Table of Contents

Go Back

Effects of Regulation on the Dynamics of Liberalised Power Sectors: A Cost Benefit Analysis of the Capacity Payment in Hydro Based Systems

Gabriela Elizondo-Azuela

The World Bank and Imperial College

Dr. Matthew Leach

Imperial College

Dr. Abhijit Mandal

London Business School and Warwick Business School

Key Words: liberalisation, privatisation, regulation, power sector, capacity payment

Corresponding Author:

Gabriela Elizondo-Azuela

Finance, Private Sector and Infrastructure

Latin America and the Caribbean Region

The World Bank

1818 H Street NW

Washington DC 20433, USA

gazuela@wordlbank.org

ABSTRACT

In this paper, a cost benefit analysis associated to the application of the capacity payment in the Colombian power system is reported.
The analysis results in two relevant conclusions. The first one is that the capacity payment as it is designed today will not maintain acceptable levels of reliability in the long run as it does not succeed in restoring private investments in the short to medium terms. The second conclusion is that an increase in the value of the capacity payment today, which succeeds in effectively attracting the required investments in capacity to maintain minimum levels of reliability, has higher net benefits when long terms effects are taken into consideration

I INTRODUCTION

Over the last two decades, the power sectors of many Latin American nations have been privatised and subsequently liberalised with various degrees of success from both the technical and economic points of view. The extent to which the reforms have succeeded across the region is however still under analysis.
Without a doubt, governments have benefited from privatisations and fiscal burden relief. Various analysts have in fact demonstrated the success of the reform with measurable results in terms of lower electricity prices, lower transmission and distribution losses and improved technical and economic efficiencies of privatised enterprises, among others. However there are still doubts regarding the sustainability of these improvements, specially with the fall of private investment flows after 1997. Indeed, there is widespread concern that increased uncertainties and pool prices do not provide the long term signals required to attract private investment in infrastructure projects. Conversely, private firms are neither committed to the maintenance of minimum levels of security of supply nor with the need to expand the service to poor or isolated areas.

For countries mainly based on hydroelectric generation the addition of *firm* capacity to maintain minimum levels of reserve margin during dry seasons as well as to lower price volatility have become issues of major concern (e.g. Brazil, Colombia).

As the liberalisation of power systems progressed across the region, the difficulties in designing and applying regulatory mechanisms were exposed. The performance of regulatory commissions has been poor in cases where regulators do not have experience in dealing with the complexity associated to both, the economics of regulation and company strategic behaviour. One of the most relevant weaknesses associated to the performance of regulatory commissions is the fact that the design of mechanisms is rarely the result of an analysis that considers the likely long term effects associated their application. As regulators understood the technical and economic effects of applying specific instruments and rules, a variety of adjustments and sudden modifications were carried out, increasing the overall perception of risk. But even now, after two decades of learning in the region, regulators do not analyse the long term effects of their decisions in terms of costs and benefits.

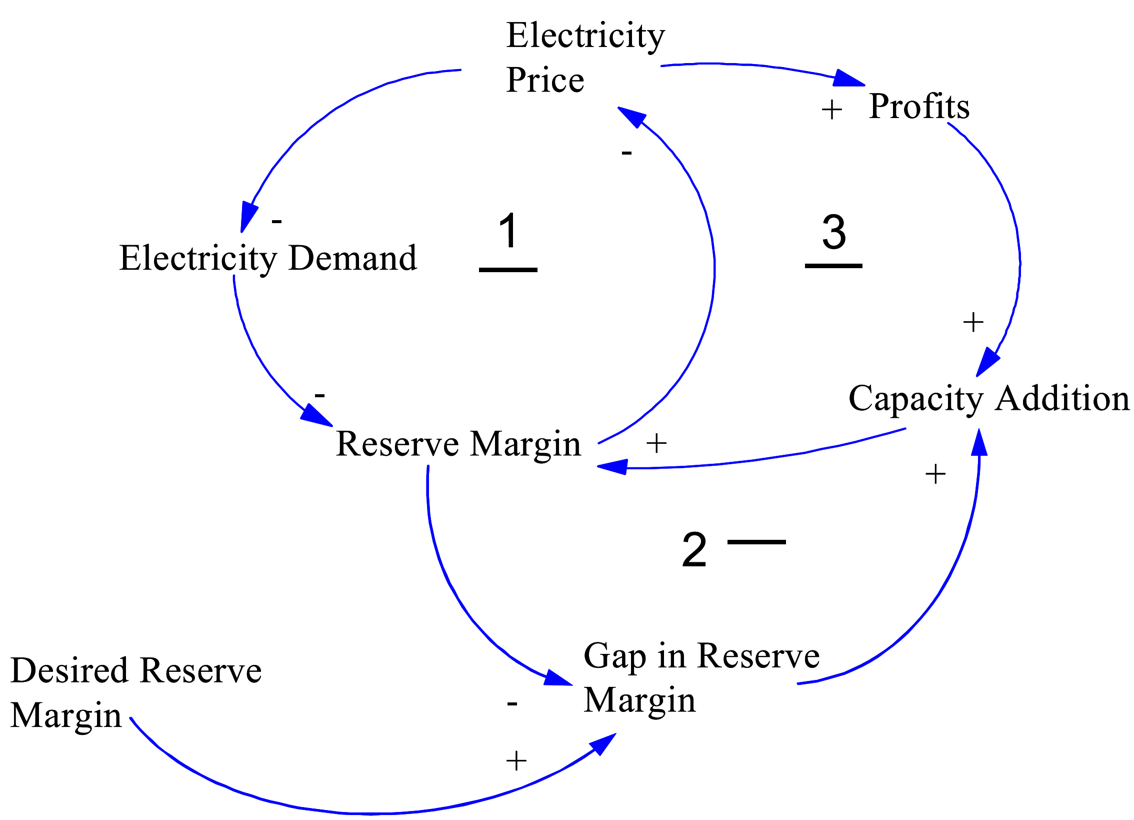
In this paper, a cost benefit analysis associated to the application of the capacity payment in the Colombian power system is reported.

The analysis throws two relevant conclusions. The first one is that the capacity payment as it is designed today will not maintain acceptable levels of reliability in the long run as it does not succeed in restoring private investments in the short to medium terms. The second conclusion is that an increase in the value of the capacity payment, which succeeds in effectively attracting the required investments in capacity to maintain minimum levels of reliability, has higher net benefits when long terms effects are taken into consideration. In other words, contrary to the expectations, the analysis demonstrates that higher capacity payments have the potential to result in higher net benefits in the long run.

II THE BASELINE

The model seeks to represent the system structurally and behaviourally considering the key variables driving the system. Annex I shows the causal loop diagrams characteristic of the system. A simplified diagram is depicted below in Figure I.

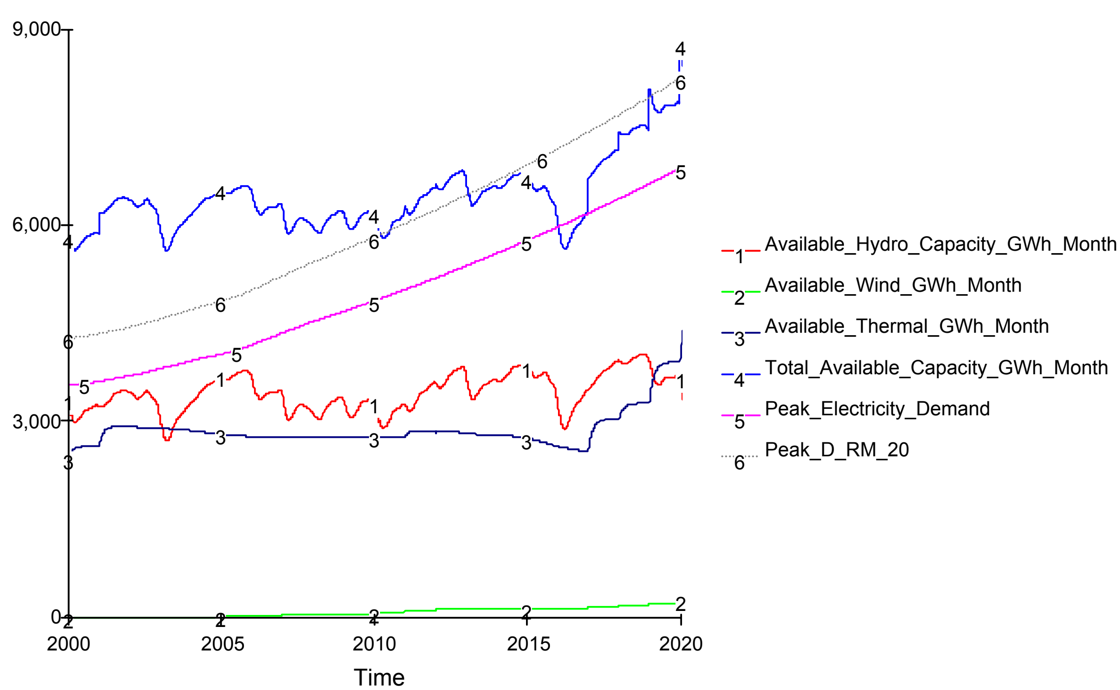
Figure I A Simplified Causal Loop Diagram



In the model, the investment behaviour of three types of generating firms is considered: public utilities, multinational utilities, and independent power producers.
The baseline simulation shows that with a conservative electricity demand growth rate and given the behaviour and constraints imposed on the participating private and public firms the reserve margin of the system will lower year by year leaving the system highly vulnerable to critical seasonality changes (see Figures II and III below). By 2015 the

system cannot ensure minimum levels of reliability leading to a rationing event that lasts about 10 months during an intense drought or ENSO event (i.e. El Niño Southern Oscillation) starting December 2015. As seen, no new thermal plants are built in the period 2000-2017[1]. Only after the rationing crises, the participating agents have an incentive to build new *greenfield* capacity.

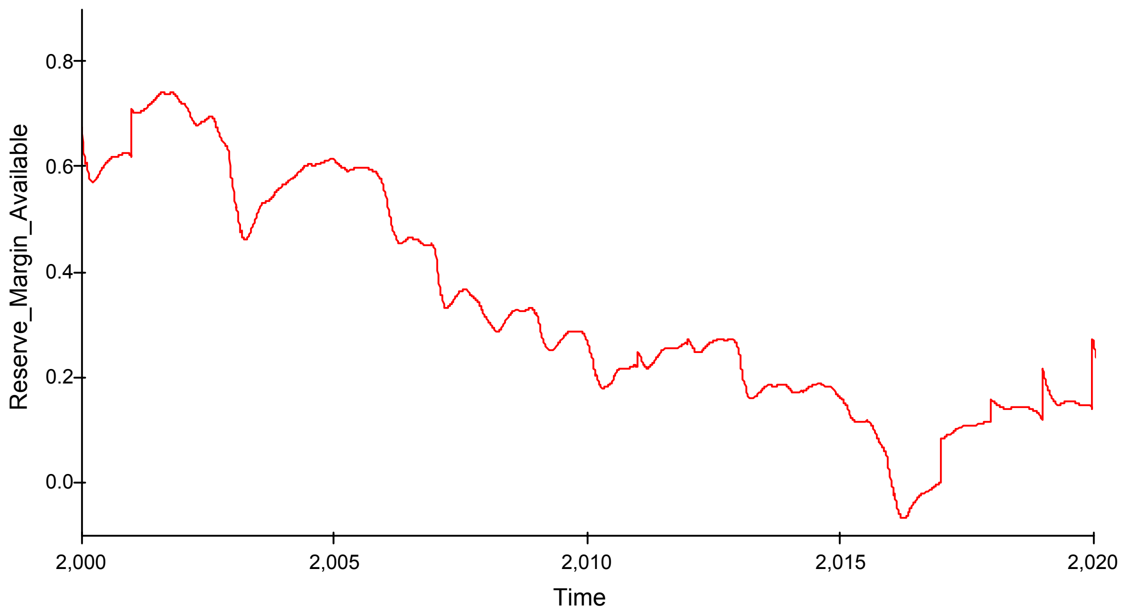
Figure II Evolution of Supply and Demand (GWh/month)



Various factors explain the reason why both private and public firms do not invest in *greenfield* or new thermal based capacity in the period 2000-2016. In this system, participant generators are constrained by different types of regulations as well as by their particular financing capacities and strategies

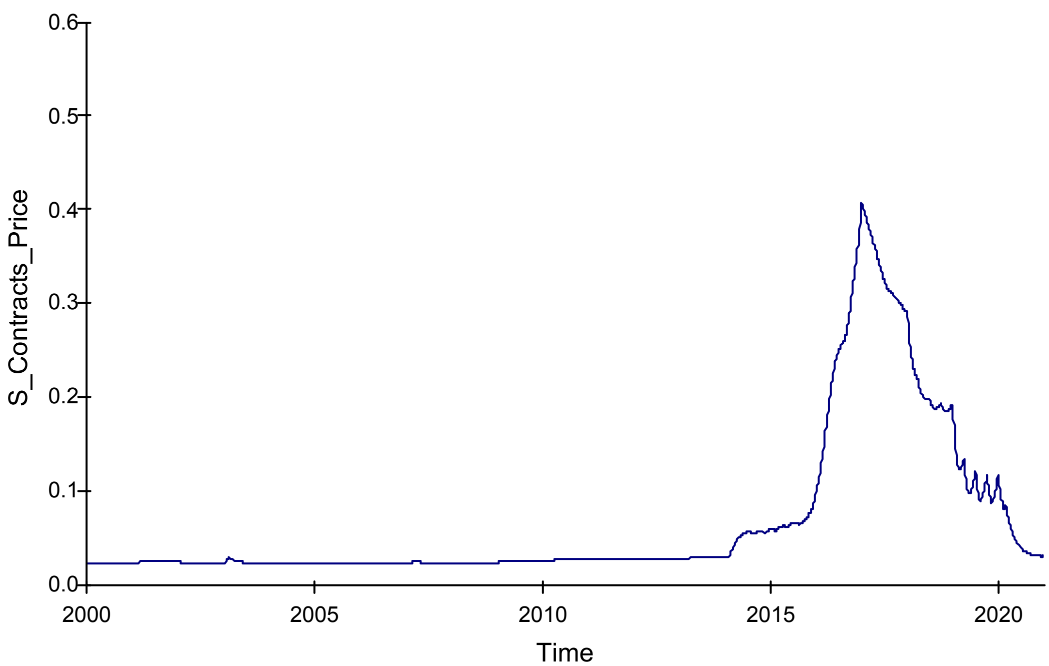
[1] Rather, some old coal and fuel oil based power plants are retired over the period of the simulation.

Figure III Evolution of Operative Reserve Margin



The evolution of contract prices as estimated by the model is shown in Figure IV below.

Figure IV Evolution of Contracts Price (USD/kWh)



In the contracts market, the volatility characteristic of spot electricity prices is minimised. Essentially, the prices negotiated in bilateral contracts function as a medium term price signal which partially replaces the long run marginal cost generally calculated under centralised or non-liberalised power markets to plan future investments in capacity additions. Still, bilateral contracts cover periods of only 2-3 years, for which the contracts price does not necessarily provides with a signal for investment in the long term.

In the model, the contracts price is a function of the spot price (e.g. simulating a typical contract for differences). Under the assumptions and conditions established in this scenario, independent power producers (IPPs) and multinational utilities (MNUs) do not invest in new capacity mainly due to the following aspects of the market:

- **Low wholesale electricity prices** in the system which result in unsustainable project debt service coverage ratios[2] (i.e. lower than one) as well as in lower than expected returns to investment.
- **High cost of capital and short maturity periods,** which result in an unsustainable coverage of the debt service.
- **Low rationing cost** which was determined through a *contingent valuation* analysis conducted at the beginning of the 1990s (i.e. its value is about one tenth of the British *Value of Lost Load* (VOLL), Concha 2002, Benavidez 2002)[3]. This affects the electricity price (e.g. the pricing curve associated to the cost of water which is a function of the reservoir volume, is also a function of the rationing cost).
- **Low load factors** for thermal based generation given the high share of hydroelectric capacity in the system which also affect the expected profitability of gas or even coal based facilities. In fact, thermal based capacity is seldom dispatched in Colombia[4].

[2] For the particular case of independent power producers (IPPs), these are calculated considering the conditions of the Colombian capital market, which imposes short maturity periods and high interest rates.
[3] The Energy Planning Unit (UPME) only conducts a monthly adjustment to inflation of the cost of rationing (Concha 2002).
[4] Average utilization capacities for gas and coal based power plants in Colombia are between 20 and 50% according to the National Dispatch Commission (CND). The baseline simulation confirms this range.

In fact, in Colombia the majority of thermal generators operating in the market have signed long term contractual agreements that not only hedge the price, but ensure the allocation of higher percentages of their output, either through real operation and dispatch of their plants or through commercialisation (i.e. trading or buying the committed output in the spot market when the pool price is lower than their variable costs).
The model has been designed assuming that public utilities (PUs) seek to balance conservative levels of profitability with the intention of maintaining minimum required levels of operating reserve. However, state owned and municipal PUs are limited not only by the maximum market share imposed by the regulation (i.e. 25% as established in CREG Resolution 128 of 1996) and financing constraints[5], but also by their own minimum demands of investment return.

Firm Capacity Payments

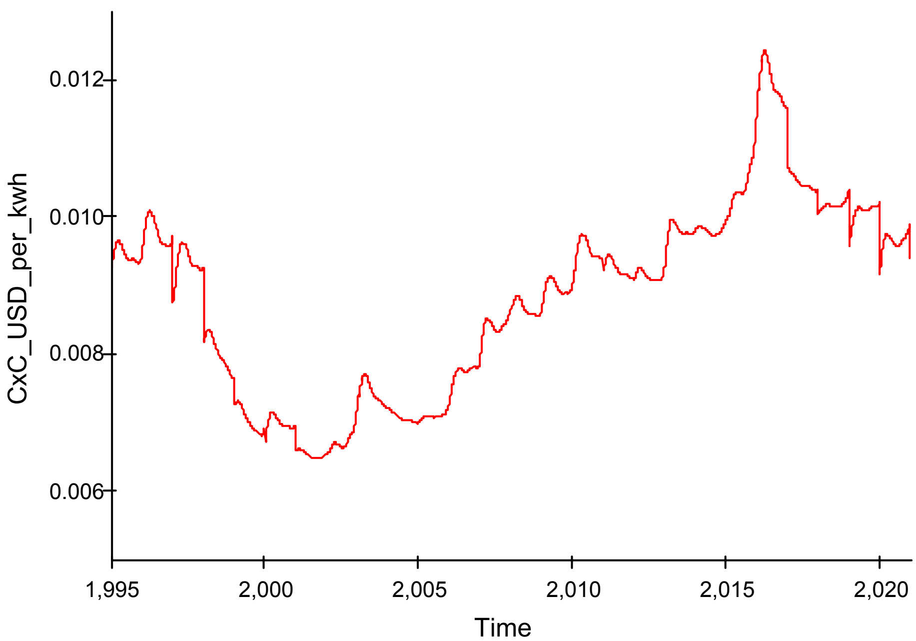
In Colombia, according to CREG Resolution 116 of 1996, a capacity payment is distributed among generating plants that provide with firm capacity given the threat of loss of load -or rationing- during critical hydrologic conditions. The capacity payment or capacity charge (CxC) in Colombia intends to provide with both a long-term price signal and a compensation allocation mechanism. The CxC is in fact an additional source of income for plants that are needed as available to the system but that are infrequently dispatched (i.e. peak load). The basic idea of the capacity payment is that, when there are periods of excess capacity and the reserve margin is high, the probability of loss of load is relatively low. Under these circumstances there is little incentive to invest. Alternatively, when there is heavy demand relative to available capacity, the reserve margin is low and the probability of loss of load increases which triggers investments in capacity. In Colombia the CxC is also seen as a price floor in the spot market, as it is

[5]Three large public utilities are considered in the model. It is assumed that EEPPM, the largest municipal utility, is able to finance capacity additions to the extent that the company has no more than 21% of the market share (Navarro, 2002). Although ISAGEN and CORELCA, State owned utilities, are in the process of being sold (so far unsuccessfully) the baseline scenario assumes that these two could have the same financing capacities as EEPPM (i.e. a rather optimistic assumption).

provided to generators even when the opportunity cost of stored water is zero during wet seasons[6] or economic structure of the merit order.

The CxC is estimated considering the fixed payment associated to the avoided capital cost of the next cheapest generation addition[7], the peak demand and the total amount of available firm capacity. According to CREG Resolution 116, only 105% of peak demand is paid as firm capacity. Based on this, the value of the CxC increases if -as the demand raises- the available firm capacity does not increase. Conversely, if there is enough firm capacity, the distribution of the total amount of resources is allocated among more generating plants lowering the CxC. The following Figure provides with the baseline estimation of the evolution of the value associated to the CxC.

Figure V Evolution of the Value of the Capacity Charge



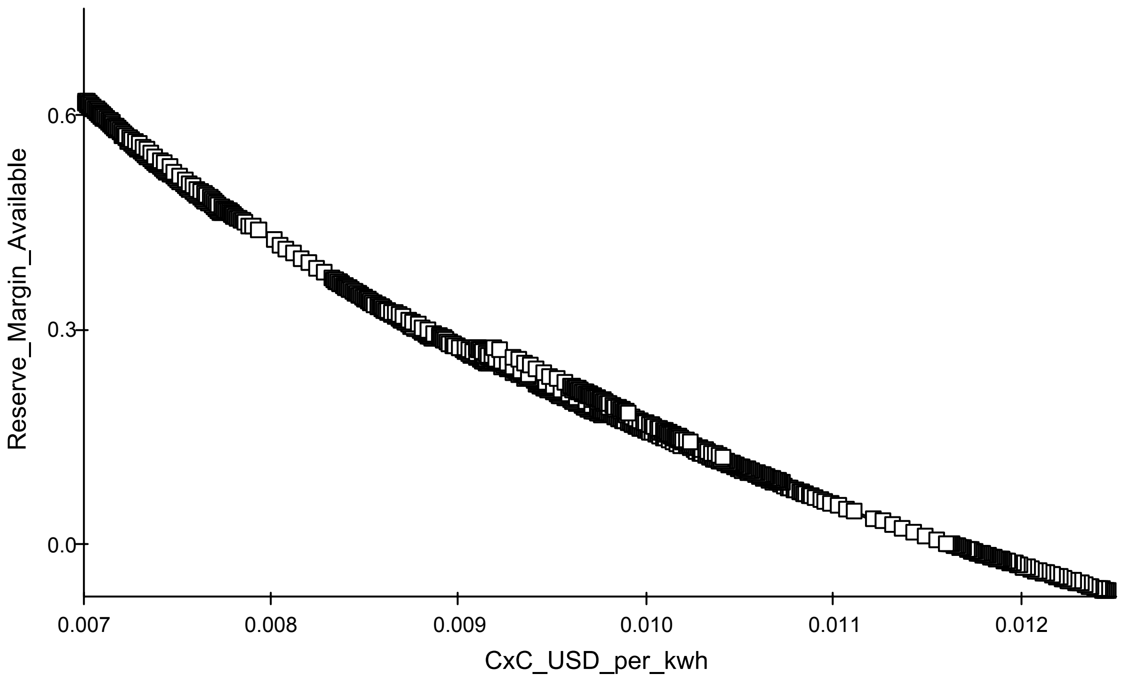
The graph in Figure VI on the other hand plots the value of the CxC as a function of the reserve margin showing the ranges under which this measure has been designed.

---

[6] The capacity payment is paid by the consumers through the electricity tariff. The regulator then collects this portion of the price and distributes it among generators with firm capacity.

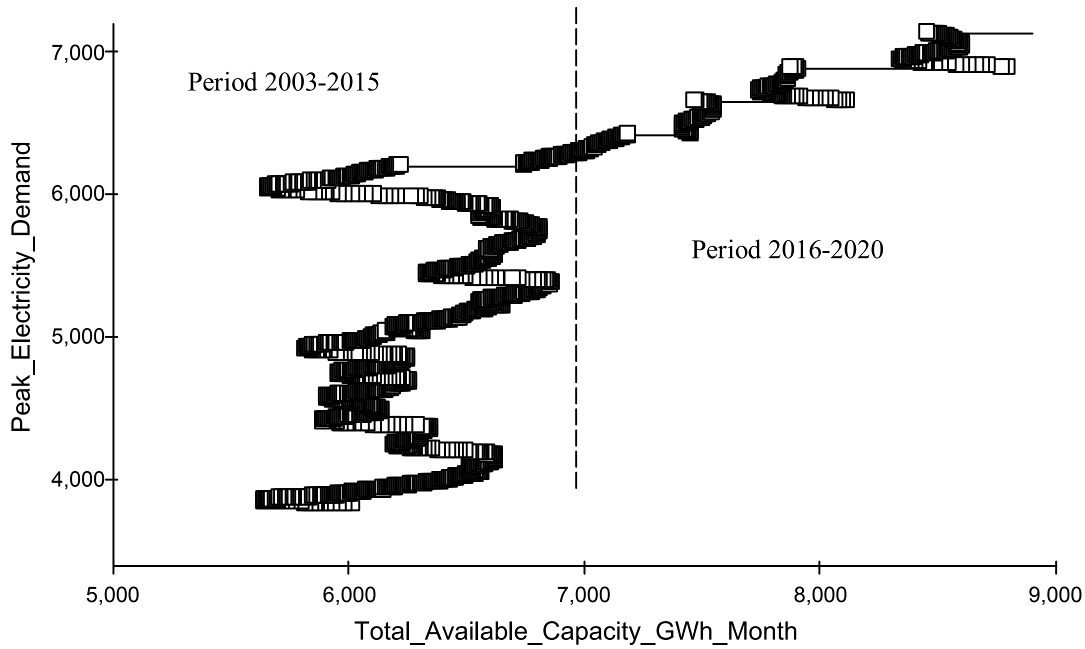
[7] As of today an OCGT plant whose capital investment is discounted at 11% to produce a fixed payment of 5.25 USD/kW-month.

Figure VI The Value of the CxC as a Function of the Reserve Margin



The CxC, as it designed today, has not provided with an effective incentive to trigger capacity additions. The following Figure shows an aspect of the Colombian electricity market that is becoming common in the liberalised power system of developing countries, specially in those with high shares of hydroelectric capacity. Investments in capacity do not respond to sustained increases in peak demand, only after the price reaches a high level, and investments are triggered, available capacity increases.

Figure VII Peak Demand vs Total Available Capacity Period 2003-2020



III EFFECTS OF OWNERSHIP STRUCTURE

In this section different scenarios of ownership share have been conducted to assess the effects of the behaviour of different types of firms on reserve margin's sustainability. The intention is to demonstrate the behaviour of both private and public enterprises as hypothesised in the model. In Section IV a cost benefit analysis of different values of capacity payment are assessed considering a mixed ownership (as in the baseline).

3.1 Investment Under Public Ownership

Scenario A *Pre-liberalisation*. This scenario simulates an ideal expansion plan in which capacity additions are fully financed by a centralised public utility (i.e. the government)[8]. Results are depicted below in Figures VIII to XI and quantitatively reported in Annex II.

[8] The simulation mimics the least cost planning exercise which is performed with the Super Olade Bids model under centralised non liberalised power systems.

Figure VIII Evolution of Supply and Demand (GWh/month)

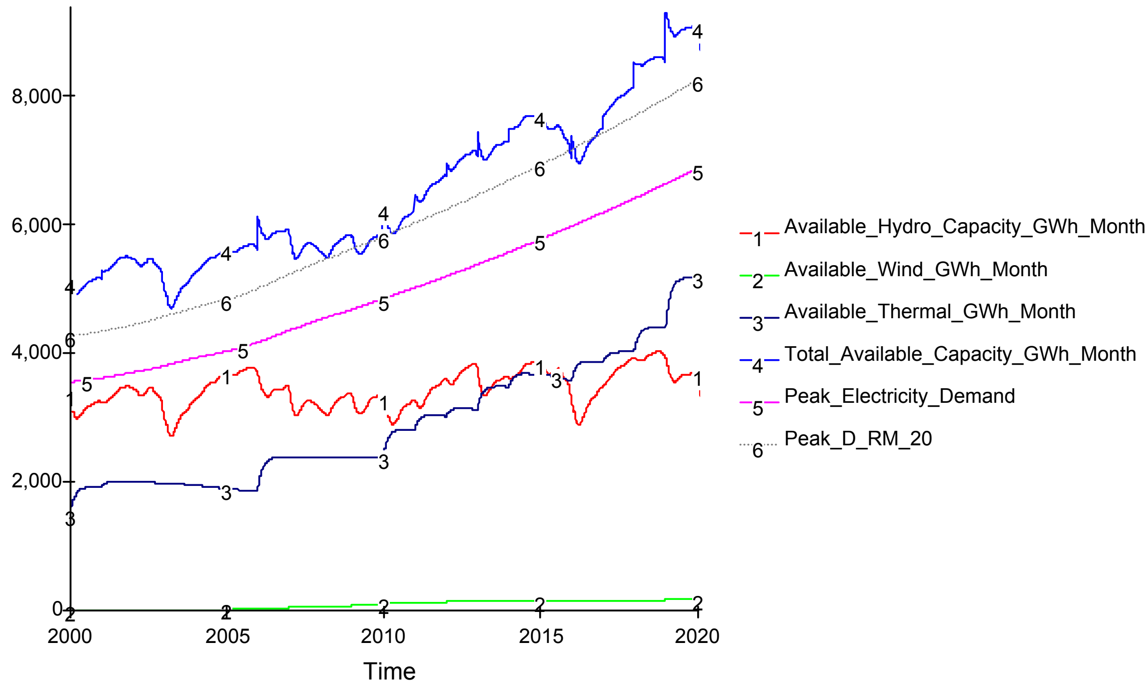
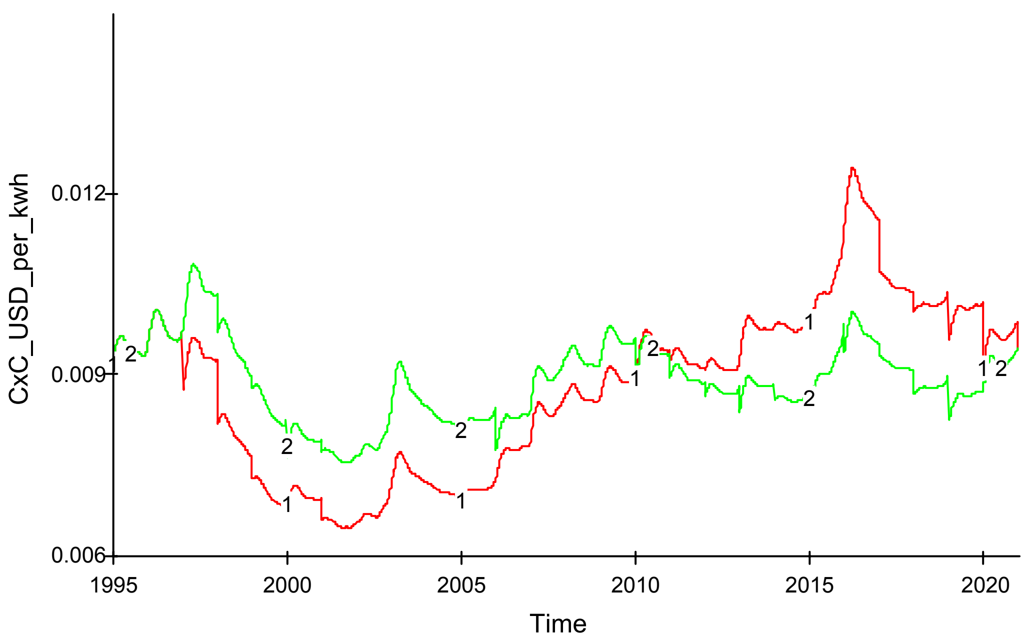
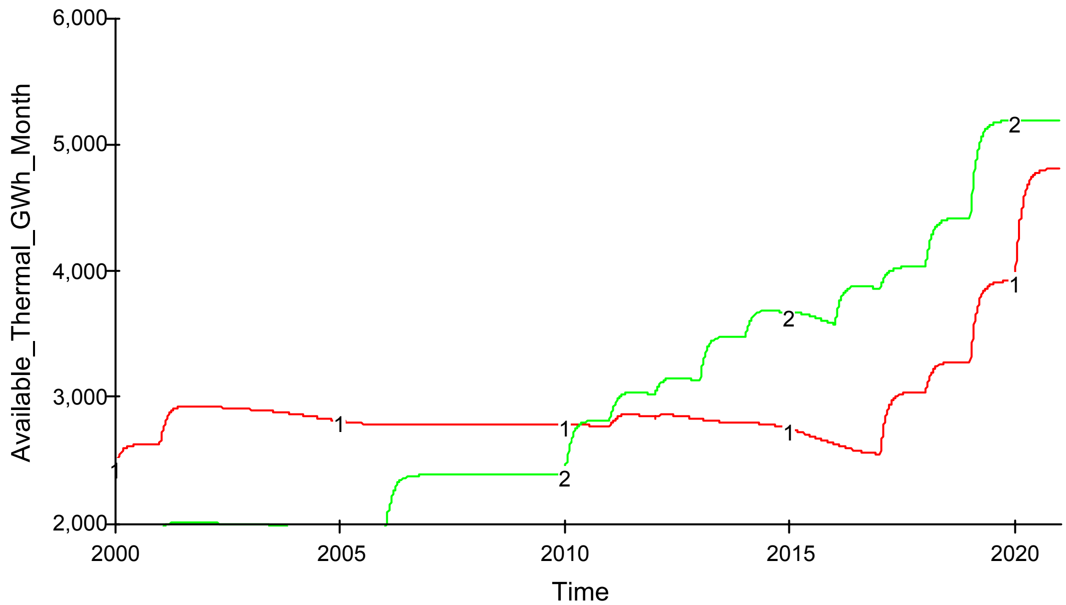


Figure IX Evolution of the Value of Capacity Payment



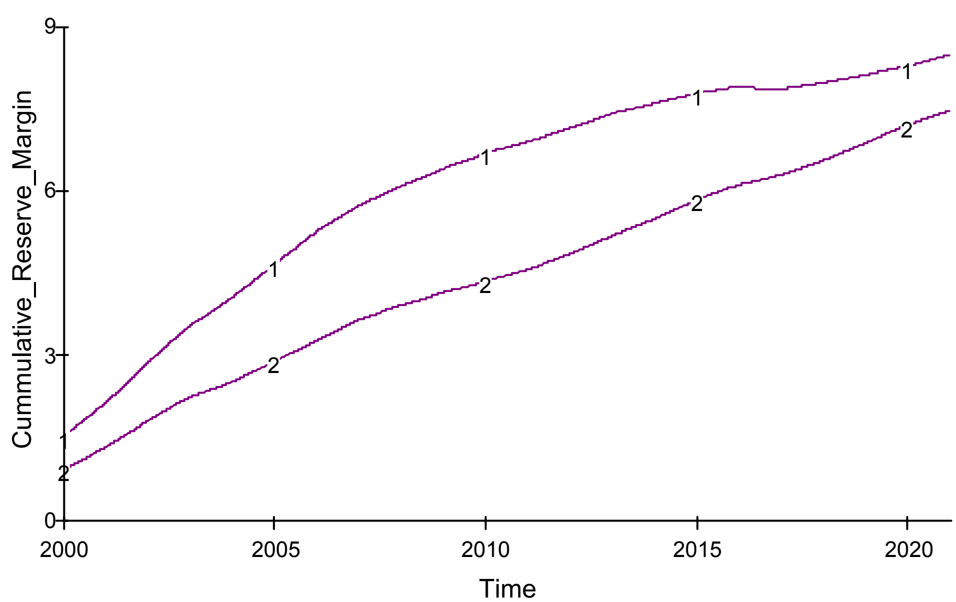
Note: Line 1 is the baseline, Line 2 is Scenario A

Figure X Evolution of Thermal Based Generation (GWh/month)



Note: Line 1 is the baseline, Line 2 is Scenario A

Figure XI Cumulative Reserve Margin



Note: Line 1 is the baseline, Line 2 is Scenario A

As seen, under this scheme, the rationing event is completely avoided, electricity prices are lower, and although the government has to invest in the installation of about 2,184 MW of thermal based capacity (in addition to the 660 MW hydro plant considered in the baseline), ultimately the net benefits reach 2,934 USD Million over the period 2000-2020 (i.e. mainly due to elimination of rationing and associated costs).

Indeed, Scenario A would require resources from the federal budget in the amount of 2.12 billion USD over the 20 year period, which would reduce the availability of budgetary resources for other more pressing priorities (e.g. education and health). Discouraging the participation of the private sector, on the other hand, would only diminish the overall amount of resources available for infrastructure development and lower the efficiency of national resources allocation.

The cumulative reserve margin[9] is lower in scenario A than in the baseline (see Figure XI). This is explained by the investment behaviour exhibited by the various firms. In the baseline simulation, investments by independent power producer (IPPs) in the years after the liberalisation responded to their expectations regarding the evolvement of a competitive profitable market rather than to high prices. After this transitional period (1995-2000), private firms –in the model- do not invest until electricity prices are high enough to obtain minimum returns to investment. In Scenario A, a minimum reserve margin (20%) is always maintained. Figures VIII and XI show how under a least cost ideal expansion plan, the timing of investments to maintain a minimum reserve margin provides with a more efficient system in terms of reliability of supply management (i.e. which is the rationale the behind ideal expansion plan).

The evolution of carbon emissions under Scenario A is closer to the one calculated by UPME with the Super Olade Bids model to produce an ideal expansion plan.

[9] This index measures the degree to which the evolution of investments contribute to the maintenance of the reserve margin.

3.2 Investment Under Private Ownership

Scenario B. This test simulates an scenario in which public utilities have no resources to invest in capacity additions and the sustainability of the system is only dependent on private initiatives. The intention is to investigate whether a private ownership structure alone (as opposed to a mixed ownership structure) would ensure the long term sustainability of the system.

As shown quantitatively in Annex II and below in Figures XII to XVI, this scenario does not result in positive net benefits. Not only the rationing crises is worse than the one exhibited in the baseline simulation, but the electricity prices are also higher under this scenario. The reason behind this outcome relies on the behaviour of private firms. In the model, the investment of private firms respond to high electricity prices and for this reason the maintenance of tight reserve margins work out in their favour. Indeed, the sustainability of a minimum reserve margin to protect the system from rationing events does not form part of the strategic behaviour of private firms.

Figures XII to XVI illustrate the nature of private firm's investment in liberalised systems. Only after some years and when the reserve margin is close to the peak demand (2010-2014), independent power producers (IPPs) and multinational utilities (MNUs) invest in thermal based generation. Without the participation of public firms, the operative reserve margin decreases sooner than in the baseline, triggering earlier private investments in thermal capacity (see Figure XIV). The reserve margin however is never above minimum required levels (e.g. 20%). For this reason the system is vulnerable to the ENSO event of 2016 and the rationing crises reaches a deficit of 3,077 GWh.

Figure XII Evolution of Supply and Demand (GWh/month)

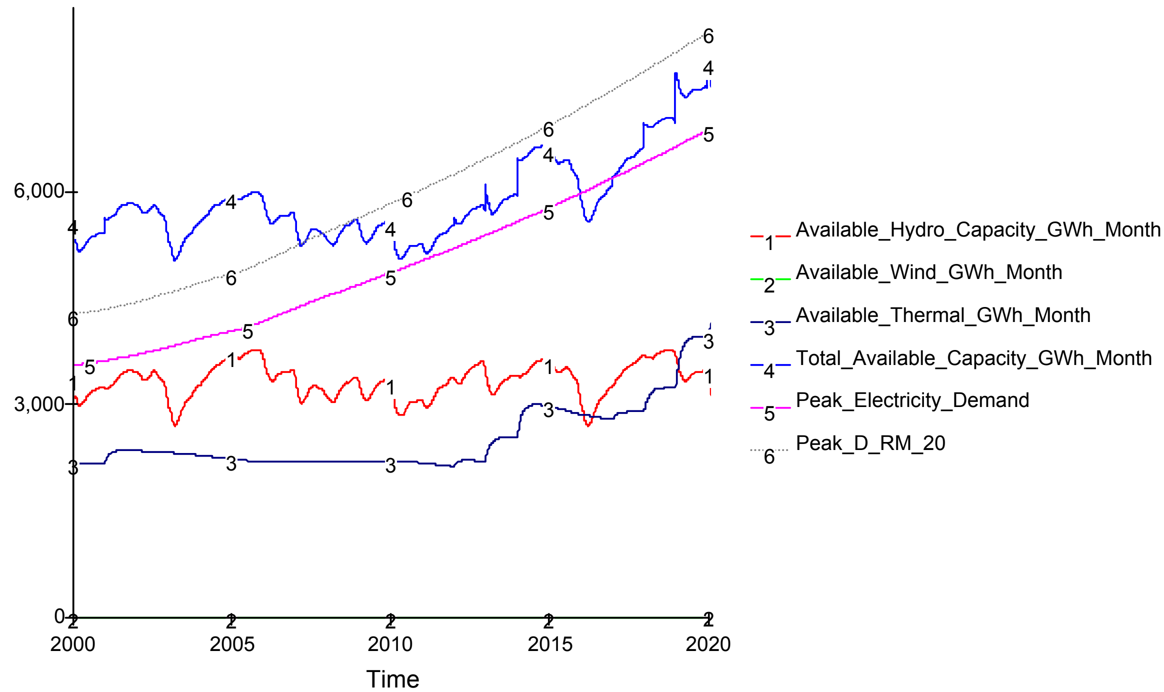
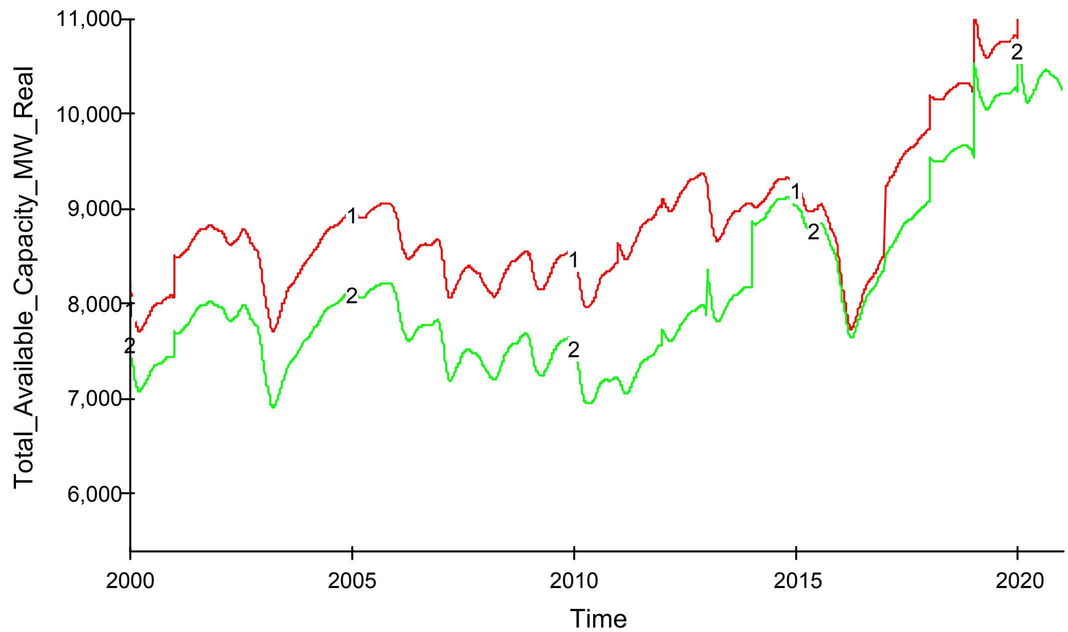
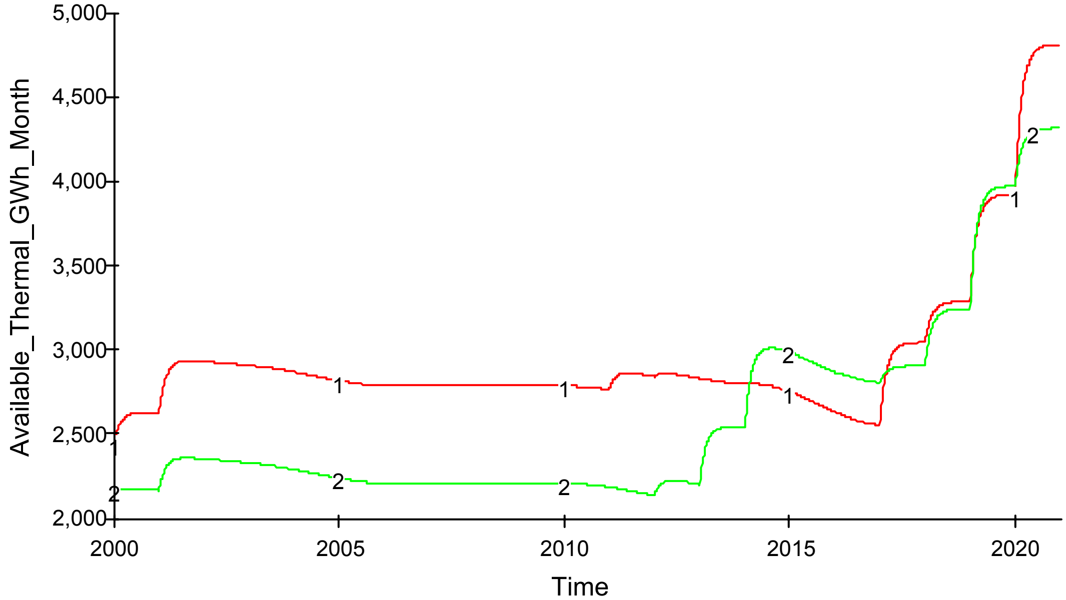


Figure XIII Evolution of Available Capacity (MWs)



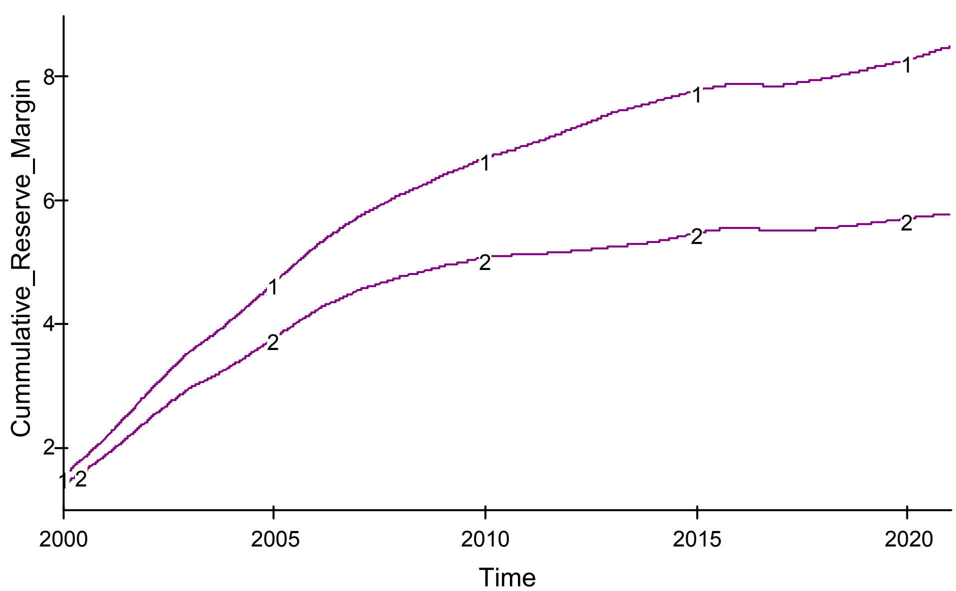
Note: Line 1 is the baseline, Line 2 is Scenario B

Figure XIV Evolution of Thermal Based Generation (GWh/month)



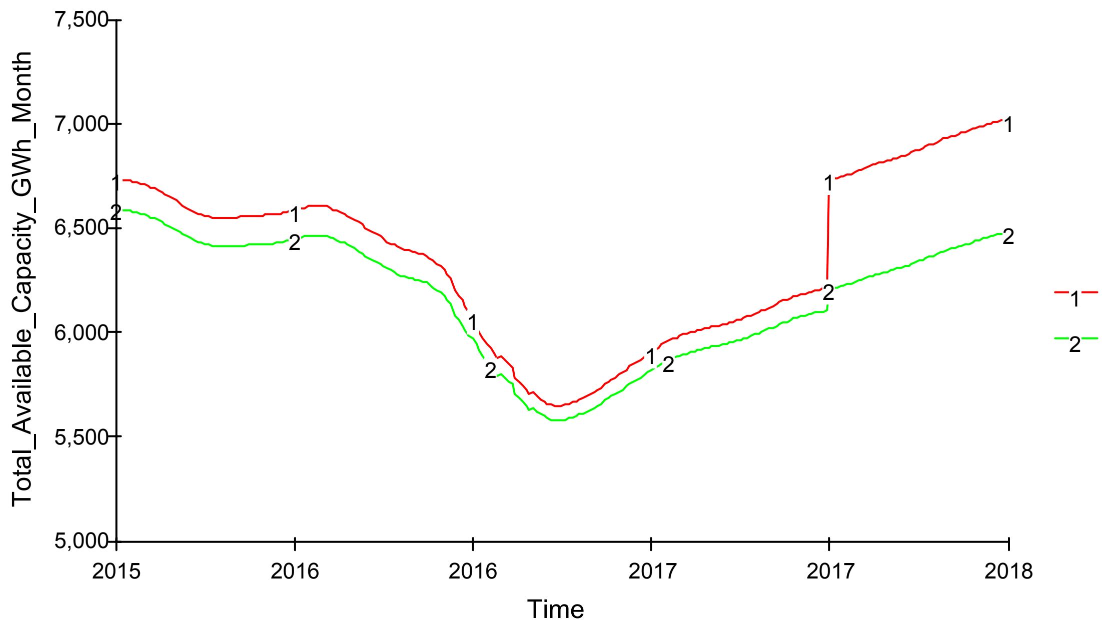
Note: Line 1 is the baseline, Line 2 is Scenario B

Figure XV Cumulative Reserve Margin



Note: Line 1 is the baseline, Line 2 is Scenario B

Figure XVI Rationing Crises 2015-2017



Note: Line 1 is the baseline, Line 2 is Scenario B

IV COST BENEFIT ANALYSIS OF THE CAPACITY PAYMENT

In Scenarios C to E, changes in the design of the capacity payment will be tested to assess the effects of higher payments on system's reliability and associated costs and benefits. Indeed, one would expect that an increase in the value of the capacity charge would only result in an increase to the total costs of supplying electricity or the use of more public resources. After all the capacity charge would increase the electricity price in order to promote a higher reserve margin.

What would then be the costs and benefits associated to an increase in the value of the capacity payment? Or would an increase in the value of the capacity payment prevent the gradual lowering of the reserve margin and ensure the sustainability of the required optimal reserve margin?

The following changes to the design of the capacity payment will be tested in three different scenarios:

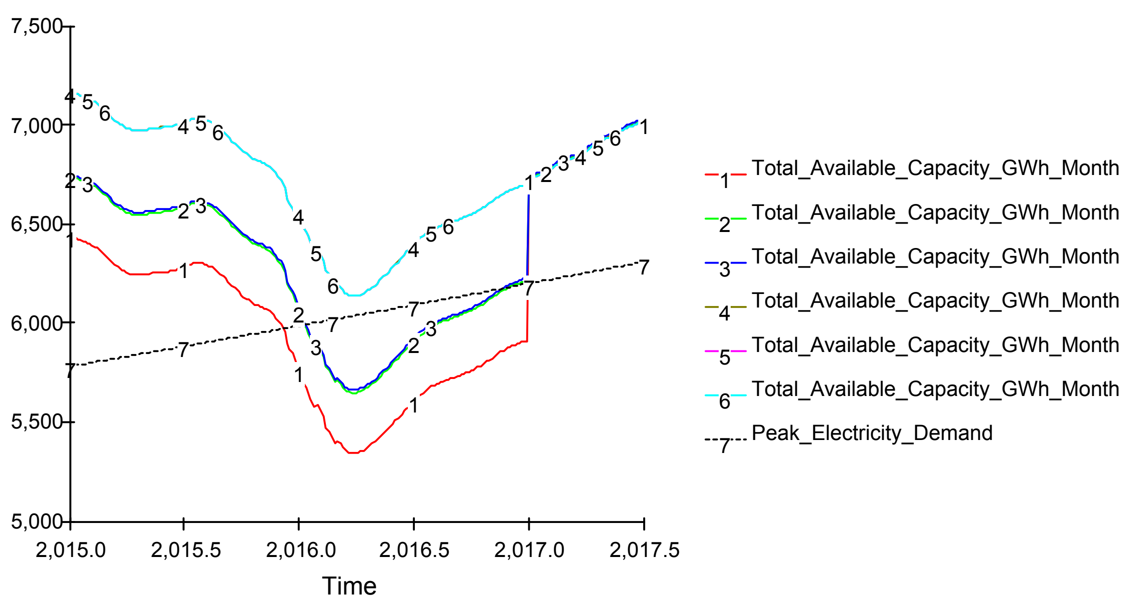
Scenario C: An increase in the value of the capacity charge through an increase in the discount rate used to calculate the monthly payment associated to the same technology (i.e. an OCGT)

Scenario D: An increase in the reserve margin policy

Scenario E: A combination of the previous. The idea is to find out whether these two measures are additive, synergic or neutralised among each other.

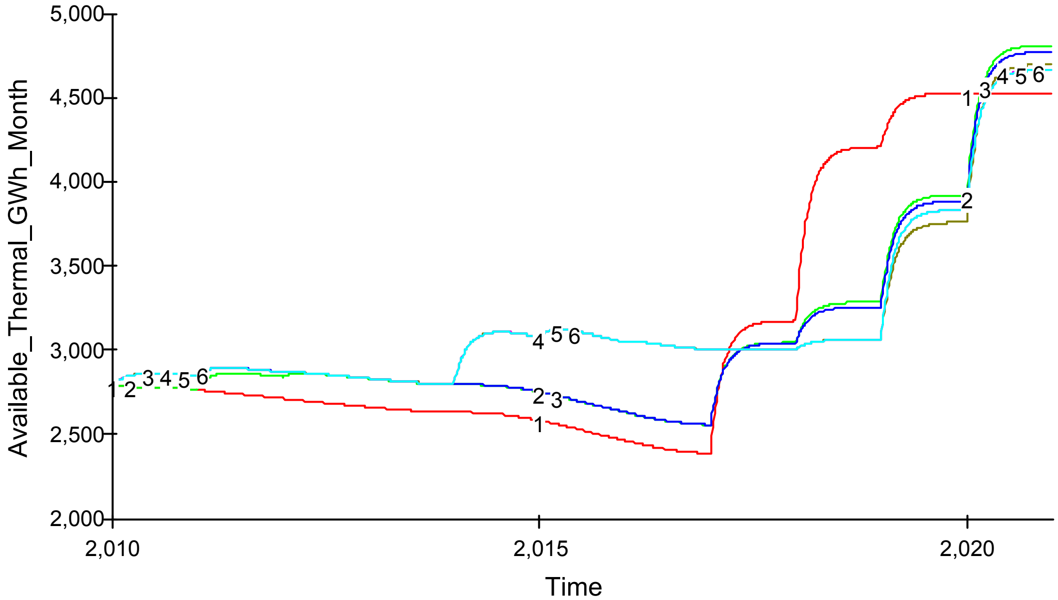
Scenario C. This scenario considers an increase in the discount rate considered in CREG Resolution 116 to a apply a more realistic value that reflects the country risks. To find an "optimum", a test has been performed with a range of values that go from 0 to 16%. The quantitative results are provided in Annex III and depicted in Figures XVII to XIX.
The test shows that the net benefit to the system is maximised when applying a capacity payment estimated with a discount rate of 14%. The maximisation of the net benefit stems from two important effects on the dynamic nature of the system: a) avoided rationing (see Figure XVII) and b) lower electricity prices due to earlier investments in greenfield capacity (see Figure XVII)

Figure XVII Total Available Capacity During Rationing Event



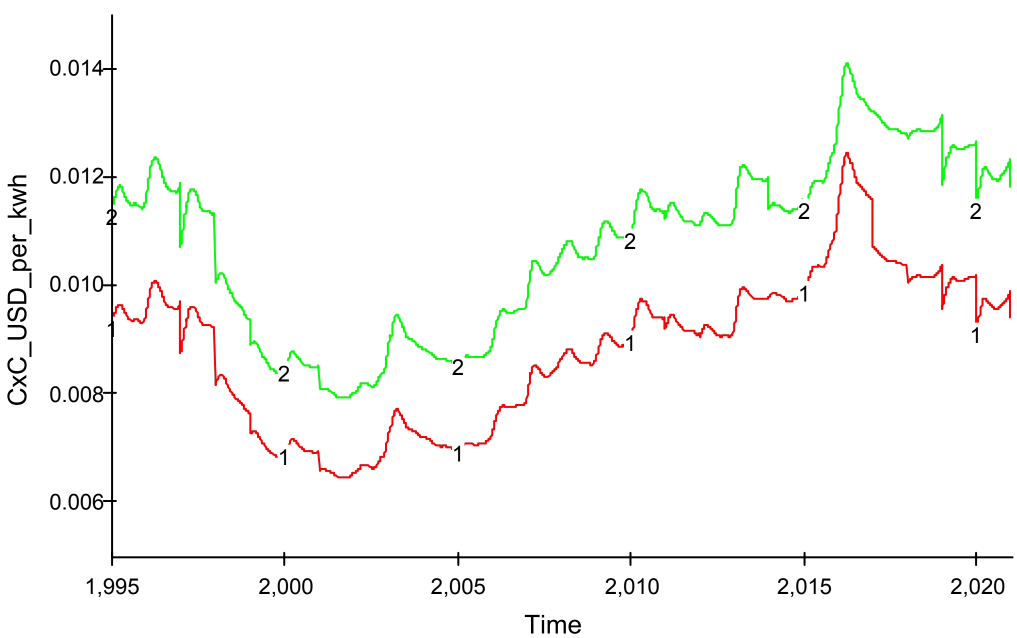
Note: Line 1 is r=0, line 2 is r=11, line 3 is r=12, line 4 is r=13, line 5 is r=14, line 6 is r=15

Figure XVIII Evolution of Thermal Based Generation Period 2010-2020



Note: Line 1 is r=0, line 2 is r=11, line 3 is r=12, line 4 is r=13, line 5 is r=14, line 6 is r=15

Figure XIX Baseline and Scenario C

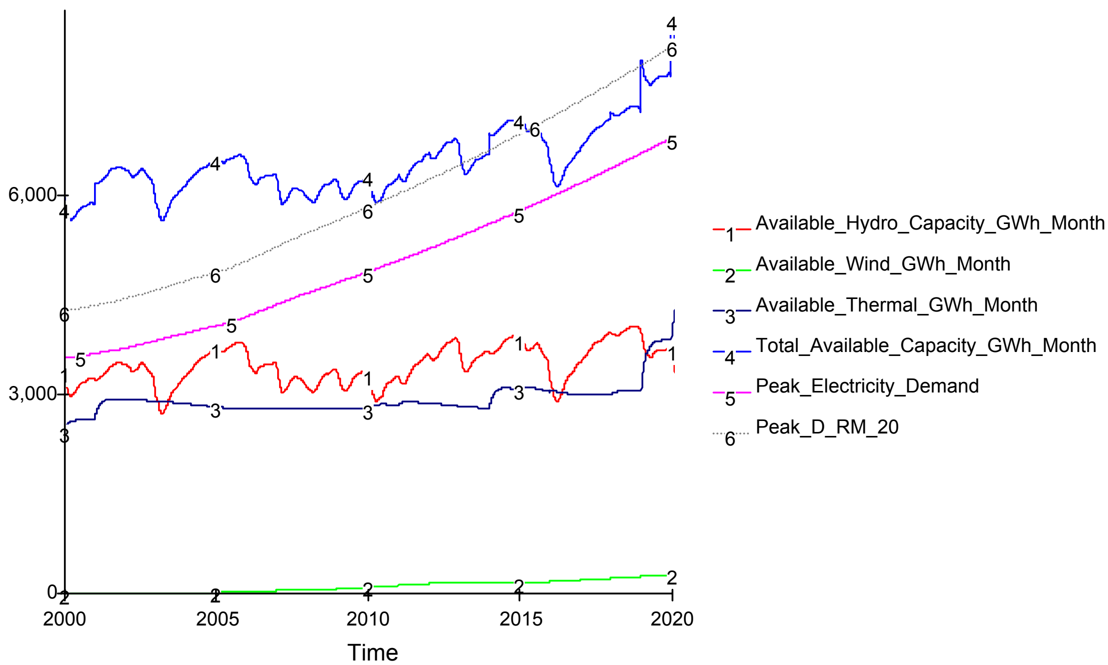


Note: Line 1 is the baseline, Line 2 is scenario r=14

This increase in the value of the capacity charge raises the annual payment by the regulator from about 527.5 to 646 million USD in 2003, or in the order 20-25% every year. This measure would indeed increase the reserve margin to minimum required levels of reliability (i.e. 20%) after 2013 and even, avoid the rationing after 2015 that results from the rain pattern scenario used in the baseline and in this scenario (see Figure 6.17 below)[10].

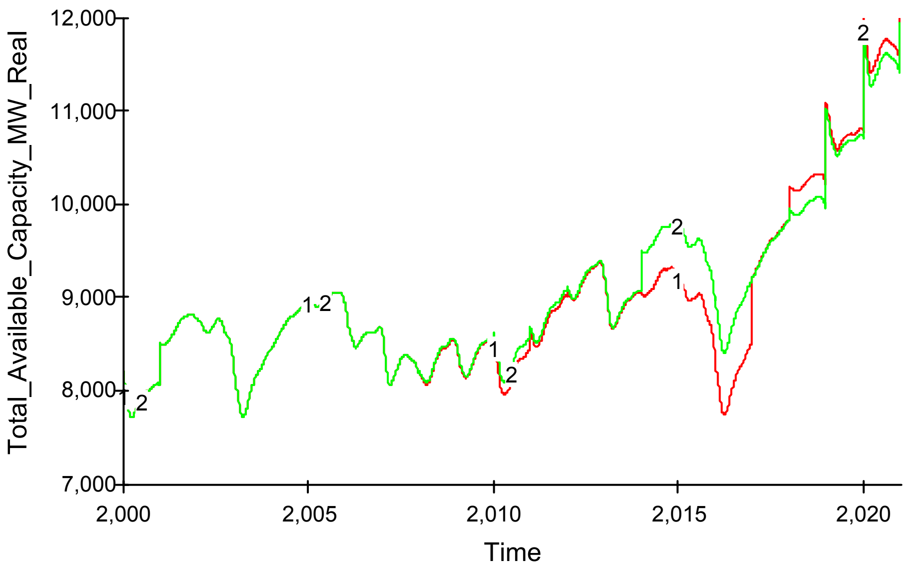
Figure XXI compares the baseline scenario and Scenario A (discount rate at 14%) in terms of total available capacity.

Figure XX Evolution of Capacity and Reserve Margin, Scenario C



[10] Recall that the rain scenario was chosen to follow the same pattern as in the two decades 1980-1990 and 1991-2000.

Figure XXI Evolution of Capacity (Baseline and Scenario A)



Note: Line 1 is the baseline, Line 2 is Scenario C

Most important is however to find out what is the total balance of costs to the system and the evolution of investments to analyse in detail the effects of this change to the value of the capacity payment.

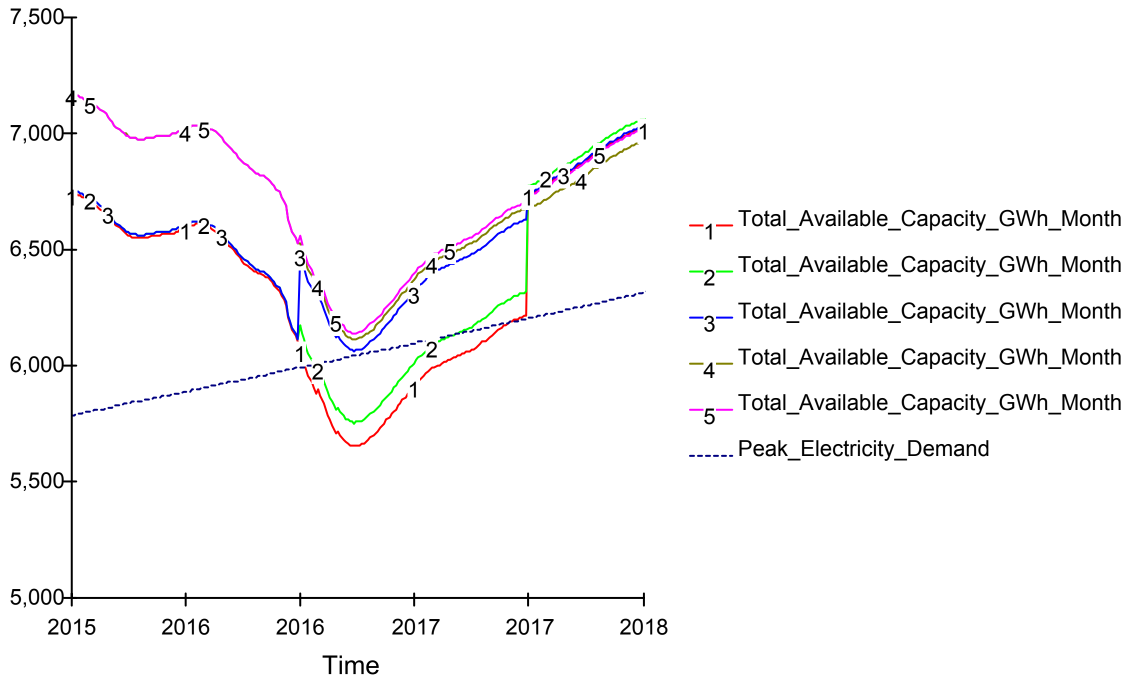
Increasing the discount rate used to estimate the capacity payment has in fact three notorious consequences:

1. Investments are anticipated by about three years, as depicted in Figure XVIII
2. Rationing is avoided (see difference in Figures XX and XXI)
3. Thanks to earlier investments, total costs to the system are ultimately 2,860 USD million lower if avoided costs of rationing are considered (see Annex III).

System dynamics models are concerned with long term behavioural patterns and the dynamic tendencies of complex systems. Indeed, precise quantitative estimates are not the focus of the analysis. This exercise demonstrates a counter-intuitive result. While an increase in the discount rate of the capacity payment signify millions of dollars in extra annual costs to the consumer, ultimately, early investments in capacity avoid price spikes as well as the high costs associated to the rationing event, resulting ultimately in important savings to the system. This benefit however can only be estimated when considering long term patterns. Indeed, the provision of a higher capacity payments has the potential to avoid rationing in the long term. In effect, this instrument allows the early investment of most cost effective efficient technology, lowering not only the total cost to the system in terms of electricity price (i.e. the diffusion of more efficient capacity lowers the electricity price in the wholesale market as this capacity displaces inefficient most costly technology), but the rationing threat. The idea that an increase in capacity charge (CxC) would only result in higher electricity prices has been falsified. Indeed, allowing an increase in revenues results in earlier investments in efficient capacity which results in high positive net benefits to the system when considering the avoided cost of rationing.

Scenario D This scenario considers an increase in the amount of firm capacity paid considered in CREG resolution 116 established at 5% above the peak demand through changes in the reserve margin policy. Different tests have been carried out to find the optimum value. Results are shown in Annex IV and in Figures XXII and XVI below.

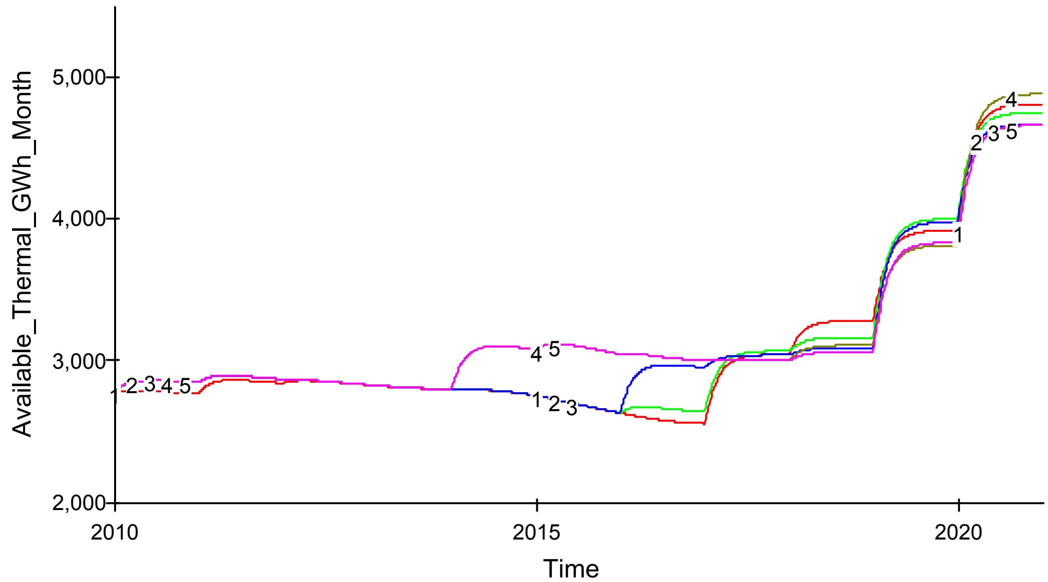
Figure XXII Total Available Capacity During Rationing Event



Note: Line 1 is the baseline, lines 2, 3, 4, 5 correspond to CxC provided to 10, 15, 20, 30% of peak demand.

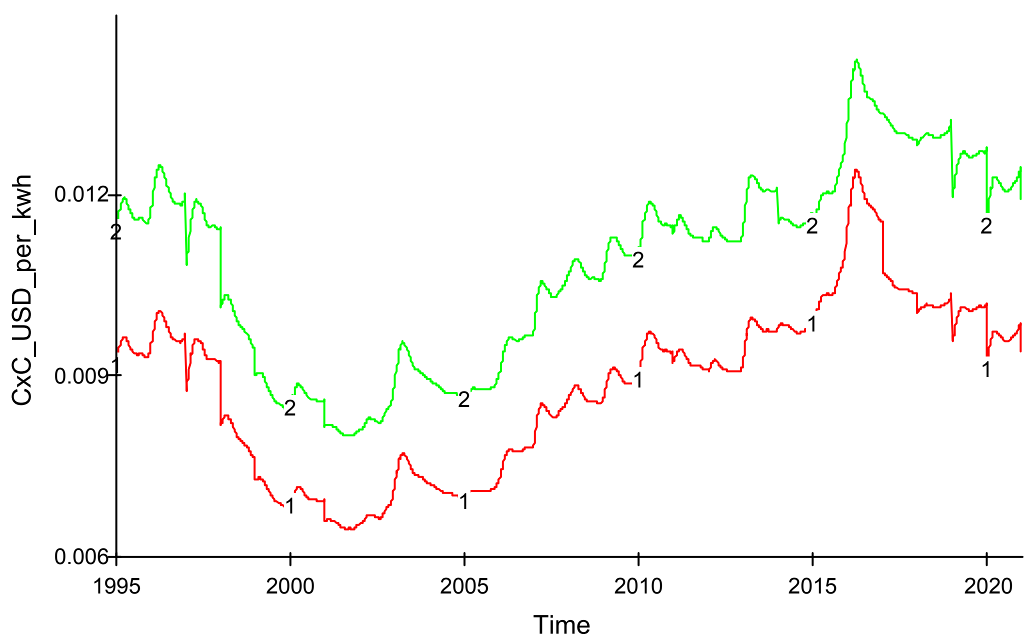
According to the results, the net benefits are maximised when the regulator pays 130% of peak demand as firm capacity to generators that provide with this service. This is indeed an interesting result since a reserve margin of 30% has been always considered an optimum almost as a rule of thumb. The results of the test confirm this hypothesis showing the same effects than in Scenario C, the increase in the cost of the CxC is covered by a decrease in the total costs of electricity to the system and most importantly to the elimination of rationing. Again, the reason being investments triggered four years in advance (see Figure XXIII).

Figure XXIII Evolution of Thermal Based Generation Period 2010-2020



Note: Line 1 is the baseline, lines 2, 3, 4, 5 correspond to CxC provided to 10, 15, 20, 30% of peak demand.

Figure XXIV Capacity Payment (Baseline and Scenario B)



Note: Line 1 is the baseline, Line 2 is Scenario B with 130% peak demand

The comparison between Scenarios C and D is depicted in Figures XXV and XXVI below. Effectively the two measures result in almost equal effect in terms of net benefits.

Figure XXV Capacity Payment (Scenarios C and D)

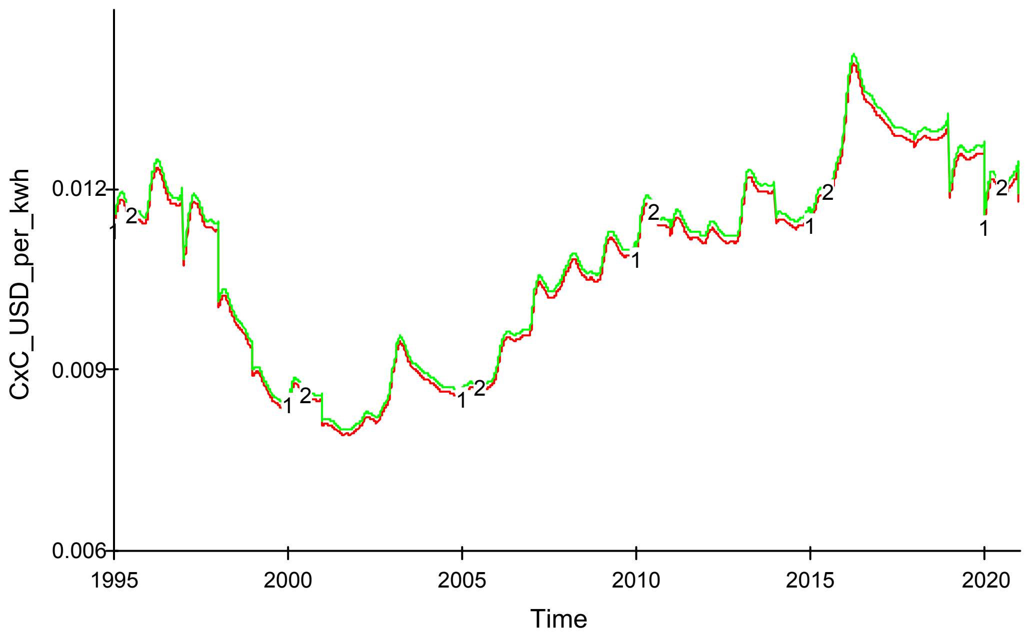
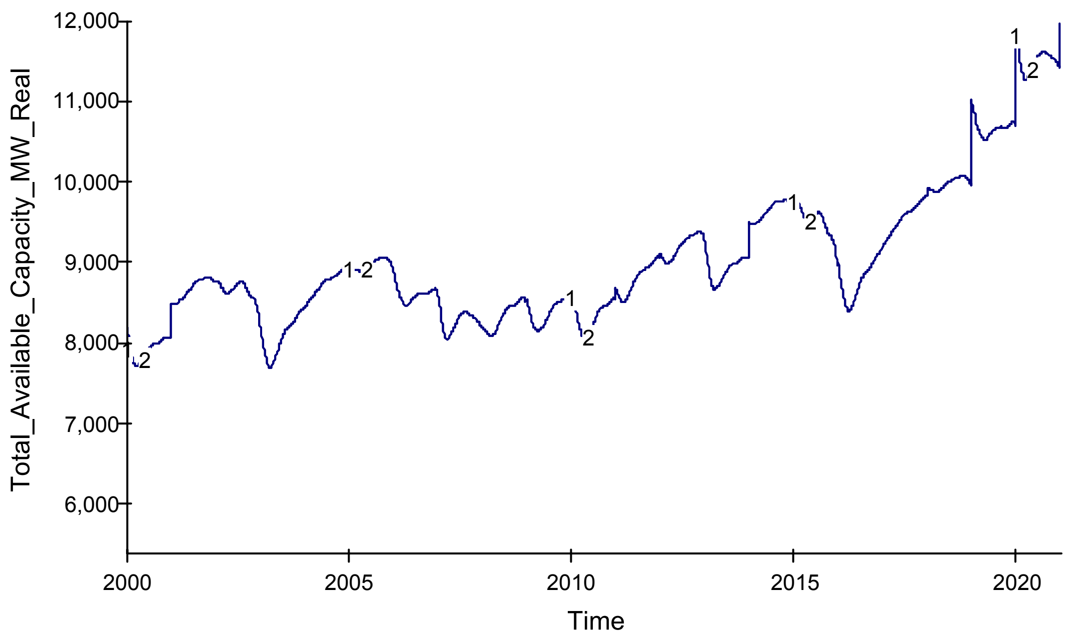
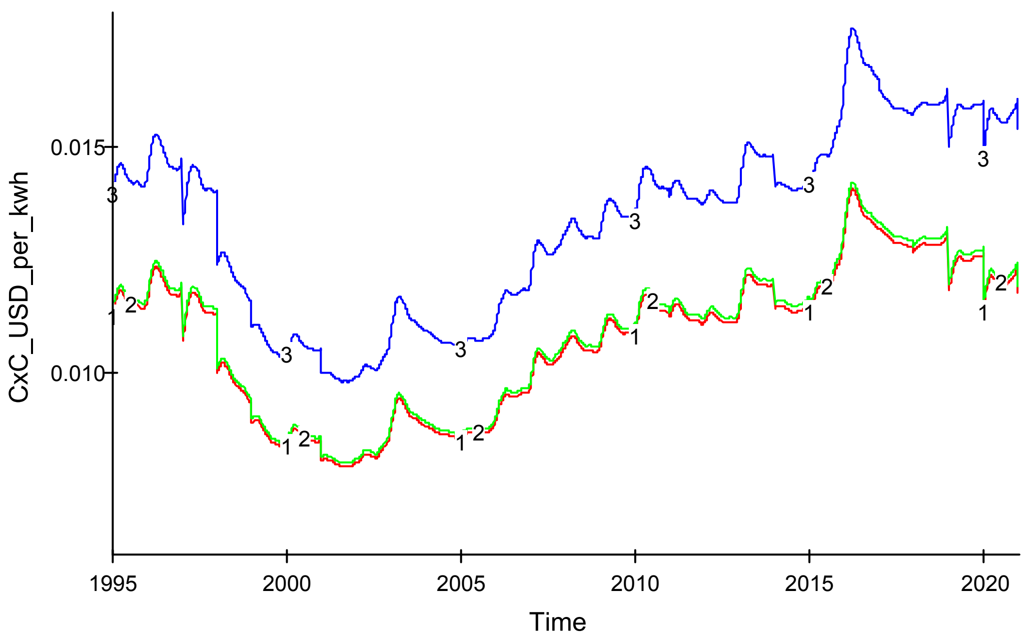


Figure XXVI Evolution of Capacity (Scenarios C and D)



Scenario E This scenario combines the two modifications carried out in tests C and D to test weather the two policies are *additive or synergic* (positively or negatively) or on the contrary neutralised. Results comparing tests C, D and E are provided in Figures XXVII and XXIX. As shown, the two policies together are not additive neither in benefits nor in costs in terms of evolution of reserve margin. Marginally, it does however increases the additions of wind and gas based capacity and lowers investments in coal based capacity, with the consequent lowering in carbon emissions.

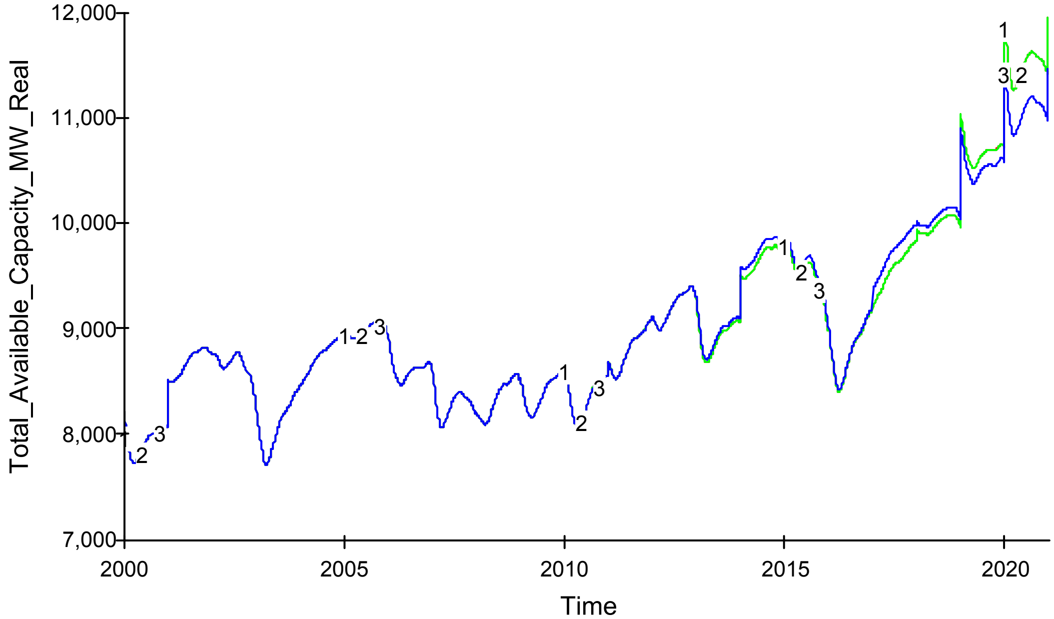
Figure XVII Value of Capacity Payment (Scenarios C, D and E)



Note: Line 1 is Scenario C, Line 2 is Scenario D and Line 3 is Scenario E.

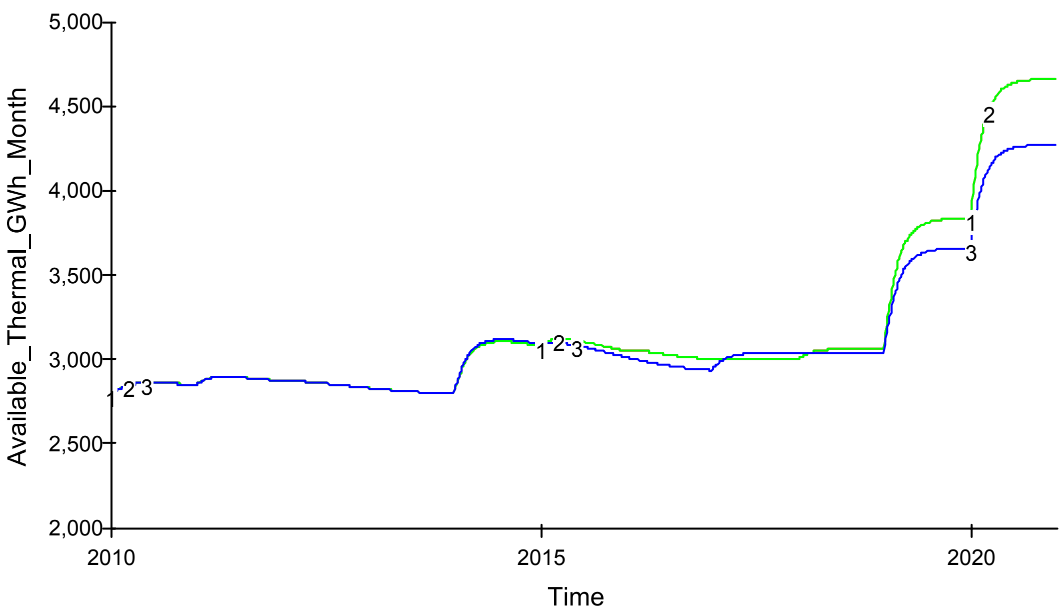
The total net benefits for the system associated to Scenario E are 0.32% lower than those of Scenarios C and D. Ultimately, in terms of benefits, the three scenarios are similar despite the difference in capacity payment between Scenarios C-D and Scenario C.

Figure XXVIII Evolution of Total Available Capacity (Scenarios C, D and E)



Note: Line 1 is Scenario B, Line 2 is Scenario C and Line 3 is Scenario D.

Figure XXIX Evolution of Thermal Available Capacity (Scenarios C, D and E)



Note: Line 1 is Scenario A, Line 2 is Scenario B and Line 3 is Scenario C.

Considering both Scenarios C and D it can be established that the measure does not have an additive result except for the additionality in terms of emission reductions and the support to renewable energy. From the perspective of the Clean Development Mechanism (CDM, a flexible mechanism under the Kyoto Protocol), a regulatory change such as the one shown in Scenario C would prove additional and has the potential to reduce more carbon emissions than the installation of a 80 MW run of river plant for a period of 21 years (see World Bank 2003).

V CONCLUSIONS

The following conclusions can be derived from the scenarios considered and reported above.

The *status quo* will not keep acceptable levels of reliability in the long term

The results of the baseline simulation suggest that despite of the overcapacity exhibited in the Colombian ESI today –with a 66% share of hydroelectric capacity- the reserve margin of the system can lower gradually leaving the system highly vulnerable to seasonality changes and ENSO events after 2010. Investments in capacity do not respond to sustained increases in peak demand until after the price reaches a level required to reach expected returns to investment. Indeed, investments are triggered by price spikes which lead to waves of boom and bust in the construction of plants.

Under the assumptions and conditions established in this scenario private firms do not invest in *greenfield* facilities before 2015, mainly due to low wholesale electricity prices and low load factors associated to thermal based capacity. In addition, the financing constraints imposed by commercial banks (i.e. high costs of capital, low maturity periods) contribute to the lack of private investment in the sector.

The capacity charge today does not succeeds in restoring private investment flows

The capacity payment provided as designed by the energy regulatory body in CREG Resolution 116 is not sufficient for two reasons: a) it is calculated with a discount rate of 11% while the minimum return to investment sought by a private investor is 15% due to the risk premium demanded for the particular case of Colombia and b) it only pays 105% of the demand in firm capacity, whilst the system needs at least 20% of reserve margin. Regardless of the allocative inefficiency (which related to political economy issues) associated to this instrument in the Colombian setting, the resources available to ensure the availability of the necessary amount of firm capacity to avoid rationing events, is insufficient.

Higher capacity payments have the potential to result in higher net benefits

While an increase in the discount rate of the capacity payment signify millions of dollars in extra annual costs to the consumers, ultimately, early investments in capacity avoid the high costs associated to rationing events, resulting ultimately in important savings to the system. This benefit however can only be estimated when considering long term patterns. Indeed, the provision of a higher capacity payment has the potential to attract on a sustainable basis the financing needed over time to expand services to future consumers and avoid rationing in the long term. In effect, this instrument allows the early investment of most cost effective efficient technology, lowering not only the total cost to the system in terms of electricity price (i.e. the diffusion of more efficient capacity lowers the electricity price in the wholesale market as this capacity displaces inefficient most costly technology), but the rationing threat.

The idea that an increase in capacity charge (CxC) would only result in higher electricity prices has been falsified. Indeed, allowing an increase in revenues results in earlier investments in efficient capacity which results in high positive net benefits to the system It has been therefore being demonstrated that a simple regulatory measure has the potential to solve a problem. Indeed, it has been extensively recommended that the regulators of Latin American countries apply simple transparent regulations as opposed to complex configurations that have not been tested or fully explored in other more developed systems (e.g. auctioning options and futures).

The structure of the system in terms of ownership matters

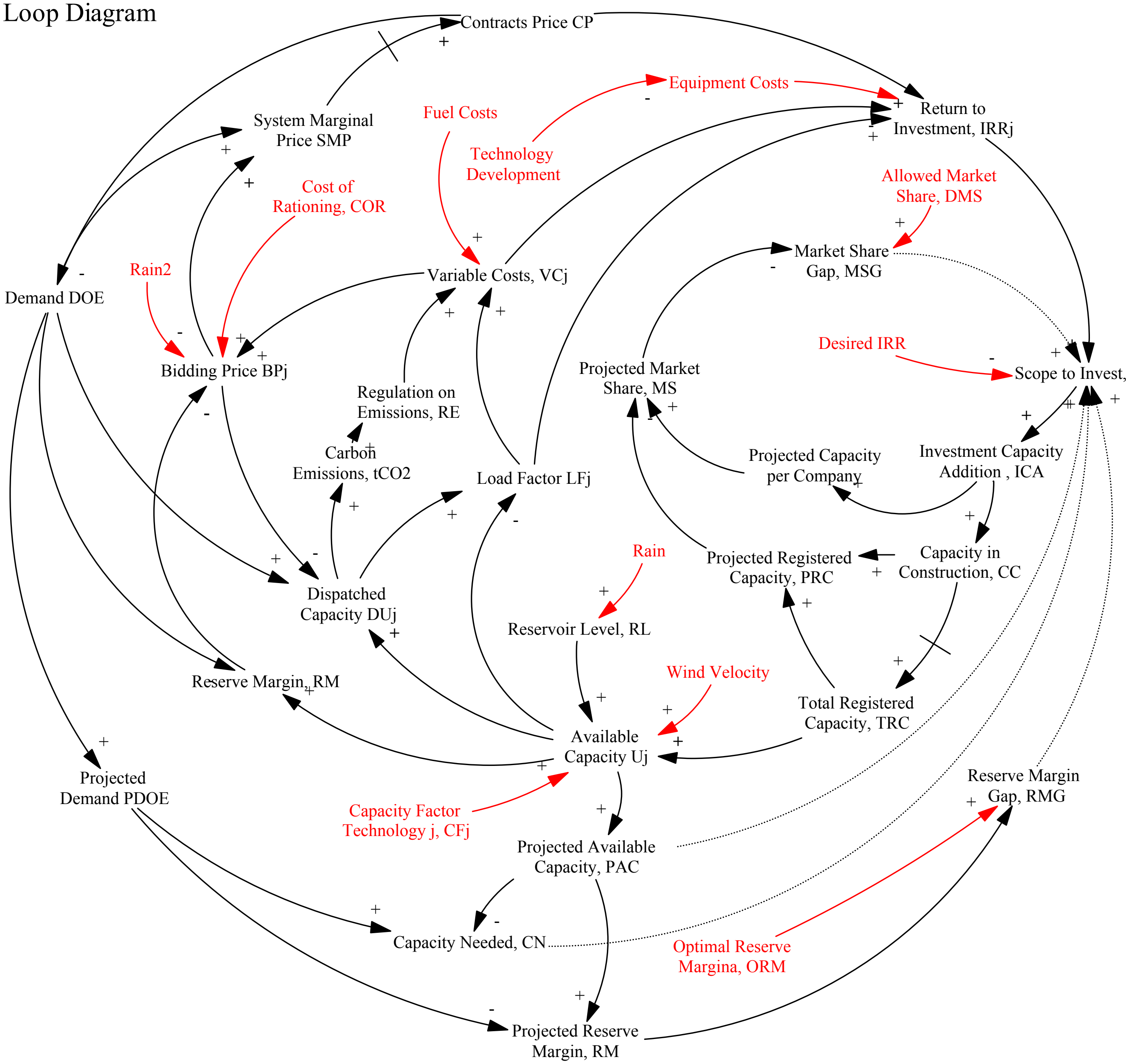
A mixed ownership will deliver a more sustainable system when the appropriate incentives to trigger investment in *greenfield* capacity are in place. Neither a centralised

State-owned nor a private-led market structure will allow the sustainable development of a system with high shares of hydroelectric capacity and the need to sustain high reserve margins. In terms of net benefits, it has been shown that a mixed ownership outperforms the alternatives.

Recommendations

Regulatory frameworks have to be designed bearing in mind local capacities and institutional approaches. The application of simple measures that contribute to restore private investment flows, which can be easily implemented and monitored are therefore recommended. For instance, the capacity payment suggested in Scenario C could be assigned through transparent and competitive capacity auctions, conducted under the purview of the regulator (i.e. as opposed to distributed among generators based on the outputs of complex models), or even a parallel capacity market to the energy spot market can be set up. Later on, and depending on the capacity of the system, a forward energy trading market whose prices signal expectations about future supply/demand balances can be developed.

Annex I. Causal Loop Diagram



Annex II Quantitative Comparative Analysis 2000-2020			
Indicators	**Baseline**	**Scenario A Public**	**Scenario B Private**
Total Registered Capacity by 2020 (MW)	19,699.16	19,312.95	16,717.54
Total Registered Capacity by 2016 (MW)	15,190.38	17,195.39	14,409.99
Total Registered Capacity by 2015 (MW)	15,323.39	16,785.00	14,518.69
Gas Based (MW)	6,746.50	6,884.86	6,045.79
Coal Based (MW)	1,276.26	991.69	521.05
Wind Based (MW)	960.20	720.20	94.49
LRMC (2000-2015) (USD/MWh)	24.30	32.30	19.20
LRMC (2000-2020) (USD/MWh) (1)	47.20	28.30	54.40
Total Cost to System as Electricity Sold (USD Million) (2)	**180.86**	101.95	418.36
Total Cost to System Considering both Electricity and Rationing Cost (USD Million) (3)	**3036.01**	101.95	4,735.41
Total Cost System (USD Million / year) (3)	**9.043**	5.10	20.92
Cumulative Reserve Margin	8.52	7.50	5.82
Cumulative Rationing (GWh)	2,009.25	-	3,076.99
Rationing Duration (months)	10.68	-	12.12
Rationing Period	2016.03-2016.92	-	2015.99-2017.00
Cumulative Carbon Emissions (Million Tons)	194.36	249.55	227.75
NET BENEFITS: Avoided Costs of Rationing	-	**2,934.06**	-1,699.4

Note 1: After 2015 a drought forces the system into rationing and the LRMC increases. The magnitude of the COR influences very much this value.
Note 2: As total amount of electricity purchased at marginal spot price (does not consider rationing cost).
Note 3: Total Cost including rationing, per year (cost of rationing has been considered constant 100 USD/MWh for the calculation of LRMC and Rationing)
Note 4: Estimated considering the difference between the investment by PUs (government) in Scenario M and the baseline, which is 4,735 MWs. (see Table 6.1 for indicative capital costs)
Note 5: Considers the addition lf the large hydroelectric plant Pescadero-Ituango (1600 MW)

Annex III The Costs and Benefits of Applying Different Values of Capacity Payment Period 2000-2020							
	Tests						
	No CxC	**BL r=11**	**r=12**	**r=13**	**r=14**	**r=15**	**r=16**
Total Wind Capacity 2020 (MW)	461	960	1000.2	1000.2	1080	1080	1080
Total Coal Based Capacity 2020 (MW)	1149	1276	1240	1270	1080	1080	1080
Total Gas Based Capacity 2020 (MW)	5800	6750	6690	6700	6630	6630	6630
Cost to System (only Electricity Price) (USD Million)	190.57	180.8	181.36	172.71	170.53	172.94	175.34
Benefits in terms of Cost of Electricity Avoided	-	9.77	9.21	17.86	**20.04**	17.63	15.23
Total Cost to System Considering Rationing Cost (USD Million)	5393.4	**3036**	1731	172.71	170.53	172.94	175.34
Avoided Rationing GWh	5,690	1996	1071	0	0	0	0
Avoided Cost of Rationing	-	2,357	3,662	5,221	5,223	5,220	5,218
Cost of Capacity Payment	0	**44.80**	48.11	51.48	54.9	58.37	61.89
Emissions	224.82	194.2	191.98	191.6	190.1	190.1	190
Avoided Emissions at Market Costs (USD Million)	-	30.62	32.84	33.22	34.72	34.72	34.82
TOTAL NET BENEFIT (USD Million)	0	2,343	3,646	5,202	**5,203**	5,196	5,190

Note: The Cost and Benefit Analysis is calculated against an scenario of no capacity payment or r=0, (as opposed to against the baseline). This however does not changes the conclusions reached but only the magnitude of the quantitative results.

Annex IV The Costs and Benefits of Applying Different Values of Capacity Payment Period 2000-2020									
	Tests								
	BL R105	**R110**	**R115**	**R118**	**R120**	**R125**	**R130**	**R135**	**R140**
Total Wind Capacity 2020 (MW)	960	1000	1000	1000	840	1000	1080	1080	1080
Total Coal Capacity 2020 (MW)	1276	1244	919	919	1300	1269	1080	1080	1080
Total Gas Based capacity 2020 (MW)	6750	6693	6343	6343	6822	6705	6630	6630	6630
Cost to System (Electricity Price) (USD Million)	180.86	180.54	185.90	186.80	175.61	173.98	170.93	172.41	173.90
Total Cost System w/ Rationing Cost (USD Million)	3,036.01	1,730.50	185.90	186.80	175.61	173.98	170.93	172.41	173.90
Total Cost Capacity Payment	44.80	46.94	49.08	50.36	51.21	53.34	55.48	57.61	59.74
Carbon Emissions (Million Tons CO2)	194.2	191.9	193	193	195.3	191.6	190.13	190.1	190.1
Avoided Emissions at Market Costs (USD Million)	-	11.5	6	6	-5.5	13	19.5	20.5	20.5
TOTAL NET BENEFIT (USD Million)	**-**	**1,303.37**	**2,845.83**	**2,843.65**	**2,853.99**	**2,853.49**	**2,854.40**	**2,850.79**	**2,847.17**

Note: The Cost and Benefit Analysis is calculated against an scenario of no capacity payment or r=0, (as opposed to against the baseline). This however does not changes the conclusions reached but only the magnitude of the quantitative results.

Annex V Quantitative Comparative Analysis 2000-2020				
Indicators	**Baseline CxC 11%**	**Scenario A CxC 14%**	**Scenario B CxC 130 D**	**Scenario C Both**
Total Registered Capacity by 2020 (MW)	19,699.16	19,507.48	19,507.36	19,080.01
Total Registered Capacity by 2019 (MW)	17,464.17	17,448.19	17,448.13	17,425.12
Total Registered Capacity by 2016 (MW)	15,190.38	15,984.12	15,984.11	16,123.70
Total Registered Capacity by 2015 (MW)	15,323.39	15,987.00	15,986.99	16,176.72
Gas Based (MW)	6,746.50	6,630.44	6,630.35	6,165.17
Coal Based (MW)	1,276.26	1,080.65	1,080.62	878.45
Wind Based (MW)	960.20	1,080.20	1,080.20	1,320.20
LRMC (2000-2015) (USD/MWh)	24.30	25.00	25.00	25.40
LRMC (2000-2020) (USD/MWh) (1)	47.20	22.80	22.80	22.80
Total Cost to System as Electricity Sold (USD Million) (2)	**180.86**	**170.53**	**170.93**	**173.44**
Total Cost to System Considering both Electricity and Rationing Cost (USD Million) (3)	**3036.01**	**170.53**	**170.93**	**173.44**
Total Cost System (USD Million / year) (3)	**9.043**	**8.53**	**8.55**	**8.672**
Total Cost CxC (USD Million)	**44.80**	**54.90**	**55.48**	**59.08**
Cumulative Reserve Margin	8.52	8.72	8.72	8.72
Cumulative Rationing (GWh)	2,009.25	0	0	0
Rationing Duration (months)	10.68	0	0	0
Cumulative Carbon Emissions (Million Tons)	194.36	190.14	190.13	**181.88**
Total Benefit = Avoided Cost of Rationing – Cost Regulatory Measure (Million USD)	NA	**2,855.38**	**2,854.40**	**2,847.28**

Note 1: After 2015 a drought forces the system into rationing and the LRMC increases. The magnitude of the COR influences very much this value.

Note 2: As total amount of electricity purchased at marginal spot price (does not consider rationing cost).

Note 3: Total Cost including rationing, per year (cost of rationing has been considered constant 100 USD/MWh for the calculation of LRMC and Rationing)

Back to the Top