which is estimated with a radiative transfer model and satellite data, with hourly data from 2004 until 2016 at 90 m spatial resolution [19]. The results of this explorer have been validated using 140 surface solar irradiance stations throughout the country.

The Yearly Simulations are performed using a rolling planning methodology, considering a step of 7 days, with 2 days of look ahead for boundary conditions. Thus, 53 unit commitment simulations are carried out sequentially to solve the entire year, with hourly resolution. Each yearly simulation takes about 5 h, solved using CPLEX 12.6 with a tolerance of 0.01% on an Dell T630 with 20 core 2.6 GHz Intel Xeon E5-2660 v3 processor and 128 GB of RAM.

4.5. Clusters

The generation mix of the Chilean power system contains a wide range of fuels and technologies as is apparent from Table 1. Likewise, the number of power plants is large. Since, the purpose of this study is to investigate the impact of cycling on the operation costs of thermal power plants, rather than analyzing particular impacts on specific power plants, two major thermal plant groups are considered, namely coal cluster and natural gas cluster. Additionally, solar PV cluster and hydro clusters are formed to represent the renewable generation systems.

Coal cluster: It consists of 27 units with a total power capacity of 4783 MW. These power plants use steam turbine technology and are engaged to supply base load demand.

Natural gas cluster: This cluster is composed of 17 units accounting for 4511 MW of power capacity. The technologies in this cluster include gas turbines and combined cycle gas turbines, normally dispatched to meet the peak demand as well as to support ramping operation.

Solar PV Cluster: Thin-film solar PV cells are considered for the generation technology. The seasonal variability of solar generation is captured by considering annual solar generation data published in [19].

5. Results

The analysis is conducted for both the coal and natural gas cluster. From the evaluated values of $NS$ (from Equation (2)) and $OH$ (from Equation (4)), and for all possible combinations of scenarios and cased defined in Figure 4 and Table 2, the $EOH$ is estimated (from Equation (1)) and is plotted in Figure 5. It can be noticed that the change in the $EOH$ of coal cluster remains almost the same in Reference Scenario, Scenario 2 and Scenario 3. Cycling requirements of coal units are not increased until higher solar PV penetration scenarios (S4 and S5) are reached. However, cycling requirements shows a minimal increase. Moreover, the range of change in $EOH$ values for coal cluster ($\approx 800$) is not
significantly as compared to the case for natural gas cluster (£7000). Due to the fact that the coal units are operated as base load units, no significant changes are observed in coal cluster’s NFVC. Hence, the NFVC results for coal cluster are not considered for further analysis.

In contrast to the results observed for coal cluster, the results for the natural gas cluster show significant increment in their cycling requirements. Since gas turbine and combined cycle gas turbine power plants are usually committed for peak load variation and ramping requirement due their flexibility, a significant increment in cycling of the units under this cluster is expected. Consequently, an increment in the NFVC of the cluster is observed. The NFVC of the natural gas cluster for all possible combinations of scenarios and cases defined in Figure 4 and Table 2 is estimated using the formulation developed in Equation (8).

The estimated values of NFVC of natural gas cluster for different scenarios and cases are plotted in Figure 6. It is observed that avoidance of variability in costs associated with NS, LF and OH can cause the investor to experience risk of NFVC estimation error ranging from 7 to 16 USD/MWh for the scenarios presented. From the plot it is found that the weighting factors have a significant impact on the NFVC of the thermal plants. Among others, weighting factors related to OH and LF have greater influence on the NFVC as compared to the weighting factor for NS. The reason behind the phenomena is the presence of combined cycle gas turbines in the cluster and hence frequent shut-down and start-up is avoided by the unit commitment tool. Additionally, the result implies that the NFVC of generating units in the natural gas cluster are highly sensitive to the variable costs associated with operating hours and load following.

![Figure 5. EOH of the units from coal and natural gas cluster for different scenarios and cases.](image)

![Figure 6. Non-fuel variable costs (NFVC) of the units from natural gas cluster for different scenarios and cases.](image)
Comparison of Figures 5 and 6 provides detailed insight into the system responses to variations in NFVC of natural gas cluster. According to (1), higher values of weighing factors will result in a larger number for $EOH$. No variation in $EOH$ with incremental values of $\beta$ and $\gamma$ is observed from Figure 5. This indicates that system reduces $OH$ and $LF$ of units in natural gas generation cluster as weighing factor corresponding to these parameters. However, it is observed from Figure 6 that the $NFVC$ increases sharply with the increment of $\beta$ and $\gamma$. This happens due to the fact that the system increases $NS$ to reduce $OH$ and $LF$ for those generating units. The major overhaul costs of natural gas-based units increase greatly with increased $NS$, compared to $OH$ and $LF$ [9].

Furthermore, the impact of increasing penetration of solar PV in the Chilean power system on the $NFVC$ of the thermal units in natural gas cluster is apparent from Figure 6. The $NFVC$ increases significantly as the installed capacities of additional solar PV are 1200 and 2400 MW, that is, for scenarios $S2$ and $S3$. However, the rate of $NFVC$ increment with respect to additional installed capacity of solar PV reduces between the range of 2400 to 3600 MW. Additionally, the sensitivity of $NFVC$ on the weighting factor for $NS$ increases when there is a higher penetration range of solar PV in the system. This is due to the fact that the unit commitment tool does not keep all the units from natural gas cluster running at the same time to minimize the cost. As a result, start-up events are more frequent with larger shut-down periods. Consequently, the $NS$ increases and $OH$ reduces for each unit. This phenomenon increases the sensitivity of weighting factor corresponding to $NS$ and reduces the dependency of cycling of the thermal units on the further growth of solar PV capacity after 2400 MW.

The values of $\Delta NFVC_{Rate}$ for different scenarios and cases are presented in Figure 7 to observe the change in $NFVC$ due installation of per 100 MW additional solar PV into the system. It can be seen in Figure 6 that the incremental $NFVC$ for units in natural gas cluster can vary between 0.7 USD/MWh–100 MWp to 3.9 USD/MWh–100 MWp based on the penetration level and thermal unit characteristics as modeled by the weighting factors in this study. Additionally, it is noted from the plot in Figure 7 that the sensitivity of $\Delta NFVC_{Rate}$ on $LF$ is very high and increasing the weighting value of $LF$ raise the incremental $NFVC$ rate with respect to solar PV penetration significantly. This phenomenon indicates that the ramping operation and subsequently requirement for maintenance operation of the units increases considerably with the penetration of variable renewable resources into the system.

![Figure 7. $\Delta NFVC_{Rate}$ of the units from natural gas cluster for different scenarios and cases.](image-url)

The feedback of the operation costs in the developed methodology enables the ‘Yearly Simulation Tool’, that is, unit commitment program to minimize the overall cost of system by reducing the committed hours (i.e., $OH$) of the units which requires frequent shut-down and start-up. As a result, the sensitivity of $\Delta NFVC_{Rate}$ on the $a$ increases and sensitivity of $\Delta NFVC_{Rate}$ on $\beta$ decreases as apparent from Figure 7. The slope and vertical axis intersect from linear approximation of $\Delta NFVC_{Rate}$
is presented in Table 3. The % error introduced from linear approximation of $\Delta NFVC_{Rate}$ is also presented in the Table 3. It is found that the linear approximation can reduce the number of scenarios and simulation effort. However, the linear approximation can introduce significant errors in analysis. In this case, the error is higher for lower penetration of solar PV system.

### Table 3. % error introduced by the linear approximation in the incremental curve of non-fuel variable costs (NFVC).

| $\Delta NFVC$ | S2      | S3      | S4      | S5      | Slope     | Intersect |
|--------------|---------|---------|---------|---------|-----------|-----------|
| BC           | 64.552  | −6.287  | −5.993  | −3.565  | $4.23 \times 10^{-4}$ | 1.667     |
| $\alpha_{−1}$ | 53.978  | −5.386  | −5.325  | −3.667  | $2.49 \times 10^{-4}$ | 1.074     |
| $\alpha_{−2}$ | 67.703  | −6.524  | −6.167  | −3.538  | $5.11 \times 10^{-4}$ | 1.963     |
| $\alpha_{−3}$ | 70.105  | −6.697  | −6.294  | −3.518  | $9.8 \times 10^{-4}$ | 2.259     |
| $\beta_{−1}$ | 68.234  | −6.563  | −6.196  | −3.533  | $4.4 \times 10^{-4}$ | 1.685     |
| $\beta_{−2}$ | 60.951  | −6.000  | −5.780  | −3.597  | $4.07 \times 10^{-4}$ | 1.648     |
| $\beta_{−3}$ | 57.427  | −5.700  | −5.558  | −3.631  | $3.9 \times 10^{-4}$ | 1.630     |
| $\gamma_{−1}$ | 44.840  | −4.699  | −3.570  | −4.666  | $4.16 \times 10^{-4}$ | 2.013     |
| $\gamma_{−2}$ | 33.542  | −3.451  | −1.581  | −5.532  | $4.09 \times 10^{-4}$ | 2.360     |
| $\gamma_{−3}$ | 26.218  | −2.444  | 0.082   | −6.231  | $4.02 \times 10^{-4}$ | 2.707     |

6. Conclusions and Future Work

The increasing share of renewable energy in power systems imposes challenges for the economic operation of conventional power plants. Increased operation costs of the thermal power plants are expected in the coming years due to the variability in the availability of energy from renewable energy resources. This paper proposes indicators to identify the cycling impacts on the variable O&M costs of the thermal generation units. A novel methodology is developed to evaluate the indicators of cycling impacts for expected future scenarios. The proposed indicators and methodology are applied to the Chilean power system and the impact of additional solar PV installation capacity on the NFVC of coal and natural gas-based generation clusters is analyzed.

In relation to the Coal cluster, the present study discovered that in the Chilean power system, coal units’ cycling requirements are not increased significantly even in high levels of solar PV penetration, since coal units operates mainly as base load, for the scenarios considered.

Regarding the natural gas cluster’s results, there are possibilities to observe frequent maintenance requirement for the combined cycle and natural gas units due to the growth of PV solar energy in the Chilean system. This is reflected in the NFVC of the natural gas cluster, which presents an increase of up to 9 USD/MWh depending on the solar PV penetration level and the weighting factors of $EOH$ function. This corresponds to an increment of marginal NFVC rate between 0.05 and 0.11 USD/MWh for every 100 MW of additional solar PV installed capacity, depending on the sensitivity considered.

This study shows the effectiveness of the proposed methodology to analyze and quantify the increase on conventional thermal generators’ variable costs due to alternative penetration scenarios of PV technology, from the perspective of an investor in new thermal power plants. Additionally, the proposed framework can aid the system planners and operators to realize the changing trend of system operations and insights of the cost model for thermal generation plants.

Finally, as future work, we propose to analyze the renewable variability with a lower resolution which is capable of representing renewable resource variability and load following repercussions over the $EOH$ calculation. Robust stochastic optimization techniques for ‘Yearly Simulation Tool’ are to be developed in future to assist the stakeholder in decision making. Additional indicators are to be developed to model the associated lifetime degradation and frequency of the maintenance cycles of conventional thermal units. Furthermore, dynamic costs associated to cycling operations that can be included in the unit commitment and planning problem to endogenize the relationship between maintenance costs and the cycling operation of the conventional thermal generation units in the simulation model. Finally, since estimation of weighting factors $\alpha$, $\beta$ and $\gamma$ appears to be essential for
the application of the proposed methodology, more research and development of a robust methodology for their estimation is suggested.

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**Nomenclature**

- **NFVC** Non-fuel variable costs [USD/MWh]
- **EHS** Equivalent Hot Start
- **EOH** Equivalent Operating Hours
- **EFOR** Equivalent Forced Outage Rate
- **O&M** Operation and Maintenance
- **NS** Number of starts
- **OH** Operating hours
- **LF** Load following
- **X_t** Power output of generator during time t
- **Z_t** Integer variable that indicates a start-up in time t
- **W_t** Integer variable that indicates generator is online in time t
- **LF_t** Variable that measure load following in time t
- **UC** Unit Commitment
- **MO_{cost}** Major overhaul costs
- **EOR** Equivalent Operating Hours that trigger a major overhaul
- **AE** Annual energy generated
- **MW_p** MW of installed capacity
- **SIC** Central Interconnected System
- **SING** Northern Interconnected System
- **CCGT** Combined Cycle Gas Turbine

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