Identifying Sustainable Electricity Options for Chile

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by

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Abbreviations

ADP Abiotic depletion potential

AP Acidification potential

BAU Business as usual

BESS Battery energy storage solutions

C/O Carbon oxygen ratio

CBC COIN-OR Branch-and-Cut

CDEC Load Economic Dispatch Centre

CCaLC Carbon calculations over the life cycle of industrial activities

CC Combined cycle gas turbine

CCS Carbon capture and storage

CEMS Continuous emissions monitoring systems

CFB Circulating fluidised bed

CHP Combined heat and power

CIF Cost, Insurance and Freight

CNE National Energy Commission

CML Centrum milieukunde Leiden, Environmental centre Leiden

CO Carbon monoxide

COP21 The Conference of the Parties held in Paris in 2015

CSP Concentrating solar power

CV Calorific value

DCB Dichlorobenzene

ED Economic dispatch

EIA Environmental Impact Assessment

ENSO El Niño Southern Oscillation

EP Eutrophication potential

FAETP Freshwater aquatic ecotoxicity potential

FOB Free On Board

GaBi Ganzheitliche bilanz, holistic balance

GDP Gross domestic product

GEMIS Global emission model of integrated systems

GHG Greenhouse gas emissions

GWP Global warming potential

HCFC-22 Chlorodifluoromethane

HTP Human toxicity potential

IEA International energy agency

IMF International Monetary Fund

IPCC Intergovernmental Panel on Climate Change

ISO International organization for standardization

LCA Life cycle assessment

LCC Life cycle cost

LCI Life cycle inventory

LCIA Life cycle inventory assessment

LCOE Levelized cost of electricity

LGSE General Law of Electric Utilities

LNG Liquefied natural gas

MAETP Marine aquatic ecotoxicity potential

MC Monte Carlo simulation

MCDA Multi-criteria decision analysis

NCRE non-conventional renewable energy

NDC Nationally determined contribution

NEEDS New energy externalities development for sustainability

NMVOC Non-methane volatile organic compounds

NO_x Nitrogen oxides

O&M Operation and maintenance

OC Open cycle gas turbine

ODP Ozone depletion potential

OECD Organisation for Economic Co-operation and Development

PAH Polycyclic aromatic hydrocarbon

PC Pulverised coal

POCP Photochemical oxidant creation potential

PPA Power purchase agreement

PPP Purchasing Power Parity

PSE Power system expansion

ppm Parts per million

PV Photovoltaic

R11 Tricholorofluoromethane

RE Renewable electricity

ReCiPE RIVM and Radboud University, CML and PRé

SD Standard deviations

SERNAGEOMIN National Service of Geology and Mining

SIC Central Interconnected System

SING Interconnected System of Norte Grande

SMA Chilean environmental protection agency

tcf Trillion cubic feet

TETP Terrestrial ecotoxicity potential

TRACI Tool for the reduction and assessment of chemical and other environmental impacts

UK United Kingdom

UN United Nations

UNFCCC The UN Framework Convention on Climate Change

US United States

USD United States Dollar

VOCs Volatile organic compounds

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Abstract

This research aims to assess the environmental and economic sustainability of current and future electricity generation in Chile from a life cycle perspective. Life cycle assessment has been carried out for each technology taking into account resources, energy, emissions and waste flows across the life cycle stages from cradle to grave. As a result, eleven environmental impacts have been estimated. The year 2050 has been chosen as the target year for the future scenarios that have been obtained through an investment optimization model. This linear programing model has been created to find cost-optimal options that enables high renewable penetration with operation flexibility provided by short- and long-term storage options. A multi-criteria decision analysis (MCDA) has been applied to support decision-making; this consists of aggregating several indicators into a single score.

About 60% of power is currently supplied by coal, gas and oil, 34 % by hydropower, while biomass, biogas, wind and solar photovoltaics (PV) produce the remainder. The results reveal that in the current electricity system hydropower is the most sustainable option across all impacts, followed by wind and biogas. Electricity from natural gas has lower impacts than biomass, solar PV and wind for seven, six and four impacts respectively. Solar PV has the highest abiotic depletion due to the use of scarce elements in its manufacture. Coal and oil are the least sustainable options with impacts mostly attributed to fuel production and combustion. The use of petroleum coke as secondary fuel in coal plants worsens the impacts. While in the past 10 years the electricity demand grew by 44%, all the impacts except ozone depletion increased by 60%-170%. The economic figures show that hydropower and coal have the lowest costs of 49.9-64.9 and 75.3 $/MWh respectively. Despite this, in the last decade the country has endured high hydrological variability, volatile fossil fuel prices, gas curtailments, high level of market concentration, and high power demand, that have caused large electricity prices (126 $/MWh) to affect the Chilean economy and society.

The current power options plus concentrating solar power and geothermal have been the options considered to develop future scenarios. Twelves future scenarios have been obtained divided in six Business as usual (BAU) scenarios whose renewable power contribution range from 80% to 88%, and six Renewable electricity (RE) scenarios which 100% of electricity is from renewables. The results suggest that all scenarios have lower environmental impacts than at the present. For example, the BAU scenarios have 51% lower environmental impacts than the current electricity system, while the RE scenarios have 87% lower impacts. The depletion of resources in the future scenarios is higher than the present mainly due to solar PV contribution. Due to the high costs, natural gas and oil are not included in any scenario, while biomass power had marginal power contribution. When solar PV reaches above 20% of electricity share, other renewable power options experience energy spillage and thermal power plants are cycling more often, resulting in a reduction of capacity factors and leading to a rising of costs. MCDA helped to identify the most sustainable scenario: RE260'Base', and to highlight the importance of hydropower to keep the system costs low thanks to its long-term storage capacity.

Declaration

that no portion of the work referred to in the thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.

Copyright Statement

Dedication

My humble effort I dedicate

to my beloved father and mother,

whose effort, love and prays led me to pursue my goals;

to my sweet and loving wife,

whose dedication, love and encouragement made possible this important achievement.

Acknowledgements

“*A man from the town of Neguá, on the coast of Colombia, could climb into the sky. On his return, he described his trip. He told how he had contemplated human life from on high. He said we are a sea of tiny flames. “The world,” he revealed, “is a heap of people, a sea of tiny flames.” Each person shines with his or her own light. No two flames are alike. There are big flames and little flames, flames of every color. Some people’s flames are so still they don’t even flicker in the wind, while others have wild flames that fill the air with sparks. Some foolish flames neither burn nor shed light, but others blaze with life so fiercely that you can’t look at them without blinking, and if you approach you shine in fire.*” *(short story from The Book of Embraces by Eduardo Galeano)*

Undertaking this PhD has been a challenging experience that has led me to acquire knowledge in a field that at the beginning liked me but after some time I got passionate about. This acquired knowledge has not only helped me to carry out my research but has encouraged me to continue discovering more. On this journey, I have met many people with different interests and from varied cultures which have also contributed to perceive the world through many colours and shapes. Every person I have met on this journey have helped me in different ways and I am very grateful for that.

I greatly appreciate the support received by my supervisor Professor Adisa Azapagic during these four years. Many thanks for the opportunity she gave me to pursue this PhD, her guidance and expert feedback which allows me giving my best in this research.

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Chapter 1: Introduction

1.1. BACKGROUND

The modern lifestyle and economic development drive the growing use of natural resources, land-use change and waste generation. For that reason, society is being affected by externalities related to industrial systems which provide goods to satisfy the needs of society [1].

In 1987, sustainable development was defined by the United Nations (UN) as "development that meets the needs of the present without compromising the ability of future generations to meet their own needs" [2]. In achieving sustainability, energy plays a significant role, because it contributes to all three dimensions of sustainable development: the economy, the environment and society. Regarding the economic dimension, energy is a significant factor for macroeconomic growth, since it underlies the supply chains of major economic activities including transport, mining, manufacturing and the digital economy. In relation to the environmental dimension, it contributes significantly to global and local impacts via the extractive industries and direct emissions to air, land and water. In terms of the social dimension, energy is considered a basic human need, alongside food and shelter [3]. Electricity as a source of energy is an important factor for sustainable development; however, current electricity systems have negative impacts on the environment and can generate economic and social problems, including the impacts of climate change and local pollutants emitted by thermal power plants. For that reason, electricity systems should be designed to overcome these issues and contribute to sustainable development.

The current electricity system in Chile is highly dependent on fossil fuels, which provided 60% of 70.4 TWh of electricity generated in 2014; the rest was from hydropower (34%) and other renewables (6%). The majority of fossil fuels are imported (90% of the fossil fuel supply) [4]. This makes the country vulnerable to the security of energy supply and high electricity costs, in addition to contribution to climate change and other environmental impacts associated with the use of fossil fuels like coal, oil and natural gas. On the other hand, the diverse geography and climate provides a generous potential for development of renewable electricity sources.

The electricity system in Chile is divided into the northern and central zones which together cover 99% of the country's electricity generation. In 1982, the electricity sector was deregulated and divided into three segments: generation, transmission and distribution. The deregulation stimulated private investment that increased electricity supply coverage to households from 38% to 86% for the rural population and from 95% to 98% for the urban population in 20 years [5]. However, the sector has been recently experiencing difficulties due to increasing electricity prices and the distrust of communities for many proposed power projects due to environmental and social concerns.

Chile has committed to the international climate agreement of the UN Framework Convention on Climate Change (UNFCCC) at the Conference of the Parties (COP21) held in Paris in 2015. The national target is a reduction of greenhouse gas (GHG) emissions by 30% per unit of GDP by 2030 relative to 2007. As the main contributor to GHG emission is the energy sector (75% in 2010), the mitigation plan considers targets and actions with the ultimate goal of attaining reduction of emissions generated by the energy sector. The main target for electricity generation is for renewables to reach a contribution of 70% of the mix by 2050 [6].

1.2. AIMS, OBJECTIVES AND NOVELTY

In an attempt to contribute towards the mitigation plan as well as to address other sustainability challenges that the electricity sector is facing, this research aims to assess the environmental and economic sustainability of the current electricity generation and to identify sustainable options for a future electricity supply in Chile in 2050. The assessment considers technical, environmental, and economic aspects of different electricity technologies relevant to Chile, using life cycle assessment and economic assessment.

This research is the first attempt to develop a sustainability assessment of the Chilean electricity sector using a life cycle approach and considering a range of environmental and economic indicators. A similar methodology for sustainability assessment of electricity options has been successfully applied in other countries, such as Mexico [7], United Kingdom [8], Turkey [9], and Nigeria [10]. However, Chile has unique economic, geographical and resource characteristics which necessitate a holistic assessment catered to the country.

The specific objectives of the study are:

- to apply an integrated methodology for life cycle sustainability assessment of electricity generation for Chile;
- to estimate life cycle environmental impacts and economic indicators of current electricity generation in Chile;
- to define future scenarios for electricity supply in Chile up to 2050 and to evaluate their environmental and economic sustainability;
- to identify the most desirable electricity scenarios taking into account different preferences for different environmental and economic aspects; and
- to make recommendations to electricity companies and policy makers for improving the sustainability of the future electricity sector in Chile.

The main novelties of this research include:

- first life cycle assessment of electricity generation in Chile for the current situation and for future scenarios up to 2050;
- development of an optimisation framework for defining economically optimal electricity scenarios up to 2050 considering supply and demand and a broad range of technologies, including storage;
- integration of the economic and environmental sustainability assessments through multi-criteria decision analysis to identify most sustainable (desirable) scenarios for a future electricity system in Chile.

1.3. STRUCTURE OF THE THESIS

The thesis is presented in the alternative format as a compendium of five papers (Chapters 2-6). One paper has already been published in the peer-review journal Science of the Total Environment [11] (Chapter 4). The other four papers are pending submission to appropriate journal (Chapters 3, 5-6).

The research methodology implemented is presented in the next section. The first paper in Chapter 2 contains a review of sustainability implications of the electricity generation in Chile. The second paper (Chapter 3) considers the life cycle assessment of electricity generation from fossil fuels in Chile. This is followed by the life cycle assessment of current electricity supply in Chile including all the electricity options as part of Chapter 4. The next paper (Chapter 5) focuses on identification of future scenarios. This article presents a new framework based on power system expansion and economic dispatch with the aim of developing power scenarios with flexibility. The life cycle environmental sustainability and economic aspects of future scenarios have been assessed in the last paper (Chapter 6). Finally, the conclusions and recommendations are summarised in Chapter 7 alongside recommendations for policy makers and industry as well as suggestions for future research. All appendices are presented at the end of the thesis.

1.4. METHODOLOGY

An overall approach based on existing work such as [7–10] has been applied to the Chilean electricity system. The approach selected enables the integration of sustainability assessment with future scenarios considering life cycle thinking. The reason for selecting this methodology is because it contributes to estimate environmental impacts, taking into account economic indicators for different technologies, systems and scenarios. This methodology has been adapted including a new developed investment optimization model called FutuRES that stands for "Future Renewable Electricity Scenarios". This model enables to identify future scenarios and to carry out economic assessment simultaneously by considering technical aspects and costs of technologies, electricity demand, and power and fuel markets' features. The environmental sustainability has been assessed from a life cycle perspective from cradle to grave taking into account input and output flows of energy, resources, emissions and wastes. Therefore, the methodology allows to identify economic and environmental sustainable options and to propose improvements. The methodology is detailed in the next sections.

1.4.1. Economic and environmental sustainability assessment methodology for electricity supply

As can be observed in Figure 1, this methodology consists of the following consecutive steps: 1) selection of indicators, 2) selection of technologies, 3) electricity mix definitions, 4) economic assessment, 5) environmental assessment, and 6) selection of desirable scenarios. These are described in turn below.

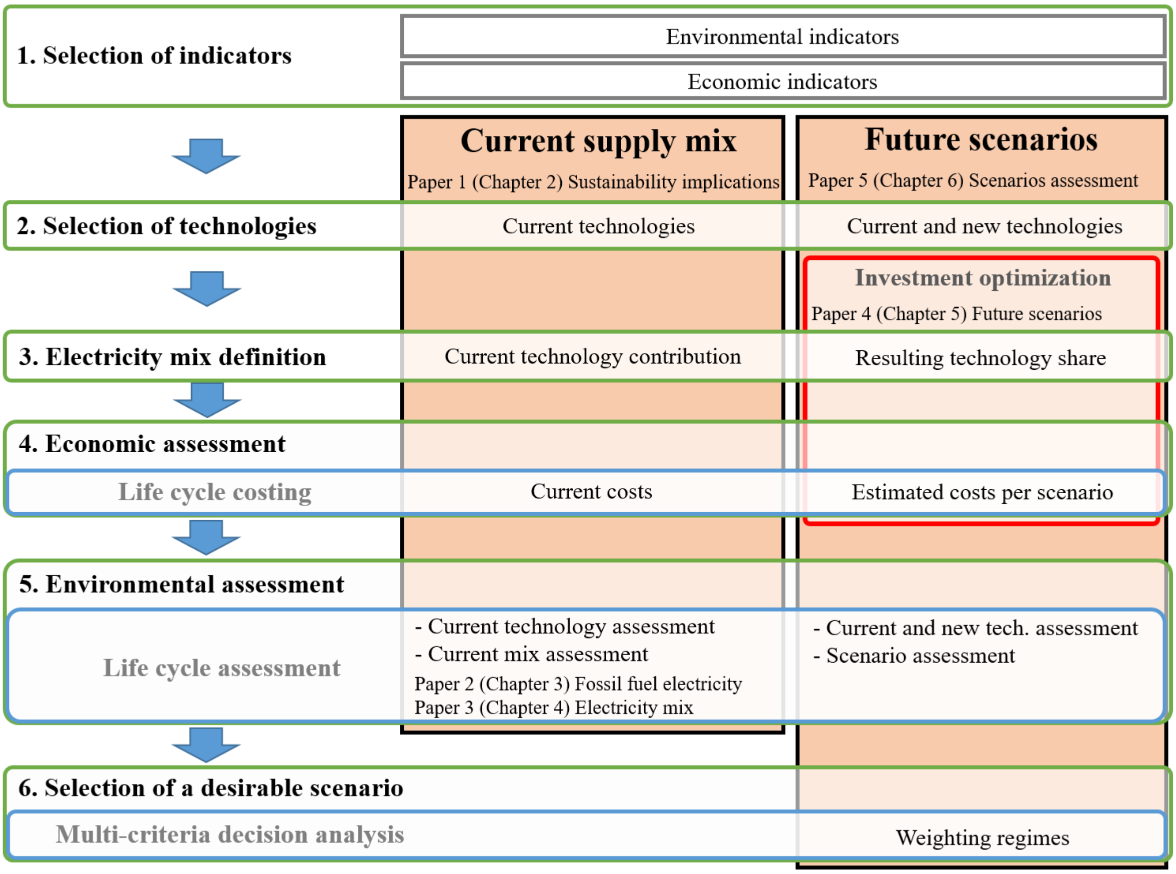

Figure 1. Economic and environmental sustainability assessment methodology of electricity supply.

1.4.1.1. Selection of indicators

The selection of environmental and economic indicators draws on existing techniques and literature, alongside consideration of the sustainability issues associated with the electricity sector as discussed in detail in Chapter 2. The indicators take a life cycle approach in order to ensure that each issue is evaluated comprehensively, therefore they draw on life cycle assessment and life cycle costing as described below.

1.4.1.1.1. Life cycle impact assessment method and power generation

Several environmental impacts can be chosen to assess the environmental sustainability under a life cycle approach [12]. The life cycle approach is supported by life cycle assessment (LCA), a tool designed to make an integrated environmental assessment of goods and services [13]. The life cycle impact assessment (LCIA) is a stage of LCA that consists on conversion of emissions and resources into indicators that reflect resource scarcity, human health pressures and eco-system quality [14]. The impacts are categorized according to the environmental problem (midpoint category) or damage (endpoint category) [13]. There are several LCIA methods. CML 2 Method [15] and TRACI [16] are midpoint category LCIA methods. Eco-Indicator 99 [17] is an endpoint category method, while

Impact 2002+ [18], LIME [19], and ReCiPe [20] are combined midpoint and endpoint methods .Several authors have addressed the complexity to classify and recommend LCIA methods with regards to impacts [14].

CML method is the most common LCIA methodology applied to assess life cycle impacts for electricity generation technologies [21–28] and power systems research [8–10, 29, 30]. Due to this fact, the use of CML method facilitates the comparison of results with other studies. Table 1 shows the 11 CML 2001 environmental impacts considered in this work.

1.4.1.1.2. Economic indicators

Life cycle costing (LCC) has been applied for the economic evaluation. LCC is defined as "an economic evaluation of different design options taking into account every significant cost to obtain assets along the economic life of each option expressed in present currency" [31]. For power systems, LCC is used to estimate and compare all costs associated with the production of electricity in different scenarios. The economic indicators considered are (Table 1): levelized cost of electricity, and cumulative investment costs [12]. In section 1.4.1.4 - 0 each indicator is described.

Table 1. Environmental and economic indicators applied

Aspects	Indicators			
	Issues	Name	Abbreviation	Unit
Environment	Climate change	Global Warming Potential	GWP	kg CO_2 eq.
	Resource depletion	Abiotic Depletion Potential	ADP elements	kg Sb eq.
		Abiotic Depletion Potential fossil	ADP fossil	MJ
	Emissions to air, water and land	Human Toxicity Potential	HTP	kg DCB eq.
		Acidification Potential	AP	kg SO_2 eq.
		Eutrophication Potential	EP	kg PO^{3-}_4 eq.
		Ozone Depletion Potential	ODP	kg R11 eq.
		Photochemical Oxidant Creation Potential	POCP	kg C_2H_4 eq.
		Freshwater Aquatic Ecotoxicity Potential	FAETP	kg DCB eq.
		Marine Aquatic Ecotoxicity Potential	MAETP	kg DCB eq.
		Terrestrial Ecotoxicity Potential	TETP	kg DCB eq.
Economic	Costs	Levelized Cost of Electricity	LCOE	$/MWh
		Cumulative Investment Cost	Investment	$ bn

1.4.1.2. Selection and specification of technologies

All technologies comprising the current Chilean electricity mix have been included in the analysis taking 2014 as the base year. Thus, the analysis includes the fossil fuel options coal, oil, and natural gas power and the renewable options hydropower (both reservoir and run-of-river), biomass, biogas, wind and solar photovoltaics (PV). Current technologies and those with a significant future deployment potential in the country (concentrating solar power (CSP) and geothermal power) have been taken into account to shape future scenarios by 2050 (see Chapter 5). As part of this stage, technical specification has been collected for each power option and the 174 power plants currently in use have been analysed.

1.4.1.3. Definition of electricity mix

In the first instance, the existing Chilean electricity mix is modelled for the base year, 2014. In 2015, the government published the Energy policy 2050 [6]. The main target established by the policy has been to achieve 70% of the electricity generation by renewables by 2050. Therefore, this research wants to assess if this target is achievable and if it is possible to exceed the target by reaching 100% of renewables in the mix. This is why in this work it has been set the identification of future scenarios by 2050 taking into account technical and economic aspects and assessing their environmental impacts.

By contrast, the year 2030 was not considered in this research as a future target year for the following reason: As the power system investments in Chile are based on long-term contracts, investments are now being determined to meet the demand for 2025-2030, while many fossil fuel projects under operation will continue to work by then. Therefore, the configuration of the electricity system in 2030 has already been identified and consequently the different scenarios that can be assessed are limited.

As shown in Figure 1, the future scenarios have been determined though optimization programming which is outlined below.

1.4.1.3.1. Investment optimization

The new framework FutuRES has been developed to determine future scenarios. This framework combines two optimization models for power system expansion (PSE) and economic dispatch (ED), as described in detail in Chapter 5. The PSE model was programmed as part of this work as well as the coding for integrating the ED model. The PSE model is designed to determine the power contribution and installed capacity for future scenarios. The ED model was obtained from an open source project "PowerGAMA" [32] and includes a novel approach to the storage value for CSP technologies. This enables the model to incorporate short-term storage into the scenario optimization as part of economic dispatch. The ED model estimates the utilization rate of each technology by identifying the economic operation for the scenarios and contributes to reach scenarios with flexibility. Several factors have been considered for the development of scenarios, such as electricity demand growth, technology costs, carbon tax, hourly electricity load and future technological development, among others.

The investment optimization modelling has resulted in twelve future scenarios encompassing a broad decision space. These scenarios are described in detail in Chapter 5.

1.4.1.4. Economic assessment

LCOE represents the discounted lifetime cost of capital and use of a power generation asset [33]. The levelized cost of electricity (LCOE) is a key economic indicator to monetize the electricity costs [34]. Its usefulness lies by allowing comparison among technologies or electricity systems and it has been widely used in several reports of energy experts [34–37] because of its transparency and simplicity [35]. In equations 1 and 3 are described the calculation of LCOE for a generating technology and for electricity mix respectively. The cumulative investment is the capital costs incurred over the planning horizon and provides information about the actual investment required for each scenario (equation 4) [38]. These two indicators, LCOE and cumulative investment have been also determined in research based on sustainability assessment of power systems or technologies [10, 12, 39, 40].

$$LCOE_{g,t} = f_{g,t}^{inv} + f_{g,t}^{OM} + v_{g}^{OM} + v_{g,t}^{fuel} + v_{g,t}^{carbon} \qquad \text{(Eq. 1)}$$

where:

$LCOE_{g,t}$: levelized cost of electricity of a g technology at t year ($/MWh)

g : subscript of technology type

t : subscript of year

$f_{g,t}^{inv}$: annualised capital cost of a g technology at t year ($/MWh)

$f_{g,t}^{OM}$: operation and maintenance fixed cost of a g technology at t year ($/MWh)

v_{g}^{OM} : operating and maintenance variable cost of a g technology at t year ($/MWh)

$v_{g,t}^{fuel}$: fuel cost of a g technology at t year ($/MWh)

$v_{g,t}^{carbon}$: carbon taxes payable of a g technology at t year ($/MWh)

As a difference of operation and maintenance fixed ($f_{g,t}^{OM}$) and variable (v_{g}^{OM}) costs, fuel costs ($v_{g,t}^{fuel}$) and carbon tax ($v_{g,t}^{carbon}$) which are usually estimated in \$/MWh, capital cost ($I_{g,t}^{capital}$) is found in literature as \$/kW, therefore to include the capital costs in the levelized costs formula, the capital costs is converted into annualised capital cost (in \$/MWh) taking into account discount rate (r_g), capacity factor ($CF_{g,t}$) and technology lifespan (τ_g).

$$f_{g,t}^{inv} = \frac{I_{g,t}^{capital}}{8760 \cdot CF_{g,t}} \cdot \frac{r_g}{1 + \left(1 + r_g\right)^{-\tau_g}} \qquad \text{(Eq. 2)}$$

where:

$CF_{g,t}$: capacity factor of a g technology at t year (%)

$I_{g,t}^{capital}$: initial capital cost of a g technology at t year (\$/MW)

r_g : discount rate of a g technology (%)

τ_g : lifespan assumed of a g technology (years)

8760 : number of hours per year

The levelized costs of electricity of the electricity mix ($LCOE_t^{MIX}$) is calculated with equation 3. This indicator enables to compare the costs of different electricity mixes and scenarios.

$$LCOE_t^{MIX} = \sum_{g} F_{g,t} \cdot LCOE_{g,t} \qquad \text{(Eq. 3)}$$

where:

$LCOE_t^{MIX}$: levelized cost of electricity of the electricity mix at t year (\$/MWh)

$F_{g,t}$: electricity contribution of a g technology at t year (%)

The cumulative investment is displayed in equation 4. It is estimated considering the capital costs ($I_{g,t}^{capital}$) so that the new build capacity ($Var_{g,t}^{new}$) is transformed into investment cost by technology and by year. Then costs are added throughout all technologies and over the investment period.

$$CI = \sum_{g,t} I_{g,t}^{capital} \cdot Var_{g,t}^{new} \qquad \text{(Eq. 4)}$$

where:

CI	: cumulative investment over the planning horizon ($)
g	: subscript of technology type
t	: subscript of year
$I_{g,t}^{capital}$	: initial capital cost of a g technology at t year ($/MW)
$Var_{g,t}^{new}$	: new build capacity of a g technology at t year (MW)

1.4.1.5. Environmental assessment

Life cycle assessment (LCA) is an environmental sustainability assessment tool used to quantify the environmental impacts in the life cycle of a product, process, service or activity. LCA can be used for different purposes, including comparison of alternative products or identification of opportunities for improvements [13, 41].

The LCA methodology is standardised by the ISO standards (ISO 14040 and ISO 14044) and as shown in Figure 2 it involves four phases: goal and scope definition, inventory analysis, impact assessment and interpretation [42, 43].

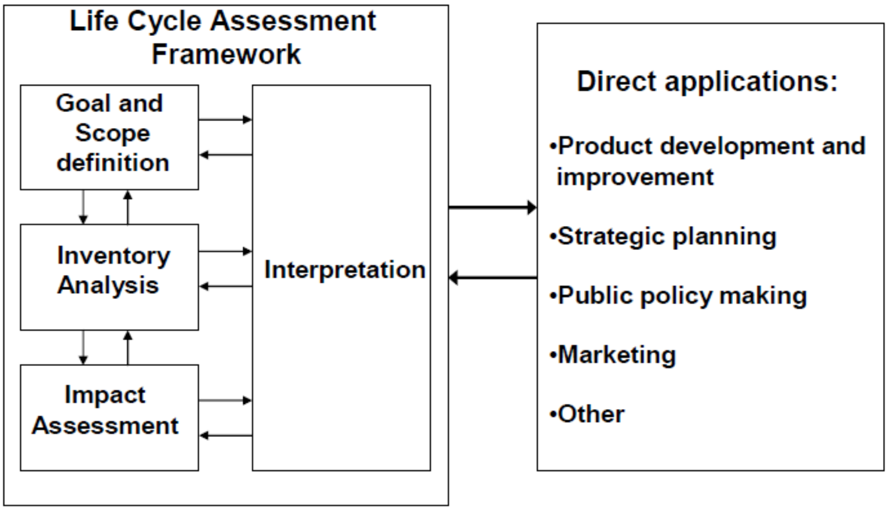

Figure 2. Stages in the life cycle of an activity considered by LCA (based on [42]).

The first, goal and scope definition phase, defines the purpose of the study, the system boundaries and the functional unit. The stages typically considered in the life cycle of a system include: extraction and processing of raw materials; manufacturing; transportation and distribution; use; reuse; recycling; and disposal (Figure 2).

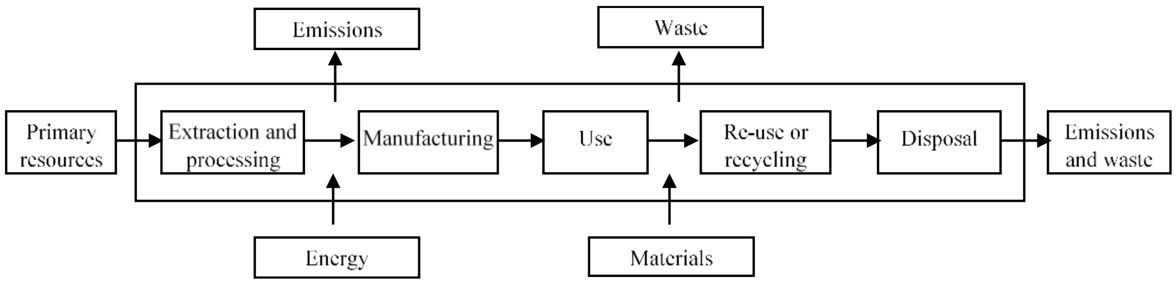

Figure 3. Stages in the life cycle of an activity considered by LCA [44].

The purpose of the LCA in this work is to assess and compare the environmental sustainability of different electricity options for Chile and the system boundaries are drawn from "cradle to grave": therefore, the system considers all environmental burdens generated or resources consumed through all life cycle stages until generation of electricity. In this work the main life cycle stages considered are fuel production, fuel transport, fuel processing, power plant construction, operation and plant decommissioning, including recycling as part of the decommissioning stage.

The definition of the functional unit is another key step in the first phase of LCA and represents the unit in which the impacts are analysed. The functional units selected in this research are focused on electricity generation instead of electricity consumption. This research is focused to study the impacts associated with generation technologies that allows comparing primarily the technologies and then the mix of technologies in the system. On the contrary, electricity consumption considers generation, import and export of electricity, and also electricity losses in transmission and distribution networks. Thus, when it comes to identify the contribution of technologies, technology allocations need to be established for each import. That is why electricity consumption is out of the scope of this research.

Two functional units are defined for this work:

i) generation of 1 kWh of electricity; and
ii) total generation of electricity in Chile over one year.

The former is used to compare different electricity options (Chapter 3 and 4) and different future electricity scenarios among them and the base case (Chapter 6). The latter to assess and compare current electricity mix with the past (Chapter 3 and 4) and with the future scenarios (Chapter 6).

The life cycle inventory (LCI) phase consists of collection of data and calculation to express and summarise the data according the functional unit. For this study, LCI takes into account direct emissions collected for operating thermal power plants in Chile, technical parameters of power plants, fuel composition, infrastructure associated with transport and processing of fuel as well as distances and transport media [45–49]. Ecoinvent has been used as the background database [50], providing life cycle inventory data to enable modelling of the foreground systems. The LCI and data assumption are described in detail at the relevant points in this dissertation (Chapter 3 and 4).

The impacts assessment is carried out using the CML 2001 method as indicated in section 1.4.1.1.1. In this research the environmental impacts have been estimated using GaBi LCA software [51].

The last phase is the interpretation. It consists of the identification of relations between impact assessment and inventory analysis leading to obtaining findings. The findings need to be consistent with the research aims and scope which in turn give rise to draw conclusions.

1.4.2. Multi-criteria decision analysis (MCDA)

Robust decisions involving a range of options must consider a range of environmental, economic and social criteria. Often, there is no single best option in relation to all criteria. Decisions may lead to an improvement in some criteria and a decline in others. In order to support improvements and solve these problems, MCDA methods provide various structured techniques for decision makers [12].

MCDA methods address problems that involve multiple criteria based on preferences for each criterion. This is particularly useful in energy systems because of the various issues that need to be considered and a diverse range of stakeholder perspectives. For that reason, MCDA has been used extensively in relation to sustainable energy [8, 12, 52–55].

Generally, the first step in MCDA involves identification of options or scenarios to be considered and sustainability indicators which will be used as decision criteria. This is followed by defining preferences for different decision criteria by assigning weights of importance. The indicators are then aggregated into a single score based on the weights of importance so that the alternatives or scenario can be compared more easily, thus facilitating identification of the most sustainable option [54, 56].

Derringer's desirability function [57, 58] is simple and easy to handle multi-criteria decision analysis method and flexible for taking into account preferences of decision makers [59, 60]. Additionally, Derringer's desirability function approach are available in several analysis software packages [59]. It has been implemented broadly in several research [60–64].

Derringer's desirability function has been implemented in this study [57, 58] and is described through equations 5 and 6. The overall desirability (D_j) of an alternative or scenario j can be measured based on the individual desirability function ($d_{j,i}$) associated with a criterion or indicator i. The individual desirability represents the conversion of each indicator to a dimensionless scale based on the performance ($Y_{j,i}$) of each scenario regarding an indicator. The individual desirability ranges from 0 for an undesirable situation to 1 for a fully desirable situation. The individual desirability function is chosen from a set of functions based on which situation is more desirable. It may be the case, for example, that the preferred value is the minimum, the maximum, or a specific target value [58]. Derringer's desirability function has the ability to define individual desirability function for each indicator considering if lower, higher or a target values is best. For all of the indicators in this study, a lower value reflects the best condition, as shown in equation 5.

$$d_{j,i} = \begin{cases} 1, & Y_{j,i} \leq Low_i \\ \dfrac{High_i - Y_{j,i}}{High_i - Low_i}, & Low_i < Y_{j,i} < High_i \\ 0, & Y_{j,i} \geq High_i \end{cases} \qquad \text{(Eq. 5)}$$

Where:

j : subscript for scenario

i : subscript for indicator

$d_{j,i}$: individual desirability function of a j scenario regarding an i indicator

$Y_{j,i}$: performance of each j scenario regarding an i indicator

Low_i : the lowest value across the different scenarios regarding an i indicator

$High_i$: the highest value across the different scenarios regarding an i indicator

Where Low_i represents the lowest value across the different scenarios regarding a particular indicator, and $High_i$ is the highest one.

Overall desirability function (equation 6) is calculated using the geometric mean of the individual desirability functions. Weightings can be chosen to express the importance of individual desirability. The overall desirability values are obtained for each scenario.

$$D_j = \left(\prod_{i=1}^{m}\left(d_{j,i}\right)^{w_i}\right)^{\frac{1}{\sum_{i=1}^{m} w_i}}, \qquad i \in \{1,2,\dots,m\} \tag{Eq. 6}$$

Where:

D_j : overall desirability of a scenario

$d_{j,i}$: individual desirability function of a j scenario regarding an i indicator

w_i : weighting assigned to an i indicator in a weighting regime

m : total numbers of indicators

Since the overall desirability varies significantly depending on the weight allocated to each indicator, six different weighting regimes have been modelled in this research as a sensitivity analysis. Different weightings have been assigned to the indicators in each regime. The weighting regimes implemented represent conditions such as all indicators have the same weights entailing more importance to environmental indicators (about 85%) due to 11 out of 13 are environmental indicators. Another regime evaluates economic and environmental aspects with the same importance (50%) distributing weightings equally through the environmental and economic indicators, and also regimes that give higher importance to either economic or environmental aspects and providing equal weights to their corresponding indicators, the results from the MCDA are in Chapter 6.

1.4.3. Data quality assessment

A data quality assessment has been carried out in order to assess the validity of the outcomes of the LCA and the economic assessment for the current situation and for the future scenarios. For these purposes, the pedigree matrix method has been implemented [65]. The data required for modelling of energy systems for LCA and the economic assessment can be obtained in different ways and from varied sources of information. It is essential to know the quality of the data used in this research. In Table 2 is presented a description of the data quality and the associated score for each criterion. In this research, the data collected and implemented have been ranked according to the pedigree matrix described in Table 2. The overall data quality score is the result of adding up the scores obtained from all the criteria.

The data quality assessment implemented in this research is detailed in chapter 6.

Table 2. Pedigree matrix for assessing the data quality (adapted from [65]).

Criteria	Score				
	1 (High)	2	3	4	5 (Low)
Reliability	Verified data based on measurements	Verified data partly based on assumptions or non-verified data based on measurements	Non-verified data partly based on qualified estimates	Qualified estimate	Non-qualified estimate
Completeness	Representative data from all sites relevant for the market considered, over an adequate period to even out normal fluctuations	Representative data from >50% of the sites relevant for the market considered, over an adequate period to even out normal fluctuations	Representative data from only some sites (<<50%) relevant for the market considered or >50% of sites but from shorter periods	Representative data from only one site relevant for the market considered or some sites but from shorter periods	Representativeness unknown or data from a small number of sites and from shorter periods
Temporal correlation	Less than 3 years of difference to the time period of the dataset	Less than 6 years of difference to the time period of the dataset	Less than 10 years of difference to the time period of the dataset	Less than 15 years of difference to the time period of the dataset	Age of data unknown or more than 15 years of difference to the time period of the dataset
Geographical correlation	Data from area under study	Average data from larger area in which the area under study is included	Data from area with similar production conditions	Data from area with slightly similar production conditions	Data from unknown or distinctly different area
Further technological correlation	Data from enterprises, processes and materials under study	Data from processes and materials under study but from different enterprises	Data from processes and materials under study but from different technology	Data on related processes or materials	Data on related processes on laboratory scale or from different technology

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Chapter 2: Sustainability implications of the electricity generation in Chile

This paper is pending submission to an appropriate journal.

This paper contains a review of economic, environmental and social sustainability implications of the electricity generation in Chile. It also describes the actions carried out by the country to overcome the issues identified.

Tables and figures have been amended to fit into the structure of this thesis. The thesis author is the main author of the paper and is the one who read and collected the data for the review paper, and who also wrote the original manuscript. The co-authors are the supervisors of this PhD project and contributed to the paper by reviewing the original manuscript and requesting additional data and information not present in the original manuscript.

Chapter 2

Sustainability implications of the electricity generation in Chile

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Abstract

The electricity sector in Chile was liberalized in 1982 allowing private companies to invest in energy technologies under competitive conditions. Since then, investors have chosen the most economical options taking into account technical and geographical conditions as well as their financial and business strategies in order to ensure profits. As a result of that, the electricity system is shaped by power technologies, with coal heading the current installed capacity. Although economical electricity production options were implemented, the electricity sector in Chile has faced high prices caused by different reasons such as, longer drought periods, a highly concentrated market with low competition, higher fossil fuel price volatility, transmission related constraints and few new investments. This electricity production system has caused many environmental and social impacts. The rise of greenhouse gas emissions and local pollutants, and the release of heavy metals have increased the health risk for the community and increased the loss of biodiversity. The land-use change, increase in water use and population displacement have affected local communities, while high electricity prices has had a negative impact on energy affordability for the community. In addition, high prices have also affected the economy by reducing productivity, competitiveness, employment and national economic growth. Therefore, access for new competitors to the system, reduction of renewable technology barriers and the implementation of an energy policy with higher environmental and social requirements can lead to the development of a more sustainable electricity system.

Keywords: electricity prices; coal power; renewable technologies; social issues; environmental impacts.

2.1. INTRODUCTION

Electricity contributes to all three dimensions of sustainable development: the economy, the environment and society [1]. Electricity is a significant factor for macroeconomic growth when it comes to the economic dimension. It also contributes significantly to global and local environmental impacts such as global warming, acidification, erosion and smog. Furthermore, in terms of social dimension, electricity is considered a basic human need, alongside food and shelter.

The modern history of electricity in Chile started in 1982, when the electricity sector was deregulated with the enactment of the General Law of Electric Utilities (LGSE) [2]. This regulation was developed to promote investment decisions in the electricity system to be made by private agents on the basis of economic signals such as electricity prices [3].

The regulation process has been successful according to Serra [4] and Pollitt [5]. It has allowed private investments and an increase in efficiency within the sector, in a period where: Electricity consumption grew significantly (8% annual); electricity supply to households increased from 38% to 86% in rural areas, and from 95% to 98% in urban areas over a period of 20 years [4, 5]. This regulation model -based in the competitive liberation of the electricity sector- has become popular throughout the region, being implemented in several countries in Latin America [6]. On the contrary, Mundaca [7] suggests that this liberalization -implemented on the basis of a neo-liberal economic model- follows the financial benefits of companies without taking into societal interests. In line with this, energy specialists interviewed by Pistonesi [8] have stated that: This model is not in harmony with national interests; it leaves the government with a reduced capacity to plan properly; and it allows investors to make decisions in the short term with economic, environmental and social consequences over the long term.

The current electricity system in Chile relies greatly on imported fossil fuels and hydroelectricity [9–11]. Fossil fuel dependence makes the country vulnerable to external events by reducing the security of the energy supply [12–15], contributing to high electricity costs and to several environmental impacts, including climate change [14].On the other hand, the diverse geography and climate in Chile gives the country an enormous potential for the development of renewable electricity sources and provides the opportunity to shift towards using sustainable electricity [16]. In this vein, the recent energy policy prepared by the Chilean government has the aim of reaching a more sustainable electricity system by 2050 through continuous improvements based on four attributes: Reliability, social inclusiveness, economic competitiveness and environmental sustainability [17].

In an attempt to address the sustainability challenges that the electricity sector is facing, this article aims to discuss the causes that have led to the electricity system facing many sustainability issues. Additionally, the progress which is achieved by the implementation of renewable technologies is presented in order to glimpse its future contribution to sustainability.

2.2. CONFIGURATION OF THE CURRENT ELECTRICITY SYSTEM

Chile's electricity system owns two interconnected power systems: The Interconnected System of Norte Grande (SING) and the Central Interconnected System (SIC) [9]. The SING is located in the northern part of the country shaped by thermal power plants. This system produced 17.7 TWh in 2014 to supply electricity mainly to mining companies (89%) and 6% of the country's population (11%) [18, 19]. The SIC is located in the central zone of Chile with a production of 52.2 TWh in 2014 to supply electricity to 93% of the country's population (61%) and to mining and manufacturing industries (39%). This system is shaped by hydropower plants and thermoelectric plants [9, 20]. A transmission line connecting both interconnected systems is expected to be in operation for 2018 and a new system (the National Electricity System) will be established [21].

The installed capacity of the electricity system (SING and SIC) in 2014 was 20,265 MW divided by 32% hydro, 25% natural gas, 22% coal, 14% oil, 4% wind, 2% biomass, and 1 % solar [22–24]. In the same vein, the electricity production was 70 TWh (Figure 4) with the following breakdown: 40% coal, 34% hydro, 15% natural gas, 5% oil, 4% biomass, 2% wind and 1% solar [18].

2.3. SUSTAINABILITY OF THE ELECTRICITY SYSTEM

Several authors have analyzed specific aspects of the sustainability of the Chilean electricity sector. MAPS Chile [25] assessed the environmental perspective with a focus on climate change through the estimation of greenhouse gas (GHG) emissions and the development of mitigation scenarios. Gebremedhin [14] and Foundation Chile [26] analyzed the economic and environmental dimension of the electricity system taking into account economic indicators, GHG emissions, land use and local contaminants such as nitrogen oxides, sulfur dioxide and particulate matter. Likewise, as a consequence of the development of the government energy policy by 2050 [17], a strategic environmental assessment study reported the sustainability topics needed to be considered during the policy implementation. This study assessed climate change, social wellbeing, aboriginal affairs, vulnerable groups, equal energy access, endogenous energy resources, environmental quality, integration and local development, harmonious and balanced land use, biodiversity conservation, energy efficiency, regional and international energy integration, energy security, energy cost and price, competitiveness and the energy market [27]. An analysis of the causes and consequences of the development of the electricity system over the last two decades -as addressed from a sustainability perspective- is presented in the following sections.

2.3.1. Economical perspective

2.3.1.1. Major periods

Over the last two decades the electricity sector has experienced several crises which led to a restriction in the supply and increase of electricity prices (Figure 5) with a significant impact on society [3, 28, 29]. In the present study, three major periods have been identified, namely: i) reform adjustments; ii) gas curtailment and iii) coal and liquefied natural gas (LNG).

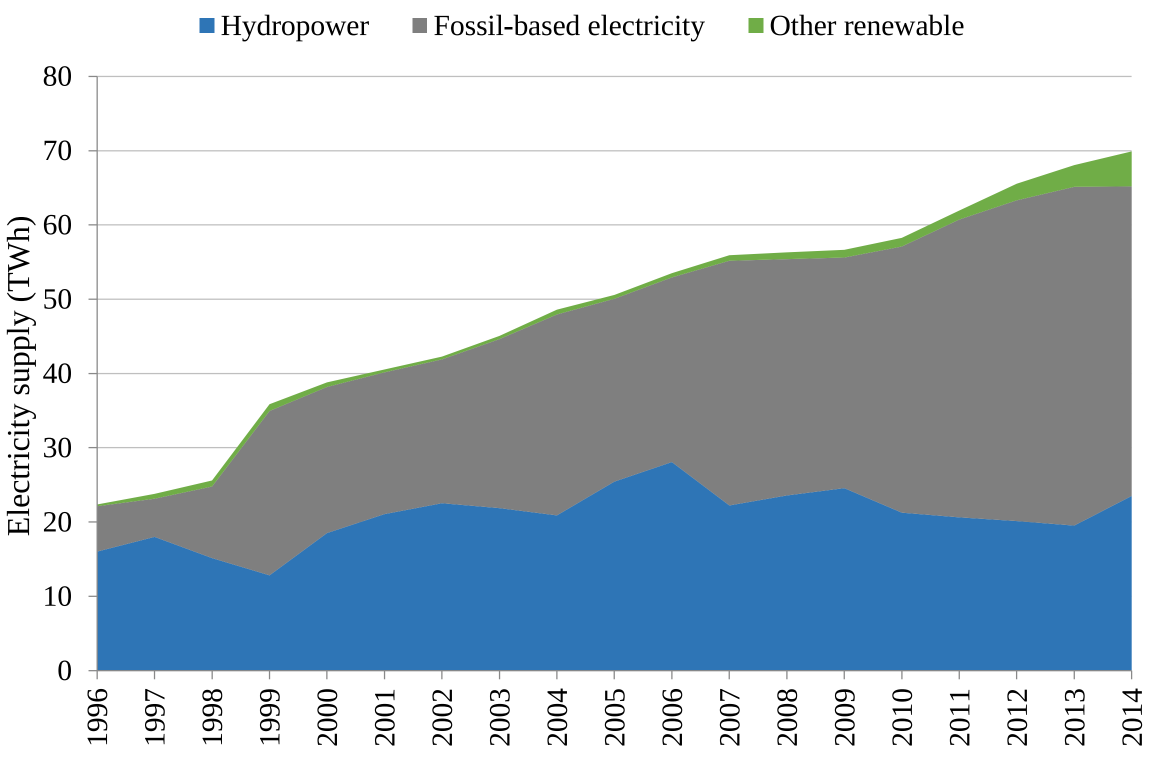

Figure 4. Electricity supply in Chile between 1996 and 2014 [18].

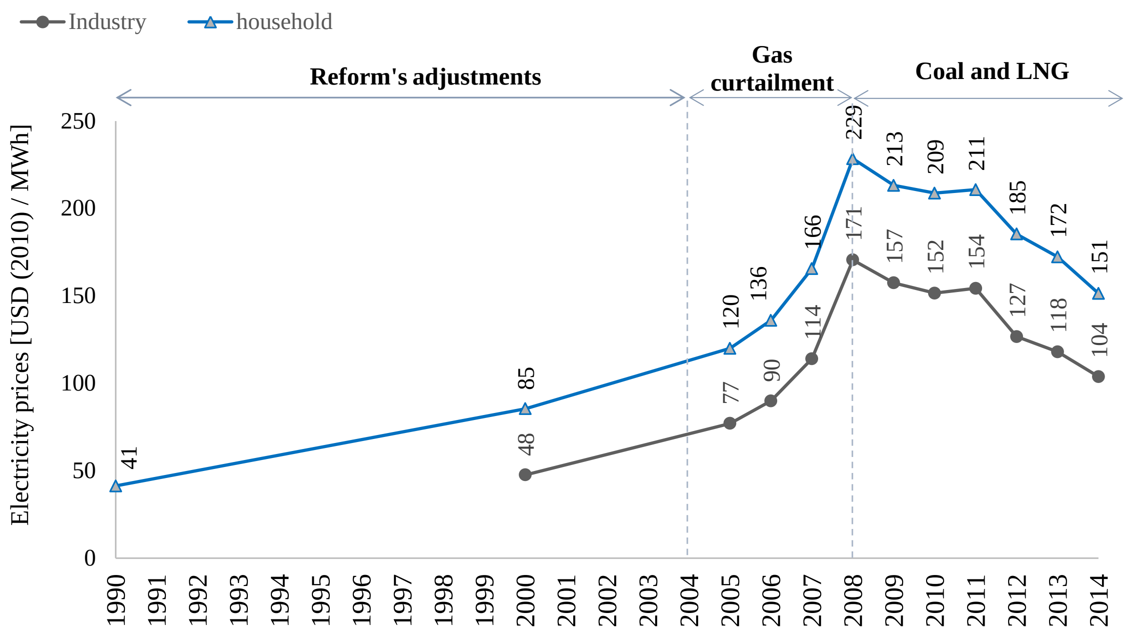

Figure 5. Electricity prices in Chile between 1990 and 2014 [30]. [LNG: Liquefied natural gas].

2.3.1.1.1. Reform adjustments

After the reform of 1982, the electricity sector has been in a state of continuous improvement with regards to the regulations in order to adjust to the unforeseen. Examples of these events are the crisis in 1998-1999 when hydropower in the central interconnected system (SIC) was affected by a severe drought that caused the rationing of the electricity supply to the residential and industrial sectors [3]. A second crisis in 1999 affected the northern interconnected system (SING). This system was not able to cope with a rapid growth in demand, due to the high consumption of mining companies. This was solved with the connection to the natural gas from Argentina between 2000 and 2004. The reform adjustments period is characterised by low prices in electricity with a steady increase caused by the aforementioned crisis [4].

2.3.1.1.2. Gas curtailment

The third crisis started in 2004 and its effects increased in 2007 when Argentina sharply restricted the export of natural gas to Chile [3]. Gas curtailment from Argentina from 2004, together with higher rates of energy demand between 2006 and 2008, and a lingering period of drought led to the increased use of fuel oil and diesel power plants causing electricity prices to go up [7, 29, 31].

2.3.1.1.3. Coal and LNG

As a result of the gas curtailment, natural gas consumption fell sharply from a high point of 8.4 bm^3 (billion cubic meters) in 2005 to 2.8 bm^3 in 2008 [32]. In response, coal power was promoted in order to reduce the prices and increase capacity in the system. A 100% increase can be observed (2 GW) in the new coal power capacity over four years alone (2008-2012) (Figure 6). Simultaneously, the government set the conditions to implement the supply of LNG. The gas market improved in 2009 due to the opening in Chile of the new Quintero LNG terminal, obtaining 3.3 bm^3. This recovery was followed by the advent of Mejillones LNG terminal. These developments were important to fulfil the natural gas demand, then at 5.0 bm^3 by year 2012 [32] and allowed many gas power plants to start up again. These two issues contributed to reduce electricity prices for the industry sector, with coal power commissioning the most preponderant event [7, 10, 33]. Electricity prices for the industry dropped from 171 $/MWh in 2008 to 118 per $/MWh in 2013. The electricity price for industry in the country dropped below the average price of the Organisation for Economic Co-operation and Development (OECD) countries to 123 $/MWh in 2013 (Figure 7) [30]. In spite of this, the electricity prices for industry in this period have remained higher in comparison to other South American countries such as Argentina, Venezuela, Paraguay, Bolivia, and Ecuador [11, 34]. Countries such as the United States and Peru are copper and metal ore exporters and therefore competitors [31, 35].

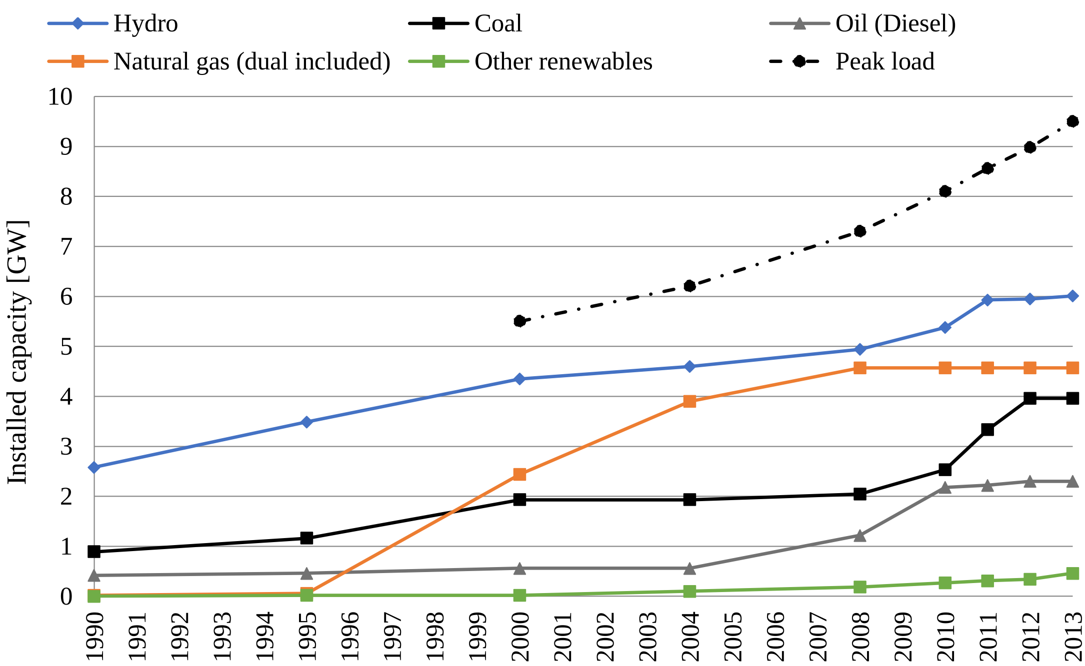

Figure 6. Accumulated installed capacity by technology in the period 1990 and 2013[9, 24].

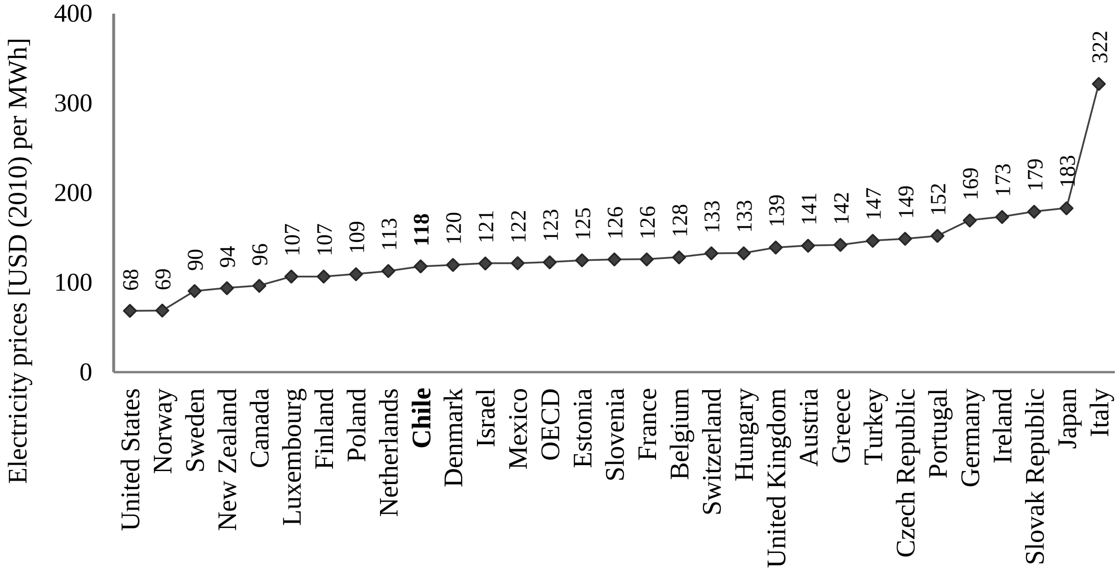

Figure 7. Electricity prices for industry in 2013 in OECD countries [Prices 2010=100] [30].

On the other hand, prices of electricity in households remained high because of the increasing prices gained in the auctions as set for the residential and commercial consumption sector whose contracts are established over the long-term. When electricity prices of households within countries of the OECD (Figure 8) are compared, the situation confirms that the Chilean society is enduring higher electricity prices. Figure 8 shows Chile in position 17 out of 30 with 240 $/MWh of Purchasing Power Parity (PPP) and above the OECD average of 170 $/MWh (PPP) [30].

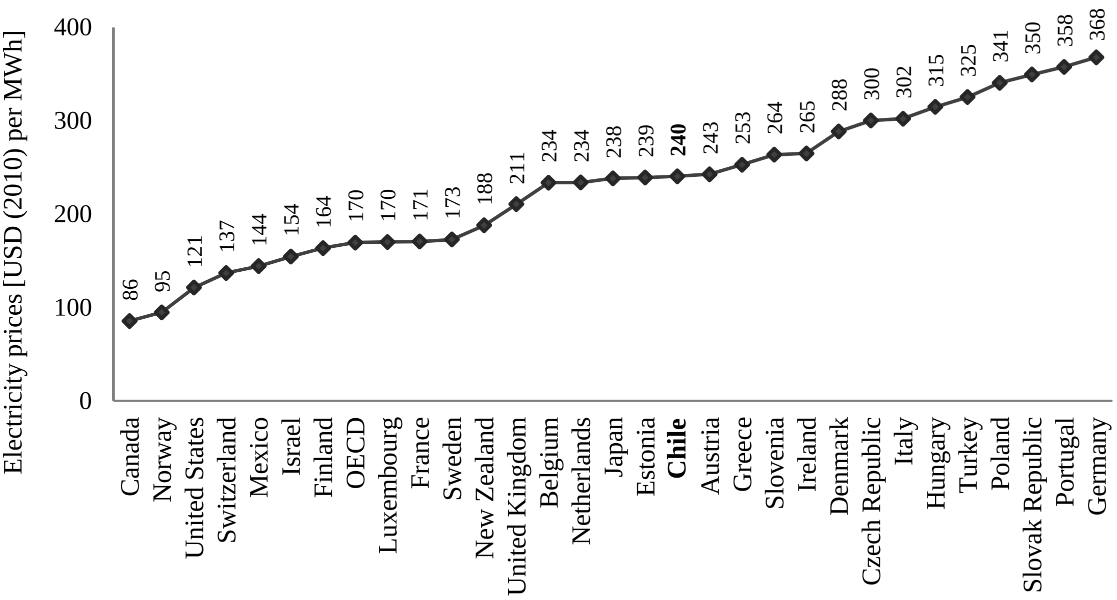

Figure 8. Household electricity prices in 2013 in OECD countries. Purchasing power parity. [Prices 2010=100] (taxes included) [30].

2.3.1.2. <u>The underlying factors of higher prices</u>

High electricity prices experienced by the electricity system over the last 15 years (Figure 5) can be explained due to the effect of at least three factors: Hydrological variability, a concentrated market and fossil fuel dependence and price volatility.

2.3.1.2.1. Hydrological variability

In relation to hydroelectricity, hydropower plants contributed to 52.3% of the total capacity of the SIC system in 2009. Hydropower is an efficient technology; however, it is vulnerable to hydrological conditions. In a wet-year condition, hydropower plants can supply over 81% of the overall electricity demand; however, in a dry-year the same installed capacity can produce just 27% of the electricity demanded [29]. As previously mentioned, the droughts suffered by the country in the past have contributed to the electricity system experiencing difficulties. For example, in 1998-1999, the phenomenon called El Niño Southern Oscillation (ENSO) provoked a severe and unexpected drought [36]. The system operator -as usual- dispatched a high production of hydroelectricity, awaiting upcoming rains and ignoring the rain deficit (Figure 9) [3]. The most recent drought episode lasted nearly three years between 2010 and 2013 [37, 38] and this phenomenon may increase in intensity in the upcoming years [39].

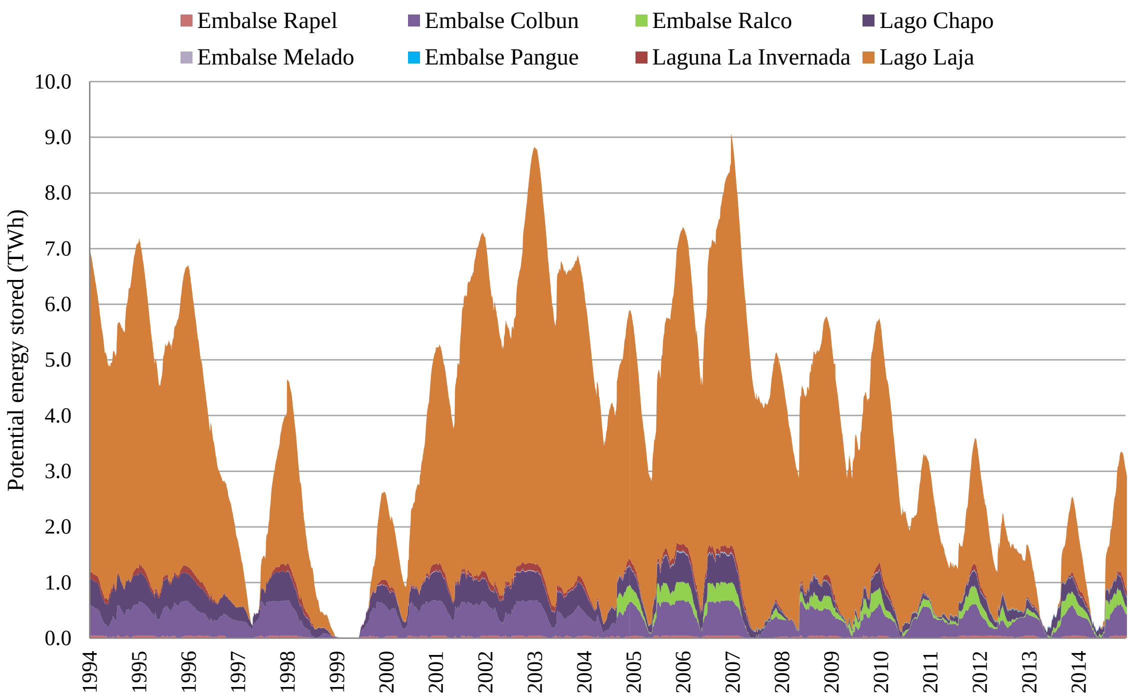

Figure 9. Total accumulated energy in reservoirs for hydroelectric power between 1994 and 2014 [40].

2.3.1.2.2. A concentrated market

Another explanation behind the higher prices is that the sector is highly concentrated. The companies Endesa, Gener and Colbun owned 92.1% of the installed capacity of SIC in 2001, and today their shares still reach 76% [4, 9, 35]. This highly concentrated market may allow companies to exert market power through many ways [4, 13, 41–43]. For instance, the vertical integration of the previously estate-owned company (Endesa). This company -after the privatisation process- was in a favourable position as it was in charge not only of generation, but also of the transmission system [4, 43, 44]. Practices such as carrying out strategically low levels of investment in new power plants, leaving power plants out of work through the use of a strategic maintenance plan, or over investing in peak load technology can increase the number of hours that the system capacity is restricted to [13, 42, 45, 46]. The lack of competition has been identified by the government as one of the major problems in the electricity market, where a concentrated market causes less investment, higher electricity prices and more profitability for market agents [11, 35].

2.3.1.2.3. Fossil fuel dependence and price volatility

Finally, the third major cause behind high electricity prices is fossil fuel dependence and price volatility. In 2007 many fuel oil and diesel power plants were commissioned (Figure 6) in order to fulfil the energy demand left by natural gas due to the gas curtailment [7, 10]. Gradually, the electricity demand increased from 2009 onwards, and the electricity from fossil fuels reached a peak in 2013 showing a higher dependency on fossil fuel (Figure 4), whilst in the same period the international price of fossil fuels showed a trend of high variability (Figure 10).

2.3.1.3. Economic effects of high electricity prices

Since 2004 high electricity prices in Chile have been causing serious consequences for the economy, affecting investment, consumption, employment and productivity [31]. An estimation carried out by Garcia [47] demonstrated a permanent increase of 10% in electricity prices which may cause a reduction in quarterly GDP growth by up to 0.2%. For instance, the increase in electricity price is transferred to companies and the community. This provokes a decrease in net income for households and an increase in total costs for companies. In that sense, a fall in the purchase power of households occurs, reducing asset demand and generating a recessive economic environment [31].

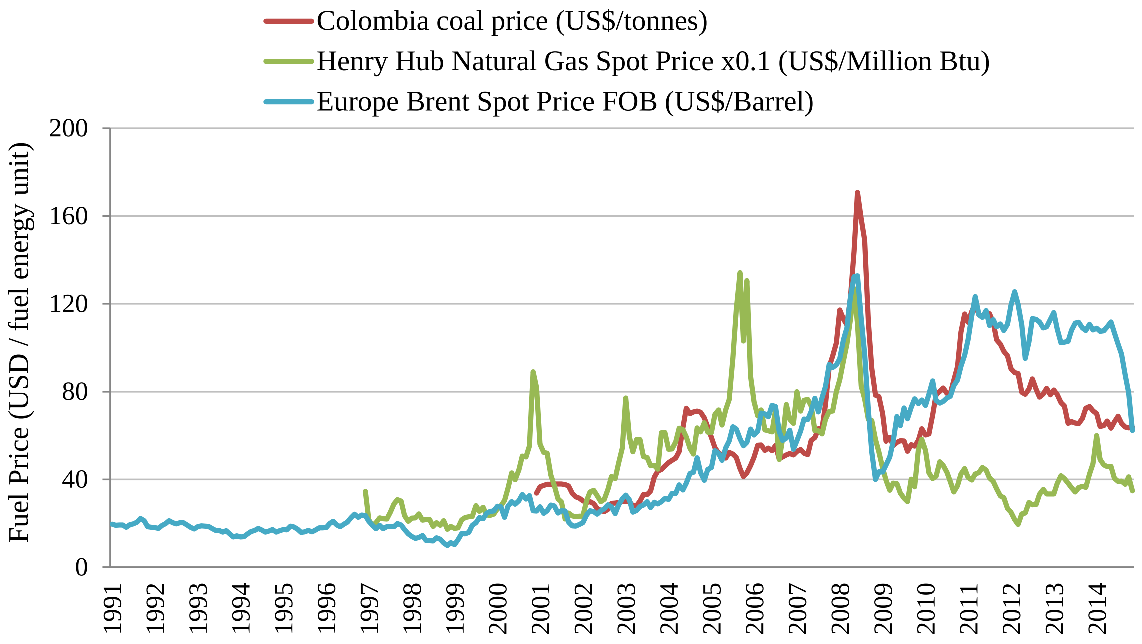

Figure 10. International prices of fossil fuel between 1991 and 2014 [48, 49].

A report from the International Monetary Fund (IMF) stated that the price of electricity in Chile does not differ significantly from the average for the rest of the world [34]. However, Chile's economic competitors had lower electricity prices than Chile [34]. An example is the case of copper. Chile is the world's main copper exporter and the copper industry is a significant economic activity for the country; however, Peru and US (also copper producing countries) have significantly lower electricity prices [31]. Overall, a higher electricity price makes companies less competitive and reduces their profits in a globalised economy [47]. As a result, exports lose dynamism, domestic consumption becomes more intensive in imports, and investors go to economies where the electricity price is lower [31]. Finally, companies with intensive electricity use -such as copper companies in Chile- can become less profitable and reduce their work force. This reduces the income of households and tax revenues and diminishes the flexibility of the economy [47]. Moreover, uncertainty about the future trend of electricity prices results in a delay in investment decisions [31].

2.3.2. The environmental perspective

In 1994, Chile enacted a general law on the environment [50] and implemented the environmental impact assessment system focused on taking into account environmental aspects associated with new investment projects, including new power projects. In spite of this, power projects have not been able to avoid the contamination and subsequent environmental impacts in the surrounding communities. The districts of Tocopilla, Mejillones, Huasco, Ventana, Quinteros and Coronel are all examples of this situation. The installed coal power capacity in those districts represents 89% of total coal power in the country and, similarly, installed gas power capacity represents 43% [24]. All of those districts have been declared by the authority as contaminated zones of particulate matter, with the classification of latent areas or saturated zones, dependant on the level of contamination [51]. This has led the government to implement decontamination plans focused on tightening emission norms for fossil-based power plants [52]. Other local contaminants associated with combustion of fossil fuels such as SO_2, NOx, and heavy metals have been found in dust and sea sediment in these districts. In this vein, a high content of heavy metals -well above international standards- has been found in the soil and roofs of primary schools in those localities causing great concern among the local communities [53–57]. The craft fishing sector has also shown a strong opposition to thermoelectric projects and has argued that power projects have caused a reduction in fish species due to the release of heavy metals and warm water discharged by cooling systems [55].

In terms of global impacts, the burning of fossil fuels in the electricity sector is associated with global warming due to the emission of greenhouse gases [7, 58, 59]. Several studies in Chile have been focused on quantifying emissions, identifying actions to mitigate emissions and preparing plans to adapt to climate change [26, 60–63]. The total greenhouse gas (GHG) emissions in Chile reached an equivalent value of 92 million tonnes of CO_2 in 2010 [58]. It has been estimated that electricity generation and transmission represents 29% of those emissions (27 million tonnes CO_2 equivalent) [64]. The Chilean Government presented a mitigation plan in 2014 where the main aspects proposed for the electricity sector were: The promotion of renewable energy technologies with the integration of distributed generation; the reduction of transmission constraints; the promotion of energy storage technologies; the improvement in mechanisms designed to control the generation and demand of electricity, and; the implementation of low carbon technologies, such as carbon capture and storage for thermal power plants and nuclear power [25, 59, 63].

2.3.3. Social aspects

The poorest family groups in Chile spend 12.7% of their household income on energy where electricity represents a 63% of this energy expenditure (Figure 11). This level of expenditure compromises energy affordability and increases inequality [65].

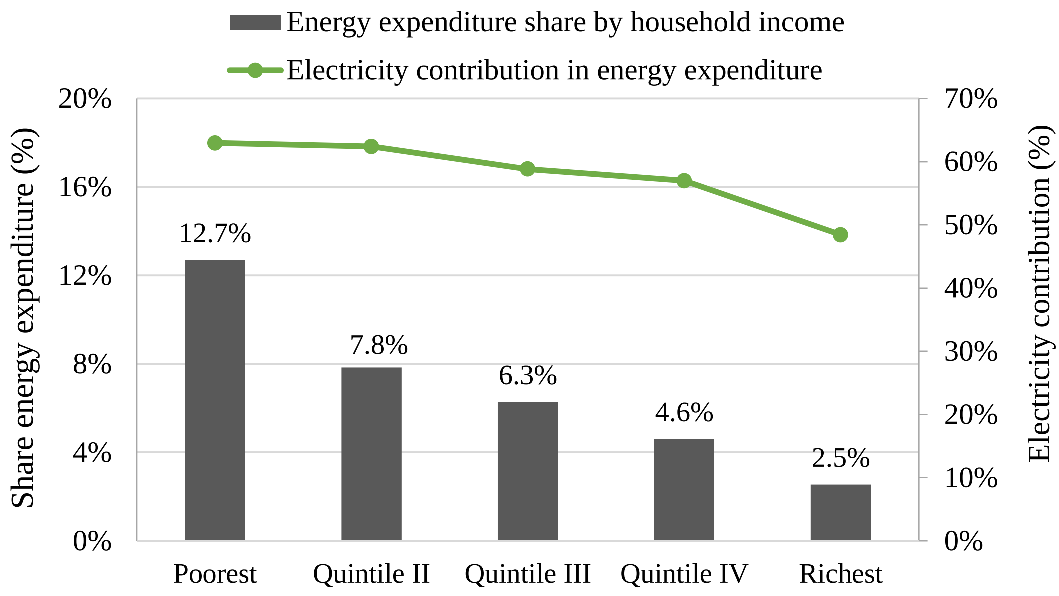

Figure 11. Share of energy expenditure of household income and electricity contribution in 2012 [65].

The development of electricity projects has faced social opposition since 1992 when indigenous leaders disapproved the construction of the Pangue and Ralco hydropower plants and were requested to leave their ancestral territories [66, 67]. In 2011, the Ministry of Energy conducted a study to identify the difficulties experienced by electricity projects in progression to commissioning or gaining environmental permits (Figure 12) [68]. In total, 10 projects (predominantly hydropower dams and thermal power plants) received 102 administrative or legal objections, demonstrating high social opposition [68]. This is in part explained by Mundaca [7], who stated that Chile's environmental framework law permits private companies to choose the information to be presented in the Environmental Impact Assessment (EIA) system and therefore, allows manipulation, lessens transparency and suppresses opportunities for public discussion on the assessment process. Similarly, Berdegue [69] stated that society's continuous opposition to new power projects is due to the lack of legitimacy in the environmental assessment process which does not provide an effective space for discussion. Furthermore, the distribution of costs and benefits for affected communities is not adequate.

Similarly, the National Institute of Human Rights delivered a report [55] with the selection of 97 projects in different sectors -either in evaluation or operation- which shows conflicts with communities. From those projects, 37% are conventional power plants.

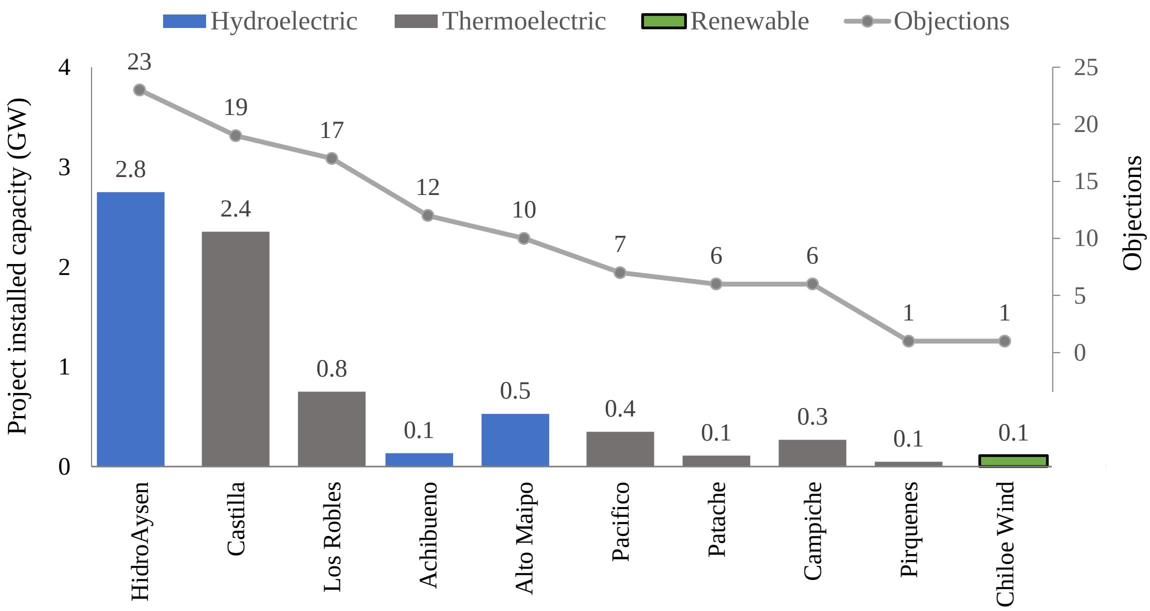

Figure 12. Power projects with legal objections [68]

2.4. RENEWABLE ENERGY

2.4.1. Renewable energy regulation and the quota system

Two type of consumers were created by the General Law of Electric Utilities [2]: Regulated and non-regulated consumers. Non-regulated consumers are intense energy-use companies who can make direct contracts with generators. Regulated consumers are residential and commercial consumers who should receive their electrical supply from their distribution companies. Therefore, regulated consumers pay a tariff established by the authority. The law also defined the wholesale market, which can be classified as the contracts market and the spot market. The contract market is classified as follows: i) non-regulated consumers and generators, who can negotiate freely for their electricity supply by establishing contracts; and ii) generators and distribution companies, for which distribution companies -in representation of regulated consumer- awards bid with the lowest prices through an open competitive tendering process. The spot market was designed for generators to trade differences between: a. the contractual commitments of the generators with its customers, and; b. its actual dispatched electricity [3, 9]. The electricity dispatch is established by the system operator on the basis of the variable costs. The power plants with lower costs are dispatched primarily. In this way, the electricity of the system is valued according to the marginal costs as a result of the system operation [70].

The Law 20,257 [71] defined non-conventional renewable energy (NCRE) as: Renewable energy sources or combinations of these not largely used in Chile at the moment in order to produce electricity. Concepts such as wind power, geothermal energy, solar energy (thermal and photovoltaic), marine and biomass power are considered in this definition [9, 10, 72]. Hydropower plants with less than 40 MW of installed capacity are also part of the NCRE. The quota system is the most significant instrument developed to promote these non-conventional renewable energy sources. In this sense, every year, a previously stabilised amount of electricity should be produced from NCRE. This quota rule applies to generation companies with an installed capacity above 200 MW of conventional power generation [9]. The target increases annually until 2025, when 20% of the total electricity produced should be from NCRE [73].

The quota system has successfully promoted NCRE [11]. As the overnight costs of NCRE projects have been higher, long-term contracts with generation companies - called the power purchase agreement (PPA) - have allowed, to some extent, the leverage of renewable energy technologies in the country [74]. However, the contribution of NCRE has still been low [11].

NCRE project developers have established other mechanisms to finance their projects. They have made PPAs of a proportion of the energy to be produced by the project, while the rest would be traded in the spot market, where generation companies trade the energy produced in order to fulfil their respective contracts [10, 72]. Secondly, all of the electricity produced by the projects can be traded in the spot market [72, 75].

Since NCRE projects have low or null operational costs, the system operator must dispatch them in the first instance. This contributes to reduce the spot price; however, its variability poses a challenge to the system operator to meet supply and demand at any moment [72, 75]. Despite the options, the spot market has not been a convincing alternative, because the spot market has a high variability in prices, due to the significant contribution of hydropower and the fluctuation of fossil fuel prices, allowing NCRE investors to assume a high risk [11].

With the reduction in the cost of wind and solar photovoltaic (PV) power, these projects have become more economically competitive [11]. However, despite this progress, NCRE projects had not been able to set contracts with regulated-consumers (distribution companies), which represent 50% of the electricity demand in the country. This was mainly because the intermittency and variability of solar and wind energy do not allow them to present bids in the auctions for regulated-consumers. The auctions' proceedings would have required that projects awarded should ensure that the contracted energy must be available 24 hours a day whenever required [74].

The government has taken further action to improve the deployment of NCRE [35]:

1. Implementation of a scheme of hourly energy-blocks in the auctions. This scheme divides the day into three or more periods allowing NCRE projects to present a bid for those blocks where they are more likely to produce energy [11, 76].
2. Extension of contract terms from 15 years to 20 years in order to ensure the payback period. NCRE can now bid in regulated-consumer auctions with contracts long enough to ensure their feasibility [76].
3. Interconnection between SIC and SING has been fostered. This will contribute to transport renewable energy (mainly solar) from the northern part of the country - one of the highest solar radiation regions in the world - to the rest of the country [35].
4. Reform of the transmission system and definition of the “Electricity Generation Development Poles” which are zones with greater renewable energy resources. Consequently, it would be possible to construct a unique transmission line with the capacity to transport the potential energy of a particular development pole to the main transmission system [21]. This will be useful considering that areas with greater renewable energy sources are more commonly situated far away from the main transmission lines. Additionally, this reform aims to improve the transmission capacity in current areas where today’s renewable projects cannot inject the total energy produced due to transmission line congestion [21].

2.4.2. Deployment of renewables and their current power potential

The installed capacity of NCRE sources represents less than 3% of the total installed capacity in 2008 [9]. With the implementation of reforms, a significant growth in new NCRE has occurred, with 2014 experiencing a very sharp growth of 288% in new investments in relation to 2013 [77]. Solar PV rose from 4 MW in 2013 to 402 MW in 2014, wind from 335 to 836 MW, and biomass from 420 MW to 466 MW. Plants under construction have a capacity of 1,242 MW, allowing NCRE to increase by more than 50% by 2015 [77].

Additionally, the perspectives of the deployment of NCRE are even more auspicious considering the capacity of projects which are environmentally approved. The pool of projects waiting to be commissioned has a capacity of 14,725 MW. The most promising option is solar PV with a significant power potential of 1500 GW [78, 79], and currently with 833 MW under construction and more than 12,000 MW of projected plants (Table 3).

Table 3. Situation of non-conventional renewable energy in Chile in 2014 [77].

Technology	Online plants	Under construction	Environmentally approved	EIA[d] under process
Biomass (MW)	466	0	134	69
Biogas (MW)	43	0	1	8
Wind (MW)	836	165	5,225	2,179
Run-of-river[a] (MW)	350	134	337	215
Solar PV[b] (MW)	402	833	8,149	4,008
Solar CSP[c] (MW)	0	110	760	370
Geothermal (MW)	0	0	120	0
Total (MW)	**2,097**	**1,242**	**14,725**	**6,849**

[a]Run-of-river < 20MW, [b]PV: Photovoltaic, [c]CSP: Concentrating solar power, [d]EIA: Environmental impacts assessment.

2.5. CONCLUSION

High levels of market concentration in Chile has entailed to low competition and it has led to market agents to exert market power. This, together with hydrological variability, volatile fossil fuel prices, curtailment in natural gas supply, and high energy demand have contributed to high prices in the final years of the 2000's decade. In order to reduce prices, new coal power plants were developed over the following years. However, the reduction in prices was still low. High prices have had economic and social consequences. At the macroeconomic level, the high prices have driven to a loss of competitiveness and productivity causing a reduction in economic growth rate. Besides, the current fossil-based power plants have contributed to several environmental impacts such as the existence of highly contaminated districts with air pollution of particulate matter and heavy metals affecting the soil and water in the land and coast. Consequently, the Chilean society has been shown strong opposition to new investments in the electricity sector, as the poorer classes cannot afford the high costs of electricity to fulfil their basic energy needs and because of the environmental impacts that these technologies cause.

Renewables have become regarded as strategic resources as they contribute to energy security by reducing fossil fuel dependency, to increase investment diversification and to reduce greenhouse gas emissions and other environmental impacts. In order to increase renewables investment, a quota system for renewables has been successfully implemented by establishing that big electricity companies to develop or contract new investments in renewables. In order to attain lower prices and increase the sustainability of the system, the government fostered competitiveness in the market. This has been achieved by reducing the barrier for renewables by means of changes in electricity tendering procedures of the regulated consumers. This resulted in attracting a high interest of international investors through long-term contracts and conducting current big electricity companies to bid lower costs of electricity than before. The reduction of electricity prices and the increase in new renewables investments was also triggered by the reduction of capital cost of wind and solar PV alongside high capacity factors that are available in the country making those technologies much more competitive.

Several electricity sustainability issues experienced in the last decade in the country are being addressed through proper implementation of policies taking advantage of rich natural resources that the country has. Although the investments in renewables have increased in recent years, there is still a high contribution of fossil fuel in the electricity system. Therefore, the economic, social and environmental impacts need to be assessed in order to identify further improvements in the system to enhance the sustainability of the sector.

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Chapter 3: Life cycle environmental impacts of electricity from fossil fuels in Chile

This paper is pending submission to an appropriate journal.

This paper presents the life cycle assessment (LCA) of current electricity generation from fossil fuel in Chile. Tables and figures have been amended to fit into the structure of this thesis. The thesis author is the main author of the paper and is the one who collected the life cycle inventory data needed to model the fossil fuel electricity options for Chile and interpreted the results. The thesis author also wrote the original manuscript. The co-authors are the supervisors of this PhD project and contributed to the paper by reviewing the LCA model implemented and results in the original manuscript and requesting modifications to improve the resulting manuscript.

Life cycle environmental impacts of electricity from fossil fuels in Chile

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Abstract

This study uses life cycle assessment to evaluate the environmental impacts of electricity generated from fossil fuels in Chile over a period of ten years, from 2004-2014. The focus on fossil fuels is highly relevant for Chile because 60% of electricity currently comes from natural gas, coal and oil. The impacts are first considered at the level of individual technologies, followed by the evaluation of the fossil-fuel electricity mix in the period. The study has been carried out using detailed primary data from 94 operating plants. Considering individual technologies, electricity from gas has the lowest impacts in all 11 impact categories considered. By contrast, coal power shows the worst performance for eight categories, with eutrophication, freshwater and marine ecotoxicity being between ten and 240 times greater than for gas. However, oil is worse than coal for photochemical oxidants (31%) and depletion of elements and ozone layer (four and eight times, respectively). Between 2004 and 2014, the annual environmental impacts doubled, while electricity generation rose only by 55%. The only exception to this is ozone depletion which fell by 5%. The highest impacts occurred in 2014 mainly because of the high contribution of coal power. Therefore, the environmental performance of fossil-based electricity in Chile has worsened over time due to the growing share of coal power, coupled with the increasing electricity demand. Consequently, policy should aim to reduce the contribution of coal electricity, along with reducing the total generation from fossil fuels.

Keywords: Climate change; power generation; coal; oil; gas; life cycle assessment.

3.1. INTRODUCTION

Historically, the electricity in Chile was mainly supplied by hydropower [1]. However, since the 90s, steady economic growth has led to an increase in electricity consumption, which has been growing by 7% annually [2]. Consequently, electricity demand could no longer be covered only by new hydropower installations, but had to be supplemented by coal, natural gas and oil power [1, 3, 4]. As can be seen in Figure 13, this trend has continued over the years and nowadays the majority of electricity is generated from fossil fuels (60%) [5–7]. In total, 94 power plants are in operation in Chile: 19 coal, four gas, 60 oil and 11 dual-fuel (oil and gas) installations. Their total installed capacity is 10.4 GW, comprising the following technologies (Figure 14): circulating fluidised bed (4%), pulverised coal (36%), combined cycle (32%), open cycle (20%) and diesel engine (8%).

In term of electricity generation from fossil fuel, coal contributes 69%, natural gas 24% and oil 7% [7]. As Chile has low reserves of fossil fuels, most are imported [5, 6]. A growing number of studies are reporting a significant potential of renewable energies [8–24] which could gradually substitute fossil fuels. However, in the case of hydropower, which is still a significant contributor to power generation in Chile (34%), the major difficulty in continuing its development is the social opposition [25]. Therefore, the government is implementing measures for the deployment of other renewable energy sources, such as solar, wind and geothermal [26, 27]. However, the contribution of these technologies is still low [28]. Therefore, in the medium term, fossil fuels will continue to contribute significantly to the electricity generation profile of Chile.

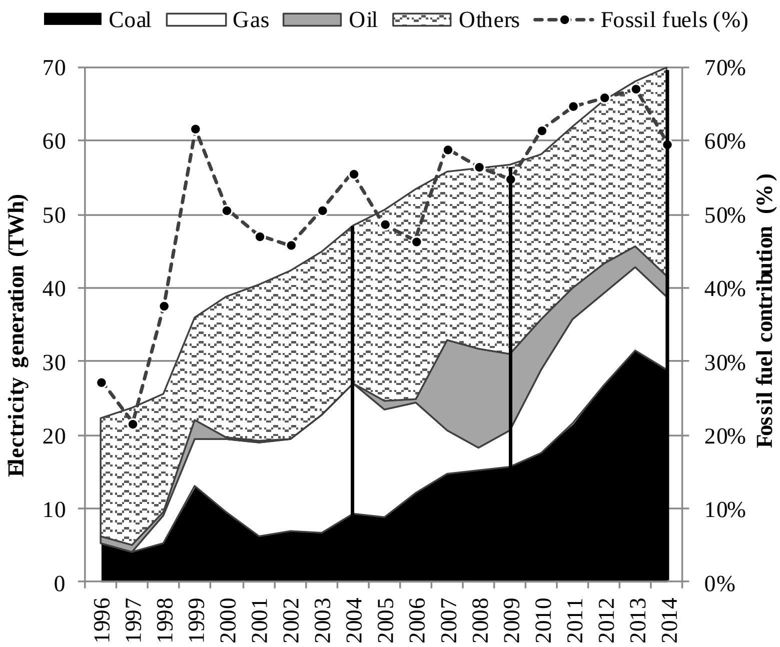


Figure 13. Electricity generation in Chile by source and contribution of fossil fuel in the period 1996-2014. [Vertical black lines denote the years chosen for the assessment in this study (2004, 2009 and 2014) [7, 29]].

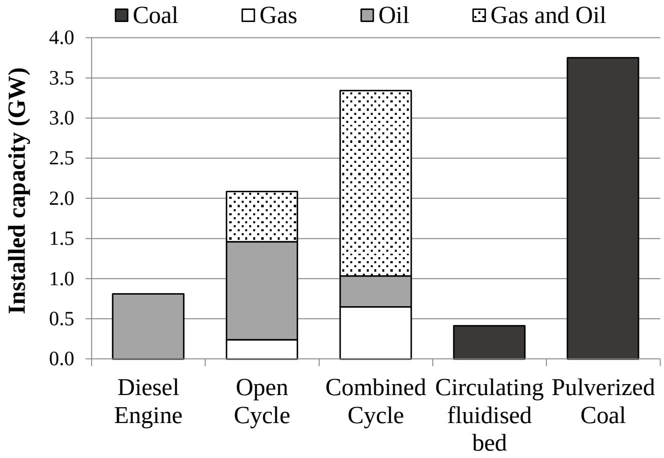


Figure 14. Current installed capacity in Chile by technology and fuel [30].

Globally, electricity has been by far the most important source of anthropogenic CO_2 since 1970s [31] contributing to climate change, and Chile is no exception [1]. As a result of a high contribution of fossil fuels to the electricity generation, the electricity sector emitted 30% of the total greenhouse gas (GHG) emissions in the country in 2010, equating to 27 Mt of CO_2 eq. [32]. The Chilean Government has committed to reducing GHG emissions per unit of GDP by 30% by 2030, relative to 2007 [33]. However, at present there is scant information on the contribution of fossil fuel electricity to the GHG emissions on a life cycle basis, with other life cycle impacts being also largely unknown. Although two recent studies estimated life cycle impacts of electricity in Chile [34, 35], they both considered the whole electricity sector rather than focusing on the fossil-fuel sources. A similar situation is found for other countries, in which life cycle assessment studies (LCA) have been carried out for the whole sector [36–39]. Therefore, this paper focuses of fossil-fuel power in Chile in an attempt to provide comprehensive information on its environmental impacts and inform policy. The impacts are estimated through LCA for each technology as well as for the fossil-fuel electricity mix. A temporal evolution of the impacts over a ten-year period (2004-2014) is also considered to determine how the impacts may have changed and why. The study relies on real data from the 94 plants currently operating in Chile. These are detailed in the next section, together with methods and assumptions used in the study.

3.2. METHODOLOGY

The LCA study has been carried out following the ISO 14040 and ISO 14044 standards [40, 41], with the goal and scope defined next, followed by the inventory data and impacts considered in this work.

3.2.1. Goal and scope definition

The main goal of the study is to estimate the life cycle environmental impacts of fossil-fuel electricity generation in Chile over the period from 2004 to 2014. Two functional units are considered:

- 1 kWh of electricity generated by coal, natural gas and oil power plants; and
- annual generation of electricity from these plants over the ten-year period.

As illustrated in Figure 15, the scope of the study is from ‘cradle to grave’. The following stages are included: extraction, transport and processing of fossil fuels, power plant construction, operation and decommissioning, and end-of-life waste management. Transmission, distribution and use of electricity are outside the system boundaries as the focus is on generation.

3.2.2. Inventory data and assumptions

This study considers plants which are part of two major electricity transmission systems in Chile, representing 98% of the total electricity generation [7]. These systems are the Interconnected System of Norte Grande (SING) and Central Interconnected System (SIC).

Primary data have been sourced from the National Energy Commission (CNE), Energy Ministry, National Service of Geology and Mining (SERNAGEOMIN), Environmental protection agency (SMA), Load Economic Dispatch Centre of Central Interconnected System (CDEC-SIC) and the Load Economic Dispatch Centre of Interconnected System of Norte Grande (CDEC-SING). Additional information has been obtained from other institutional reports and academic literature as indicated below. The background data have been sourced from Ecoinvent 2.2 [42].

3.2.2.1. Current situation: fuel supply and power plants

The base year chosen for the study is 2014, the most recent year for which detailed data have been available. Total generation of fossil-based electricity in 2014 was 41,634 GWh, of which coal contributed 69%, gas 24% and oil 7%. Detailed data on the coal, gas and oil power plants are provided in Table 4-Table 6, while an overview of all data and assumptions can be found in Table 7. The following sections provide more detail on each type of fuel and the technologies respective generating technologies.

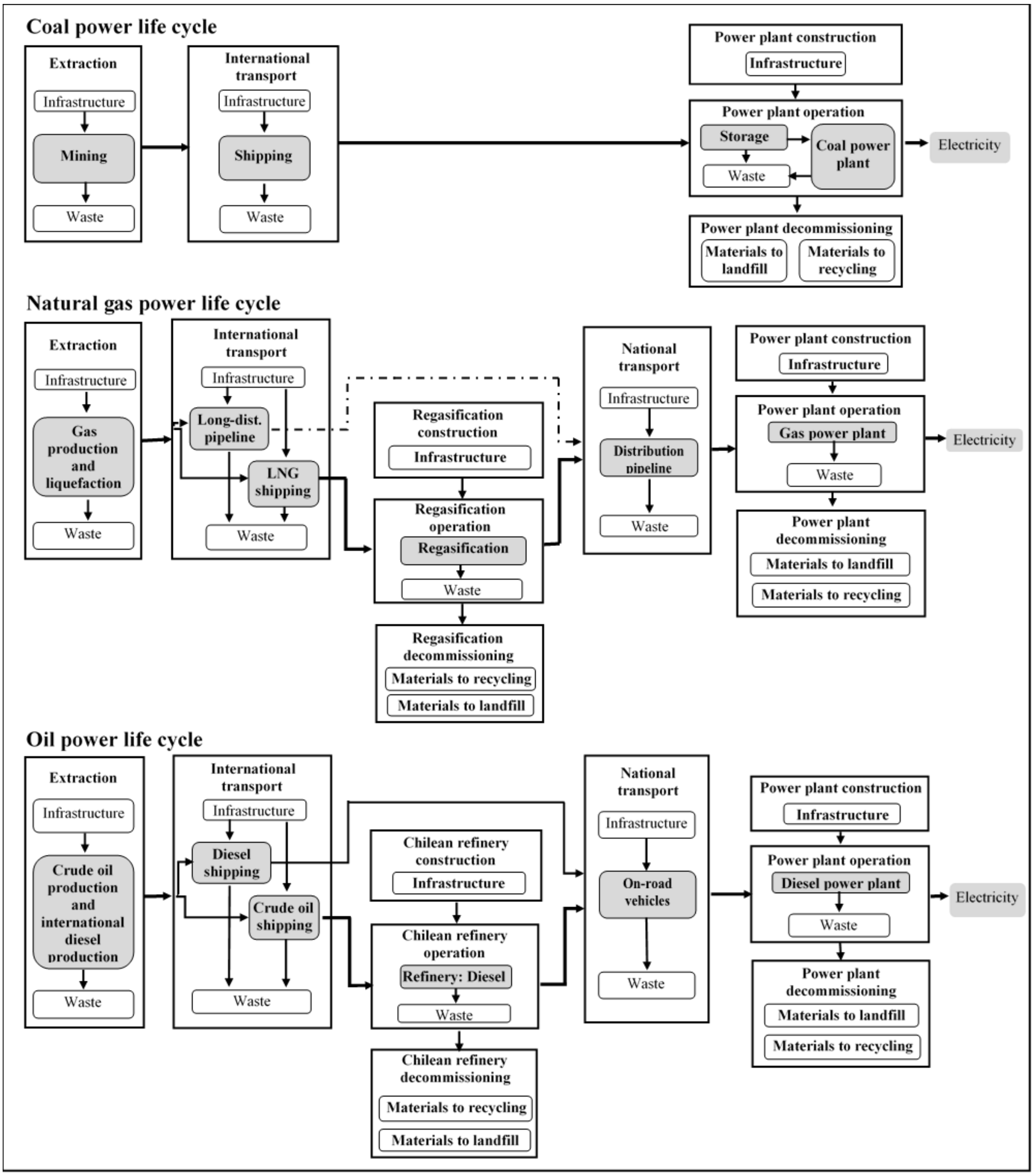


Figure 15. The life cycle of coal, gas and oil electricity from cradle to grave.
[Dashed lines represent processes that took place only in 2004 LNG: liquefied natural gas].

3.2.2.2. Coal power plants

Coal reserves in Chile are estimated at 1.2 bn t of subbituminous coal located in the southernmost part of the country, the Magallanes region [43]. A coal mine came online in 2013 in that region, with a 12-year projected annual supply capacity of 6 Mt [44]. At present, this covers only 14% of coal demand for electricity [6]. The coal is shipped to a distance of 3200 km to the coal power plants located in the north. The rest of the coal demand is covered through the imported bituminous coal: 54% from Colombia, 24% from the US and 8% from Australia [45].

Gross calorific value (CV) and composition of coal have been determined from 160 coal certificates of analysis [46], allowing the estimation of the average CV and coal composition by country. In addition, two coal power plants used petroleum coke as secondary fuel imported from the US. One plant consumed petroleum coke as primary fuel; this plant is located in the refinery facilities in Chile and the petroleum coke is supplied by the refinery itself [47]. In terms of transport and storage, each coal power plant has its own port. Therefore, only the shipping between coal mines (Chilean, Colombia, US, Australia and Indonesia mines) and the coal power plants is considered.

The majority of coal electricity is produced in pulverised coal plants with only a small share of circulating fluidised bed installations (Figure 14). For the purposes of this study, all plants are assumed to use pulverised coal. The efficiencies of coal power plants have been obtained from CNE reports [48, 49]. Emissions of CO_2, SO_2, NO_x and particulates from coal power plants have been obtained through direct emission measurements in power plants with continuous emissions monitoring systems (CEMS) [46]; see Table 8. The CEMS records for each coal power plant have been provided by the environmental protection agency (SMA).

Table 4. Coal power plants in Chile in the base year [6, 7, 29, 50].

	Power plant	Type[a]	Emission control systems[b]	Installed capacity (MW)	Electricity generation (GWh)	Share (%)	Efficiency (%)
1.	CTTAR	PC	ESP - BDC	158	911	3.2%	33%
2.	CTM1 - 2	PC	ESP	341	2,248	7.8%	34%
3.	CTA	CFB	ESP - NOx (Limestone)	169	1,044	3.6%	36%
4.	CTH	CFB	ESP - NOx (Limestone)	170	1,095	3.8%	38%
5.	CTTO U12 - 13	PC	ESP	171	1,012	5.9%	29%
6.	CTTO U14 - 15	PC	ESP	269	1,707	3.5%	33%
7.	CT NTO1	PC	ESP	136	1,045	3.6%	36%
8.	CT NTO2	PC	-	141	1,058	3.7%	36%
9.	CT ANG1 - 2	PC	ESP - SDA	545	3,955	13.7%	36%
10.	CT Santa María	PC	ESP - Wet scrubber - LowNOx	370	2,623	9.1%	41%
11.	CT Bocamina I	PC	ESP	130	5,08	1.8%	39%
12.	CT Ventanas 1	PC	ESP	120	7,49	2.6%	35%
13.	CT Ventanas 2	PC	ESP - LowNOx	220	1,178	4.1%	36%
14.	CT N. Ventanas	PC	BDC - SDA - LowNOx	272	2,183	7.6%	35%
15.	CT Campiche	PC	BDC - SDA - LowNOx	272	2,156	7.5%	38%
16.	CT Guacolda 1-2[c]	PC	ESP - BDC	304	2,428	8.4%	39%
17.	CT Guacolda 3[c]	PC	ESP - Wet scrubber - LowNOx	152	1,216	4.2%	39%
18.	CT Guacolda 4	PC	ESP - LowNOx - SCR	152	1,245	4.3%	39%
19.	CT Petropower[d]	CFB	BDC - NOx (Limestone)	75	530	1.8%	29%

[a]PC: Pulverised coal; CFB: Circulating fluidised bed.
[b]ESP: Electrostatic precipitator; BDC: Baghouse dust collectors; SDA: Spray dryer absorber; Wet scrubber: desulphurisation system; LowNOx: Low NOx burner; SCR: Selective catalytic reduction.
[c]Petroleum coke used as secondary fuel.
[d]Petroleum coke used as primary fuel.

Table 5. Natural gas power plants in Chile in the base year [6, 7, 29, 50].

	Power plant[a]	Type[b]	Emission control systems[c]	Installed capacity (MW)	Electricity in 2014 (GWh)	Share (%)	Efficiency (%)
1.	CTM3	CC	LowNOx	250	499	5%	43%
2.	CTTO U16	CC	-	400	1,460	15%	46%
3.	Gas Atacama 1	CC	LowNOx	389	28	<1%	42%
4.	San Isidro I	CC	-	379	1,751	18%	45%
5.	San Isidro II	CC	-	399	2,358	24%	49%
6.	Nueva Renca	CC	SCR	379	452	5%	47%
7.	Nehuenco I	CC	Wet scrubber	368	1,076	11%	45%
8.	Nehuenco II	CC	Wet scrubber	398	1,930	19%	49%
9.	Nehuenco III	OC	Wet scrubber	108	2	<1%	28%
10.	Taltal 1	OC	-	123	77	1%	29%
11.	Taltal 2	OC	-	122	114	1%	29%
12.	Candelaria 1	OC	Wet scrubber	136	2	<1%	28%
13.	Candelaria 2	OC	Wet scrubber	136	1	<1%	28%
14.	Quintero A	OC	LowNOx	120	97	1%	28%
15.	Quintero B	OC	LowNOx	120	150	1%	28%

[a]Power plants no. 3-13 also produce electricity from oil.
[b]CC: Combined cycle; OC: Open cycle.
[c]Wet scrubber: desulphurisation system; LowNOx: Low NOx burner; SCR: Selective catalytic reduction.

3.2.2.3. Natural gas power plants

Chile covers about 20% of the total consumption with national gas reserves [6]. The gas is produced in Magallanes region, but due to low production and geographical limitations for its transportation, it is just consumed by the local communities. The remaining 80% of the gas demand is imported from Trinidad and Tobago as liquefied natural gas (LNG). LNG is shipped to Chile and processed in two regasification plants [45]. Once regasified, it is distributed through a pipeline network to the power plants. Currently, electricity generation from natural gas consumes about 54% of natural gas imported [7, 29, 45].

Both open and combined cycle plants are used for electricity generation from natural gas (Table 5). The efficiency of power plants has been estimated for each power plant based on the electricity produced and the amount of gas consumed [7, 29]; for details, see Table 5. Data for natural gas properties and composition are specific to LNG from Trinidad and Tobago [45]. Direct emissions of combined cycle plants have been estimated through CEMS records, whilst for open cycle plants, the emissions have been estimated using GEMIS 4.8 [51] due to a lack of primary data.

3.2.2.4. Oil power plants

Oil-fired power plants in Chile typically use diesel to produce electricity. Some of the diesel is produced in Chile (43%) and the rest is imported from the US (57%) [45, 47]. Only 3% of the diesel produced in Chile is from the domestic crude oil, with the majority imported from South American countries (84%) and the UK (16%) [6, 45]. Chile's refineries are configured to produce 34% of diesel from crude oil processed [52, 53]. Both crude oil and diesel are transported by tanker from exporting countries to Chile for further processing and diesel is subsequently transported to power plants by trucks. The diesel composition is based on data from a Chilean refinery [47].

Oil power plants use open and combined cycle as well as diesel engine. Their efficiency and direct emissions have been determined in the same way as those of natural gas plants (Table 6). For combined cycle power plants, direct emissions have been obtained through CEMS records, whereas, open cycle turbines and diesel engines, though modelling in GEMIS.

Table 6. Oil power plants in Chile in the base year [6, 7, 29, 50].

	Power plant[a]	Type[b]	Emission control systems[c]	Installed capacity (MW)	Electricity in 2014 (GWh)	Share (%)	Efficiency (%)
1.	Gas Atacama 1	CC	LowNOx	389	320	12%	41%
2.	Gas Atacama 2	CC	LowNOx	383	558	20%	42%
3.	San Isidro I	CC	-	379	21	1%	43%
4.	San Isidro II	CC	-	399	39	1%	46%
5.	Nueva Renca	CC	SCR	379	725	26%	46%
6.	Nehuenco I	CC	Wet scrubber	368	233	8%	50%
7.	Nehuenco II	CC	Wet scrubber	398	107	4%	50%
8.	Nehuenco III	OC	Wet scrubber	108	5	<1%	29%
9.	Taltal 1	OC	-	123	7	<1%	31%
10.	Taltal 2	OC	-	122	1	<1%	31%
11.	Candelaria 1	OC	Wet scrubber	136	7	<1%	29%
12.	Candelaria 2	OC	Wet scrubber	136	6	<1%	29%
13.	Rest of open cycle plants (24 plants)[d]	OC		1220	350	13%	35%
14.	Diesel engine plants (35 plants)[d]	DE		810	366	13%	36%

[a]Power plants no. 1-12 also generate electricity from natural gas.
[b]CC: Combined cycle; OC: Open cycle; DE: Diesel engine.
[c]Wet scrubber: desulphurisation system; LowNOx: Low NOx burner; SCR: Selective catalytic reduction.
[d] A full list can be found in Table 33 in the appendices.

Table 7. Assumptions and summary of inventory data for the base year [6, 7, 29, 42, 45–48, 50, 54–57].

Coal	Natural gas	Oil
Electricity generation by fuel		
- Fossil fuels share: 69% - Plant type: pulverised coal - η[a]: 36%, CF[b]: 81% - For details, see Table 4.	- Fossil fuels share: 24% - Plant type: CC[c] and OC[4] - CC[c] share: 96%, η[a]: 47%, CF[b]: 53% - OC[d] power share: 4%, η[a]: 28%, CF[b]: 11% - For details, see Table 5.	- Fossil fuels share: 7% - Plant type: CC[c], OC[d] and DE[e] - CC[c] share: 73%, η[a]: 44%, CF[b]: 15% - OC[d] power share: 14%, η[a]: 34%, CF[b]: 6% - DE[e] power share: 13%, η[a]: 36%, CF[b]: 8% - For details, see Table 6.
Plant construction		
- Lifetime: 38 years - Data from Ecoinvent based on average size of the plant of 460 MW	- Lifetime: 35 years - Data from Ecoinvent based on average size of the plants of 400 MW and 100 MW for CC[c] and OC[d] plants, respectively.	- Lifetime: 35 years. Plants with lower capacity factors: 45 years. - Data from Ecoinvent based on average size of the plants of 400 MW, 100 MW and 10 MW for CC[c], OC[d] and DE[e] plants, respectively.
Plant decommissioning		
- Steel: 93% recycled. Aluminium: 43% recycled. Copper: 50% recycled. The system is credited for recycled materials. - Concrete and plastics are not recycled. Materials not recycled are disposed in landfills.		
Fuel extraction and processing		
- Coal: 10.7 Mt/yr - Contribution, CV[f] Chile: 14%, 18.9 MJ/kg Colombia: 54%, 26.8 MJ/kg US: 24%, 26.0 MJ/kg Australia: 8%, 27.0 MJ/kg - Petroleum coke: 473 kt - Contribution, CV[f] Chile: 42%, 32.5 MJ/kg US: 58%, 32.5 MJ/kg - Coal composition: (as received) Carbon: 57.5% Hydrogen: 4.4% Sulphur: 0.7% Oxygen: 12.5% Nitrogen: 1.2% Ash: 9.7% Water: 14.0% Chlorine: 130 ppm Fluor: 10 ppm - Density: 920 kg/m^3	- Natural gas: 1,923 MNm^3/yr - Contribution, CV[f] LNG[g]: 100%, 41.1 MJ/Nm^3 Long-dist. pipeline: 0%, 39.1 MJ/Nm^3 - Quintero regasification plant capacity: 5,475 MNm^3 - Data from Ecoinvent based on evaporation plant of average size of 42,300 MNm^3/yr - Natural gas sales in Chile in 2014 accounted to 3,317 MNm^3 processed at two terminals and distributed through 836 km of pipelines - Natural gas composition: Methane C1: 96.78% Ethane C2: 2.78% Propane C3: 0.37% Butane C4+: 0.06% Nitrogen: 0.01% - LNG[g] density: 431.03 kg/m^3 - Gas density: 0.74 kg/Nm^3	- Diesel: 523 kt/yr - Contribution: Chile (Refinery): 43% US (Import): 57% - CV[f]: 45.6 MJ/kg - Crude oil with destination to refinery South America: 84% (Chile:3.6%) UK: 16% - Chilean refinery produce 34% of diesel from crude oil processed - Diesel composition: Carbon: 86.1% Hydrogen: 13.5% Sulphur: 0.4% - Density: 0.84 t/m^3
Transport		
- Distance by ship Chile: 3,220 km Colombia: 4,585 km US: 8,785 km Australia: 11,959 km	- Distance LNG[g]: 12,684 km Long-distance pipeline: 558 km	- International transport by tanker US: 8,785 km (diesel) UK: 11,112 km (crude oil) South America: 5,204 km (crude oil) - From refinery to power plants: 664 km by lorry (28 t).

[a]η: Power plant efficiency.
[b]CF: Capacity factor. As capacity factors of power plants can vary significantly year by year, an average capacity factor from the last three years has been estimated for each power plant.
[c]CC: Combined cycle power plant.
[d]OC: Open cycle power plant.
[e]DE: Diesel engine power plant.
[f]CV: Gross calorific value.
[g]LNG: Liquefied natural gas.

Table 8. Emission factors for coal, natural gas and oil power plants by technology[a] [46, 51].

	Coal plants	Natural gas plants		Oil plants		
	Pulverised coal[a] (g/MJ_{in})	Combined cycle[a] (g/MJ_{in})	Open cycle[b] (g/MJ_{in})	Combined cycle[a] (g/MJ_{in})	Open cycle[b] (g/MJ_{in})	Diesel engine[b] (g/MJ_{in})
CO_2	97.5	61.9	56.1	88.9	80.5	75.9
NOx	0.167	0.129	0.025	0.295	0.265	0.829
SO_2	0.337	0.001	0.001	0.185	0.474	0.192
Particles	0.007	-	-	-	-	-

[a]Determined by hourly data records from continuous emissions monitoring systems (CEMS).
[b]Determined through GEMIS software considering characteristics of each plant.

3.2.3. Previous years

In addition to the base year (2014), electricity generation in 2004 and 2009 is also considered. These two years have been chosen for the following reasons. The import of cheap natural gas from Argentina peaked in 2004, which also meant that the contribution of gas to electricity generation from fossil fuels peaked at 65% in that year. A progressive curtailment of the imports from Argentina then occurred between 2004 and 2008, which led to difficulties in 2009, when the electricity generation deficit had to be met with diesel. This increased the share of diesel to 33% of the total generation from fossil fuels. At the same time, the share of coal power grew from 35% in 2004 to 51% in 2009. Due to the high cost of diesel, the prices of electricity increased significantly. Finally, to reduce the cost, the contribution from coal power plants continued to grow until 2014, exacerbated by a long-lasting drought which led to low generation from hydro plants [1, 2, 29]. In summary, the contribution of different fuels to electricity from fossil fuels was as follows:

- 2004: coal 35%; gas 65%; oil 0%;
- 2009: coal 51%; gas 16%; oil 33%; and
- 2014: coal 69%; gas 24%; oil 7%.

The assumptions and inventory data for 2004, 2009 and 2014 are given in Table 9.

3.2.4. Environmental impact assessment

The power systems have been modelled using Gabi v6.0 [58]**.** The following 11 environmental impacts are considered, estimated according to the CML 2001 method (April 2015 update) [59]: abiotic depletion potential of fossil resources (ADP_{fossil}), abiotic depletion potential of elements ($ADP_{elements}$), eutrophication potential (EP), freshwater aquatic ecotoxicity potential (FAETP), global warming potential (GWP), human toxicity potential (HTP), marine aquatic ecotoxicity potential (MAETP), ozone layer depletion potential (ODP, steady state), photochemical oxidants creation potential (POCP), and terrestrial ecotoxicity potential (TETP). The CML methodology has been chosen to maximise comparability with prior literature on fossil-based electricity technologies in other countries, ensuring that the LCA results for Chile can be contextualised and compared with those (see Section 3.3.2).

Table 9. Inventory data for fossil-based electricity in Chile in 2004, 2009 and 2014.

Category	Description (unit)	2004	2009	2014
General	Total electricity generation (GWh/yr)	26,912	31,051	41,634
	Contribution of coal (%)	35%	51%	69%
	Contribution of natural gas (%)	65%	16%	24%
	Contribution of oil (%)	0%	33%	7%
Coal	Pulverised coal plant efficiency (%)	35%	36%	36%
	Coal consumption (1000s t)	3,601	4,870	10,742
	Coal from Chile (%)	5%	11%	14%
	Coal from Colombia (%)	17%	66%	54%
	Coal from Indonesia (%)	23%	10%	0%
	Coal from US (%)	23%	11%	24%
	Coal from Australia (%)	32%	2%	8%
	Consumption of petroleum coke (1000s t)	720	1,289	473
	Petroleum coke from Chile (%)	19%	68%	42%
	Petroleum coke from US (%)	81%	32%	58%
	Gross calorific value of coal from Australia (MJ/kg)	21.0	25.0	27.0
	Gross calorific value of coal from Chile (MJ/kg)	18.9	18.9	18.9
	Gross calorific value of coal from Colombia (MJ/kg)	21.0	25.0	26.8
	Gross calorific value of coal from Indonesia (MJ/kg)	21.0	25.0	20.7
	Gross calorific value of coal from US (MJ/kg)	21.0	25.0	26.0
	Gross calorific value of petroleum coke (MJ/kg)	32.5	32.5	32.5
	Distance from Australia (km)	11,959	11,959	11,959
	Distance in Chile (mine to power plant) (km)	3,220	3,220	3,220
	Distance from Colombia (km)	4,585	4,585	4,585
	Distance from Indonesia (km)	11,959	11,959	11,959
	Distance from US (km)	8,785	8,785	8,785
Natural gas	Contribution of combined cycle plants (%)	100%	100%	96%
	Contribution of open cycle plants (%)	0%	0%	4%
	Combined cycle plant efficiency (%)	47%	48%	47%
	Open cycle plant efficiency (%)	28%	28%	28%
	Natural gas consumption (MNm^3)	3,453	920	1,923
	Liquefied natural gas (%)	0%	42%	100%
	Natural gas from Argentina (%)	100%	58%	0%
	Gross calorific value of gas (MJ/Nm^3)	39.1	39.9	41.1
Oil	Contribution of combined cycle plants (%)	-	81%	73%
	Contribution of diesel engine plants (%)	-	9%	13%
	Contribution of open cycle plants (%)	-	10%	14%
	Combined cycle plant efficiency (%)	-	44%	44%
	Diesel engine plant efficiency (%)	-	36%	36%
	Open cycle plant efficiency (%)	-	34%	34%
	Diesel consumption (1000s t)	-	1,959	523
	Diesel from Chile (%)	-	45%	43%
	Diesel from US (%)	-	0%	57%
	Diesel from Korea and Japan (%)	-	55%	0%
	Distance from US (km)	-	-	8,785
	Distance from Korea and Japan (km)	-	18,838	-
	Crude oil from Latin America refined in Chile (%)	-	84%	84%
	Crude oil from UK refined in Chile (%)	-	16%	16%
	Gross calorific value of oil (MJ/kg)	-	45.6	45.6

3.3. RESULTS AND DISCUSSION

3.3.1. Environmental impacts of fossil-based technologies

The environmental impacts of electricity from coal, gas and oil, expressed per kWh and showing the contribution of different life cycle stages, are summarised Figure 16. These results refer to the base year (2014). As can be seen, electricity generation from gas has the lowest impacts across all the impact categories. Coal is the worst option overall, with the highest values in eight out of 11 impact categories considered. For example, if compared with oil, coal has around 20% higher GWP and AP, four times greater HTP, and 45 times higher MAETP. However, oil performs worse than coal in three impacts – POCP, $ADP_{elements}$ and ODP – which are 31%, four and eight times higher than coal, respectively.

The majority of the impacts are mainly due to the extraction of fossil fuels and operation of power plants. The construction and decommissioning of power plants are only significant for $ADP_{elements}$ which can be reduced by 15% through material recycling at the end of useful lifetime of the plants. These results are discussed in more detail below. Note that all the results incorporate the credits for material recycling.

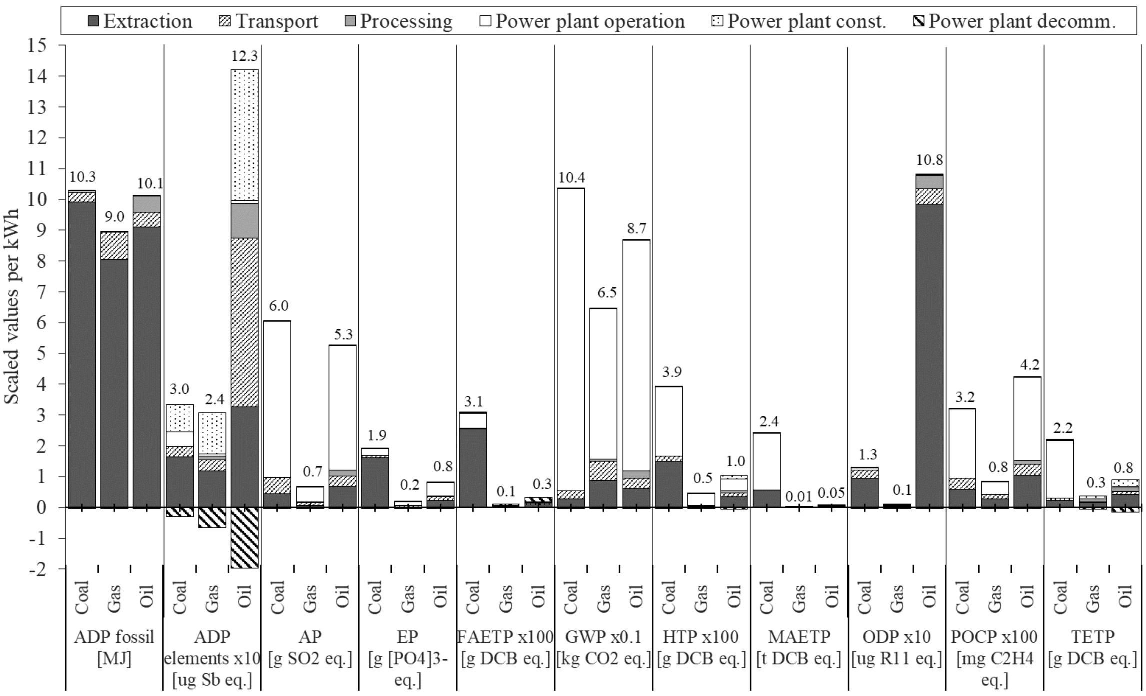


Figure 16. Environmental impact per kWh of electricity.

[Values shown represent the net impacts, with the recycling credits. The scaled impacts should be multiplied by the factor shown in brackets for relevant categories. ADP: abiotic depletion potential, AP: acidification potential, EP: eutrophication potential, FAETP: freshwater aquatic ecotoxicity potential, GWP: global warming potential, HTP: human toxicity potential, MAETP: marine aquatic ecotoxicity potential, ODP: ozone depletion potential, POCP: photochemical oxidant creation potential, TETP: terrestrial ecotoxicity potential].

3.3.1.1. Abiotic depletion potential of fossil resources (ADP_{fossil})

Electricity generation from coal and oil have similar values for depletion of fossil resources (10.3 and 10.1 MJ/kWh, respectively) while the impact for gas is somewhat lower (9 MJ/kWh). These differences are associated with the efficiency of plants and calorific value of the fuels, both of which are highest for gas. Extraction of fuels is the main contributor with a share of 96% for coal and 90% for gas and oil. Transport of fuel represents 5% for oil and the rest for coal and gas and is mainly due to fuel consumption by vehicles.

3.3.1.2. Abiotic depletion potential of elements ($ADP_{elements}$)

Oil power leads to the highest depletion of elements (123 µg Sb eq./kwh), which is four times higher than coal (30 µg Sb eq./kWh) and five times greater than gas (24 µg Sb eq./kWh). The high impact from oil is largely related to its lorry transport between the refineries and power plants. Gold and lead are the main elements depleted, associated with gold content in electronic parts of the vehicle and the use of lead for vehicle batteries [60].

Construction and decommissioning of plants have significant contributions (53% for gas, 38% for oil and 32% for coal). Fuel extraction is also important for coal (45%) and gas (32%). The high contribution of construction and decommissioning is attributed to use of scarce materials within power plants and their equipment. Therefore, the capacity factors of power plants and recycling rates are significant factors. For example, electricity from gas and oil is mostly produced in combined cycle plants, which contain scarce elements like chromium and copper. In addition, oil power is a peak-load technology, leading to a low capacity factor of 15%, and therefore the depletion due to construction is higher per unit of electricity generated. By contrast, coal power is considered a base-load technology and consequently has a higher capacity factor (81%), leading to a lower contribution of construction and decommissioning to $ADP_{elements}$. The consumption of copper, gold, molybdenum, zinc and chromium in the use of explosives and metals for the mine infrastructure play a key role for this impact from coal [61]. The recycling of copper and steel, as part of the decommissioning stage, reduces the impact across the three options by 8% for coal and 17% for oil and gas.

3.3.1.3. Acidification potential (AP)

Coal and oil have an order of magnitude higher AP than gas: 6 and 5.3 vs 0.7 g SO_2 eq./kWh, respectively. The combustion of fuel to produce electricity is the most important process for this impact with a contribution of 84% for coal, 77% for oil and 73% for gas. Coal combustion has the highest impact because of higher emission factors (Table 8) and the lowest efficiency among fossil fuel plants. It can also be noted that oil has a much higher impact than gas despite both fuels being predominantly burned in high efficiency combined cycle plants. This is due to the SO_2 emissions from oil being 185 times higher than for gas, related to the sulphur content in oil of 0.4%. Furthermore, 13% of oil-fired power generation occurs in diesel engines which have NO_x emission factors about five times higher than typical coal and gas plants. This explains why oil power, in spite of a higher efficiency (42%), has a higher AP.

3.3.1.4. Eutrophication potential (EP)

At 1.9 g PO_4^{3-} eq./kWh, coal has the highest EP, double that of oil (0.8 g PO_4^{3-} eq./kWh) and ten times higher than gas (0.2 g PO_4^{3-} eq./kWh). This is mainly due to mining (84%), related to the release of significant amounts of phosphate to freshwater [61]. The higher impact of coal compared to the other two options is also compounded by its lower calorific value and efficiency of power plants, both of which increase the demand for coal per unit of electricity generated. In relation to coal mining, there are significant differences among mines in terms of environmental burdens and energy content of coal. For example, coal from Australia has 4.7 times higher environmental burdens than that from South America because Australian coal beds are typically deeper and require more energy for excavation [42, 61]. Therefore, the Australian coal causes 22% of the EP attributable to extraction, despite its contribution to the imported-coal mix of only 8%. By contrast, fuel combustion in power plants is the main contributor to the impact from gas (68%) and oil power (53%); for coal, its contribution is much lower (12%). NO_x emissions are the main cause of EP for all the power plants.

3.3.1.5. Freshwater aquatic ecotoxicity potential (FAETP)

Coal power is again the worst option for this impact (310 g DCB eq./kWh), with the value ten times higher than for oil (32 g DCB eq./kWh) and 28 times higher than for gas (11 g DCB eq./kWh). Mining and combustion of fuel are major hotspots for coal power (82% and 16%, respectively). Mining releases a significant amount of elements, such as nickel, beryllium, cobalt and vanadium, that contribute to freshwater ecotoxicity. Vanadium and beryllium are also released from the ash. For gas and oil, the main hotspot is plant decommissioning (37% and 45%, respectively) because of the release of copper during the scrap disposal.

3.3.1.6. Global warming potential (GWP)

Electricity from coal emits 1036 g CO_2 eq./kWh, while for oil the GWP is 868 g CO_2 eq./kWh and for gas 646 g CO_2 eq./kWh. Emissions of CO_2 account for 98% of total GHG emitted along the life cycle of the three options. Combustion of fuels is the main hotspot with a contribution of 95% for coal, 86% for oil and 76% for gas. In the gas life cycle, extraction and transport of LNG contribute together 23% of the impact, for which CO_2 is again the main GHG emitted. CO_2 is emitted by machinery used for the extraction of gas, by compressors for its liquefaction and for transportation and refrigeration of the LNG.

3.3.1.7. Human toxicity potential (HTP)

This impact is four times higher for coal (393 g DCB eq./kWh) than for oil (97 g DCB eq./kWh) and nine times greater than for gas power (46 g DCB eq./kWh). The combustion of fuel makes a large contribution for all three options: 75% for gas, 57% for coal and 35% for oil. In the case of coal combustion, the main contributor is the emission of hydrogen fluoride to the air and vanadium and thallium to freshwater from ash. For the combustion of oil and gas, the emission of polycyclic aromatic hydrocarbons (PAH) is the main contributor to this impact category.

3.3.1.8. Marine aquatic ecotoxicity potential (MAETP)

The MAETP for coal power is estimated at 2407 kg DCB eq./kWh, which is 44 times higher than for oil power (55 kg DCB eq./kWh) and 172 times greater than for gas (14 kg DCB eq./kWh). This is largely due to the combustion of coal (76%), related to hydrogen fluoride emitted to air. The rest of the impact from coal power is attributed to coal extraction, associated with beryllium released to freshwater. On the other hand, the impact from oil and gas power is distributed quite evenly across the life cycle stages, except for the combustion of fuels, which has a negligible contribution.

3.3.1.9. Ozone layer depletion (ODP)

For this impact, oil power has the highest ODP (108 µg R11 eq./kWh), which is eight times larger than that of coal (13 µg R11 eq./kWh) and two orders of magnitude worse than for gas (1 µg R11 eq./kWh). Extraction of fuel has the highest contribution across the options: 91% for oil, 73% for coal and 44% for gas. Transport is the second significant stage, with the respective contributions of 5%, 22% and 37%. Oil production and transportation involve the use of fire suppressants, such as halon 1301, which is a major contributor in this case. It should be noted, however, that this introduces some uncertainty since the Montreal Protocol covers the use of halons and has led to their elimination in many sectors and regions [62]. However, certain critical uses in the petrochemical industry are granted exemption, thus the actual use of halons will vary from country to country and between businesses. A similar situation applies to the transport of natural gas through long-distance pipeline in which halogenated compounds may be used as coolant for compressors, leading to higher ODP when gas is piped over large distances. In previous years natural gas was supplied in Chile via long-distance pipeline from Argentina and, therefore, potentially incurred high ODP, whereas nowadays gas is just supplied by tanker as LNG. If natural gas supplies once again came from Argentina, the ODP of gas power would increase from 1 µg to 15.2 µg R11 eq./kWh, higher than coal, but still lower than oil.

3.3.1.10. Photochemical oxidant creation potential (POCP)

The POCP of electricity from oil and coal is estimated at 420 mg C_2H_4 eq./kWh and 320 mg C_2H_4 eq./kWh, respectively, while for gas power, the impact is equivalent to 83 mg C_2H_2 eq./kWh. Combustion of fuels is the main source, contributing 63% for oil, 70% for coal and 47% for gas power, largely due to NO_x and SO_2 emissions. However, emissions of non-methane volatile organic compounds in diesel engine plants contribute to oil power being the worst option.

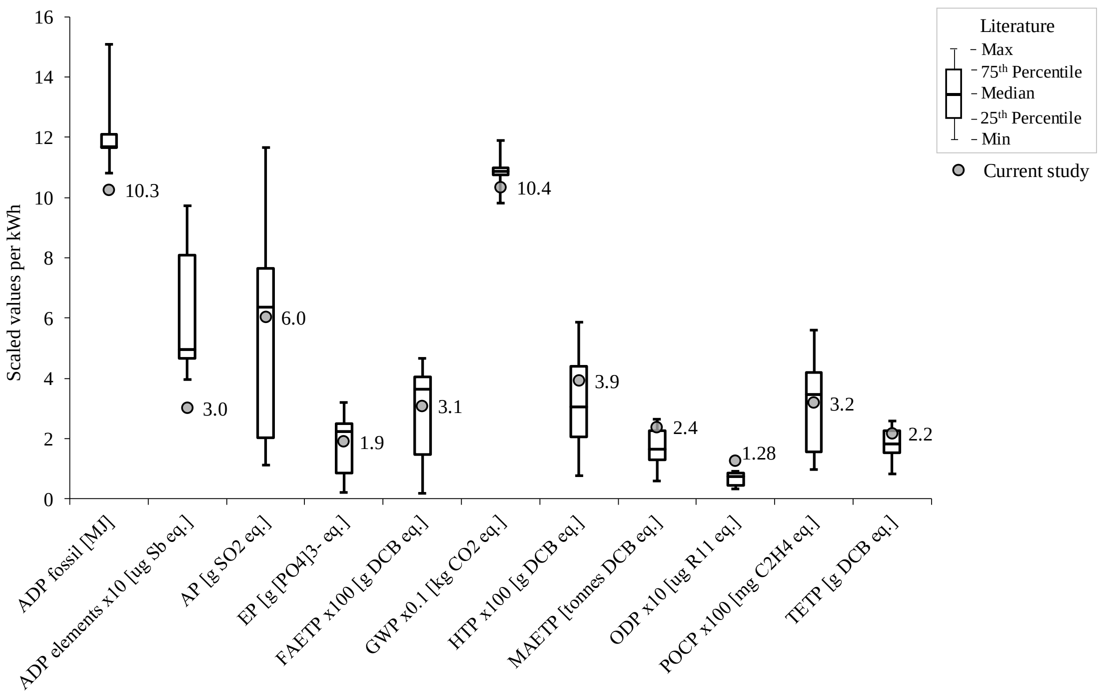
3.3.1.11. Terrestrial ecotoxicity potential (TETP)

Electricity from coal has a TETP of 2.2 g DCB eq./kWh, four times larger than oil (0.8 g DCB eq./kWh) and seven times above gas (0.3 g DCB eq./kWh). Combustion causes nearly 85% of the impact for coal power, while extraction is the main life cycle stage for oil and gas, with a contribution of 41% and 35%, respectively. Other stages with a significant contribution for oil and gas are construction and decommissioning of power plants, along with fuel reprocessing installations. Heavy metals released to air are the main burdens across the options. For coal power, heavy metals present in coal are released during its combustion; for oil and gas power, they are emitted in the production of the steel used for infrastructure and machinery. However, recycling of steel and other end-of life materials has only a small benefit for oil and gas power, reducing the impact by 16% in both options. Coal is not affected by recycling because its impact is attributed to coal combustion and its combustion emissions.

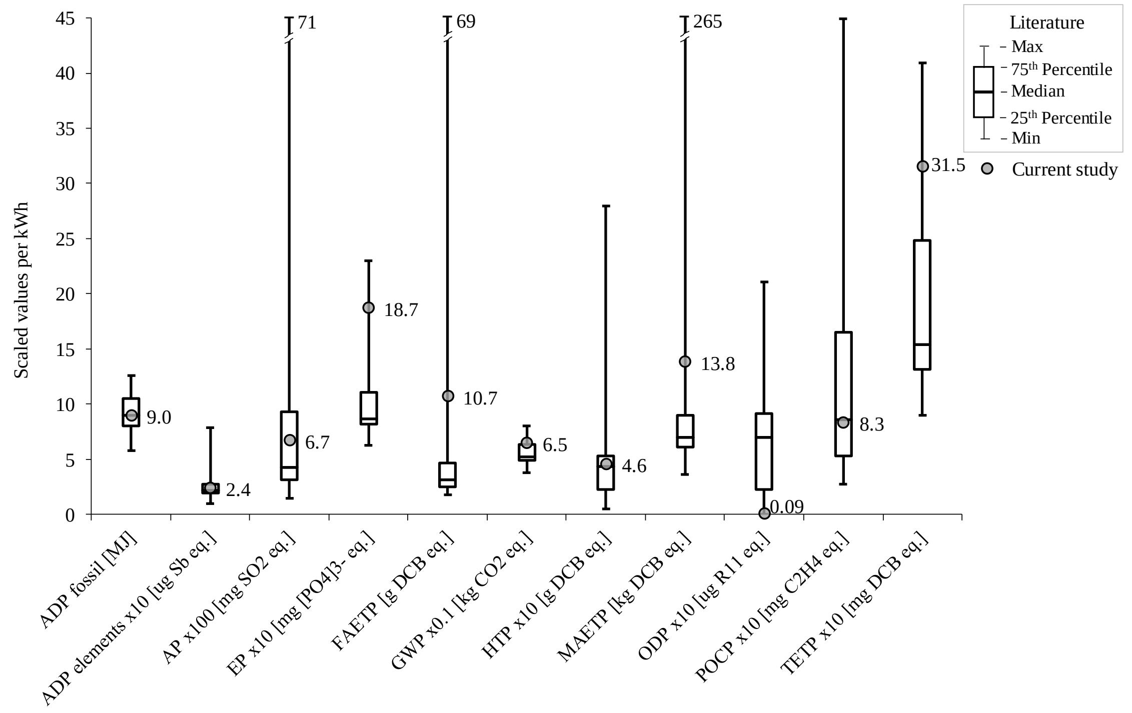
3.3.2. Comparison of results with literature

The impacts obtained in this study have been compared to values in literature to validate the results and to identify any differences. As mentioned in the introduction, there are no other studies focusing on fossil-based electricity in Chile. Instead, the comparison here is with the impacts of individual fossil-fuel options estimated for other regions, including European countries, the US, Japan, Mexico and Turkey [36, 37, 42, 63]. Only those values that have been estimated using the same impact assessment method used here (CML) are considered. The results are compared in Figure 17.

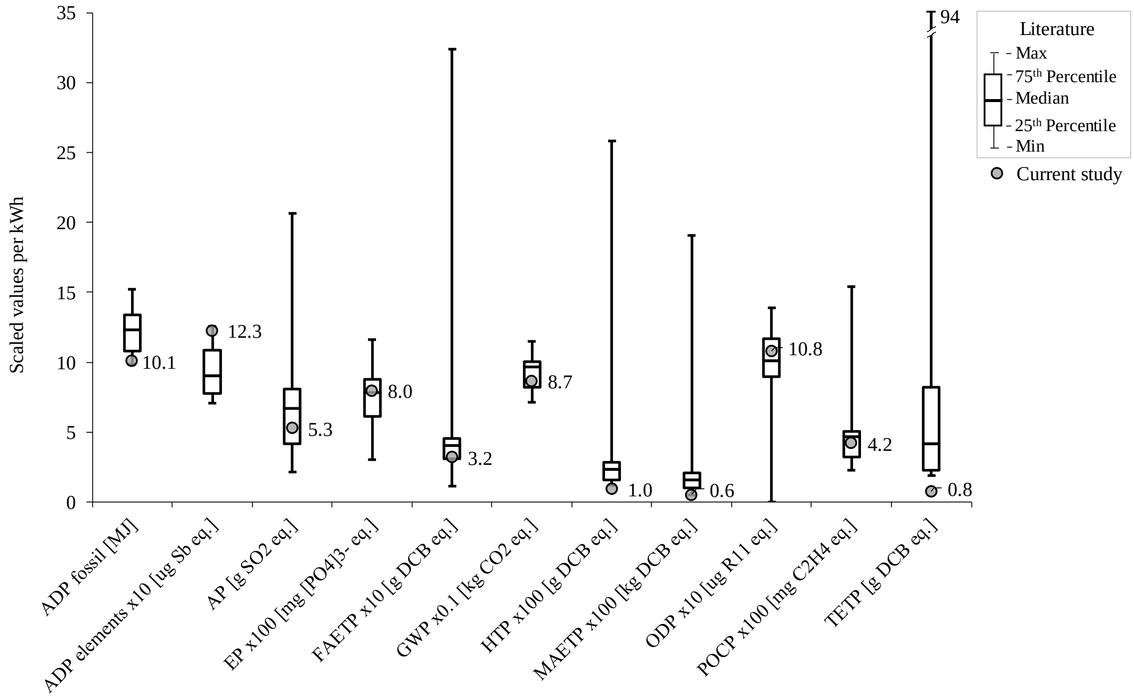
As can be seen in Figure 17, most results in this study fall within the ranges found in the literature. An exception is ODP for coal power which is higher than elsewhere. This is related to the high ODP of petroleum coke, which contributes 4% to the electricity supply in Chile. The main source of this impact from petroleum coke is halon 1301. Two other impacts from coal also fall outside the range – ADP_{fossil} and $ADP_{elements}$ – both of which are lower than in the literature. This is because coal used in Chile has higher calorific value than elsewhere, together with greater efficiency of power plants and capacity factors [42].



(a) Coal power



(b) Gas power



(c) Oil power

Figure 17. Comparison of the results from the current study with the literature for coal, gas and oil power. [For the impacts nomenclature, see Figure 16]

As opposed to coal, the ODP of gas is lower than in the literature. This is due to the absence of long-distance pipelines for the transport of gas and the associated use of halogenated compounds [64] since Chile uses LNG. For oil, HTP, MAETP and TETP are below the literature ranges. This is mainly a result of the higher efficiency of combined cycle power plants, which generate 73% of total power from oil in Chile, while other countries typically use diesel engines which have lower efficiency.

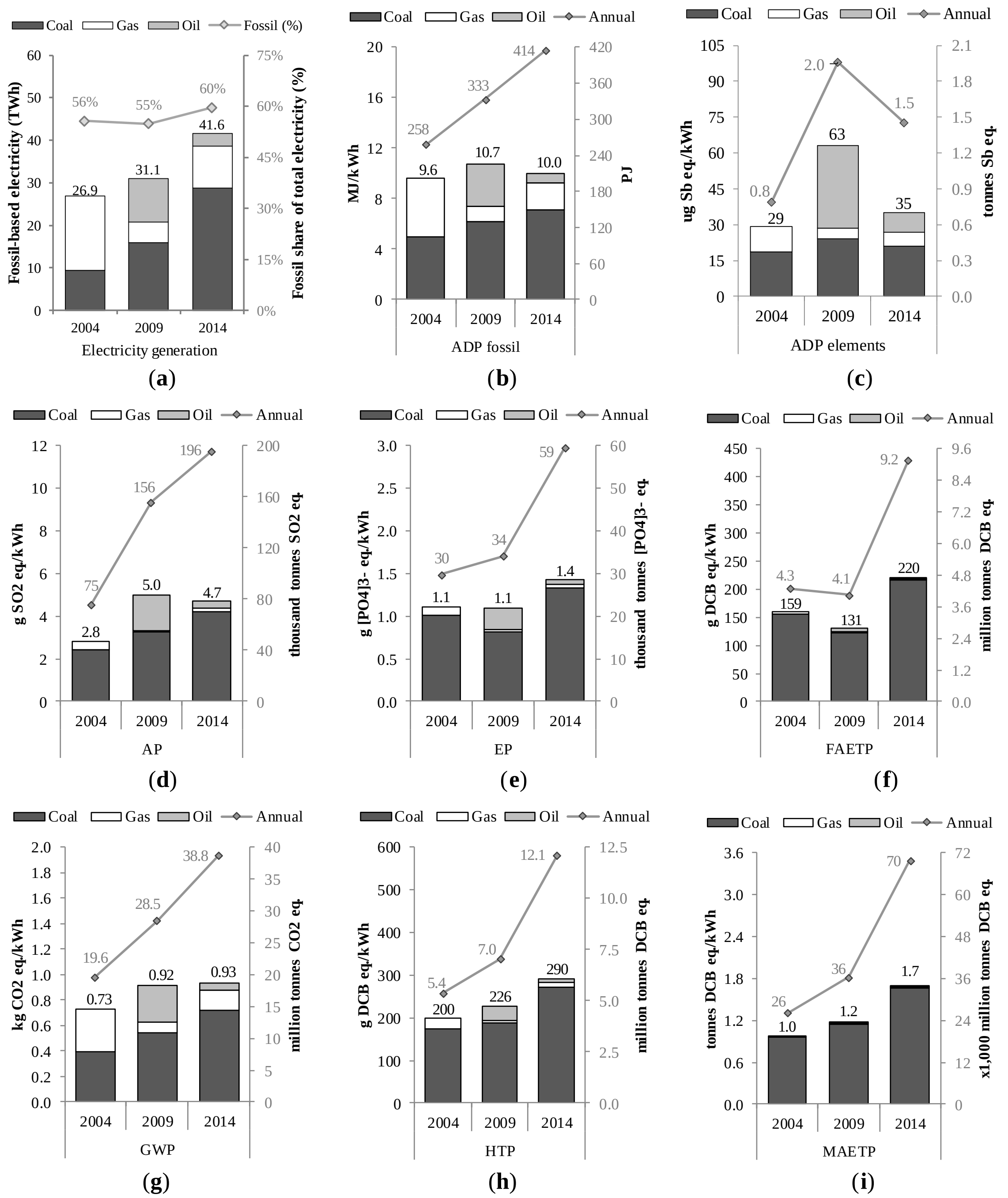
3.3.3. Change in impacts over time

This section discusses the impacts of fossil-based electricity generated in the ten-year period from 2004 to 2014 to find out how they may have changed over the years and why. Both per-kWh and total annual impacts are considered. For the base year, these have been estimated based on the results in the previous sections and the contribution of each technology to the total generation (Table 9). For the previous years, the data in Table 9 have been used to estimate first the impacts of individual technologies and then their total annual impacts based on the amount of electricity they generated in those years.

As shown in Figure 18, the year 2014 exhibited the highest per-kWh impacts for six and the year 2009 for five impacts. Most of the impacts were lowest in 2004. The latter is due to a major contribution (65%) of gas and lower share of coal (35%) than in the other two years. Nonetheless, 32% of coal came from Australia which has higher EP and FAETP, leading to a worse outcome in 2004 than in 2009 for those two indicators. Furthermore, 2004 experienced a peak in gas imports from Argentina, which was transported by long-distance pipelines, causing a higher ODP than in 2014. The subsequent lack of natural gas in 2009 resulted in an increase in oil electricity, together with a slight rise in coal power. Consequently, 2009 saw the highest ADP_{fossil}, $ADP_{elements}$, AP, ODP and POCP. In 2014, coal had a higher contribution than in the previous years, increasing EP, FAETP, GWP, HTP, MAETP and TETP.

In addition to the changes in electricity mix on a year-by-year basis, overall electricity consumption has increased steadily over the decade [2, 7]. This has led to an increase in annual impacts through the years, which can be seen in Figure 18 for eight impacts (ADP_{fossil}, AP, EP, GWP, HTP, MAETP, POCP and TET). However, for $ADP_{elements}$ and ODP, the year 2009 had the highest impacts per kWh. Hence, despite total generation being higher in 2014, the annual impacts decreased compared to 2009.

Overall, it can be seen that, while electricity generation increased by 55% during the last 10 years, the annual environmental impacts went up by an average of 108% in the same period. Only ODP decreased by 5%, while the remaining 10 impacts increased by between 60% (ADP_{fossil}) and 167% (MAETP), with a 98% increase in GWP. It can also be observed from Figure 18 that the share of coal in the per-kWh impacts grew steadily over the years, in line with its share in the generation.



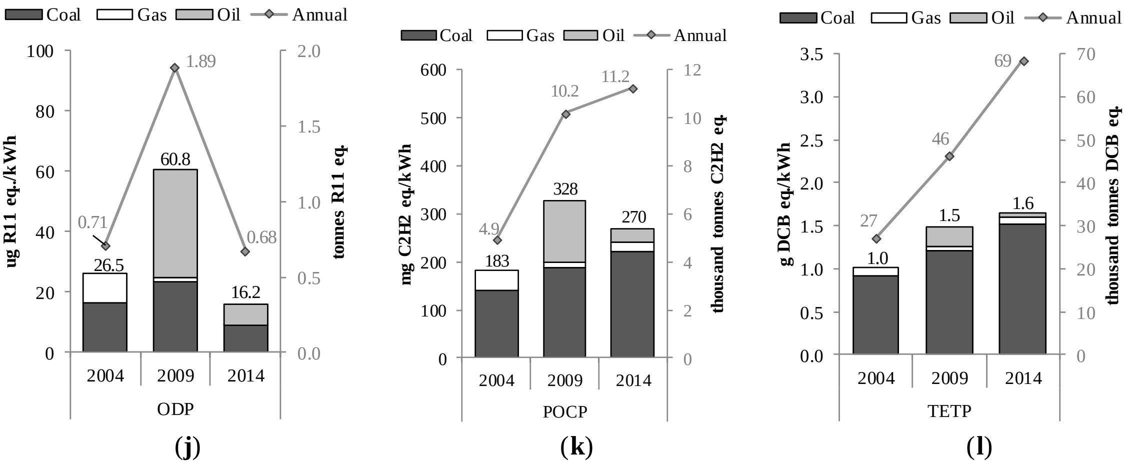


Figure 18. Environmental impacts of fossil-based electricity in Chile over the period 2004-2014. [For impacts nomenclature, see Figure 16].

3.4. CONCLUSIONS

This study has estimated the environmental impacts of the fossil-based electricity generation in Chile and their evolution over a period of ten years, from 2004 to 2014.

Considering individual technologies, the results demonstrate that electricity from gas has the lowest impacts for all 11 impact categories considered. By contrast, coal power shows the worst performance for eight categories, with EP, FAETP and MAETP being between ten and 240 times greater than for gas. The impacts of oil power are typically in between, with three impacts higher than coal (POCP, $ADP_{elements}$, and ODP).

In terms of life cycle stages, operation of power plants is the main hotspot for AP, GWP, HTP, MAETP, POCP and TETP. Extraction of fuels also plays a major role for $ADP_{elements}$, ADP_{fossil}, ODP, FAETP, and TETP and has a significant contribution to the rest. Construction and decommissioning of power plants are significant for $ADP_{elements}$ and TETP of oil and gas power, but recycling of copper and steel helps to reduce those impacts. Finally, transport and processing of fuels typically have a minor contribution.

When fossil-fuel electricity mix is considered over the years, six per-kWh impacts were highest in 2014 and five in 2009. Year 2004 had the lowest values for eight impact categories, exceeding 2009 only in EP and FAETP, and 2014 in ODP.

In terms of total annual impacts, an increase in ten environmental impacts can be seen from 2004 to 2014. This deterioration of environmental performance is mostly caused by the rise of coal power, leading to an average increase across all impacts of 108% over the period, despite an increase in electricity demand of only 55%.

The worsening of environmental impacts over time runs contrary to the goals of sustainable development and should be addressed through appropriate policies. Based on the results of this work, policy in the short-term future should aim to:

- increase the efficiency of all power plants;
- prioritise coal consumption from mines with lower environmental impacts, such as those in South America, and avoid the use of petroleum coke;
- improve measures for emissions control not only for power plants but also across the life cycle, including copper and steel production and ash disposal; and
- displace coal and oil with gas power as soon as possible.

In the medium term to longer terms, it is critical to evaluate and broaden the deployment of renewable power technologies and possibly carbon capture and storage. A potential role of nuclear power could also be explored.

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Chapter 4: Assessing the environmental sustainability of electricity generation in Chile

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This paper presents the life cycle assessment (LCA) of current electricity generation in Chile. Tables and figures have been amended to fit into the structure of this thesis. The thesis author is the main author of the paper and is the one who collected the life cycle inventory data needed to model all the current electricity options and electricity mix for Chile and interpreted the results. The thesis author also wrote the original manuscript. The co-authors are the supervisors of this PhD project and contributed to the paper by reviewing the LCA model implemented and results in the original manuscript and requesting modifications to improve the resulting manuscript.

Chapter 4

Assessing the environmental sustainability of electricity generation in Chile

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Abstract

Around 40% of electricity in Chile is supplied by renewables and the rest by fossil fuels. Despite the growing electricity demand in the country, its environmental impacts are as yet unknown. To address this gap, the current study presents the first comprehensive assessment of the life cycle environmental sustainability of electricity generation in Chile. Both the individual sources and the electricity mix over the past 10 years are considered. The following sources present in the electricity mix are evaluated: coal, oil, natural gas, biogas, biomass, wind, solar photovoltaics (PV) and hydropower. In total, 10 electricity technologies and 174 power plants installed across the country have been considered. Eleven environmental impacts have been estimated, including global warming, human toxicity, ecotoxicities, as well as resource and ozone layer depletion. The results reveal that hydropower is environmentally the most sustainable option across the impacts, followed by onshore wind and biogas. Electricity from natural gas has 10%-84% lower impacts than biomass for seven categories. It is also 13%-98% better than solar PV for six impacts and 17%-66% than wind for four categories. Solar PV has the highest abiotic depletion potential due to the use of scarce elements in the manufacture of panels. While the electricity demand has grown by 44% in the past 10 years, all the impacts except ozone layer depletion have increased by 1.6-2.7 times. In the short term, environmental regulations should be tightened to improve the emissions control from coal and biomass plants. In the medium term, the contribution of renewables should be ramped up, primarily increasing the hydro, wind and biogas capacity. Coal and oil should be phased out, using natural gas as a transitional fuel to help the stability of the grid with the increasing contribution of intermittent renewables.

Keywords: fossil fuels; renewable technologies; environmental sustainability; climate change; resource depletion; LCA.

4.1. INTRODUCTION

From the 1970s to the '90s, the electricity mix in Chile was mainly shaped by hydropower, with a lower contribution from fossil fuel power plants (Figure 19). However, high electricity demand, public objections to new hydropower projects, hydrological variability and the lack of planning in the sector have resulted in the current electricity mix being dominated by fossil fuels [1]. In 2014, 174 power plants were in operation in Chile, with fossil fuel technologies contributing 60% to the total electricity supply, hydropower 34% and other renewable options 6% (Table 10) [2]. Electricity from coal is generated using pulverised coal which provides 41% of total electricity. For gas and oil, both combined and open cycle plants are used (16.6% and 1.2% of the total generation, respectively). Oil power is generated by diesel engines, which contribute only 0.5% to the total due to their high costs [3]. Biomass electricity is mainly supplied by combined heat and power (CHP) plants (3.5% of the total), with the majority produced by the pulp and paper industry. Hydroelectricity is produced using reservoirs and run-of-river systems, with contributions of 19% and 15%, respectively. Finally, solar photovoltaics (PV) and wind contribute only 0.7% and 2% to the generation mix.

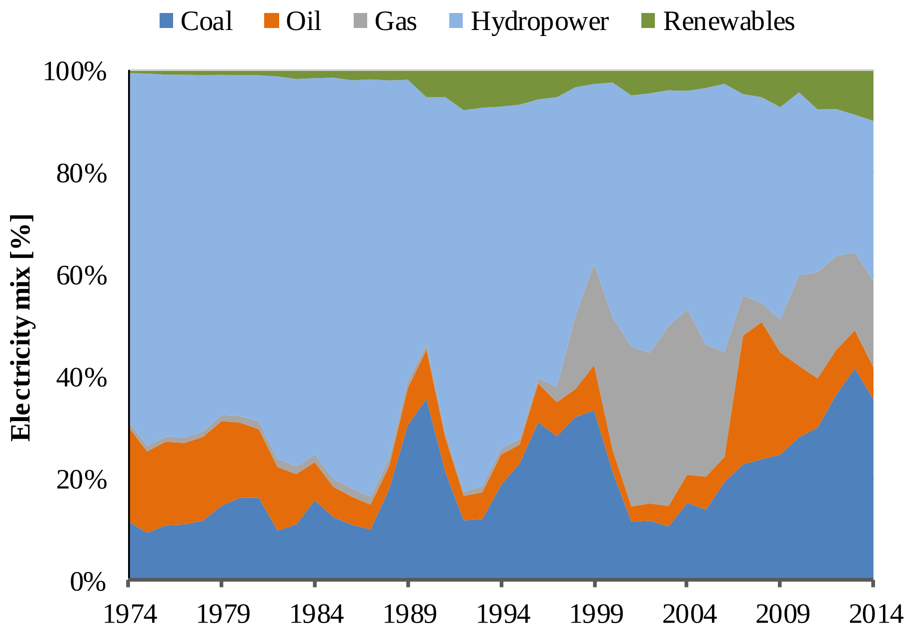


Figure 19: Historical electricity mix in Chile between 1974 and 2014 [2].

Table 10. Electricity generation in Chile in 2014 by source and technology [2].

Technology	**Electricity generation by source (GWh)** Coal	Natural gas	Oil (diesel)	Biomass & biogas	Hydro	Wind	Solar	Total	**Contribution (%)**
Pulverized coal	28,892							28,892	41.4
Combined cycle		9,554	2,002					11,556	16.6
Open cycle		443	377					820	1.2
Diesel engine			366					366	0.5
Combined heat and power				2,427				2,427	3.5
Biogas engine				283				283	0.4
Reservoir					13,092			13,092	18.8
Run-of-river					10,450			10,450	15.0
Onshore turbine						1,425		1,425	2.0
Photovoltaics							464	464	0.7
Total	28,892	9,997	2,745	2,710	23,542	1,425	464	69,775	100

The electricity sector in Chile faces many challenges. Electricity generation is the main contributor to greenhouse gas (GHG) emissions in the country [4]. Energy security is low due to a lack of indigenous fossil fuels [5] and the high cost of electricity has hampered economic growth [6]. The electricity sector also contributes the most to social and environmental conflicts (37%) in the country [7]. Even though hydropower has a significant generation potential (Table 11) and is the most economical option with low environmental impacts, its development has been slow. This is due to its effects on land use, related social implications and public opposition which have discouraged investments in this technology [8]. These problems suggest the need for identifying sustainable electricity options to help improve the sustainability of the sector in the country.

The Chilean government has started stimulating the diversification of electricity supply with the deployment of renewable and low-carbon technologies, while at the same time trying to reduce electricity prices [1]. Owing to its geographical characteristics and variety of climates, Chile has abundant renewable resources, such as solar, wind, geothermal, hydro and biomass [9, 10]. As illustrated in Table 11, the solar power potential is outstanding, with an estimated 100-548 GW for concentrating solar power (CSP) and more than 1,263 GW for solar photovoltaics (PV). This huge potential is due to the vast areas with the highest solar irradiation in the world, with capacity factors of up to 40% for solar PV systems [11]. Similarly, wind power potential is also significant, with estimated values of 37-40 GW and a capacity factor of 34% [11]. Geothermal, hydro and biomass potentials are also significant, with an average of 15 GW each.

Table 11. Estimated potential for renewable power and capacity factors in Chile [9, 11].

Technology	Potential (GW)	Capacity factor
Solar photovoltaics	1,263[a]	33%
Solar concentrating solar power	100 – 548	52%
Wind	37 – 40	34%
Hydropower	12 – 20	63%
Geothermal	16	
Biomass	14	
Total	1,864	

a One axis tracking.

In an attempt to improve the sustainability of the national electricity supply, the Chilean government defined environmental, economic and social actions for the sector in its *Energy Policy 2050* [1, 12, 13]. In spite of that, there are still no comprehensive studies in Chile of the sustainability of the current electricity system. This paper aims to address this gap by establishing a baseline for the environmental sustainability of electricity supply in Chile, to assist the government and the industry in identifying the hotspots and how to address them. Life cycle assessment (LCA) has been used for these purposes, to enable consideration of whole electricity supply chains.

LCA has been used previously to study the environmental impacts of electricity generation in other countries, but there is no comprehensive LCA study for Chile. Examples of studies elsewhere including Mexico [14], Nigeria [15], Turkey [16], United Kingdom [17], Portugal [18] and Brazil [19]. Several LCA databases (e.g. CCaLC [20], Ecoinvent [21] and Gabi [22]) also provide life cycle inventories (LCI) for electricity systems in different countries. However, only the Ecoinvent database [23] has recently included the LCI of electricity generation in Chile. These data have been developed from European LCI datasets, simply accounting for the Chilean electricity mix. This is inadequate as it fails to consider country-specific parameters, such as power plant efficiencies, capacity factors, types of technology, heating values of fuels, actual emissions from power plants, end-of-life waste management, etc. This study considers all of these parameters (around 140), for all 174 plants. In addition, it also follows the temporal evolution of the impacts over the period of 10 years (2004-2014). The impacts are estimated for each technology present in the Chilean electricity mix to allow their comparison and identification of hotspots. This is followed by the evaluation of the environmental sustainability of the electricity mix, both for the current situation and over the past decade. The results are used to make suggestions for improving the environmental sustainability of electricity supply in Chile. As far as we know, this is the first such study of the life cycle environmental sustainability of electricity in Chile.

4.2. METHODOLOGY

The environmental sustainability of the electricity mix has been assessed using attributional LCA and following the ISO 14040 [24] and ISO 14044 [25] standards. The goal and scope of the study are defined below, with the inventory data detailed in section 4.2.2 and the impact assessment method in section 4.2.3.

4.2.1. Goal and scope definition

The main goals of the study are:

i. to estimate and compare the environmental impacts of electricity sources and technologies currently present in the electricity mix;
ii. to estimate the impacts of the current electricity mix;
iii. to map the temporal evolution of impacts from electricity over the past 10 years; and
iv. to identify environmental hotspots and make recommendations for future improvements.

Consequently, the following functional units have been considered:

- 1 kWh of electricity generated by each source and technology (study goals i and iv);
- 1 kWh of electricity generated by the Chilean electricity mix (goals ii-iv); and
- annual electricity generation over the past 10 years (goal iii).

The scope of the study is from ‘cradle to gate’ as shown in Figure 20. The following life cycle stages have been considered for each source and technology: fuel production, transport and processing (where relevant), power plant construction, operation and decommissioning. Transmission, distribution and use of electricity are excluded as the focus is on electricity generation.

As indicated in Table 10, the following electricity technologies have been considered: pulverised coal, open and combined cycle turbines (oil and gas), diesel engine (oil), gas engine (biogas), CHP (biomass), reservoir and run-of-river (hydropower), onshore wind and multi-crystalline solar PV.

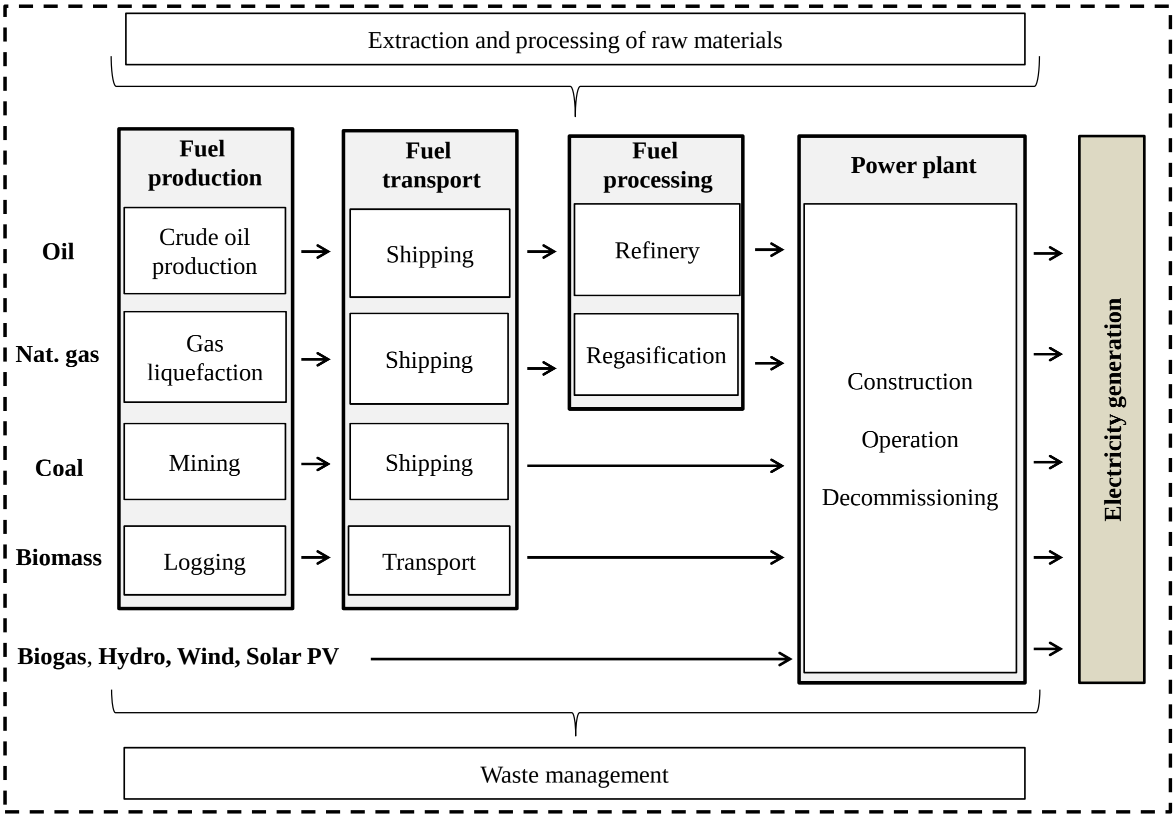


Figure 20. Scope of the study and the life cycle stages for different electricity sources.

4.2.2. Inventory data

All 174 plants connected to the two major electric interconnected systems in Chile - Central Interconnected System (SIC) and Interconnected System of Norte Grande (SING) – have been considered. These plants generate 98% of the total electricity supply in the country.

Primary data have been collected from the National Energy Commission (CNE) [2] and Load Economic Dispatch Centre of the Central Interconnected System (CDEC-SIC) [26]). Further academic literature and institutional reports have also been considered, as detailed further below. The year 2014 is taken as the base year as the most recent and comprehensive data were available during the course of this study. The Ecoinvent 2.2 database [21] has been used for the background data. The following subsections detail the LCI for each technology, together with the main assumptions.

4.2.2.1. <u>Fossil fuels</u>

An overview of the inventory data and assumptions for electricity from fossil fuels can be found in Table 12-Table 14. Hourly data for air emissions have been considered for each power plant, sourced from the Chilean Department for the Environment [27]. As mentioned earlier, fossil-based electricity supplies 60% of electricity in Chile, 68% of which is from coal (41% of the whole electricity mix). There are 18 coal power plants in operation, most of which use hard coal; the exception are two installations that are partially fed with petroleum coke (petcoke). Two types of technologies are used for coal power generation: pulverised coal (PC) and circulating fluidised bed (CFB). However, only 8% of the coal power installed capacity is CFB. Therefore, for both simplicity and lack of data on CFB, only PC has been considered, assuming that it supplies 100% of electricity from coal.

As shown in Table 14 and Table 13, natural gas and oil are used in combined and open cycle plants. The installed capacity of combined cycle (CC) power plants is 3,345 MW_e. In 2014, 83% of the electricity was produced from natural gas and 17% from diesel. There are 31 plants with open cycle (OC) gas turbines and a total installed capacity of 2,085 MW_e. They generated 820 GWh of electricity in 2014, of which 443 GWh (54%) was from natural gas and 377 GWh (46%) from oil. Finally, there are 35 diesel engine power plants that supplied 366 GWh of electricity in the same year. All natural gas is shipped in liquefied form and regasified in Chile.

Table 12. Inventory data for electricity generation from coal in 2014

Life cycle stage	Data
Fuel supply	Annual consumption: 11.2 million tonnes (95% coal, 5% petcoke) Mass contribution and calorific value (higher heating value): Australian coal: 8%, 27 MJ/kg Colombian coal: 54%, 26.8 MJ/kg Chilean coal: 10%, 18.9 MJ/kg USA coal: 23%, 26.0 MJ/kg Chilean petcoke: 2%, 32.5 MJ/kg USA petcoke: 3%, 32.5 MJ/kg Average sulphur content (weighted to account for the above mass contributions): 0.7%
Transport (shipping)	Australia: 11,959 km Chilean coal mines: 3,220 km Colombia: 4,585 km USA: 8,785 km
Power plant (pulverised coal)	Installed capacity: 4,167 MW_e Electricity generation: 28,892 GWh/yr Efficiency: 36% Capacity factor: 81% Lifespan: 38 yr Ash disposal: 4 g of ash waste/MJ fuel burned Direct emissions (after emission control)[a] CO_2: 97.5 g/MJ NOx: 170 mg/MJ SO_2: 340 mg/MJ Particles: 6.7mg/MJ

[a] Mean values of hourly emissions averaged over a year and expressed per unit of higher heating value of fuel.

Table 13. Inventory data for electricity generation from oil (diesel) in 2014.

Life cycle stage	Data			
Fuel supply and processing	Crude oil mix to refinery: Latin-American countries: 84% UK: 16% Diesel mix: Chile (from refinery): 43% USA: 57% Refinery: Crude processing capacity: 11 million m^3 (three refineries) Annual diesel consumption: 523 thousand tonnes Calorific value (High heating value): 45.6 MJ/kg Average sulphur content (weighted to account the above imports): 0.4%			
Transport (shipping)	Diesel import from the USA: 8,785 km Crude oil import from Latin-American countries: 5,204 km Crude oil import from the UK: 11,112 km Diesel distribution from refinery to power plants: 664 km			
Power plant		*Combined cycle*	*Open cycle*	*Diesel engine*
	Installed capacity	1,005 MW_e	1,600 MW_e	810 MW_e
	Electricity generation	2,002 GWh/yr	377 GWh/yr	366 GWh/yr
	Efficiency	44%	34%	36%
	Capacity factor	22%	3%	5%
	Lifespan	45 years	45 years	45 years
	Direct emissions (after emission control)[a]			
	CO_2	88.9 g/MJ	80.5 g/MJ	75.9 g/MJ
	NO_x	295 mg/MJ	265 mg/MJ	829 mg/MJ
	SO_2	185 mg/MJ	474 mg/MJ	192 mg/MJ

[a] Mean values of hourly emissions averaged over a year and expressed per unit of higher heating value of fuel.

Table 14. Inventory data of electricity generation from natural gas in 2014

Life cycle stage	Data		
Fuel supply and processing	Annual liquefied natural gas (LNG) consumption: 1.9 billion Nm^3 Higher heating value: 41.1 MJ/Nm^3 Evaporation plant: Quintero's regasification plant capacity: 5,475 million Nm^3/yr		
Transport (shipping)	LNG import from Trinidad and Tobago: 12,684 km Gas network: 153 m/PJ (estimated from gas sales and total length of pipeline)		
Power plant		*Combined cycle*	*Open cycle*
	Installed capacity	2,340 MW_e	485 MW_e
	Electricity generation	9,554 GWh/yr	443 GWh/yr
	Efficiency	47%	28%
	Capacity factor	46%	10%
	Lifespan	35 years	45 years
	Direct emissions (after emission control)[a]		
	CO_2	61.9 g/MJ	56.1 g/MJ
	NOx	129 mg/MJ	25 mg/MJ
	SO_2	0.7 mg/MJ	0.7 mg/MJ

[a] Mean values of hourly emissions averaged over a year and expressed per unit of higher heating value of fuel.

4.2.2.2. Renewables

4.2.2.2.1. Electricity from biogas

There are eight biogas plants in Chile with an installed capacity of 42 MW_e (Table 15 and Table 34 in appendix). They contributed only 0.4% to the total electricity supply in 2014 (Table 10). The majority (83%) of biogas electricity is produced by two landfills located in Santiago de Chile: Loma Los Colorados and Santa Marta. A further 15% is produced by anaerobic digestion of sewage sludge from the wastewater treatment plant of El Tebal and the remaining 3% is from manure and organic waste. Biogas engine is the main technology used for co-generation of electricity and heat [28, 29]. The latter is used for heating the anaerobic digesters but it is not utilised in landfill biogas generation.

Electricity from manure and organic waste is not considered due to the low contribution (3%) and a lack of specific data. Furthermore, production of biogas in landfills is assumed 'burden free' as it is produced from landfilled waste through its natural decomposition. Therefore, only the burdens associated with the production of biogas by anaerobic digestion of sewage sludge are considered for the biogas mix. Exergy allocation has been applied between electricity and heat, assigning 60% of the burdens to the former [30]. The emissions of NO_x and SO_2 from biogas production have been sourced from the GEMIS database [31]. The infrastructure-related impacts of the biogas plants have been taken into account but had to be scaled up (see section 4.2.2.3) because the size of the co-generation plant in Ecoinvent (160 kW_e) is lower than the average plant in Chile (1 MW_e).

Table 15. Inventory data for electricity generation from biogas and biomass in 2014.

Life cycle stage	Data		
		Biogas	*Biomass*
Fuel supply	Fuel use	22 million Nm^3 biogas from sewage plants	1.5 million m^3 cereal straw and husks (no burdens)
		126 million Nm^3 biogas from landfill (no burdens)	10 million m^3 ind. res. wood
	Calorific value	22.7 MJ/Nm^3	19.1 MJ/kg cereal straw and husks 18.3 MJ/kg ind. res. wood
	Density		169 kg/m^3 cereal straw and husks 239 kg/m^3 ind. res. wood
Transport	Cereal straw bales	50 km	
	Ind. residual wood	20 km	
Power plant		*Biogas engine*	*Biomass CHP*
	Installed capacity	42 MW_e (1 MW_e mean size)	431 MW_e (10 MW_e mean size)
	Electricity generation	283 GWh/yr	2,427 GWh/yr
	Efficiency	32%	18%
	Capacity factor	77%	63%
	Lifespan	20 years	Boiler: 20 years; Building: 80 years
	Direct emissions (before exergy allocation and after emission control)		
	NO_x	15 mg/MJ	88 mg/MJ
	SO_2	21 mg/MJ	2.5 mg/MJ

4.2.2.2.2. Electricity from biomass

Chile has 19 biomass plants, which provide around 3.5% of the total electricity generation (Table 10). The majority of this (79%) is produced by the pulp and paper industry and the rest by energy companies. The pulp and paper industry generates electricity from industrial wood residues (73%) and black liquor (27%). The energy companies also use industrial wood residues (60%) as well as agricultural crop residues (40%) [32]. Electricity is co-generated with heat in a CHP plant. The former is supplied to the central interconnected system (SIC) and the heat is used for the wood drying process in the pulp and paper industry and wood-using energy companies. There is only one plant that uses agricultural crop residues (cereal straw and husks) and releases the heat without using it.

For the modelling of biomass electricity, it has been assumed that all the feedstock comes from industrial wood residues and agricultural crop residues (Table 15 and Table 34 in the appendix). The black liquor has been omitted due to its low contribution to the total electricity generation (<1%) and a lack of data. No environmental burdens have been considered for agricultural residues as they have no economic value and are normally burned at the farm. However, industrial wood residues have an economic value. Hence, their impacts have been estimated using economic allocation, based on their contribution of 15% to the total revenue from wood products [33, 34]. Exergy allocation has been used to allocate the impacts between the electricity (77%) and heat [30].

A distance of 50 km has been assumed for the cereal straw and husks and 20 km for the wood residues. Emissions from the CHP plants have been estimated using GEMIS [31]. The main input parameters used to estimate the emissions were the mean size of the CHP plants (10 MW_e), efficiency (18%) and standard bag filters for control of particulates. The CHP plant from the Ecoinvent database has a 580 kW_e capacity, but the average power capacity of CHP plants in Chile is 10 MW_e. Therefore, the impacts have been scaled down accordingly (section 4.2.2.3).

4.2.2.2.3. Electricity from wind and solar PV

Currently, 16 onshore wind farms are in operation with a total capacity of 831 MW_e (Table 35 in the appendix). There are no offshore wind installations in Chile. Most of the wind farms have 2 MW_e turbines (Table 16). Inventory data for this size of turbine have been obtained from Kouloumpis et al. [35], based on a Vestas design. This type has been selected because 59% of the 407 wind turbines in Chile are Vestas. A capacity factor of 27% has been considered.

The 19 solar PV plants in Chile have a total installed capacity of 401 MW_e and an average capacity factor of 24% (Table 16). The majority of solar electricity in the country is provided by ground-mounted mono- and multi-crystalline PV (83%), with the balance supplied by thin-film technologies [36–38]. For modelling purposes, it has been assumed that all the solar electricity is generated by multi-crystalline PV due to a lack of data for thin-film and mono-crystalline panels. The average lifespan of solar panels has been assumed at 30 years and the annual degradation rate 0.7% [39–41].

4.2.2.2.4. Hydroelectricity

Ten reservoirs and 95 run-of-river power plants are in use in Chile (Table 36 in the appendix), with a total capacity of 3,726 MW_e and 2,722 MW_e respectively (Table 16). All the hydropower plants are located between the Valparaiso and Los Lagos regions, in the Andes mountains range, an area with a dry temperate climate [5]. The hydroelectricity system has been modelled considering construction, operation and decommissioning of the plants. Emissions of methane have been considered for the reservoir technology, arising from organic matter in the water body and anaerobic activity over the lifespan of the reservoir [42]. Many factors influence the production of methane in reservoirs, such as water depth, climate, flooded vegetation, organic load of tributaries and reservoir dimensions. As specific data were not available for these emissions, the Ecoinvent data for the Alpine-region reservoirs have been used instead, considering that this region has similar geographic and climate conditions to Chile. Methane emissions of 14 mg CH_4/kWh have thus been assumed. No emissions have been considered for run-of-river due to the low residence time of the water. For the reservoir plants, the impacts from construction correspond to the Ecoinvent data for a plant of 95 MW_e, and for the run-of-river, for an 8.6 MW_e plant [43]. In Chile, the average size of the former is 373 MW_e and the latter 29 MW_e; therefore, the data in Ecoinvent have been scaled up (section 4.2.2.3).

Table 16. Summary of inventory data and assumptions for hydropower [21, 26], wind and solar PV [2, 26].

Parameter	Solar PV	Onshore wind	Reservoir	Run-of-river
Installed capacity	401 MW_e (multi-crystalline)	831 MW_e (2 MW_e mean)	3,726 MW_e (373 MW_e mean)	2,722 MW_e (29 MW_e mean)
Electricity generation	464 GWh/yr	1,425 GWh/yr	13,092 GWh/yr	10,450 GWh/yr
Capacity factor	24%	27%	43%	60%
Lifespan	30 years	Moving parts: 20 years Fixed parts: 40 years	100 years	80 years
Degradation rate	0.7%/yr			
Methane missions			14 mg CH_4/kWh	

4.2.2.3. Infrastructure

As mentioned earlier, some of the power plants in Ecoinvent had either larger or smaller capacities than those installed in Chile. Therefore, it has been necessary to scale their impacts accordingly. This has been done for hydropower, biogas, and biomass power plants and for the regasification plant for natural gas. In LCA, the environmental impacts are normally scaled linearly with respect to the size of infrastructure. However, due to the economies of scale, this relationship is likely to be non-linear. Therefore, the “economies of scale” method, typically used for scaling the capital costs of process plants, has been applied. This is based on the approach in Coulson et al. (1993) [44], adapted for use in LCA [45]:

$$\mathrm{I_A} = \mathrm{I_R} * \left(\frac{\mathrm{S_A}}{\mathrm{S_R}}\right)^{0.6} \qquad \text{(Eq. 7)}$$

where:

I_A environmental impacts of the actual infrastructure

I_R environmental impacts of reference infrastructure

S_A size or dimensions of the actual infrastructure

S_R size or dimensions of reference infrastructure

0.6 the economy of scale factor.

4.2.2.4. End-of-life waste management

Copper, aluminium and reinforcing and stainless steel have been assumed to be recycled after the decommissioning of power plants. The system has been credited for this using the “avoided burdens (net scrap)” approach [46–50]. This takes into account the recycled content of metals in the construction and their recycling rates at the end of life. If the recycled content is lower than the recycling rate, a credit is given to the system; otherwise, no credits are included. The recycled content for different metals has been assumed as follows: aluminium 32%, copper 18% and steel 37% [51]. Data for recycling of structural metals in Chile have not been available so a recycling rate of 50% has been assumed, with the rest landfilled. Only 1% of the ash from coal plants is recycled in cement factories due to the large deposits of pozzolans and lime; hence, its recycling is not considered in the study.

4.2.2.5. Temporal evolution of impacts

The temporal evolution of the impacts from electricity generation in Chile focuses on the years 2004, 2009 and 2014. These years have been chosen as they are representative of changes in the electricity mix over the period. The impacts have been estimated using the data in Figure 19 and Table 17. As can be seen, the share of hydropower has declined by 10% over the period, from 43% in 2004 to 33.7% in 2014. Natural gas followed a more drastic trend, reducing its contribution from 36% in 2004 to 9% in 2009, before going up to 14% in 2014. The share of coal, on the other hand, has been increasing and it is now the main contributor in the mix, having surpassed hydropower. Oil has a low contribution now, but between 2007 and 2010 it peaked at 18%, caused by the steady increase in electricity demand and the shutdown of gas power plants due to a disruption in gas supply.

Each year has been modelled taking into account the values of different parameters, such as the electricity and fuel mixes, capacity factors, heating values, etc. The detailed life cycle inventory for each year can be found in Table 37 to Table 40 in the appendix.

4.2.3. Environmental impact assessment

GaBi v7.0 software [22] has been used to model the system. The latest version of CML 2001 (April 2016) impact assessment method [46] has been applied to determine the environmental impacts. This methodology considers the following 11 environmental impacts all of which have been estimated: global warming potential (GWP), human toxicity potential (HTP), abiotic depletion potential of elements (ADP), abiotic depletion potential of fossil resources (ADP_{fossil}), acidification potential (AP), eutrophication potential (EP), ozone layer depletion potential (ODP), photochemical oxidants creation potential (POCP), freshwater aquatic ecotoxicity potential (FAETP), marine aquatic ecotoxicity potential (MAETP) and terrestrial ecotoxicity potential (TETP).

Table 17. Electricity generation and contribution of different sources for in the period 2004-2014 [2, 52].

	2004	**2009**	**2014**
Electricity generation (TWh)	48.6	56.6	69.8
Contribution (%)			
Coal	19.4	27.8	41.4
Oil	-	18.3	3.9
Natural gas	36.1	8.7	14.3
Biogas	-	-	0.4
Biomass	1.3	1.7	3.5
Solar PV	-	-	0.7
Wind	-	-	2.0
Hydropower	43.1	43.5	33.7

4.3. RESULTS AND DISCUSSION

4.3.1. Environmental impacts of technologies (base year)

Life cycle environmental impacts of the technologies are summarised and compared using a heat map in Table 18. As can be seen, coal is environmentally the least sustainable option for eight of the impacts while hydropower is the best option for all the categories, followed by biogas and wind. The most impacting life cycle stages are fuel production and power plant operation, each contributing on average 40% to the total impacts of fossil, biogas and biomass options (Figure 21). For the rest of the renewable technologies, power plant construction represents the most significant stage with an average contribution of around 90%. Each impact category is analysed in detail in the following sections.

Table 18. Environmental impacts of electricity technologies in Chile in the base year (2014).

	Electricity sources and technologies											
Impacts per kWh	Coal PC[a]	Oil CC[a]	Oil OC[a]	Oil DE[a]	Gas CC[a]	Gas OC[a]	Biogas	Biomass CHP[a]	Solar PV[a]	Wind onshore	Hydro reservoir	Hydro RoR[a]
GWP [g CO_2 eq.]	1,039	836	988	924	632	975	36	50	40	8	3	2
HTP [g DCB eq.]	394	100	126	97	46	74	9	120	53	25	3	2
ADP [µg Sb eq.]	33	121	154	191	27	47	36	30	1,165	81	6.1	5.4
ADP_{fossil} [kJ]	10,342	9,454	12,213	11,807	8,713	14,454	312	595	419	91	20	17
AP [mg SO_2 eq.]	6,070	4,131	8,783	7,911	682	473	340	776	254	33	8	6
EP [mg PO_4^{-3} eq.]	1,913	666	818	1,546	193	149	40	218	104	21	3	3
ODP [µg R11 eq.]	15	101	129	125	0.9	1.4	2.9	5.4	6.3	0.5	0.2	0.1
POCP [mg C_2H_4 eq.]	298	253	462	779	75	87	34	424	22	3.6	0.9	0.7
FAETP [g DCB eq.]	308	28	40	58	11	21	7.4	8.3	49	26	0.8	0.7
MAETP [kg DCB eq.]	2,403	53	69	76	15	26	10	12	173	18	1.4	1.2
TETP [mg DCB eq.]	2,200	770	830	1,150	300	420	210	580	450	570	90	70

[a] PC: Pulverised coal; CC: Combined cycle; OC: Open cycle; DE: Diesel engine; CHP: Combined heat and power; PV: Photovoltaics; RoR: Run-of-river.

Legend: red indicates the highest, amber medium and green the lowest impacts.

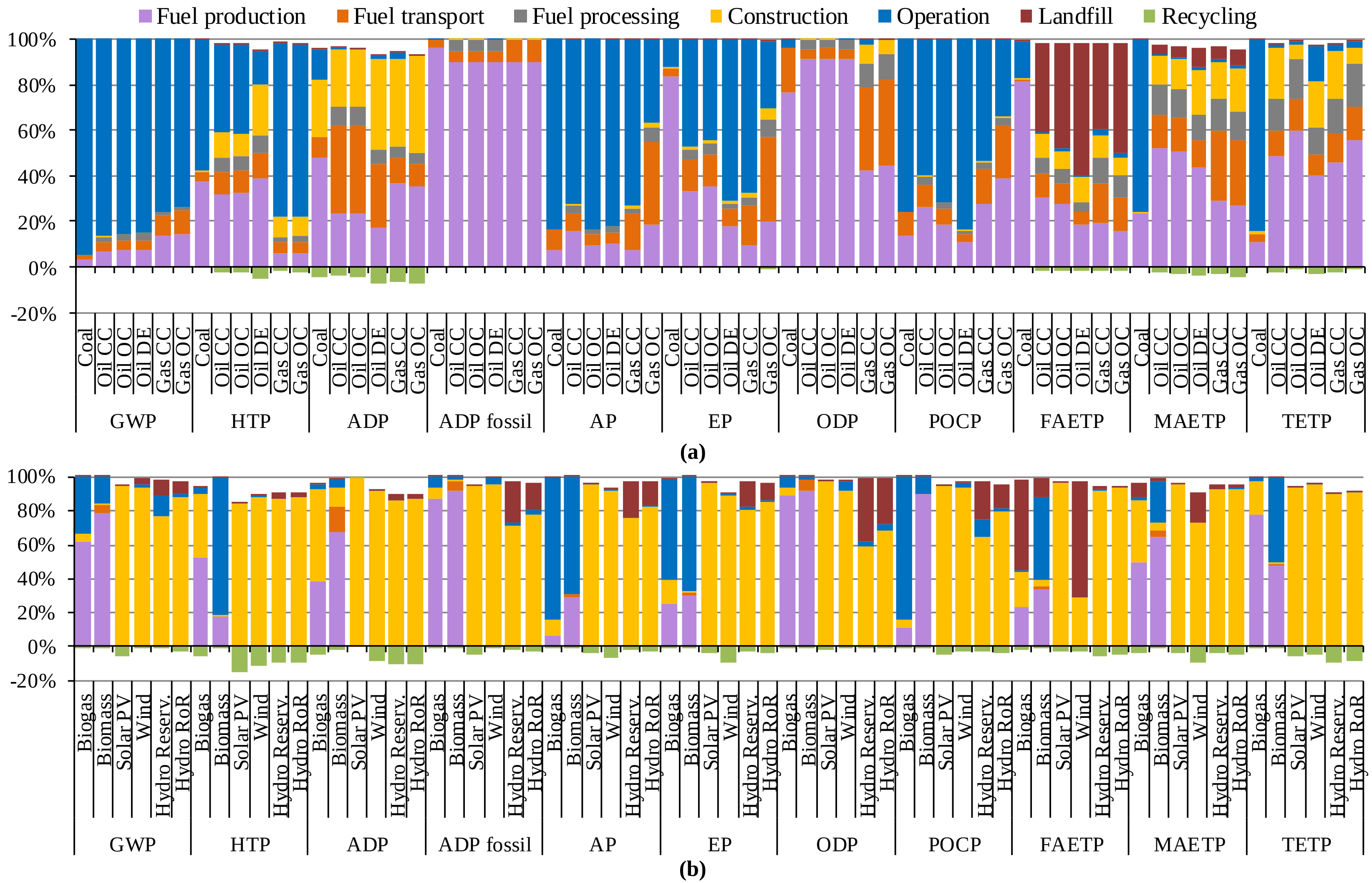


Figure 21. Contribution of life cycle stages to environmental impacts by power technology. (a) Fossil fuel technologies. (b) Renewable technologies. [Hydro RoR: Hydropower from run-of-river, Hydro Reserv.: Hydropower from reservoirs]

4.3.1.1. Global warming potential (GWP)

Run-of-river and reservoir hydropower plants, along with wind electricity, have the lowest GWP (<8 g CO_2 eq./kWh). By contrast, the impact of coal power is around 130 times higher (1,039 g). Oil power has a GWP similar to coal (836-988 g CO_2 eq./kWh) because open cycle power plants have low efficiency (31% on average). Among the fossil-based options, natural gas in combined cycle plants generates electricity with the lowest GWP (632 g CO_2 eq./kWh) due to a higher efficiency (47%). Even so, it still has 13 times higher emissions than biomass (50 g CO_2 eq./kWh), the worst renewable option for this impact. The latter, along with solar PV, has a four times higher impact than hydropower and wind.

For fossil-fuel power plants, their operation contributes more than 76% to the GWP due to the emissions associated with the burning of fuels. In the case of renewable options, two groups can be distinguished. The first group comprises biomass and biogas, where the impact is mainly due to fuel production (62% for biogas and 79% for biomass) and power plant operation (33% for biogas and 15% for biomass). CO_2 is the main GHG as a result of fossil fuel used in machinery and because of fugitive emissions of CH_4 during the anaerobic digestion and storage of sewage sludge for biogas production [53, 54]. In the operation stage, N_2O is the main GHG emitted during the combustion in power plants for both biogas and biomass power options.

The second group consists of hydropower, wind and solar PV where the contribution to GWP is mainly associated with the construction stage, with CO_2 being the main GHG. Cement and steel production, along with diesel used in the construction machinery, are the main contributing processes for hydropower plants. The same processes, plus the use of glass fibre in wind turbines, contribute to GWP of wind electricity. Additionally, the production of crystals and wafers is the main contributor to the impact in the manufacture of solar PV panels. Recycling reduces the GWP across the technologies to a small degree. Only solar PV shows a slightly higher reduction in GWP (5%) due to the system credits for the avoidance of virgin aluminium production.

4.3.1.2. Human toxicity potential (HTP)

Coal power has the highest HTP among all the technologies evaluated (394 g DCB eq./kWh), followed by open cycle oil plants and biomass (126 and 120 g, respectively). Among the fossil fuel technologies, natural gas in combined cycle plants is the best option for this impact

(46 g DCB eq./kWh). It is even better than renewable technologies, such as solar PV and biomass (53 and 120 g DCB eq./kWh, respectively). Both types of hydropower technologies have the lowest HTP (<3 g DCB eq./kWh). The next best source of electricity is wind (25 g DCB eq./kWh).

Power plant operation and fuel production are the two main contributing stages for fossil fuel technologies with contributions of 14%-76% and 6%-79%, respectively. Coal emits hydrogen fluoride into the atmosphere during combustion and vanadium is emitted to water bodies due to the disposal of ashes. Both the combustion and ash disposal cause 34% of HTP associated with coal electricity. The release of selenium related to the overburden in mines in fuel production contributes 19% to the total. Other combustion options, such as biomass and open and combined cycle oil power plants, generate significant air emissions of polycyclic aromatic hydrocarbon (PAH) as a result of incomplete combustion which is in turn due to lower flame temperatures and an inadequate C/O ratio [55]. Biomass has the highest emissions of PAH, followed by open cycle oil power plants, with contributions to HTP equivalent to 67 and 35 g DCB eq./kWh, respectively. In the case of solar PV, wind and hydropower, the construction stage is the principal contributor, mainly due to the release of chromium (+VI) in the stainless steel production process. Additionally, PV panel production emits selenium, vanadium and thallium.

End-of-life recycling reduces HTP significantly, mostly for the renewable options with the exception of biomass. Solar PV has the highest reduction (18%) while for the rest of renewable technologies the reduction ranges between 6%-11%. Oil power from diesel engines is the only fossil fuel option that has a reduction in HTP greater than 5%. Diesel engine, biogas and wind options benefit from the credits for copper recycling. The credits for hydropower options are related to alloyed steel recycling. For solar PV, the main credits come from the recycling of aluminium used for frames, mounting structures and inverters.

4.3.1.3. Abiotic depletion potential of elements (ADP)

Solar PV has the highest depletion of elements (1,165 µg Sb eq./kWh). This is six times greater than the second largest impact – power from oil in diesel engines (191 µg) – and about 190 times larger than the least impactful technology, hydropower (5-6 µg). The three oil power technologies have the largest ADP (121-191 µg Sb eq./kWh) among the fossil fuel alternatives, with values four times higher than coal (33 µg) and natural gas power (27-47 μg). Wind also has an ADP higher than coal and natural gas (81 μg Sb eq./kWh,). Natural gas, biogas and biomass have the lowest ADP, ranging from 27 to 36 μg Sb eq./kWh.

Fuel production and construction are the main contributing stages for fossil fuel options (48%-77%), biogas (93%) and biomass (78%). Construction is the main hotspot for solar PV, wind and hydropower, with a contribution of 85%. The influence of the construction stage is correlated with the capacity factors and lifespan: its influence is lower for technologies with high capacity factors and long lifespans, like hydropower, coal, biogas and natural gas. Copper is the main element depleted by the construction of coal, gas, oil, biogas and wind installations. For solar PV, gold and silver, used for electronic parts, are the main hotspots. As aluminium is an abundant element, its recycling has negligible positive effect on the ADP of solar PV. On the other hand, recycling of metals from coal, natural gas, wind and hydropower plants reduces their impact by 5-10%.

4.3.1.4. Abiotic depletion potential of fossil fuels (ADP_{fossil})

Fossil-based technologies have ADP_{fossil} values ranging from 8,713 kJ/kWh (gas combined cycle) to 14,454 kJ/kWh (gas open cycle). For the renewable options, the impact varies from 17 kJ/kWh (run-of-river hydropower) to 595 kJ/kWh (biomass). Biomass, biogas and solar PV have the highest ADP_{fossil} among the renewables (312-595 kJ/kWh) but this is still only 5% of the average impact of the fossil fuel options (11,164 kJ/kWh).

The extraction of fuel is the main contributor (90%) for the fossil fuel options. For the renewables, ADP_{fossil} is mainly caused by the consumption of fossil fuel for the production of construction materials, such as cement and metals, and for the use of machinery associated with soil movement in the case of hydropower plants and with logging for biomass. Hence, this impact is mainly associated with the construction stage (85%) for wind, solar and hydropower options, while for biogas and biomass, extraction of fuel is the most significant process (90%).

4.3.1.5. Acidification potential (AP)

Open cycle oil and coal power are the options with the highest AP: 8,783 and 6,070 mg SO_2 eq./kWh, respectively. This is due to SO_2 emissions from fuel combustion. Among the renewables, biomass is the worst option for this impact (776 mg SO_2 eq./kWh) because of NO_x emissions generated in low-temperature flames. Electricity from biomass has higher impact than natural gas (473-682 mg SO_2 eq./kWh). Solar PV also has a high AP compared to the remaining renewables (254 mg SO_2 eq./kWh). Still, it is about half the lowest impact from natural gas but about eight times greater than the values for hydropower (6-8 mg SO_2 eq./kWh) and wind (33 mg), the best options for this category.

Plant operation is the most significant life cycle stage, with an average contribution of 72% for fossil fuel options, 84% for biogas and 69% for biomass. As mentioned earlier, this is due to the emissions of SO_2 and NOx. These are also generated during the production and construction of solar PV, wind and hydropower plants. The main processes causing the AP of solar PV are the use of solar-grade silicon for manufacture of wafers, aluminium alloy and copper for construction and mounting of panels, solar glass for solar cells and electricity for manufacturing of panels. For wind and hydropower options, the production of copper and steel, together with the fabrication of glass fibres for wind turbines, are the most contributing processes. An average of 86% of this impact is attributed to the construction of these plants.

4.3.1.6. Eutrophication potential (EP)

Coal power has the highest EP (1,913 mg PO_4^{3-} eq./kWh), followed by the oil technologies. Regarding the latter, the EP of diesel engines (1,546 mg PO_4^{3-} eq./kWh) is nearly double the impact from the combined and open cycle plants (666 and 818 mg PO_4^{3-} eq./kWh, respectively). Electricity from biomass has the highest EP (218 mg PO_4^{3-} eq./kWh) among the renewables and even greater than the natural gas options (149-193 mg). Solar PV is the second worst renewable alternative with 104 mg PO_4^{3-} eq./kWh. Hydropower and wind are again the best options (3 and 21 mg PO_4^{3-} eq./kWh, respectively).

Coal extraction (84%) and power plant operation (12%) are the main hotspots for coal power. Phosphate, released during the extraction of coal, is the main burden followed by NO_x emitted during coal combustion. The plant operation causes around 50% of the EP for the oil, biomass and natural gas options, also related to NO_x emissions from fuel combustion. Construction is the main contributing stage for hydropower, wind and solar PV. The copper content in PV panels and inventers, together with electricity consumption for panels manufacture, cause most of the EP of this technology. This is specifically due to phosphate emissions from copper refineries and coal in the electricity mix of countries where solar PV is produced, such as China.

4.3.1.7. Ozone depletion potential (ODP)

The oil technologies have the highest ODP (101-129 µg R11 eq./kWh). The next worst option is coal power, but its impact is seven times lower (15 µg R11 eq./kWh). Solar PV has the highest ODP among the renewables, followed by biomass power (6.3 and 5.4 µg R11 eq./kWh, respectively). The natural gas options have lower impact (0.9-1.4 µg R11 eq./kWh) than biogas, biomass and solar PV (2.9-6.3 µg). The reason for this is that natural gas is shipped in liquefied form, avoiding long-distance pipelines that use ozone-depleting fire suppressants. The hydropower options have the lowest impact (0.1-0.2 µg R11 eq./kWh), followed by wind (0.5 µg).

The main contributing stage for the fossil-based technologies is fuel production (73%). The extraction and processing of crude oil produces significant amounts of ozone-depleting substances [56]. As mentioned in section 4.2.2.1, there are two coal power plants that also use petcoke as a secondary fuel. This increases the ODP of coal power due to the petcoke-related burdens from the combustion of heavy fuel oil in the refinery's furnace. Solar PV panel production releases chlorodifluoromethane (HCFC-22) emissions that contribute to ODP. These gases are intermediate compounds for the production of fluorocarbon film used for solar-glass coating [57]. Hence, construction is the main contributing stage for solar PV (98%). Halon 1301 is emitted in the life cycle of biomass power, mainly associated with combustion of diesel in machinery during logging and wood transport to sawmills. As a result, the fuel production stage causes 89% of the impact.

It should be noted, however, that the estimates of ODP have a margin of uncertainty due to the Montreal Protocol which has led to a reduction in use of ozone-depleting substances in many regions and sectors [58].

4.3.1.8. Photochemical oxidants creation potential (POCP)

Power from diesel engines is the worst option for POCP (779 mg C_2H_4 eq./kWh), followed by open cycle oil plants (462 mg) and biomass (424 mg). The last has a 40% higher impact than coal (297 mg C_2H_4 eq./kWh) and around five times greater than gas (75-87 mg). Solar PV and biogas are the least preferred renewable options for this category (22 and 34 mg C_2H_4 eq./kWh, respectively). Hydropower and wind have the lowest POCP (07-0.9 and 3.6 mg C_2H_4 eq./kWh).

Power plant operation is the main contributor to the impact from coal (76%), oil (60%-84%) and biogas (84%) power due to the emissions of SO_2, NO_x, CO and non-methane volatile organic compounds (NMVOC). Fuel production is the key hotspot (90%) for biomass electricity, related to NMVOC emissions from the logging machinery and transport to sawmills. For solar PV, wind and hydropower, the construction stage causes 83% of POCP. Like the AP, the POCP of solar PV is largely due to the use of materials (solar grade silicon, aluminium alloy and copper) and electricity for the manufacturing of panels.

4.3.1.9. <u>Freshwater, marine and terrestrial ecotoxicity potentials (FAETP, MAETP and TETP)</u>

Coal has the highest ecotoxicity potentials, at least double the impacts of the next closest option, oil power from diesel engines. Solar PV is the worst renewable technology for FAETP and MAETP, while biomass has the largest TETP. Open cycle natural gas, together with wind power, have FAETP and MAETP twice as high as the combined cycle natural gas, biogas and biomass (see Table 18). Hydropower is the best performing option across the three impacts.

For coal, plant operation is the main contributor to MAETP (76%) and TETP (84%), and fuel production to FAETP (82%). For the other fossil fuel options, fuel production, fuel transport and plant construction are significant contributing stages for the three impacts. Additionally, fuel processing is important for TETP and landfill disposal for FAETP.

The main burdens causing FAETP of coal power are nickel, beryllium, cobalt and vanadium emitted to water during coal extraction. For oil power from diesel engines, leaching of copper from landfills to water bodies is the main contributor to FAETP. In the case of solar PV, the vast majority of FAETP (97%) is related to the release of beryllium, cobalt, copper and vanadium to water during the production of photovoltaic cells and inverters.

For MAETP, plant operation is the most significant contributor for coal power mainly due to the hydrogen fluoride emission during combustion. The impact from diesel engines and solar PV is associated with hydrogen fluoride and beryllium emissions from crude oil refining and the production of components for solar PV systems.

Mercury emissions from combustion are the main burden for TETP of coal and oil power. For the latter as well as for solar PV, TETP is caused by chromium, vanadium and mercury generated in the production of steel.

4.3.1.10. Comparison of results with literature

As shown in Figure 22, most of the impacts of fossil fuel options estimated in this work are within the ranges found in the literature, with some exceptions. This includes ADP for coal (33 µg Sb eq./kWh) which is slightly below the lowest literature value (36 µg Sb eq./kWh); see Figure 22a. This impact is associated mostly with the infrastructure and in Chile, coal power plants have high capacity factors (81%) and good efficiency (38%-41%) as most of the installations are new and the coal has a high heating value (25.8 MJ/kg). All these factors imply a lower requirement of resources for coal production and transport per kWh. Furthermore, the ODP for coal (15 µg R11 eq./kWh) is above the maximum value in the range (11 µg R11 eq./kWh). The use of petcoke as a secondary fuel in coal power plants explains this difference.

For the three oil technologies, TETP is below the range, while MAETP and HTP are within the lower range of the literature values (Figure 22b). These impacts are mainly associated with the release of heavy metals and toxic compounds, mostly in oil production (ecotoxicities), and from combustion in power plants (HTP). Heavy fuel oil is the main fuel considered in the literature for oil power [56]. In Chile, oil power plants are fed by diesel instead of heavy fuel oil. Because oil (diesel) used in Chile has a higher calorific value (45.6 MJ/kg) than heavy fuel oil (41.1 MJ/kg), the consumption of fuel is lower, leading to lower ecotoxicities. The lower HTP is justified because the combustion of heavy fuel oil produces higher emissions of PAH, nickel and vanadium than the combustion of diesel [56].

EP is the only impact for diesel-engine power with a value (1546 mg PO_4^{-3} eq./kWh) above the literature range (1460 mg). According to the literature, the average efficiency of oil technologies is 38% [56], somewhat higher than the average efficiency in Chile (36%). As indicated in section 3.1.6, operation is a significant stage for oil electricity; therefore, a lower efficiency leads to a higher impact than in the literature. It can be noted that even though open cycle plants have a lower efficiency (34%) than diesel engines, their EP is within the literature range. This is due to NO_x emissions (265 mg/MJ) being 68% lower than from diesel engines (829 mg NO_x/MJ).

As can be seen in Figure 22c, both natural gas technologies have ODP (0.9-1.4 µg R11 eq./kWh) significantly below the minimum value reported in the literature (12.7 µg R11 eq./kWh). This is because the natural gas is liquefied and shipped, avoiding the use of long-distance pipelines that are associated with significant emissions of ozone-depleting substances, as mentioned in section 4.3.1.7.

The impacts of renewable technologies in the current study fall within the lower range of the literature values, and for some categories, below the range. For example, biogas power has lower values for GWP, HTP, ADP, AP and POCP; for the rest of the impacts, the values are in the lower part of the range (Figure 22d). According to the countries analysed in the literature, the biogas mix is made up of 52% biogas from anaerobic digestion of biowaste and 48% sewage sludge. However, in Chile, 85% of biogas comes from landfills and the rest from digestion of sewage sludge. As landfill gas is assumed to be burden free, the impacts of biogas electricity in the current study are 44%-88% lower than those reported in the literature.

The ADP and ecotoxicity impacts from biomass power are below the literature values, while POCP and ODP are above the range. In the literature [54, 59], biomass power is mainly generated using softwood (72%), such as cereal straw, husks and sawdust. Furthermore, the capacity factor is 23% and ashes are disposed both in landfills and spread on farmland. However, in Chile, 90% of biomass comes from industrial wood residues, the capacity factor is 63% and the ash is only landfilled. The higher ODP and POCP values are justified because the industrial wood residues have a higher economic value in Chile and, therefore, the impacts allocated to the residues are higher (15%) than in the literature (3%-5%) [33, 34]. The low ADP value is associated with the higher capacity factor in Chile. The lower FAETP and MAETP impacts are due to both the greater contribution of industrial wood residues (minimal use of softwood) and the higher capacity factor. The lower TETP in this study is due to the absence of farmland spreading as a way of using the ashes. According to the literature, chromium is the main element released to agricultural soil due to the use of ashes on land and represents about 86% of TETP for electricity from biomass [59, 60].

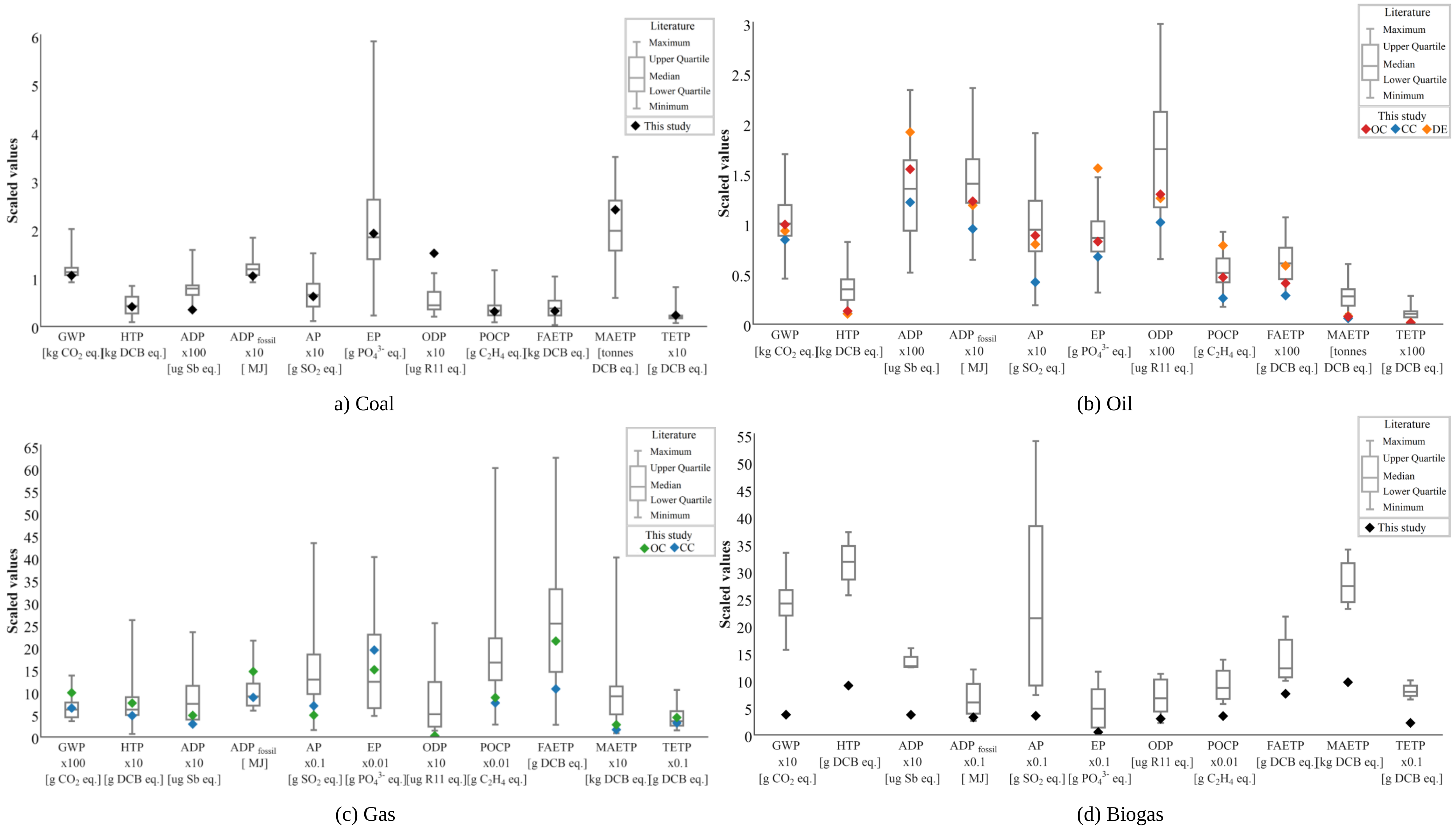
Solar PV has the largest ADP in comparison with all the technologies in Chile (1,165 µg Sb eq./kWh); however, the impact still falls below the minimum literature value (1,800 µg). This is due to the location of the PV and the difference in solar irradiation. The location of most solar PV systems in the Chile is in the Atacama Desert, an area with one of the highest solar radiation in the world, leading to an unusually high capacity factor (>24%). These conditions are more favourable than those in the literature and explain the lower ADP per kWh, and also a lower value for the rest of the impacts compared with the literature ranges. Similar applies to wind power, for which most impacts are below the range. This is due to the much higher capacity factor in Chile (27%) than in the literature (8.6%-15%) [17, 57]. In the case of hydropower, Chile has also higher capacity factors for the reservoirs (43%) and run-of-river plants (60%) than those in the literature (24% and 52%, respectively) [43]. This, together with the recycling rates and the scaling of the infrastructure, explains the lower impacts from Chile's hydropower than the values reported in the literature.

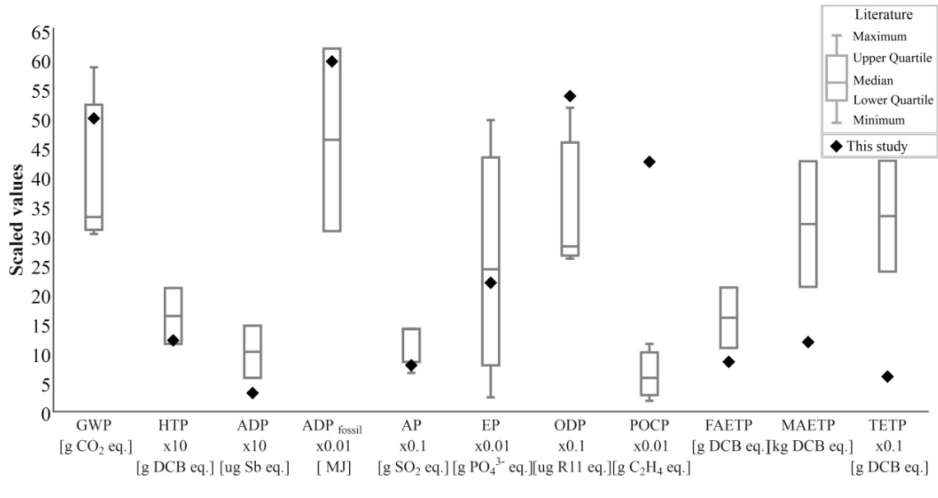
4.3.2. Environmental impacts of current electricity mix

The impacts of the electricity mix in Chile are presented in Figure 23. These have been estimated based on the contribution of different technologies to the total generation and their impacts discussed in the previous sections. For example, the GWP is estimated at 560 g CO_2 eq./kWh, with the majority related to coal. A similar trend can be noticed for all other impacts, for which coal is the hotspot. Its average contribution to the impacts is 79%, with contributions of >88% for HTP, AP, EP and ecotoxicities. ADP is the only impact where the contribution from coal (38%) is lower than its share in the electricity mix (41%).

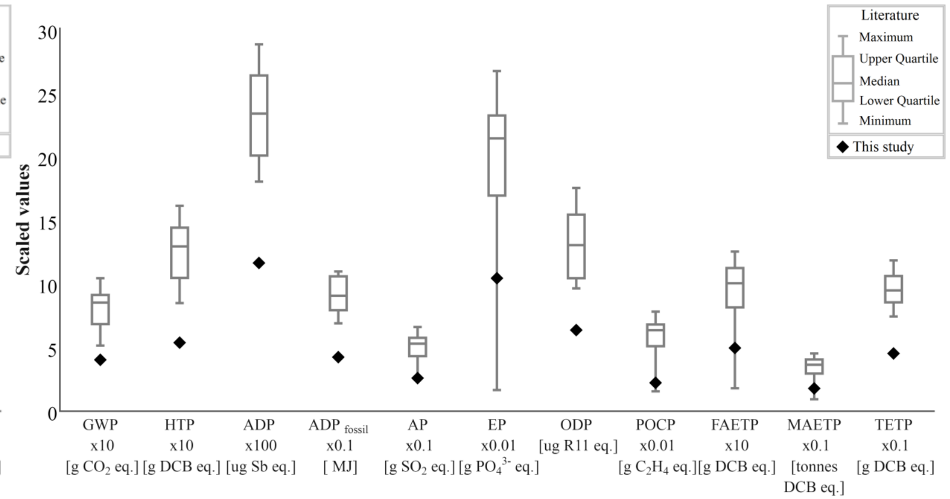
The second highest contributor to the impacts is oil power, with an average of 8%, while its share in the electricity mix is only 4%. Oil has the highest contribution to ODP (39%) and ADP (15%). Natural gas also contributes to GWP (17%) and ADP_{fossil} (21%), higher than its share in the generation mix (14%).

Although solar power contributes to the electricity mix by less than 1%, its contribution to ADP is 23%. However, for the rest of the impacts, solar power has a lower contribution than its share in the mix. On the other hand, hydropower is the second major source of electricity (34%), but its average contribution to the impacts is below 1%. The contribution of biomass, wind and solar PV to the impacts is also far below their contribution to electricity generation.

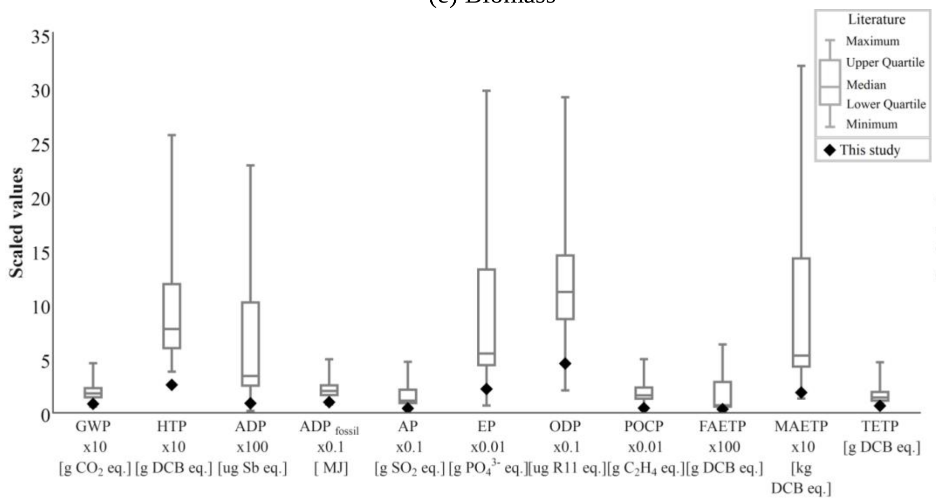

Literature
Maximum
Upper Quartile
Median
Lower Quartile
Minimum
This study
Scaled values
GWP [kg CO2 eq.]
HTP [kg DCB eq.]
ADP x100 [ug Sb eq.]
ADP fossil x10 [MJ]
AP x10 [g SO2 eq.]
EP [g PO4 3- eq.]
ODP x10 [ug R11 eq.]
POCP [g C2H4 eq.]
FAETP [kg DCB eq.]
MAETP [tonnes DCB eq.]
TETP x10 [g DCB eq.]
a) Coal
OC CC DE
GWP [kg CO2 eq.]
HTP [kg DCB eq.]
ADP x100 [ug Sb eq.]
ADP fossil x10 [MJ]
AP x10 [g SO2 eq.]
EP [g PO4 3- eq.]
ODP x100 [ug R11 eq.]
POCP [g C2H4 eq.]
FAETP x100 [g DCB eq.]
MAETP [tonnes DCB eq.]
TETP x100 [g DCB eq.]
(b) Oil
OC CC
GWP x100 [g CO2 eq.]
HTP x10 [g DCB eq.]
ADP x10 [ug Sb eq.]
ADP fossil [MJ]
AP x0.1 [g SO2 eq.]
EP x0.01 [g PO4 3- eq.]
ODP x10 [ug R11 eq.]
POCP x0.01 [g C2H4 eq.]
FAETP [g DCB eq.]
MAETP x10 [kg DCB eq.]
TETP x0.1 [g DCB eq.]
(c) Gas
GWP x10 [g CO2 eq.]
HTP [g DCB eq.]
ADP x10 [ug Sb eq.]
ADP fossil x0.1 [MJ]
AP x0.1 [g SO2 eq.]
EP x0.1 [g PO4 3- eq.]
ODP [ug R11 eq.]
POCP x0.01 [g C2H4 eq.]
FAETP [g DCB eq.]
MAETP [kg DCB eq.]
TETP x0.1 [g DCB eq.]
(d) Biogas



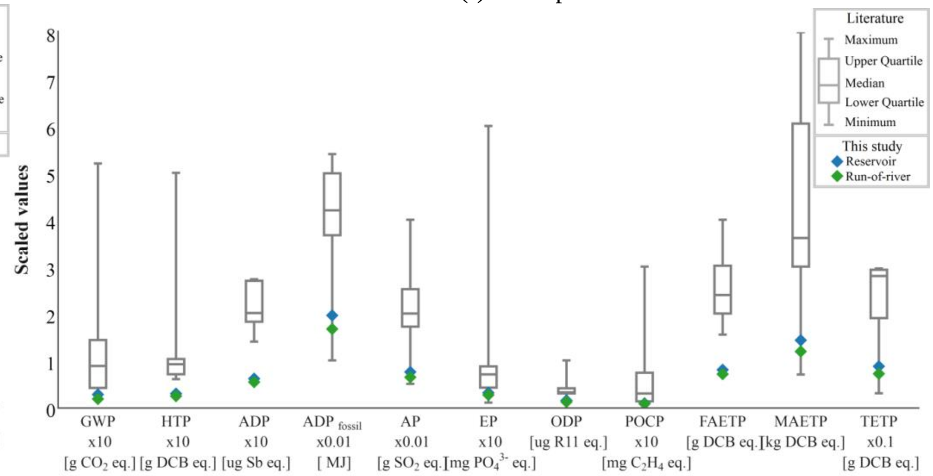
(e) Biomass



(f) Solar photovoltaics



(g) Wind



(h) Hydropower

Figure 22. Comparison of environmental impacts of electricity options with the literature.

[All impacts expressed per kWh of electricity generated. Literature data: [14, 16–19, 21, 23, 35, 53]. Some impacts have been scaled to fit on the scale. To obtain the original values, multiply by the factor shown on the x-axis. OC: open cycle. CC: combined cycle. DE: diesel engine.]

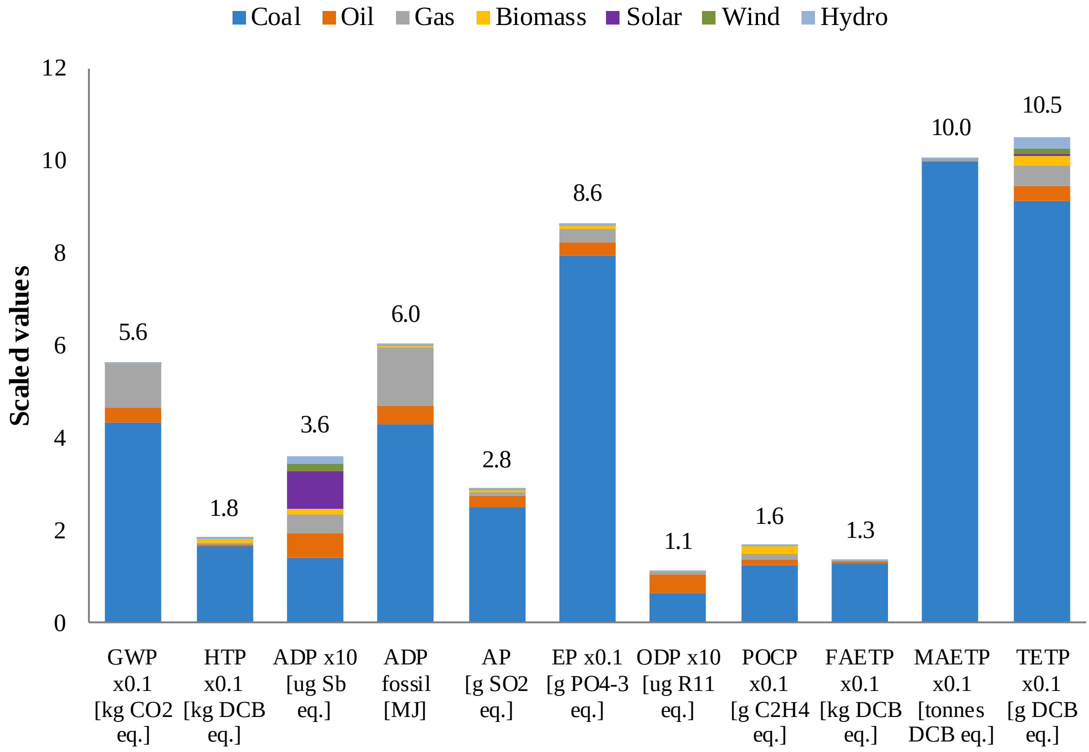


Figure 23. Life cycle environmental impacts of current electricity mix, showing contribution of sources. [All impacts expressed per kWh. Some impacts have been scaled to fit on the scale. To obtain the original values, multiply by the factor shown on the x-axis.]

4.3.2.1. Comparison of results with literature

The impacts of the electricity mix in Chile are compared in Figure 25 with the impacts reported in the literature [14, 16–18, 21] for some other countries with similar electricity profiles (see Figure 24). It can be seen that most of the impacts are within the range. However, EP (860 mg PO_4^{3-} eq./kWh) and MAETP (1,000 kg DCB eq./kWh) are above the median literature values (534 mg PO_4^{3-} eq./kWh and 590 kg DCB eq./kWh, respectively). This is due to these two impacts being caused mainly by coal (>92%; Figure 23) and its contribution to the electricity mix in Chile is higher (41%) than in the selected countries (17% on average). Furthermore, ADP (36 µg Sb eq./kWh) is below the literature median value (67 µg Sb eq./kWh). The ADP is associated with solar and oil power, which contribute only 4.6% to electricity in Chile, while their median contribution in the other countries considered is 8%. Besides, coal has an ADP of 33 µg Sb eq./kWh, which is in the lower range of the values found in the literature (see section 4.3.1.10) and the hydropower options have a high contribution to the mix and very low ADP (5-6 µg Sb eq./kWh). Finally, the ODP in Chile (11 µg R11 eq./kWh) is also below the literature median (25 µg R11 eq./kWh) because natural gas and solar PV in the other countries have higher ODP due to the distribution of natural gas through pipelines and a lower solar irradiation, respectively.

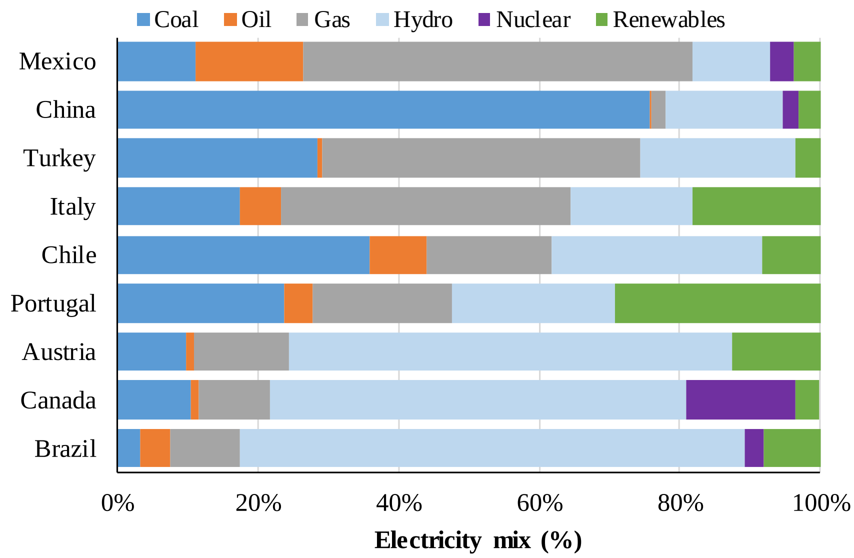


Figure 24. Electricity mix of selected countries in comparison with Chile
[Average technology contribution between 2011 and 2014 [61]]

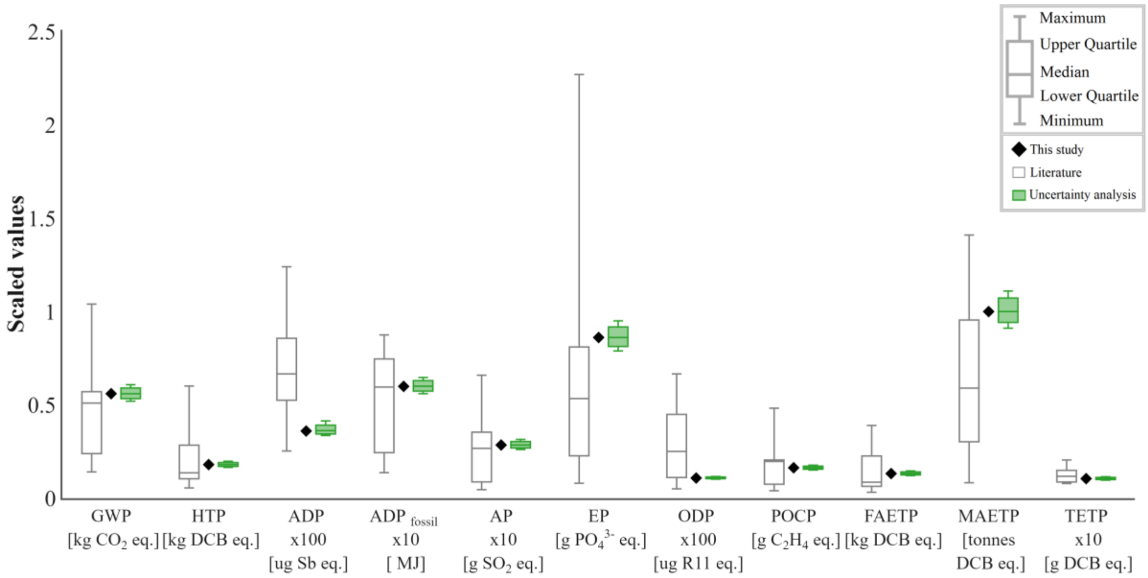


Figure 25. Comparison of environmental impacts of the electricity mix with the literature, also showing the results of the uncertainty analysis.

[All impacts expressed per kWh of electricity generated. Literature data: [14, 16–18, 21]. Some impacts have been scaled to fit on the scale. To obtain the original values, multiply by the factor shown on the x-axis.]

4.3.2.2. Uncertainty analysis

The analysis so far has been based on the average values of around 140 LCA parameters obtained from power plants and grouped according to technology and source of energy. Each parameter considered represents a mean value in its group, estimated using normal distribution. An uncertainty analysis has been carried out using Monte Carlo (MC) simulations to test the reliability of the results based on the mean values of the parameters.

For these purposes, the parameters have been varied in MC within their standard deviations (SD), estimated using the aforementioned normal distribution. As it would be impractical to consider all the parameters, first a sensitivity analysis has been carried out to identify those that are likely to contribute to the uncertainty the most. The sensitivity analysis has been carried for over 30 parameters, which have been selected based on their contribution to one or more impacts. The results indicate that only four parameters have a significant influence on the results. These have then been varied within their SD ranges in 10,000 MC iterations with 90% confidence intervals, as follows:

- efficiency of coal power plants: SD = ±7.9%;
- SO_2 emissions from coal plants: SD = ±3.7%;
- efficiency of combined cycle oil power plants: SD = ±6.9%; and
- capacity factor of solar PV: SD = ±30%.

The results of the MC simulations are given in Figure 25 and Figure 26. The box plots in these figures represent the interquartile ranges and the whisker bars are the dispersion ranges between the 10^{th} and 90^{th} percentile. It can be seen that all the impacts except ADP deviate from their median value by ≤ 11%, with the ADP deviating by 14%. The latter is due to the high contribution of solar PV and oil power to the depletion of resources (see section 4.3.1.3) and their variations in the capacity factor (PV) and the efficiency of power plants (oil). The next highest variation is found for AP, MAETP and FAETP (11%) which is mostly associated with the variation in the efficiency of coal power plants. Therefore, the results can be considered robust over the range of values of key parameters.

4.3.3. Temporal evolution of impacts

As indicated in Figure 27, all the impacts but ODP increased by 1.6-2.7 times from 2004 to 2014; GWP doubled. This is much higher than the increase in electricity generation of 44% over the period. The increase in the impacts is due to the growing share of coal in the electricity mix over the period (Table 17), which is also reflected in the increasing contribution of coal to the overall impacts. In 2014, it contributed more than 70% to the majority of impacts, with the exceptions of ADP (38%) and ODP (57%).

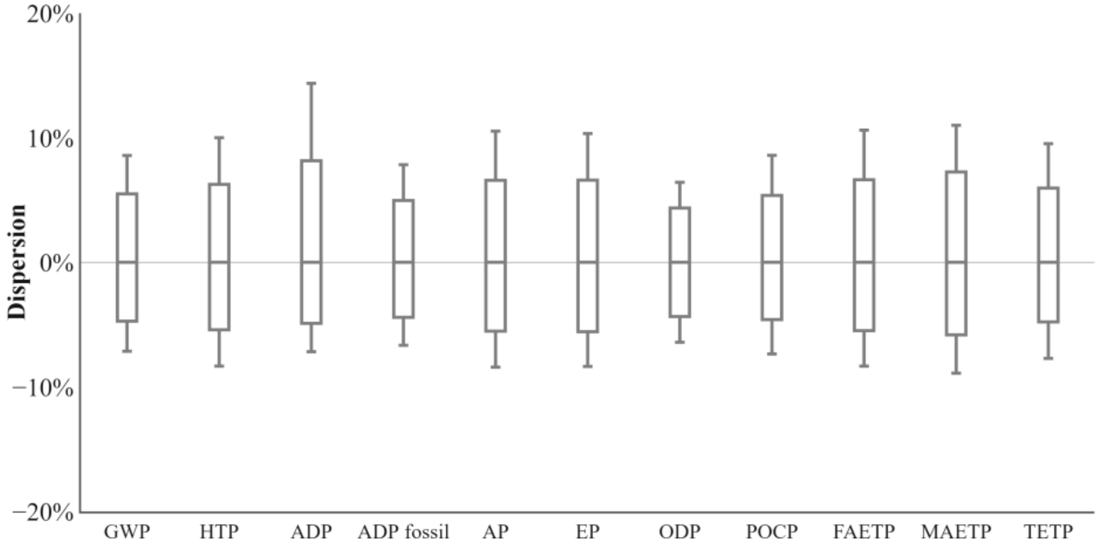


Figure 26. Results of the uncertainty analysis for the electricity mix in 2014 showing dispersion of the results relative to the baseline
[The box plots represent the interquartile ranges and the whiskers the dispersion ranges between the 10th and 90th percentile].

On the other hand, ODP first increased by 2.4 times in 2009 and then decreased by 2.7 times in 2014, effectively being 12.5% lower now than in 2004. The reason for this is the high contribution of natural gas from Argentina in 2004 transported by long-distance pipelines and the use of petcoke in coal power plants. The contribution of the latter decreased from 26% in 2004 to 5.3% in 2014. A further reason for high ODP is that the share of oil peaked in 2009, producing 18% of electricity (Table 17) and being the second major contributor (after coal) to all the impacts in that year. However, electricity generation from oil has been declining since and in 2014 it contributed only 3.9%, in consequence reducing its relative contribution to the impacts. By contrast, the contribution of natural gas is only notable for GWP and ADP_{fossil}, especially in 2004, when 36% of the electricity was generated from gas, compared to 14.3% in 2014.

Despite hydropower historically having a high share in the electricity mix (34%-43.5%), its contribution to the impacts over time has been negligible. The contribution of the other renewables is also negligible – while in the previous years, this was due to their minute share in the mix (<2% of biomass), this grew to a cumulative supply of 7% of electricity in 2014. The renewables only have a significant contribution to ADP, mainly due to solar PV (see section 4.3.1.3).

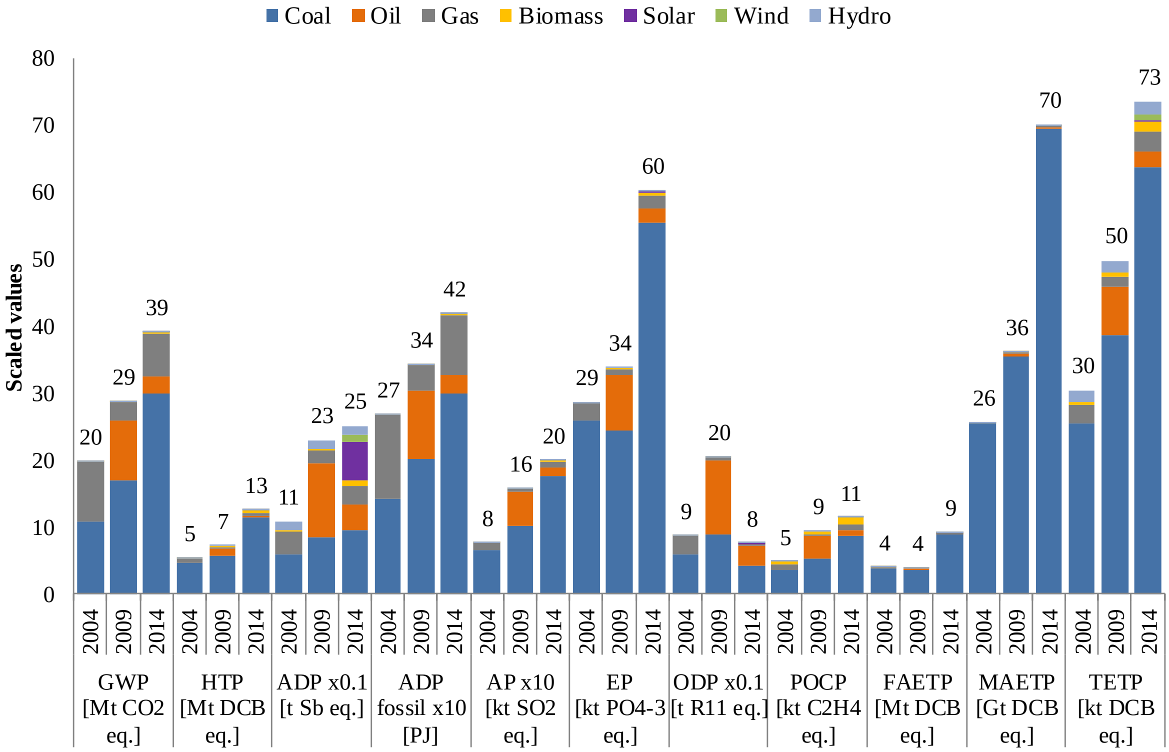


Figure 27. Total annual environmental impacts for years 2004, 2009 and 2014.
[All impacts expressed per year. Some impacts have been scaled to fit on the scale. To obtain the original values, multiply by the factor shown on the x-axis.]

4.4. CONCLUSIONS AND RECOMMENDATIONS

This paper has presented the first comprehensive evaluation of the life cycle environmental sustainability of electricity generation in Chile. Eleven environmental impacts have been estimated, considering 174 power plants installed across the country. The results reveal that coal is the worst option for eight impacts while hydropower is the best alternative for all the categories, with run-of-river being slightly better than reservoirs. Biogas and wind follow hydropower closely. However, natural gas has lower impacts than biomass, wind and solar PV for several categories. Biomass power has at least twice the human toxicity and 12 times greater potential for creation of photochemical oxidants compared with the nearest renewable option and has similar values to fossil fuel options. Solar PV has the highest resources depletion, six times larger than the closest option, and the second largest marine aquatic ecotoxicity.

Coal power is the worst option for global warming, eutrophication and ecotoxicity and also has high values for depletion of fossil fuels, photochemical oxidants and acidification. Its ozone depletion is high due to the use of petroleum coke as a secondary fuel. On the other hand, ozone depletion for natural gas is low because the gas is supplied in a liquefied form, avoiding the use of long-distance pipelines.

The most impacting life cycle stages are fuel production and power plant operation, each contributing on average 40% to the total impacts of fossil-based, biogas and biomass options. For the rest of the renewables, power plant construction is the most significant stage with an average contribution of around 90%.

The significant contribution of coal in Chile's electricity mix (41%) is the reason for its high contribution to the impacts, causing more than 88% of human toxicity, ecotoxicities, eutrophication and acidification. Additionally, although solar PV contributes less than 1% to the electricity mix, it is responsible for 23% of the depletion of elements per unit of electricity generated.

The environmental sustainability of the electricity supply in Chile has worsened over the past 10 years. Although the electricity demand grew by 44% over the period, the annual impacts increased by 1.6-2.7 times. The only exception is ozone depletion which in 2014 was 12.5% lower than ten years before.

Based on the results of this work, the following improvements could be pursued to improve the environmental sustainability of the electricity system in Chile. In the short term:

- To reduce the impacts from coal electricity, the efficiency of power plants should be increased.
- The efficiency of biomass plants should also be improved, along with using low-emissions machinery and vehicles.
- Legislation for fossil-fuel and biomass plants should be tightened to reduce emissions of SO2, NOx, polycyclic aromatic hydrocarbons and hydrogen fluoride as well as to stipulate safe disposal of ash.
- Oil electricity currently used for peak loads should be replaced by a cleaner alternative, such as natural gas.
- The use of petcoke should be phased out.

In the medium to long term, the following should be considered:

- The share of renewables in the electricity supply should be ramped up while coal and oil should be phased out. In particular, hydropower, wind and biogas should be prioritised, Other emerging options, such as geothermal, should also be investigated. Any negative social impacts from these technologies should be minimised.

- Multi-crystalline solar PV depletes a significant amount of scarce materials. Hence, other solar alternatives should be considered, such as thin-film PV cells and concentrating solar power. The commercialisation of advanced PV panel recycling techniques should also be prioritised.
- Implementation of carbon capture and storage systems should be evaluated for both fossil and biomass options to mitigate carbon emissions.

Finally, future research should focus on the economic and social sustainability of the current electricity system as well as on the evaluation of the above-mentioned improvement options to ensure the sustainable development of the future electricity sector in Chile.

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Chapter 5: FuturES: A framework for development and optimisation of future electricity scenarios

This paper is pending submission to an appropriate journal.

This paper presents an investment optimization framework based on power system expansion and economic dispatch with the aim of developing future power scenarios with flexibility. Tables and figures have been amended to fit into the structure of this thesis. The thesis author is the main author of the paper and is the one who collected data of electricity options for Chile, identified costs trends, developed the power system expansion model and adapted the economic dispatch and interpreted the results. The thesis author also wrote the original manuscript. The co-authors are the supervisors of this PhD project and contributed to the paper by reviewing the original manuscript and requesting modifications to improve the resulting paper.

Chapter 5

FuturES: A framework for development and optimisation of future electricity scenarios

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Abstract

Electricity systems around the world are still dominated by fossil-based technologies, with lesser contributions from nuclear power and renewables. This trend is starting to change driven by the need to mitigate climate change and future electricity systems are expected to have much larger contributions of renewables. Therefore, this paper presents a newly-developed framework for developing Future Electricity Scenarios (FuturES) with high penetration of renewables. A multi-period linear programming model has been created for power-system expansion planning and an economic dispatch model, PowerGAMA, has been used to evaluate the technical and economic feasibility of the developed scenarios while matching supply and demand. Application of FuturES is demonstrated through a case of Chile which has an ambition to achieve a grid with 100% renewables. Four cost-optimal scenarios have been developed for the year 2050 using FuturES: two Business as usual (BAU) and two Renewable electricity (RE) scenarios. The BAU scenarios are unconstrained in terms of the type of technology and can include all 11 options considered in the study, while the RE scenarios aim to phase-out all fossil-fuel power plants and have only renewables in the mix, including storage via concentrating solar and reservoir hydropower. The results show that both BAU scenarios have the levelized cost of electricity (LCOE) lower or equal to today's costs ($72.7-77.3 vs $77.6/MWh) and include 81%-90% of renewables in the mix. The RE scenarios are slightly more expensive than today's costs, with the LCOE of $81-87/MWh. The cumulative investment for the BAU scenario falls between $123-$145 bn, compared to $147-$157 bn for the RE scenarios. The annual investment across the two scenarios is estimated at $4.0±0.4 bn, with the highest investments

for solar PV, wind and hydropower run-of-river options. The results also demonstrate that both RE scenarios show sufficient flexibility in matching supply and demand, despite solar PV and wind power having a combined contribution of 41% and 50%. Therefore, the FuturES framework is a powerful tool for helping solve the challenges of achieving cost-efficient power systems with high penetration of renewables.

Keywords: climate change; energy planning; energy storage; levelized cost; renewable energy; system optimisation.

NOMENCLATURE

Sets

G	: set of power generation technologies
T	: set of years of the planning horizon

Subscripts

g	: technology type
t	: year
t_0	: starting year
t_{end}	: target year

Variables

$Var_{g,t}^{new}$	: new build capacity (MW)
$Var_{g,t}^{phaseout}$	: phase-out capacity (MW)

Parameters

$B_{g,t}^{plan}$	: scheduled new-build capacity (MW)
b_g	: learning rate value (%)
$C_{g,t}^{fuel}$	: fuel cost per year ($/fuel)
$CF_{g,t}$	: capacity factor (%)
$CO2_t^{tax}$	: carbon tax ($/t)
$CO2_g^{emi}$	: CO_2 emission factor (kg/MJ)
cv_g	: calorific value (MJ/fuel)
$D_{g,t}^{total}$	: total decommissioning capacity by technology (MW)

$D_{g,t}^{plan}$	: decommissioning capacity of current plants (MW)
eff_g	: power plants efficiency (%)
$E_{g,t}$	: electricity generated (MWh)
E_t^{demand}	: power demand per year (MWh)
$f_{g,t}^{inv}$	: annualised capital cost ($/MWh)
$f_{g,t}^{OM}$	: operation and maintenance fixed cost ($/MWh)
$I_{g,t0}^{capital}$	: initial capital cost of a technology ($/kW)
$LCOE_{g,t}$	: levelized cost of electricity ($/MWh)
N_g^{max}	: maximum annual new-build capacity allowed per technology (MW)
$P_{g,t}^{total}$	: total installed capacity (MW)
$P_{g,init}^{total}$	: initial total installed capacity by technology (MW)
PO_g^{max}	: maximum annual phase-out capacity (MW)
$PO_{g,t}^{quota}$	: Additional available capacity due to phased-out (MW)
$Q_t^{NCRE_{min}}$	: minimum power share of all non-conventional renewable energy options in a year (%)
$Q_{g,t}^{tech_{max}}$	: maximum electricity share of a technology in a year (%)
q	: share of additional capacity (%)
r_g	: discount rate (%)
S_g	: share of the capital cost for operating and maintenance fixed cost (%)
S_t^{loss}	: annual electricity loss (%)
$S^{NCRE_{min}}$	: all non-conventional renewable energy share obligation at the target year (%)
$S_{t0}^{NCRE_{min}}$	: all non-conventional renewable energy quota obligation at starting year (%)
$S_g^{tech_{maxEnd}}$	: maximum electricity share of technology g by the target year (%)
$t^{NCRE_{min}}$	: non-conventional renewable energy target year
$t_g^{phaseout_{start}}$	: phase-out starting year for a technology g

$t_g^{tech_{maxInit}}$: initial year when a technology g starts its maximum electricity share obligation

$v_{g,t}^{carbon}$: carbon taxes payable by *g* in year *t* ($/MWh)

$v_{g,t}^{fuel}$: fuel cost ($/MWh)

v_g^{OM} : operating and maintenance variable cost ($/MWh)

$W_{g,t}$: global cumulative installed capacity in year *t* (MW)

$W_{g,t0}$: current global cumulative installed capacity (MW)

Z : objective function total system costs ($)

γ_g^{NCRE} : binary parameter to set if a technology is a non-conventional renewable energy

κ_g^{hydro} : binary parameter to set if a technology is hydropower

$\lambda_g^{learning}$: binary parameter to set if a technology has a learning rate

τ_g : lifespan assumed by technology (years)

$\phi_g^{phaseout}$: binary parameter to set if a technology is set to be phase-out

$\omega_g^{tech_{max}}$: binary parameter to set if a technology has a maximum electricity obligation by the target year

5.1. INTRODUCTION

Climate change is driving society toward a low-carbon economy and the majority of countries are endeavouring to reduce greenhouse gas emissions. Electricity generation is responsible for approximately 25% of global greenhouse gas (GHG) emissions. Therefore, the Intergovernmental Panel on Climate Change (IPCC) has highlighted the important role of the decarbonisation of electricity generation and the deployment of renewable energy technologies as potential sectorial mitigation pathways and measures [1]. A recent study showed that, between 2014 and 2016, the global energy-related CO_2 emissions have remained constant after decades of increase [2]. The development of renewable technologies, such as solar PV and wind, has been crucial in achieving this, allowing them to become more competitive and triggering high investment in recent years.

Although, renewable power options are predominantly capital-cost intensive as opposed to fossil-based technologies which are marginal-cost plants, driven by the operational and fuel costs. This poses a new challenge to traditional electricity markets that are mostly based on marginal cost [3]. When it comes to consider an electricity market with increasing renewables participation, many authors state [4, 5] that electricity markets only based on marginal costs do not contain sufficient information or mechanisms for investors to gain the necessary confidence to fund new, capital-intensive power plants. Some South American countries that have experienced this situation of low marginal costs due to the high contribution of hydropower whose operational costs are far lower than fossil fuel plants. They have resolved this through long-term contracts for investments while keeping short-term markets for energy trading so that can be secured dispatch electricity at optimal costs at all times [4]. In this way, electricity market regulations have to adapt to the changes posed by the increase of renewable power options with almost negligible variable costs that potentially can discourage new investments in an only-energy marginal cost market and trigger to a lack of electricity supply.

In this context, it is becoming increasingly important to analyse future electricity systems shaped mainly by renewables to ensure that they are viable and efficient. However, achieving a power system dominated by renewables poses many challenges, including keeping the electricity cost low and maintaining a secure and reliable supply. On the latter point in particular, it is crucial to attain flexibility in the system since wind and solar PV exhibit variability, intermittency and unpredictability [6], making it more difficult to match electricity supply with demand. In the last decades, sufficient flexibility has been achieved primarily via hydropower, pumped hydro storage systems, and oil and gas thermal power plants, with the support of base-load power options, such as nuclear, coal, biomass power and hydropower run-of-river. In future power systems shaped by renewables, storage systems will play a key role in achieving flexibility [6–8]. Nowadays, depending on energy resource availability and geography, countries can take advantage of hydropower, pumped hydro or concentrating solar power (CSP) thermal storage, while others that lack such natural resources can rely on battery energy storage solutions (BESS).

Optimisation tools have been used previously to define and optimise future power systems; this is discussed in more detail on section 2. To contribute to the effort of identifying optimal future power scenarios, this work aims to define optimal electricity scenarios with flexibility. To this end, this paper presents a framework for defining Future Electricity Scenarios (FuturES). FuturES is a deterministic power system expansion optimisation model which minimises total system costs as the objective function, under the assumption of perfect market competition. The developed framework integrates the optimisation model with the economic dispatch model "PowerGAMA" [9]. This economic dispatch model evaluates the extent to which the resulting optimised scenarios can operate with flexibility by implementing storage value approach [10–12] in water reservoirs and in concentrating solar power (CSP) with storage. Therefore, FuturES allows the modelling and optimisation of future electricity scenarios where CSP and hydropower work as backup for scenarios with high penetration of renewables. The framework is generic and can be used in different regions and countries. To demonstrate its application, Chile is considered as an illustrative case study, as the country has very ambitious plans for increasing contribution of renewables in the electricity system to up to 100% by 2050.

5.2. LITERATURE REVIEW

Simulation and optimization models are used in energy models and power systems models for different purposes. Decision-support models are importantly required for generation companies which are exposed to higher risk trading in electricity markets. Also, regulatory organizations use analysis-support models to follow market performance [13]. These models are developed though mathematical programming that take into account economic or financial relationship in combination with technical features of electricity production and market. Therefore, there are many models whose characteristics pose challenge to attain controllable solution times and to mitigate computational effort [14].

The use of models in energy models and power systems has more than 50 years [15], since then multiple applications have been developed, and in the last decade the diversity of solutions has increased rapidly [16]. In this line, general purpose energy models most widely used are MARKAL [17], TIMES [18] and MESSAGE. Also, open-source projects have emerged with active supporting communities of developers and energy modelers. Examples of this are OSeMOSYS [19], PyPSA [20], Calliope [21], URBS [22], and Switch 2.0 [23].

General purpose energy models to represent potential deployment of the energy system over long-term planning horizon either national, regional or global ambit [24]. Also, these energy models are able to manage interactions between power systems and other primary energy groups and markets. Different features are supported for these modelling tools such as power flow, multiperiod optimization, investment optimization, unit commitment, and inter-hour relationship [20, 23]. Although, different modelling tools may have or not all the features, also exist differences in the way they implement each feature. For example, in order to overcome larger computing times in long-term models, time slice are defined to represent dynamics associated with dispatch in representative periods like seasons while modelling decades as time horizon [19]. This kind of variation among tools obey to different challenges that models are required to solve.

Nowadays the challenges of power system planning are to foreseen how the power systems are able to operate with high penetration of renewable, how to develop cleaner power systems at low costs and how to reach 100% renewable power systems [16]. Give the heterogeneity of countries and regions according to their resources, each power system may require special models to represent best particular conditions. This may lead to attain different investments and technologies across the systems.

Energy storage options are considered crucial to reach high renewables penetration in systems [25]. Hydropower and pumped hydro have been for long time the most economic and well-developed storage technology. There are two consider for modelling storage. First, storage dispatch may vary significantly when a system has important capacity of variable technologies, this stablish the model has to have a low time resolution; and second, when storage exhibit high contribution may act as price-maker, as occur with water reservoirs. Methods have been developed and are being investigated [10, 11, 26–29]. Stochastic dual dynamic programming has widely used to determine storage value and coordination in hydrothermal system [30–33]. However, this method is preferred to optimize the operation of power systems given its complexity and characteristic, modelers who are focused in generation expansion planning investigates alternative options that represent best the challenge of system planning considering storage and the current limitations [26]. Concentrating solar power offers short-term storage and currently models oversimplify its storage capacity. PowerGAMA [9] has developed a novel extension of storage value approach that enhance the modelling of short-term storage in CSP.

5.3. METHODOLOGY

This section first gives an overview of the FuturES framework, followed by detailed descriptions of its two constituent parts: power system expansion (PSE) and economic dispatch (ED) models.

5.3.1. The FuturES framework

FuturES framework is based on two optimisation models and a simplified representation of the power market, as illustrated in Figure 28. It begins with a power system expansion (PSE) model which has been developed in this study (Section 5.3.1.1) to identify the total power capacity in the future and the contributions of different technologies. The main variable in this model is the new-build capacity for each technology, which is decided by the model based on each technology's levelized cost of electricity (LCOE) and power output, with the objective to minimise total generation costs.

The capacity factor of the generation technologies is a significant parameter in determining outputs and costs, and several previous energy scenario studies have assumed constant capacity factors (see, for example [34, 35]). This assumption can be true if the electricity mix remains similar through time; however, when new technologies are included in the scenarios, it is more likely that the capacity factors may change. To overcome this problem, the inclusion of a second model based on minimisation of marginal costs through economic dispatch (ED) is essential. This model integrates the outputs of the PSE model (the total capacities of each technology) with technical parameters of the involved technologies, such as variable or marginal costs, wind profile, solar radiation and water inflow. After running the ED model, it determines the capacity factor of each technology, hourly marginal costs, filling level of storage systems, the energy spillage (solar, wind and hydropower run-of-river energy harvested but not dispatched) and load shedding.

The load shedding and capacity factors are considered indicators of flexibility; when there is no load shedding, and the resulting capacity factors of the ED model are equal to the capacity factors assumed in the PSE model, then the scenario is considered to be feasible. If the capacity factors are different, the LCOE of the technologies initially estimated in the PSE model will be inconsistent with their expected operation. This leads to an under– or overestimation of the costs of some technologies. Therefore, the capacity factors of the PSE model are replaced by the capacity factors obtained from the ED model and a new iteration begins, as shown in Figure 28. The starting year (t_0) of the PSE model maintains the actual capacity factors of the technologies in that year. The resulting capacity factors of the optimal economic dispatch model are set as the capacity factors for the last year (t_{end}) of the evaluating period, and the capacity factors between years t_0 and t_{end} are estimated through linear interpolation. Consequently, the combined PSE and ED models continue to iterate until the model converges. In other words, the two models run until the capacity factors of PSE and ED by year t_{end} are similar and reach the condition of feasibility of no load shedding.

The FuturES framework has been developed using Python programming language alongside Pyomo, an open-source tool for modelling optimisation applications [36] with COIN-OR

Branch-and-Cut (CBC) mixed-integer linear solver [37]. As mentioned earlier, the PSE model has been developed in this study, while a Python application PowerGAMA [9] has been used as the ED model. They are described in turn in the next sections.

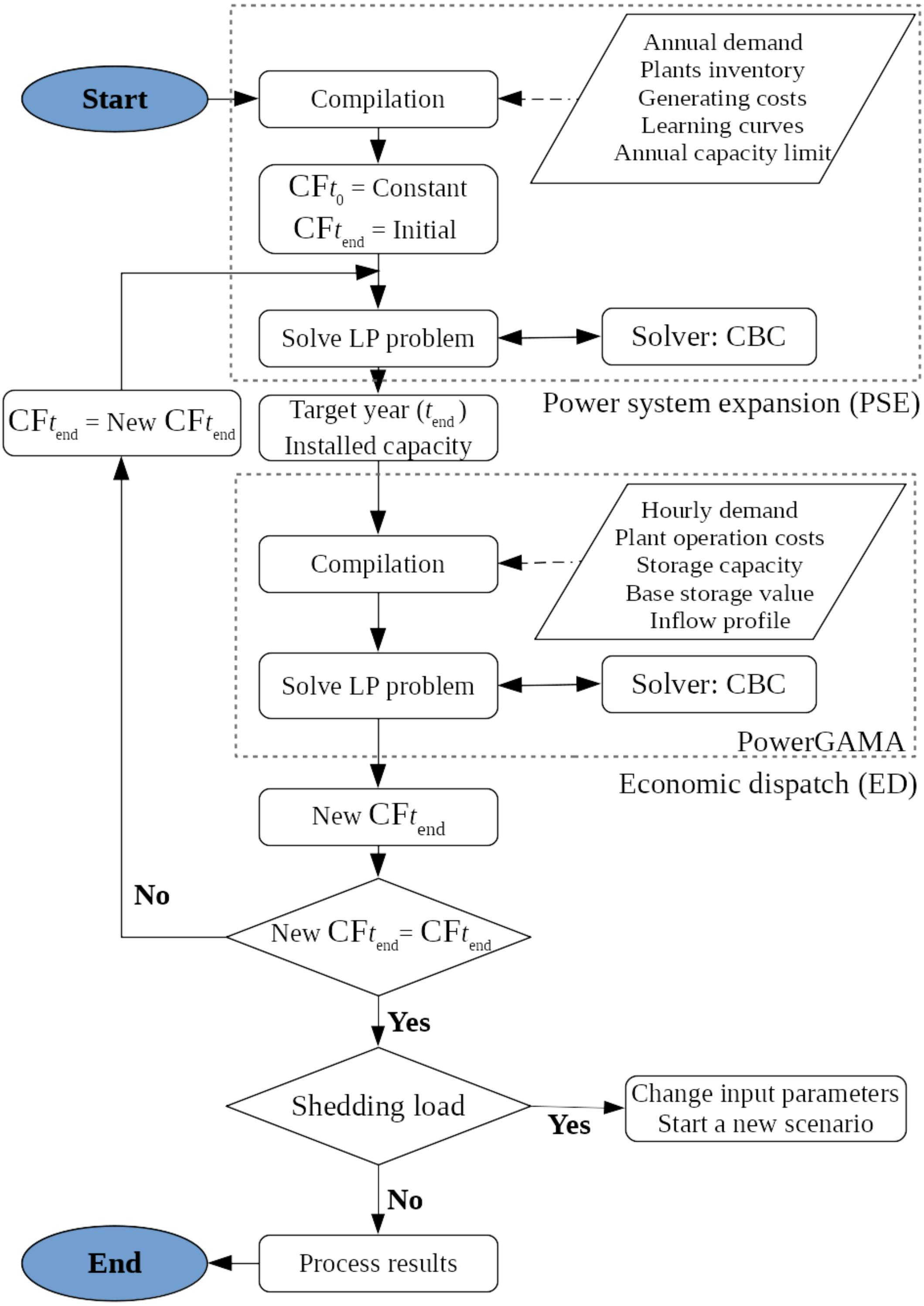

Figure 28. FuturES framework to obtain power mix scenarios.

[CFt_0: capacity factor at starting period, CFt_{end}: capacity factor at the target year, LP: linear programming, CBC: COIN-OR Branch-and-Cut mixed integer linear programming solver]

5.3.1.1. Power system expansion model

A linear programming problem can generally be formulated as:

$$\begin{aligned} &minimise \quad f(x) \\ &s.t. \quad h(x) = a \\ &\qquad g(x) \leq 0 \\ &\qquad x \in R^n \end{aligned} \tag{Eq.8}$$

where $f(x)$ is an objective function; $h(x)$ represents the equality constraints, $g(x)$ are the inequality constraints, and x is a vector with n real variables. The objective function and constraints are provided in the following sections.

5.3.1.1.1. Objective function

The objective function to be minimised, z, represents the total system costs over the life cycle of each power technology over the planning period and is defined as follows:

$$Z = min \sum_{g \in G} . \sum_{t \in T} E_{g,t} \cdot LCOE_{g,t} \quad \text{(Eq. 9)}$$

where $E_{g,t}$ is the electricity generated by a technology g in a year *t*, while $LCOE_{g,t}$ is the levelized cost of electricity for technology g in a year *t*. $E_{g,t}$ is a function of two types of variables, $Var_{g,t}^{new}$ and $Var_{g,t}^{phaseout}$, that represent the new-build capacity online in the given year and the existing capacity awaiting phase-out, respectively. For simplicity, these are included as part of the total installed capacity ($P_{g,t}^{total}$) function as shown below:

$$E_{g,t} = 8760 \cdot CF_{g,t} \cdot P_{g,t}^{total} \quad \text{(Eq. 10)}$$

where $CF_{g,t}$ is the capacity factor of a technology in a year *t* and 8760 is the number of hours per year. The total installed capacity of a technology g in a year, $P_{g,t}^{total}$, is defined as:

$$P_{g,t}^{total} = \begin{cases} P_{g,init}^{total} + B_{g,t}^{plan} + Var_{g,t}^{new} - D_{g,t}^{total} - Var_{g,t}^{phaseout}, & \text{if } t-1 < t_0 \\ P_{g,t-1}^{total} + B_{g,t}^{plan} + Var_{g,t}^{new} - D_{g,t}^{total} - Var_{g,t}^{phaseout}, & \text{if } t-1 \geq t_0 \end{cases} \quad \text{(Eq. 11)}$$

$P_{g,t}^{total}$ is made up of the initial existing capacity ($P_{g,init}^{total}$) or the capacity in the previous year ($P_{g,t-1}^{total}$), a scheduled new-build capacity ($B_{g,t}^{plan}$), which represents plants under construction and will come online according to a plan, the new-build capacity ($Var_{g,t}^{new}$), which is the main decision variable of the program, minus the total decommissioned capacity ($D_{g,t}^{total}$) and the phase-out capacity ($Var_{g,t}^{phaseout}$). The last is a decision variable considered for technologies like coal that can eventually be phased out. The decision variables are all in the domain of positive real numbers.

The total decommissioned capacity ($D_{g,t}^{total}$) constitutes old plants that are planned to be decommissioned ($D_{g,t}^{plan}$) and new-build capacity that has reached the end of its lifespan within the modelling period ($Var_{g,t-\tau_g}^{new}$), where τ_g represents the lifespan of a technology:

$$D_{g,t}^{total} = D_{g,t}^{plan} + Var_{g,t-\tau_g}^{new} \quad \text{(Eq. 12)}$$

$LCOE_{g,t}$ is defined by the sum of levelized and annualised investment cost ($f_{g,t}^{inv}$), fixed and variable operating and maintenance costs (O&M) costs ($f_{g,t}^{OM}$ and v_g^{OM}, respectively), fuel costs ($v_{g,t}^{fuel}$) and carbon taxes ($v_{g,t}^{carbon}$):

$$LCOE_{g,t} = f_{g,t}^{inv} + f_{g,t}^{OM} + v_g^{OM} + v_{g,t}^{fuel} + v_{g,t}^{carbon} \quad \text{(Eq. 13)}$$

The levelized and annualised investment cost is defined as follows:

$$f_{g,t}^{inv} = \frac{I_{g,t0}^{capital}}{8.76 \cdot CF_{g,t}} \cdot \frac{r_g}{1 + \left(1 + r_g\right)^{-\tau_g}} \cdot \left(1 + \lambda_g^{learning} \left(\left(\frac{W_{g,t}}{W_{g,t0}}\right)^{log_2(1-b_g)} - 1\right)\right) \quad \text{(Eq. 14)}$$

The investment cost of a technology for a particular year is estimated taking into account the initial capital cost of a technology ($I_{g,t0}^{capital}$) which is annualised considering the discount rate (r_g) and technology lifespan (τ_g). The capacity factor ($CF_{g,t}$) and 8.76 convert the annual investment cost to levelized cost of electricity from per kW-yr to per MWh. The cost must also be adjusted through time based on a learning rate (b_g) for that particular technology, with a learning rate binary parameter ($\lambda_g^{learning}$) to set if a technology has a learning rate or not and is considered as an input for the model. The application of the learning is based on the global accumulated installed capacity of the technology at initial modelling time ($W_{g,t0}$), and the global accumulated installed capacity of the technology at a year t ($W_{g,t}$).

O&M fixed costs ($f_{g,t}^{OM}$) are defined as follows:

$$f_{g,t}^{OM} = \frac{I_{g,t0}^{capital} \cdot S_g}{8.76 \cdot CF_{g,t}} \cdot \left(1 + \lambda_g^{learning}\left(\left(\frac{W_{g,t}}{W_{g,t0}}\right)^{log_2(1-b_g)} - 1\right)\right) \quad \text{(Eq. 15)}$$

where S_g is a fraction of investment costs used to estimate O&M fixed costs. Fuel costs ($v_{g,t}^{fuel}$) are expressed as follows:

$$v_{g,t}^{fuel} = \frac{3600 \cdot C_{g,t}^{fuel}}{cv_g \cdot eff_g} \quad \text{(Eq. 16)}$$

where 3600 is a factor to convert between MJ and MWh; $C_{g,t}^{fuel}$ is the cost of fuel per unit of mass or volume, cv_g the calorific value of the fuel for technology g in MJ per unit of mass or volume and eff_g is the fuel efficiency of the technology. $C_{g,t}^{fuel}$ and cv_g are parameters expressed in different units depending on the kind of fuel, for example for coal, natural gas, and diesel the units are tonnes, Nm^3, and billion barrels (bbl), respectively.

Carbon costs are estimated taking into account the carbon tax per tonne of CO_2 emitted ($CO2_t^{tax}$), the carbon emission factor ($CO2_g^{emi}$), the power plant efficiency and a factor 3.6 to convert from MJ to kWh as shown below:

$$v_{g,t}^{carbon} = \frac{3.6 \cdot CO2_t^{tax} \cdot CO2_g^{emi}}{eff_g} \quad \text{(Eq. 17)}$$

5.3.1.1.2. Energy balance

The power demand is estimated at the consumer side (E_t^{demand}); therefore, the energy loss in the grid (S_t^{loss}) needs to be included in order to estimate the total energy demand at the supply side ($E_t^{demand}(1+S_t^{loss})$). Total energy demand must be equal to or lower than the electricity supply, as follows:

$$\sum_{g \in G} E_{g,t} \geq E_t^{demand}(1+S_t^{loss}), \forall t \in T \qquad \text{(Eq. 18)}$$

5.3.1.1.3. Non-negative total capacity

For each technology, the total capacity in each year must not be negative. This constraint is essential; otherwise, if more economical technologies are available, the model can set a phase-out capacity exceeding the sum of the other capacity variables in equation 4, creating an illogical condition. This constraint is defined as follows:

$$P_{g,t}^{total} \geq 0, \forall g \in G, \forall t \in T \qquad \text{(Eq. 19)}$$

5.3.1.1.4. New-build capacity

In each year the total electricity demand must be satisfied by the supply. When the current installed capacity cannot fulfil the power demand, the model evaluates the available technologies to decide the new-build capacity. $\phi_g^{phaseout}$ is a binary parameter that indicates if a technology is going to be phased-out and, if so, that particular technology cannot be eligible for new-build capacity. For the rest of technologies, the new-build capacity must be equal to or lower than the sum of maximum annual new-build capacity (N_g^{max}), total decommissioning capacity and a phase-out quota capacity ($PO_{g,t}^{quota}$), as follows:

$$Var_{g,t}^{new} \leq \begin{cases} N_g^{max} + D_{g,t}^{total} + PO_{g,t}^{quota}, & \text{if } \phi_g^{phaseout} = 0, \forall g \in G, \forall t \in T \\ 0, & \text{if } \phi_g^{phaseout} = 1, \forall g \in G, \forall t \in T \end{cases} \qquad \text{(Eq. 20)}$$

The phase-out quota capacity represents the power capacity of a technology to achieve a share (q) of the total phase-out electricity in a particular year. The share q ensures that the PSE model does not select only the most economical option to replace the phased-out power plants. In other words, q ensures that more than one power option is invested in, thereby guaranteeing some supply diversity. The phase-out quota is defined by the following equation:

$$PO_{g,t}^{quota} = \frac{q \cdot \sum_{g \in G} Var_{g,t}^{phaseout} \cdot CF_{g,t}}{CF_{g,t}} \quad \text{(Eq. 21)}$$

5.3.1.1.5. Phase-out of plants

$\phi_g^{phaseout}$ is a binary parameter created to establish if a technology has been selected to be phased-out ($\phi_g^{phaseout} = 1$). If not, the phase-out capacity decision variable ($Var_{g,t}^{phaseout}$) must be equal to zero. Technologies that are to be phased out are set a phase-out starting year ($t_g^{phaseout_{start}}$). Before that year, the phase-out capacity decision variable must be zero, otherwise the capacity must be equal or lower than a maximum annual phase-out capacity (PO_g^{max}) for a particular technology, as follows:

$$Var_{g,t}^{phaseout} \leq \begin{cases} 0, \text{ if } \phi_g^{phaseout} = 0, \forall g \in G, \forall t \in T \\ 0, \text{if } \phi_g^{phaseout} = 1 \text{ and } t \leq t_g^{phaseout_{start}}, \forall g \in G \\ PO_g^{max}, \text{ if } \phi_g^{phaseout} = 1 \text{ and } t > t_g^{phaseout_{start}}, \forall g \in G \end{cases} \quad \text{(Eq. 22)}$$

5.3.1.1.6. Hydropower capacity retention

A binary parameter (κ_g^{hydro}) has been defined to indicate if a technology is a hydropower option. This is necessary to account for the unique system benefits of hydropower options, such as flexibility, reliability, security and in-built storage capacity. Due to these benefits, it is assumed that system operators with existing hydropower capacity would not wish to lose that capacity. Therefore, the new-build capacity of hydropower options must be equal or higher than the total decommissioning capacity, so that the total hydropower capacity remains constant or increases:

$$Var_{g,t}^{new} \geq D_{g,t}^{total}, \text{if } \kappa_g^{hydro} = 1, \forall g \in G, \forall t \in T \quad \text{(Eq. 23)}$$

5.3.1.1.7. Non-conventional renewable electricity

Many countries have implemented policy framework to enable corporate sourcing of renewables, such as quota support schemes and green certificates [38, 39]. Examples of such countries in Europe include Netherlands, Norway, Sweden and the UK and in South America Argentina, Brazil, Chile and Mexico. Australia, China, India and the US also have such policy frameworks in place. To reflect this in the model, non-conventional renewable electricity (NCRE) is defined to include all renewable options except large hydropower plants. A minimum quota ($Q_t^{NCRE_{\min}}$) for the electricity supplied by NCRE options is set to increase with time. A binary parameter (γ_g^{NCRE}) has been established so that the model can identify the NCRE options as follows:

$$\sum_{g \in G} \gamma_g^{NCRE} \cdot E_{g,t} \geq Q_t^{NCRE_{min}} \sum_{g \in G} E_{g,t}, \forall t \in T \qquad \text{(Eq. 24)}$$

The quota ($Q_t^{NCRE_{min}}$) increases through time linearly; therefore, $S^{NCRE_{min}}$ represents the quota share at a target year ($t^{NCRE_{min}}$) usually set in energy policies, while $S_{t0}^{NCRE_{min}}$ is the quota at the starting year. After the target year, the quota remains constant as defined below:

$$Q_t^{NCRE_{min}} = \begin{cases} \dfrac{S^{NCRE_{min}} - S_{t0}^{NCRE_{min}}}{t^{NCRE_{min}}} \cdot t + S_{t0}^{NCRE_{min}}, \text{ if } t_0 \leq t \leq t^{NCRE_{min}} \\ S^{NCRE_{min}}, \text{ if } t^{NCRE_{min}} < t \leq t_{end} \end{cases} \qquad \text{(Eq.25)}$$

5.3.1.1.8. Maximum energy share of a technology in the production mix

A constraint is defined to allow specific technologies to be set a quota ($Q_{g,t}^{tech_{max}}$) of electricity that ensures an electricity production equal or lower than the quota ($S_g^{tech_{maxEnd}}$) in the last year of the planning horizon. The constraint starts in a predefined year ($t_g^{tech_{maxInit}}$) where the existing quota ($Q_{g,t}^{tech_{max}}$) of the technology is set at 100%, after which point the quota decreases linearly through the years until reaching the target quota ($S_g^{tech_{maxEnd}}$). The technologies possessing their maximum possible quota in any given year can be identified by the model due to a binary parameter ($\omega_g^{tech_{max}}$) equal to 1. The constraints are defined as follows:

$$E_{g,t} \geq Q_{g,t}^{tech_{max}} \sum_{g \in G} E_{g,t}, \text{ if } \omega_g^{tech_{max}} = 1, \forall g \in G, \forall t \in T \qquad \text{(Eq. 26)}$$

$$Q_{g,t}^{tech_{max}} = \frac{1 - S_g^{tech_{maxEnd}}}{t_g^{tech_{maxInit}} - t_{end}} \cdot (t - t_{end}) + S_g^{tech_{maxEnd}}, \text{ if } t \geq t_g^{tech_{maxInit}} \qquad \text{(Eq. 27)}$$

5.3.1.2. Economic dispatch model

PowerGAMA (Power Grid and Market Analysis) is a simulation tool developed by Svendsen [9]. The emphasis of this model is on the modelling of storage systems via the use of storage values. Although PowerGAMA is based on optimal power flow, in the present study only the economic dispatch simulation tool has been used. Therefore, PowerGAMA has been implemented to run economic dispatch for scenarios from the PES model, focusing on the implementation of storage strategies to enable high penetration of renewables.

Storage values have been estimated as follows:

$$v_{i,h} = v_{i,0} \cdot \hat{v}_{\ i,f} \cdot \hat{v}_{\ i,h}, \qquad \text{(Eq. 28)}$$
$$\forall i \in [technologies\ with\ storage], \forall h \in [0..8760], \forall f \in [0\%..100\%]$$

where $v_{i,h}$ is the storage value of a technology with storage capacity i in hour h. It depends on a base storage value $v_{i,0}$, relative storage value related to the filling level of the storage $\hat{v}_{\ i,f}$, and a relative storage value which relates to time of the year; f is the filling level and varies according to the optimal dispatch. The base storage value is a parameter set by the modeller based on a tuning process [9]. The filling level- and time-related storage values are specific to local conditions and are shown in section 5.4.1.2 for the Chilean case.

5.4. CASE STUDY: ELECTRICITY SCENARIOS FOR CHILE

As mentioned earlier, application of the FuturES framework is illustrated through a case of Chile. This section provides motivation for the study, followed by the input data used in the modelling.

Chile contributes accounts only for 0.22% of worldwide emissions greenhouse gas (GHG) emissions [40]. Despite this, the country has shown to be very vulnerable to the effects of climate change [41]. Chile has ratified the Paris agreement on climate change and committed to reducing its GHG emissions [42]. The nationally determined contribution (NDC) committed by the country has been linked with the evolution of the Gross Domestic Product (GDP), but the lack of a reliable long-term GDP forecast makes it difficult to estimate future emission targets.

Chile has deployed significant solar PV and wind capacity, contributing 3.3% and 2.9% of the total electricity supply, respectively with solar PV doubling its capacity every year since 2014 [43]. This has been possible owing to technology cost reductions, the successful implementation of public policies in the sector and the outstanding resource availability in some areas of the country [39, 44, 45]. Despite this, fossil-fuel technologies still contribute 60% of total electricity supply. The new energy policy sets two targets for the renewables penetration in the electricity system: 60% by 2035 and 70% by 2050 [46]. However, a recent study has estimated that renewable sources will have a contribution of about 75% by 2030 [47], suggesting that both targets can be met much sooner than envisaged by the policy. Therefore, the government is considering increasing the 2050 target to 90% or even 100% [48].

For that reason, the FuturES framework models two scenarios in Chile for the year 2050: business as usual (BAU) and Renewables Energy (RE). The former considers both the fossil and renewable options in the mix while the latter aims to phase out fossil fuels and maximise the contribution of renewables. The inventory data and assumptions are presented below, together with a description of how the scenarios have been developed.

5.4.1. Power technologies and resources

Eleven power generating options have been considered as part of this work. These power technologies have been selected by considering the current options (in the baseline year 2015), as well as technologies that are not yet part of the national power system but have high potential for future deployment, such as concentrating solar power (CSP) with energy storage and geothermal [49–52].

There are other power options that can be potentially considered for technology prospection. Such as nuclear power or marine power technologies. However, in this research, those options were not included because they face some technical, economic or/and legal limitations for Chile.

Estimations determined in marine energy for Chile suggest that the country has significant potential of wave power than that of tidal stream. However, two reports conclude that the current technologies are not mature, they require be further studied and developed to make more reliable estimations and also to identify cost-optimal options. The areas that can be currently deployed are associated with significant tidal streams areas but are located far away from the main power system [53–55].

Nuclear power has been studied by the national nuclear energy commission in Chile [56]. Preliminary studies have been discussed in the context of the development of the energy policy by 2050. According to the Energy policy, nuclear power is not dismissed as a potential alternative but it requires further studies toward to clarify the regulatory framework required and technical and economic analysis [46, 57]. A policy update should be carried out every five years, so the opportunity to take a decision on nuclear can be made by 2020. If a decision is made by then, the materialization of a nuclear power project may be by 2050 or later, hence, out of the planning horizon of this study.

The selected technologies have been organised into different categories (Figure 29), based on whether or not they are conventional (fossil fuels and hydro), non-conventional (all renewables except hydro) and/or able to store energy. Depending on the type of technology, the constraints described in sections 5.3.1.1.6-5.3.1.1.8 may apply.

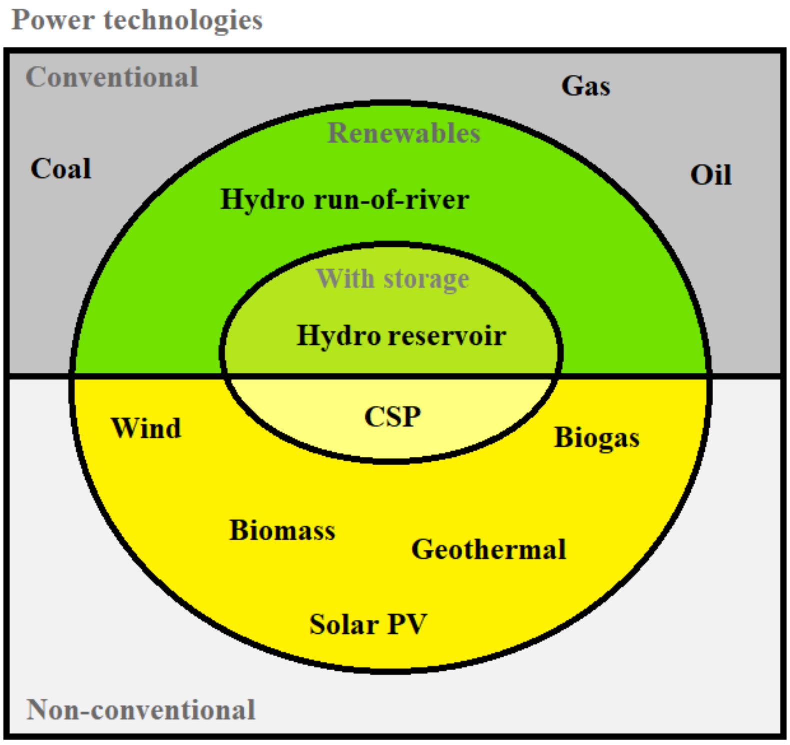

Figure 29. Classification of technologies considered in the study.

5.4.1.1. Technical and economic parameters for the PES model

The main technical and economic parameters and assumptions for each technology are presented in Table 20 and Table 21. Note that all costs are in US$. An inflation rate has not been included in the analysis and, therefore, all the costs are based on the year 2015. Considering that Chile has historically maintained inflation to a level that has allowed price stability, this assumption should not affect the results in the planning horizon [58].

The maximum annual new-build capacity (N_g^{max}) has been calculated considering the current technical potential for each technology, along with the historical trend of investment [59–62] (see Table 19 and Figure 30). Based on the historical investment trends, rates of investment can be estimated directly from real-life outcomes in different periods. This is particularly useful because such rates reflect underlying aspects that cannot be quantified easily, such as the difficulty in obtaining environmental permits for hydropower projects due to its historically low social acceptability. In Chile, hydropower reservoirs and run-of-river have both had a constant increase in capacity between 1990 and 2017 of 171 MW/yr. Coal power has had a steady investment between 2008 and 2018 of 348 MW/yr. Oil power had a short period of high investment between 2004 and 2010 at a rate of 270 MW/yr, while gas power had a rate of 347 MW/yr between 1995 and 2008. Finally, renewable options have had a high increase in investment between 2013 and 2017 at a rate of 869 MW/yr, mostly for solar PV and wind power. Based on these values, conservative assumptions have been made for the maximum annual new-build capacities (N_g^{max}) which are shown in Table 20. However, for solar PV, CSP and wind, which have high future potential in the country (Table 19) but uncertain sustainable growth rates, the annual new-build capacities have been varied from 260MW and 750MW, as explained in detail in section 5.4.3.

Regarding other parameters in Table 20, the total initial installed capacity has been estimated based on all operating power plants at the end of 2014. The technology lifespan has been defined for each technology based on literature [63, 64]. The capacity factors of the technologies in 2015 have been obtained from records of the system operation in that year and the capacity factor by 2050 is an output value from the simulation (Figure 28). The year of decommissioning of current power plants has been estimated based on the starting year of operation and the lifespan of each power plant, the latter of which is based on 2015. Similarly, current plants which are under construction have been included in the model [63, 64]. Table 41 and Table 42 in the appendix provide a breakdown of the capacity undergoing decommissioning or construction in every year for which data are available.

Table 19. Current installed capacity and potential capacity by technology in Chile [52, 51].

Technology	Installed capacity (GW)	Potential (GW)
Coal	4.2	-
Gas	3.7	-
Oil	3.8	-
Biomass	0.4	14
Biogas	0.0	1
Run-of-river	2.7	12 – 20[a]
Reservoir	3.7	
Wind	0.9	37 – 40
Photovoltaics (PV)	0.5	1263
Concentrating solar power (CSP)	-	100 – 548
Geothermal (Geo)	-	16

[a] Hydropower potential for both options (Run-of-river and reservoir).

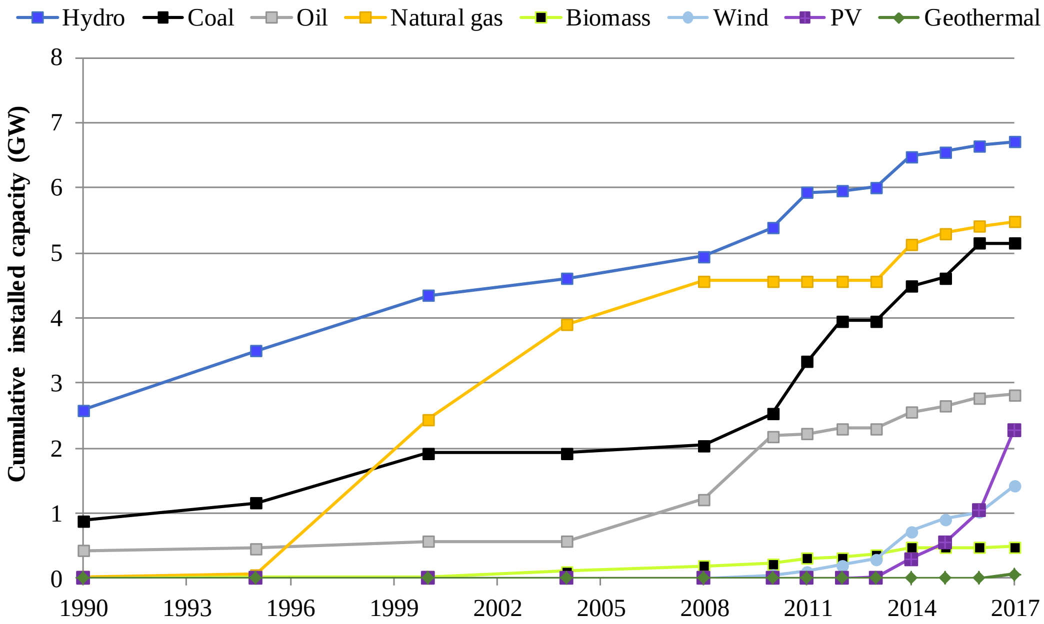

Figure 30. Cumulative installed capacity by technology in Chile over the period 1990 to 2017 [59–62].

Investments costs, fixed costs, variable costs, learning rates and global cumulative installed capacity trend (Figure 53 in the appendix) for wind, solar PV and CSP have been obtained from literature [65–70] and the following assumptions have been made:

- The Chilean energy authority has set a carbon tax of 5 \$/t CO_2. Based on literature [71, 72], the price of this tax is assumed to be increased to 10 \$/t CO_2 from 2030.
- To estimate annualised investment costs, a discount rate of 7% is assumed [73, 74].
- Fuel costs have been obtained from US data based on their Free On Board (FOB) price [75]. The Cost, Insurance and Freight (CIF) costs [64, 75, 76] have been

estimated to reflect the fuel costs in the country in any given year (Figure 54 in the appendix).

- Since biomass prices depend on the local market, the biomass cost has been estimated on the basis of biomass production, processing and transport costs in Chile, obtained from literature [76], and is assumed to stay constant throughout the time period of the assessment.
- The potential for biogas power has been estimated based on the biogas production capacity of existing landfill sites (Table 19), yielding a relatively low maximum of 1 GW. Therefore, a low annual new-build capacity has been assumed of 25 MW/yr and zero fuel cost has been considered for this technology since the biogas is produced in landfill from waste. Other sources of biogas are not considered due to a lack of data.

Table 20. Technical parameters considered for the power system expansion model [51, 60, 61, 63, 64].

Parameters	Technology										
	Coal	Gas	Oil	Biomass	Biogas	Run-of-river	Reservoir	Wind	PV	CSP	Geothermal
Maximum new-build capacity (MW/yr)	260	260	260	100	25	60	60	260 - 750	260 - 750	260 - 750	150
Initial installed capacity (MW)	4179	3722	3836	408	47	2726	3714	890	509	0	0
Current electricity share [a]	36.2%	16.5%	3.7%	3.0%	0.3%	17.7%	17.4%	3.2%	2.0%	-	-
Lifespan (yr)	38	35	35	40	20	80	80	25	20	25	25
Current capacity factor [a]	0.79	0.41	0.09	0.67	0.62	0.6	0.43	0.28	0.25	0.35	0.6
Maximum capacity factor [b]	0.8	0.8	0.8	0.8	0.8	0.6	0.43	0.32	0.25	0.35	0.8
Efficiency [a]	36%	46%	42%	18%	32%						
Carbon emissions (kg CO_2/MJ)	98	62	89	-	-						
Calorific value (unit)	29,290 (MJ/t)	1055 (MJ/Nm^3)	6120 (MJ/bbl)	18,100 (MJ/t)	-						

[a] Data for 2015.

[b] The maximum capacity factor for PV, wind, reservoir and run-of-river reflect the annual capacity factor for each technology in 2015 [61] and for CSP has been obtained from a report [51].

Table 21. Economic parameters considered for the power system expansion model[a].

Parameters	Technology										
	Coal	Gas	Oil	Biomass	Biogas	Run-of-river	Reservoir	Wind	PV	CSP	Geothermal
Initial capital cost ($/kW) [67]	3000	1150	1150	3100	3500	4050	2200	1800	1800	9000	7800
Capital cost share for fixed cost [67]	2%	1%	1%	3.5%	3.5%	1%	1%	2%	1.5%	1%	1.5%
Variable costs ($/MWh) [67]	2	3	4	10	15	3	3	0	0	0	2
Learning rate [65, 66]	-	-	-	-	-	-	-	10%	15%	11%	
Discount rate	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
Carbon emission tax 2015-2029 ($/t CO_2) [71, 72]	5	5	5								
Carbon emission tax 2030-2050 ($/t CO_2)	10	10	10								
Fuel costs (unit) [b]	83.2 ($/t)	7.4 ($/Nm^3)	43.4 ($/bbl)	58.9 ($/t)							
LCOE ($/MWh) [c]	75.3	88.1	195.8	133.2	98.4	64.9	49.9	77.6	93.7	281.2	151.6

[a] All data for 2015.

[b] Data for coal, gas and oil from [75] and for biomass from [76].

[c] Levelized cost of electricity estimated by 2015 based on current capacity factor, lifetime, discount rate and costs described in this study.

5.4.1.2. Technical and economic parameters for the ED model

The main assumptions considered for the ED model are shown in Table 22, while the relative storage values are presented in Figure 31 and Figure 32; the hourly profile of hydropower, wind and solar availability can be found in Figure 55 to Figure 57 in the appendix. Merit order is established according to the technologies' variable costs, fuel costs and carbon tax. The selected base storage values for the two technologies with storage (reservoir and CSP) are also indicated in Table 22 along with the assumed storage capacity and initial filling level.

As can be seen in Table 22, most of renewable options have variable costs near to zero. From Table 21, hydropower reservoirs have variable costs of 3 $/MWh whereas CSP has zero variable cost. Since these two options have built-in storage, a shadow price of the storage should be estimated. The shadow price reflects the opportunity cost of using a unit of stored energy in the present, and not later [77].

To estimate the opportunity costs (or shadow price) for stored energy is very challenging [78]. In this model, a simple approximation of estimation of shadow price has been implemented through the use of storage value. Base storage values are chosen for reservoir hydropower and CSP based on a strategy to enable the use of the storage as efficiently as possible.

Table 22. Input data assumed by 2050 for economic dispatch model [63, 64].

Technology	Merit order[a] ($/MWh)	Base storage value ($/MWh)	Storage capacity (h)	Initial filling level
Coal[b]	44			
Gas[b]	91			
Oil[b]	175			
Biomass[c]	75			
Biogas[c]	15			
Run-of-river[c]	3			
Reservoir	-	20	1670	35%
Wind[c]	0			
PV[c]	0			
CSP	-	46	17	40%
Geothermal[c]	2			

[a] Marginal costs: Variable costs + fuel costs + CO_2 tax.
[b] Marginal cost estimated from variable costs assumed constant between 2015-2050 (see Table 21), fuel costs in 2050 estimated from fuel cost trend (see Figure 54 in the appendix and Eq. 9) and carbon tax in 2050 from 10 $/t CO_2 (see Table 21 and Eq. 10).
[c] Marginal costs estimated from variable costs assumed constant in 2015-2050 (see Table 21) and for biomass, fuel cost is also assumed to be constant between 2015-2050 (see section 5.4.1.1).

As Chile has large reservoir hydropower capacity with low price, this technology is used as back-up for the variable renewable options (wind and solar PV). A base storage value of \$20/MWh has been selected to ensure the readiness of reservoir power plants when other renewables are not available. Furthermore, the dispatch of coal power can be delayed by the dispatch of hydropower reservoir since coal power has a marginal cost of \$44/MWh, which is higher than that of reservoirs (\$20/MWh). A base storage value of \$46/MWh has been assumed for CSP to position its marginal costs above coal's marginal cost and reservoir hydropower's storage value, and also below biomass, gas and oil power marginal costs (Table 22). This is necessary to enable CSP to support peak-load options. Although reservoir and CSP storage values depend on the filling level and the time of the year and/or hour of the day (equation 28), the storage value will vary around the base storage value. Ultimately, the storage value is related to the utility of energy storage to the grid at any given time. So, for example, CSP can have a storage value of zero between 23:00 and 4:00 and above \$70/MWh when its storage filling level is below 60% (Figure 31 and Figure 32 (a)) [from equation 28: 70 = 46 x 0.95 x 1.6]. The lower storage value at night allows CSP to empty the storage, while during the day the storage filling level increases to be available for peak-load times. Similarly, reservoirs increase their storage value in summer when there is lack of precipitation, reaching storage values above \$35/MWh when the filling level is below 40% [from equation 28: 35 = 20 x 1.4 x 1.25] which eventually can be higher than coal and even CSP.

Different operating modes can be established for CSP with storage; for example, as base-load or peak-load dispatch mode. As mentioned before, in this study CSP is considered as a peak-load option. This is reflected in Figure 32 (a) which shows high relative storage values at high solar radiation times of the day and before peak-load hours, after which the relative storage value reduces until reaching zero at night. The storage values for reservoir hydropower in Figure 32 (b) are based on the inverse of water inflow records (precipitation) [61]. Therefore, in winter and spring when high precipitation occurs, the relative storage value is low for reservoirs (i.e. stored energy is cheap), leading to hydropower being the first option to be dispatched after wind and solar PV.

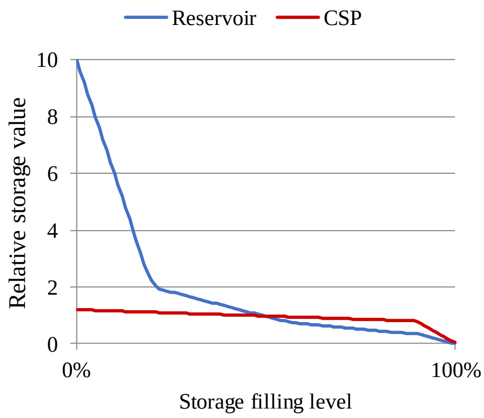

Figure 31. Relative storage value depending on the storage filling level for hydro and solar CSP (adapted from [9]).

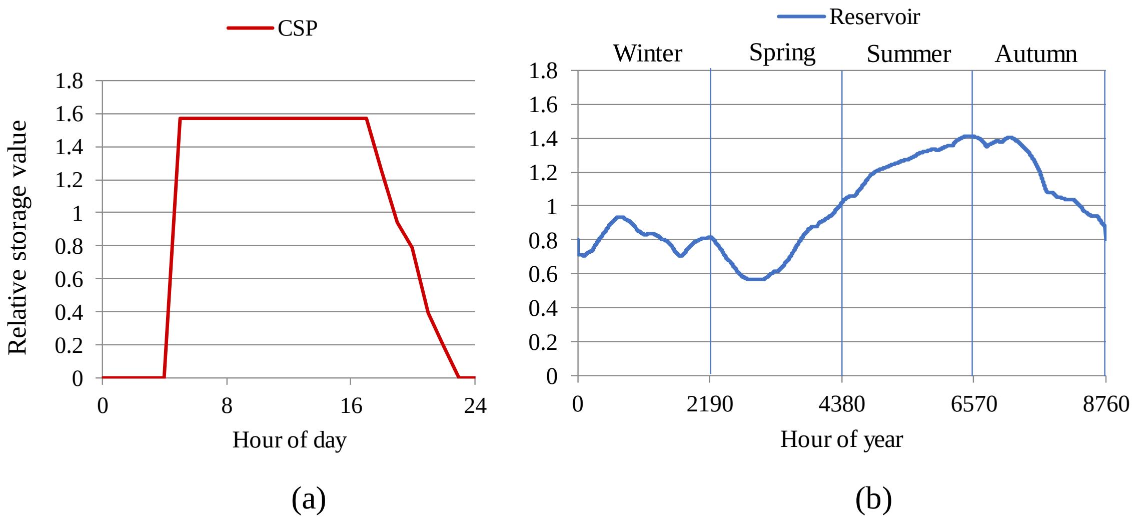

Figure 32. Relative storage value for CSP depending on time of day with 17 hours of storage per day (a) and for reservoir hydropower with 1670 hours of storage per year (b).
[Both figures obtained based on criteria in [9]].

5.4.2. Electricity demand

The annual electricity demand in Chile is expected to increase by 2.4% in the period from 2015 to 2050 (75 TWh to 160 TWh respectively) [79]. Based on this and a 7% energy loss due to transmission [63, 64], the average load by 2050 has been estimated at 18,261 MW. Figure 33 shows the hourly load profile for 2050 which has been developed from historical records of ten years of power dispatch [61] by applying typical hourly load curves to the expected demand in the 2050. Thus, the model assumes that the load profile in Chile does not change significantly over the period of assessment, with the highest loads occurring between hours 8-21 in the autumn and winter months of the year. Although the highest peak-load occurs between hours 20-21. Due to about 54% of electricity consumption is attributed to industry where mining has the highest consumption in this sector with a constant load during the day [80].

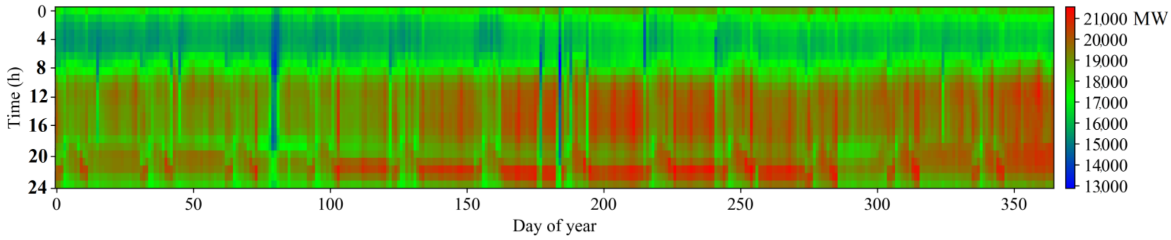

Figure 33. Load profile (MW) in 2050 estimated based on historical records for an average load 18,261 MW.

5.4.3. Scenarios – rationale and constraints

The two future scenarios – BAU and RE – have been defined based on the Chilean energy policy of 2015 which set a minimum target of 70% for the contribution of renewables to the electricity supply in 2050 [46]. BAU has no constraints on the type of technology deployed and, therefore all 11 options (Table 20) can be chosen by the model. The RE scenario imposes the constraint that 100% of the electricity should be provided by renewable options by 2050. Also, in order to improve the electricity from wind, solar PV and other renewables, the government enacted a quota system policy with a target of 20% of non-conventional renewable energy (NCRE) electricity by 2025 starting from 10% from 2015 [81]. This constraint has been implemented to all scenarios as shown in Table 23.

The annual new-build capacity limit is a significant parameter that may distinguish the scenarios developed by the model. Since wind and solar PV are becoming more competitive and have high potential, along with CSP, the BAU and RE scenarios are further divided into two sub-scenarios, based on the cap on the annual new-build capacity for solar PV, CSP and wind power:

i) one with a low annual new-build capacity limit of 260 MW; and
ii) another with a high value of 750 MW.

These two values have been obtained after initial testing of different annual new-build capacity values which demonstrated that values lower than 260 MW and higher than 750 MW resulted in infeasible scenarios. This is because in the lower range the model does not have enough new-build capacity to meet the future demand. In the higher range, the model considers higher investment for solar and wind with large energy spillage and reduced dispatch of the other technologies, which in turn leads the model to look for new-build capacity to meet the demand, until its runs out of new-build capacity after some iterations. Therefore, the four resulting scenarios are referred to as BAU_{260}, BAU_{750}, RE_{260} and RE_{750}. These scenarios are summarised in Table 23 with reference to the constraints described in section 5.3.1.1.

Table 23. 2050 scenarios and key constraints.

Constraints		Scenarios			
Description	Section describing constraints	BAU_{260}	BAU_{750}	RE_{260}	RE_{750}
Maximum total new build capacity (MW/yr) for solar PV, CSP & wind	5.3.1.1.4	260	750	260	750
Fossil-based power phased out by 2050	5.3.1.1.5	No	No	Yes	Yes
Hydropower options replaced at end of lifetime	5.3.1.1.6	Yes	Yes	Yes	Yes
Non-conventional renewable electricity quota in the mix in 2015	5.3.1.1.7	10%	10%	10%	10%
Non-conventional renewable electricity quota in the mix in 2025	5.3.1.1.7	20%	20%	20%	20%

A sensitivity analysis has also been carried out to evaluate the extent to which the technologies with storage (CSP and reservoirs) help to keep costs low while providing flexibility. Therefore, two additional BAU and RE scenarios have been modelled: i) without CSP; and ii) without new-build capacity for hydropower (run-of-river and reservoirs).

5.5. RESULTS AND DISCUSSION

The following sections discuss the outputs of the FuturES framework applied to the case of Chile. First, the makeup of the optimised scenarios obtained through the modelling is discussed, followed by their feasibility, economic assessment and a sensitivity analysis. Finally, the limitations and recommended future work are outlined.

5.5.1. Installed capacity, electricity contribution and capacity factors

A summary of the main results of the optimisation model is presented in Table 24 and Figure 34. These show the estimated installed capacity, capacity factors and electricity generation from different sources taking into account the annual new-build capacity limits of 260 MW (BAU_{260} and RE_{260}) and 750 MW (BAU_{750} and RE_{750}).

Regarding the capacity factors, it can be seen in Table 24 for BAU_{260} that biogas, wind and geothermal power have higher capacity factors than in RE_{260}. Similarly, when BAU_{260} and BAU_{750} scenarios are compared with each other, BAU_{260} has higher capacity factors. These variations can be explained as follows. Hydropower reservoir and run-of-river, wind, solar PV and CSP depend strongly on the resource availability (weather conditions); therefore, it is expected that the capacity factor of these options should be derived from their local resource availability (Table 20). In BAU_{260}, the installed capacities of these technologies are maximised according to their expected capacity factors. However, in other scenarios it is possible to produce excess energy at times from these technologies, leading to energy spillage and, hence, the capacity factors become lower. This is observable, for instance, for wind power in RE_{260} where the capacity factor is 30% instead of 32% (Table 24) due to some of the harvested wind energy exceeding demand at the time of generation. In BAU_{750} and RE_{750}, energy spill is even higher. For example, run-of-river has capacity factors of 47% and 49% for BAU_{750} and RE_{750}, respectively, instead of its potential capacity factor of 60%. In the case of wind, BAU_{750} and RE_{750} have a capacity factor of 25%, 7 percentage points below the maximum capacity factor. For both run-of-river and wind, this energy spillage occurs because in these scenarios the installed capacity of solar PV is larger than the demand around midday, leaving the other power options without demand to fulfil. Reservoir and CSP do not show energy spillage in any scenario, since both options store the energy to be dispatched later.

Table 24. Capacity and capacity factors for the technologies in the proposed 2050 scenarios[a].

Technologies		2015	BAU_{260}	BAU_{750}	RE_{260}	RE_{750}
Coal	Capacity (MW)	4179	9876	6500	-	-
	Capacity factor (%)	79%	36%	28%		
Gas	Capacity (MW)	3722	-	-	-	-
	Capacity factor (%)	41%				
Oil	Capacity (MW)	3836	-	-	-	-
	Capacity factor (%)	9%				
Biomass	Capacity (MW)	408	-	-	4000	4000
	Capacity factor (%)	67%			3%	4%
Biogas	Capacity (MW)	47	635	618	1073	449
	Capacity factor (%)	62%	70%	55%	66%	57%
Run-of-river	Capacity (MW)	2726	5974	5804	6418	5632
	Capacity factor (%)	60%	60%	47%	60%	49%
Reservoir	Capacity (MW)	3714	5928	5931	6212	6092
	Capacity factor (%)	43%	43%	43%	43%	43%
Wind	Capacity (MW)	890	11,741	12,419	12,413	13,081
	Capacity factor (%)	32%	32%	25%	30%	25%
PV	Capacity (MW)	509	14,611	27,702	15,111	25,807
	Capacity factor (%)	25%	25%	22%	25%	23%
CSP	Capacity (MW)	-	-	4831	5524	2073
	Capacity factor (%)			35%	35%	35%
Geothermal	Capacity (MW)	-	1215	-	2642	5000
	Capacity factor (%)		67%		59%	53%
Total	Capacity (MW)	20,031	49,980	63,805	53,394	62,134

[a] BAU: Business as usual; RE; Renewable electricity. The subscripts “260” and “750” refer to the annual cap on the new-build capacity in MW for solar PV, concentrating solar power and wind as described in section 5.4.3.

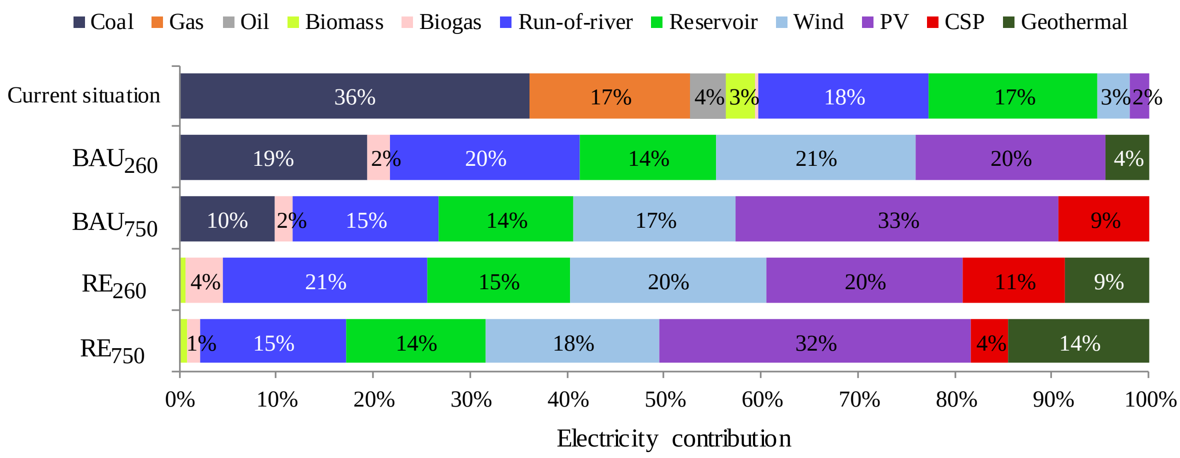

Figure 34. Contribution of different technologies to electricity generation in the four scenarios. [BAU: Business as usual; RE; Renewable electricity. The subscripts "260" and "750" refer to the annual cap on the new-build capacity in MW for solar PV, concentrating solar power and wind]

In terms of the contribution of different technologies to the electricity mix, it is notable from Figure 34 that the only fossil fuel option retained in the BAU scenarios by 2050 is coal power, which decreases from 57% at present to 19% (BAU_{260}) and 10% (BAU_{750}). This is due to the fact that, even when fossil fuel options are allowed by the constraints in the model, by 2050 gas and oil power are no longer cost competitive against coal and the renewables.

Over the period of 2015 to 2050, the installed capacity of coal increases from 4179 MW to 9876 MW in BAU_{260} and to 6500 MW in BAU_{750} despite its relative share in the mix decreasing. This is partly due to the fact that the total electricity demand over the same period doubles, but also due to a significant reduction of the capacity factor from 79% to 36% in BAU_{260} and to 28% in BAU_{750}. This is a consequence of the increase in solar PV and wind power, the fluctuations and variability of which force the other technologies to reduce their capacity factors via increased regularity in the ramping up and down of their output.

Solar PV increases its contribution significantly in all scenarios, from 2% in the current situation to 20-33% by 2050 due to the large Chilean solar resource and rapidly decreasing costs. In each scenario it is the option with the highest contribution by 2050, followed by wind and hydropower run-of-river. Hydropower reservoir decreases from 17% in the present day to approximately 14% in all scenarios as the other renewables become more cost competitive. Nevertheless, its overall installed capacity still increases by 60%-67% compared to the present, suggesting that the hydropower maintains competitive and the capacity retention constraint described in section 5.3.1.1.6 may not be necessary for Chile to ensure continued use of hydro reservoirs.

Geothermal has a higher contribution in the RE scenarios (9% in RE_{260} and 14% RE_{750}) in order to fill, in part, the electricity generation gap left by fossil fuels after their phasing out. Finally, biogas power has the lowest contribution (<4% in all scenarios) due to its low annual new-build capacity.

Regarding the total installed capacity, the absence of energy spillage, together with the lowest installed capacity of solar PV and wind, leads to the BAU_{260} scenario having the lowest total installed capacity of 49,980 MW (Table 24). However, BAU_{750} has the largest installed capacity of 63,805 MW caused by the high energy spillage of hydropower run-of-river, wind and solar PV and large installed capacity of solar PV, wind and coal power. Because the model chooses coal as an economic option together with solar PV, this enables high new-build capacity for both power options, even though the high capacity of solar PV leads to a low capacity factor for coal (28%). While RE scenarios have lower energy spillage than BAU_{750}, they have total installed capacity in between BAU_{260} and BAU_{750}.

5.5.2. Scenario feasibility

The PSE model prioritises technologies with low levelized costs of electricity, while the ED model prioritises technologies with low marginal costs (variable costs, fuel costs and carbon tax). After running the two models iteratively (Figure 28), it can be seen that technologies with low investment costs and low marginal costs (wind, solar PV, hydropower run-of-river and reservoirs) are prioritised, while high marginal cost technologies (oil, gas and biomass) are avoided. For example, oil and gas power have the lowest investment costs (Table 21), but high marginal costs (Table 22). In addition to this, since the ED model considers these options at peak-load times, their capacity factors are lower (Table 24) causing large LCOE and consequently, new-build capacity is discouraged by the PSE model (Figure 35). A worse situation is found in the case of biomass power since it has higher both the investment and fuel costs (Table 21) as a result of the low calorific value of biomass (18,100 MJ/t) and low efficiency (18%) of the power plants.

The installed capacities of CSP are 4831 MW in BAU_{750}, 5524 MW in RE_{260} and 2073 MW in RE_{750}, (Table 24). These capacities allow CSP to attain the maximum capacity factor due to a high availability of solar radiation, with a LCOE of 139 \$/MWh across the scenarios. When solar radiation is low, as in autumn and winter, CSP seldom has excess energy to store and therefore can barely contribute to grid flexibility for BAU_{750}, RE_{260} and RE_{750}. Hence, in those periods, hydropower reservoirs provide the main contribution at peak-load times, supplemented by biomass (except for BAU_{260} which relies mostly on reservoirs).

Wind and solar PV have the highest contributions to electricity generation in all the scenarios (17%-21% in BAU and 20%-33% in RE). This is a result of their low capital costs estimated on the basis of their learning rates, which lead to the 2050 LCOEs of $45-50/MWh for solar PV and $49-63/MWh for wind power. In BAU_{750}, wind has its lowest capacity factor of 25%, causing an increase in the LCOE (64 $/MWh) due to electricity spillage. Even though higher installed capacities of wind and solar PV lead to spillage of energy, investments in these two options are prioritised to the detriment of other renewable options due to their very low LCOEs.

As illustrated in Figure 36 and 37, the higher contribution of hydropower reservoirs in the RE scenarios occurs in autumn when solar radiation is low. Therefore, reservoirs provide seasonal storage and support the fluctuations in solar and wind power, assuming that sufficient water inflow is available. Although hydropower reservoirs have enough storage capacity, their maximum dispatchable load is not usually sufficient to replace the missing solar PV, CSP and wind output during autumn and winter due to the very high installed capacities of those technologies in the RE scenarios. Hence, biomass is dispatched for short periods as the only other flexible non-fossil technology. This low utilisation of the biomass plants leads to very high LCOEs of up to $1295/MWh. Such a high cost would likely not be tolerated by the market without other financing mechanisms in addition to the standard energy market as included in the PSE model. An example would be the inclusion of a capacity market for reserve margin in order to provide a supplementary financing mechanism for technologies that contribute to grid flexibility. Such considerations are outside the scope of this work and could be explored as part of future research.

In summary, it can be seen that all the scenarios are fully feasible in terms of grid stability and electricity supply, including the ones with a 100% renewables, demonstrating that it is possible to deploy such systems in the future. The following section discusses the economic feasibility of the scenarios.

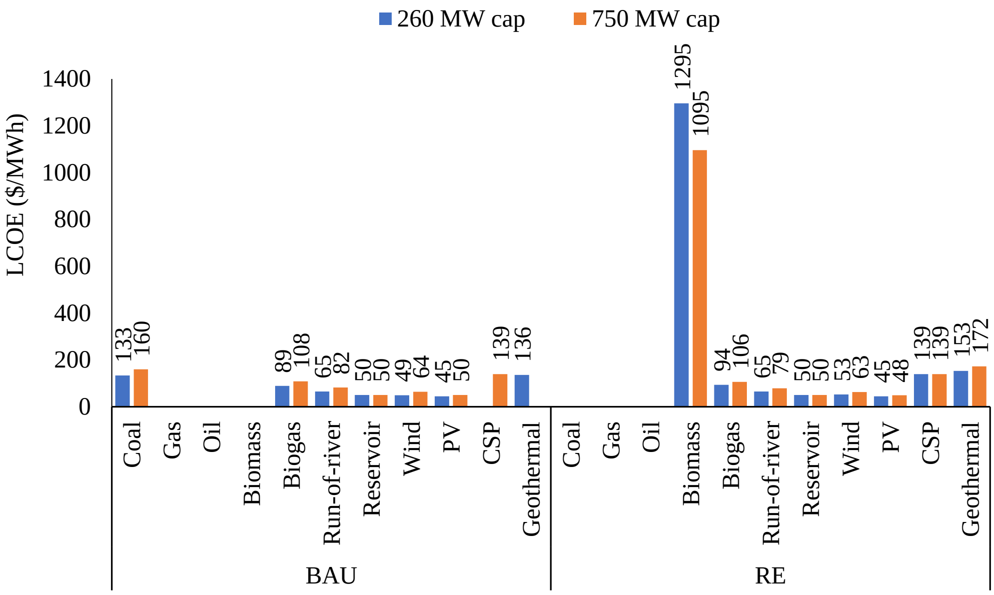

Figure 35. Levelized cost of electricity (LCOE) in 2050 for different technologies.
[BAU: Business as usual; RE; Renewable electricity. The subscripts "260" and "750" refer to the annual cap on the new-build capacity in MW for solar PV, concentrating solar power and wind]

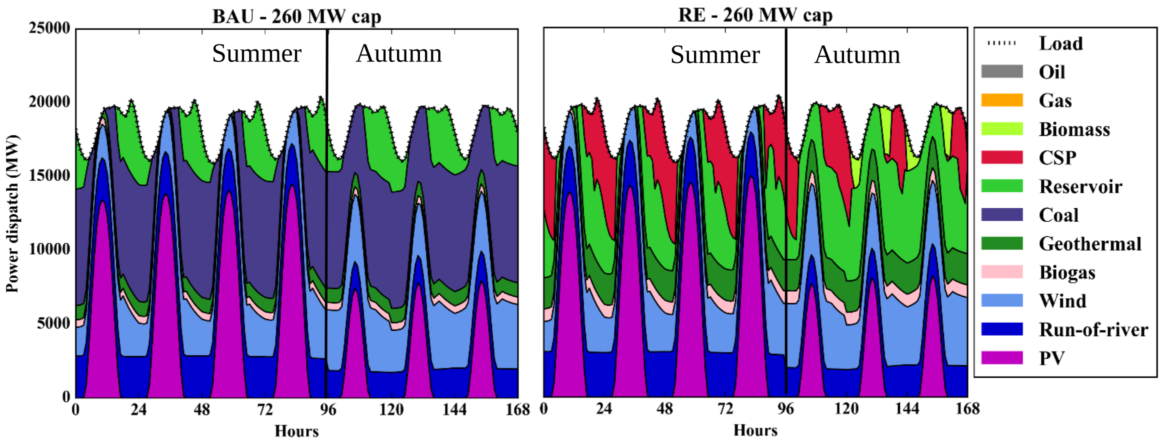

Figure 36. Load dispatch for a sample of seven days for the BAU and RE scenarios for the annual new-build capacity limit of 260 MW for solar PV, concentrating solar power and wind
[BAU: Business as usual; RE: Renewable electricity]

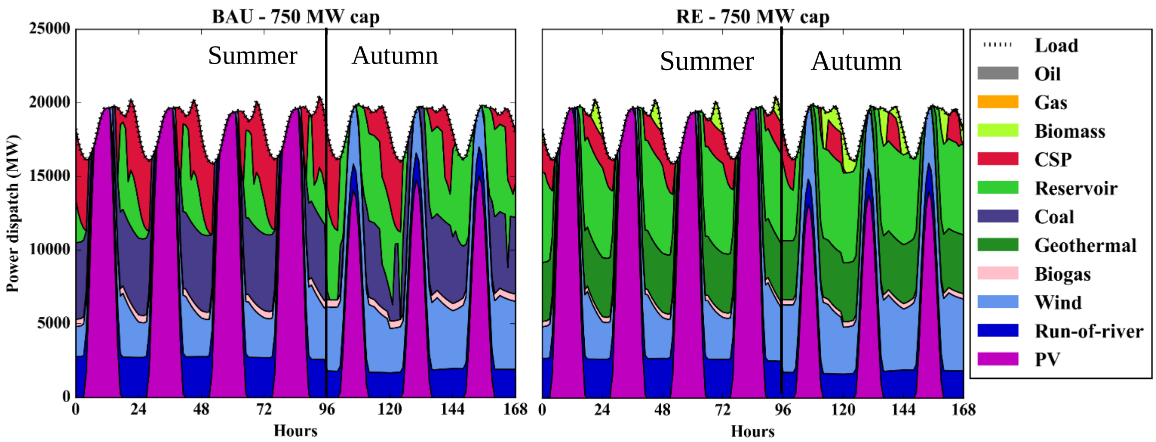

Figure 37. Load dispatch for a sample of seven days for the BAU and RE scenarios for the annual new-build capacity limit of 750 MW for solar PV, concentrating solar power and wind.
[BAU: Business as usual; RE: Renewable electricity]

5.5.3. Economic assessment

The optimised LCOEs obtained through the FuturES framework are presented in Figure 38 for each scenario. As indicated, the two BAU scenarios have the lowest LCOE by 2050 (\$72.7/MWh for BAU_{260} and \$77.3/MWh for BAU_{750}) with up to 6% reduction compared to the current situation (77.6 \$/MWh). The RE scenarios show LCOEs that are 5% to 12% (\$81.3-86.9/MWh) higher than today's electricity cost and 12% to 20% higher than BAU_{260}.

Based on the learning rates assumed for solar PV, CSP and wind [65, 66], their costs are expected to decrease greatly over the coming decades. Therefore, these options are systematically selected as new-build capacity to meet the demand. As discussed above, biomass power has been included in both RE scenarios, but the very low capacity factors (3%-4%) and therefore high LCOEs have discouraged its investment.

Regarding the total system cost (Figure 39), the RE scenarios are the most expensive in 2050 with total costs of \$356-361 bn, while the BAU scenarios are in the range of \$337-338 bn. The higher costs of the RE scenarios are due to higher contributions of biogas and geothermal power as base-load options and the energy spillage of wind and hydropower run-of-river, which in turn lead to lower capacity factors (25% wind and 49% run-of-river) than their resource availability could support (32% wind and 60% run-of-river), as can be observed in Table 24. When RE_{260} is compared with RE_{750}, the higher annual new-build capacity of 750 MW for wind, solar PV and CSP for RE_{750} allows wind and solar PV to have greater installed capacity than RE_{260}. However, during periods of high resource availability, this high installed capacity causes the generation of wind and solar PV to be greater than the load (demand). Therefore, energy spillage occurs and the capacity factor of other generators, such as run-of-river, is reduced, which leads to RE_{750} having higher overall system costs. These higher costs could potentially be offset if the energy spillage could instead be put to productive use elsewhere in the economy via some form of demand-side management, the consideration of which is beyond the scope of the current study.

Figure 39 also shows that capital costs contribute the most (67%) to the total system costs in the BAU scenarios, followed by fuel (17%) and fixed costs (13%); carbon tax adds a further 3%. In the RE scenarios, the contribution of the capital costs is even higher (70%) but that of the fuel costs is lower (12%) than in the BAU scenarios; the fixed costs account for 17% of the total.

In addition to the capital costs, the cumulative investment has also been estimated (Figure 40). This represents the investment cost of power plants that need to come online in a specific year and is aggregated over the period 2015 and 2050. This differs from the capital costs which have been estimated considering annualisation of the investment of each technology, taking into account lifespan and discount rate while including existing capacity along with new capacity. As can be seen in Figure 40, the BAU_{260} and BAU_{750} scenarios have the lowest cumulative investment, estimated at $123 and $145 bn, respectively. The latter is close to the investment of $147 bn needed for the RE_{260}, while for RE_{750} the value is slightly higher at $157 bn.

As illustrated in Figure 40, the BAU scenarios have lower investments in biogas, biomass and gas power due to their LCOEs being higher than coal, wind, solar PV and run-of-river. However, the RE scenarios exhibit lower investments in biogas due to its low annual new-build capacity and its high LCOE, but also, in coal, gas and oil power due to the fossil fuel power phase-out constraint.

In relation to low and high annual new-build capacity limits (260 or 750 MW), it can be seen that the cumulative investments are larger in scenarios with the higher limit due to the increased investment in solar PV and wind in both the BAU and RE scenarios (Figure 40). It is also notable that BAU_{750} has lower investment in coal power than BAU_{260} (reducing from $27 to $17 bn) due to the model diverting the funding into renewable projects, most of which become cheaper than coal power in future.

Across all scenarios, there is a clear trend of investments led by solar PV (with an average investment over the period of $31 bn), wind ($23 bn) and hydropower run-of-river ($20 bn). In the RE scenarios, geothermal power and CSP also have significant contributions ($34 and $18 bn, respectively). The average annual investment estimated across all the scenarios is $4.0 ± 0.4 bn.

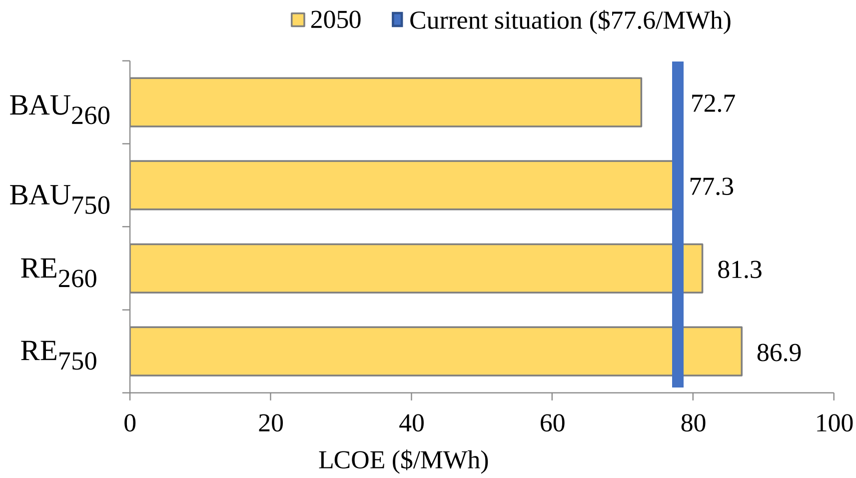

Figure 38. Estimated levelized cost of electricity for the different scenarios compared to the current situation.
[BAU: Business as usual; RE; Renewable electricity. The subscripts "260" and "750" refer to the annual cap on the new-build capacity in MW for solar PV, concentrating solar power and wind]

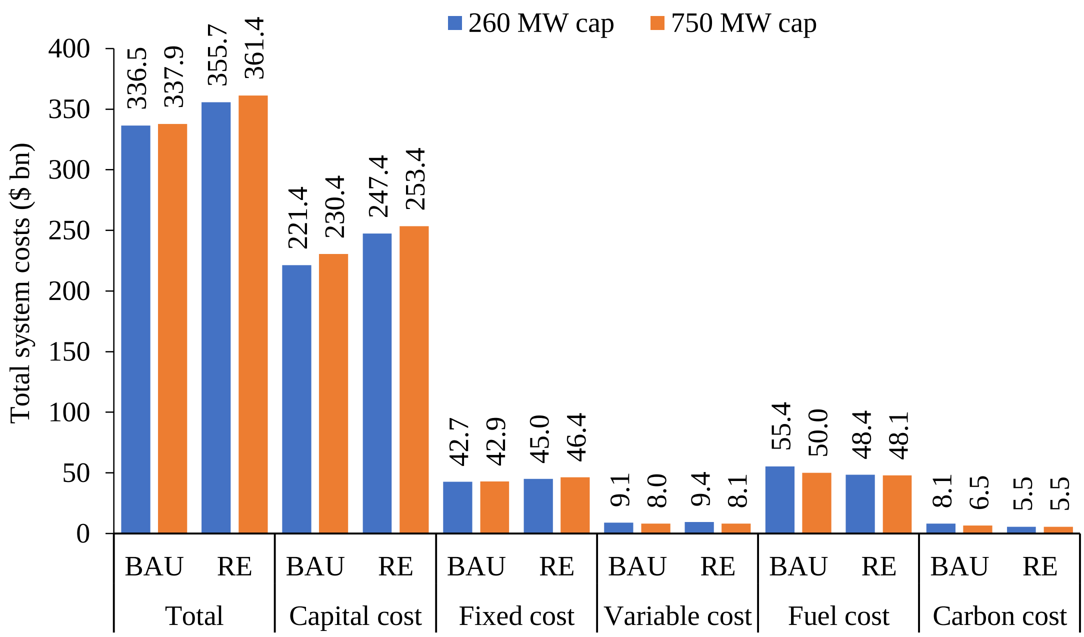

Figure 39. Total system costs in 2050 and contribution analysis by scenario.
[BAU: Business as usual; RE; Renewable electricity. The subscripts "260" and "750" refer to the annual cap on the new-build capacity in MW for solar PV, concentrating solar power and wind]

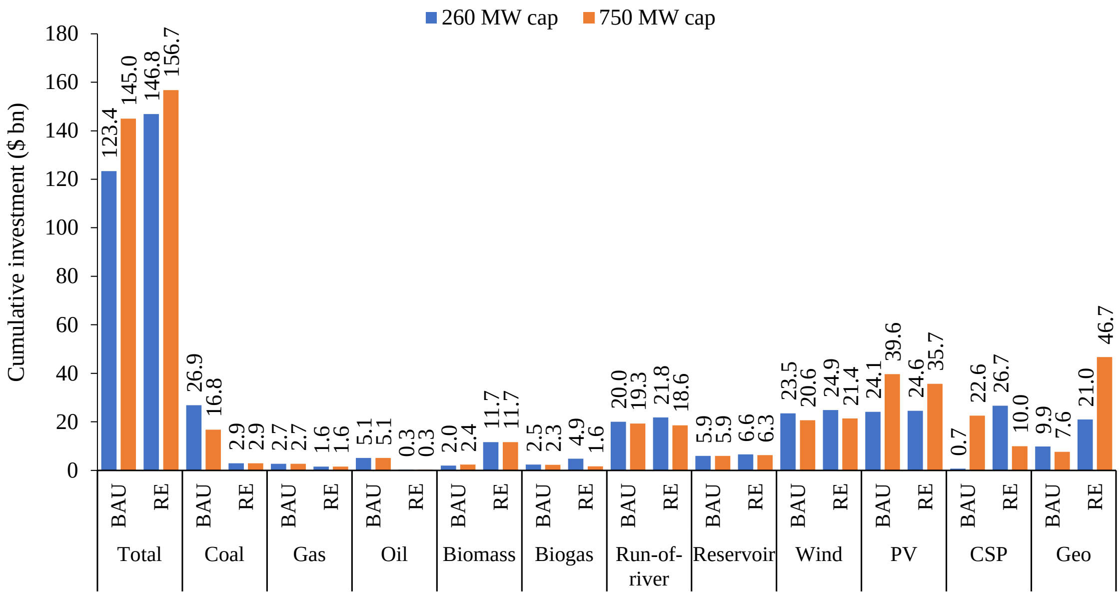

Figure 40. Total cumulative investment by technology.
[BAU: Business as usual; RE; Renewable electricity. The “260 MW cap” and “750 MW cap” refer to the annual limit on the new-build capacity in MW for solar PV, concentrating solar power and wind]

5.5.4. Sensitivity analysis

Two sensitivity analyses have been carried out to investigate the effect of the technology contribution in the scenarios by selecting different discount rates; and the impacts on the electricity costs when storage options are absent in the resulting scenarios.

<u>Discount rates</u>

The levelized cost of electricity (LCOE) is a widely preferred indicator to compare cost of power technologies and electricity scenarios. However, selecting a discount rate is not trivial. The international energy agency dedicates a chapter in its report “Projected cost of generating electricity 2015” [82] to discuss about the effect on LCOE of choosing different discount rates. Following the Chilean methodology [63-64] to determine the cost of electricity, 7% discount rate has been utilized in this research. In order to identify the effect the discount rate in the resulting scenarios, three discount rates have been compared: 3%, 7% and 10%. The resulting technology contribution in the future scenarios at different discount rates are presented in Figure 41. The levelized cost of electricity of each technology per scenario are presented in Figure 42. As the RE scenarios have very low variation among different discount rates, the analysis is focussed on BAU scenarios where the variation is notorious. Therefore, the Figure 42 shows the LCOE of BAU scenarios’ technologies.

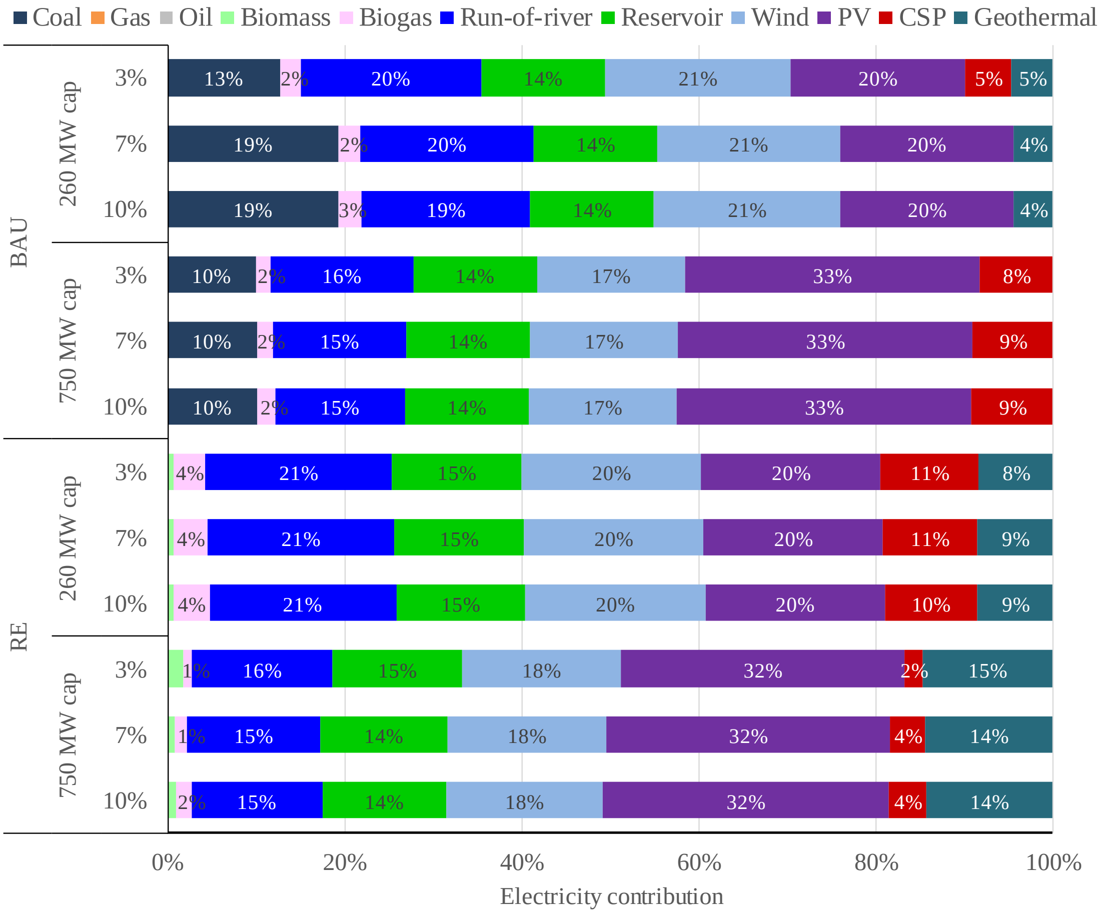

Figure 41. Electricity contribution by technology of the resulting scenarios at three different discount rates (3%, 7%, and 10%). [BAU: Business as usual; RE; Renewable electricity. The “260 MW cap” and “750 MW cap” refer to the annual limit on the new-build capacity in MW for solar PV, concentrating solar power and wind]

As mentioned above, from the resulting technology contribution of RE scenarios can be inferred that there are not significant variations among the scenarios. While in BAU scenarios, when the condition of existing an annual limit on new-build capacity of 260 MW, only 3% discount rate scenario shows a significant difference from the two others scenarios where have the same contribution. In the 3% scenario, coal power has a lower contribution of 13%, while CSP has a contribution of 5%. These differences can be explained from the LCOE of technologies in Figure 42. It can be seen that coal power with 3% discount rate has higher LCOE than CSP and geothermal, contrary to the other scenarios (7% and 10%) where coal power is more economical. Hence, the optimal investment in the 3% discount rate scenario is reached investing more in CSP than coal. From the annuity formula (Eq. 14), when coal power investment cost has similar lifespan than CSP and geothermal power but less than a half of the investment costs of CSP and geothermal power, the reduction of discount rate from 7% to 3% causes a higher reduction of annualisation of investment cost for the most expensive technologies.

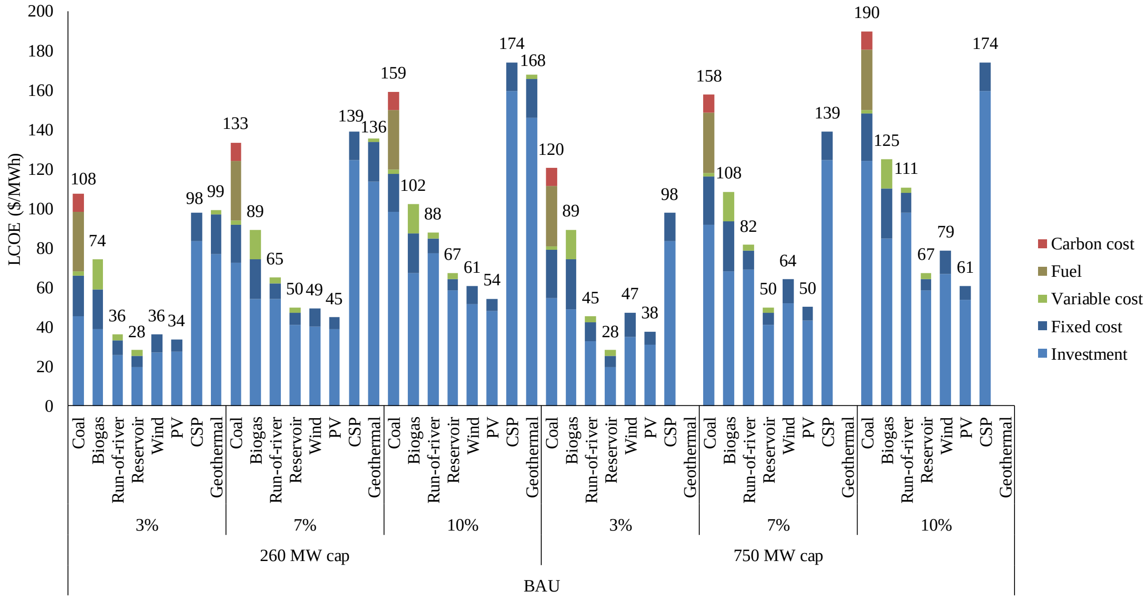

Figure 42. LCOE of technologies at three different discount rates (3%, 7%, and 10%) for BAU scenarios. [BAU: Business as usual. The "260 MW cap" and "750 MW cap" refer to the annual limit on the new-build capacity in MW for solar PV, concentrating solar power and wind]

The results of the sensitivity analysis over the discount rates suggest that the variation of 3%, 7% and 10% do not cause significant variation on the resulting technology contribution of the scenarios. With the exception of BAU "260 MW cap" scenario that coal power reduces its electricity contribution from 19% to 13% allowing CSP investment.

<u>Long-term and short-term storage options</u>

The LCOE of the scenarios have been estimated without CSP and new hydropower capacity for both, reservoir and run-of-river. The results are shown in Figure 43, which compares the LCOEs of the original scenarios with four new scenarios: $\text{BAU}_{\text{260-No CSP}}$, $\text{BAU}_{\text{750-No new hydro}}$, $\text{RE}_{\text{260-No CSP}}$ and $\text{RE}_{\text{750-No CSP}}$.

Since in the base case the BAU_{260} scenario does not have CSP, the results show that there are no differences in the LCOE between this and $\text{BAU}_{\text{260-No CSP}}$ scenario. The remaining scenarios without CSP have only marginally lower LCOE than their equivalent base-case scenarios (Figure 43). This outcome appears counterintuitive since the optimisation model should choose the minimum cost option, and thus the four base-case scenarios should be the cheapest within their respective constraints. The explanation of this outcome is that, in the base-case scenario, CSP has zero marginal cost at peak-load times; hence, the model selects this option in preference to geothermal power, leaving the latter with lower capacity factor. As a consequence, geothermal has higher LCOE than CSP in the presence of CSP. However, when geothermal power is not in competition with CSP, it is dispatched more frequently, attaining a high capacity factor and a lower LCOE than that of CSP.

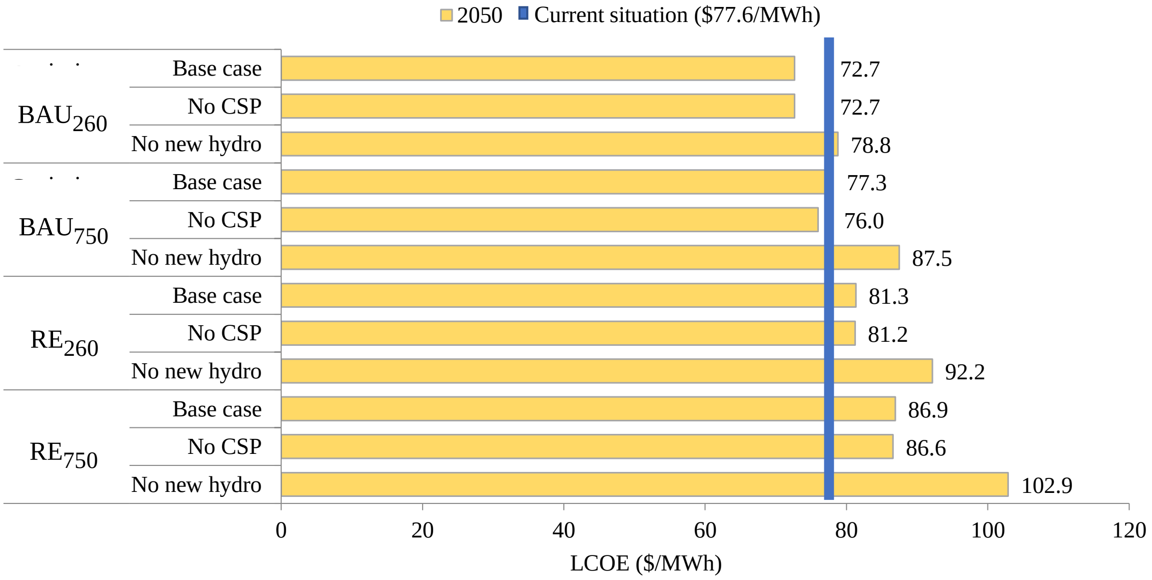

Figure 43. LCOE of scenarios with sensitivity analysis.
[BAU: Business as usual; RE; Renewable electricity. The subscripts “260” and “750” refer to the annual cap on the new-build capacity in MW for solar PV, concentrating solar power and wind]

While the cost impacts of omitting CSP from the mix are minimal, the effect of omitting new-build hydropower is much more pronounced: the BAU scenarios with no new hydropower have 8% - 13% higher LCOEs than the base-case scenarios, while the RE scenarios with no new hydro are 13%-18% more expensive than their base-case equivalents. The seasonal storage capacity of hydropower reservoirs, along with their relatively low investment costs per unit capacity; enable both reservoirs and run-of river hydropower to play a critical role in helping keep a low cost of electricity while maintaining flexibility in the power system.

5.5.5. Limitations and considerations for future research

This study has been developed based on a simplified representation of complex interactions in power systems with as reasonable as possible considerations of the main aspects that drive the power market. The main limitations of the study are:

- This model is based on a single node, assuming there are no distance and site-specific differences between the options. In that sense, transmission and distribution power constraints were assumed equal for all 11 technologies.

- Although hydropower has been represented by two distinct power options (reservoir and run-of-river), in reality, interactions occur among those two options, such as in serial disposition of plants with the effect of upstream inflows and water infiltration. These relationships have not been taken into account.

To improve the quality of the modelling and to be able to draw further recommendations, future studies in this field should include the following:

- consideration of technological improvements for biomass power to find out if this option can be more competitive as well as evaluation of this technology for peak-load dispatch;
- estimation of biogas potential and its production cost, since in this study only landfill gas with zero marginal cost is considered, while the high installed capacity estimated in the RE scenarios would require additional production of biogas;
- evaluation of the effects of including other energy storage systems (e.g. pumped storage and batteries);
- integration of small- and medium-scale distributed energy generation systems into the power system;
- investigation into the effects of climate change on water availability for hydropower generation;
- assessment of alternative uses of energy spillage, such as hydrogen production, water desalination, energy export/import and regional grid integration; and
- estimations of future load profiles taking into account electric vehicles, electrical heating devices and consumer behaviour.

5.6. CONCLUSIONS

A new framework Future Electricity Scenarios (FuturES) has been developed with the aim of developing cost-optimal electricity mixes with a high penetration of renewables. The framework integrates two optimisation models based on power system expansion and economic dispatch. The former has been developed as part of this research and the latter is an open source optimisation program (PowerGAMA). The framework enables consideration of different power technologies taking into account their technical and economic characteristics. These are used to identify the configuration of future electricity systems, including installed capacity, capacity factors, investment and levelized costs of electricity. One of the key features of the FuturES is consideration of system’s flexibility as a critical issue for electricity grids with high penetration of renewables. This is achieved through the evaluation of energy storage vlue and has been implemented for hydropower reservoirs and concentrating solar power with thermal storage.

The FuturES framework has been applied successfully to the case of Chile through the development of cost-optimal scenarios for the year 2050. Two scenarios – Business as usual (BAU) and Renewable electricity (RE) – have been developed considering 11 power sources: coal, gas, oil, biogas, biomass, hydropower reservoir and run-of-river, onshore wind, solar photovoltaics, concentrating solar power with thermal storage and geothermal. BAU is unconstrained in terms of the technologies included in the mix, while RE considers the phasing out of all fossil fuel option by 2050. Each scenario has been subdivided into two sub-scenarios considering low and high constraints on new-build capacity for solar PV, CSP and wind: 260 MW/yr (BAU_{260} and RE_{260}) and 750 MW/yr (BAU_{750} and RE_{750}).

The results reveal that the cost-optimal electricity mixes in 2050 based on the BAU_{260} and BAU_{750} scenarios comprise 81% and 90% renewables, respectively. This is close to the RE scenarios with 100% renewables. This high penetration of renewables is possible as a result of the continued cost reductions expected for renewables over the coming years. Based on historical hourly demand profiles for Chile, both RE scenarios show sufficient flexibility in matching supply with demand, despite solar PV and wind power having a combined contribution of 41% and 50%.

Run-of-river hydropower is used as a baseload option in all BAU and RE scenarios, while coal power provides baseload only in the BAU scenarios. As gas and oil power have high marginal costs, they operate at low capacity factors within the modelled power systems, which leads to higher LCOEs than for the hydropower options, solar PV and wind. Consequently, no gas or oil capacity is selected by the model in either of the BAU scenarios. Biomass also has high marginal costs and, consequently, very low capacity factors (3%-4%). Together with high capital costs, this leads to a levelized cost of electricity (LCOE) above 1295 $/MWh for biomass. Hence, biomass is only retained in the RE scenarios to substitute for missing solar generation in the winter months.

Both BAU_{260} and BAU_{750} have lower costs than today's electricity costs ($72.7 and $77.3 vs $77.6 per MWh). The RE scenarios show up to 12% higher costs than at present and 12% to 20% higher than BAU. The cumulative investments for the BAU and RE scenarios are between $123 to $157 bn, requiring an annual average investment of $4.0±0.4 bn. Excluding the CSP from the mix results in a lower total LCOE in the BAU_{750}, RE_{260} and RE_{750} scenarios due to the knock-on effects of CSP on geothermal power when both are present in the system. Reservoir and run-of-river hydropower are shown to be crucial options in keeping a low cost of electricity: excluding hydropower increases the costs of the system by 8-18% (up to 102.9 $/MWh).

If all the costs are considered, the future BAU scenarios are the most economical, although this means that the coal power capacity would double. All scenarios sit within approximately ±10% of the present day system costs in 2050.

This paper has demonstrated that the FuturES framework is a powerful tool for providing economic and technical insights into the challenges of achieving cost-efficient power systems with high penetration of renewables. The outputs of the framework can also be used for analysing the environmental and social consequences of the resulting scenarios – this is the topic of a forthcoming paper by the authors.

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Chapter 6: Assessing the economic and environmental sustainability of future power supply scenarios for Chile

This paper is pending submission to an appropriate journal.

This paper presents the life cycle environmental sustainability and economic aspects of future scenarios for Chile by 2050. The assessment takes into account the environmental impacts of the technology in the current electricity mix and future scenarios features reported from the previous three chapters. The current power mix is also compared with the future scenarios to determine the environmental and economic sustainability of different electricity configurations.

Tables and figures have been amended to fit into the structure of this thesis. The thesis author is the main author of the paper and is the one who analysed the indicators of each electricity mix and carried out the multi-criteria decision analysis and interpreting the results. The thesis author also wrote the original manuscript. The co-authors are the supervisors of this PhD project and contributed to the paper by reviewing the original manuscript and giving guidance on what aspects need to be improved through this paper.

Chapter 6

Assessing the economic and environmental sustainability of future power supply scenarios for Chile

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Abstract

This paper presents for the first time an economic and environmental sustainability assessment of future electricity generation in Chile up to 2050. Twelve electricity scenarios are considered, defined using systems optimization, taking account into different electricity demand, fossil fuel and renewable technologies and energy storage. The scenarios are evaluated on levelized and investments costs as well as on eleven life cycle environmental impacts. A multi-criteria decision analysis (MCDA) is used to identify the most desirable scenarios considering these economic and environmental indicators. The results suggest that all future scenarios will have lower environmental impacts than at present. The business as usual (BAU) scenarios have 51% lower impacts than the present electricity system. The impacts of the scenarios dominated by the renewables are 87% lower, with global warming potential being 95% lower. The only impact that increases across all scenarios is abiotic depletion potential (ADP), mainly due to solar photovoltaics (PV). In scenarios where, solar PV contributes 20% to the electricity mix, ADP is eight times greater than at present and when it reaches 32%, ADP attains 13 times higher. The scenario with the lowest impacts comprises around 20% of solar PV, wind and run-of-river each, 15% of hydro reservoir, 11% of concentrating solar power (CSP), 9% of geothermal, 4% of biogas and 1% of biomass (RE_{260} 'Base'). The BAU scenario with 20% solar PV has the lowest levelized (72.7 $/MWh) and investment ($ 123 bn) costs due to a balanced contribution of economic power options including coal, solar PV and wind, but also due to non-dispatchable power options such as solar PV, wind, run-of-river and geothermal performed low energy spillage avoiding costs increase, as occurs when solar PV has 32% power contribution. The results of the

MCDA suggest that RE_{260} 'Base' is the most desirable scenario across the different weights of the decision criteria considered. Four out of twelve scenarios with low contribution of run-of-river and reservoir had the highest levelized (90.3 $/MWh average) and investment ($159 bn) costs, highlighting the importance of hydropower to keep the costs low.

Keywords: renewable scenario, environmental impacts, economic indicators, MCDA, global warming potential, levelized cost of electricity.

6.1. INTRODUCTION

Current electricity generation in Chile is shaped mainly by fossil fuels representing 60% of the total supply, to which coal and natural gas are the main contributors. Due to the lack of domestic fossil fuels, the country is compelled to import these fuels, negatively affecting the costs of electricity, national energy security and the environment. Society urges the government to find sustainable options of electricity generation by reducing imports of fossil fuels, phasing out coal power plants, diversifying supply and investing in renewable power options [1].

The costs of electricity in Chile have fluctuated significantly from 50 $/MWh in 2000 to a record high in 2008 of 160 $/MWh. The cost to industrial users has been approximately 100 $/MWh in recent years. Even though these costs have reduced since 2008, they are still relatively high: the electricity price for industrial users, before tax, is the second highest among the IEA members, exceeded only by Japan [2].

However, the prospects for simultaneous cost reduction and improved environmental performance have improved in recent years. One of the contributing factors is the continuing cost reduction of renewable technologies such as wind power and solar photovoltaics [3]. Moreover, the presence of vast areas with the highest solar radiation in the world enable the country to have high solar potential either for photovoltaics or concentrating solar power [4]. Meanwhile, the government has implemented successfully several policies aimed at improving competition, developing transmission infrastructure, promoting renewables and discouraging fossil fuels, including Chile becoming the first country in South America to implement carbon taxes [5–7].

Coal power represents 41% of current electricity generation and is now the main source of electricity followed by hydropower and natural gas. The large investment in coal power, prompted by rapidly increasing electricity demand and low coal costs, has led to the power system doubling its direct CO_2 emissions in the last decade up to 33 CO_2 million tonnes per year [8]. Direct CO_2 emissions associated with electricity supply tend to vary from 200 to 500 g CO_2/kWh due to the impact of hydrology in hydropower availability [2].

In Chile, climate change is increasingly seen as a critical issue, particularly due to its implications for national water stress and scarcity. Therefore, the Chilean congress ratified in 2017 the Paris Agreement committing to reduce the CO_2 intensity of GDP by 30% by 2030 from the 2007 levels as the Nationally Determined Contribution (NDC) [9]. Although this is a target that includes all sectors, the council of ministers for sustainability adopted a mitigation plan for the energy sector with measures mainly focused on the power system, acknowledging that significant reductions in this sector would be the easiest way to achieve the NDC. The mitigation plan considers actions stated in the Energy Policy 2050 along with additional measures to comply with the Paris Agreement by bringing economic benefits due to the energy efficiency measures and the low costs of renewables that will prevent import of fossil fuels [10, 11].

Identifying future electricity scenarios is a topic of interest to both the government and industry. The government has recently estimated scenarios by 2046 as part of the long-term power planning process established by the Energy Policy 2050 [12]. Another study has been carried out by the association of power generation companies to identify the challenges posed by reaching high renewable penetration by 2030 [13]. Both studies focus on technical, economic and local and global contaminants such as particulates, sulphur dioxide and CO_2.

Economic and climate change implication has been mostly investigated in Chile when it comes to analysing future power scenarios. It exists international experiences and research that have addressed the analysis of economic implications of future electricity scenarios by taking into account several environmental impacts and also social aspects allowing to undertake an integrated sustainability assessment for power generation [14–17].

Therefore, the main novelty of this study is its broader analysis of sustainable electricity generation options based on the estimation of 13 indicators across twelves future scenarios for Chile up to 2050. The future scenarios are evaluated with comparison to the current mix, and the choice of the preferred scenario is explored using multi-criteria decision analysis (MCDA).

In the following sections detail the methodology (section 6.2), the results (section 0) and the conclusions (section 6.4).

6.2. METHODOLOGY

The methodology implemented in this research is described in Chapter 1 for the selection of indicators and MCDA, for the definition of scenarios and the economic assessment is found in Chapter 5, and in Chapter 3 and 4, the LCA of generation technologies is detailed. The methodology is summarised in the diagram shown in Figure 44. The approach begins with the selection of indicators related to power generation, followed by the identification and selection of technologies that are part of current power mix or have significant potential for deployment in the country. Third, an investment optimization model is used to define future scenarios based on technical aspects, electricity demand trends, current costs and future cost trends. Fourth, economic modelling and life cycle assessment are carried out for the resulting future scenarios. Finally, a multi-criteria decision analysis is implemented to identify the most favourable scenarios based on the application of different weights to each indicator.

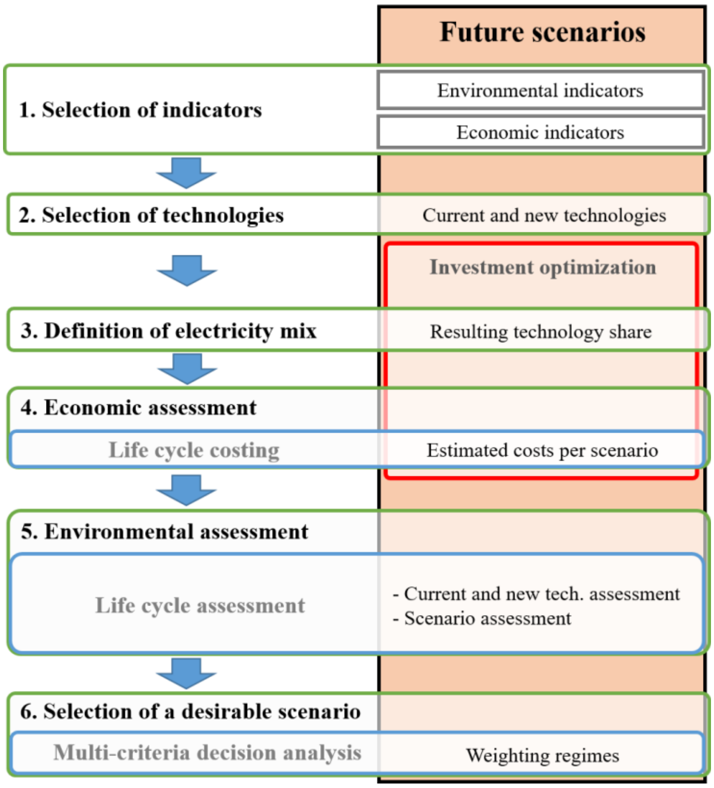


Figure 44. Economic and environmental sustainability assessment methodology for future electricity generation.

6.2.1. Environmental and economic indicators

Eleven environmental impacts and two economic indicators have been considered. The indicators are presented in Table 25. The environmental indicators have been selected based on literature [17–22] from studies that have analysed the environmental impacts of electricity systems from a life cycle perspective including global warming potential, human toxicity potential, abiotic depletion potential, abiotic fossil fuel depletion potential, acidification potential, eutrophication potential, ozone depletion potential, photochemical oxidant creation potential, freshwater aquatic ecotoxicity potential, marine aquatic ecotoxicity potential and terrestrial ecotoxicity potential. The economic indicators selected are levelized costs of electricity (LCOE) and cumulative investment. The indicators have been selected in order to allow comparison among the resulting scenarios; therefore, the environmental indicators and LCOE have been estimated per unit of electricity generated (kWh or MWh) while the cumulative investment is expressed in billions of U.S. dollar, representing the investment incurred in the planning period.

Table 25. Life cycle environmental impacts and economic indicators.

Aspects	Indicators		
	Name	Abbreviation	Unit
Environment	Global Warming Potential	GWP	g CO_2 eq./kWh
	Abiotic Depletion Potential	ADP	µg Sb eq./kWh
	Human Toxicity Potential	HTP	g DCB eq./kWh
	Abiotic Depletion Potential fossil	ADP fossil	MJ/kWh
	Acidification Potential	AP	mg SO_2 eq./kWh
	Eutrophication Potential	EP	mg PO^{3-}_4 eq./kWh
	Ozone Depletion Potential	ODP	µg R11 eq./kWh
	Photochemical Oxidant Creation Potential	POCP	mg C_2H_4 eq./kWh
	Freshwater Aquatic Ecotoxicity Potential	FAETP	g DCB eq./kWh
	Marine Aquatic Ecotoxicity Potential	MAETP	kg DCB eq./kWh
	Terrestrial Ecotoxicity Potential	TETP	mg DCB eq./kWh
Economic	Levelized Cost of Electricity	LCOE	$/MWh
	Cumulative Investment	Investment	$ bn

6.2.2. Electricity technologies

Eleven power technologies have been considered in this study. The selection of the technologies is associated with the current installed capacity and the future potential in the country as shown in Table 19. Coal, natural gas, oil (diesel), biomass, biogas, run-of-river, reservoir, wind and solar photovoltaics (PV) are power options that currently generate electricity in the country. Whereas, concentrating solar power (CSP) and geothermal are option with significant power potential.

6.2.3. Future scenarios

As a result of the investment optimization model carried out for electricity generation in Chile (Chapter 5), two main scenarios were obtained: BAU (Business as usual) and RE (Renewable energy). BAU scenario includes all the available technologies to shape the power mix by 2050, whereas RE scenario only considers renewable power options. Twelves sub-scenarios were also modelled based on variations in the build rate and the presence or absence of two key technologies, as follows: Since investment limits for new-build capacity were necessary to be established as constraints of the optimization model, options such as solar PV, wind and CSP were set with two different annual new-build capacity limits of 260 MW/yr and 750 MW/yr leading to two groups of scenarios for BAU and two for RE (BAU$_{260}$, BAU$_{750}$, RE$_{260}$, and RE$_{750}$). Additionally, for each of these groups of scenarios three sub-scenarios were developed. ‘No CSP’ consisted of a scenario without considering new-build capacity of CSP, ‘No new hydro’ consisted of no investment in hydropower through the planning horizon where only the current hydropower capacity could contribute to the mix. The rationale behind these technology constraints was to explore the influence of the energy storage provided by reservoirs and molten salts in hydropower and CSP, respectively. The ‘Base’ scenario included both hydropower and CSP.

The installed capacities of each technology by 2050 in all twelve scenarios are shown in Table 26.

Table 26. Technology installed capacity (MW) by future scenario in 2050.

Scenario		Coal	Gas	Oil	Biomass	Biogas	Run-of-river	Reservoir	Wind	PV	CSP	Geothermal
BAU$_{260}$	Base	9876				635	5974	5928	11,741	14,611		1215
	No CSP	9876				635	5974	5928	11,741	14,611		1215
	No new hydro	10,914				783	4054	3768	12,001	14,611	587	2641
BAU$_{750}$	Base	6500				618	5804	5931	12,419	27,702	4831	
	No CSP	10,327				753	6204	5932	12,731	27,010		
	No new hydro	5500				584	4056	3764	12,704	25,952	2423	4852
RE$_{260}$	Base				4000	1073	6418	6212	12,413	15,111	5524	2642
	No CSP				3565	1176	6425	6221	12,426	15,126		5634
	No new hydro				5600	1163	4266	4063	12,396	15,128	7193	4488
RE$_{750}$	Base				4000	449	5632	6092	13,081	25,807	2073	5000
	No CSP				5000	1168	6480	6221	13,443	25,300		4666
	No new hydro				4050	911	4325	4282	12,943	27,341	10,524	4250

6.2.4. Economic and environmental assessment

The environmental and economic assessments of each technology are based on previous work by the authors, with the addition of life cycle assessments for geothermal and CSP technologies. The methods and assumptions are outlined below.

6.2.5. Environmental life cycle assessment

The environmental indicators in this study are the result of LCA modelling detailed in Chapter 3 and 4. This modelling follows the LCA methodology described in the standard ISO 14040 and 14044 [23, 24]. Background inventory data are based on Ecoinvent 2.2 [25], while the modelling is implemented using Gabi 7 LCA software [26]. The life cycle impact assessment methodology used is CML2001 with the 2015 update [27]. The life cycle stages modelled are shown in Figure 45.

Estimating the future technological progress of each individual electricity generation technology would require a large variety of assumptions to be taken, particularly as the technologies in question are at differing stages of maturity and are likely to change at different rates. Consequently, to minimise uncertainty, the data and assumptions used to model the current situation of electricity generation are assumed to remain valid in the future scenarios.

However, as a result of the investment optimization modelling (see Figure 44), the electricity contribution and capacity factors for all the technologies vary across the future scenarios, hence these parameters were taken into account to carry out the LCA of each scenario (see Table 27 and Table 28).

The life cycle inventory of oil, natural gas, coal, biomass, biogas, hydro, wind and solar PV can be found in [8]. Data on CSP and geothermal are not provided in [8] as they are not present in the current Chilean electricity mix. Therefore, geothermal power and CSP have been modelled using life cycle inventory (LCI) data obtained from Ecoinvent and the NEEDS [28] databases respectively. The dataset adopted from Ecoinvent is “electricity production, deep geothermal” and “electricity, solar tower, with salt storage, at power plant, 180 MW, scenario: 2050” is the dataset obtained from NEEDS.

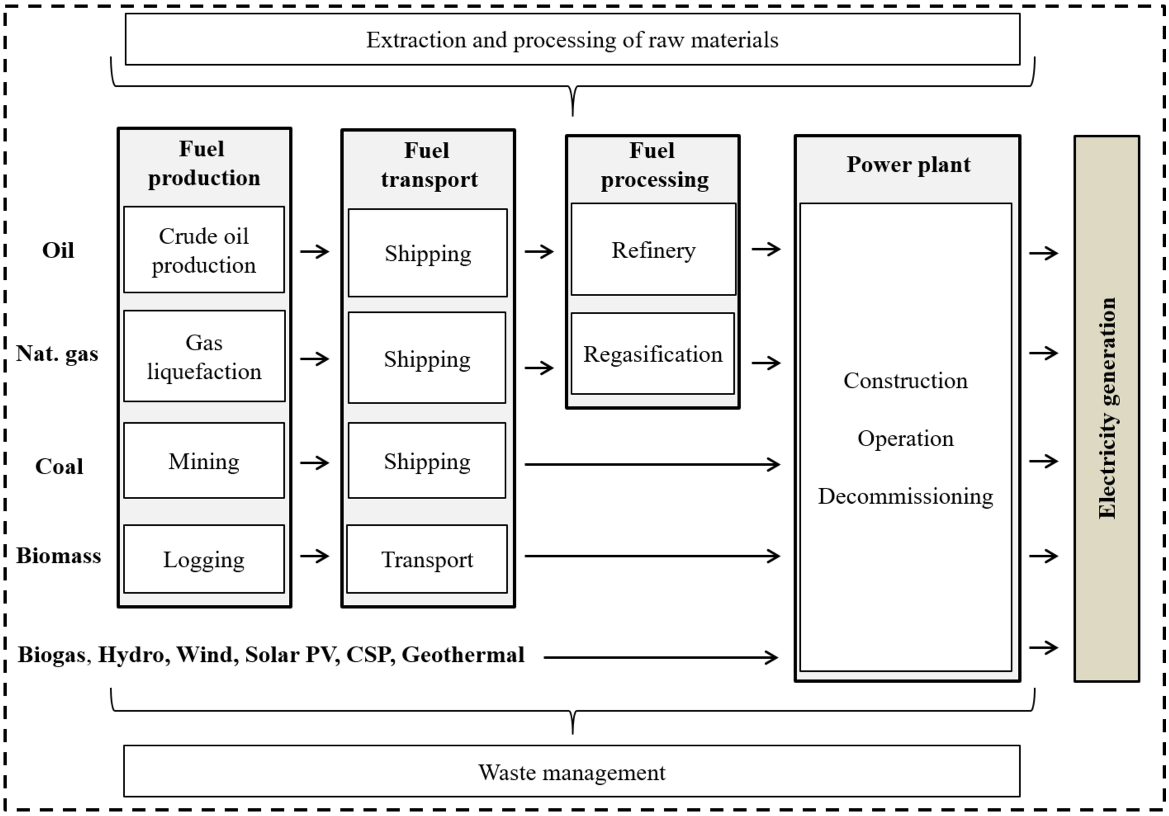


Figure 45. Diagram of life cycle stages considered to assess the environmental impacts of Chilean electricity generation.

Table 27. Technology electricity contribution determined by future scenario.

Scenario		Coal	Gas	Oil	Biomass	Biogas	Run-of-river	Reservoir	Wind	PV	CSP	Geothermal
Current situation		41%	15%	4%	4%		15%	19%	2%	1%		
BAU$_{260}$	Base	19%				2%	20%	14%	21%	20%		4%
	No CSP	19%				2%	20%	14%	21%	20%		4%
	No new hydro	23%				3%	13%	9%	21%	20%	1%	10%
BAU$_{750}$	Base	10%				2%	15%	14%	17%	33%	9%	
	No CSP	17%				2%	16%	14%	17%	33%		
	No new hydro	9%				2%	11%	9%	18%	32%	5%	14%
RE$_{260}$	Base				1%	4%	21%	15%	20%	20%	11%	9%
	No CSP				1%	4%	21%	15%	20%	20%		18%
	No new hydro				1%	5%	14%	10%	22%	20%	14%	15%
RE$_{750}$	Base				1%	1%	15%	14%	18%	32%	4%	14%
	No CSP				1%	4%	17%	15%	18%	32%		13%
	No new hydro				1%	2%	11%	6%	17%	33%	20%	9%

Table 28. Technology capacity factor determined by future scenario

Scenario		Coal	Gas	Oil	Biomass	Biogas	Run-of-river	Reservoir	Wind	PV	CSP	Geothermal
Current situation		79%	41%	9%	67%	62%	60%	43%	27%	25%		
BAU$_{260}$	Base	36%				70%	60%	43%	32%	25%		67%
	No CSP	36%				70%	60%	43%	32%	25%		67%
	No new hydro	38%				75%	60%	43%	32%	25%	35%	69%
BAU$_{750}$	Base	28%				55%	47%	43%	25%	22%	35%	
	No CSP	31%				55%	48%	43%	25%	22%		
	No new hydro	30%				58%	49%	43%	26%	23%	35%	54%
RE$_{260}$	Base				3%	66%	60%	43%	30%	25%	35%	59%
	No CSP				5%	66%	60%	43%	30%	25%		60%
	No new hydro				5%	71%	60%	43%	32%	25%	35%	60%
RE$_{750}$	Base				4%	57%	49%	43%	25%	23%	35%	53%
	No CSP				5%	55%	49%	43%	25%	23%		51%
	No new hydro				3%	48%	48%	26%	24%	22%	35%	40%

6.2.6. Economic assessment

The economic assessment has been carried out together with the investment optimization that led to obtain the future scenarios (see Chapter 5). Levelized cost of electricity (LCOE) and cumulative investment are the two economic indicators estimated and are reported for each scenario in Table 31.

6.2.7. Identification of desirable scenarios

MCDA methods address problems that involve multiple criteria based on preferences or weights for each criterion. For that reason, MCDA had been used extensively in relation to sustainable energy [29]. Generally, the first step in MCDA involves identification of options or scenarios to be considered and indicators which will be used as decision criteria. This is followed up by defining preferences for different decision criteria by assigning weights of importance. The indicators are then aggregated into a single score based on the weights of importance so that the alternatives or scenario can be compared more easily, thus facilitating identification of the most desirable option [30, 31].

Multi-criteria decision analysis (MCDA) has been implemented to identify desirable scenarios based on the set of indicators estimated for each future scenario. Derringer's desirability function has been implemented in this study [32, 33]; for the calculation method, see Chapter 1. An overall desirability function is determined for each scenario as the geometric average of individual desirability functions and weights. The individual desirability functions are based on normalization of indicators in a range from 0 to 1, where 0 represents least desirable indicator value and 1, most desirable. The normalization (individual desirability function) is defined according to what is expected: lower, higher or a target indicator value is best. This gives transparency and simplicity to this model, and therefore, it has been included in this research as a MCDA tool. Weightings can be chosen to express the importance of indicators.

Since the overall desirability varies significantly depending on the weight allocated to each indicator, four different weighting regimes are modelled assigning different importance to the indicators throughout the weightings. The specific weights under each of the four weighting regimes are given in Table 29, while the four regimes are described as follows:

- **Weighting regime 1. Equal aspects:** the environmental and economic aspects have 50% importance each. The contribution of each indicator within the two aspects is equal (50%/11 ≈ 4.5% each environmental indicator weight, and 50%/2 = 25% each economic indicator weight).
- **Weighting regime 2. Equal aspects + GWP + LCOE:** as for regime 1, but with greater weighting placed on one economic indicator and on one environmental indicator reflecting their prominence in policy. Consequently, the weight of GWP (16.7%) is larger than the rest of environmental indicators (3.3%), as is the weight of LCOE (33.3%) compared to the cumulative investment cost (16.7%).
- **Weighting regime 3. Environment + GWP + LCOE:** the environmental aspect (85%) has greater importance than the economic aspect (15%). The weight of GWP (28.3%) is larger than the rest of environmental indicators (5.7%), as is the weight of LCOE (10%) compared to the cumulative investment cost (5%).
- **Weighting regime 4. Economic + GWP + LCOE:** the economic aspect (85%) has greater importance than environmental aspect (15%). The weight of GWP (5%) is larger than the rest of environmental indicators (1%), as is the weight of LCOE (56.7%) compared to the cumulative investment cost (28.3%).

Table 29. Indicator weightings for each of the four situations to undertake Multi-criteria decision analysis.

Aspects	Indicators	1. Equal aspects		2. Equal aspects + GWP + LCOE		3. Environment + GWP + LCOE		4. Economic + GWP + LCOE	
		Aspect weighting	Indicator weighting	Aspect weighting	Indicator weighting	Aspect weighting	Indicator weighting	Aspect weighting	Indicator weighting
Environment	GWP	50%	4.5%	50%	16.7%	85%	28.3%	15%	5.0%
	ADP		4.5%		3.3%		5.7%		1.0%
	HTP		4.5%		3.3%		5.7%		1.0%
	ADP fossil		4.5%		3.3%		5.7%		1.0%
	AP		4.5%		3.3%		5.7%		1.0%
	EP		4.5%		3.3%		5.7%		1.0%
	ODP		4.5%		3.3%		5.7%		1.0%
	POCP		4.5%		3.3%		5.7%		1.0%
	FAETP		4.5%		3.3%		5.7%		1.0%
	MAETP		4.5%		3.3%		5.7%		1.0%
	TETP		4.5%		3.3%		5.7%		1.0%
Economic	LCOE	50%	25.0%	50%	33.3%	15%	10.0%	85%	56.7%
	Investment		25.0%		16.7%		5.0%		28.3%

6.2.8. Data quality assessment

To assess the quality of the data used in this research a data quality assessment has been carried out. The assessment follows the pedigree matrix method as described in chapter 1. The pedigree matrix establishes five criteria for the data utilized in the study. On each criterion, the data is ranked from 1 (good quality) to 5 (poor quality). Where the criteria are reliability, completeness, temporal correlation, geographical correlation and technological correlation.

The data have been categorized according to the main purpose for which they were collected. The selected categories are closely related with the life cycle stages and economic indicators. The categories are as follows: fossil fuel production, fossil fuel composition, biomass and biogas production, fuel transport, fuel processing (crude oil refinery and gas regasification), power plants operation (technical parameters), power plants operation (emissions), power plants construction (renewables and fossil fuel), power plants decommissioning (landfill and recycling), capital cost (current costs and future estimations), fuel costs (current costs and future estimations), and fixed, variable and carbon costs.

The data have been ranked for each data category according to the criteria indicated above. The overall data quality score is the result of the summation of each criterion score and the average of the category as shown in Table 32. The overall data quality score ranges from 5 to 25 as follows:

High quality: 5 -11

Medium quality: 12 – 18

Low quality: 19-25

6.3. RESULTS AND DISCUSSION

Table 31 summarises the environmental and economic impacts for the future scenarios. In section 6.3.1, the environmental impacts are discussed; in section 6.3.2 the economic indicators are compared; and in section 6.3.3, the results of the multi-criteria decision analysis are presented to identify the most desirable scenarios.

6.3.1. Environmental impacts

In Figure 46 the eleven environmental impacts are shown for each scenario and for the current situation. In Table 30 are shown the annual environmental impacts for current situation and the scenarios.

6.3.1.1. Impacts relative to current situation

It can be seen across all the impacts that the current situation has the highest impacts with the exception of abiotic depletion potential (ADP). According to [8], the high power contribution of coal, natural gas and oil power in the current electricity system, and the higher impact contribution that these power options have in comparison to renewable technologies explain these findings. In contrast, renewables tend to require greater use of raw materials per unit of electricity, leading to higher ADP. This is particularly true of solar PV, explaining its dominance of the result.

As seen in Table 27, the coal contribution in the current situation is 41%, while its highest contribution in the future scenarios is 23% (BAU_{260}, ‘No new hydro’) due to it being gradually outcompeted on costs by the renewables. The variation of coal across the scenarios is a key predictor of environmental impacts due to the high emissions of coal power.

To compare the current situation with the future scenarios, we are going to group scenarios with similar impact performance in order to avoid analysing one by one and the estimator used is the “impact reduction” that represents one minus the quotient of the division between the scenario’s impact and current situation impact.

For example, the impact reduction of the BAU_{260} scenarios and BAU_{750} ‘No CSP’ is, on average, 51% ± 12% across all impacts except ADP. The same estimator for BAU_{750} ‘Base’ and BAU_{750} ‘No new hydro’ scenarios is 68% ± 10%. While for all RE scenarios the reduction average regarding current situation is 87% ± 10%.

The impacts reduction average of BAU_{260} scenarios and BAU_{750} 'No CSP' regarding the current situation for global warming potential (GWP), abiotic depletion potential of fossil fuel (ADP fossil), ozone depletion potential (ODP) and photochemical oxidant creation potential (POCP) are from 63% to 55%. This is explained because there are power options a part of coal in current electricity mix that contributed significantly to these impacts and they are not present in the mentioned BAU scenarios such as natural gas, oil and biomass power.

Although the impact reduction average of RE scenarios regarding the current situation is 87% for all the impacts, there are impacts whose impact reduction average are higher than the average of all impacts, such as GWP (95% reduction among RE scenarios), ADP fossil (94% reduction among RE scenarios), acidification potential (AP) (96% reduction among RE scenarios), eutrophication potential (EP) (94% reduction among RE scenarios) and marine aquatic ecotoxicity potential (MAETP) (94% reduction among RE scenarios). This is due to the environmental burdens that contribute to those impacts in the current situation are barely present in renewable power options. Conversely, there are impacts among RE scenarios whose reduction regarding the current situation are lower than the reduction reached in GWP, ADP fossil, AP, EP and MAETP, like terrestrial ecotoxicity potential (TETP) where the average impact reduction among RE scenarios is 64%. Similarly, ODP has an impact reduction among RE scenarios regarding current situation of 74%. Freshwater aquatic ecotoxicity potential (FAETP) has also a low reduction of 84%. In these cases, the environmental burdens of some renewable technologies are also significant that lead to maintain high impacts even though fossil-based power options are not present. This is explained in more detail bellow.

ADP is the only impact that increases regarding the current situation. From Figure 46 (b) can be seen that solar photovoltaic power is the main and more significant technology that contributes to ADP followed by geothermal and wind power. BAU_{260} and RE_{260} scenarios have together an impact average that is 8 times greater than current situation. Whereas, BAU_{750} and RE_{750} scenarios have an impact average 13 times larger than current situation.

BAU scenarios have 7 times higher of GWP, ADP fossil, AP, EP, and MAETP than the same impacts in RE scenarios, while the rest of the impacts are three times larger. Coal power is the main technology that contribute to this difference between BAU and RE, since it is present in BAU scenarios.

6.3.1.2. Influence of capacity factor

The results suggest that electricity contribution is a parameter that affects to the impacts significantly more than capacity factor. The capacity factors of the technologies vary across BAU and RE scenarios. Most of the impacts are caused by coal power in both, in current situation and BAU scenarios whose impacts are mostly originated in the operation of coal power plants or coal production (fuel production) stage instead of plant construction stage where capacity factor used to be a significant parameter. Since construction stage is the most important stage for renewable options with exception of biogas and biomass, the capacity factor is also a parameter whose variation does affect the impacts for RE scenarios. Hydropower run-of-river is an option with high variation of capacity factor between the scenarios RE_{260} and RE_{750} from 60% to 49%, but its environmental impacts are neglected due to the low environmental burden attributed to this option. Geothermal has also a reduction of capacity factor between the scenarios RE_{260} and RE_{750} from 60% in RE_{260} to a range of 53%-40% among RE_{750} scenarios but considering that geothermal power contribution has also reduced its power contribution average from 14% in RE_{260} to 12% in RE_{750}, this cancels the effect of the reduction of capacity factor over impacts such as ODP and TETP. Since solar PV is an option that causes high environmental impacts among renewables for impacts such as HTP, ADP, ODP, FAETP, MAETP and TETP and its variation of capacity factor is neglected, the increase of electricity contribution between scenarios RE_{260} and RE_{750} from 20% to 32% is the main responsible of the impacts rise between both scenarios.

6.3.1.3. Impacts in renewable scenarios

6.3.1.3.1. Impacts among scenarios

As indicated above, ADP is an impact that is highly correlated with the solar PV contribution. The depletion of natural resources caused by this power option is higher than the other power options analysed in this study. When it comes to compare the renewable scenarios, the results show clear differences of impact values between scenarios RE_{260} and RE_{750} across the impacts. In all the impacts, RE_{750} scenarios have higher impacts caused by the lower power contribution of hydropower run-of-river and wind power and higher solar PV contribution. RE_{750} scenarios have been created assuming annual investments of 750 MW for solar PV, wind and CSP. Since solar PV has lower costs, this option reached high contribution. Due to the investment costs of run-of-river and wind by 2050 would be slightly higher than solar PV, the high investment of solar PV causes the dispatch of run-of-river and wind to be lower and therefore it lead to reach lower contribution of hydropower run-of-river and wind power. GWP, ADP fossil, AP, EP and MAETP are impacts that have reached very low values in both, RE_{260} and RE_{750} scenarios. HTP, ODP, POCP, FAETP and TETP are impacts that still remain high across RE scenarios.

6.3.1.3.2. Significant technologies, impacts and burdens

Reaching renewables scenarios does not entail necessarily low impacts. As observed for HTP, ODP, POCP, FAETP and TETP, this impacts still remain high across RE scenarios.

Solar PV, geothermal and biomass are power options in RE scenarios that their contributions to HTP (52%, 19% and 5% respectively) are larger than their individual power contribution (26%, 13% and 1% respectively). Arsenic, chromium (+VI) and selenium are emitted to air and water bodies during photovoltaic panel manufacturing while benzene is emitted to air during well drilling for geothermal and polycyclic aromatic hydrocarbon (PAH) is emitted to air during combustion of biomass.

There are four power options in the RE scenarios that their contributions to ODP are higher than their power contribution. These options are solar PV, geothermal, biogas, and biomass with ODP contributions of 61%, 26%, 4% and 2% respectively, while their power contributions are 26%, 13%, 3% and 1% respectively. Solar PV and geothermal power have high contributions to ODP since they show larger contribution of electricity as well. Release of chlorodifluoromethane (HCFC-22) occurs during production of fluorocarbon film for PV panel manufacturing and halon (1211) is a burden of natural gas and diesel when burned in compressor for well drilling.

Similarly, to ODP, solar PV, geothermal, biogas, and biomass contribute greater to POCP than their power contribution. The POCP contribution for solar PV, geothermal, biogas and biomass are 37%, 22%, 7% and 27% respectively. In this case, it can be highlighted that biomass POCP contribution is 27 times higher than its power contribution. This is due to non-methane volatile organic compounds (NMVOC) emitted by machinery during crop and logging of biomass. The low calorific values and density of the biomass and the low efficiency of biomass power plants increase the effect of the emissions resulting in a high POCP per unit of electricity generated of biomass power. Geothermal power impact contribution is twice its power generation. This power option has burdens associated with steel use and fossil fuel (natural gas or diesel) combustion in compressors during deep well drilling. Carbon monoxide (CO), nitrogen oxides (NO_x), sulphur dioxide (SO_2) and NMVOC are the main emissions.

For FAETP, Solar PV and wind are the only two power options with higher impact contribution than their power contribution. Solar PV FAETP contribution is 24% whereas wind power FAETP contribution is 24%. Copper and beryllium are the main elements emitted to water bodies for both power options.

Finally, Solar PV, wind and geothermal show contributions to TETP of 32%, 29%, and 25% respectively and have lower electricity contribution than their TETP contribution in the RE scenarios. For these three options, chromium and mercury are the main elements released to air as burden of steel production.

6.3.1.4. Effects of the lacks of hydropower and CSP

According to the environmental impacts performance of each sub-scenario ('Base', 'No CSP' and 'No new hydro'), there is a clear trend that the 'Base' scenarios show the lowest impact across each top-level scenario with the exception of ADP where the differences among sub-scenarios are not significant. The 'Base' scenario of RE_{260} shows to have the third lowest ADP while exhibits the best performance across all other impacts. The RE_{260} 'Base' scenario has a combination of aspects that allows having the best performance across all scenarios. The aspects can be summarised as follow: i) since it is a renewable scenarios, it lacks of fossil fuels that use to contribute highly in many impacts such as GWP, HTP, ADP fossil, AP, EP, POCP, FAETP and MAETP; ii) it has higher electricity contribution of hydropower options which impacts contributions are the lowest among other power option considered in this study; iii) it has a lower electricity contribution of solar PV whose contribution is large than other power option for ADP, HTP, ODP, and the ecotoxicities; and iv) it has a lower electricity contribution geothermal power that has also high contribution to impacts such as HTP, ODP, POCP, and TETP.

6.3.1.5. Annual impacts

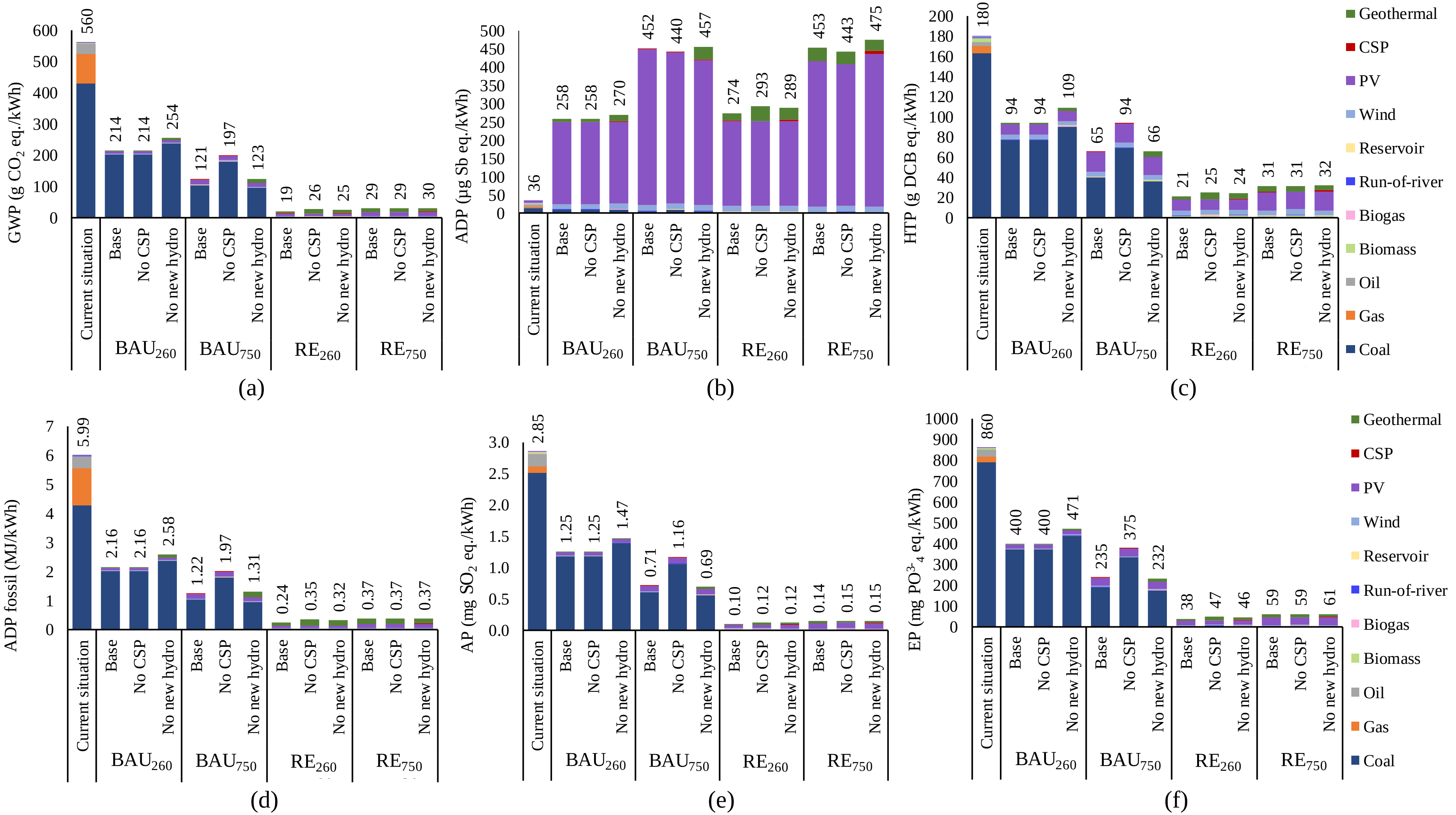
Table 30 contains the annual environmental impacts of each scenario and the current situation. The current electricity generated has been 75 TWh and the expected power production by 2050 is 160 TWh whose estimated growth between the period is 113%.

From the analysis of the results, it can be highlighted the significant increase of ADP from current situation (2.5 t Sb eq.) and future scenarios. BAU_{260} and RE_{260} have in average a depletion of 43.8 t Sb eq., and BAU_{750} and RE_{750} show the highest depletion of 72.5 t Sb eq.. These figures exhibit an annual depletion of 17 times current impact for BAU_{260} and RE_{260} and 29 times for BAU_{750} and RE_{750}.

GWP is one of the impacts that have significant reduction regarding current situation. In BAU the reduction is about 24% from 39.4 Mt CO2 eq. to 30 Mt CO2 eq. and in RE the reduction is more marked of 89% entailing reducing to 4.2 Mt CO2 eq. Other impacts that have significant reduction are ADP fossil, AP, EP and POCP with reductions of 28%, 13%, 7% and 20% for BAU respectively and 87%, 90%, 86% and 78% for RE respectively.

A different situation occurs with MAETP that BAU impact increases by 1% regarding current situation but for RE the reduction is significative of 87%. ODP shows lower reduction in comparison to mentioned impacts where it reduces only 2% in BAU with regards to current situation and 43% in RE.

TETP is the second impact after ADP that increases significantly regarding current situation. However, in this case the rise only occurs in BAU by 43% while RE show a low reduction of 18%. Other impacts that have impact increase in BAU are HTP and FAETP by 10% and 22% respectively, and a reduction of 65% and 63% in RE respectively.



GWP (g CO2 eq./kWh)
560
214
214
254
121
197
123
19
26
25
29
29
30
ADP (μg Sb eq./kWh)
36
258
258
270
452
440
457
274
293
289
453
443
475
HTP (g DCB eq./kWh)
180
94
94
109
65
94
66
21
25
24
31
31
32
ADP fossil (MJ/kWh)
5.99
2.16
2.16
2.58
1.22
1.97
1.31
0.24
0.35
0.32
0.37
0.37
0.37
AP (mg SO2 eq./kWh)
2.85
1.25
1.25
1.47
0.71
1.16
0.69
0.10
0.12
0.12
0.14
0.15
0.15
EP (mg PO3-4 eq./kWh)
860
400
400
471
235
375
232
38
47
46
59
59
61
Current situation
Base
No CSP
No new hydro
BAU260
BAU750
RE260
RE750
Geothermal
CSP
PV
Wind
Reservoir
Run-of-river
Biogas
Biomass
Oil
Gas
Coal
(a)
(b)
(c)
(d)
(e)
(f)

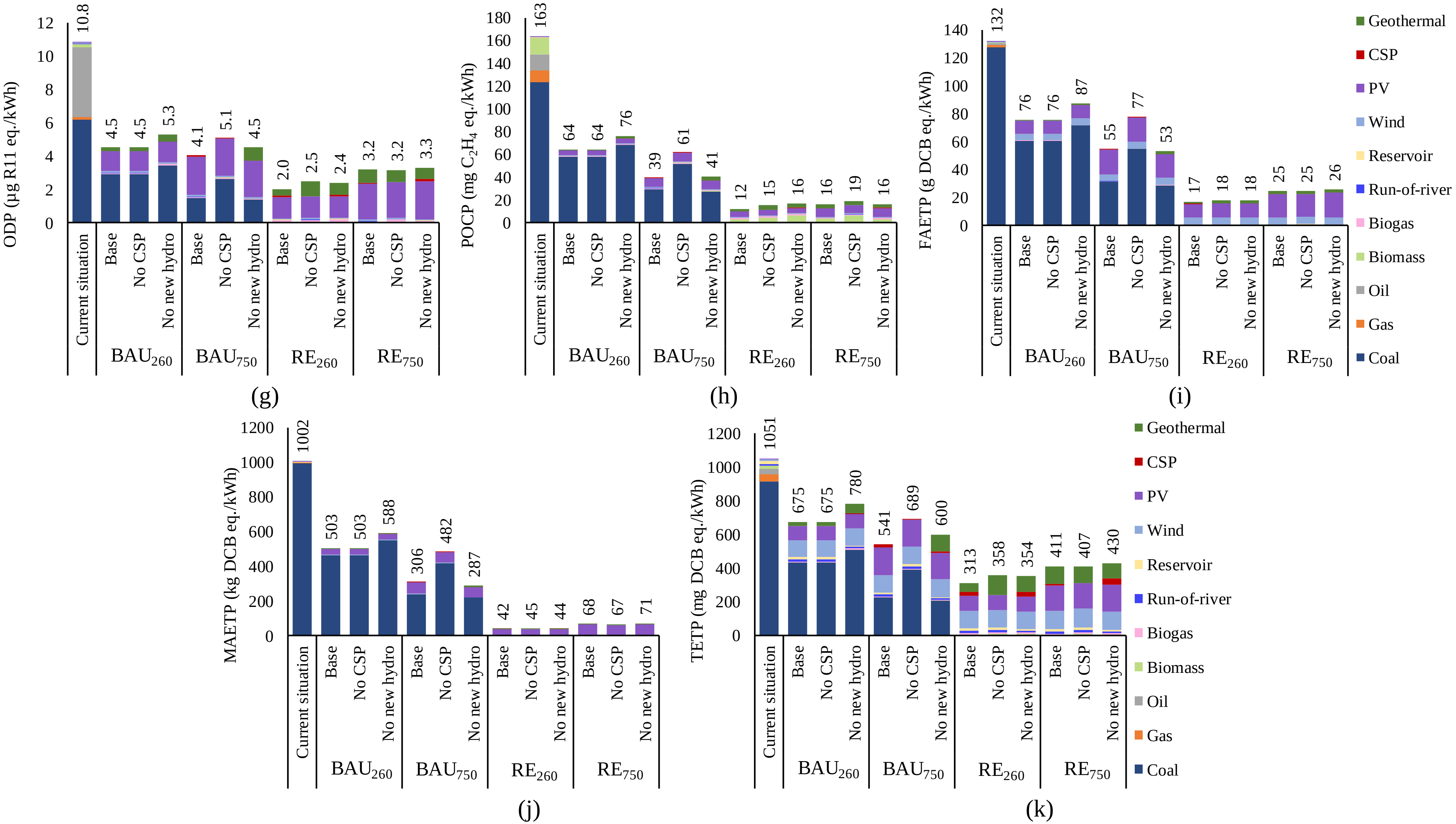


Figure 46. Life cycle environmental impacts of the current situation and the future scenarios.

Table 30. Annual environmental impacts of current situation and by scenarios.

Scenario		GWP ($Mt\ CO_2$ eq.)	ADP elements (t Sb eq.)	HTP (Mt DCB eq.)	ADP fossil (PJ)	AP (kt SO_2 eq.)	EP (kt PO^{3-}_4 eq.)	ODP (kg R11 eq.)	POCP (kt C_2H_4 eq.)	FAETP (Mt DCB eq.)	MAETP (Gt DCB eq.)	TETP (kt DCB eq.)
Current situation		39.4	2.5	12.7	422	200	60.6	763	11.5	9.3	70.6	74
BAU_{260}	Base	34.3	41.3	15.0	345	199	63.9	722	10.3	12.1	80.5	108
	No CSP	34.3	41.3	15.0	345	199	63.9	722	10.3	12.1	80.5	108
	No new hydro	40.7	43.2	17.5	412	235	75.4	845	12.2	14.0	94.2	125
BAU_{750}	Base	19.4	72.3	10.4	195	114	37.6	648	6.3	8.8	49.0	87
	No CSP	31.6	70.5	15.0	316	185	60.0	809	9.8	12.4	77.2	110
	No new hydro	19.7	73.0	10.6	209	110	37.1	723	6.5	8.5	46.0	96
RE_{260}	Base	3.1	43.9	3.4	38	16	6.1	326	1.9	2.7	6.7	50
	No CSP	4.1	46.8	3.9	55	19	7.6	396	2.5	2.9	7.1	57
	No new hydro	4.0	46.2	3.9	51	19	7.4	384	2.6	2.9	7.0	57
RE_{750}	Base	4.7	72.5	5.0	60	22	9.4	512	2.6	4.0	11.0	66
	No CSP	4.6	70.9	5.0	59	24	9.5	508	3.1	3.9	10.8	65
	No new hydro	4.8	76.0	5.1	59	24	9.7	531	2.6	4.1	11.4	69

6.3.2. Economic indicators

The results show that both levelized cost of electricity (LCOE) (Figure 47) and cumulative investment cost (Figure 48) are lower for the BAU scenarios than the RE scenarios. The LCOE average of each top-level scenario in \$/MWh are 74.7, 80.3, 84.9 and 92.1 for BAU_{260}, BAU_{750}, RE_{260} and RE_{750} respectively. The LCOE of RE_{260} is the lowest of the renewables scenarios, while BAU_{260} has the lowest LCOE of all scenarios. The same trend can be seen for cumulative investment, the investment averages are \$125 bn, \$145 bn, \$158 bn and \$163 bn for BAU_{260}, BAU_{750}, RE_{260} and RE_{750} respectively.

Therefore, for either LCOE or investment, BAU_{260} has the lowest averages while RE_{750} has the highest. Among the sub-scenarios (‘Base’, ‘No CSP’ and ‘No new hydro’) of each top-level scenario (BAU_{260}, BAU_{750}, RE_{260} and RE_{750}), the ‘No new hydro’ constraint results in higher costs than the ‘Base’ or ‘No CSP’ equivalents. On average across all scenarios, preventing the system from installing new hydro capacity causes a 14% higher LCOE and 11% larger investment.

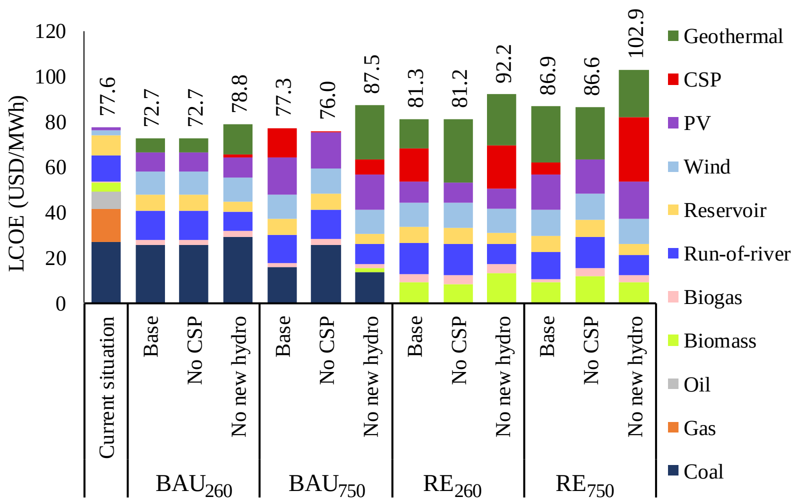


Figure 47. Levelized costs of electricity (LCOE) of current situation and future scenarios.

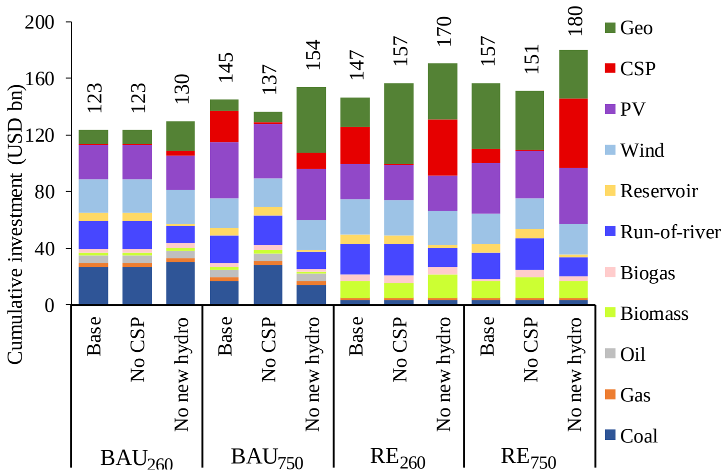


Figure 48. Cumulative investment costs of future scenarios.

Table 31. Summary of environmental and economic indicators for each future scenario by 2050.

Aspects	Indicators	Unit	Current situation	BAU_{260} Base	BAU_{260} No CSP	BAU_{260} No new hydro	BAU_{750} Base	BAU_{750} No CSP	BAU_{750} No new hydro	RE_{260} Base	RE_{260} No CSP	RE_{260} No new hydro	RE_{750} Base	RE_{750} No CSP	RE_{750} No new hydro
Environment	GWP	g CO_2 eq./kWh	560	214	214	254	121	197	123	19	26	25	29	29	30
	ADP	µg Sb eq./kWh	36	258	258	270	452	440	457	274	293	289	453	443	475
	HTP	g DCB eq./kWh	180	94	94	109	65	94	66	21	25	24	31	31	32
	ADP fossil	MJ/kWh	5.99	2.16	2.16	2.58	1.22	1.97	1.31	0.24	0.35	0.32	0.37	0.37	0.37
	AP	mg SO_2 eq./kWh	2846	1246	1246	1470	713	1159	688	98	117	118	139	147	147
	EP	mg PO^{3-}_4 eq./kWh	860	400	400	471	235	375	232	38	47	46	59	59	61
	ODP	µg R11 eq./kWh	10.8	4.5	4.5	5.3	4.1	5.1	4.5	2.0	2.5	2.4	3.2	3.2	3.3
	POCP	mg C_2H_4 eq./kWh	163	64	64	76	39	61	41	12	15	16	16	19	16
	FAETP	g DCB eq./kWh	132	76	76	87	55	77	53	17	18	18	25	25	26
	MAETP	kg DCB eq./kWh	1002	503	503	588	306	482	287	42	45	44	68	67	71
	TETP	mg DCB eq./kWh	1051	675	675	780	541	689	600	313	358	354	411	407	430
Economic	LCOE	USD/MWh	77.6	72.7	72.7	78.8	77.3	76.0	87.5	81.3	81.2	92.2	86.9	86.6	102.9
	Investment	USD bn	-	123	123	130	145	137	154	147	157	170	157	151	180

Legend: red indicates the highest, amber medium and green the lowest indicator's values.

6.3.3. Identification of desirable scenarios

6.3.3.1. Weighting regimes

As indicated in section 6.2.7, four different weighting regimes have been modelled as part of the multi-criteria decision analysis. Due to overall desirability function is estimated from geometric average of individual desirability functions as shown in equation 29 (adapted from equation 6 in Chapter 1) for weights (w_i) ranging 0 – 1 and the sum of all weights must be equal to 1, to identify the desirability reduction attributed to economic or environmental aspects, logarithm to base 10 of individual desirability needs to be determined as stated in equation 30. Therefore, overall desirability of each scenario under the four regimes are shown in Figure 49 to Figure 52, where the overall desirability ranges from zero to one and the highest value represents the most desirable scenario for each regime. While in each figure the negatives values represent desirability reductions associated with either economic or environmental aspects.

$$D_j = \prod_{i=1}^{m} \left(d_{j,i}\right)^{w_i}, \qquad i \in \{1,2,\dots,m\} \qquad \text{Eq. 29}$$

j : subscript for scenario

i : subscript for indicator

$d_{j,i}$: individual desirability function of a j scenario regarding an i indicator

D_j : overall desirability of a scenario

w_i : weights assigned to an i indicator in a weighting regime

m : total numbers of indicators

$$Log_{10}(D_j) = \sum_{i=economic} w_i \cdot Log_{10}\left(d_{j,i}\right) + \sum_{i=environment} w_i \cdot Log_{10}(d_{j,i}) \qquad \text{Eq. 30}$$

Figure 49 displays results of regime 1. Weights has been assigned to indicators evenly through the aspects. Environmental and economic aspects have 50% importance each. It can be seen all future scenarios are more desirable than the current situation with exception of RE_{750} 'No new hydro'. RE_{260} 'Base' is ranked best with an overall desirability 0.58 followed by BAU_{260} 'Base' and 'No CSP' with 0.57. By comparison, the current situation scores 0.04 which is only beaten by RE_{750} 'No new hydro' with 0.02. The worst option among BAU scenarios is BAU_{750} 'No new hydro' with 0.4. A part of RE_{750} 'No new hydro' in renewables scenarios, RE_{260} 'No new hydro' has a lower desirability (0.36) than BAU_{750} 'No new hydro'. Current situation performs the worst option with regards of environmental aspect while RE_{750} 'No new hydro' has the worst economic aspect.

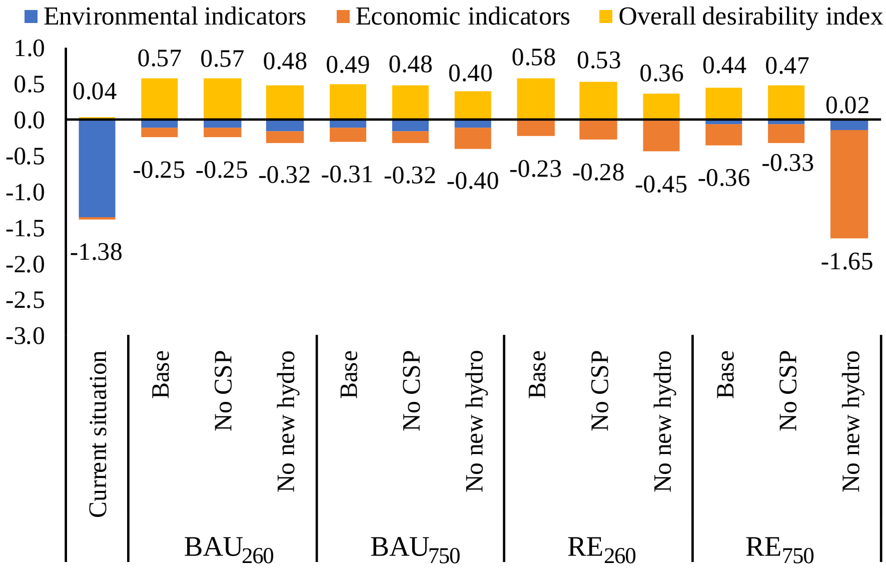


Figure 49. Overall desirability of scenarios based on weighting regime 1 and desirability reducing aspects. [Due to overall desirability function is estimated from geometric average of individual desirability functions, to display the effects of environmental and economic aspects, logarithm to base 10 of individual desirability is determined with relevant weightings].

In Figure 50 is shown the results of the weighting regime 2 that consists in allocating 50% importance to each aspect. In this case like in the next two weighting regimes, GWP has higher importance in environmental aspect while LCOE has higher importance than cumulative investment to reflecting their prominence in policy (Table 29). In this case the situation remains similar to the regime 1, but RE_{260} 'Base' has increased the overall desirability from 0.58 to 0.66, followed by BAU_{260} 'Base' and 'No CSP' with three one-hundredths of difference (0.63).

In Figure 51, the results of the regime 3 is displayed. In this case environmental aspect has 85% of importance than economic with 15%. In this case is more notorious the differences, for example, RE_{260} 'Base' still has the highest desirability 0.85, while in BAU scenarios BAU_{260} 'Base' has the largest desirability among BAU scenarios (0.6). Also, current situation becomes the worst option with near zero desirability and RE_{750} 'No new hydro' is the second worst option with a desirability of 0.23. All the other renewables scenarios perform better desirability than all BAU scenarios. Mostly because of economic aspects, renewables scenarios have seen reduced their desirability, but in a low rate where most of renewables scenarios range from 0.71 to 0.85, while BAU scenario range from 0.52 to 0.6 driven by environmental aspects.

Figure 52 has the results of regime 4 which consisted on provide to economic aspect 85% weight and consequently environmental aspects has 15% of importance. RE_{750} 'No new hydro' has the lowest desirability near zero, followed by RE_{260} 'No new hydro' with 0.24.

Current situation possesses the third worst performance with a desirability of 0.34 and followed by BAU_{750} 'No new hydro' (0.37). Then the rest of BAU scenarios are between 0.54 and 0.67. BAU260 'Base' and 'No CSP' have the best desirability (0.67) while RE260 'Base' has the highest desirability for renewables. Current situation is the unique whose reduction is mostly attributed to environmental aspect.

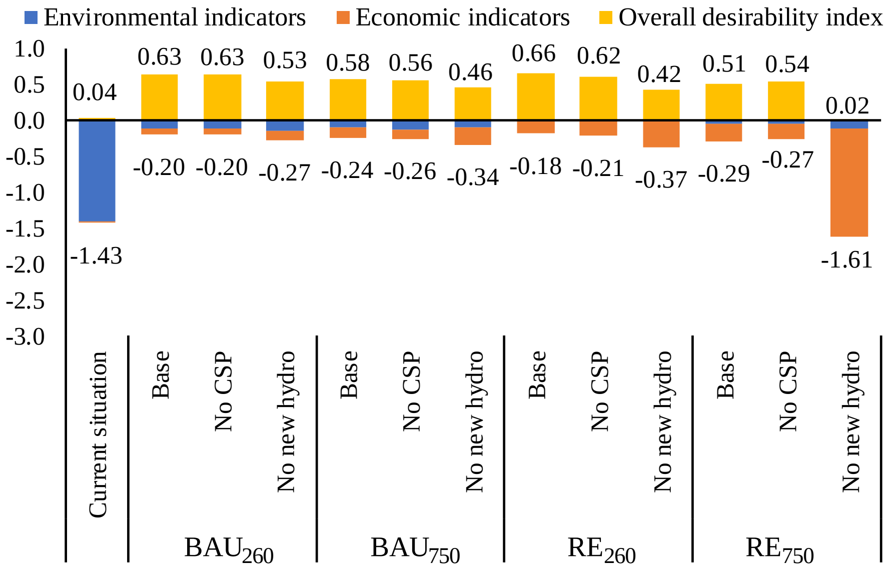


Figure 50. Overall desirability of scenarios based on weighting regime 2 and desirability reducing aspects. This weighting regime shows preference to economic indicators

[Due to overall desirability function is estimated from geometric average of individual desirability functions, to display the effects of environmental and economic aspects, logarithm to base 10 of individual desirability is determined with relevant weightings].

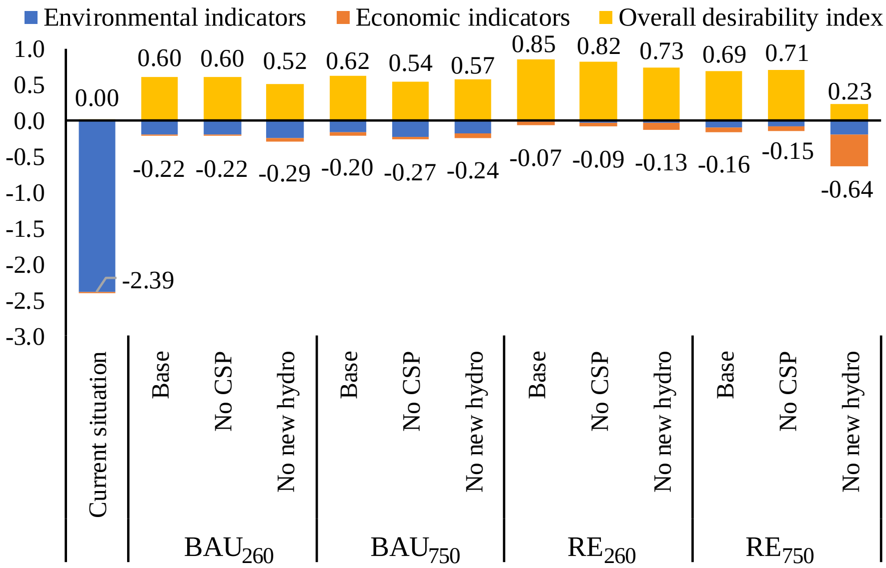


Figure 51. Overall desirability of scenarios based on weighting regime 3 and desirability reducing aspects. This weighting regime shows preference to environmental indicators

[Due to overall desirability function is estimated from geometric average of individual desirability functions, to display the effects of environmental and economic aspects, logarithm to base 10 of individual desirability is determined with relevant weightings].

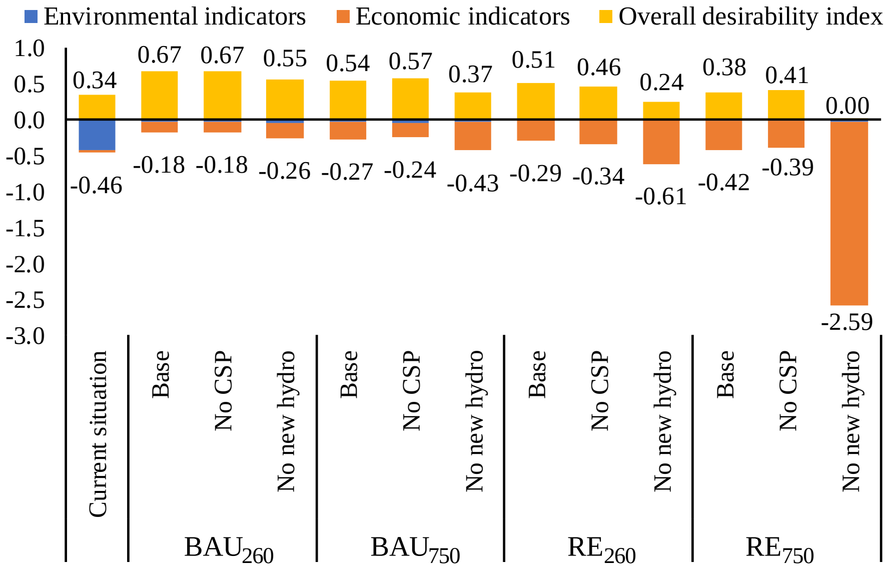


Figure 52. Overall desirability of scenarios based on weighting regime 4 and desirability reducing aspects. This weighting regime shows preference to economic indicators.

[Due to overall desirability function is estimated from geometric average of individual desirability functions, to display the effects of environmental and economic aspects, logarithm to base 10 of individual desirability is determined with relevant weightings].

6.3.3.2. Overall desirability of scenarios

It can be seen for three (1, 2, and 3) out four regimes, RE_{260} 'Base' has performed the highest desirability what confers to be the most desirable scenario. BAU_{260} 'Base' and 'No CSP' become the second most desirable option since it has in two regimes the second highest desirability (1 and 2) and in the regime 4, the highest one (0.67).

RE_{750} 'No hydro' has the worst performance in three regimes (1, 2 and 4) while in regime 3 has the second lowest desirability. The current situation has been considered the second worst mix because in two regimes (1 and 2) it has had the second worst performance and in the regime 3, it performed the worst desirability. All the scenarios with 'No new hydro' in general performed low desirability driven by economic aspects, where RE_{750} 'No new hydro' possess the lowest desirability. Current situation has the second lowest desirability caused by its low environmental performance.

6.3.4. Data quality

As described in section 6.2.8, the data have been categorized and ranked according to five criteria. From the Table 32 is observed that the overall data quality is in the limit between high quality data and medium quality. The temporal correlation is the criterion with a high score across the data categories. That is because, most of the collected data represent information generated in the year analysed (2014) or few years before. When it comes to consider the data categories, “Power plant operation (emissions)” is the category with the best data quality followed by “Fossil fuel composition” and “Power plant operation (technical parameters)”. These data represent information of emission of CO_2, NOx and SO_2 obtained from each coal and oil power plant with a high time-resolution. While fuel composition certificates of each coal power plant were also collected. These data were provided by the Chilean environmental agency. In the case of power plant operation, technical specifications of each power plant in the Chilean electricity system are provided by the National Energy agency with hourly, daily and monthly resolution depending on the kind of parameter to require. On the contrary, “Power plant decommissioning (landfill and recycling)” was information not available in Chile, therefore, it has been obtained data based on countries, electricity mixes or technologies with similar characteristics to the Chilean electricity system.

Table 32. Pedigree matrix results for sources of literature data.

Data category	Criteria						
	Amount of data sources	Reliability	Completeness	Temporal correlation	Geographical correlation	Technological correlation	Total
Overall data quality (average)		**2.6**	**2.3**	**1.5**	**2.4**	**2.8**	**11.5**
Fossil fuel production	5	3.0	2.0	1.0	2.0	3.0	11.0
Fossil fuel composition	1	2.0	1.0	1.0	2.0	2.0	8.0
Biomass and biogas production	1	3.0	3.0	1.0	3.0	3.0	13.0
Fuel transport	3	3.0	2.0	2.0	3.0	4.0	14.0
Fuel processing (refinery and regasification)	1	3.0	2.0	1.0	3.0	3.0	12.0
Power plant operation (technical parameters)	3	2.0	2.0	1.0	1.0	2.0	8.0
Power plant operation (emissions)	4	1.0	1.0	1.0	1.0	2.0	6.0
Power plant construction (renewables and fossil fuel)	2	3.0	3.0	3.0	3.0	3.0	15.0
Power plant decommissioning (landfill and recycling)	1	4.0	3.0	3.0	3.0	4.0	17.0
Capital cost (current costs and future estimations)	4	2.0	2.0	1.0	2.0	2.0	9.0
Fuel costs (current costs and future estimations)	3	2.0	3.0	1.0	3.0	2.0	11.0
Fixed, variable and carbon costs	1	3.0	3.0	2.0	3.0	3.0	14.0

6.4. CONCLUSIONS

In this work, an economic and environmental sustainability assessment has been conducted for future electricity generation in Chile, focusing on the economic and environmental aspects. Twelve scenarios have been considered on the basis of eleven environmental impacts and two economic indicators. The scenarios represent electricity supply mixes in 2050 comprising eleven different technologies. Life cycle assessment and levelized costing have been carried out to evaluate the technologies against the sustainability indicators, while MCDA has been applied to all scenarios under four different weighting regimes.

From the environmental assessment it can be inferred that ten out 11 impacts will decrease by 51%-87% compared to the current situation impacts. Abiotic depletion potential is the only impact that will increase by 8 - 13 times, largely due to solar PV. Solar PV is predominantly responsible for the impacts increase of 36% between both RE_{260} and RE_{750} scenarios because the power contribution differs from 20% in RE_{260} to 32% in RE_{750}. There are no significant impact differences among sub-scenarios (‘Base’, ‘No CSP’ and ‘No new hydro’) regarding top-level RE scenarios (RE_{260} and RE_{750}). Coal power is responsible of BAU scenarios have 7 times higher of global warming, fossil fuel depletion acidification, eutrophication, and marine aquatic ecotoxicity than the same impacts in RE scenarios, while the rest of the impacts are three times larger. BAU_{260} ‘Base’ scenario has the lowest LCOE and cumulative investment, while RE_{750} ‘No new hydro’ has the highest values of both economic indicators. All the ‘No new hydro’ sub-scenarios show also to have the highest LCOE regarding their corresponding top-level scenarios.

The MCDA analysis suggests that RE_{260} ‘Base’ scenario has the highest overall desirability and could be considered most desirable for the criteria considered. RE_{260} ‘Base’ scenario has the lowest environmental impacts throughout the scenarios and also the lowest LCOE and investment from all renewables scenarios. BAU scenarios are less sustainable because of their high environmental impacts in general, but they present the advantage of performing lower LCOE and investment. RE_{750} ‘No new hydro’ showed the lowest overall desirability in three out four weighting regimes, where the economic and environmental aspects had equal weighting and in that that the economic aspect was more important. This is due to this scenario’s highest abiotic depletion potential, LCOE and investment costs and the highest environmental impacts among the renewable scenarios. The current situation has been considered the second worst mix because in two regimes with equal weight aspects it has had the second worst performance and in the regime with environment preference, it performed the worst desirability. All the scenarios with 'No new hydro' in general performed low desirability driven by economic aspects.

With solar PV on the grid of above 20% electricity, it can meet all the demand at times when solar radiation is high. This means that other power options are not dispatched at those times, leading to energy spillage in other non-dispatchable options, like wind and run-of-river, and reducing their capacity factors. The reduction of capacity factors across of all power options affects significantly the cost of the electricity, while inducing a marginal increase in environmental impacts. Additionally, since solar PV contribute significantly to several impacts, the higher its power contribution, the greater the impacts of the power system.

Coal power will still be an economic option that can be eventually driving new investment even at lower capacity factors, considering carbon price established by the government at 5 \$/t CO_2 by 2030 and at 10 \$/t CO_2 onward. This can allow to maintain today's level of electricity prices while the environmental impacts can be reduced to a 49% of today' impacts per unit of electricity generated.

The main conclusion of this research is that 100% renewable scenario can be achieved by 2050 assuming a decision on phasing out the fossil power plants. Reaching a renewable electricity system could result in 12% costs increase in the business as usual scenarios with the benefit of reducing the environmental impacts to a 13% of today's impacts.

As a result of this study, the following recommendations can be drawn to help policymakers and stakeholders make decisions towards a more sustainable electricity system in Chile:

- To assess the sustainability of power systems, not only costs and greenhouse gas emissions need to be taken into account, but also other environmental, social and economic indicators. Therefore, a life cycle thinking should be adopted by the government and private sector which enables policy and decision making on the basis of identifying hotspot and opportunities to improve the sustainability of electricity generation.
- Coal power is the least sustainable option, producing significant impacts during mining and combustion. However, coal power will still be a cost-competitive option, and new investments could take place even though its power contribution may reduce in the power mix. Therefore, in order to promote a more sustainable electricity generation, new instruments should be enacted that allow internalizing all the

impacts caused by this technology, such as increasing carbon taxation, or addition of carbon capture and storage systems in power plants. (policy-tech)

- Increasing the contribution of solar PV, geothermal and wind power in the power generation mix would significantly increase the depletion of resources. Therefore, recycling and use of technologies with higher efficiency and better utilization of materials should be pursued.
- As the solar PV and wind are becoming more economical, their power contribution in the system will increase. As a result, thermal power options, in the short-term, will be forced to increase their flexibility while keeping their generation costs low. Therefore, alternatives to improve flexibility in power technologies should be investigated.
- Due to climate change, precipitations may reduce in areas where current hydropower plants are. Hydropower reservoirs located in the two most important catchments, “Laja” and “Maule” catchments, will often have lower levels of water storage. Therefore, adapting these reservoirs to pumped hydroelectric storage should be explored. This can improve the storage capacity for integrating variable power options and prevent the construction of new hydropower dams, reducing land change use, avoiding intervention on other catchments and preventing population displacement.
- The high penetration of solar (PV and CSP) and wind power technologies will require measurements to avoid energy spillage either managing the demand or finding mechanisms to deliver the excess of energy to new load sources, therefore the following recommendation can be considered:
  - Development of regional grid interconnections to import and export electricity according to the needs should also be considered.
  - Implementation of demand-response mechanisms, such as shifting load, should be explored.
  - Power-to-gas projects by producing hydrogen as an energy vector should also be considered.
  - The feasibility of projects which provide flexible load should be examined. Water desalination can be considered as an attractive alternative for this purpose considering that areas with high solar radiation also have water scarcity in Chile.

    - Although the transmission system has been out of the scope of this study, an efficient transmission capacity should be prioritized to minimize losses and bottlenecks.
- Biomass is a renewable option with the capability of being used as a dispatchable option, which would be highly valued in future power systems. However, technical considerations need to be improved as well as reducing its environmental impacts. The following suggestion can be developed:
    - Best mechanisms that promote biomass availability for electricity generation through energy crops and biofuels should be identified.
    - Methods for increasing biomass power plant efficiency and reducing emissions should be investigated.
    - Wider deployment of combined heat and power from biomass should be considered.

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Chapter 7: Conclusions, recommendations and future work

The main aim of this research was to assess the environmental and economic sustainability of electricity generation in Chile. To assess the sustainability of the electricity sector the current generation system has been taken into account and sustainable options of electricity generation for the future have been identified. In Chapter 1, the methodology presented comprises of an environmental and economic sustainability assessment, the creation and evaluation of scenarios and the multi-criteria decision analysis. The sustainability implications considered in this work are associated with the use of resources, release of contaminants to air, soil and water bodies, and the costs to produce electricity. Life cycle assessment has been implemented to assess the environmental impacts, and levelized cost of electricity and investment costs have been considered for the economic assessment. To evaluate the sustainability of the electricity generation, a multi-criteria decision analysis has been carried out for the current situation and future scenarios that takes into account all the indicators.

The outcomes of this research are presented Chapter 2-6. The review paper in Chapter 2 states an overview of significant aspects that have been affecting the sustainability of electricity in Chile. In Chapter 3, a paper based on the estimation and comparison of life cycle environmental impacts of electricity generation from fossil fuel in Chile is presented. Coal, oil and natural gas are the energy resources evaluated with consideration of different technologies, such as pulverized coal-fired boiler, open and combined cycle turbines, and a diesel engine. The impacts have been estimated on a life cycle basis, considering stages such as fuel production, transport, and processing, as well as power plant operation, construction and decommissioning. The environmental impacts are estimated both per unit of electricity for each option and for the total annual generation over the last decade.

Chapter 4 takes the above analysis further to estimate life cycle environmental impacts of the current electricity generation in Chile. All the electricity generation options in the country were included in the analysis, considering 174 power plants and including coal, oil, natural gas, biomass, biogas, wind, solar photovoltaics and hydropower reservoir and run-of-river options. The environmental impacts are estimated for the electricity mix as well as for the total annual generation in the last decade.

Chapter 5 contains the work carried out to determine future scenarios of electricity in Chile by 2050. An optimization framework has been developed to identify cost-optimal electricity mixes with flexibility to allow high penetration of renewables through long- and short-term storage. The outputs of the optimization model have been used to define 12 futures scenarios in Chile up to 2050. The scenarios were evaluated from a perspective of technology contribution, flexibility aspects and economic performance.

Finally, Chapter 6 presents the results of the environmental and economic sustainability assessment carried out for the future scenarios. The LCA impacts estimated for the scenarios have been used for the environmental assessment, and the levelized costs and investment costs for the economic evaluation. The most desirable scenario was identified through multi-criteria decision analysis (MCDA), considering different weights of importance for the environmental and economic criteria.

According to the research objectives outlined in Chapter 1, the following have been achieved:

- An integrated methodology to assess the environmental and economic sustainability for electricity generation in Chile has been successfully selected, adapted and implemented.
- Life cycle environmental impacts and levelized cost of electricity have been estimated for the current electricity generation.
- Twelve future scenarios have been identified up to 2050 from an optimization framework developed as part of the study. The optimization framework was implemented, and electricity costs and cumulative investments were estimated. In addition, eleven environmental impacts have been estimated through life cycle assessment.
- Stakeholders' preferences were simulated through multi-criteria decision analysis considering different weight regimes for the criteria of interest. As a result, the most desirable scenarios were identified.
- Based on the outcomes of this research, a range of recommendations have been made to improve the sustainability of electricity generation in Chile and to help policymakers and industry to make decisions based on evidence provided by this research.

The key conclusions and findings of the research are summarized below. This is followed by recommendations to policy makers and energy companies.

7.1. CONCLUSIONS

The conclusions are presented according to their temporal context and their implications. Consequently, the conclusions obtained from the economic and environmental sustainability assessment of current electricity situation are drawn first, followed by the conclusion from the sustainability assessment of future electricity scenarios.

7.1.1. Economic and environmental sustainability assessment of current electricity situation for Chile

7.1.1.1. Economic implications

- Concentrating solar power has the largest investment costs throughout the technologies evaluated with an overnight cost of 9000 $/kW, followed by geothermal power of 7800 $/kW and run-of-river of 4050 $/kW, while gas and oil power shows the lowest costs of 1150 $/kW.
- Taking into account only the power generation component of electricity costs, and based on a 7% discount rate, the estimated levelized costs of electricity in Chile is 77.6 $/MWh.
- The technologies with the lowest LCOE are reservoir, run-of-river and coal with costs of 49.9 $/MWh, 64.9 $/MWh and 75.3 $/MWh respectively. Concentrating solar power, oil, and geothermal have had the highest costs of 281 $/MWh, 196 $/MWh and 152 $/MWh respectively.
- The actual cost of electricity in Chile in 2013 was 104 $/MWh where the power generation components represent about 75%. In the last decade, the year 2008 was the year that the electricity cost reached the highest value of 171 $/MWh.
- About 60% of electricity is supplied by fossil fuels, and 34 % by hydropower reservoir and run-of-river. This together with high hydrological variability, volatile fossil fuel prices, of the curtailment of natural gas, high levels of electricity market concentration and high demand have caused the last decade to have larger electricity prices (average of 126 $/MWh).
- The higher cost of electricity has caused a loss in competitiveness and productivity in the national economy.
- The increase of new coal power investments as a way to reduce the costs of electricity has led to the Chilean society to show opposition to the development of new power projects since most of the projects produce environmental impacts and the electricity costs are still not affordable.

7.1.1.2. Environmental implications

- Coal power exhibits the worst environmental performance among all the generation technologies in current electricity mix, with the highest values in eight out eleven environmental impacts including global warming, eutrophication and ecotoxicity.
- The consumption of petroleum coke as secondary fuel in coal power generation causes coal power to have larger ozone depletion than other countries' coal power impact.
- Natural gas power is the most sustainable option as it has the lowest impacts among fossil fuel options, but also shows better performance than biomass, wind and solar PV power for several impacts.
- The fact that natural gas is transported in liquefied form causes the natural gas power to have lower ozone depletion by avoiding long-distance pipeline.
- The most significant life cycle stages for biogas, biomass and fossil fuels are fuel production and power plant operation which exhibit a contribution of 40% each to the impacts.
- Hydropower reservoir and run-of-river are the most sustainable power options since they have the lowest impacts, followed by wind and biogas.
- In terms of environmental impacts of the electricity mix, because coal power has a great contribution to the electricity mix (41%), this option is responsible for about 88% of human toxicity, ecotoxicities, eutrophication and acidification.
- Even though solar PV generates only 1% of total electricity, its contribution to abiotic depletion in the electricity mix is about 23%. This is due to having the highest impacts at the technology level, where the closest power option (oil power) has an impact that represents one-sixth of solar PV impact.
- Over the past ten years the electricity generation has increased 44% whereas all the impacts have grown from 60% to 170%, which is mostly associated with the rise of coal power contribution through the period.

7.1.2. Economic and environmental sustainability assessment of future electricity scenarios for Chile

7.1.2.1. Futures scenarios modelling

- The optimization framework developed has shown to be effective by determining future scenarios of electricity by considering long-term and short-term power storage technologies (hydropower reservoir and concentrating solar power respectively) and allowing to achievement of flexibility in the operation.
- Twelves scenarios have been obtained and grouped as Business as usual (BAU) and Renewable electricity (RE). Eleven power options have been considered including coal, gas, oil, biomass, biogas, hydropower reservoir and run-of-river, onshore wind, solar PV, concentrating solar power and geothermal.
- Although BAU scenarios are unconstrained in terms of technologies, natural gas, oil, and biomass power do not contribute in any BAU scenario. This is due to their high marginal costs. The fact of having high marginal costs causes to these options to be dispatched less and consequently reaching lower capacity factor. Hence, low capacity factors drive to have higher electricity costs than hydropower reservoir and run-of-river, wind, and solar PV.
- Despite BAU scenarios having a coal power contribution, they reach higher renewables share (81%-90%) than the current situation (40%).
- RE scenarios are constrained by phasing out all fossil fuel options by 2050, in spite of that, flexibility has been attained in the operation even though the contribution of variable renewable options to the electricity mix is between 41% and 50%.
- Despite the high marginal cost (75 $/MWh) and investment cost (3100 $/kW) of biomass power, this power option has been retained in RE scenarios because it provides electricity when solar PV generates less electricity in winter.

7.1.2.2. Economic implications

- Across all scenarios solar PV achieves the lowest costs (45-50 $/MWh), followed by reservoir (50 $/MWh), wind (49-64 $/MWh) and run of river (67-79 $/MWh).
- Biomass is only present in RE scenarios, it has the highest cost of electricity (1095-1295 $/MWh), followed by geothermal (136-172 $/MWh) and concentrating solar power (139 $/MWh).

- When solar PV reaches above 20% of electricity share, it leads to energy spillage of other non-dispatchable power options and increases cycling in thermal power plants causing a reduction of capacity factors which in turn causes rising of costs.
- BAU_{260} 'Base' is the scenario with the lowest levelized cost of electricity because it has a low solar PV electricity share (20%), low geothermal (4%) and a high contribution of coal (19%).
- Coal power with electricity costs that ranges in 133-160 $/MWh is still a competitive power option over geothermal (136-172 $/MWh) considering a condition of 10 $/t CO_2 of carbon tax.
- Annual investment of on average $4 bn would be required up to 2050.
- The cumulative investments required for BAU and RE scenarios through the evaluation horizon are between $123 and $157 bn.
- Hydropower options have been shown to be essential to maintain low costs of electricity, promoting their investment helps to avoid rise of electricity costs by 8% to 18%.
- The electricity costs of all scenarios vary by around ±10% with respect to today's costs.
- Phasing out fossil fuel power options helps to reach total renewables scenarios at about 12% electricity costs increase with respect to BAU scenarios.

7.1.2.3. <u>Environmental implications</u>

- BAU scenarios have on average 49% of current electricity mix impacts, while RE scenarios have on average 13% of the mix impacts.
- Solar PV is the main power option that leads scenarios to cause high resource depletion. When solar PV contribution is about 20% of the scenarios' electricity, the resource depletion of scenarios is eight times higher than current electricity mix and when it is 32%, the depletion is 13 times larger.
- Coal power contribution ranges from 9% to 23% in BAU scenarios leading to the global warming, fossil fuel depletion, ozone depletion and photochemical creation to perform on average 37%-45% of the impacts in the current electricity mix.
- Also, coal power is responsible for BAU scenarios having seven times higher global warming, fossil fuel depletion, acidification, eutrophication, and marine aquatic ecotoxicity than the same impacts in RE scenarios, while the rest of the impacts are three times larger.

- The environmental impacts between BAU_{260} and BAU_{750} do not vary significantly, whose impacts are mainly attributed to the coal power contribution. Whereas RE_{750} scenarios show on average 36% larger impacts than RE_{260} attributed mostly to high environmental burdens of solar PV than other renewable options.
- There are no significant impact differences among sub-scenarios 'Base', 'No CSP' and 'No new hydro'.
- RE_{260} 'Base' has the lowest environmental impacts across all scenarios.
- Annual impacts decrease by 71% in RE scenarios with respect to current annual impacts with the exception of abiotic depletion that rises up to 29 times.
- With respect to the current situation, annual human toxicity and the annual ecotoxicities increase by 19% average in BAU scenarios whereas abiotic depletion rises up to 17 times. The rest of impacts diminish by 16% on average.

7.1.2.4. Multi-criteria decision analysis

- For three out the four weighting regimes, RE_{260} 'Base' has the largest overall desirability ranging from 0.58 to 0.85. When economic indicators have had higher preference, this scenario obtained the sixth position although it still had the highest score among renewables.
- RE_{750} 'No new hydro' showed the lowest overall desirability in three out four weighting regimes, where the economic and environmental aspects had equal weighting, and when the economic aspect was more important. This is due to this scenario having the highest abiotic depletion potential, LCOE and investment costs across all scenarios, and also having the highest environmental impacts among the renewable scenarios.
- The current situation has the second lowest overall desirability in two weighting regimes and it had the lowest score in the weighting regime where a high importance was given to environmental impacts. This is due to the current electricity mix having the worst environmental performance because ten out 11 environmental impacts were the highest among all scenarios.
- Even though RE_{260} 'Base' did not have the lowest electricity costs, cumulative investments and resource depletion, these indicators were lower in this scenario than other RE scenarios. Additionally, RE_{260} 'Base' had the lowest impacts for the rest of indicators. In contrast, BAU scenarios were more desirable in terms of LCOE and investment (low values), but they had low environmental performance. Therefore,

RE_{260} 'Base' has been identified as the most desirable scenario, obtaining the highest overall desirability in three out four weighting regimes.

7.2. POLICY AND INDUSTRY RECOMMENDATIONS

- Life cycle sustainability assessment should be adopted by the government and private sector to evaluate environmental, social and economic implications of future power systems.
- In general, both hydropower options, reservoir and run-of-river have been shown to be crucial to achieve more sustainable power systems, since they are the main source of electricity and have still potential for new investment in the country. They have the lowest environmental impacts due to their low environmental burdens associated with their construction processes and material requirements, but also, to their long-lasting lifespan. Even though they have high investment costs, their levelized costs of electricity are relatively low. Also, the long-term storage capacity for reservoirs enables operation flexibility of the system by integrating highly variable renewable options like solar photovoltaic and wind. Therefore, both hydropower options need to be promoted.
- Precipitations will decrease in areas where current hydropower plants are located. Hydropower reservoirs located in the two most important catchments, "Laja" and "Maule" catchments, will probably often have lower levels of water. Therefore, the adaptation of these reservoirs to be pumped hydroelectric storage should be evaluated. This can prevent the construction of new hydropower dams reducing land use change, avoiding intervening with other catchment areas and preventing population displacement.
- Solar photovoltaics, CSP and wind also have high potential and are becoming very cost competitive. From these three options, wind power has lower environmental impacts, hence, it is an option that needs to be prioritized for deployment.
- Although solar PV has lower global warming potential, it still needs to address technical improvements to reduce its significant contribution to depletion of resources, human toxicity, ozone depletion and ecotoxicities.
- Increasing the contribution of solar photovoltaics, geothermal and wind power in the power generation mix would significantly increase the depletion of resources. Therefore, recycling and developing and selecting technologies with more efficiency and better use of material can be prioritized.

- Costs of CSP will decrease due to technical improvements and scalability. Therefore, CSP can contribute to the diversification of the electricity system, improving the energy security. Furthermore, another benefit of this technology is that its environmental impacts are comparable to wind and hydropower options.
- Biogas, biomass and geothermal power also need to be considered but their costs and environmental impacts should be improved, particularly human toxicity, ozone depletion, photochemical oxidants and ecotoxicities.
- Since solar PV and wind are becoming more economical, their power contribution in the system will increase. Thermal power plants will be forced to increase their flexibility while keeping their generation costs low. Therefore, alternatives for improving flexibility in thermal power technologies should be investigated.
- The high penetration of solar (PV and CSP) and wind power technologies will require measurements to avoid energy spillage by either managing the demand or finding mechanisms to deliver the excess of energy to new load sources, therefore the following recommendation can be considered:
    - Development of regional grid interconnections to import and export electricity according to the needs.
    - Implementation of demand-response mechanisms, such as shifting load, should be explored.
    - To evaluate the development of power-to-gas projects by producing hydrogen as an energy vector.
    - The feasibility of projects which provide flexible load should be examined. Water desalination can be considered as an attractive alternative for this purpose considering that areas with high solar radiation also have water scarcity in Chile.
    - Although the transmission system has been out of the scope of this study, an efficient transmission capacity should be prioritized to minimize losses and bottlenecks.
- Biomass is a renewable option with the capability of being used as a dispatchable option, which would be highly valued in future power systems. However, technical considerations need to be improved as well as reducing its environmental impacts. The following suggestion can be developed:
    - To identify better mechanisms that promote biomass availability for electricity generation through energy crops and biofuels.

  - To investigate methods to increase biomass power plant efficiency and reduce emissions.
  - To expand the use of combined heat and power from biomass.
- Coal power is the least sustainable option, producing significant impacts during mining and combustion. However, coal power will still be a cost-competitive option, and new investments could take place even though its power contribution may be reduced in the power mix. Therefore, in order to promote a more sustainable electricity generation, new instruments should be enacted that allow internalizing all the impacts caused by this technology, to increase carbon taxation, and forcing the implementation of carbon capture and storage systems in power plants.
- Production of steel has burdens that cause high human toxicity and ecotoxicities. These burdens are propagated through other products that make an intensive use of steel like power technologies. Therefore, new regulations should be considered to promote more sustainable production of steel.

7.3. RECOMMENDATIONS FOR FUTURE WORK

- Considering solar PV is a technology that will increase its contribution, different solar PV technologies should be analysed from a life cycle perspective.
- Social sustainability assessment should also be considered as well as other environmental impacts not considered in this research, such as land use change and water footprint.
- Preferences for different sustainability criteria should be obtained through a survey of stakeholders.
- The sustainability assessment could be broadened to take into account generation, transmission and distribution.
- The sustainability of electricity systems in other South American countries should also be studied.
- Dynamic LCA can be developed for future scenarios to reflect background processes in the electricity mixes more accurately.
- Evaluation of new scenarios should be modelled considering distributed generation and batteries.
- Home batteries and bulk batteries should be compared from a perspective of optimization programming or simulation in order to take into account benefits and limitation of each technology. The resulting scenarios can be evaluated through a life cycle approach.

7.4. CONCLUDING REMARKS

This research has integrated environmental and economic indicators for assessing the sustainability of current electricity situation and future electricity scenarios for Chile.

It is hoped that this work will be of interest to the energy industry, policy makers, researchers, and the general audience, and also to contribute to stimulating constructive dialog about how to create more sustainable electricity systems.

Appendices

Appendix 1. Power plants in Chile in the base year

Table 33. Oil power plant in Chile in the base year.

	Power plant	Type[a]	Emission control systems[b]	Installed capacity (MW)	Electricity in 2014 (GWh)	Share (%)	Efficiency[c] (%)
1.	Gas Atacama 1	CC	LowNOx	389	320	12%	41%
2.	Gas Atacama 2	CC	LowNOx	383	558	20%	42%
3.	San Isidro I	CC	-	379	21	1%	43%
4.	San Isidro II	CC	-	399	39	1%	46%
5.	Nueva Renca	CC	SCR	379	725	26%	46%
6.	Nehuenco I	CC	Wet scrubber	368	233	8%	50%
7.	Nehuenco II	CC	Wet scrubber	398	107	4%	50%
8.	Nehuenco III	OC	Wet scrubber	108	5	<1%	29%
9.	Taltal 1	OC	-	123	7	<1%	31%
10.	Taltal 2	OC	-	122	1	<1%	31%
11.	Candelaria 1	OC	Wet scrubber	136	7	<1%	29%
12.	Candelaria 2	OC	Wet scrubber	136	6	<1%	29%
13.	Santa Lidia	OC	-	139	<1	<1%	
14.	Los Vientos	OC	-	132	10	<1%	
15.	Los Pinos	OC	-	104	130	5%	
16.	Antilhue	OC	-	103	60	2%	
17.	Emelda	OC	-	69	<1	<1%	
18.	Colmito	OC	-	58	6	<1%	
19.	Huasco	OC	-	58	1	<1%	
20.	SL de D. de Almagro	OC	-	56	<1	<1%	
21.	D. de Almagro	OC	-	24	<1	<1%	
22.	Yungay 1	OC	-	54	<1	<1%	
23.	Yungay 2	OC	-	54	<1	<1%	
24.	Yungay 4	OC	-	57	<1	<1%	
25.	Coronel	OC	-	47	23	1%	35%
26.	MIMB	OC	-	29	13	<1%	
27.	San Fco. de Mostazal	OC	-	26	<1	<1%	
28.	CTTO TG1	OC	-	25	2	<1%	
29.	CTTO TG2	OC	-	25	2	<1%	
30.	CTTO TG3	OC	-	38	11	<1%	
31.	TGTAR	OC	-	24	6	<1%	
32.	El Salvador	OC	-	24	<1	<1%	
33.	TGIQ	OC	-	24	6	<1%	
34.	Colihues	OC	-	22	32	1%	
35.	Punta Colorada	OC	-	17	23	1%	
36.	Cem Bio Bio	OC	-	14	27	1%	
37.	Los Espinos	DE	-	124	45	2%	
38.	Olivos	DE	-	115	7	<1%	
39.	SUTA	DE	-	104	173	6%	
40.	El Peñón	DE	-	90	64	2%	
41.	Termopacífico	DE	-	81	3	<1%	
42.	Trapén	DE	-	81	26	1%	
43.	Teno	DE	-	59	12	<1%	
44.	Degañ	DE	-	36	<1	<1%	
45.	Chuyaca	DE	-	15	2	<1%	36%
46.	CalleCalle	DE	-	13	3	<1%	
47.	Constitución	DE	-	9	2	<1%	
48.	GMAR	DE	-	8	7	<1%	
49.	Quellón II	DE	-	8	2	<1%	
50.	INACAL	DE	-	7	8	<1%	
51.	Maule	DE	-	6	1	<1%	
52.	ZOFRI_2-5	DE	-	5	3	<1%	

	Power plant	Type[a]	Emission control systems[b]	Installed capacity (MW)	Electricity in 2014 (GWh)	Share (%)	Efficiency[c] (%)
53.	ZOFRI_7-12	DE	-	5	4	<1%	
54.	SUIQ	DE	-	4	2	<1%	
55.	Lebu	DE	-	4	<1	<1%	
56.	Cañete	DE	-	3	<1	<1%	
57.	El Totoral	DE	-	3	<1	<1%	
58.	Estancilla	DE	-	3	<1	<1%	
59.	Placilla	DE	-	3	<1	<1%	
60.	Quintay	DE	-	3	<1	<1%	
61.	Curacautín	DE	-	3	1	<1%	
62.	Curauma	DE	-	3	<1	<1%	
63.	Eagon	DE	-	2	1	<1%	
64.	Trongol-Curanilahue	DE	-	2	<1	<1%	
65.	Concón	DE	-	2	<1	<1%	
66.	Las Vegas	DE	-	2	<1	<1%	
67.	Lonquimay	DE	-	2	<1	<1%	
68.	Los Sauces I	DE	-	2	1	<1%	
69.	Los Sauces II	DE	-	2	<1	<1%	
70.	Contulmo	DE	-	1	<1	<1%	
71.	San Gregorio	DE	-	1	<1	<1%	

[a]CC: Combined cycle, OC: Open cycle, DE: Diesel engine. [b]Wet scrubber: desulphurisation system; LowNOx: Low NOx burner; SCR: Selective catalytic reduction. [c]Efficiency of OC plants no. 13-36 and DE no. 37-71 determined from electricity produced and fuel consumed.

Table 34. Biogas and biomass power plants in Chile in 2014[1–3]

Fuel type	Power plant	Installed capacity (MW_e)	Electricity generation (GWh)	Share by source (%)	
Biogas	1 Loma Los Colorados II	18	131	83	Landfill
	2 Loma Los Colorados	2	3.5		
	3 Santa Marta	14	100		
	4 Trebal Mapocho	5	41	15	Sludge sewage
	5 Santa Irene	0.4	3	3	Manure and organic waste
	6 HBS	2	3		
	7 Las Pampas	0.4	1		
	8 Tamm	0.2	0.3		
Biomass	1 Santa Fe	67	476	90	Industrial residual wood
	2 Valdivia[a]	61	326		
	3 Nueva Aldea III[b]	37	275		
	4 Viñales	22	179		
	5 CMPC Pacífico	33	176		
	6 Energía Pacífico	16	105		
	7 Escuadrón	14	89		
	8 Arauco	24	87		
	9 CMPC Laja[b]	25	84		
	10 Nueva Aldea I	19	83		
	11 Cholguán	13	75		
	12 Cabrero	11	55		
	13 Licantén[a]	6	45		
	14 Energía BíoBío	7	41		
	15 Laja	13	40		
	16 Constitución	8	30		
	17 Energía León	7	22		
	18 Lautaro	26	192	10	Cereal straw
	19 Lautaro II	22	51		

[a] Plant only fed by black liquor.
[b] Plant partially fed by black liquor.

Table 35. Wind farms and solar power plants in Chile in 2014 [1–3].

Technology		Power plant	Installed capacity (MW_e)	Electricity generation (GWh)
Wind	1	Canela	18	27
	2	Canela II	60	130
	3	Eólica Cuel	33	94
	4	Eólica El Arrayán	115	184
	5	Eólica Los Cururos	110	149
	6	Eólica Punta Palmeras	45	28
	7	Eólica San Pedro	36	78
	8	Eólica Taltal	99	30
	9	Lebu	4	14
	10	Monte Redondo	48	110
	11	Punta Colorada	20	21
	12	Talinay	90	229
	13	Totoral	46	89
	14	Ucuquer 1	7	19
	15	Ucuquer 2	11	8
	16	Valle de los Vientos	90	215
Solar	1	Chañares	35	2
	2	La Huayca SPS-1	1	11
	3	Los Puquios	3	4
	4	Maria Elena	72	24
	5	Pozo Almonte Solar 2	8	15
	6	Pozo Almonte Solar 3	16	32
	7	Salvador	68	6
	8	SDGx01	1	2
	9	Solar Diego de Almagro	30	26
	10	Solar El Aguila	2	4
	11	Solar Esperanza	3	5
	12	Solar Hornitos	0	0
	13	Solar Las Terrazas	2	1
	14	Solar Llano de Llampos	101	219
	15	Solar PSF Lomas Coloradas	2	2
	16	Solar PSF Pama	2	2
	17	Solar San Andrés	51	99
	18	Solar Santa Cecilia	3	6
	19	Tambo Real	1	4

Table 36. Hydropower plants in Chile in 2014 [1–3].

Technology type		Power plant	Installed capacity (MW_e)	Electricity generation (GWh)
Reservoir	1	Ralco	690	2,621
	2	Pehuenche	570	2,276
	3	Colbun	474	1,962
	4	Pangue	467	1,840
	5	El Toro	450	947
	6	Rapel	378	481
	7	Angostura	324	1,300
	8	Canutillar	172	964
	9	Cipreses	106	271
	10	Machicura	95	431
Run of river	1	Antuco	320	1,285
	2	Rucúe	178	767
	3	Alfalfal	178	696
	4	La Confluencia	163	376
	5	La Higuera	155	461
	6	Abanico	136	259
	7	Chacayes	112	448
	8	Rest of run-of-river plants (88 plants < 100MW_e each)	1,479	6,158

Table 37. Life cycle inventory for coal plants in 2004, 2009 and 2014a [1–4].

	2004	2009	2014	Unit and description
Coal				
Power plant	**35**	**36**	**36%**	[%] Efficiency
	50	**85**	**81**	[%] Capacity factor
	38	38	38	[yr] Lifespan
	97.5	97.5	97.5	[g/MJ] Direct emission of CO_2
	167	167	167	[mg/MJ] Direct emission of NO_x
	337	337	337	[mg/MJ] Direct emission of SO_2
	82	82	82	[mg/MJ] Retention of NO_x
	205	205	205	[mg/MJ] Retention of SO_2
Fuel transport	11959	11959	11959	[km] Distance of coal shipment from Australia
	3220	3220	3220	[km] Distance of coal shipment from Chile
	4585	4585	4585	[km] Distance of coal shipment from Colombia
	11959	11959	-	[km] Distance of coal shipment from Indonesia
	8785	8785	8785	[km] Distance of coal and petcoke shipment from USA
Fuel contribution	**25%**	**1%**	**8%**	[%] Australia coal contribution to total coal and petcoke consumption
	4%	**6%**	**10%**	[%] Chilean coal contribution to total coal and petcoke consumption
	13%	**50%**	**54%**	[%] Colombian coal contribution to total coal and petcoke consumption
	17%	**8%**	**0%**	[%] Indonesia coal contribution to total coal and petcoke consumption
	17%	**8%**	**23%**	[%] USA coal contribution to total coal and petcoke consumption
	5%	**18%**	**2%**	[%] Chilean petcoke contribution to total coal and petcoke consumption
	19%	**8%**	**3%**	[%] USA petcoke contribution to total coal and petcoke consumption
Heating value	**21.0**	**25.0**	**27.0**	[MJ/kg] Higher heating value of coal in Australia
	18.9	**18.9**	**18.9**	[MJ/kg] Higher heating value of coal in Chile
	21.0	**25.0**	**26.8**	[MJ/kg] Higher heating value of coal in Colombia
	21.0	**25.0**	**20.7**	[MJ/kg] Higher heating value of coal in Indonesia
	21.0	**25.0**	**26.0**	[MJ/kg] Higher heating value of coal in USA
	32.5	32.5	32.5	[MJ/kg] Higher heating value of petcoke in Chile and USA

[a] Parameters in bold vary through the years.

Table 38. Life cycle inventory for natural gas plants in 2004, 2009 and 2014[a] [1–4].

Natural gas				
Technology contribution	**100**	**100**	**96**	[%] Combined cycle power plant share of total electricity from natural gas
	0	**0**	**4**	[%] Open cycle power plant share of total electricity from natural gas
Combined cycle power plant	**47**	**48**	**47**	[%] Efficiency
	65	**17**	**53**	[%] Capacity factor
	35	**45**	**35**	[yr] Lifespan
	61.9	61.9	61.9	[g/MJ] Direct emission of CO_2
	129	129	129	[mg/MJ] Direct emission of NO_x
	0.65	0.65	0.65	[mg/MJ] Direct emission of SO_2
Open cycle power plant	-	-	28	[%] Efficiency
	-	-	11	[%] Capacity factor
	-	-	45	[yr] Lifespan
	-	-	56	[g/MJ] Direct emission of CO_2
	-	-	25	[mg/MJ] Direct emission of NO_x
	-	-	0.73	[mg/MJ] Direct emission of SO_2
Gas distribution	**39.1**	**39.9**	**41.1**	[MJ/Nm^3] Higher heating value of natural gas
	1.53×10^{-7}	1.53×10^{-7}	1.53×10^{-7}	[m/MJ] Gas network. Estimated from gas sales and total length of pipeline
Regasification plant	3.04×10^{-12}	3.04×10^{-12}	3.04×10^{-12}	[Unit/Nm^3] Part of terminal per Nm^3 of liquefied natural gas (LNG)
	2.25	2.25	2.25	Scaling factor. Estimated from original size and actual size to the power of 0.6
Gas supply and transport	**0**	**43**	**100**	[%] LNG contribution to the gas mix
	100	**57**	**0**	[%] Long-distance pipeline gas contribution to gas mix
	-	12,684	12,684	[km] Distance of LNG tanker route from exporting countries
	558	558	-	[km] Long-distance pipeline from export country

[a] Parameters in bold vary through the years.

Table 39. Life cycle inventory for oil plants in 2004, 2009 and 2014[a] [1–4].

	2004	2009	2014	Description
Oil				
Technology contribution	-	**81**	**73**	[%] Combined cycle power plant share of total electricity from oil
	-	**10**	**14**	[%] Open cycle power plant share of total electricity from oil
	-	**9**	**13**	[%] Diesel engine power plant share of total electricity from oil
Combined cycle power plant	-	44	44	[%] Efficiency
	-	**75**	**15**	[%] Capacity factor
	-	**35**	**45**	[yr] Lifespan
	-	89	89	[g/MJ] Direct emission of CO_2
	-	295	295	[mg/MJ] Direct emission of NO_x
	-	185	185	[mg/MJ] Direct emission of SO_2
Open cycle power plant	-	34	34	[%] Efficiency
	-	**30**	**6**	[%] Capacity factor
	-	**35**	**45**	[yr] Lifespan
	-	80	80	[g/MJ] Direct emission of CO_2
	-	265	265	[mg/MJ] Direct emission of NO_x
	-	474	474	[mg/MJ] Direct emission of SO_2
Diesel engine power plant	-	36	36	[%] Efficiency
	-	**40**	**8**	[%] Capacity factor
	-	**35**	**45**	[yr] Lifespan
	-	76	76	[g/MJ] Direct emission of CO_2
	-	829	829	[mg/MJ] Direct emission of NO_x
	-	192	192	[mg/MJ] Direct emission of SO_2
Diesel contribution, transport and heating value	-	**45**	**43**	[%] Chile's diesel share to diesel mix (national refineries)
	-	**55**	**57**	[%] USA diesel share to diesel mix
	-	45.6	45.6	[MJ/kg] Higher heating value of diesel
	-	664	664	[km] Distance between refinery and oil power plant in road
	-	**18,838**	**8785**	[km] Average distance from diesel exporting countries
Crude oil contribution and transport	-	84%	84%	[%] Latin American crude oil share to crude oil mix
	-	16%	16%	[%] UK crude oil share to crude oil mix
	-	5204	5204	[km] Weighted average distance of crude oil from Latin American countries
	-	11,112	11,112	[km] Distance for crude oil transport from UK

[a] Parameters in bold vary through the years.

Table 40. Life cycle inventory for biogas, biomass, solar PV, wind and hydropower in 2004, 2009 and 2014[a] [1–4].

	2004	2009	2014	Description
Biogas				
Cogen-gas engine	-	-	1000	[kW_e] capacity average of biogas engine
	-	-	77	[%] Capacity factor of electricity from biogas
	-	-	20	[yr] Life time of biogas engine
	-	-	0.33	Scaling factor. Estimated from original size and actual size to the 0.6 power
Biogas contribution	-	-	0	[%] biogas contribution to biogas mix from landfill (85%, assumed zero burdens)
	-	-	15	[%] biogas contribution to biogas mix from sewage sludge plants
Biomass				
CHP plant	10	10	10	[MW_e] Average capacity of actual plant of biomass
	63	63	63	[%] Capacity factor of electricity from biomass
	20	20	20	[yr] Life time of biomass boiler
	80	80	80	[yr] Life time of biomass building
	0.18	0.18	0.18	Scaling factor. Estimated from original size and actual size to the power of 0.6
Biomass contribution and transport	20	20	20	[km] average distance travelled by truck of industrial residual wood
	-	-	50	[km] average distance travelled by truck of agricultural crops residues
	100	**100**	**90**	[%] Industrial residual wood contribution to the mix
	0	0	0	[%] Crops residues contribution to the mix (2014: 10%, assumed zero burdens)
Solar				
PV plant	-	-	24	[%] Capacity factor
	-	-	0.7	[%] Rated power degradation per year
	-	-	30	[yr] Lifespan
Wind				
Onshore	-	-	2000	[kW_e] Capacity average of each turbine in the wind farm
	-	-	27	[%] Capacity factor
	-	-	40	[yr] Lifespan of wind turbine fixed part
	-	-	20	[yr] Lifespan of wind turbine moving part
Hydropower				
Technology contribution	**58**	**59**	**56**	[%] electricity from reservoirs share of total electricity from hydropower
	42	**41**	**44**	[%] electricity from run-of river share of total electricity from hydropower
Reservoir	373	373	373	[MW_e] Average capacity of reservoirs
	40	**48**	**43**	[%] Capacity factor of reservoirs
	14	14	14	[mg/kWh] CH_4 emission factor
	100	100	100	[yr] Lifespan of reservoirs
	0.44	0.44	0.44	Scaling factor. Estimated from original size and actual size to the power of 0.6
Run-of-river	28.7	28.7	28.7	[MW_e] average capacity of run-of river
	64%	**68%**	**60%**	[%] Capacity factor of run-of river
	80	80	80	[yr] Lifespan of run-of river
	0.49	0.49	0.49	Scaling factor. Estimated from original size and actual size to the power of 0.6

[a] Parameters in bold vary through the years.

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Appendix 2: Input parameters for investment optimization model

Table 41. Capacity to be decommissioned of current power plants or under construction [1–3].

Year	Coal	Gas	Oil	Run-of-river	Reservoir	Biomass	Biogas	Wind	PV	CSP	Geothermal
2015											
2016											
2017											
2018											
2019											
2020			45								
2021											
2022											
2023											
2024											
2025			189								
2026											
2027		370									
2028		729						18			
2029								7			
2030		501	105				2	152			
2031			36	890			2				
2032							18	20			
2033	686	252					10	97			
2034	143	390					14	272			
2035	331	175	513		106	10	0	324			
2036	63					17	5	15			
2037	561	236	107					333			
2038		393					10	171	3		
2039		14	18	18				150	213		
2040		6	199						293		
2041			61	178					324		
2042		2	275						1092		48
2043		19	138	165		13		350	842		
2044			734	32		67		130	74		
2045		633	772	12		14		150			
2046		29	168	37				400			
2047		521	6	40	0	1					
2048	525	328	80	178	377	48				110	
2049	502		2	3		2			780		
2050	454		389	140					530		

Table 42. Capacity of power plants planned or under construction until 2027 [2, 3].

Year	Coal	Gas	Oil	Run-of-river	Reservoir	Biomass	Biogas	Wind	PV	CSP	Geothermal
2015											
2016	132	29	218	100			5	15	324		
2017	472	521	49	85				333	1092		48
2018	375	328		75	16		10	171	842	110	
2019				832				150	74		
2020											
2021				170							
2022											
2023								350			
2024								130	780		
2025								150	530		
2026				20				400	410		
2027				20					625		

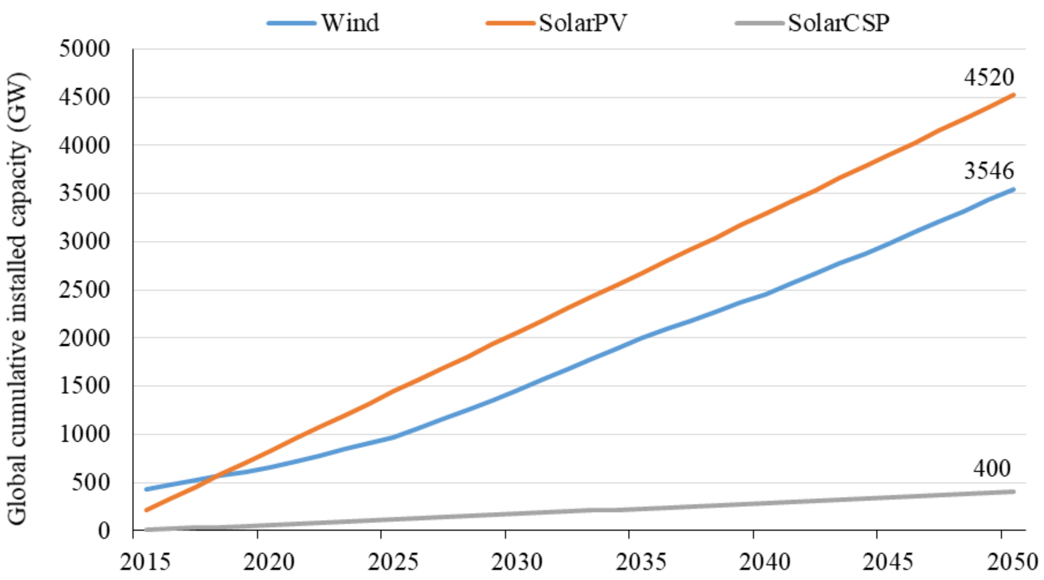

Figure 53. Global cumulative installed capacity to estimate future capital cost based on learning rate method [4–6].

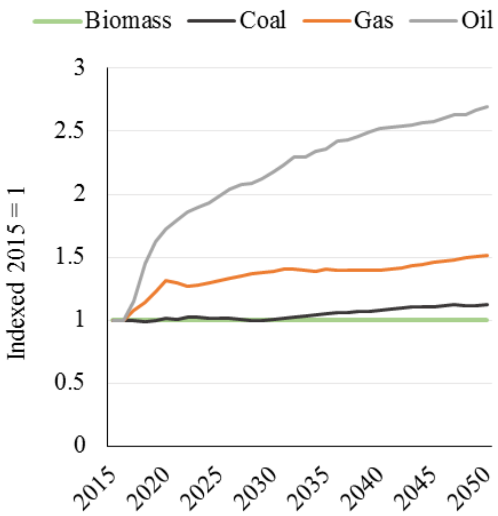

Figure 54. Variation of fuel costs from2015 to 2050 (Base scenario in 2015 of 83.8 \$/t coal, 7.4 \$/Nm^3 gas, 43.4 \$/bbl diesel and 58.9 \$/t biomass (40% humidity)) [3, 7, 8].

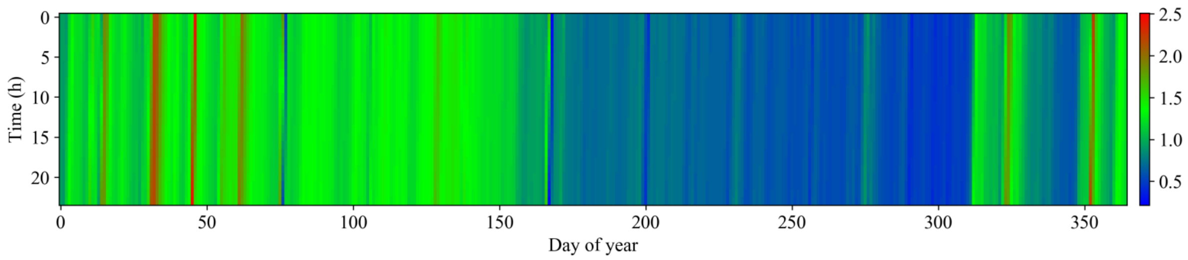

Figure 55.Variation of capacity factor (CF) for hydropower dam availability through hours-day and days in a year. Indexed CF:43%=1. Adapted from [3]

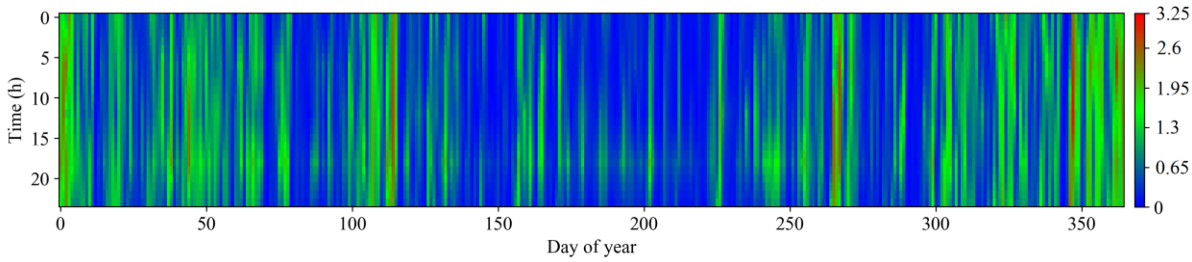

Figure 56. Capacity factor (CF) variation for wind power availability through hours-day and days in a year. Indexed CF:32%= 1. Adapted from [9].

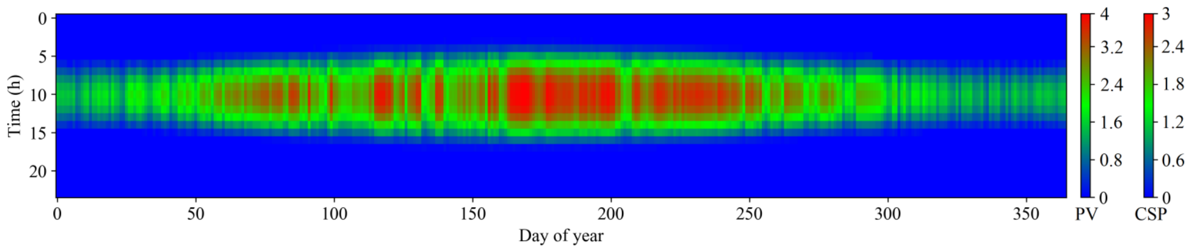

Figure 57. Capacity factor (CF) for solar power availability through hours-day and days in a year. Indexed Solar PV CF: 25% = 1 and solar CSP CF: 35% = 1. Adapted from [10].

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