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Microeconomic Policies and Productivity: An Exploration into Chile's Electricity Sector

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Abstract

During the 1970s and 80s Chile was a pioneer in economic liberalization and reforms, but since 1998 the rate of GDP halved and productivity growth grinded to a halt. Policy makers often argue that the slowdown reflects convergence and that further microeconomic reforms are uneccessary and ineffective. This paper evaluates the impact of alternative policies in Chile's Central Interconnected System (CIS), which produces three-quarters of Chile's electricity and 1.3% of total value added, on costs and productivity.

We find that some policies, which are currently being discussed in the Chilean Congress, can reduce TFP in electricity by up to 20%. More important, because electricity is an input, the impact of bad policies on the rest of the economy can be large, about 0.3% of GDP, equivalent to about one-fourth of CIS's total value added.

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1. Chile's protracted productivity slowdown

In December 1993 Eduardo Frei won the Chilean presidency in a landslide. A Christian Democrat with pro business sympathies, Frei was thought to be a competent no nonsense administrator who would continue to steer and nurture the fastest economic expansion in Chilean history. In fact, he did and achieved little and, while the economy grew fast during the first three years of his administration, Chile's golden period of 7% p.a. growth ended abruptly when the Asian Crisis hit in 1998. That external shock, a protracted hike of the minimum wage in 1998, 1999 and 2000 and a somewhat erratic management of interest rates by the Central Bank combined to cause the first recession in 15 years.

At the time many expected fast growth to resume as soon as the Asian crisis ended. But on the contrary, during the next ten years the growth rate more than halved, productivity growth sidled steadily and unemployment remained stuck at more than 8%. While several years passed before the slowdown was acknowledged, it is a fact that Chile's economy permanently slowed down.

Some argue that Chile's slowdown merely reflects convergence. As countries develop they close the gap with developed economies and the growth rate gradually falls, *ceteris paribus*. Nevertheless, this is unconvincing. One reason is that the slowdown has been rather abrupt—between 1998 and 2009, GDP per capita grew 2% p.a, a far from the 5.8% growth rate achieved during the golden period. Moreover, Chile's growth since 2000 is well below the potential rate that experts estimated before and after the Asian Crisis. As historical data shows, Chile's GDP gap with the United States, while somewhat smaller than during the 1970s and 1980s, is still wider than in any year before the Great Depression.[1] Worse, total factor productivity did not grow since 1998 and during the Bachelet administration, if anything, fell almost every year, a rather strange way of converging.

A different explanation is that the impulse of market reforms peters out before a country becomes developed. First-generation reforms, so the argument goes, exploited easy opportunities like liberalizing markets, opening the economy to international trade, balancing the fiscal budget and reducing inflation, and in any case were sustained by Chile's rich base of natural resources. But that is no longer enough and now Chile needs innovative firms to engage in self discovery, diversify into knowledge-based activities and enlarge the scope of her exports. Alas, Chile's firms are weak: they don't spend much in R&D, innovate little, patent even less and do not engage universities and public research institutes in cooperative ventures. And thus, at least in their discourse, successive administrations have set out to transform Chile in a nation of entrepreneurs and innovators nurtured

[1] Studies also indicate that labor productivity is about 40% of the US level. About one-fifth of the gap is explained by Chile's lower capital output ratio, which is between 20 and 30% smaller; two fifths are due to lower human capital (about a third less than in the United States) and the remaining two fifths are due to lower total factor productivity (between one fourth and one third less than in the United States).

and mentored deftly by a government-led national innovation strategy. Yet as is usual with most public policies in Chile, the overhaul of the innovation system did not start with systematic impact evaluations of existing programs, but simply with more spending. Moreover, advocates of a national innovation system consistently avoid particulars when asked about the details of their strategy and the mechanics that links their programs with productivity growth. On the contrary, they usually rush to point out that their role is to design the strategy and that implementation is a practical matter that can be dealt with later. It is hard not to see the national innovation system as the latest version of the silver bullet to which policy makers almost inevitably fall back when they don't know what to do next.

Yet another view blames slow growth on a poorly educated workforce. Indeed, many agree that Chile's education system is mediocre, a belief confirmed by research on academic outcomes. Some work by Maloney and Rodríguez-Clare (2007) suggests, moreover, that most of the productivity gap between Chile and the United States can be attributed to low human capital (an accumulation problem) and not low technology (the A parameter). But so far nobody has compellingly linked low human capital with the fall in productivity and per capita output growth after 1998, much less quantified the effect.

Last, some argue that productivity growth stalled because few microreforms have been introduced after Aylwin's administration and, on the contrary, during the last 15 years microeconomic policy mistakes and distortions, some small, others not so small, have protractedly piled up. Nevertheless, this view is not shared by many.

Of course, nobody knows how much faster productivity would have grown had vigorous microeconomic reforms been tried. But more fundamentally, many doubt that microeconomic reforms can achieve much at all. For example, when confronted with a specific sectoral distortion or policy mistake, macroeconomists usually argue that one sector is small and surely cannot explain the fall in *aggregate* growth. They also point out that many distortions existed before 1998, that Chile ranks fairly high in cross country competitiveness indices and that static distortions affect levels but not rates. Last, as with poor education, so far no study has mustered compelling quantitative evidence linking the slowdown with lack of microeconomic reforms. As a former Minister of Economic Affairs once claimed, micro reforms are difficult to push through and their payoff is small in any case.

In spite of widespread skepticism, this paper builds evidence on efficiency, productivity and policies from the bottom up. We model one sector in detail, Chile's Central Interconnected System or CIS, which produces about 1.3% of Chile's value added, with an intertemporal model with endogenous investment, price-responsive demand and explicit modeling of environmental externalities. We then quantify the impact of alternative policies on sectoral performance—cost, output, pollution, prices, profits and consumer surplus—and link this rather standard micro analysis of industry performance with sectoral productivity analysis. Then we link costs and price changes in the electricity sector with changes in value added in the rest of the economy using simple production theory. Assuming an exogenous trajectory of labor and capital inputs in the rest of the economy, we show that changes in value added accurately quantify the effect of sectoral changes on productivity in the rest of the economy. We find that some bad policies that affect the electricity sector, which are currently being discussed in Congress, can reduce TFP in electricity by about 15%. More important, because electricity is an input, the impact of bad policies on the rest of the economy can be large, about 0.3% of GDP, equivalent to about one-fourth of CIS's total value added.

The rest of the paper is organized as follows. Section 2 links standard sectoral microeconomic analysis with GDP accounting and productivity. Section 3 describes Chile's CIS, our intertemporal model, and the relation between electricity and pollution. In section 4 we present our analysis of alternative policies. Section 5 concludes.

2. Microeconomic policies, GDP accounting and productivity

Our welfare analysis of policies uses standard consumer and producer surplus. Yet most of the discussion of policies and growth is couched in terms of productivity—how do different policies affect the output yield of a given set of inputs. What is the relation between the two types of analysis? In this section we study the differences between standard welfare analysis on the one hand and standard GDP and productivity accounting on the other.

2.1. Supply and demand meet GDP accounting

2.1.1. Supply and demand

Figure 1a shows a simple supply-and-demand diagram of a competitive electricity market. The inverse demand curve P^d adds up demands by firms. The supply curve S is perfectly elastic at the levelized cost of electricity—the sum of the per-MWh capital cost c_0^k and the variable fuel cost c_0^v. Competition implies that the equilibrium price p_0^e equals the levelized cost of energy, $c_0^k + c_0^v$; consumption equals e_0 MWh because

$$P^d(e_0) = c_0^k + c_0^v.$$

Standard welfare analysis, in turn, says that consumer surplus equals the shaded triangle or, formally,

$$\mathrm{CS}(e_0) = \int_0^{e_0} [P^d(e) - (c_0^k + c_0^v)]de.$$

Similarly, the sum of the checkered and gridded area is the cost of electricity:

$$p_0^e e_0 = (c_0^k + c_0^v) e_0.$$

2.1.2. "Correct" GDP accounting

Assume for the moment that electricity is only an intermediate input to produce final output y. Furthermore, assume that final output is produced with capital K and energy with a constant-returns-to-scale, twice differentiable production function F such that

$$y = F(K, e)$$

which satisfies the Inada conditions. As is well known, Euler's theorem implies that $y = F^K K + F^e e$. Next assume that capital is exogenous to the energy sector (this is partial equilibrium analysis) so that $K = \overline{K}$ and that in equilibrium $e = e_0$. Then

$$y_0 = F(\overline{K}, e_0)$$

is the gross output of the final-good sector. Moreover, in equilibrium, the price of energy is equal to its value marginal product. Thus if y is the nummeraire good, r_0 is the equilibrium return on capital and $F_0^e = p_0^e$, we can rewrite gross output as

$$y_0 = r_0 \overline{K} + p_0^e e_0.$$

Also,

$$\mathrm{va}_0^y \equiv y_0 - p_0^e e_0 = r_0 \overline{K}$$

is the value added of the final-good sector.

Now $p_0^e e_0$ is the gross output of the electricity sector. If fuel is fully imported (as in Chile), the sector's value added is

$$\mathrm{va}_0^e = (p_0^e - c_0^v)\, e_0 = c_0^k e_0.$$

GDP is thus

$$\mathrm{va}_0^y + \mathrm{va}_0^e \equiv Y_0 = r_0 \overline{K} + c_0^k e_0 \tag{2.1a}$$

$$= y_0 - c_0^v e_0. \tag{2.1b}$$

Equation (2.1a) is the standard definition of GDP, the sum of the value-added of the electricity sector and the rest of the economy. Equation (2.1b) restates GDP as the difference between the gross output of the rest of the economy and the cost of imported fuel to produce electricity.

2.1.3. GDP accounting and the demand for energy

How does GDP accounting relate to standard welfare analysis? The link is through the demand curve P^d: holding K constant, the demand for energy is equal to the value marginal product of energy, hence

$$P^d(.) \equiv F_0^e(.;\overline{K}).$$

Furthermore,

$$y_0 = F(\overline{K}, e_0) = \int_0^{e_0} F_0^e(e;\overline{K})de \equiv \int_0^{e_0} P^d(e)de.$$

It follows that the area below the demand for energy in Figure 1a equals the gross value of output in the final-goods sector. Also,

$$\text{va}_0^y = \int_0^{e_0} \left[P^d(e) - p_0^e\right] de,$$

i.e. consumer surplus—the shaded triangle in Figure 1a—equals the value added of the final-good sector. Last, (2.1b) implies that

$$Y_0 = \int_0^{e_0} \left[P^d(e) - c_0^v\right] de,$$

i.e. GDP equals the sum of the shaded triangle and the checkered rectangle in Figure 1a, which in turn is equal to GDP. Thus we have shown the direct link between standard supply-and-demand analysis and "correct" GDP accounting.

2.1.4. Electricity as a final good

Electricity is also a final good.[2] Does our analysis change? Assume that households consume e_0^h of electricity. The main difference is that, as can be seen in Figure 1b, consumer surplus is not measured in GDP. In other words, the contribution to GDP of electricity is just c_0^k per MWh, the value added by the electricity sector equal to the checkered area in Figure 1b.

2.1.5. GDP accounting at constant prices

In practice national accountants face a daunting task and measure real GDP at prices of a base year. To compare value added and GDP with our "correct" measures of gross output, let p_b^e, c_b^v, and c_b^k be the respective prices at the base year b. Then measured value added in the final-goods

[2] In Chile's SIC about 30% of electricity consumption is residential. Most of the rest is used by businesses and firms.

and electricity sectors are

$$\begin{aligned} \mathrm{va}_{0,b}^{y} &\equiv y_0 - p_b^e e_0, \\ \mathrm{va}_{0,b}^{e} &= \left(p_b^e - c_b^v\right) e_0 = c_b^k e_0. \end{aligned}$$

Measured GDP is thus

$$Y_{0,b} = \mathrm{va}_{0,b}^{y} + \mathrm{va}_{0,b}^{e} = y_0 - c_b^v e_0.$$

Now note that the difference between measured value added and "correct" value added in the final-goods sector is

$$\mathrm{va}_{0,b}^{y} - \mathrm{va}_{0}^{y} = (p_0^e - p_b^e) e_0$$

Similarly, in the electricity sector

$$\mathrm{va}_{0,b}^{e} - \mathrm{va}_{0}^{e} = (c_0^v - c_b^v) e_0.$$

In terms of Figure 1a, actual GDP calculations will get quantities right, but under or overestimate each sector's value added, depending on the difference between relative prices in the base year and the year GDP is calculated. The more frequently base years are adjusted and the more persistent relative price changes are, the less important this problem is.

2.2. Microeconomic policies and GDP

2.2.1. Electricity as an intermediate input I: changes in c_v

Policies in the electricity sector affect costs through c^v and c^k; they also affect the final-goods sector through p^e. It is helpful to consider first an increase in variable costs from c_0^v to c_1^v, as depicted in Figure 2a. The price of electricity rises from p_0^e to p_1^e, and consumption falls from e^0 to e^1. In the figure the fall in consumer surplus equals the sum of the shaded triangle and the large gridded rectangle; because the supply curve is flat, the fall in consumer surplus also equals the change in social surplus.[3] Of course, there is nothing new here. Higher costs reduce energy consumption and cause a net output and surplus loss somewhere in the economy equal to the shaded triangle. Furthermore, costs of producing final output rise causing a further surplus loss equal to the gridded rectangle.

How does the standard welfare calculation compare with GDP accounting? Recall that when electricity is an intermediate good, consumer surplus equals value added by the final-goods sector.

[3] With an upward-sloping supply curve, the change in social surplus equals the sum of changes iun consumer and producer surplus.

Formally, lost value added in the intermediate-goods sector is

$$\begin{aligned}\Delta \text{va}_0^y &= -\left[\int_{e_1}^{e_0}\left[P^d(e) - p_0^e\right] de + (c_1^v - c_0^v)e_1\right] && (2.3a)\\ &= [(y_1 - y_0) + (e_0 - e_1)p_0^e] - (c_1^v - c_0^v)e_1 && (2.3b)\end{aligned}$$

Equations (2.3a) and (2.3b) decompose the fall in value added in three terms. The first two capture the effect of using less electricity; it is the same as the shaded triangle in Figure 2a. The third captures the effect of paying more for an input; it is the same as the gridded rectangle in Figure 2a. It follows that when GDP accounting considers changes in relative prices, there is an exact correspondence between changes in consumer surplus and changes of value added in the final-goods sector. The reason is straightforward: the reduction in the final-goods' sector value added is equal to the increase in costs plus the net value of lost output.

Now the fall in value added by the electricity sector is equal to the checkered rectangle in Figure 2a; formally, $\Delta \text{va}_0^e = -(e_0 - e_1)c_0^k$. Thus, after some algebra the change in GDP is

$$\begin{aligned}\Delta Y &= \Delta \text{va}_0^y + \Delta \text{va}_0^e\\ &= (y_1 - y_0) + (e_0 - e_1)c_0^v - (c_1^v - c_0^v)e_1\end{aligned}$$

The first term, $y_1 - y_0$, is the change in gross output in the final-goods sector. The second term, $(e_0 - e_1)c_0^v$, shows the savings in variable costs due to reduced electricity consumption. The last term, $(c_1^v - c_0^v)e_1$, captures the effect of the relative price change on costs and value added by the final-goods sector.

The change in GDP wrought by a change in c^v is *larger* than the fall in social surplus because standard welfare analysis ignores the fall of value added in the electricity sector, $(e_0 - e_1)c_0^k$. Why? The reason may be obvious, and yet it is subtle. Standard welfare analysis correctly acknowledges that only final output creates economic value and that costs reduce net economic surplus. Thus, the fall in $(e_0 - e_1)c_0^k$ is a *benefit*, which is offset by the loss of output. GDP accounting, by contrast, includes capital costs in value added, hence GDP falls when capital costs in the electricity sector fall, *ceteris paribus*.

A second limitation is that national accountants compute year-to-year real GDP at constant prices. Because the measured change in value added by the final-goods sector is

$$\Delta \text{va}_b^y = (y_1 - y_0) + (e_0 - e_1)p_b^e,$$

value added ignores the loss in surplus caused by the increase in variable costs, $(c_1^v - c_0^v)e_1$. This is important, for many if not most microeconomic policies work their effect through changes in relative prices.

The measured change in value added by the electricity sector is, in turn, $\Delta \text{va}_b^e = -(e_0 - e_1)c_b^k$. After some algebra, it can be seen that the measured change in GDP is

$$\Delta Y_b = \Delta \text{va}_b^y + \Delta \text{va}_b^e = (y_1 - y_0) + (e_0 - e_1)c_b^v.$$

When compared with changes in social surplus, changes in GDP at constant prices miss the effect of higher input costs and prices, but include the lost value added by the electricity sector, which does not affect social surplus. On the other hand, when compared with "correct" GDP, measured GDP misses the increase in variable costs.

2.2.2. Electricity as an intermediate input II: changes in c_k

Figure 2b depicts the effect of an increase in capital costs from c_0^k to c_1^k. As with a change in variable costs, the price of electricity rises from p_0^e to p_1^e, and consumption falls from e^0 to e^1. Indeed, the welfare analysis is exactly as before, because it makes no difference what causes higher costs in the electricity sector.

As before, lost value added in the intermediate-goods sector is

$$\begin{aligned} \Delta \text{va}_0^y &= -\left[\int_{e_1}^{e_0} \left[P^d(e) - p_0^e\right] de + (c_1^k - c_0^k)e_1\right] \\ &= \left[(y_1 - y_0) + (e_0 - e_1)p_0^e\right] - (c_1^k - c_0^k)e_1. \end{aligned}$$

But now the change in value added in the electricity sector is

$$\Delta \text{va}_0^e = (c_1^k - c_0^k)e_1 - (e_0 - e_1)c_0^k,$$

the difference between the large and small checkered rectangles in Figure 2b. Hence, if the demand for electricity is sufficiently inelastic, value added by the electricity may well increase, even though the origin of higher costs may be inefficient policies! It follows that the change in GDP is

$$\Delta Y = \Delta \text{va}_0^y + \Delta \text{va}_0^e = (y_1 - y_0) + (e_0 - e_1)c_0^v. \tag{2.4}$$

Now even "correct" GDP accounting fails to capture that higher capital costs per MWh decrease social surplus.

At constant prices the measured change in value added by the final-goods sector is, as before, $\Delta \text{va}_b^y = (y_1 - y_0) + (e_0 - e_1)p_b^e$. In turn, the measured change in value added by the electricity sector is, just as before, $\Delta \text{va}_b^e = -(e_0 - e_1)c_b^k$. It follows that the measured change in GDP is

$$\Delta Y_b = \Delta \text{va}_b^y + \Delta \text{va}_b^e = (y_1 - y_0) + (e_0 - e_1)c_b^v;$$

save for c_b^v, it is the same as (2.4).

2.2.3. Electricity as a final good

As Figure 2c shows, when electricity is a final good and its price increases, consumer and social surplus fall and lost welfare equals the sum of the shaded triangle and the striped rectangle. But now consumer surplus is not part of GDP, and the effect on consumers is therefore ignored by GDP accounting. Moreover, GDP accounting will capture only the effect of the cost increase on value added in the electricity sector.

If the increase in price occurs due to increases in variable costs, the change in value added equals, as before, the checkered rectangle. But if the increase in price is due to higher capital costs, GDP may even increase, as the striped rectangle will be part of the value added by the electricity sector. Thus, GDP may even increase, because now it will not be offset by lost value added in the final-goods sector. Of course, this does not happen when GDP is measured at constant prices. The conclusion is that GDP accounting is a fairly misleading tool to assess the economic effect of policies in sectors that produce goods sold to consumers.

2.3. Policies and productivity

We can now relate productivity and policies. Productivity change is the expansion or contraction of production possibilities holding factor inputs constant. The main question is how much policies affect productivity in the electricity sector and in the rest of the economy.[4]

As said, policies affect the cost of producing electricity and its price. In equilibrium, changes in the price of electricity alter both the final consumption of electricity and consumption by businesses. Nevertheless, productivity analysis is interested only in changes wrought the rest of the economy, not on final consumption.

In the rest of the economy, electricity consumption affects the productivity of capital and labor. *Ceteris paribus*, the productivity of given capital and labor input falls when electricity input is lower, because output falls; this is captured by real GDP calculations as a matter of course. In addition, higher input prices reduce value added in the rest of the economy—they are akin to an internal terms of trade shock wrought by one sector in the economy. GDP calculations at constant prices do not capture this effect. Because of this, productivity in the rest of the economy will be overestimated. Over long periods, however, the base year changes and presumably GDP accounting captures long-term movements in relative prices.[5]

[4] According to the Central Bank's 2009 input-output matrix, electricity generation accounted for about 1.7% of total value added.

[5] We are not experts in national accounting, and would appreciate a correction if we are wrong.

Now when a policy changes electricity consumption as an intermediate output, a natural estimate of the effect is the change in value added by our final-goods sector given by equation (2.3b), which we repeat here with a slight modification:

$$\Delta \text{va}_0^y = [\Delta y + (e_0 - e_1)p_0^e] - (c_1^v - c_0^v)e_1, \tag{2.5}$$

with $\Delta y \equiv y_1 - y_0$. Because our partial equilibrium analysis of the electricity sector in section 4 gives us estimates of each term in equation (2.5), we can compute the change in value added in the rest of the economy for each policy. Furthermore, with an exogenous estimate of GDP, one can also compare Δva_0^y relative to GDP, which equals

$$\frac{\Delta \text{va}_0^y}{Y_0}. \tag{2.6}$$

With a negative sign, expression (2.6) quantifies the effect of policy on aggregate productivity in the rest of the economy. When capital (and labor) in the rest of the economy are fixed, this expression shows the fall in total value added produced by these factors. At the same time, expression (2.6) quantifies the rate of real cost increase caused by electricity in the rest of the economy. As Harberger (1998) shows, a given change in TFP equals the rate of real cost change with opposite sign.

At the sectoral level, policies affect how efficiently generators deploy capital and the optimal mix of fuel and capital and directly affects aggregate productivity.[6] Because input prices are exogenous to the electricity sector and the same across policies, one can estimate the effect of policies on total factor productivity directly from differential changes in costs per MWh; this is what we do below in section 4.[7] Of course, one might estimate the changes in the productivity of capital, because we have estimates of the capital stock. But the exercise would make little sense, because policies affect the efficient capital intensity through the capital-fuel mix. At the sectoral level, an intermediate input matters as much as capital or labor when it comes to computing total factor productivity.[8]

Last, because we perform partial equilibrium analysis, we assume that the trajectory of capital and labor inputs in the rest of the economy is exogenous to the electricity sector. This simplification is inevitable to study the electricity sector in detail. But, of course, in reality the cost and price of electricity affects investment, employment and growth—cheaper electricity increases the marginal return on capital, especially in energy-intensive and should lead to faster accumulation and growth, at least for a while. We do not have much to say about this.

[6] Almost no labor is used to produce electricity—according to the Central Bank's 2009 input-output matrix, wages and salaries amount to just 7% of total value added by electricity generation.

[7] Again, this follows directly from Harberger (1998): the rate of real cost chenge equals the change in TFP with opposite sign.

[8] See Domar (1961) and Hulten (1975).

3. Preliminaries: modeling Chile's electricity market

In this section we briefly describe Chile's Central Interconnected System (CIS), the model we use to study the impact of microeconomic policies and the basics of the relation between electricity and the environment.

3.1. Chile's CIS

While there are four disjoint electricity systems in Chile, in what follows we consider only the CIS, which is by far the largest. Indeed, CIS extends from Chile's Second Region to its Tenth, covering around 92.2% of Chile's population in 2010, and comprising around 76% of its total installed capacity.

In December 2010 CIS total capacity was 12,147 MW and about two thirds of the energy generated on average comes from hydro plants. Nevertheless, hydro availability is volatile. In a very wet year, such as 1972-73, over 81% of generation could be supplied by hydroelectric plants.[9] But in a very dry year, such as 1998-99, only a little more than 11,000 GWh, or roughly 27% of the quantity generated could be supplied by hydroelectric plants. In other words, over half of the hydroelectric energy normally available or close to one third of annual generation is lost.

Hydro generation is complemented with natural gas-fired turbines (22.8% of installed capacity), coal (12.2%), diesel turbines (18.7%) and others, including renewables (2.2%). The high share of natural gas reflects investments made between 1998 and 2004, when combined-cycle turbines fueled with imports from Argentina were massively installed and the share of hydro in total capacity fell from 80% in 2003 to 52.3% in 2009. After the Argentine government restricted natural gas exports, hydro generation and coal became profitable again and combined cycles turbines were made to run with diesel, which is more expensive.

Generators exchange energy and power in the so-called spot market. In order to minimize the system's operation costs, the Economic Load Dispatch Center (CDEC for its Spanish acronym) centrally dispatches plants according to strict merit order.[10] The system's marginal cost (also known as spot price) is the running cost of the most expensive unit required to meet the instantaneous system's load, and changes every half hour. The spot price is used to value energy transfers from net sellers (those that generate more than their contractual obligations) to net buyers (those that generate less than their contractual obligations).

[9] The hydrological year begins in April and ends in March of the following year. The rainy season in central Chile runs from May through Septembrer. The thaw in the Andes Mountains (where water is stored as snow) starts in October and ends in March.

[10] This means that plants are ordered according to their variable cost per MWh and only the cheapest plants run to meet demand each half hour. CDEC also optimaly manages the water in reservoirs, in particular the large Laja lake. See Galetovic and Muñoz (2009).

In addition, each generation unit is paid a monthly capacity payment based on its annual availability. The price of capacity (also called capacity spot price) equals the capital cost of the peaking technology, a diesel turbine. An annual capacity balance is calculated for the system's peak hour and generators with more capacity than their customers' load sell capacity to generators with deficit at the capacity spot price.

Because only generators exchange energy and power in the spot market and dispatch is mandatory, it is sometimes claimed that the term "spot market" is an oxymoron—in a market, so the argument runs, wholesale customers directly bid and exchange energy at the spot price.[11] This description of the Chilean market overlooks three facts. One is that it is built on the premise that generators sell electricity to large customers through long-term contracts. Hence, contract prices smooth out the hourly, daily and seasonal variation of the marginal cost of energy, which is substantial. It is also the case that any generators' opportunity cost of energy and capacity is always given by the spot price, a direct consequence of mandatory marginal cost dispatch. Hence, even unregulated contracts with large clients, which represent about 40% of energy sold, must reflect expected marginal costs in equilibrium. Consequently, the rule used to set regulated energy and capacity prices just follows the logic of a competitive contract market. Last, entry into generation is free, hence expected spot prices must be high enough to pay for operation and investment costs in equilibrium. In other words, free entry and the resulting composition of generation plant determines average spot prices.

That said, the 1982 law, which created the electricity market, introduced neither customer access to the wholesale market nor retail competition for small customers. Instead, it defined "large" costumers—those who consume more than 2 MW—and "small" customers—the rest. Large customers, it was thought, can bargain supply conditions and tariffs with generators, and were left alone. Each small customer, by contrast, pays regulated capacity and energy prices and is supplied by a distributor who has a legal monopoly, buys energy and capacity under regulated wholesale contracts and pays transmission charges on behalf of customers. Therefore, distributors develop and maintain the medium- and low-voltage grid and deliver electricity to regulated costumers inside their concession area.

[11] For example, Joskow (2000a, 2000b), argues:

> What is generally referred to as a spot market in Chile is not really a market in the sense that the spot markets for energy in California, Norway, or England and Wales are markets. Indeed, it is little different from the centrally dispatched power pools like PJM that existed in the United States for decades before restructuring. Generators are dispatched based on estimates of their marginal production costs, and the marginal cost of the last supply unit called to meet demand determines the market clearing price. Network congestion and constraints are centrally managed by the system operator (the CDEC in Chile) in conjunction with the least-cost dispatch of generators. While this mechanism for dispatch and spot-price calculation gives generators incentives to keep their costs low and their availability high, it represents a simulated spot market for energy rather than a real spot market.

3.2. A brief introduction into the Emma model

As said, Chile's electricity regulation combines centralized dispatch with free entry into generation and contracting. Because of this, the short run of Chile's CIS is almost fully determined by, on the one hand, the system's load and, on the other, by the available capacity and water availability. Consequently, policies work almost exclusively through investment decisions. This section briefly describes the Emma model (Spanish acronym for"electricity, markets and the environment") which we use to study the intertemporal impact of alternative policies.[12]

Description and basic assumptions Emma is an intertemporal integrated assessment model that minimizes the private expected cost of supplying electricity—the sum of capacity, operation and outage costs. Just as it is done in the CIS, in our model plants are dispatched by merit order and water from the Laja reservoir is used optimally.[13] 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. This 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[14]—average revenue per MWh is approximately equal to the average marginal cost. Moreover, the time profile a solar plant's output has little correlation with prices.[15] Nevertheless, it is known that intermittent generation from wind and solar causes incremental investments in transmission to maintain system stability. We do not model this cost here.

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 about water rights (see the next section). We assume that renewables, described in Table 1, become gradually available over the years. The initial fraction of the renewable supply curve in Figure 3 is 20% in 2010 and this fraction increases linearly until the total potential is fully available by 2025.

Precipitation uncertainty is modeled assuming four hydrologies (dry, intermediate, normal and wet), 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.[16]

[12] This subsection is rather technical and can be skipped without loss of continuity. It is based on Galetovic, Hernández, Muñoz and Neira (2012).

[13] Laja is the only reservoir in Chile that has interannual storage capacity. There are also smaller reservoirs in the CIS that we model as run-of-river plants, whose availability varies in every demand block.

[14] The correlation coefficient of output and prices of wind plants in the CIS ranged, in 2011, from -0.1 to -0.02.

[15] Assuming a standard generation profile of photovoltaic cells and the hourly marginal costs of the CIS in 2011 we estimate that the correlation coefficient of output and prices of solar plants is approximately 0.15, and the average revenue is approximately 6% higher than the average marginal cost.

[16] We assume that coal and natural gas prices are positively correlated with the price of oil.

Formally, if r is the discount rate, π is the probability of a hydrology-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

$$\sum_{t=1}^{60} \frac{1}{(1+r)^t} \sum_{j=1}^{16} \pi_j \cdot [k(t) + c_j(t) + o_j(t)] \tag{3.1}$$

subject to producing the energy demanded each year—given the prices that consumer's pay—and complying with renewable quotas and environmental standards. Notice 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 (3.1) over the whole 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 One novel feature of Emma is that 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, 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 cost is distributed pro rate 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's 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, as we have seen, 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, marginal 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.[17] At the same time, hydro and renewables obtain Ricardian rents because their supply curves are upward sloping.

It should be noted that in Chile's CIS, a significant fraction 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 Colbún, another generator who owns water rights, to jointly develop the large HydroAysén project in southern Chile.[18] Emma has a module that models the joint strategic behavior of Endesa and Colbún, assuming that they expand their installed capacity to maximize their joint profits.

3.3. Electricity and the environment

Power plants that run on fossil fuels emit CO_2, other greenhouse gases (GHGs) and air pollutants: particulate matter (PM_{10} and $PM_{2.5}$[19]), sulfur oxides (SO_x) and nitrogen oxides (NO_x). CO_2 emissions and greenhouse gases contribute to global climate change. 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, damaging health, materials, visibility and crops. Any efficiency analysis of electricity generation must quantify these damages. In this section, which follows Galetovic, Hernández, Muñoz and Neira (2012), we briefly explain how environmental externalities are modeled by Emma.

3.3.1. 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 wrought by emitting one additional ton of the pollutant.

Formally, if $\mathrm{md}_i(s)$ 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

$$D_i(t_i) = \int_0^{t_i} \mathrm{md}_i(s)\, ds \tag{3.2}$$

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

[17] The strong duality theorem ensures that, if output is values with these shadow prices, marginal projects earn zero profits. We thank Heinz Müller for making us aware of this.

[18] We estimate that Endesa's water rights account for 22% of the total hydro potential in GWh/year and that Endesa + Colbún's water rights account for 47%. The latter number includes the water rights owned by Endesa, Colbún, and HidroAysén.

[19] Particulates smaller than 2.5μm.

with the amount emitted. Hence (3.2) can be simplified to

$$D_i(t_i) = \mathrm{md}_i \times t_i \tag{3.3}$$

It is important to distinguish between marginal damage and marginal per capita damage. Per capita damage is the harm on a particular individual or thing (e.g. a building) by a given concentration level of a given pollutant. On the other hand, the marginal damage wrought by an additional ton of the pollutant is a linear function of the number of individuals and marginal per capita damage, vis

$$\mathrm{md}_i = (\#\text{ of individuals}) \times (\text{damage per person})_i \tag{3.4}$$

A straightforward implication of (3.4) is that marginal damages grow with the size of the population around the source, ceteris paribus.

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 of Cifuentes et al. (2010) for the marginal damages of $PM_{2.5}$, SO_x and NO_x[20] 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.[21]

We assume four different locations such that marginal damages differ because of population size (see table notes). We further assume that the value of the marginal damages in 2010 are the ones estimated by Cifuentes et al. (2010), but over time they 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. While per capita damages are larger in the United States, the marginal damages of emissions are larger in Chile because population densities around the sources of emissions are larger in Chile.

Note that in equations (3.2) and (3.4) total damage is a function of emissions t_i. Nevertheless, in practice the damage is caused by the exposure of individuals and things (like buildings or crops) to pollution. As shown in Figure 4a, 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.

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

[20] We quantify only the effects of $PM_{2.5}$, SO_x and NO_x emissions. On the one 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).

[21] Muller and Mendelsohn (2007) also include the damage to timber, materials, visibility and recreation.

emissions, because tall smokestacks disperse pollutants away from the source. On the other hand, they also show that in rural areas concentration levels do not depend on whether the source is at ground level or through a high stack. This is one source of imprecision in the assessment of environmental costs.

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.

3.3.2. The damage caused by CO_2 emissions

The adverse effects of climate change are floods, droughts, change in storm patterns, temperature, higher sea levels, among others, causing costs in those affected human activities. The marginal damage of CO_2 is the present value of all incremental economic costs (present and future), caused by the incremental climate change of emitting an additional ton of CO_2 into the environment. As Figure 4b shows, the damage caused by greenhouse gases 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 CO_2 for five post-Copenhagen scenarios using the RICE-2010 model. In our evaluations we assume that the marginal damages of CO_2 over time are the prices of CO_2 reported in Nordhaus' (2010) optimal scenario. This scenario maximizes economic welfare, assuming that all countries mitigate emissions optimally from 2010 on, equaling the marginal cost of reducing CO_2 to the marginal damage of CO_2 in all sectors of the economy. Therefore, in this case CO_2 prices can be interpreted as marginal damages. Table 2 exhibits the marginal damage of CO_2 emissions, estimated in Nordhaus (2010). The price of CO_2 increases over time and ranges from $5.6 in 2010 to $55.8 in 2063 per ton of CO_2.[22]

Finally, to compute the total damage of CO_2 we assume that the marginal damage is constant with power plant emissions but increases over time.

4. Policies, efficiency and productivity in Chile's CIS

4.1. Endowments and the scope of an efficient energy policy

Good microeconomic policy fosters the efficient use resources, but outcomes also depend on factor endowments. How is Chile's CIS endowed to produce electricity? In the long run there are four

[22] In the long term, the price of CO_2 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 CO_2. To convert from dollars per ton of carbon to dollars per ton of CO_2 divide by 3.67.

sources of energy. One is to tap Chile's vast reserves of hydroelectricity. Second, generators can also import fossil fuels: coal, LNG and diesel. Third, while it seems unlikely, the CIS might go nuclear. Last, imports of natural gas may resume at some unknown date in the future, since there are vast reserves of natural gas in Argentina and pipelines that cross the Andes are already sunk. How should one compare them?

4.1.1. Some basic electricity economics

Electricity can be produced with several different technologies and, because electricity demand varies over a day, week, month and year, cost minimization implies that different technologies will optimally coexist in equilibrium.[23] Base loads—i.e. those consumptions that do not vary over the course of a day, week, month or year, like those needed to keep refrigerators working—are efficiently served with high-capital, low-fuel cost technologies. By contrast, loads that are only present at peak hours should be served with low-capital, high-fuel cost technologies, like diesel turbines.

At the same time, it is also the case that the bulk of capacity additions should come from only one base load technology, that with the lowest "levelized" cost. The levelized cost is the average cost per MWh or unit of energy. It combines capital and fuel costs by prorating the cost of a unit of capacity over all MWh produced. Of course, the more intensely capacity is used (i.e. the higher the so-called "availability factor"), the lower is the levelized cost of energy. Formally, let f be the annual cost of the capacity needed to produce one MW of power continuously with a given technology, let c the fuel cost of producing one MWh of energy and let $\lambda \in [0, 1]$ be the availability factor and recall that a year has 8,760 hours.[24] Then

$$\text{levelized cost per MWh} = \frac{f}{\lambda \cdot 8,760} + c. \tag{4.1}$$

As can be seen from (4.1), cost variations between technologies stem from variations in f, c *and* λ. For example, hydro plants are cheap to run ($c \approx 0$), but expensive to build (f is large) and their availability factor varies a lot depending on precipitation patterns. Fossil fuel plants, by contrast, are more expensive to run ($c > 0$), but cheaper to build and their availability factor is high. Last, nuclear plants are cheap to run (c is smaller than for fossil fuels) and their availability factor is very high. Nevertheless, they are very expensive to build, so that f is large. Which one is more cost effective depends on all three parameters and is ultimately a practical matter.

[23] The seminal reference is Boiteaux (1960).

[24] Power is the ability to perform mechanical work and is measured in watts (W). Energy is the use or generation of power during a given time period and is measured in watts per hour or watt-hours (Wh). For example, a 100 W light bulb consumes 50 Wh of energy if it is on for half an hour. One kilowatt (kW) = 1,000 watts (W), one megawatt (MW) = 1,000 kW and one gigawatt (GW) = 1,000 MW.

4.1.2. The levelized cost of energy in Chile's CIS

Figure 5 shows the levelized cost of energy of each technology.[25] Argentine natural gas is clearly the cheapest generation alternative, at approximately US$46/MWh. Not surprisingly, between 1997 (when natural first gas arrived) and 2004 (when the Argentine government reneged on its 1991 trade agreement and curtailed natural gas exports), capacity expanded exclusively with gas-fired combined-cycle plants.

But unless imports resume, the main source of cheap energy is hydroelectricity. Indeed, based on a detailed count of available water resources, we conclude that hydroelectricity can add about 75,000 GWh per year of energy at lower cost than coal (around US$85.5/MWh) and LNG (around US$87.4/MWh).[26] This is substantial: recall that currently yearly consumption of electricity in the CIS is about 45,000 GWh. Thus, Figure 5 indicates that Chile's CIS should expand with hydro for a long time.

Figure 5 largely maps the scope for an efficient energy policy. It is apparent that when natural gas exports from Argentina were first curtailed and then suspended, the CIS was hit by a large supply shock, which increased the long-run cost of electricity—roughly the difference between the hydro supply curve and the system's levelized cost with Argentine natural gas. Given that Argentine gas exports will not resume in the foreseeable future, the main implication is that policy should facilitate the development of Chile's hydro potential. Nevertheless, while it is not apparent from Figure 5, investments in hydro have been rather slow in practice. Whether the CIS develops along the hydro supply curve or expands mainly with fossil fuels will probably be influenced by policies. In what follows, we quantify the effect of alternative policies with our intertemporal model Emma.

4.2. Baseline

Assumptions All simulations estimate the system's expected operation between 2010 and 2049 with actual installed capacity in 2010 and under construction until 2016. Between 2016 and 2049 we study the effects of alternative policies by imposing different constraints on investment plans.

In the baseline case, the system freely invests in hydro according to the supply curve in Figure 5. Also, Endesa + Colbún choose their sequence of hydro investments to maximize joint profits and the rest of the system minimizes expected investment and operation costs given the behavior of Endesa + Colbún.[27] Fossil fuel plants install emissions abatement equipment to comply

[25] The levelized cost of energy includes capital, operation, and maintenance costs.

[26] The levelized cost of diesel-fired plants is not shown in Figure 5 because it is well above nuclear, at approximately US$220/MWh.

[27] As we mentioned above, Endesa and Colbún own 47% of available water rights (measured in GWh) and both have an alliance to jointly develop the large HydroAysén project in southern Chile. This justifies modeling both as a single agent who plays a Stackelberg game with the rest of the system.

with current environmental standards, including the recent regulation of SO_x and NO_x emissions. Furthermore, generators must either meet a quota of non-conventional renewables, which increases from 5% of total energy in 2010 to 10% in 2024 as mandated by the current law. Thus, the baseline case combines actual investments, regulation and market structure with unrestricted development of Chile's hydro potential.[28]

We assume that both Endesa + Colbún and the planner make their intertemporal decisions discounting flows at a 10% annual real rate. Thus, when deciding whether to make an investment, intertemporal costs and benefits are discounted at this rate.

At the same time, to report outcomes in Table 3, we discounted yearly flows at the rate of growth of the demand for electricity and then averaged out over 40 years. This might be unconventional but it is also convenient because it scales quantities to levels at the initial year.[29] For example, the first line and column of Table 3 says that 40,385 GWh are sold every year on average in the baseline case and that the yearly average capital cost is US$1,844 million. In addition, not discounting by time preference allows us assess the average yearly performance of each policy without weighing the present outcomes more than future outcomes. Thus, for example, when reporting results, we weigh US$1 of capital costs incurred in 2030 the same as US$1 of capital costs incurred in 2012. In this way we have a better sense of the year-by-year performance induced by alternative policies, which is convenient when assessing the effects of policies on productivity.

The composition of generation Panel (a) in Figure 6 shows the composition of generation between 2010 and 2049. The figure shows the share of hydro at the bottom, followed by, coal, LNG, NCRE and diesel. Three periods can be distinguished.

First, between 2010 and 2015 the share of hydro falls from 69% to 56% and coal's grows accordingly; this reflects that about half of the capacity that will become operational until 2016 will burn coal. Second, in 2016 hydro's share jumps back to 69% and remains there until about 2032.[30] This reflects that from 2016 on, the system expands with hydro, just as Figure 5 suggests. Note also that coal's share steadily falls, partly because NCREs expand to comply with the law, but also because LNG capacity expands to serve the peak, whose size grows year by year.

Third, after 2033, when all efficient hydro projects are already operational, the system expands with fossil fuels, again a direct consequence of Figure 5. Consequently, while hydro generation remains roughly constant in levels, its share steadily falls. On the other hand, the share of coal rises from about 10% in 2033 to one-third in 2049 as coal substitutes for hydro as base load technology.

[28] At the time of the last revision (December 2012) the entry schedule of new plant was already dated. Hence, the "predicted" evolution of the system between 2010 and 2014 does not coincide with reality.

[29] In the appendix we report results with standard discounting.

[30] Indeed, between 2010 and 2015 the model "builds" 2,500 MW of nominal hydro capacity. Massive entry of hydro capacity as soon as the model admits it suggests that investments in hydro are behind schedule.

Last, LNG is still the technology of choice to serve the peak, so its share remains constant at about 20%.

Prices Panel (a) in Figure 7 shows the expected levelized price of energy.[31] As capacity grows between 2010 and 2016 and massive investments in hydro enter in 2016, it falls to US$59/MWh in 2016. From then on the levelized price of energy steadily increases as the system climbs up the hydro supply curve. By 2030 the levelized price is about US$90/MWh and, by the time hydro investments run out it reaches US$94/MWh and remains there as the system expands with coal as base load technology and LNG to serve the peak.

Economic outcomes Column 1 of Table 3 summarizes the economic outcomes of the baseline case. It can be seen that 40,385 GWh are generated on average, which cost US$2.6 billion. About 70% of the total cost of generation are capital costs (US$1.8 billion) and 30% are operation costs (US$754 million)—environmental costs are small.

As the lower panel in Table 3 shows, hydro generators make substantial profits—US$818 million per year. This follows from Figure 5: as the equilibrium price of electricity increases over time along the supply curve, inframarginal capacity earns Ricardian rents. By contrast, fossil-fuel generators earn close to zero profits, which is a consequence of competitive entry.

To put these magnitudes in perspective, note that the IMF estimated Chile's GDP in 2011 at around US$250 billion. At the same time, the Central Bank (2012) estimates that roughly 90% of generation's value added are capital costs and gross operating surplus. In our base case capital costs and profits add up to 2.8 billion (see column 1 in Table 3), i.e. the contribution to total value added is roughly 3.0 billion per year or about 1.2% of GDP.[32]

4.3. Estimating the cost of not having Argentine natural gas

Natural gas found and lost Until the early 1990s capacity in Chile's CIS expanded mainly with hydro generation, complemented with a few coal plants and diesel turbines, mainly backups against severe droughts. But in 1991 Chile and Argentina signed a protocol to freely trade natural gas and mandated open access to gas pipelines.[33] By the mid 1990s two pipelines were under construction and in 1997 the first combined cycle plants began to generate in Chile's CIS. Electricity prices fell precipitously and capacity began to expand almost exclusively with natural gas. But gas cuts

[31] Expected levelized costs include the marginal cost of energy, the marginal cost of capacity, and a postage charge due to the non-conventional renewables quota.

[32] The Central Bank (2012) estimates that in 2009 electricity generation contributed 1.7% of total value added. Since about 75% of Chile's electricity is generated in the SIC, it follows from this estimate, that the SIC contributes about 1.3% of total value added.

[33] "Acuerdo de complementación económica N°16," signed on August 2, 1991.

began in May 2004 and soon the Argentine government suspended further export permits, thus violating the 1991 agreement that made gas exports possible. Worse, protracted and increasing gas cuts ensued, as shortages in Argentina, which were caused by the price controls introduced in the aftermath of the 2001 devaluation, worsened.

In this section we estimate the cost of losing Argentine natural gas comparing the baseline trajectory of the system with what would have happened had natural gas been freely available in the same conditions that prevailed until 2004.

Prices and quantities Figure 5 shows that no hydro investments are competitive with Argentine natural gas. Indeed, the share of hydro falls fast from 60% in 2010 to 40% in 2020 and 15% in 2045. Panel (a) in Figure 7, on the other hand, shows the trajectory of the levelized price of energy. It is just US$50/MWh during this decade and stabilizes at slightly less than US$60/MWh after 2024, once the 10% non-conventional renewable requirement is met. As can be seen from column 2 in Table 3, average energy prices are about one-third lower than in the base case (US$61/MWh against US$89/MWh).

Column 2 in Table 3 reports the economic outcomes with Argentine natural gas. Electricity consumption is about 13% higher than in the baseline (45,263 GWh against 40,385 GWh). Yet the annual total cost of generation is 12% lower on average (US$2.3 billion against US$2.6 billion). Because natural gas generation is less intensive in capital, capital costs are almost 29% lower (US$1.3 billion against US$1.8 billion), and the share of capital costs is smaller, 57% against slightly more than 70%. Last, while natural gas is a fossil fuel, environmental costs barely change.

Our exercise suggests that the recovery of Argentine natural gas would have large welfare and distributive effects. As column 2 on Table 3 indicates, consumer surplus is on average some US$1.2 billion higher, equivalent to 45.3% of baseline system cost or slightly less than 0.5% of GDP.[34] By contrast, generator profits fall, because natural gas reduces the Ricardian rents of hydro generators (but of course, not of NCRE generators). All in all, social surplus is US$656 million higher, equivalent to 25.1% of baseline system cost or about 0.25% of current Chilean GDP.

Efficiency and productivity As column 2 in Table 3 shows, the return of Argentine natural gas would increase value added in the rest of the economy in US$813 million every year on average. In other words, GDP would be permanently higher by 0.3%. Depending on your point of view, this may seem large or small. It is large if the yardstick is the size of Chile's CIS—about one-

[34] In what follows we will refer most comparisons to baseline total system costs, US$2,609 million. In this case,

$$45.3\% = \frac{1,182}{2,609}$$

fourth of CISs value added.[35] Moreover, Chile's CIS is "large", macroeconomically speaking—its contribution to total value added (about 1.3% in 2009) would rank in the 82nd percentile among 111 sectors. On the other hand, 0.3% of GDP might not seem very large in the sense that, sure enough, it is by far not enough to account for Chile's productivity slowdown, a usual argument one hears from macroeconomists. We will return to this discussion in section 5.

In any case, note that Argentine natural gas would increase total factor productivity in Chile's CIS by 27% compared with the baseline case. This, of course, despite of the fact that the value added by generators would fall substantially, from about US$3 billion to about US$1.8 billion. But this is precisely the point: Argentine natural gas produces the same amount of electricity with fewer resources.

4.4. Red tape and policy uncertainty

Is red tape important? Perhaps most would agree that red tape slows entry and productivity growth, but careful cost estimates for specific sectors are hard to come by. In Chile's electricity sector, casual observation suggests that it has become increasingly difficult over time to get regulatory clearance to build new plants, especially large hydro projects and coal plants. It is also the case that through judicial action and sometimes direct lobby, those who oppose projects on principle or to extract rents, have been able to delay them and, sometimes, obtained their cancellation. Last, getting eminent domain to build new transmission lines is difficult and some argue that this has slowed down investments in capacity.

Regardless of the explanation, there are clear indications that investments are delayed beyond of what is efficient. As said, The base case indicates that about 2.500 MW of hydro capacity should enter as soon as possible. By contrast, until 2014 only 700 MW of hydro capacity and 800 in coal will enter.[36] Worse, at the time of writing (October 2012) no further projects are under construction, so that new capacity will not enter before 2017 at the earliest.

We can evaluate the consequences and costs of slowing down investments by comparing the baseline with restrictive regimes. While this exercise assumes the constraints, it is realistic: if the future of coal became uncertain when Suez's Barrancones project was canceled after a presidential request despite having received environmental clearing[37], now it looks unlikely, because a recent ruling of Chile's Supreme Court cancelled the 700 MW Castilla coal plant questioning the environmental evaluation methodology used by the agency in charge.

[35] The Central Bank's 2009 input-output matrix distinguishes 111 sectors. The median sector (non-ferrous mining) contributes 0.36% of total value added. The 90th percentile sector (real estate development) contributes 2.7% of total value added. The largest sector (copper mining) contributes 13,2% of total value added.

[36] See Galetovic and Hernández (2012).

[37] Apparently the President intervened to please vociferous opposition of environmental groups who oppose coal plants.

To estimate the consequences of slowing down investments we have simulated two restrictive investment regimes:

Freezing Chile's hydro potential The first simulation calculates the system's expected expansion and operation from 2010 on, with plants under construction until 2014. After 2014, we assume that hydro entry only two hydro plants are built, Alto Maipo (a 500 MW run-of-river plant near Santiago) and Endesa + Colbún's 2,750 MW project HidroAysén. We assume that no other hydro project is ever undertaken.

Neither hydro nor coal The second simulation assumes that no further hydro or coal projects are developed besides the ones under construction until 2014. The system is then forced to expand with LNG.

Prices Panel (b) in Figure 7 shows the evolution of the expected levelized price of energy. There is little difference between either restrictive regime—the price of energy quickly approaches US$90/MWh. But at the same time, until 2030 the price of energy is between US$10 and US$25/MWh higher than the baseline. After 2030 the difference narrows and eventually disappears, but only because prices rise in the baseline case when new hydro projects run out. Two conclusions follow. First, large but isolated hydro projects have little impact on prices. Second, as far as the price of energy is concerned, there is not much difference between expanding with coal or LNG, a fact that is already suggested by Figure 5.

Economic outcomes Columns 3 and 4 in Table 3 show the economic impact of restrictive regimes. Compared with the baseline, neither average yearly generation nor costs change much, because after hydro projects run out around 2030 system expansion is almost the same. Furthermore, note that the cost of local externalities remains of the same order of magnitude, which confirms that current environmental regulation is effective to control local pollution.

On the other hand, the distributive effects of restrictive regimes are rather large. If only HidroAysén and Alto Maipo are built, consumers lose US$236 million a year on average, but yearly generator profits rise by US$238 million. On the other hand, because both Alto Maipo and HidroAysén have relatively low costs, the cost of generation does not change by much compared with the baseline (in both cases on average electricity costs US$64/MWh) but Ricardian rents increase. Thus, limited hydro development allows the owners of hydro plants to earn rents without lowering the price of energy.

Column 4 shows that when neither hydro nor coal develop, consumers lose even more (US$322 million) but generator profits increase only a little (US$71 million). The reason is that generation costs per MWh rise almost 10% with no further hydro investments, from US$64/MWh on average in the baseline to US$70/MWh with neither hydro nor coal. All in all, social surplus falls by US$250 million. This is large; for example, it amounts to about 40% of the benefit of recovering Argentine natural gas.

Note that incumbent hydro generators like restrictive regimes. Compared with the baseline hydro generators as a group earn only US$10 million more (US$828 million in the neither-hydro-nor-coal case against US$818 million in the baseline). But this obscures the fact that in the restrictive case hydro capacity is frozen at its initial level. Hence rents per installed MW of capacity are substantially higher.

Efficiency and productivity Columns 3 and 4 in Table 3 show that productivity in generation does not change much when some hydro development is allowed and the system expands with coal, but falls 8% when the system is forced to expand with LNG. Value added in the rest of the economy falls, depending on the case, by US$156 million or US$222 million, between one fifth and one-fourth of the increase in value added that would accrue with the return of Argentine natural gas.

4.5. Environmental policies

4.5.1. Introduction

As in the rest of the world, the environmental impact of fossil fuels generation is hotly debated in Chile. Currently all projects must pass an environmental evaluation, carried out by the Environmental Impact Evaluation System (SEIA for its Spanish acronym). SEIA forces plants to install abatement equipment for pollutants, particularly particulate matter, and ensure compliance with environmental standards. Second, a recent regulation imposed rather stringent emission standards on SO_x and NO_x. Last, the quota of renewable energy forces companies to supply at least 5% of their annual sales of electricity with non conventional renewable energies (NCRE) in 2010, increasing to 10% in 2024.[38] If a company doesn't meet the quota, it has to pay a fine of about US$42/MWh for each unmet MWh.

It seems fair to say that many consider that the current environmental control system (SEIA) is ineffective, while others think that it is very expensive. Still others believe that NCREs are necessary to decrease CO_2 emissions. Not coincidentally, a bill is currently in Congress which would increase the NCRE quota to 20% by 2020. To evaluate the impact of the environmental policies we simulated the following:

Uncontrolled emissions (without SEIA) This simulates how the system would have expanded had neither SEIA existed nor standards on NO_x and SO_x emissions imposed.

[38] NCRE include biomass, biogas, geothermal, tidal, solar, wind and small hydroelectric power plants (smaller than 20 MW).

A 20% NCRE quota by 2020 The quota increases from 5% in 2010 to 20% in 2020.[39] Generators cannot pay a fine for noncompliance.

Optimal environmental policy In this case generators pay the marginal damage of SO_x, NO_x, PM and CO_2 emissions. Existing and new plants optimally install abatement equipment to minimize their cost of generating electricity + the environmental damage they cause. The global marginal damage caused CO_2 emissions is valued following Nordhaus (2010).

4.5.2. Assessing the effect of current environmental policies

Environmental policies and the environment Table 4 shows the environmental impact of each policy. Note that with the exception of column 5 ("uncontrolled emissions"), total emissions of local pollutants vary only marginally across policies.[40] Indeed, by simulating what would happen with no regulation at all, it becomes apparent that current environmental regulation is quite effective. For example, compared with the base case, uncontrolled emissions of SO_x would be almost 17 times larger and NO_x emissions are 18 times larger. Particulate material emissions, in turn, are some 3,300 times larger. In other words, current regulation succeeds in making them almost negligible—the denominator is small. Thus, current regulation has nearly eliminated particulate material and strongly reduced SO_x and NO_x emissions.

Economic impact As can be seen in column 5 in Table 3, with uncontrolled emissions consumers would gain US$156 million, because the price of energy would be slightly lower (see the dotted line in Figure 7c). But generator profits would fall by US$116 million and compensate in part what consumers gain. More important, as column 5 shows, uncontrolled emissions would increase the social cost of generation by US$457 million on average each year and reduce social surplus by US$416 million. These effects are large, of the same order of magnitude as those caused by Argentine natural gas. Thus, the social benefit of forcing the installation of abatement equipment is substantial.

An alternative way to appreciate the effectiveness and efficiency of current policies is to compare them against the optimal policy, which forces generators and consumers to internalize all environmental externalities. Note that, as column 7 shows, an optimal policy would barely change social surplus and prices relative to the baseline (see Figure 7c).[41] Indeed, with an optimal policy emissions are slightly higher, which suggests that current environmental standards in are quite strict.

[39] The quota increases to 15% in 2015 and increases every year in 1% until it reaches 20% in 2020.

[40] Column 10 ("bad policies added") also shows simulations with uncontrolled emissions.

[41] The alert reader may wonder how an optimal policy may make social surplus fall relative to the baseline. The answer is that our system is not fully optimized to begin with, because it inherits investments—we minimize costs conditional on them.

Efficiency and productivity It is often claimed that there is a trade off between economic efficiency and the environment. Nevertheless, our results put this in doubt because the economic burden of current environmental standards is rather small. As can be seen in Table 3, doing away with current environmental regulations would reduce the average price of electricity from US$89/MWh in the baseline case to US$84/MWh and value added by the rest of the economy would increase by US$114 million. This is not negligible, but is much smaller than the reduction in the cost of emissions. Also, the average cost of producing electricity would fall, but only marginally, from US$64/MWh in the baseline case to US$63/MWh, and TFP in electricity generation would increase only by 2%.

Indeed, uncontrolled emissions have a small positive effect on measured TFP in electricity generation and value added in the rest of the economy only because standard efficiency and productivity measures ignore environmental impacts. Indeed, in this case column 5 indicates that the environmental cost per MWh of uncontrolled emissions is about US$11/MWh. As can be seen by comparing the damage wrought by poll generated MWh, current environmental policies reduce this cost to almost nothing. Should one consider these costs in productivity calculations, TFP in electricity generation turns out to *fall* by 13% with uncontrolled emissions (see column 5 in Table 3, line TFP electricity (social)).

4.5.3. Renewable's policies

Environmental effects Sound environmental policies are part of sound microeconomic policy, but some environmental policies which are currently popular are ineffective and very expensive.

Column 7 in tables 2 and 3 show the impact of the so called 20/20 policy currently being discussed in the Chilean Congress—20% of electricity generated by NCRE by 2020. Compared with the baseline, the incremental abatement of local pollution is negligible, because emissions are small in the first place. Yet the policy is very expensive and massively redistributes wealth to the owners of renewables.

The price of energy As Figure 7c shows, a 20/20 policy increases the price of energy almost immediately, to about US$90/MWh. This may seem surprising; after all, the policy forces the 20% renewables quota only after 2020. But Figures 6(a) and 6(c), which show the composition of generation in the baseline and with a 20/20 policy, explain why. Essentially, because NCREs have low or negligible operation costs, they substitute baseload hydro generation and this slows investments in hydro as soon as the policy is announced. As can be seen in Table 3, over time the price of energy rises from US$89/MWh in the baseline to US$109/MWh or 22%.

Economic impact As can be seen in column 6, the steep rise of the price of energy reduces consumption by 5% on average (from 40,385 GWh in the baseline to 38,473 GWh), and consumer surplus falls by US$790 million. Generators' profits rise by US$484 million and, consequently, social surplus falls on average by US$302 million. The magnitude of this effect is large—a little less than half of the gain that would accrue with Argentine natural gas.

It is interesting to decompose the gain of generators. Both hydro and fossil fuel generators *lose* somewhat with a 20/20 policy, because they are displaced by NCREs. But the owners of NCREs gain US$806 million in Ricardian rents, about the same as hydro generators in the baseline case, but with far fewer MW of capacity. Large Ricardian rents are the mirror image of the large costs wrought by a 20/20 policy. Indeed, renewable quotas are quite expensive because their supply curve is upward sloping and their impact is highly nonlinear. As we have shown elsewhere (see Galetovic, Hernández, Muñoz and Neira, 2012), a 5% quota is not binding, a 10% quota causes a small deadweight loss, but increasing the quota from 10% to 20% multiplies the deadweight loss by a large factor.

Efficiency and productivity As column 6 in Table 3 shows, a 20/20 law would reduce value added in the rest of the economy in US$532 million per year on average, or about 0.2% of GDP—about two-thirds of the effect of recovering Argentine natural gas. Total factor productivity in generation would fall by 9% on average compared with the baseline case. By contrast, value added by generation increases, from about US$3 billion to about US$3.6 billion. But this only says that more capital is used to produce less electricity.

4.5.4. The composition of generation and CO_2 emissions

As far as the discourse goes, reducing CO_2 emissions should be one of the main goals of environmental policies. Figure 8 shows the trajectory of CO_2 emissions with each policy. Until about 2030 one can hardly see any difference. But from then on, CO_2 emissions with either the optimal policy or a 20/20 law are much larger when compared with uncontrolled emissions and, to a smaller extent, with the baseline case. Interestingly, in the long run taxing CO_2 emissions is not only the more efficient policy but also the most effective.

It is commonly thought that policies affect emissions through changes in the price of energy. If energy is more expensive, consumers use less and emissions fall, or so the argument goes. In reality, however, most of the differences across policies stem from differences in fuel composition. As can be seen in Figure 6, with uncontrolled emissions and, to a lesser extent, in the baseline case, the share of coal is larger than with either the 20/20 law or with a carbon tax; consequently, CO_2 emissions are larger.

In view of these results one might argue that both a 20/20 law and a carbon tax have similar effects. But this overlooks that, as we have seen, a 20/20 law is considerably more expensive. Again, the reason becomes apparent comparing figures 6c and 6d. An optimal policy takes full advantage of hydro generation, a cheap zero-carbon technology and, when hydro runs out, switches to LNG, a technology that is marginally more expensive than coal but which emits about half per MWh . Thus, the carbon tax slows the growth of CO_2 emissions by tilting the scale towards LNG, which pays a lower tax per MWh. As a result, coal is squeezed out and its share falls fast.

By contrast, the 20/20 law achieves reductions in CO_2 emissions by increasing the share of NCREs, a clean but expensive technology. Moreover, NCREs retard the development of hydro, a clean but cheap technology.

4.6. Competition policies and water rights divestment

Ever since public utilities were privatized in the late 1980s it has been claimed that Endesa retards the development of hydro capacity to maintain high energy prices. Antitrust concerns were heightened by the alliance between Endesa and Colbún to build HydroAysén, because they own about 50% of the remaining available hydro potential. More generally, some claim that antitrust policy is key to ensure efficiency and productivity growth. In this section we estimate the potential gain of mandating the divestment of water rights.

Column 8 in Table 3 exhibits the system's performance with divested water rights. Compared with the baseline, gains are rather negligible. The price of energy barely falls, costs per MWh do not change and consumption increases very little. The conclusion is that for the time being market power and water right divestment should not be a concern.

4.7. The value of good microeconomic policies

Let us now summarize by comparing good with bad policies. We estimate the impact of combining good policies and compare it with the impact of combining bad policies:

Good policies Divested water rights, optimal environmental policies and no NCRE quota.

Bad policies 20/20 law, uncontrolled emissions and neither hydro nor coal development.

As usual, our benchmark is the baseline case.

Good policies do little; bad policies hurt a lot Columns 9 and 10 in Table 3 present the results. Perhaps the main conclusion is that in Chile's electricity sector good policies can do little to improve resource allocation, but bad policies can hurt a lot. On the one hand, column 9 is very similar to column 1 and, as Figure 7 (d) shows, prices follow a very similar path. On the other hand, bad policies would reduce social surplus by a magnitude similar to the loss of Argentine natural gas. For this reason, in what follows we comment on the effect of bad policies.

Prices and economic outcomes Figure 7d shows that prices would be considerable higher with bad policies. Essentially, in this case cheap hydro capacity is not used and, at the same time, users must pay for the NCREs quota. On average, the price of energy is 28% higher than in the baseline—US$114/MWh against US$89/MWh. Consequently, yearly consumption falls by 6.5% on average (37,783 GWh against 40.385 GWh) and consumers lose US$959 million per year. Social surplus falls by less, because profits of NCREs generators rise; but the fall is still large, US$571 million.

The environment Our bad policies case combines uncontrolled emissions with a 20% NCRE requirement. Because now the system expands with LNG, a fossil fuel, one might think that NCREs are a far mor effective environmental tool, but this is not so. For one, as can be seen in Table 4, emissions are considerably higher than in the baseline case. For another, pollution is less than in the uncontrolled case (column 9) because now the system expands with LNG instead of coal. In any case, the bad policy case confirms that current environmental policies are very effective.

Efficiency and productivity As column 10 in Table 3 shows, bad policies would reduce value added in the rest of the economy by US$654 million per year on average, or about 0.3% of GDP. Private total factor productivity in generation would fall by 12% on average compared with the baseline case, and 17% if higher environmental costs are treated as any other cost.

General lessons Our conclusion is that in the case of Chile's CIS bad policies hurt. At the same time, provided that the system is allowed to expand with water, policy has little more to do. This is of course not a general statement and might seem close a tautology—after all, the baseline assumes that hydro resources are used efficiently. But it says something quite fundamental: when prices reflect relative scarcities, policy deals appropriately with externalities and resources at hand are used efficiently, then there is little room for policy to improve resource allocation. Policy is needed either to correct externalities or to set rules that facilitate bilateral exchanges. This fundamental lesson is too often forgotten.

5. Conclusion

We began this paper discussing the possible causes of Chile's productivity and growth slowdown. Many doubt that vigorous microeconomic reforms are effective to permanently accelerate productivity and GDP growth. This paper quantified the effect of a supply shock, the value of good microeconomic policies and the cost of bad policies in Chile's CIS, which produces about 1.3% of total value added. To conclude we summarize our results and discuss a few implications that go beyond Chile's CIS.

We have shown that an intertemporal model with endogenous investment and price-responsive demand is appropriate to evaluate how different policies affect sectoral TFP. Essentially, with exogenous input prices the evolution of sectoral TFP can be directly deduced from the evolution of unit costs. Moreover, with simple production theory one can link policies in one sector with value added and productivity in the rest of the economy—the link is through the demand curve of the rest of the economy for the goods and services that the sector produces and that are used as inputs in the rest of the economy.

Of course, our quantification beyond the sectoral level is subject to limitations because we assumed that the trajectory of employment and the capital stock in the rest of the economy is exogenous. More generally, we have quantified effects on levels but not on rates of growth. But this is hardly a defect of sectoral analysis. Rather, the problem is that the growth literature, beyond telling us that steady economic growth only occurs if the marginal products of all reproducible factors of production are bounded away from zero, has been unable to tell us in empirically meaningful way how this is brought about in practice. Beyond using a coefficient estimated from some cross-country growth regression, there is little that one can do to estimate the rate-of-growth effects of a policy. By contrast, production theory tells us *how* to quantify level effects: one only needs to know the elasticity of demand. Until growth economists produce such a synthesis, estimating credible rate-of-growth effects will not be possible.

Our main finding is that some policies in Chile's CIS can have effects of the order of 20% on its own TFP and change value added in the rest of the economy in magnitudes as large as 0.3% of GDP. Macroeconomically speaking, are these effects "small" or "large"? 0.3% of GDP might not seem very large in the aggregate, in the sense that, sure enough, it is by far not enough to account for Chile's protracted productivity slowdown. Neither can reductions of TFP within Chile's CIS explain much of the slowdown, because it accounts for only 1.3% of GDP. But significant micropolicies tend to have effects of this order of magnitude. For example, Chumacero et al. (2004) estimated the free trade agreements that Chile signed with the United States and the European Union in the early 2000s raised the level GDP by 1%.[42] Corbo and Schmidt-Hebbel (2003), in turn, estimated that pension fund privatization, one of the major reforms ever implemented in Chile, increased the level of GDP between 1.92% and 9.75%.[43]

Moreover, if the yardstick is Chile's CIS, these effects are large—about one-fourth of CISs value added. So whatever your macroeconomic yardstick for "large" is, we have shown that the claim that micro policies can't have sizable effects at the sectoral level is rather indefensible. Thus, perhaps one might excuse the Minister of Finance or the president of the Central Bank for not caring about micropolicies. But we should not excuse a sectoral minister unless she musters compelling

[42] Former President Ricardo Lagos thinks that free trade agreements are one of the main achievements of his administration.

[43] This is an estimate for 2001.

evidence that micropolicies are right. Similarly, we should not excuse the Minister of Economic Affairs, who is nominally in charge of micropolicy, unless he musters compelling evidence that micropolicies are right in most sectors. If, on the other hand, there are reasons to think that government is introducing bad policies into many sectors (as today in Chile's electricity sector); or that a given minister inherits significant distortions in many sectors; or that new policies in many sectors have become necessary to keep up; then the Minister of Economic Affairs is not doing its job unless he cares deeply about efficient micropolicies.

Indeed, perhaps neither should we excuse the Minister of Finance for not caring. To see why, note that Chile's CIS is "large" macroeconomically, at least in relative terms. As the Central Bank's 2009 input-output matrix shows, the median of 111 sectors (non-ferrous mining) contributes 0.36% of total value added; the 90th percentile sector (real estate development) contributes 2.7% of total value added; and the largest sector (copper mining) contributes 13,2% of total value added. Chile's CIS contribution to total value added (about 1.3% in 2009) would rank in the 82nd percentile among 111 sectors. Arguing that sectoral micropolicies are not relevant because sectors are not large relative to GDP comes close to saying that productivity in most sectors doesn't matter macroeconomically! In practice the point is different: by definition, micropolicy is a pointillist exercise with potentially large effects provided that policies improve simultaneously and continuously in many sectors. And this is perhaps the main reason why most ministers of Finance and of Economics Affairs are loath to attempt them: it requires, at the same time, attention to detail and ability to think and implement many consistent policies simultaneously. And then there are the uncountable small and large fights with organized pressure and interest groups. In recent Chilean history only Sergio de Castro, Hernán Buchi and perhaps Alejandro Foxley have been proved up to the task and then, the first two, in very unusual political circumstances.

Of course, micropolicies could be irrelevant after all: if current policies in most sectors would allow or facilitate bilateral exchanges and deal appropriately with market power and externalities, then prices would reflect relative scarcities, resources at hand would be used efficiently and there would be little scope for further policy to improve resource allocation. Indeed, we have seen that in Chile's electricity sector environmental regulations deal appropriately with externalities, concentration of water rights is not a significant problem and policy has little room for improvement *provided that hydro generation can be freely developed*. But we have also seen that the scope for introducing bad policies that hurt efficiency and productivity is also large. For example, a renewables 20/20 policy would be akin to a large negative supply shock and currently hydro and perhaps coal development have grinded to a halt. More generally, it is hard not to fear that significant distortions have been protractedly introduced in many sectors, especially during the last decade. Nevertheless, this is the topic for another paper.

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Appendix

A. The Chilean price system

This appendix explains the Chilean price system. It follows Galetovic and Muñoz (2011).

Large customers Customers who demand more than 2MW buy their electricity directly from generators and pay unregulated market prices for energy (p_e^m) and capacity (p_c^m). They must also pay a per-kWh transmission charge τ_i. Thus, if customer i consumes E_i kW and her load during the peak hour is D_i, her total bill is

$$E_i \cdot (p_e^m + \tau_i) + D_i \cdot p_c^m. \tag{A.1}$$

These prices are typically set by competitive tender. Because most unregulated customers are directly connected to the transmission grid, they pay no distribution charge.

Regulated customers Customers who use 2MW or less capacity pay regulated prices for energy (p_e^r) and capacity (p_c^r). In addition, they must pay their share of the value added of distribution and a per kWh transmission charge, τ. Hence, customer's j total bill is

$$E_j \cdot (p_e^r + \tau_j) + D_j \cdot p_c^r + \mathrm{VAD}_j. \tag{A.2}$$

Node prices p_e^r and p_c^r are set by NEC every April and October.

Now in 1982 hourly metering equipment was very expensive and an energy-only tariff was designed for residential and commercial customers. Thus to transform the per-kW capacity charge into an energy charge, a load-coincidence factor ψ is estimated. Similarly, to transform the per-kW VAD charge a so-called responsibility factor δ is used. The total bill of a customer with an energy-only meter is thus

$$E_j \cdot (p_e^r + \psi p_c^r + \tau_j + \delta \cdot \mathrm{VAD}_j), \tag{A.3}$$

where the term in parenthesis is the so-called BT1 tariff.

Node prices As can be seen from (A.1), (A.2) and (A.3), regulated prices are determined by the node prices. How are these set?[44] Begin with the energy node price. Let $E(t)$ be the energy projected to be consumed at time t, $mc(E(t))$ be the the system's marginal cost at time t, given $E(t)$ and ρ the real discount rate. Given these parameters p_e^r is the average price that yields exactly the same revenue in present value as generators would expect to obtain if they would sell their energy at the system's marginal cost over the next 48 months, viz.

$$p_e^r \int_0^{48} E(t)\, e^{-\rho t} dt = \int_0^{48} \mathrm{mc}(E(t); h)\, E(t)\, e^{-\rho t} dt; \tag{A.4}$$

hence

$$p_e^r = \frac{\int_0^{48} \mathrm{mc}(t; h)\, E(t)\, e^{-rt} dt}{\int_0^{48} E(t)\, e^{-rt} dt}.$$

The capacity node price equals the cost of investing in a diesel-fired turbine meant to run at the system's peak hour. This cost equals the sum of I_t, the cost of the turbine, and I_l, the cost of the transmission line needed to connect it to the high-voltage grid. Both are brought to a yearly equivalent assuming an 18-year recovery period, a system reserve margin, η and a 10% real discount rate. Thus

$$p_c^r = (1 + \eta) \frac{1}{R} (I_t + I_l) \tag{A.5}$$

[44] See Galetovic and Muñoz (2009) for details.

with

$$R \equiv \left[\int_0^{18} e^{-0.1t} dt\right]^{-1}$$

In principle, energy and capacity node prices are directly passed through to customers. Nevertheless, when the electricity law was designed in the early eighties, regulatory discretion was restrained by forcing the energy node price to lie within a band determined by unregulated market prices. The band was determined as follows. First, the so-called baCIS levelized node price was defined as

$$\overline{p}^b = p_{\text{e}}^r + p_{\text{c}}^r \cdot \frac{1}{\ell f} \cdot \frac{1}{h}$$

where ℓf is the system's load factor and $h = 8.760/12$ is the average number of hours per month. Second, the percentage difference between the market levelized price $\overline{p}^m$ and the levelized node price, $\overline{p}^b$, defined as

$$\Delta \equiv \frac{\overline{p}^b - \overline{p}^m}{\overline{p}^m},$$

was calculated. Third, the levelized node price, $\overline{p}^n$, was determined as

$$\begin{array}{lll} \overline{p}^m \cdot 1.05 & \text{if} & \Delta > 0.05; \\ \overline{p}^b & \text{if} & -0.05 \leq \Delta \leq 0.05; \\ \overline{p}^m \cdot 0.95 & \text{if} & \Delta < 0.05.^{45} \end{array} \tag{A.6}$$

Last, if P is total peak capacity consumed, the energy node price is

$$p_e^r = \frac{E \cdot \overline{p}^n - P \cdot p_{\text{c}}^r}{E}.$$

Hence, the energy node price was restricted to vary within a band (A.6) whose limits were determined by market prices paid by large customers.

It is important to note that both the model used by NEC to calculate the energy node price and the model used by CDEC to operate dispatch solve the same optimization problem, with essentially the same data. The only difference is that CDEC's model uses a finer partition of loads and months than NEC's. Moreover, CDEC voluntarily uses the regulated capacity price p_{c}^r to value capacity transfers among generators.

Recent changes In response to the Argentine gas cuts (see below) the law was amended in 2005 and auctions for long-term regulated contracts substituted for the node price.[46] Thus, in new contracts the regulated energy tariff paid by customers will be the winning bid—the price of capacity will still be calculated with formula (A.5). Moreover, over the life of the contract, which lasts at least 10 years, tariffs will be adjusted following an exogenous indexation rule.

[45] The band was changed in May 2005. See the Appendix in Galetovic and Muñoz (2009) for details.
[46] See Barroso et al. (2007).

Table 1
Availability and costs of non-conventional renewable energies in Chile's CIS

	Small hydro 1[6]	Small hydro 2	Small hydro 3	Wind 1[7]	Wind 2	Wind 3	Bio-mass 1	Bio-mass 2	Bio-mass 3	Bio-gas[8]	Geo-thermal 1[9,10,11]	Geo-thermal 2	Geo-thermal 3	PV Solar[12]	Solar thermal[12]
Capacity factor	60%	60%	60%	30%	25%	20%	90%	90%	90%	90%	72%	72%	72%	30%	30%
Exploration's success prob.	-	-	-	-	-	-	-	-	-	-	30%	15%	5%	-	-
Available capacity (MW)[1]	267	544	333	150	300	1,050	325	650	2,274	350	150	300	1,050	1,051	500
Available Energy (GWh/year)[2]	1,404	2,858	1,748	394	657	1,840	2,562	5,123	17,931	2,759	941	1,883	6,590	2,762	1,314
Investment US$/kW (plant)	2,467	2,467	2,467	2,409	2,409	2,409	3,500	3,500	3,500	2,828	3,964	4,556	6,923	6,325	5,260
O&M in US$/kW-year (plant)[3]	20	20	20	32	32	32	68	68	68	68	173	173	173	12	60
Average distance to transmission system (km)[4]	40	60	80	3	3	3	3	3	3	3	65	65	65	3	3
Investment US$/kW (transmission)[5]	798	2,284	6,580	211	211	211	562	562	562	562	715	715	715	357	357
Investment in US$/MWh	50	50	50	108	130	162	52	52	52	42	79	91	138	283	236
O&M in US$/MWh	4	4	4	12	15	18	9	9	9	14	29	29	29	5	23
Variable fuel costs in US$/MWh	-	-	-	-	-	-	31	70	103	64	-	-	-	-	-
Other variable costs in US$/MWh	-	-	-	8	8	8	-	-	-	-	-	-	-	-	-
Transmission in US$/MWh	16	46	132	10	11	14	8	8	8	8	13	13	13	15	15
Total costs US$/MWh	70	100	186	137	163	202	100	139	172	128	121	133	180	303	273

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 Galetovic and Muñoz (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: let I is the total investment cost conditional to success in the exploration, let π be the probability of success and λ the fraction of the investment that takes place after a successful exploration. Then, the total expected cost of a kW of geothermal is $\lambda I + \frac{(1-\lambda)}{\pi} I$. 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 (2010). (13) The rest of the parameters come from estimations obtained in interviews with experts.

Table 2
Marginal damages caused by CO_2 and pollutants
(In US$/ton)

	(1) CO_2	(2) $PM_{2.5}$	(3) SO_2	(4) NO_X
Nordhaus	5.6 to 55.8	-	-	-
Big city[1]	-	29,679	434	4,268
Small city[1]	-	8,330	138	1,228
Town[1]	-	325	5	42
M&M[2] (EE.UU.)		3,220	1,310	260
M&M[3] urban	-	3,300	1,500	300
M&M[3] rural		1,100	900	300

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 3
Comparative evaluation of the system's performance under each policy
(annual averages, in millions of US$)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Baseline	With Argentine natural gas	Freezing water	Neither water nor coal	Uncontrolled emissions	NCRE's quota = 20%	Optimal environmental policy	Water rights divestment	Good policies added	Bad policies added
Total sales (GWh)[1]	*40,385*	45,263	39,973	39,605	41,590	38,473	39,714	40,823	40,354	37,783
Capital cost	*1,844*	1,315	1,450	1,234	1,886	2,127	1,868	1,881	1,846	1,648
Operation cost	*754*	980	1,110	1,544	727	593	678	751	716	1,126
Environmental cost	*11*	10	22	10	468	7	12	11	12	184
Total	*2,609*	2,304	2,582	2,789	3,081	2,727	2,558	2,643	2,574	2,958
Δ generators' profits	*0*	–527	238	71	–116	484	97	–24	–22	561
Δ consumer surplus	*0*	1,182	–236	–322	156	–790	–254	30	–96	–959
Δ environmental cost	*0*	–1	11	–1	457	–4	1	0	0	173
Tax collections	*0*	0	0	0	0	0	144	0	148	0
Δ social surplus[4]	*0*	656	–9	–250	–416	–302	–13	7	30	–571
Δ value added	*0*	813	–156	–222	114	–532	–173	25	–65	–654
Δ residential surplus	*0*	369	–80	–100	42	–258	–81	5	–31	–305
TFP electricity (private)	*100*	127	100	92	102	91	100	100	101	88
TFP electricity (social)	*100*	127	100	92	87	91	100	100	101	83
Price/MWh	*89*	61	95	97	84	109	91	88	87	114
Cost/MWh	*64*	51	64	70	63	71	64	64	63	73
Pollution damage/MWh	*0.3*	0.2	0.6	0.3	11	0.2	0.3	0.3	0.3	4.9
Hydro profits	*818*	291	1,001	828	685	686	973	784	946	721
Fossil fuel profits	*20*	3	71	76	40	–24	–30	24	–34	52
NCRE profits	*146*	163	150	151	143	806	139	153	50	772

Notes: (1) Total sales are equal to generation less average transmission losses. (2) Capital costs include the annuity paid to initial capacity. (3) Environmental costs are the sum of the social cost of pollution and CO_2. (4) Change in social surplus = Δ Consumer surplus + Δ Generators' profits – Δ Environmental costs.

Table 4
Comparative evaluation of the environmental impact of each policy
(annual averages)

	(1) *Baseline*	(2) With Argentine natural gas	(3) Freezing water	(4) Neither water nor coal	(5) Uncontrolled emissions	(6) NCRE's quota = 20%	(7) Optimal environmental policy	(8) Water rights divestment	(9) Good policies added	(10) Bad policies added
Emissions (thousand tons)										
SO_x	21	3	36	13	343	14	22	20	22	124
NO_x	17	13	30	15	311	11	24	17	24	169
PM 2.5	0	0	1	0	109	0	0	0	0	40
Emissions (baseline = 100)										
SO_x	100	14	174	65	1,665	67	108	99	105	604
NO_x	100	77	180	91	1,841	64	143	99	143	1,001
PM 2.5	100	10	161	73	33,264	72	139	99	135	12,025
Damage (US$ millions)										
SO_x	5	1	9	3	84	3	5	5	5	29
NO_x	5	9	12	6	107	3	6	5	6	61
PM 2.5	1	0	2	1	277	1	1	1	1	93
CO_2 emissions										
Emissions (thousand tons)	28,452	35,083	46,470	36,154	39,632	20,220	18,152	28,166	18,977	29,997
Emissions (baseline = 100)	100	123	163	127	139	71	64	99	67	105
Damage (US$ millions)	206	259	338	269	284	148	135	203	139	223

Figure 1a
Microeconomic analysis and GDP accounting:
Electricity as an intermediate input

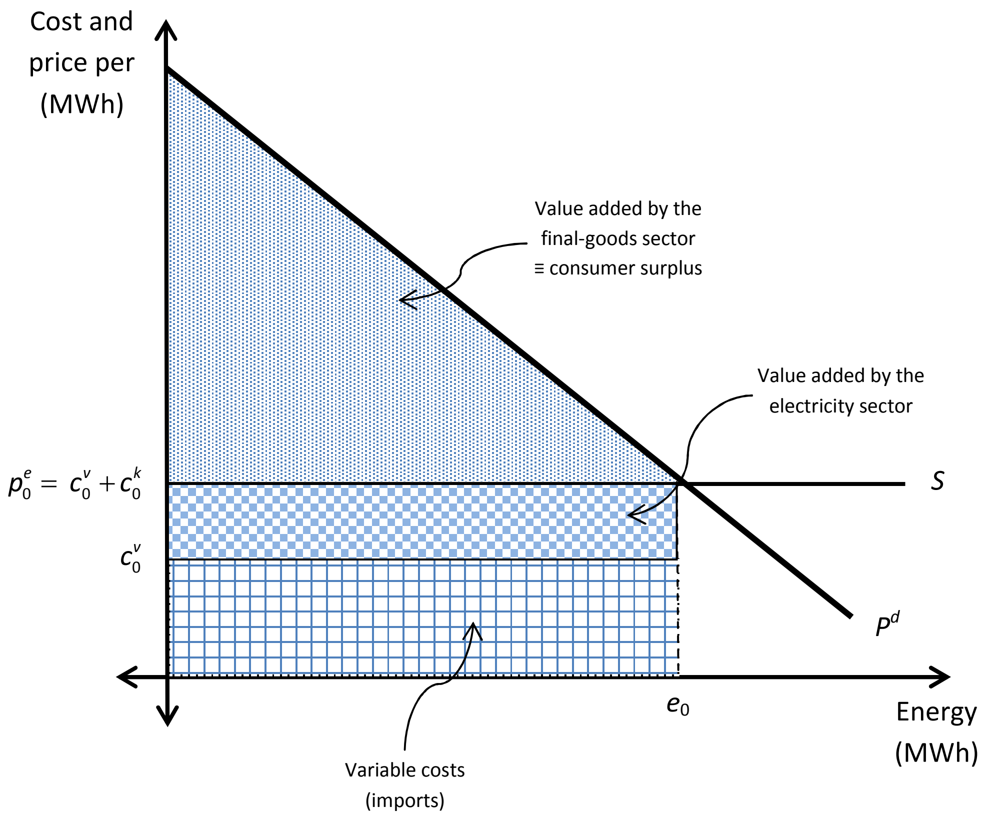


Figure 1b
Microeconomic analysis and GDP accounting:
Electricity as a final good

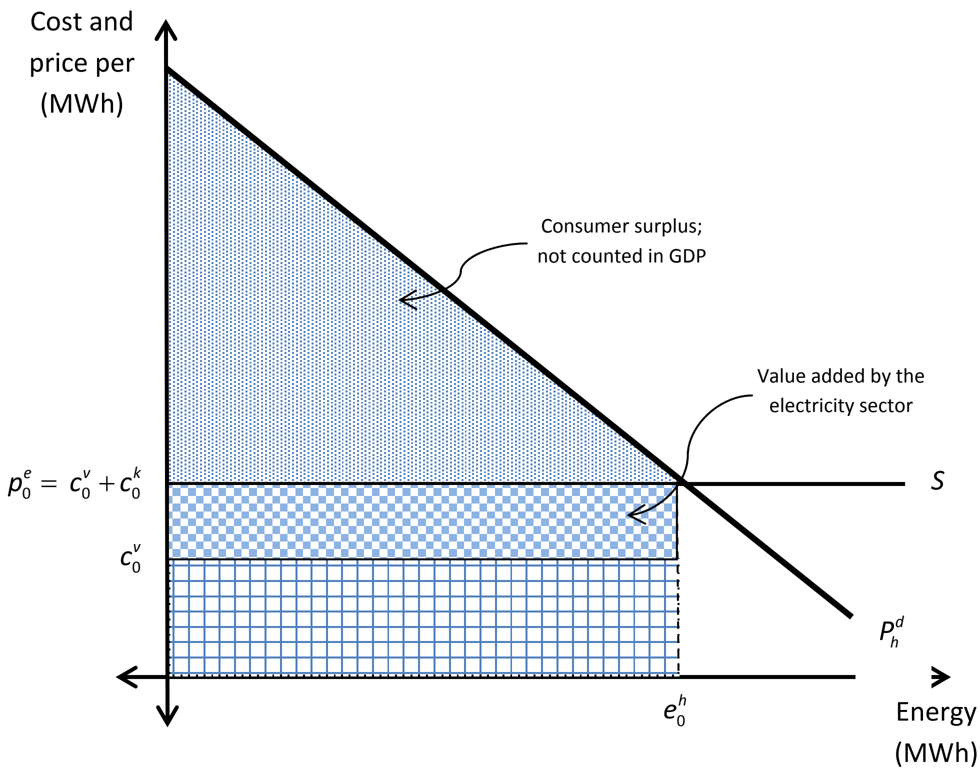


Figure 2a

The long-run effect of an increase in variable costs

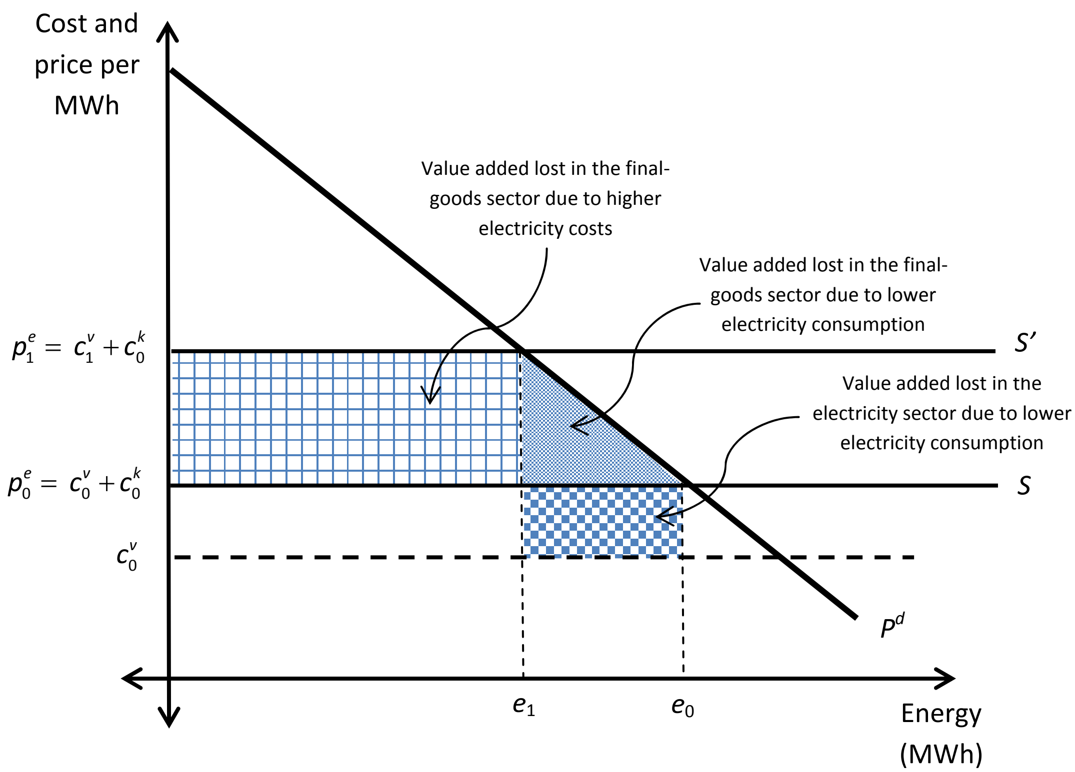


Figure 2b
The long-run effect of an increase in capital costs

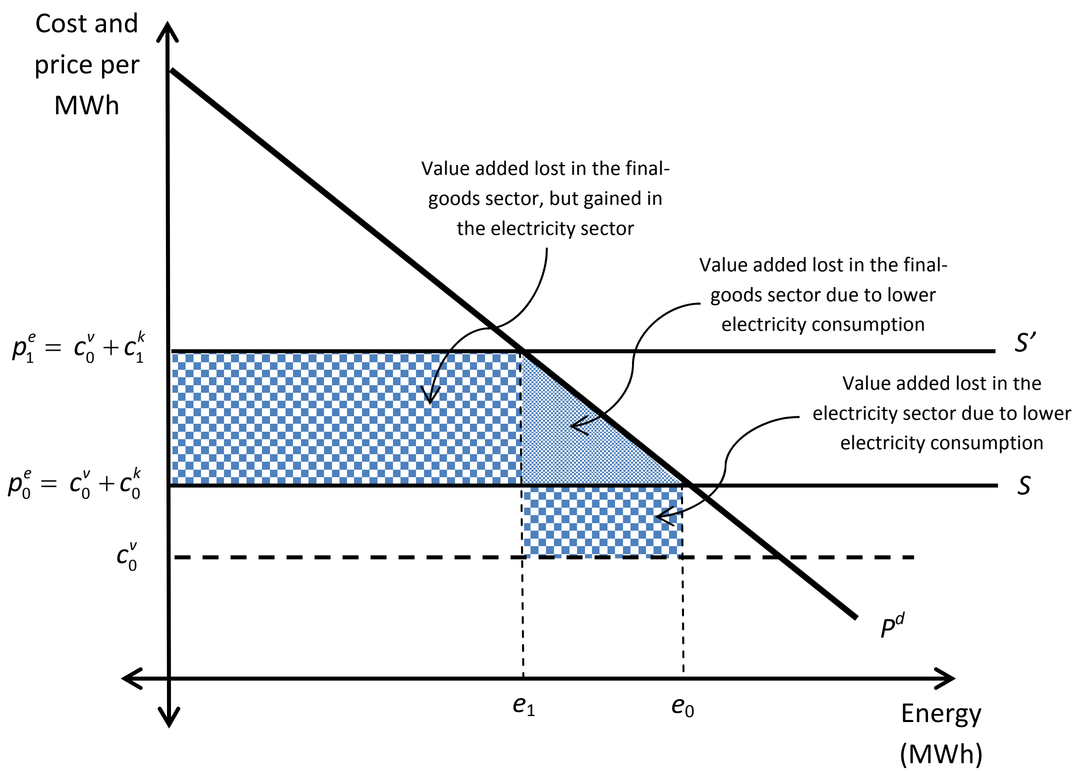


Figure 2c

Electricity as a final good

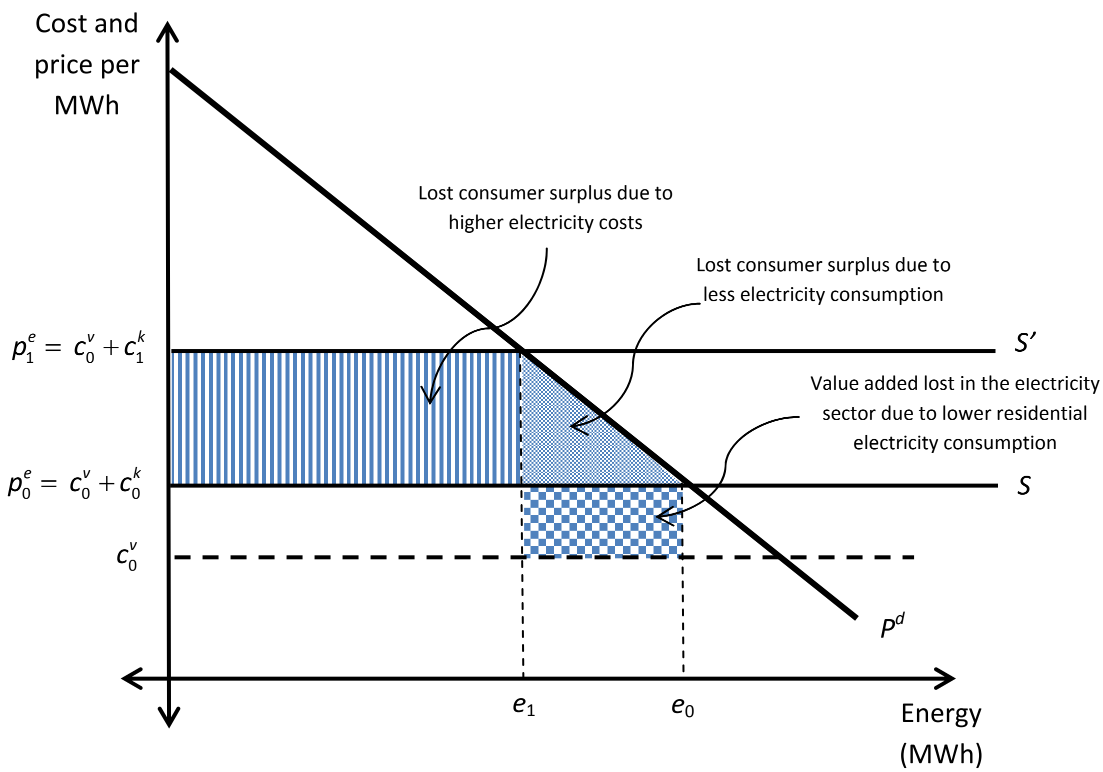


Figure 3
The nonconventional renewable energy supply curve

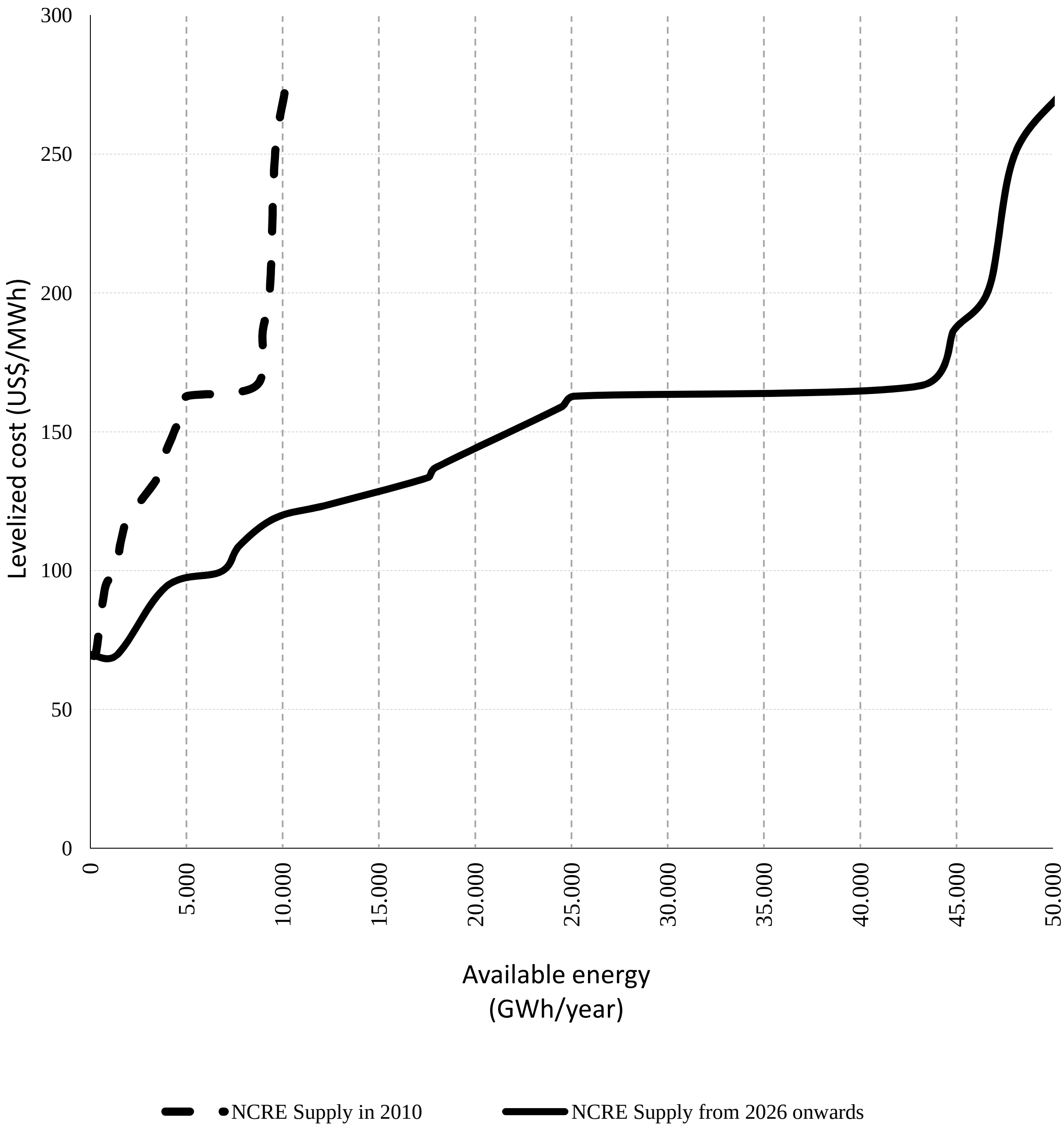
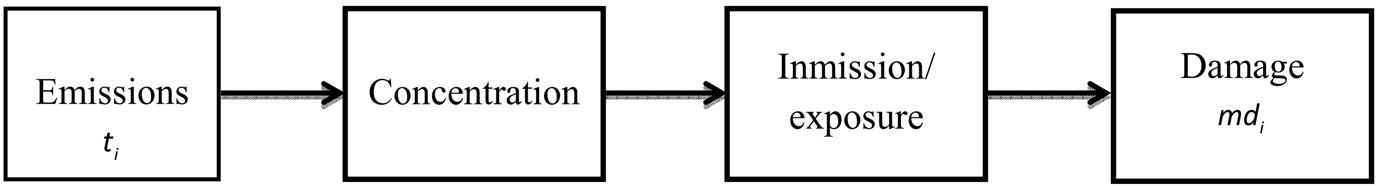


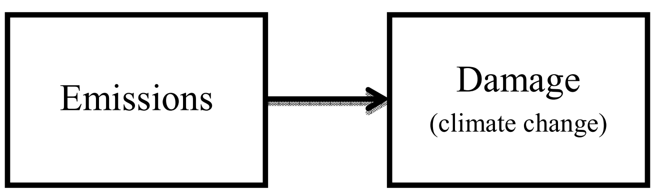
Figure 4
The mapping between emissions and damage

(a) Local pollutants



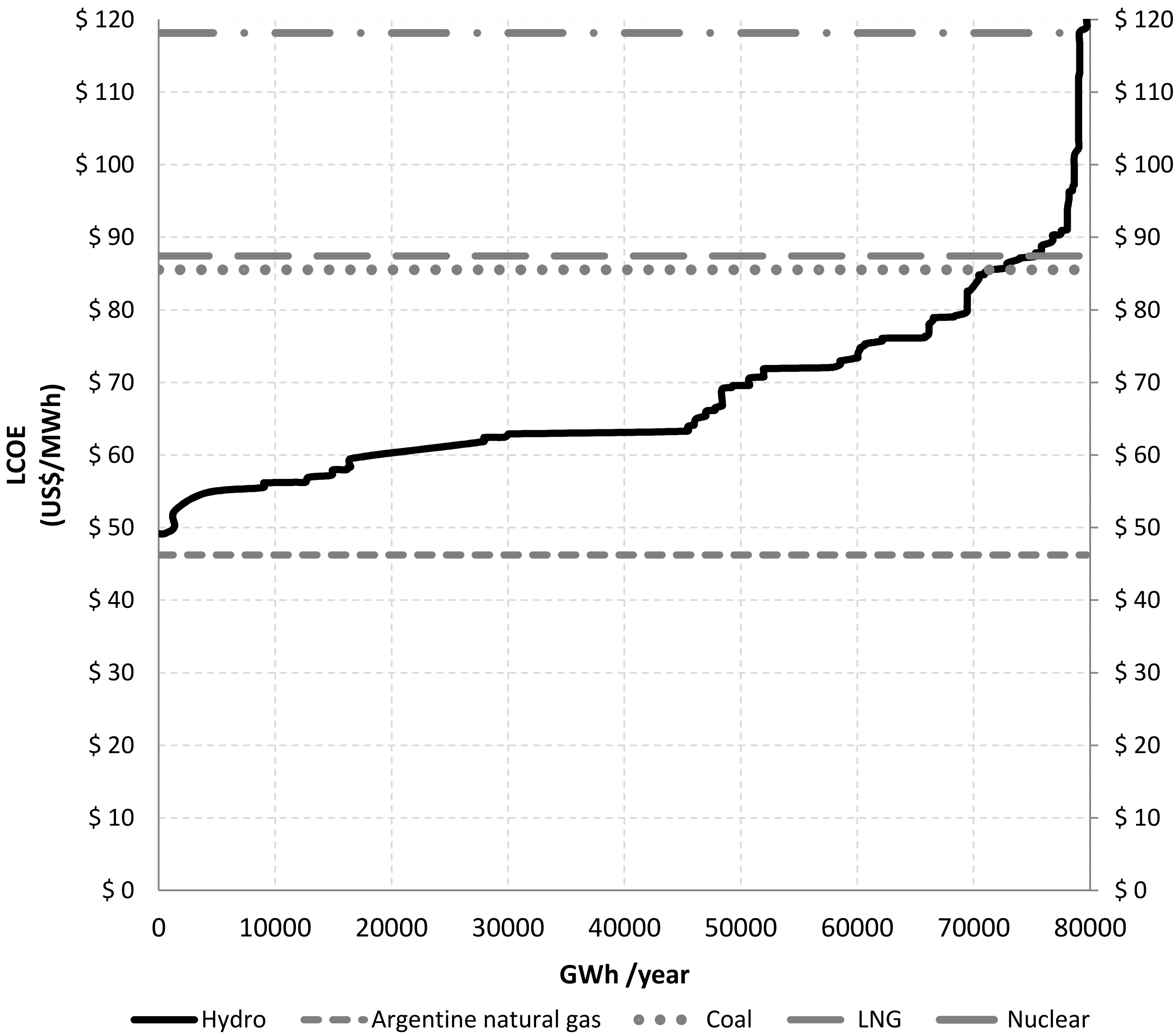
We assume a direct relation between emissions (t_i) of pollutant i and the marginal damage it causes (md_i). In practice, emissions of local pollutants interact with the local environment and affect concentrations. Damage depends on inmissions or exposure to the pollutants.

(b) Greenhouse gases



The damage caused by greenhouse emissions is global, and is a direct function of the carbon content of the fossil fuel burned.

Figure 5
The levelized cost of electricity in Chile's SIC



Notes: (1) *The hydro supply curve* The supply curve of hydro power was estimated from detailed public records of water rights still not in use. These records are used to assess yearly patent fees that the owners of unused rights have to pay. Each record reports the size of the water right in cubic meters per second and its location. Geo referencing of each right allowed us to estimate its height and generation potential. Projects were then connected to the main grid at minimum cost. Availability factors vary across regions according to empirical yearly precipitation variability. The robustness of the supply curve was tested with Monte Carlo simulations. (2) *Assumptions and parameter values* We estimated the annuity of each technology assuming a 10% real rate of return. Except for hydro, availability factors are assumed to be 85%. Coal plants consume 7.2% of their output; Argentine gas- and LNG-fired combined cycles consume 1% of their output. The levelized cost of fossil-fuel power plants includes the cost of abatement equipment needed to comply with current environmental standards. The cost of environmental externalities is not included. (3) *Cost data sources* Investment and maintenance costs for coal, LNG, and Argentine natural gas were obtained from EIA (2010). Average operation costs for coal and LNG were obtained from historical data. Investment, maintenance and operation costs for nuclear plants were obtained from De Carvalho et al. (2009). (4) *Investment/fuel cost/variable cost* Hydro: US$261.7/kW-year + transmission. Coal: US$306/kW-year, US$97/ton and US$38.2/MWh. LNG: US$123/kW-year, US$9.925/MMbtu and US$70.1/MWh. Argentine natural gas: US$123/kW-year, US$4/MMbtu and US$29,3/MWh. Nuclear: US$772/kW-year and US$14.5/MWh.

Figure 6 - The composition of generation under alternative environmental policies.

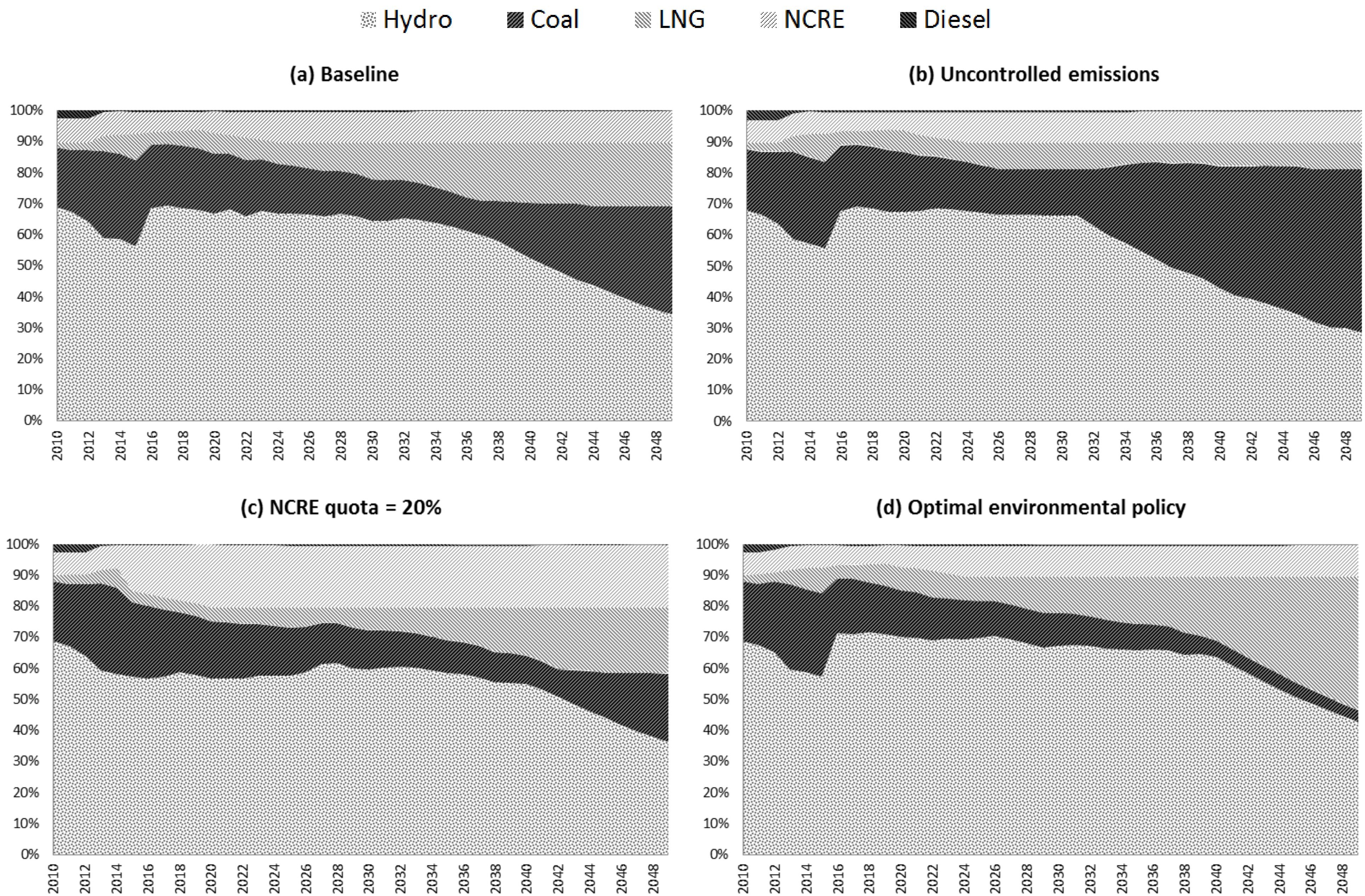


Figure 7 - Expected levelized price of energy under alternative policies.

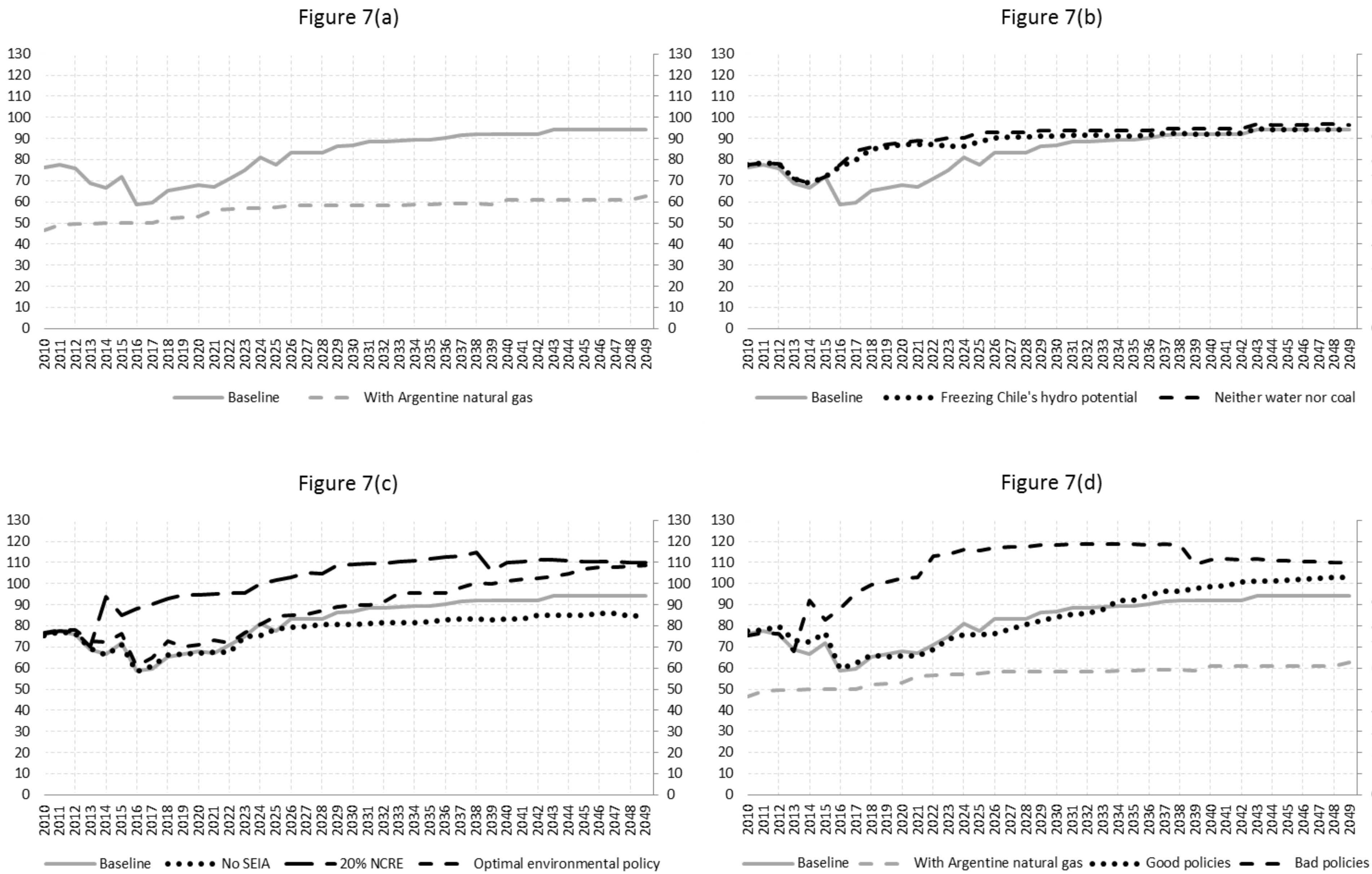


Figure 8
CO2 emissions under alternative policies
(in thousands of tons)