Are Renewable Portfolio Standards Effective to Reduce CO₂ Emissions?

Alexander Galetovic\textsuperscript{a,}\textsuperscript{*}, Cristián Hernández\textsuperscript{b}, Cristián Muñoz\textsuperscript{c}, Luz María Neira\textsuperscript{d}

\textsuperscript{a}Facultad de Ciencias Económicas y Empresariales, Universidad de los Andes, Santiago, Chile. Av. Monseñor Álvaro del Portillo 12455, Las Condes, Santiago. Tel: +56/2/2618 1259. Fax: +56/2/2214 2006; E-mail: alexander@galetovic.cl.

\textsuperscript{b}Facultad de Ciencias Económicas y Empresariales, Universidad de los Andes, Santiago, Chile. Av. Monseñor Álvaro del Portillo 12455, Las Condes, Santiago. Tel: +56/2/2618 1431. Fax: +56/2/2214 2006; E-mail: chernandez@uandes.cl.

\textsuperscript{c}Departamento de Ingeniería Eléctrica, Pontificia Universidad Católica de Chile and AES Gener S.A. Tel: +56/2/2686 8904; Fax: +56/2/2686 8990; email: cmmunozm@uc.cl.

\textsuperscript{d}Facultad de Ciencias Económicas y Empresariales, Universidad de los Andes, Santiago, Chile. Av. Monseñor Álvaro del Portillo 12455, Las Condes, Santiago. Tel: +56/2/2618 1834. Fax: +56/2/2214 2006; E-mail: lmneira@uandes.cl.

Abstract

We quantify the intertemporal impact of Renewable Portfolio Standards (RPSs) on CO₂ emissions, pollution, and welfare. We find that the investments in renewable energy imposed by an RPS substitute investments in base load technologies. Therefore, its environmental benefit depends on the emission intensity factors of base load technologies, not on system average emission intensity factors. In many systems hydro is the technology that expands with base load demand, hence an RPS may have little impact on emissions and pollution.

We also find that RPSs can be quite expensive and that their cost is highly nonlinear. With detailed data on Chile’s main power system we estimate that a 5% RPS is not binding, a 10% RPS causes a small welfare loss but a 20% RPS multiplies the welfare loss by a factor of 51, to about 13% of the cost of generation. An RPS also rises the price paid by consumers and, with a 10% RPS, they lose the equivalent to 3% of the cost of generation; with a 20% RPS the loss rises by a factor of 8.

Scarcity rents obtained by renewable generators are substantial. With a 10% RPS they earn a rent which is equivalent to about 3% of the cost of generation. With a 20% RPS, scarcity rents

\textsuperscript{*}Galetovic gratefully acknowledges the financial support of Instituto Milenio P05-004-F “Sistemas complejos de Ingeniería” and the hospitality of the Stanford Center of International Development, the Center for Latin American Studies at Stanford University, and the Hoover Institution, where parts of this research were done. Galetovic gratefully acknowledges the partial financial support of AES Gener. The contents of this paper are the exclusive responsibility of the authors and in no way commit AES Gener S.A.

\textsuperscript{*}Corresponding author.
increase about four times, to about 18% of the cost of generation.

*Keywords:* renewable energy, energy policy, environmental economic assessment

*JEL classification:* Q58, L94, L98, L51

1. **Introduction**

It is often thought that policies that force investments in nonconventional renewable energy,¹ like Renewable Portfolio Standards (RPSs), are effective to reduce pollution and CO₂ emissions.²³ In this paper we assess RPSs: How effective are they to reduce CO₂ emissions and pollution? And how expensive are they? We show that RPSs are ineffective, unless the power system’s base load capacity is expanding with fossil fuel fired plants, and in any case, they are very expensive.

To quantify the intertemporal impact of RPSs on CO₂ emissions, pollution, and welfare and to model investment decisions we use our integrated assessment model Emma (Spanish acronym for “electricity, markets and the environment”), using Chile’s Central Interconnected System (CIS) as a case study.⁴ Emma overcomes two shortcomings of standard cost-benefit analysis of environmental policies in the electricity industry. First, it jointly solves for the private investment plan in capacity and the operation of the system. This is important because, as we explain below, most of the effects of environmental policies work through endogenous adjustments of the investment plan. Second, most standard cost-benefit assessment models assume that demand does not respond to price changes. This omission is unfortunate because it obscures the fact that environmental policies directly affect consumption growth and consumer surplus and, we show, these effects are large.

Our main finding is that investments in renewable energies forced by an RPS substitute mainly

---

¹Nonconventional renewable energies include geothermal, wind, solar, tidal, biomass, landfill gas and small hydroelectric power plants. Hydro projects smaller than 20MW and a fraction of hydro plants between 20MW and 40MW are considered nonconventional renewable energy in Chile.

²Tietenberg and Lewis (2012) make the following definition of the term Renewable Portfolio Standards: “these standards specify enforceable targets and deadlines for producing specific proportions of electricity from renewable resources.”

³RPSs are one of many policies that countries have used to promote renewables. Among other policies are auctions, feed-in tariffs, and fiscal incentives, like tax credits. So far, 118 countries have mechanisms to support renewable energy and at least 96 countries have set generation targets (see Renewable Energy Policy Network for the 21st Century (2011)). Green and Yatchew (2012) discuss and describe support mechanisms in several countries.

⁴The CIS is the largest electricity system in Chile. We describe the CIS in the next section.
investments in base load technologies and barely touch the rest. Therefore, the environmental benefit of an RPS depends mainly on the emission intensity factors of the base load technologies that renewables substitute, not on system average emission intensity factors. Because in many systems hydro is the technology that expands with base load demand, RPSs may have little if any impact on emissions.  

Indeed, we show that RPSs will have almost no impact in Chile’s CIS for the next 20 years, because renewables will substitute investments in hydro. Only when profitable hydro resources are fully used many years from now, renewables will substitute investments in coal, and have sizable effects on lowering emissions.

Our second finding is that RPSs are expensive and, because the supply curve of renewables is upward sloping, their costs are highly nonlinear with the size of the RPS. In the case of Chile’s CIS a 5% RPS is not binding, a 10% RPS causes a small loss of welfare, but increasing the RPS from 10% to 20% multiplies the welfare loss by a factor of 51.

An RPS also has important redistributive effects, which are also nonlinear. Forced investments in renewables rise the price that consumers pay. With a 10% RPS, they lose the equivalent to 3% of the cost of generation. But with a 20% RPS the loss rises by a factor of 9, to the equivalent of about 26% of the cost of generation. With the opposite sign, the same applies to producer’s profits. Because the supply curve of renewable energy is upward sloping and steep, scarcity rents are substantial. Indeed, with a 10% RPS the owners of renewables earn a scarcity rent which is equivalent to about 2% of the cost of generation. With a 20% RPS, scarcity rents increase about five times to about 11% of the cost of generation.

To determine the effects of an RPS in a system with fully tapped hydro resources, we simulated alternative scenarios in which the expansion with hydro is restricted. Then, the only alternatives to expand the CIS’s capacity are fossil-fuel-fired plants and renewables. Again we find that renewables

---

5It has been argued that reservoirs are net producers of CO₂ because they generate methane (CH₄). Nevertheless, Svensson (2005) performed a study of 167 hydro power stations that shows that reservoirs emit 75gCO₂/kWh on average and a median of 6.7gCO₂/kWh (methane emissions are shown in its CO₂ equivalent), assuming their “extreme estimate” of methane emissions. Note that the average value is about one-fourth and the median around 1/50 of the CO₂ intensity factor of a combined cycle gas fired plant, which is above 300g/kWh.

Also, when a reservoir is very intensive in methane generation (e.g. large tropical reservoirs built over densely forested areas), Ramos et al. (2009) shows that the cost of extracting and pumping the methane is less than the market price of natural gas, thus, substantially reducing the CO₂ intensity factor of those reservoirs.
substitute base load capacity—in this case coal—triggering a larger reduction of CO\textsubscript{2} and pollutants. However, the costs of the RPS are still high, and are larger than its environmental benefits—economic welfare decreases US$ 4.5 billion with a 20% RPS, which is equivalent to 7% of the cost of generation.

We contribute to a growing literature on the economic and environmental effects of RPSs. Kaffine et al. (2012), Cullen (forthcoming), and Novan (2011) estimate the emissions of pollution and CO\textsubscript{2} offset by wind generation in Texas, California, and the Upper Midwest, by identifying substitution patterns between wind and fossil fuels, taking wind capacity as given. We complement their analysis determining the long run substitution patterns between renewables and conventional technologies by modeling investment decisions. As said, we find that an RPS substitutes investments in base load technologies; therefore, the effectiveness of an RPS to reduce emissions depends mainly in the base load expansion technologies.

Bushnell (2010) and Chao (2011) also find that increasing the share of intermittent renewable energy (e.g. wind) decreases the optimal capacity of base load technologies (e.g. hydro, coal, nuclear or combined-cycle gas plants) and increases the optimal capacity of peak load technologies (combustion turbines). While we do not model intermittency, we go beyond their analysis by studying the effects of RPSs on the system’s investment path, using careful modelling of supply curves of renewable energy, and quantifying their environmental and economic impact.

Borenstein (2012) analyzes the private and the public economics of renewable electricity generation. He points out that meaningful cost-benefit assessments of alternative renewable technologies go beyond their levelized cost and include aspects such as the value of the externalities they mitigate, the location where they generate, their daily generation profile, and within-technology cost heterogeneity. To this, we would add that thorough assessments of alternative policies must consider a price-responsive demand, because, as we show below, a substantial part of the welfare effects of alternative policies are changes in consumer surplus. Our integrated assessment model quantitatively assesses how these aspects interact by solving an intertemporal optimization model that returns the optimal investment and generation path, subject to the constraints imposed by alternative environmental policies. In our model each technology is characterized by its cost structure, its availability factor, and its emissions under alternative abatement technologies. We model cost heterogeneity of renewables and hydro with upward sloping supply curves—both built from data on
actual resource availability—, and value environmental externalities with their marginal damage. Demand, in turn, is modeled with constant price-elasticity demand functions.

Last, Green and Yatchew (2012), Menanteau, Finon, and Lamy (2003), and Schmalensee (2012) show how different mechanisms to promote renewable energy differ in their ability to meet the generation targets with renewables. They also survey how alternative support mechanisms have worked in several countries that have tried them in the recent past. Similarly, Newbery (2012) argues that market design and regulation also determine the ability of a given policy to meet generation targets. Our paper, by contrast, studies the prospective environmental and economic impact of RPSs. While we assume in each case that the policy is effectively implemented (subject to the constraint of an upward sloping supply curve), our analysis sheds light on the costs of achieving these targets. We show that ambitious targets are likely to be expensive and that their cost should increase over time. This may cast doubts on their long-run sustainability.

The rest of the paper is organized as follows. Section 2 discusses three preliminaries: it presents the supply curve of renewables, explains the basic economics of an RPS and discusses how to measure the damage caused by pollution. Section 3 presents our analysis of RPSs. Section 4 concludes.

2. Preliminaries

2.1. Availability and levelized costs of renewable energy in the CIS

The Central Interconnected System (CIS) extends from Chile’s II region to its X, covering around 92.2% of Chile’s population, and comprising around 76% of its total installed capacity. In December 2010 CIS total capacity was 12,147 MW. On average, about two thirds of the energy generated comes from hydro plants. Hydro generation is complemented with natural gas-fired turbines (22.2% of installed capacity), coal (11%), diesel turbines (16.2%) and renewable energy (4.3%).

How much renewable energy is available in the CIS? Table 1 and Figure 1 present the first estimate of the supply curve of renewable energy in Chile’s CIS. We estimate that the total availability

---

6Due to Argentina’s ban on exports, currently only 6% of the CIS capacity is running with natural gas. The rest of the combined cycle turbines are running with diesel. These plants will run again with natural gas as imports of LNG increase within the next 10 years.
of renewable energy is approximately 9,000 MW that can produce 50,700 GWh/year on average. This might seem sizable given CIS’s current installed capacity, but the last row in Table 1 shows that the levelized cost of energy varies and in most cases is much higher than the levelized cost of conventional base load technologies, like large hydro projects and coal (coal’s levelized cost of energy is approximately US$80/MWh in Chile). Thus, a sharp distinction must be made between physical and economic availability of renewable energy. Indeed, as can be seen from Figure 1, there are barely 2,500 GWh/year available at levelized cost of less than US$80/MWh, which is the current market price of electricity, \( p^m \). Any expansion of renewables beyond that requires subsidies. The area \( A \) represents the scarcity rents earned by these projects.

Figure 1 also shows that the supply curve of renewable energy is upward sloping and that the slope varies significantly, being very steep in some sections. This might seem obvious and hardly worth mentioning, but we note it because most of the time analysts assume a constant levelized cost for each technology, and this is a very misleading assumption. For example, the levelized cost of energy of small hydroelectric plants, in Table 1, varies from US$70/MWh to US$186/MWh as a consequence of the volatility of the river flow, hydraulic head and location, because resources are located at different distances from the transmission system. Similarly, the levelized cost of a wind plant varies from US$137/MWh to US$202/MWh, depending on the capacity factor. And the levelized cost of geothermal projects varies from US$121/MWh to US$180/MWh with the probability of finding an appropriate source. As said, most of current assessments of policies that foster investments in renewable energy ignore heterogeneity. Instead, they assume a marginal technology with unlimited availability and constant levelized cost, or, when considering limited availability of resources, costs are assumed constant within technologies.

2.2. The basic economics of an RPS

As we have already said, in Chile an RPS target below 2,500 GWh/year is redundant. But if the target exceeds 2,500 GWh/year, the policy forces additional investments in renewable energy. The basic economics is as follows.

Assume, for example, that the policy imposes a quota of \( q^r = 20,000 \) GWh/year. The marginal

\footnote{Of course, total renewables generation in a year depends on the vagaries of the weather, especially small hydro, wind and solar plants.}
The project will establish the price $p^r$ that will be paid for each GWh generated with renewable energy. It can be seen in Figure 1 that this price is approximately US$165/MWh. If $p^m$ is the equilibrium price with no policy, the total subsidy that consumers will pay is the area $B+C$, that corresponds to

$$(p^r - p^m) \times q^r$$  

(1)

Not all the subsidy is lost of economic welfare. Indeed, the welfare loss caused by the policy is area $C$. The rest, area $B$, is a transfer from consumers to the owners of renewable projects—a scarcity rent. The RPS will increase the scarcity rents of the owners of renewables from area $A$ to area $A + B$.

Note that RPSs set targets relative to the system’s total generation or consumption. Therefore, as the demand for electricity grows over time so will the demand for renewable energy, the price $p^r$ paid to renewable projects, and the overall cost of the policy. Also, because the supply curve of renewable energy is upward sloping, the cost of the policy is nonlinear with the size of the RPS. Last, the cost of an RPS will vary across countries, because it depends on the local costs and availability of renewables. Therefore, each assessment of an RPS must consider local circumstances.

Note that support mechanisms for investments in renewable energy implemented through RPSs or auctions, are equivalent. The price $p^r$ that producers of renewable energy receive can be set through feed-in tariffs and fiscal incentives, to achieve the same generation target $q^r$. Therefore, the costs of these mechanisms should be similar, ceteris paribus.  

2.3. The damage wrought by CO$_2$ and air pollutants

Power plants that run on fossil fuels emit CO$_2$, other greenhouse gases (GHGs), and air pollutants: particulate matter (PM$_{10}$ and PM$_{2.5}$), sulfur oxides (SO$_x$), and nitrogen oxides (NO$_x$). CO$_2$ emissions and greenhouse gases contribute to global climate change and the damage they cause does not depend on where the emission occurs. On the other hand, air pollutants affect only the area surrounding the source, and damage health, materials, visibility and crops.

---

$^8$In practice, the cost wrought by mechanisms that foster renewable energies through prices varies, because the amount of investment is uncertain. For example, Spain supports renewable energy through feed-in tariffs that are differentiated by technology. Because they set the feed-in tariff too high for PV solar, they surpassed the target of 500MW by more than 2,000MW (Barroso et al., 2010), increasing the overall cost of the policy.

$^9$Particulates smaller than 2.5µm
The damage caused by air pollutants. We quantify the total damage caused by the emission of an air pollutant with the marginal damage caused by its emissions. The marginal damage of the emission of an air pollutant is the value assigned to the externality caused by emitting one additional ton of the pollutant.

Formally, if $md_i (s)$ is the marginal damage of air pollutant $i$ when the amount emitted is $s$, then the total damage ($D_i$) caused by emissions $t_i$ is

$$D_i(t_i) = \int_0^{t_i} md_i (s) \, ds$$  \hspace{1cm} (2)

We assume that the marginal damage is constant within a locality, no matter the amount emitted by each power plant. Therefore, the total damage of emissions of a power plant is linear with the amount emitted and (2) can be simplified to

$$D_i(t_i) = md_i \times t_i$$  \hspace{1cm} (3)

Note that in equations (2) and (3) total damage is a function of emissions $t_i$. Nevertheless, in practice the damage is caused by the exposure of individuals and things (e.g. buildings and crops) to pollution. As shown in Figure 2a, emissions interact with the local environment to determine the concentration of the pollutant in the air and only then humans and things are exposed and damaged. As a consequence, the marginal damage caused by an additional ton of the pollutant depends on the number of persons around the source of emission. For this reason, we assumed four different locations such that marginal damages differ because of population size (see table notes).

Table 2 exhibits the estimates of the marginal damages caused by PM$_{2.5}$, NO$_x$ and SO$_x$ in Chile and the United States. For Chile, we use the estimates by Cifuentes et al. (2010) for the marginal damages of PM$_{2.5}$, SO$_x$, and NO$_x$ \textsuperscript{10} emitted by each power plant in Chile, which consider only mortality, morbidity and the reduction of agricultural yields. Muller and Mendelsohn (2007) estimate that these effects account for 94% of the total damage in the United States.\textsuperscript{11}

\textsuperscript{10}We quantify only the effects of PM$_{2.5}$, SO$_x$ and NO$_x$ emissions. On the other hand, these are the pollutants that cause major concern (USEPA, 1995); on the other, there aren’t any estimates of the marginal damage of other pollutants in Chile—carbon monoxide (CO), volatile organic compounds (VOC) and trace metals like mercury (Hg), nickel (Ni), vanadium (V), arsenic (As) and cadmium (Cd).

\textsuperscript{11}Muller and Mendelsohn (2007) also include the damage to timber, materials, visibility and recreation.
We use the value of the marginal damages estimated in 2010 by Cifuentes et al. (2010). Over time these converge to the ones estimated by Muller and Mendelsohn (2007) for the United States as Chile’s GDP per capita gradually converges to USA’s GDP per capita. Note that the marginal damages of emissions are larger in Chile than in the United States because population densities around the sources of emissions are larger.

One source of imprecision in the assessment of environmental costs is that the mapping between emissions and concentration is highly dependent on local conditions and even on the characteristics of each source. For example, Muller and Mendelsohn (2009) show that ground-level emissions in urban areas increase concentrations nearby more than high-stack emissions, because tall smokestacks disperse pollutants away from the source. On the other hand, they also show that concentration levels in rural areas do not depend on whether the source is at ground level or a high stack.

Similarly, the mapping between exposure and immission on the one hand and damage on the other is subject to considerable uncertainty. Protracted exposition to pollution increases the prevalence of several chronic and acute diseases (morbidity), and lowers life expectancy (mortality). However, both morbidity and life expectancy are influenced by many other factors and it is not easy to quantify the incremental contribution of pollution.

The damage caused by CO₂ emissions. The adverse effects of climate change, among others, are floods, droughts, change in storm patterns and temperature, and higher sea levels, causing costs in those affected human activities. The marginal damage of CO₂ is the present value of all incremental economic costs caused by the incremental climate change of emitting an additional ton of CO₂ into the environment. In contrast to pollution, the damage caused by CO₂ does not depend on local conditions around the source, but only on the carbon content of the fuel burned.

Nordhaus (2010) estimated the price per ton of CO₂ for five post-Copenhagen scenarios using the RICE-2010 model. In our assessment we assume that the marginal damages of CO₂ over time are the prices of CO₂ reported in Nordhaus’ (2010) optimal scenario.¹² This scenario maximizes economic welfare, assuming that all countries mitigate emissions optimally from 2010 on, equaling the marginal cost of CO₂ abatement to the marginal damage of CO₂ in all sectors of the economy. Therefore, in this case CO₂ prices can be interpreted as marginal damages. Table 2 exhibits the

¹²See Tol (2011) for a full review of the studies about the marginal cost of carbon emissions.
marginal damage of CO₂ emissions, estimated in Nordhaus (2010). The price of a ton of CO₂ increases over time and ranges from $7.9 in 2012 to $55.9 in 2063.¹³,¹⁴

Finally, to compute the total damage of CO₂ we assume that the marginal damage is constant with power plant emissions but increases over time.

3. An evaluation of RPSs

3.1. A brief introduction into the Emma model

Description and basic assumptions. Emma is an intertemporal integrated assessment model that minimizes the private expected cost of electricity generation—the sum of capacity, operation, and outage costs. Just as it is done in the CIS, in Emma plants are dispatched by merit order and water from the Laja reservoir is used optimally.¹⁷,¹⁸ We assume that the generation profile of hydro plants follows the historic profile. We also assume that both wind and solar plants produce their average output during all hours.¹⁹

Existing capacity in 2010 is taken as given and, from then on, the model optimally installs new plants—hydro, coal, natural gas, diesel, nuclear, and renewables. It also optimally chooses plant location in three different zones, that differ in population size and transmission costs. Available hydro projects are carefully modeled with a supply curve which we built with public information.

¹³These values are linear interpolations of the values reported in RICE-2010’s optimal scenario and are in 2010 dollars.
¹⁴In the long term, the price of CO₂ in Nordhaus (2010) is capped by the price of the technology that can replace all carbon fuels. Nordhaus (2010) argues that the price of this technology is $1,260 per ton of carbon, which is equivalent to $343.3 per ton of CO₂. To convert from dollars per ton of carbon to dollars per ton of CO₂ divide by 3.67.
¹⁵See the appendix for a full description of Emma.
¹⁶In the CIS, generators must pay power outages, hence outage costs are part of private costs.
¹⁷Laja is the only reservoir in Chile with interannual storage capacity.
¹⁸There are also smaller reservoirs in the CIS that are as run-of-river plants, whose availability varies in every demand block.
¹⁹This simplification does not invalidate our results, because in Chile’s CIS, the output of wind plants does not correlate with the marginal cost of energy (the correlation coefficient of output and prices of wind plants in the CIS ranged from -0.1 to -0.02 in 2011)—average revenue per MWh is approximately equal to the average marginal cost. Similarly, the time profile of the output of a solar plant has little correlation with prices. This implies that the expected levelized price is an adequate estimate of the price that a generator expects when investing.
about water rights. We assume that renewables become gradually available over time. The initial fraction of the renewable supply curve in Figure 1 is 20% in 2010 and the fraction increases linearly until the total potential is fully available by 2025.

Precipitation uncertainty is modeled assuming four hydrologic scenarios, each one with independent probabilities that mimic the historical distribution of precipitation in the CIS. Fossil fuel price uncertainty is modeled with four equally-likely price vectors.

Formally, if \( r \) is the discount rate, \( \pi \) is the probability of a hydrologic scenario-fuel price vector combination, \( k(t) \) is the annuity payment of the total cost of the installed capacity in year \( t \), \( c(t) \) is the operation cost during year \( t \) and \( o(t) \) is the outage cost during year \( t \), Emma minimizes

\[
\sum_{t=1}^{60} \frac{1}{(1+r)^t} \sum_{j=1}^{16} \pi_j \cdot [k(t) + c_j(t) + o_j(t)]
\]

subject to producing the energy demanded each year—given the prices that consumer’s pay—and complying with the RPS and the environmental standards. Note that Emma is an intertemporal model, not a dynamic programming model—there are no reservoir level states and the optimization finds the vector that minimizes (4) over the entire planning horizon.

The simulations assume that the demand for electricity grows about 5% p.a. until 2020, and then at lower rates as the rate of GDP growth eventually converges to developed country levels.

Demand responds to price. Both energy prices and consumption are endogenous, as the demand for power responds to the price of energy. This way, every year, installed plants are dispatched to fill the load duration curve of three types of customers—residential/commercial, regulated LV-HV (for low voltage and high voltage) and non regulated HV—, which determines the system’s marginal costs and expected spot prices. Residential clients pay a regulated energy tariff, called BT1. The BT1 tariff is obtained from the sum of the expected marginal costs, the capacity cost, and the distribution cost, all adjusted by average losses. Regulated LV-HV and non regulated HV clients pay separate tariffs for energy and capacity during peak hours. The energy price for LV and HV clients is equal to the expected marginal cost, also adjusted by average losses and the capacity

---

20 To calculate the LCOE of each project the following parameters of each plant were considered: water flow rate, hydraulic head, location, distance to transmission system and the average capacity factor of the already existing plants located near the water right.

21 We assume that coal and natural gas prices are positively correlated with the price of oil.
cost is distributed pro rata as an energy charge during the peak load block; given those prices, the demanded quantities during each block match the produced quantities every year—the model iterates until it finds the market equilibrium. Because the price each client pays during a demand block is constant, the quantity of energy demanded during each block is deduced directly from the power demanded at each instant during the respective block.

*From planning to markets.* Cost minimization is equivalent to competitive behavior. This is a plausible assumption in the CIS because, in the short run, the Economic Load Dispatch Center (CDEC for its Spanish acronym) centrally dispatches plants according to strict merit order to meet load at every moment. Dispatch is mandatory and independent of contractual obligations, which ensures competitive behavior in operation given plant installed at each moment in time. Then, in the long run, free entry of generation ensures cost minimization. Consequently, fossil fuel projects and marginal hydro projects earn zero profits, because electricity prices are calculated directly from the shadow prices of the constraints of serving the quantity of energy demanded each year. At the same time, hydro and renewables obtain scarcity rents because their supply curves are upward sloping.

It should be noted that in Chile’s CIS, about 50% of the water rights, which are necessary to build hydro plants, are owned by Chile’s main generator, Endesa. Moreover, Endesa has a strategic alliance with Colbn, another generator who owns water rights, to jointly develop a large project in the Aysn region in southern Chile. Emma has a module that models the joint strategic behavior of Endesa and Colbn, assuming that they expand their installed capacity to maximize their joint profits. Nevertheless, in this paper we assume divested water rights, which ensure competition among all generator companies. We make this assumption because our interest in this paper is to model the effect of RPSs, not the exercise of market power.

---

22Free entry is a reasonable assumption because in Chile there are no differential legal restrictions to new generators. Furthermore, many new generators have entered during the last 10 years.

23The strong duality theorem ensures that, using those shadow prices, marginal projects earn zero profits. We thank Heinz Müller for making us aware of this.

24We estimate that Endesa’s water rights account for 22% of the total hydro potential in GWh/year and that Endesa + Colbn’s water rights account for the 47%. The latter number includes the water rights owned by Endesa, Colbn, and HidroAysn.
3.2. Simulations

To estimate the effects of RPSs we simulated the following:

- **Baseline**: No obligations to generate with renewable energy are ever adopted.

- **10% RPS**: An obligation of supplying at least 5% of annual sales of electricity with renewable energy in 2010, gradually increasing to 10% in 2024 is adopted.

- **20% RPS**: An obligation of supplying at least 5% of annual sales of electricity with renewable energy in 2010, gradually increasing to 20% in 2020 is adopted.

The baseline corresponds to the cost-minimizing expansion and operation of the CIS, without policies that encourage renewables. New plants install pollution abatement equipment to comply with current environmental regulation, supervised by the Environmental Impact Evaluation System (SEIA for its Spanish acronym), which forces the installation of abatement equipments to ensure a certain air quality. For this reason, the abatement efficiency imposed to each plant varies within technologies and location. Additionally, an emission standard caps emissions per MWh for each technology, regardless of plant location.\(^\text{25}\)

The 10% RPS scenario imposes a quota of 10% of renewable energy as stated in the Chilean law, which forces generators to supply at least 5% of their annual sales of electricity with renewable energies in 2010, to gradually reach 10% by 2024.\(^\text{26,27}\) The 20% RPS scenario assumes that the obligation is raised to 20% in 2020.\(^\text{28}\) (This is currently being discussed in the Chilean Congress.)

We also simulated two benchmark scenarios to calibrate the impact of environmental policies:

- **Uncontrolled emissions**: No environmental policies are ever adopted.

- **Optimal environmental policy**: Under this policy the marginal operation cost of fossil fuel plants equals their social cost, i.e., the private cost plus the marginal damages of emissions per MWh (PM\(_{2.5}\), SO\(_x\), NO\(_x\) and CO\(_2\)).

\(^\text{25}\)Caps for emissions may be higher or lower than what allows the SEIA. The stricter cap applies.

\(^\text{26}\)Note that this applies to contracted energy since 2010. Between 2020 and 2021, as most contracts signed before 2010 expire, the law will apply to all contracts.

\(^\text{27}\)The current law states that generators who do not comply with the requirement must pay a fine for each noncompliant MWh. Nevertheless, in this paper we assume that all generators comply with the requirement, because our aim is to estimate the cost and consequences of RPSs.

\(^\text{28}\)In this case, the law applies to all contracts, not depending on when the contract was signed.
The simulation with uncontrolled emissions removes all existing abatement equipment and assumes how the CIS would expand if no environmental regulations were in place. The aim is to compare proposed policies with outcomes under the current regulation.

The optimal policy, on the other hand, minimizes the cost of supplying electricity, internalizing the cost of the externalities caused by emissions. Thus, it is a benchmark that estimates how much more environmental policies can achieve, with current regulation as a yardstick.

3.3. Results

3.3.1. The effects on CO₂ emissions

Figure 3 plots CO₂ emissions over time with each of the five policies. One can clearly distinguish two periods. During the first 20 years (between 2010 and 2030), CO₂ emissions remain flat at about 13 million tons per year with all policies but the optimal. From then on, CO₂ emissions grow in every case, but alternative policies have large differential impacts on emissions’ growth. Thus, while standard intuition is that an RPS lowers emissions instantly, our results show that the RPS may be ineffective. Why?

Figure 4 shows the evolution of the composition of generation over time for four scenarios: the baseline, 20% RPS, uncontrolled emissions, and optimal. Technologies at the bottom of each graph (renewables and hydro) do not emit CO₂. At the top are technologies that emit CO₂ and air pollutants: coal, LNG, and diesel. Panel (a) in Figure 4 shows that in the baseline demand growth is met mainly with investments in hydro until 2030.\(^{29}\) Coal capacity freezes and CO₂ emissions remain constant.

Comparison of panels (a) and (c) show that the share of renewables quickly rises with a 20% RPS. Nevertheless, until 2030 the share of fossil fuels is almost indistinguishable from the baseline, because renewables substitute hydro investments. For this reason, renewables are ineffective to reduce CO₂ emissions before 2030.

Consider next what happens after 2030. Note that CO₂ emissions trend upward in the baseline case, as the share of coal starts to increase because profitable hydro projects run out. As Figure 3 shows, now renewables become effective to reduce CO₂ emissions. Indeed, after 2030, the 20% RPS seems to be as effective as the optimal policy. Thus, while emissions in the baseline case reach

\[^{29}\text{Hydro also stimulates investments in natural gas fired plants to hedge against droughts.}\]
180 million tons by 2049, they are 40% lower under the 20% RPS. Renewables become effective only after 2030 precisely because the obligation slowed down investments in hydro capacity. Hence, after 2030 there still are profitable unexploited hydro projects. Remaining hydro is developed and, as a consequence, the share of coal in generation falls. One general lesson is that the impact of an RPS on CO₂ emissions is highly dependent on the specifics of each case.

Figure 3 might also suggest that the effects of a 20% RPS are quite close to the optimal policy. Nevertheless, a comparison of panels (c) and (d) in Figure 4 shows that this impression is wrong. The optimal policy expands hydro capacity as fast as possible. Then, when hydro runs out, the system expands with LNG and the share of coal falls precipitously. By contrast, with an RPS hydro projects develop at a slower rate and the system expands with coal plants in the long run.

RPSs also reduce emissions by reducing consumption. As discussed in Section 2.1, they raise the cost of electricity and the prices that consumers pay, reducing the quantity of electricity that consumers demand. With a 20% RPS, prices in the long run are about 25% higher than in the baseline, decreasing the quantity of electricity demanded by about 8%. Nevertheless this explains only a small fraction of the total reduction of CO₂ emissions achieved. Changes in the composition of generation are much more important.

The modest contribution of demand responses to reduce emissions is confirmed by examining the optimal policy. Note that prices are higher than in the baseline case because the policy internalizes the social cost of externalities (prices are approximately 19% higher in 2049 with the optimal policy). Consumption decreases approximately by 7%, which reduces emissions. However, the reduction of emissions is about 55%. As with RPSs, most of the decrease in CO₂ emissions comes from changes in the composition of generation.

3.3.2. Local pollution

Table III shows the added emissions of air pollutants and their social cost for 2012-2051, for each of the five policies. Renewable portfolio standards affect emissions of local pollutants, but their impact is modest. With a 20% RPS added SOₓ emissions fall by 46%, NOₓ by 48% and PM₂.⁵ by 40%. But the impact on the social cost of pollution is much lower—the social cost of

---

Benavente et. al (2005) estimated that the residential long term price elasticity of electricity of the CIS is -0.39. This is the price elasticity that we used in our simulations.
pollution is reduced only in 34%. Again the explanation is in Figure 4, panels (a) and (c): for 20 years renewables substitute hydro, barely affecting the share of fossil fuels. Only after 2030 they substitute generation with coal.

It is interesting to compare the effect of an RPS with, on the one hand, the effect of the current environmental regulation and, on the other hand, the optimal policy. An RPS reduces air pollution, but, compared with the optimal policy, too little. Indeed, the optimal policy is to reduce air pollution right away. Again, the comparison between panels (c) and (d) in Figure 4 is revealing: with the optimal policy investments in hydro occur faster than in the baseline case, and once hydro runs out, the system expands with LNG instead of coal, which pollutes less. This substitution of LNG for coal does not occur with an RPS. Also, the optimal policy induces the installation of abatement equipment, sometimes with higher efficiencies than those imposed by the current regulation, so fossil fuel plants instantly emit less.

The relative ineffectiveness of RPS can also be appreciated by contrasting the baseline case with the uncontrolled emissions case (column 4 in Table III). Current environmental policies, aim at controlling emissions of local pollutants, particularly fine particulate matter (PM$_{2.5}$). It can be seen that current environmental policies are quite effective in cutting emissions of local pollutants. Were it not for them, SO$_x$ emissions would be 16 times higher; NO$_x$ emissions would be 17 times higher; and PM$_{2.5}$ emissions would be 340 times higher. All in all, the social cost of local pollutants would be about 40 times larger (see Table III).

The contrast between uncontrolled emissions and the other policies is sharp also in terms of the cost of local pollution. As can be seen in Table III, with uncontrolled emissions this cost is US$8.2 billion in present value, about 14% of the cost of generation. With the other scenarios, the cost of local pollution falls between US$100 million and a little more than US$200 million, between 0.2% and 0.4% of the generation cost. In other words, current environmental regulation and standards effectively solve the problem of local pollution. For this reason, anything added by a renewable energy requirement will be small in absolute terms.

3.3.3. Economic effects

Most analysis of the economic effects of an RPS quantify the incremental costs of supply entailed by the policy. Total generation costs for each scenario are presented in present values for 2012-2051.
in the first two lines of Table 4, in millions of dollars.\textsuperscript{31}

Consider the 10\% RPS. It increases private generation costs from US$57,931 million to US$58,154 million and, as we have already seen, reduces environmental costs by about 11\%, from US$3,741 million to US$3,330 million. Total costs fall slightly, just 0.3\%. On the other hand, a 20\% RPS increases private production costs by about 3\%, and environmental costs fall 30\%. As a result, total costs increase, but again the change is small, 1.2\%. Thus, the impression one gets by looking at costs is that an RPS has modest effects.

Nevertheless, a thorough assessment of the economic impact of an RPS should compute its change in economic welfare. By definition, the change in economic welfare produced by a policy relative to the baseline is

\[
\Delta \text{(economic welfare)} = \Delta \text{(consumer surplus)} + \Delta \text{(generators profits)} - \Delta \text{(environmental costs)}
\]

The middle panel of Table 4 reports the calculation.

Note first that a 10\% RPS imposes a negligible loss of economic welfare—US$149 million over 40 years. This occurs because during the first 10 to 15 years the requirement can be met with “cheap” renewable energy—the initial part of the supply curve depicted in Figure 1.

One might think that an increase of the obligation to 20\% has modest effects on welfare, but this impression is wrong. Indeed, welfare loss increases 33 times, to US$7.7 billion. Why? The arithmetic is that consumers lose about US$15.3 billion, which is partly compensated by the fall in environmental costs (US$1.1 billion) and the increase in generators’ profits (about US$6.5 billion). The economics is that the supply curve of renewable energy is steep and the RPS considerably raises the price of the marginal renewable source and, of course, the subsidy paid to renewable energy.

The subsidy to renewable energy, as equation (1) shows, depends on two factors: the premium for renewable energy \((p^r - p^m)\) and the quantity demanded \((q^r)\). Figure 5 shows the price of renewable energy, taken from the supply curve, with obligations of 10\% and 20\%, and the market price of electricity in the baseline. Note that with both obligations, the premium for renewable energy is zero during the first years, hence renewable energy is not subsidized during those years. However, a 20\% RPS subsidizes renewable energy four years before than a 10\% RPS, and in most

\textsuperscript{31}All results are expressed in US dollars at 2009 price levels.
years the premium is more than twice as large as the premium of a 10% RPS. On the other hand, a 20% RPS doubles the quantity demanded of renewable energy. Therefore, as equation (1) suggests, the subsidy wrought by a 20% RPS is always more than 2 times the subsidy of a 10% RPS and, most of the time, it multiplies the subsidy of a 10% RPS of by a factor higher than four.

Once this fact is recognized, the rest follows. Higher prices for renewable energy inevitably increase the price that consumers pay—hence the large fall in consumer surplus. At the same time, the increase in the price of renewable energy rises generators’ profits. Last, because the RPS finally slows the expansion of fossil fuel technologies after 2030, environmental costs fall.

What do we learn from all this? One lesson is that generation costs, even if environmental externalities are valued, are misleading indicators of the social cost of policies. With an RPS prices increase, demand responds to price changes and this has an important quantitative impact.

The second general lesson is that the impact of policies on welfare is nonlinear. The economics is simple: supply curves of renewable energy are not flat but upward sloping. Thus, policy assessments must carefully estimate the availability of renewable energy sources and their costs.

The third lesson is that RPSs redistribute wealth from consumers to generators. If the supply curve of renewable energy is steep, the size of this redistribution will be large. More than that, quotas also redistribute wealth among generators. The last three lines of Table 4 show that the owners of renewables will increase their profits at the expense of the rest of generators.

3.4. Pollution and renewables when the system expands with fossil fuels

There are many power systems that expand exclusively with fossil fuels. In order to assess the effects of RPSs in those systems, we simulated two scenarios:

- **No expansion with hydro**: There are no further investments in hydro. No obligations to generate with renewable energy are ever adopted.

- **No expansion with hydro + 20% RPS**: There are no further investments in hydro and there is an obligation to supply at least 5% of annual sales of electricity with renewable energy in 2010, gradually increasing to 20% in 2020.

- **Optimal environmental policy without hydro**: There are no further investments in hydro and the marginal operation cost of fossil fuel plants equals their social cost.
The first scenario simulates the cost-minimizing expansion and operation of the CIS, assuming that there are no further investments in hydro and increasing demand is met with investments in fossil fuel technologies and renewables. As in the baseline, new fossil fuel plants install pollution abatement equipment to comply with the current environmental and emission standards.

The 20% RPS scenario adds an obligation to supply at least 20% of electricity sales in 2020 with renewables. On the other hand, the optimal environmental policy internalizes the cost of the externalities caused by emissions.

3.4.1. The effects on CO2 emissions and local pollution

Figure 6 shows CO₂ emissions for the three scenarios and the baseline. Note that without further investments in hydro, yearly CO₂ emissions increase fast because generation grows mainly with investments in coal (see Figure 7 panel (a)).

As can be seen in Figure 6, now the 20% RPS lowers CO₂ emissions instantly. The reason for this can be seen by comparing panels (a) and (b) in Figure 7. With an RPS, renewables substitute investments in coal. Therefore, an RPS is far more effective when coal is the base load technology.

Nevertheless, the RPS is not as effective as the optimal policy. The optimal policy lowers emissions instantly as well, but unlike the RPS, it also significantly lowers the growth rate of CO2 emissions. As Figure 7 panel (c) shows, with the optimal policy increasing demand is met with LNG, and the share of coal in generation precipitously falls.

At the same time, now the RPS reduces local pollution more than when the system expands with hydro (see Table V). But, even in this case, the RPS only has a marginal effect on emissions of local pollutants because, as discussed in Section 3.3.2, current standards and regulation already deal with the problem. The general lesson is that an RPS is not necessary when cheap and effective abatement equipment is available.

3.4.2. Economic effects

Table VI shows the change in economic welfare for these scenarios. While now an RPS is more effective to reduce CO₂ emissions and pollution, it is still expensive. Indeed, economic welfare falls US$4.5 billion, which is equivalent to 7% of the cost of generation. Again, the redistributive effects are large. Consumers lose US$13 billion of surplus, while renewable generators increase their profits in US$9.9 billion. Regardless of what technologies are substituted by renewables, if
the requirement of the RPS is large, its cost will exceed its environmental benefits, because the supply curve of renewables is upward sloping and an RPS will inevitably raise prices and the subsidy paid to renewables.

3.5. Which technologies does a renewable quota substitute?

To end this section we provide a simple explanation why RPSs substitute investments in base load technology.

Remember the well known basic economics of the optimal technology mix for electric utilities\(^\text{32}\). To simplify, assume perfect competition, deterministic behavior of supply and demand, and two technologies: base load and peak load. Assume that the annualized costs of capacity per kW for base load is \(k_b\) dollars and \(k_p\) dollars for peak load. Marginal operating costs per kWh are \(c_b\) dollars for base load and \(c_p\) dollars for peak load, and, as is standard \(k_b > k_p\) and \(c_b < c_p\).

Figure 8 (a) shows a standard load duration curve and the total cost of a kW of base load and peak load capacity per year as a function of the running hours. The classic result is that optimal running time (in hours) for peak load technology over a year is

\[
t^* = \frac{k_b - k_p}{8.760 \cdot (c_p - c_b)}
\]

Note that the total cost of supplying a load with duration longer than \(t^*\) hours is smaller using a base load plant than a peak load plant, so the minimizing cost criteria will choose to supply loads longer than \(t^*\) with base load capacity and the remaining with peak load capacity. In Figure 8 (a), \(B\) MW of base load and \(P\) MW for peak load capacity will be installed to supply demand at minimum cost.

Figure 8 (b) shows the same load duration curve and the costs of the same base load and peak load plants, but assumes that \(R\) MW of renewable energy are necessary to comply with the RPS. Because the running cost of renewables is very low, they are first in the merit order. Hence, once a renewables obligation is introduced, base and peak load capacity face a residual demand, which is obtained by shifting down the load duration curve in \(R\) MW. However, the optimal running time \(t^*\) remains the same, because it only depends on costs. Therefore, \(B' = B - R\) MW of base load capacity and \(P\) MW of peak load capacity will be built to minimize the total cost of supplying

\(^{32}\text{See Turvey (1968), Crew and Kleindorfer (1975), and Wenders (1976).}\)
electricity. The RPS substitutes for investments in base load capacity (hydro, coal, nuclear or combined cycle gas fired plants as the case may be), and it will substitute peak capacity (gas or diesel turbines) if the requirement is large enough.

While this example is simple, it captures the main effect. When demand and supply are uncertain (see Chao, 1983 and 2011), the optimal running time of each technology is determined by the annual costs of capacity, the average availability, marginal operating costs, and the expected fraction of time where demand is higher than the sum of available supply. Then, with an RPS, the optimal running time of base load technologies (their $t^*$’s) will be modified because intermittent renewable energy sources like wind and solar will be installed to meet the quota. Bushnell (2010) and Chao (2011) show that stochastic effects imply that an RPS requires more peak load capacity and less base load capacity. However, the results over energy generation are larger for base capacity because each MW of base load capacity runs for more hours in a year than a peak load MW.

4. Conclusion: characterizing cost-effective environmental policies

We began this paper claiming that RPSs are likely to be ineffective to reduce CO$_2$ emissions and pollution. Using our intertemporal integrated assessment model Emma and a simple application of the optimal technology mix for electric utilities, we have shown that a renewable quota substitutes mainly investments in base load technologies. As a result, RPSs are ineffective to reduce emissions in many systems where there are “cheap” available hydro resources to invest in base load capacity. Even when renewables substitute for coal generation, and substantially reduce CO$_2$ emissions, quotas may be very expensive because renewable supply curves are upward sloping, hence the cost increases nonlinearly with the size of the quota. To conclude, we briefly characterize cost effective environmental policies and contrast them with RPSs.

There are two ways to reduce pollution and greenhouse gas emissions. One is capturing emissions directly and the other substituting “clean” technologies for emission-intensive technologies. Both mechanisms are complements and environmental policies can be thought as rules and incentive structures that induce combinations of both.

One widely-used policy is to impose emission standards. If binding, standards either force the installation of abatement equipment or, if abatement equipment is infeasible or too costly, the abandonment of the technology.
Standards are cost-effective when abatement equipment is cheap relative to the environmental benefits they achieve. Chile's SEIA, a twenty-year old policy, and its current emission standard, which forced the installation of abatement equipment, is a case in point. As Table III shows, it has cut SO$_2$ emissions to 1/16, cut NO$_x$ emissions to 1/17, and reduced PM$_{2.5}$ emissions to 1/340. And it has been a remarkably cost-effective policy. As Column 4 in Table IV shows, the current regulation increases social surplus in about US$6.5 billion (around 11% of the cost of generation) and barely increases the cost of supply (US$56.2 billion with no standards to US$57.9 billion in the baseline case).

Now while the current environmental policies have large welfare effects, they barely take advantage of fuel substitution. As can be seen by comparing panels (a) and (b) in Figure 4, the composition of generation in the baseline case (with current environmental policies) and with uncontrolled emissions is almost the same. Moreover, current environmental policies do little to cut CO$_2$ emissions. This is why there would still be room for an optimal policy, which would substitute low-emission fuels for high-emission fuels, and fully internalize environmental externalities.

Again, we can see the effects of the optimal environmental policy over investments using the basic economics of power systems. Figure 8 (c) shows the case in which base load technology is a “clean” technology (e.g. hydro) and the peak load technology pollutes and emits CO$_2$ (e.g. coal). The optimal policy increases the marginal operation cost of the peak load technology, changing it’s optimal running time from $t^*$ to $t'$. Therefore, “dirty” peak load capacity decreases from $P$ to $P''$, decreasing emissions to the optimal levels. This explains why in the optimal policy hydro projects are developed faster and, once hydro runs out, LNG substitute for coal, as LNG emits less CO$_2$ and air pollutants. Also, the optimal policy stimulates the installation of pollution abatement equipment when convenient, making the policy even more effective. Last, panels (a) and (d) in Figure 4 show that the optimal policy would dramatically change the composition of generation. Essentially LNG substitutes for coal generation, whose share in total generation would steadily fall.

The contrast of these two policies with RPSs is stark, because RPSs are expensive and do not achieve sizable reductions of pollution and CO$_2$ emissions. This is primarily because they neither force abatement nor fuel substitutions. Therefore, they do not directly affect the emission factors of any of the technologies in the system, and since they only substitute part of the generation.

Moreover, SEIA does not address greenhouse gas emissions.
with base load capacity, the reductions they can achieve are limited. Worse, they may substitute renewables for hydro, achieving no environmental benefits at all.

The final comments are about the sustainability over time of a given RPS. As Newbery (2012) points out, the rules of the electricity market may make it impossible to meet renewable’s generation targets. Nevertheless, even when the rules of the electricity market favor renewable energy, some countries might not be able to achieve the targets because, as we have shown, supply curves of renewable energy are upward sloping and can be very steep (see Chile’s CIS supply curve). Therefore, a bold target may well become politically or economically infeasible once reality hits and costs begin to escalate nonlinearly.

References


Appendix

Appendix A. Emma: Electricity, Markets and the Environment

Appendix A.1. Features

Emma is a multiperiod partial equilibrium model of Chile's Central Interconnected System (CIS) (Chile's main power system). Given existing capacity, supply is determined by the least cost investment and operation path, while demand consists of load duration curves, divided in discrete blocks, for three customers with constant price-elasticity demand functions.

Emma includes fuel price and water inflow uncertainty, and local constraints: reservoirs (Laja and smaller reservoirs), water rights concentration, and renewable portfolio standards. It also allows internalizing the social cost of greenhouse gas (CO2) and local pollutant (SOx, NOx, and PM) emissions. These features are desirable for long run power system planning, but commercial models lack some of them.

The following sections describe how Emma finds the electricity market equilibrium. First, we describe the basic modeling assumptions for each technology. Then, we present the objective function and show the assumptions for demand and price calculations. Last, we explain the iterative process through which Emma finds the equilibrium of supply and demand. Appendix B shows the equations of the model that we cite along the discussion.

Appendix A.2. Technology assumptions

Fossil Fuels. These technologies are modeled with constant-return-to-scale plants that can be installed in three locations that differ in transmission costs and population size; therefore, differ in the marginal cost of local externalities.

Generation during each block of demand is limited by average mechanical availability (see equation B.8.) Fossil fuel price uncertainty that affects operation costs is modeled through annual price scenarios with independent probabilities that assume the prices of coal and natural gas correlate with the price of oil. Environmental costs, when internalized, are included in the marginal operation cost.

Renewables. These are the technologies that the Chilean law allows for compliance with the renewable obligation: wind, solar, geothermal, biomass, landfill gas, and hydro plants smaller than 20 MW. (Assumptions for larger hydro projects are discussed below.)

Emma assumes a discrete supply curve for each renewable technology to represent quality heterogeneity and limited resource availability. Each renewable technology is divided into subtechnologies that differ in cost, capacity factor, and resource availability.

Generation during each demand block is equal to average output (see equation B.8.) This is a reasonable assumption because, in Chile's CIS, wind and solar generation are uncorrelated with consumption and marginal cost and Emma uses annual periods.

---

34 For example, the capacity factor of a wind plant varies depending on location.
35 The correlation coefficient of output and prices of wind plants in the CIS ranged from -0.1 to -0.02 in 2011.
Hydro. Emma also assumes a discrete supply curve of hydro resources. Similarly to renewables, hydro resources vary in quality depending on their distance to the transmission grid, capacity factor, and project size in MW.

Uncertainty in water inflow that affects run-of-river plant output and reservoir energy storage is modeled assuming four hydrologic scenarios per year with independent probabilities that mimic CISs historical distribution of water inflows.

Because reservoirs store energy for peak-load hours, in Emma, the available power of reservoirs and run-of-river plants varies in each block and hydrologic scenario, following the historical generation profile of hydro plants in the CIS (see equation B.9).

As Laja is the only reservoir with inter-annual storage capacity, we model the hydro plant chain from Laja basin separately (see Figure A.1) and the model optimizes Laja reservoir generation. In Emma the efficiencies of hydro turbines are constant with the elevation of the Laja reservoir and each year the initial elevation of Laja reservoir \( E_{Laja} \) is the expected value of the previous year final elevation (see equation B.21).

Appendix A.3. Cost minimization

Formally, if \( r \) is the discount rate, \( T \) is the optimization period in years, \( k_t \) is the capacity and maintenance cost in year \( t \) (see equation B.2), \( c_t \) is the operation cost in year \( t \) (see equation B.3), and \( o_t \) is the outage cost\(^{37} \) in year \( t \) (see equation B.4), Emma minimizes

\[
\sum_{t=1}^{T} \frac{1}{(1 + r)^t} \cdot (k_t + E(c_t + o_t))
\]

subject to producing the energy demanded each year (see equation B.5), complying with renewable quotas (see equation B.6) and environmental standards\(^{38} \), discrete supply curves (see equation B.7), technology constraints (see equations B.8 through B.12), and the hydraulic balance of Laja basin (see equations B.13 through B.25).\(^{39} \)

New plants cannot be decommissioned; annual investment and maintenance costs are paid in perpetuity.

Cost minimization is equivalent to competitive behavior. This is a plausible assumption in the CIS because, in the short run, the Economic Load Dispatch Center (CDEC for its Spanish acronym) dispatches plants according to merit order. Dispatch is mandatory and independent of contractual obligations, which ensures competitive behavior in operation. Then, in the long run, free entry of generation ensures cost minimization.\(^{40} \)

Appendix A.4. Demand

Every year the model dispatches plants to fill the load duration curve of the system that is the sum of the load duration curves of three customers: residential (smaller than 10 kW), small industrial (between 10 kW and 2 MW), and large industrial (larger than 2 MW). Each curve is divided in blocks of demand for power. Formally, if \( q_{i,k,t} \) is the demand for power of customer \( i \) during block \( k \) in year \( t \), the demand for power of the system during block \( k \) in year \( t \) is

\[
q_{k,t} = \sum_{i=1}^{3} q_{i,k,t}
\]

MW, and the energy demanded during that block will be

\[
Q_{k,t} = q_{k,t} \cdot \sigma_k
\]

MWh, where \( \sigma_k \) is the duration of block \( k \) in hours.

We model the demand for power of each customer with constant price-elasticity functions; therefore, if \( \eta_i \) is the price-elasticity of customer \( i \) and \( p_{i,k,t} \) is the price of electricity for customer \( i \) in year \( t \) block \( k \), then its demand for electricity is

\[\text{[Footnote]}\]

\(^{36}\)This is done to keep the problem linear and avoid dynamic programming.

\(^{37}\)In the CIS, generators must pay power outages; therefore, outage costs are part of private costs.

\(^{38}\)Compliance with environmental standards is modeled through the inputs.

\(^{39}\)Note that Emma is an intertemporal model, not a dynamic programming model—there are no reservoir level states and the optimization finds the vector that minimizes equation B.1 over the entire planning horizon.

\(^{40}\)Free entry is a reasonable assumption because in Chile there are no differential legal restrictions to new generators. Furthermore, many new generators have entered during the last 10 years.
\[ q_{i,k,t} = A_{i,k,t} \cdot p_{i,k,t}^{q_i} \]

The $A$'s are determined exogenously based on demand forecasts.

**Appendix A.5. Prices**

Residential customers pay a flat energy tariff equal to the annual average of expected marginal costs, which are the shadow prices of the demand constraints. Note that this tariff includes the marginal cost of capacity; it is included in the marginal cost of the peak-load block. Industrial clients pay differentiated energy tariffs during peak and off-peak hours. The energy price during peak hours is the expected marginal cost during the peak-load block, which includes the marginal capacity cost. The energy price during off-peak hours is the average of expected marginal costs during off-peak blocks. All tariffs include a flat transmission and distribution charge, different for each customer, and are adjusted by average losses.

Renewable portfolio standards produce an additional charge for all customers when the marginal cost of renewable energy is higher than the average marginal cost of the system. Customers pay a surcharge such that all renewables receive for their energy a price equal to the marginal cost of renewables.

**Appendix A.6. Solving for the market equilibrium**

Figure A.2 depicts how Emma finds the equilibrium of supply and demand. Given initial load duration curves for the whole optimization horizon, $q_0$, Emma minimizes the cost of electricity and computes the price vector, $p_0$. Then, it compares the demanded quantities at price $p_0$ with the initial demanded quantities. If all quantities differ in less than $\epsilon$ MW in absolute value, the algorithm converges and the market equilibrium is $(p_0, q_0)$; otherwise, the model updates the demanded quantities for the next iteration, $q_1$, with the relation

\[ q_{i+1} = q_i + \alpha \cdot (q(p_i) - q_i) \]

where $\alpha$ is a positive arbitrary constant, less or equal than one, that is calibrated to make the process converge faster.\(^{41}\) Then, the model minimizes the cost of electricity again and repeats the process until it converges.

**Appendix B. The equations of Emma**

**Appendix B.1. Cost minimization**

**Appendix B.1.1. Sets**

- $S_1$: Technologies.
- $S_2$: Demand blocks.
- $S_3$: Hydrologic scenarios.
- $S_4$: Fuel price scenarios.
- $S_5$: Pollutants.
- $S_6$: Renewable technologies.
- $S_7$: New hydro and new renewable plants.
- $S_8$: Fossil fuel and renewable plants.
- $S_9$: Hydro plants, except the ones from Laja basin.
- $S_{10}$: Existing plants.

**Appendix B.1.2. Parameters**

- $\pi_h$: Probability of a hydrologic scenario.
- $\pi_c$: Probability of a fuel price scenario.
- $r$: Discount rate.
- $T$: Optimization horizon in years.
- $a_{i,t}$: Annuity payment per MW of technology $i$ that is built in year $t$. Includes construction, transmission line between the plant and the grid, and fixed maintenance costs.

\(^{41}\)This process is called a successive over relaxation algorithm.
\( \omega_{i,h,c} \): Marginal operation cost of technology \( i \) in US$/MWh, given the hydrology-fuel price scenario \((h,c)\).

\( \theta_{i,e,t} \): Tax per emitted ton of pollutant \( e \) by technology \( i \) in year \( t \) in US$/ton.

\( \rho_{i,e} \): Pollutant \( e \) emission intensity factor of technology \( i \) in ton/MWh.

\( \chi \): Marginal social cost of outage in US$/MWh.

\( D_{k,t} \): Demanded quantity of electricity in GWh in block \( k \) in year \( t \).

\( \gamma_i \): Percentage of electricity output consumed by the power plant.

\( \tau_t \): Fraction of renewable energy required in year \( t \), from total sales.

\( \nu_{i,t} \): Resource availability of technology \( i \) in year \( t \), in MW.

\( \sigma_k \): Duration of block \( k \) in hours.

\( \phi_i \): Average mechanical availability of technology \( i \).

\( f_{k,h} \): Capacity factor of hydro plants in block \( k \) given the hydrologic scenario \( h \).

\( \delta_i \): Construction time of technology \( i \) in years.

\( u_{i,t} \): Existing capacity of technology \( i \) in year \( t \).

Appendix B.1.3. Decision variables

\( P_{i,t} \): Total capacity in MW of technology \( i \) in year \( t \).

\( G_{i,k,t,h,c} \): Generation of technology \( i \) in GWh in block \( k \) in year \( t \), given the hydrology-fuel price scenario \((h,c)\).

\( \psi_{k,t,h,c} \): Loss of load in GWh in block \( k \) in year \( t \), given the hydrology-fuel price scenario \((h,c)\).

\( W_{i,k,t,h,c} \): Water spill from hydro plant \( i \) in block \( k \) in year \( t \), given the hydrology-fuel price scenario \((h,c)\).

All variables are positive.

Appendix B.1.4. Ancillary variables

\( k_t \): Capacity and maintenance cost in year \( t \).

\( c_t \): Operation cost in year \( t \).

\( o_t \): Outage cost in year \( t \).

Appendix B.1.5. Objective function

\[
\sum_{t=1}^{T} \frac{1}{(1+r)^t} \left( k_t + E(c_t + o_t) \right)
\]  

(B.1)

Capacity cost

\[
k_t = \sum_{l=1}^{i} \sum_{i \in S} a_{i,l} \cdot (P_{i,l} - P_{i,l-1})
\]

\[
(P_{i,0} = 0; t = 1, 2, \ldots, T)
\]  

(B.2)

Operation cost

\[
E(c_t) = \sum_{i \in S} \sum_{k \in S} \sum_{h \in S} \sum_{e \in S} \pi_h \cdot \pi_e \cdot G_{i,k,t,h,c} \cdot \left( \omega_{i,h,c} + \sum_{e \in S} \theta_{i,e,t} \cdot \rho_{i,e} \right)
\]  

\((t = 1, 2, \ldots, T)\)

(B.3)

Outage cost

\[
E(o_t) = \sum_{k \in S} \sum_{h \in S} \sum_{e \in S} \pi_h \cdot \pi_e \cdot \chi \cdot \psi_{k,t,h,c}
\]  

\((t = 1, 2, \ldots, T)\)

(B.4)
Appendix B.1.6. Constraints

Demand for electricity

\[
\sum_{i \in S_1} G_{i,k,t,h,c} \cdot (1 - \gamma_i) + \psi_{k,t,h,c} = D_{k,t}
\]

\((k \in S_2; t = 1, 2, \ldots, T; h \in S_3; c \in S_4)\) (B.5)

Renewable portfolio standard

\[
\sum_{i \in S_6} \sum_{k \in S_2} \sum_{h \in S_3} \sum_{c \in S_4} \pi_h \cdot \pi_c \cdot G_{i,k,t,h,c} \cdot (1 - \gamma_i) \geq \tau_t \cdot \sum_{k \in S_2} D_{k,t}
\]

\((t = 1, 2, \ldots, T)\) (B.6)

Supply curves of hydro and renewables

\[
P_{i,t} \leq \nu_{i,t}
\]

\((i \in S_7; t = 1, 2, \ldots, T)\) (B.7)

Technology availability (fossil fuels and renewables)

\[
1000 \cdot G_{i,k,t,h,c} \leq \sigma_k \cdot \phi_i \cdot P_{i,t}
\]

\((i \in S_8; k \in S_2; t = 1, 2, \ldots, T; h \in S_3; c \in S_4)\) (B.8)

Output of hydro plants

\[
(G_{i,k,t,h,c} + W_{i,k,t,h,c}) \cdot 1000 = \sigma_k \cdot f_{k,h} \cdot P_{i,t}
\]

\((i \in S_9; k \in S_2; t = 1, 2, \ldots, T; h \in S_3; c \in S_4)\) (B.9)

Increasing capacity

\[
P_{i,t+1} \geq P_{i,t}
\]

\((i \in S_1; t = 2, 3, \ldots, T)\) (B.10)

Construction times

\[
\sum_{t \leq \delta_i} P_{i,t} = 0
\]

\((i \in S_1)\) (B.11)

Existing capacity

\[
P_{i,t} = u_{i,t}
\]

\((i \in S_{10}; t = 1, 2, \ldots, T)\) (B.12)

Appendix B.1.7. Laja basin constraints

Sets

- \(S_{11}\): Hydro plants from Laja basin

El Toro, Abanico, Antuco, Ruce, and Quilleco.

Parameters

- \(\xi_i\): Efficiency of hydro plant \(i\).
**Decision variables**

$x_{i,k,t,h,c}$: Water flow in plant $i$, block $k$, year $t$, given the hydrology-fuel price scenario $(h,c)$. This includes turbine water flow and spills.

$X_{i,k,t,h,c}$: Power output from hydro plant $i$, given the hydrology-fuel price scenario $(h,c)$.

$V_{t}$: Initial volume of Laja reservoir in year $t$.

$V_{f,t,h,c}$: Final volume of Laja reservoir in year $t$, given the hydrology-fuel price scenario $(h,c)$.

**Constraints**

**Available power**

\[
X_{i,k,t,h,c} \leq x_{i,k,t,h,c} \cdot \xi \\
(i \in S_{11}; k \in S_{2}; t = 1,2,\ldots,T; h \in S_{3}; c \in S_{4}) \tag{B.13}
\]

\[
X_{i,k,t,h,c} \leq P_{i,t} \\
(i \in S_{11}; t = 1,2,\ldots,T) \tag{B.14}
\]

**Hydro plant generation**

\[
1000 \cdot G_{i,k,t,h,c} = X_{i,k,t,h,c} \cdot \sigma_{k} \\
(i \in S_{11}; k \in S_{2}; t = 1,2,\ldots,T; h \in S_{3}; c \in S_{4}) \tag{B.15}
\]

**Hydraulic balances**

\[
X_{Quillaco,k,t,h,c} = X_{Rucacé,k,t,h,c} \\
(k \in S_{2}; t = 1,2,\ldots,T; h \in S_{3}; c \in S_{4}) \tag{B.16}
\]

\[
X_{Rucacé,k,t,h,c} \leq I_{Rucacé,h} + I_{Antuco,k,t,h,c} + R_{Rucacé} \\
(k \in S_{2}; t = 1,2,\ldots,T; h \in S_{3}; c \in S_{4}) \tag{B.17}
\]

\[
X_{Rucacé,k,t,h,c} \leq 105 \\
(k \in S_{2}; t = 1,2,\ldots,T; h \in S_{3}; c \in S_{4}) \tag{B.18}
\]

\[
X_{Antuco,k,t,h,c} = X_{El Toro,k,t,h,c} + X_{Abanico,k,t,h,c} + I_{Antuco,h} \\
(k \in S_{2}; t = 1,2,\ldots,T; h \in S_{3}; c \in S_{4}) \tag{B.19}
\]

\[
X_{Abanico,k,t,h,c} = I_{Abanico,h} + I_{Filtration,h} \\
(k \in S_{2}; t = 1,2,\ldots,T; h \in S_{3}; c \in S_{4}) \tag{B.20}
\]

**Reservoir volume**
\[ V_t^i + 2.63 \cdot 12 \cdot \left( I_{El\ Toro,h} - \sum_{k \in S_2} \frac{1000 \cdot G_{El\ Toro,k,t,h,c}}{\xi_{El\ Toro} \cdot 8760} - I_{Filtration,h} \right) = V_{t,h,c}^f \]

\[(k \in S_2; t = 1, 2, \ldots; h \in S_3; c \in S_4) \quad (B.21)\]

\[
\sum_{h \in S_3} \sum_{c \in S_4} \pi_h \cdot \pi_c \cdot V_{t,h,c}^f = V_{t+1}^i
\]

\[(t = 1, 2, \ldots; h \in S_3; c \in S_4) \quad (B.22)\]

\[
V_{t,h,c}^f \geq V_{min}
\]

\[(t = 1, 2, \ldots; h \in S_3; c \in S_4) \quad (B.23)\]

\[
V_{t,h,c}^f \leq V_{max}
\]

\[(t = 1, 2, \ldots; h \in S_3; c \in S_4) \quad (B.24)\]

\[V_1^i = V_0 \quad (B.25)\]
Table I
Availability and costs of non-conventional renewable energies in Chile’s CIS

<table>
<thead>
<tr>
<th></th>
<th>Small hydro 1</th>
<th>Small hydro 2</th>
<th>Small hydro 3</th>
<th>Wind 1 (^7)</th>
<th>Wind 2</th>
<th>Wind 3</th>
<th>Biomass 1</th>
<th>Biomass 2</th>
<th>Biomass 3</th>
<th>Biogas (^8)</th>
<th>Geothermal (1^{9,10,11})</th>
<th>Geothermal 2</th>
<th>Geothermal 3</th>
<th>PV Solar (^{12})</th>
<th>Solar thermal (^{12})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity factor</td>
<td>60%</td>
<td>60%</td>
<td>60%</td>
<td>30%</td>
<td>25%</td>
<td>20%</td>
<td>90%</td>
<td>90%</td>
<td>90%</td>
<td>72%</td>
<td>72%</td>
<td>72%</td>
<td>72%</td>
<td>30%</td>
<td>30%</td>
</tr>
<tr>
<td>Exploration’s success prob.</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>30%</td>
<td>15%</td>
<td>5%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Available capacity (MW) (^1)</td>
<td>267</td>
<td>544</td>
<td>333</td>
<td>150</td>
<td>300</td>
<td>1,050</td>
<td>325</td>
<td>650</td>
<td>2,274</td>
<td>350</td>
<td>150</td>
<td>300</td>
<td>1,050</td>
<td>1,051</td>
<td>500</td>
</tr>
<tr>
<td>Available Energy (GWh/year) (^2)</td>
<td>1,404</td>
<td>2,858</td>
<td>1,748</td>
<td>394</td>
<td>657</td>
<td>1,840</td>
<td>2,562</td>
<td>5,123</td>
<td>17,931</td>
<td>2,759</td>
<td>941</td>
<td>1,883</td>
<td>6,590</td>
<td>2,762</td>
<td>1,314</td>
</tr>
<tr>
<td>Investment US$/kW (plant)</td>
<td>2,467</td>
<td>2,467</td>
<td>2,467</td>
<td>2,409</td>
<td>2,409</td>
<td>2,409</td>
<td>3,500</td>
<td>3,500</td>
<td>3,500</td>
<td>2,828</td>
<td>3,964</td>
<td>4,556</td>
<td>6,923</td>
<td>4,678</td>
<td>4,615</td>
</tr>
<tr>
<td>O&amp;M in US$/kW-year (plant) (^5)</td>
<td>20</td>
<td>20</td>
<td>20</td>
<td>32</td>
<td>32</td>
<td>68</td>
<td>68</td>
<td>68</td>
<td>68</td>
<td>173</td>
<td>173</td>
<td>173</td>
<td>16</td>
<td>63</td>
<td></td>
</tr>
<tr>
<td>Average distance to transmission system (km) (^3)</td>
<td>40</td>
<td>60</td>
<td>80</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>65</td>
<td>65</td>
<td>65</td>
<td>3</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>Investment US$/kW (transmission) (^5)</td>
<td>798</td>
<td>2,284</td>
<td>6,580</td>
<td>211</td>
<td>211</td>
<td>211</td>
<td>562</td>
<td>562</td>
<td>562</td>
<td>562</td>
<td>715</td>
<td>715</td>
<td>715</td>
<td>357</td>
<td>357</td>
</tr>
<tr>
<td>Investment in US$/MWh</td>
<td>50</td>
<td>50</td>
<td>50</td>
<td>108</td>
<td>130</td>
<td>162</td>
<td>52</td>
<td>52</td>
<td>52</td>
<td>42</td>
<td>79</td>
<td>91</td>
<td>138</td>
<td>283</td>
<td>236</td>
</tr>
<tr>
<td>O&amp;M in US$/MWh</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>12</td>
<td>15</td>
<td>18</td>
<td>9</td>
<td>9</td>
<td>9</td>
<td>14</td>
<td>29</td>
<td>29</td>
<td>29</td>
<td>5</td>
<td>23</td>
</tr>
<tr>
<td>Variable fuel costs in US$/MWh</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>31</td>
<td>70</td>
<td>103</td>
<td>64</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other variable costs in US$/MWh</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>13</td>
<td>13</td>
<td>13</td>
<td>13</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Transmission in US$/MWh</td>
<td>16</td>
<td>46</td>
<td>132</td>
<td>10</td>
<td>11</td>
<td>14</td>
<td>8</td>
<td>8</td>
<td>8</td>
<td>13</td>
<td>13</td>
<td>13</td>
<td>13</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Total costs US$/MWh</td>
<td>70</td>
<td>100</td>
<td>186</td>
<td>137</td>
<td>163</td>
<td>202</td>
<td>100</td>
<td>139</td>
<td>172</td>
<td>128</td>
<td>121</td>
<td>133</td>
<td>180</td>
<td>209</td>
<td>225</td>
</tr>
</tbody>
</table>

Notes: (1) In each case, except for hydropower, the availability was taken from UTFS (2008). We assume that between 2010 and 2026 the available capacity of all technologies increases linearly from 20% to 100%. (2) \(\text{available energy} = \text{available capacity} \times \text{capacity factor} \times 8.76\). (3) Fixed operation and maintenance costs come from EIA (2010). (4) Average distances come from our own estimations. (5) In each case, the cost of connecting a NCRE plant to the system, in USD/kW, was estimated assuming it corresponds to a transformer at the plant and a transmission line in 110kV between the plant and the nearest substation. For small hydro plants, the transmission costs were estimated by minimizing the cost of each project. We report average values. (6) The available capacity and energy of small hydro plants was estimated through the study of the granted water rights, that aren’t yet in use. To calculate the LCOE of each project the following parameters of each plant were considered: water flow rate, hydraulic head, location, distance to transmission system and the average capacity factor of the already existing plants located near the water right. Small hydro 1 considers projects that range from 49 – 86 US$/MWh. Small hydro 2 considers projects between 86 – 140 US$/MWh. Small hydro 3 considers projects between 140 – 197 US$/MWh. (7) The cost of a wind turbine comes from Pavez (2008) and was adjusted by CPI’s variation. The capacity factors supposed for wind turbines exceed the ones deduced by numerous studies ordered by the CNE. See Galevovic and Munhoz (2008). (8) CNE and GTZ Consultants (2009). The investment cost is the average value of the GTZ study, assuming plants smaller than 6 MW. (9) The investment costs of geothermal power plants is obtained from the following formula: \(I = \text{the total investment cost conditional to success in the exploration, } \lambda \text{ be the probability of success and } \nu \text{ the fraction of the investment that takes place after a successful exploration.}

Then, the total expected cost of a kW of geothermal is \(\lambda I + \frac{(1-\lambda)}{\nu} I\). We assume \(\lambda = 0.95\) and \(I = 3,550\) US$/kW. (10) To date, there are 10,715 MW of geothermal capacity installed around the world, and it is expected that they’ll generate 67,246 GWh (average capacity factor of 71.6%). See Holm et al. (2010). (11) We are currently working on a more precise estimate of Chile’s geothermal potential and costs. (12) The investment cost of a kW of solar energy comes from EIA (2012). (13) The rest of the parameters come from estimations obtained in interviews with experts.
Table II
Marginal damages caused by CO2 and pollutants
(In US$/ton)

<table>
<thead>
<tr>
<th></th>
<th>(1) CO2</th>
<th>(2) PM$_{2.5}$</th>
<th>(3) SO$_2$</th>
<th>(4) NO$_X$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nordhaus</td>
<td>7.9 to 55.9</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Big city$^1$</td>
<td>-</td>
<td>29,679</td>
<td>434</td>
<td>4,268</td>
</tr>
<tr>
<td>Small city$^1$</td>
<td>-</td>
<td>8,330</td>
<td>138</td>
<td>1,228</td>
</tr>
<tr>
<td>Town$^1$</td>
<td>-</td>
<td>325</td>
<td>5</td>
<td>42</td>
</tr>
<tr>
<td>M&amp;M$^2$ (EE.UU.)</td>
<td>-</td>
<td>3,220</td>
<td>1,310</td>
<td>260</td>
</tr>
<tr>
<td>M&amp;M$^3$ urban</td>
<td>-</td>
<td>3,300</td>
<td>1,500</td>
<td>300</td>
</tr>
<tr>
<td>M&amp;M$^3$ rural</td>
<td>-</td>
<td>1,100</td>
<td>900</td>
<td>300</td>
</tr>
</tbody>
</table>

Source: CO$_2$: Nordhaus (2010). PM$_{2.5}$, SO$_2$ y NO$_X$: from Cifuentes et al. (2010).
Notes: (1) Cifuentes et al. (2010) performs a stochastic assessment of the marginal damages and for each power plant reports the 5th percentile, the median, and the 95th percentile of the marginal damage for each pollutant. The group “Big city” corresponds to the 90th percentile of the vector that contains the median marginal damages of each power plant. Analogously, the group “Small city” corresponds to the 60th percentile of the median marginal damage, and the group “Town” corresponds to the 30th percentile of the median marginal damage. (2) Muller and Mendelsohn (2009). (3) Muller and Mendelsohn (2007).
Table III
Emissions and environmental costs of air pollutants and CO2 per year

<table>
<thead>
<tr>
<th></th>
<th>(1) Baseline</th>
<th>(2) 10% RPS</th>
<th>(3) 20% RPS</th>
<th>(4) Uncontrolled emissions</th>
<th>(5) Optimal</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Emissions (tons)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SOx</td>
<td>1,191</td>
<td>968</td>
<td>649</td>
<td>19,284</td>
<td>891</td>
</tr>
<tr>
<td>NOx</td>
<td>1,009</td>
<td>812</td>
<td>525</td>
<td>17,341</td>
<td>1,036</td>
</tr>
<tr>
<td>PM 2.5</td>
<td>18</td>
<td>15</td>
<td>11</td>
<td>6,157</td>
<td>18</td>
</tr>
<tr>
<td>CO2</td>
<td>1,575,473</td>
<td>1,329,859</td>
<td>947,820</td>
<td>2,184,394</td>
<td>861,251</td>
</tr>
<tr>
<td><strong>Environmental costs (millions of US$ dollars)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SOx</td>
<td>84</td>
<td>72</td>
<td>55</td>
<td>1,324</td>
<td>94</td>
</tr>
<tr>
<td>NOx</td>
<td>104</td>
<td>90</td>
<td>67</td>
<td>1,943</td>
<td>121</td>
</tr>
<tr>
<td>PM 2.5</td>
<td>19</td>
<td>17</td>
<td>15</td>
<td>4,903</td>
<td>21</td>
</tr>
<tr>
<td>Total cost of pollution</td>
<td>207</td>
<td>179</td>
<td>137</td>
<td>8,171</td>
<td>237</td>
</tr>
<tr>
<td>CO2</td>
<td>3,533</td>
<td>3,151</td>
<td>2,490</td>
<td>4,619</td>
<td>2,319</td>
</tr>
<tr>
<td>Total environmental costs</td>
<td>3,741</td>
<td>3,330</td>
<td>2,627</td>
<td>12,790</td>
<td>2,556</td>
</tr>
<tr>
<td></td>
<td>(1)</td>
<td>(2)</td>
<td>(3)</td>
<td>(4)</td>
<td>(5)</td>
</tr>
<tr>
<td>--------------------------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
</tr>
<tr>
<td></td>
<td>Baseline</td>
<td>10% RPS</td>
<td>20% RPS</td>
<td>Uncontrolled emissions</td>
<td>Optimal</td>
</tr>
<tr>
<td>Cost of generation¹</td>
<td>57,931</td>
<td>58,154</td>
<td>59,785</td>
<td>56,228</td>
<td>56,619</td>
</tr>
<tr>
<td>Environmental costs²</td>
<td>3,741</td>
<td>3,330</td>
<td>2,627</td>
<td>12,790</td>
<td>2,556</td>
</tr>
<tr>
<td>Total</td>
<td>61,672</td>
<td>61,485</td>
<td>62,412</td>
<td>69,019</td>
<td>59,175</td>
</tr>
<tr>
<td>Δ Environmental costs</td>
<td>0</td>
<td>-411</td>
<td>-1,114</td>
<td>9,049</td>
<td>-1,185</td>
</tr>
<tr>
<td>Δ Generators’ profits</td>
<td>0</td>
<td>1,281</td>
<td>6,505</td>
<td>-290</td>
<td>1,320</td>
</tr>
<tr>
<td>Δ Consumer surplus</td>
<td>0</td>
<td>-1,841</td>
<td>-15,275</td>
<td>2,836</td>
<td>-1,014</td>
</tr>
<tr>
<td>Change in economic welfare³</td>
<td>0</td>
<td>-149</td>
<td>-7,656</td>
<td>-6,503</td>
<td>1,491</td>
</tr>
<tr>
<td>Δ Renewable generators’ profits</td>
<td>0</td>
<td>1,784</td>
<td>10,620</td>
<td>-125</td>
<td>203</td>
</tr>
<tr>
<td>Δ Hydro generators’ profits</td>
<td>0</td>
<td>-503</td>
<td>-2,788</td>
<td>-1,518</td>
<td>1,887</td>
</tr>
<tr>
<td>Δ Fossil fuel generators’ profits</td>
<td>0</td>
<td>0</td>
<td>-1,327</td>
<td>1,353</td>
<td>-770</td>
</tr>
<tr>
<td>Generators’ profits</td>
<td>6,096</td>
<td>7,377</td>
<td>12,600</td>
<td>5,806</td>
<td>7,416</td>
</tr>
</tbody>
</table>

¹ Cost of generation is the sum of investment and operation costs of generation.
² Environmental costs is the sum of social cost of pollution and CO₂.
³ Δ Economic welfare = Δ Consumer surplus + Δ Generators’ profits - Δ Environmental costs.
### Table V
Emissions and environmental costs of air pollutants and CO2 per year in no expansion with hydro scenarios

<table>
<thead>
<tr>
<th></th>
<th>(1) No expansion with hydro</th>
<th>(2) No expansion with hydro + 20% RPS</th>
<th>(3) No exp. with hydro + Optimal env. policy</th>
<th>(4) Baseline</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Emissions</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(tons)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SOx</td>
<td>2,356</td>
<td>1,504</td>
<td>1,132</td>
<td>1,191</td>
</tr>
<tr>
<td>NOx</td>
<td>2,031</td>
<td>1,282</td>
<td>1,460</td>
<td>1,009</td>
</tr>
<tr>
<td>PM 2.5</td>
<td>33</td>
<td>22</td>
<td>23</td>
<td>18</td>
</tr>
<tr>
<td>CO₂</td>
<td>2,881,088</td>
<td>1,949,831</td>
<td>1,500,514</td>
<td>1,575,473</td>
</tr>
<tr>
<td><strong>Environmental costs</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(millions of US$ dollars)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SOx</td>
<td>189</td>
<td>115</td>
<td>125</td>
<td>84</td>
</tr>
<tr>
<td>NOx</td>
<td>322</td>
<td>163</td>
<td>224</td>
<td>104</td>
</tr>
<tr>
<td>PM 2.5</td>
<td>42</td>
<td>25</td>
<td>29</td>
<td>19</td>
</tr>
<tr>
<td>Total cost of pollution</td>
<td>553</td>
<td>303</td>
<td>378</td>
<td>207</td>
</tr>
<tr>
<td>CO₂</td>
<td>6,784</td>
<td>4,579</td>
<td>4,077</td>
<td>3,533</td>
</tr>
<tr>
<td>Total environmental costs</td>
<td>7,337</td>
<td>4,882</td>
<td>4,455</td>
<td>3,741</td>
</tr>
</tbody>
</table>
Table VI
The economic effects of RPS in no expansion with hydro scenarios

<table>
<thead>
<tr>
<th></th>
<th>(1)</th>
<th>(2) No expansion with hydro + 20% RPS</th>
<th>(3) No exp. with hydro + Optimal env. policy</th>
<th>(4) Baseline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of generation¹</td>
<td>60,224</td>
<td>60,880</td>
<td>57,918</td>
<td>57,931</td>
</tr>
<tr>
<td>Environmental costs²</td>
<td>7,337</td>
<td>4,882</td>
<td>4,455</td>
<td>3,741</td>
</tr>
<tr>
<td>Total</td>
<td>67,561</td>
<td>65,762</td>
<td>62,374</td>
<td>61,672</td>
</tr>
</tbody>
</table>

Δ Environmental costs    | 0                  | -2,455                               | -2,882                                      | -3,596      |
Δ Generators’ profits    | 0                  | 6,263                                | 2,940                                       | -3,462      |
Δ Consumer surplus       | 0                  | -13,221                              | -3,101                                      | 7,542       |

Change in economic welfare² | 0                  | -4,502                               | 2,721                                       | 7,676       |

Δ Renewable generators’ profits | 0                  | 9,947                                | 1,334                                       | -445        |
Δ Hydro generators’ profits   | 0                  | -2,122                               | 2,138                                       | -1,547      |
Δ Fossil fuel generators’ profits | 0                  | -1,562                               | -531                                        | -1,470      |

Generators’ profits     | 9,557             | 15,821                               | 12,498                                      | 6,096       |

¹ Cost of generation is the sum of investment and operation costs of generation.
² Environmental costs is the sum of social cost of pollution and CO₂.
³ Δ Economic welfare = Δ Consumer surplus + Δ Generators’ profits - Δ Environmental costs.
Figure 1
The nonconventional renewable energy supply curve
We assume a direct relation between emissions \((t_i)\) of pollutant \(i\) and the marginal damage it causes \((md_i)\). In practice, emissions of local pollutants interact with the local environment and affect concentrations. Damage depends on inmissions or exposure to the pollutants.

The damage caused by greenhouse emissions is global, and is a direct function of the carbon content of the fossil fuel burned.
Figure 3
CO₂ emissions
(millions of tons per year)
Figure 4 – The composition of generation under alternative policies

- Hydro
- Renewables
- Coal
- LNG
- Diesel

(a) Baseline

(b) Uncontrolled emissions

(c) 20% RPS

(d) Optimal
Figure 5
The equilibrium price of renewable energy
Figure 6
CO₂ emissions
(millions of tons per year)

- Blue line: No expansion with hydro
- Red line: No expansion with hydro + 20% RPS
- Green line: No expansion with hydro + Optimal environmental policy
- Dotted line: Baseline
Figure 7 – The composition of generation in no expansion with hydro scenarios

- **Hydro**
- **Renewables**
- **Coal**
- **LNG**
- **Diesel**
Figure 8 – How environmental policies affect the composition of generation

(a) Baseline

(b) Renewable quota

(c) Optimal