Effects of New Brazilian Electrical Power Regulatory Framework on Generation Investments

Ajax R.B.Moreira
IPEA[1]
ajax @ ipea.gov.br

Katia Rocha
IPEA
katia @ ipea.gov.br

Pedro A.M-S. David
FURNAS[2]
pdavid @ furnas.com.br

Summary

The Brazilian Regulatory[3] Framework for the Electricity Business was thoroughly to allow private investors to participate in the power generation, transmission and distribution. To be successful this policy shall provide attractive economical conditions for required investments in the system expansion, especially in new power generation.

The Power Spot and Future Markets (forward contracts) are affected by the Regulatory Framework in many important aspects, such as:

1) The cost of energy supplied on deficit situation, affects the spot price, since it reflects the expected energy cost in the energy deficit scenarios;
2) The normative value is the electricity price cap (maximum value) for the consumers, thus limiting the maximum price of forward contracts;
3) The tariff correction scheme defines how the monetary exchange rate fluctuation (R$/US$) can be passed onto the tariff. This is particularly important for the Thermopower Generation, since the Natural Gas is priced in US$, the Utilities revenues are in R$, and the exchange rate may be very volatile

The objectives of this study are:

1) Verify whether an increase in the cost of energy deficit would be enough to induce the required investments in power supply generation.
2) Propose a methodology for the calculation of the normative value, in order to attract private capital for investments while protecting the final consumers from excessive burdening.
3) Analyze the effect of the current natural gas supply policy, especially regarding the compensation for the exchange rate variation .

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[1] IPEA: Instituto de Pesquisas Econômicas Aplicadas – Economics Research Institute – Av. Pres. Antonio Carlos, 51 / 15 – Rio de Janeiro, RJ, Brazil

[2] FURNAS Centrais Elétricas – Power Utility – R. Real Grandeza, 219 / B- 607 – Rio de Janeiro, RJ, Brazil

[3] The Brazilian Government Regulatory Agency for the Electricity Business is ANEEL (National Agency for Electrical Energy)

1 Introduction

The Brazilian Regulatory Framework for the Electricity Business was thoroughly to allow private investors to participate in the power generation, transmission and distribution. So, this policy shall provide attractive economical conditions for required investments in the system expansion, especially in new power generation, since the demand has a fast growing rate, over 4% / year.

According to this Regulatory Framework the Integrated Power System shall be operated by a central dispatcher[4], who schedules all generators[5] according to a stochastic optimization model (Centralized Optimal Dispatch - COD).

The COD maximizes the inter-temporal utilization of the energy in hydroelectric reservoirs, minimizing the system operation cost. This model is driven by the reservoirs' level, forecast of future affluence to the reservoirs and of energy demand, the Thermopower plants operating costs (mainly the fuel cost), and by the energy deficit cost, set by the Regulatory Agency (ANEEL)[6].

The COD also determines the electricity price on the wholesale (spot) market - spot price ($/MWh)[7], as the system marginal operation cost, that is the dual variable associated to generation-demand balance requirement (constraint).

The generation investment decision is based on the forecasted net revenue (R), which is sum of the energy sold on long-run contracts (Rc) plus the energy sold or bought on the spot market (Rs), that is difference between the energy sold and the actual generation, as dispatched by the COD model, minus the utility operational costs (Cg). R = Rc + Rs – Cg

The maximum contract price is limited by the maximum value that can be charged on electricity tariff. This tariff cap is the Normative Value, set by the Regulatory Agency (ANEEL).

The spot price reflects the immediate and future expected energy cost, and the Energy Deficit Cost affects the latter, as it is cost considered on the possible energy deficit scenarios. As mentioned before, the Regulatory Agency (ANEEL) also sets this cost.

Another key issue for the investment on the Thermopower plants is the tariff adjustment for the operating cost variation, as the fuel (natural gas) cost, is rather volatile, especially in Brazil, as natural gas is priced in US$ and the electricity is priced in R$ and the US$/R$ exchange ratio is volatile. The tariff adjustment policy[8] is defined by the Regulatory Agency.

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[4] The Brazilian Integrated Power System Operator is the ONS (National System Operator), which is a public, non-governmental entity.

[5] The central generation dispatch consider all generators belonging to the Integrated Power System, with capacity above 30 MW

[6] The deficit cost is set based on the economic value of electricity to the economy, as the elasticity of the Brazilian GNP to electricity production.

[7] The spot price is an optimality condition of the model. It is equal to the operational costs of the marginal utility at the optimal point. This price reflects the short-term condition of shortage.

[8] The recent regulation about the supply of natural gas eliminates the price uncertainty (exchange rate risk and price fluctuations) only for the Thermopower plants that will come into operation until June 2003.

Therefore, the Regulatory Agency (ANEEL) has two control instruments to prompt investments: the Deficit Cost and the Normative Value, as well as the tariff adjustment policy.

The investment opportunity is an option to get the stochastic revenue by committing the investment-sunken costs (exercise price). Therefore, the investment shall be valued by a multi-stochastic option model, which regards the random variables (affluence, current level of reservoirs, energy demand and natural gas price), whose goal is to establish the optimal exercise rule for the investment option.

The objectives of this study are:

1) To verify whether an increase on the deficit cost effectively induces investments in power generation.
2) To propose a methodology for the setting of the Normative Value that would attract the private capital for investment while protecting the final consumers.
3) To analyze the effect of the tariff adjustment policy, regarding the natural gas price uncertainty.

The next sections are organized as follows: section 2 presents the methodology, section 3 shows the results and section 4 concludes.

2 Methodology

We have used the COD model described on Moreira, Rocha e David (2001)[9], which extends the COD model employed by ONS. This alternative model represents other economical uncertainties such as demand and natural gas price in addition to the affluence uncertainty. We also deal with the exchange rate risk, supposing that it can be expressed as an increase in the natural gas price volatility[10]. We believe it is important to consider all these uncertainties, furthermore for investment valuation.

The investment decision problem depends upon the forecast of power supply requirement. If other agents commit investments in some period in the future, the power supply requirement changes. This situation can be modeled as a stochastic game among the investors. This study does not deal with these games. We suppose that the investor observes a scenario of supply power generation for the whole planning horizon and makes his own decision regardless of the others investors' decisions.

2.1 The Normative Value Computation

As mentioned before, the generators revenue comes from the long-term contracts and from the spot market balance.

The long-run contract price (P) is found by the market bid-ask equilibrium price, set according to the expected price and risk aversion of the energy seller and buyer.

The Regulatory Agency (ANEEL) sets a ceiling price for P, by establishing the normative value, NV, which represents the maximum energy price that can be charged on consumers. As long-run contracts have a direct effect upon the Power Utility's revenue, the regulation on its maximum price has a major

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[9] A short version of the model is presented on Appendix.

[10] We admit a simple diffusion process for the exchange rate risk, where exchange rate fluctuations can increase or depress the local currency related to US$. One can consider in using a proper model like jump-diffusion process, where the exchange rate varies by uncertainty and infrequent jumps.

influence over the investment decision. A very low NV depresses the Power Utility's revenue, daunting the investments, while a too high NV allows the exercise of market power by the dealers, overburdening the final consumers.

The NV shall be set as the minimum value that does not impair investments:

NV = min {P such as $p(P|\Psi)=1$} .... eq. 1

Where Ψ is the vector of parameters that characterizes the policy, and $p(P|\Psi)$ is the proportion of states in which the investment would be exercised immediately.

2.2 The Investment Problem: A Real Option Theory Approach

The Real Options Theory addresses the investment decision problem by analyzing not only the expected net present value (NPV), but also considering the value of the option to wait, i.e., the option to delay the investment waiting for better or clearer scenarios, and also other options, like the option to discontinue, to increase or to decrease the investment, etc[11].

The underlying stochastic variable of the investment option is the Power Utility's revenue. The exercise price is the sunk cost associated to the investment. After the investment is realized, the investor starts receiving stochastic payments associated to the Power Utility operation during its lifetime.

We study the investment decision problem relating to a Thermopower and a Hydropower plant. Each one of them has its revenues and sunk cost. We present the methodology for the general case, remarking the difference between them when necessarily. The investment cost associated to the Hydropower plant is parameterized as a multiple of the investment cost on a Thermopower plant.

We summarize the investment problem as follows:

1. A Power Utility (Hydropower or Thermopower) plant, with unitary (1 TWh / year[12]) capacity.

2. The time to build will not be considered. We assume that investors start receiving the Power Utility revenue upon the option exercise.

3. The investment is paid in equal installments along the Plant lifetime. A financial correction factor (x_t^T , x_t^H [13]) is applied to adjust for the difference between this time span and the planning horizon[14].

   If the total cost of the Thermopower plant is C (US$ 650/KW), the considered investment cost is C x_t^T and for Hydropower plant it is α C x_t^H .

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[11] For a broader application of option theory to appraise real asset see Dixit and Pindyck (1994) or Trigeorgis (1996).

[12] We assume a constant efficiency for a typical natural gas plant, combined cycle, 200MW.

[13] The finance adjustment of Thermopower and hydro plants are: x_t^T =C(2,20,10,t,.1), x_t^H =C(8,40,10,t,0.1).

C(c,d,t,h,j) $= \frac{(1+j)^c-1}{j}\,\frac{j(1+j)^{d-1}}{(1+j)^d-1}\,\frac{(1+j)^t-1}{j(1+j)^{t-1}(1+j)^{h-t}}$ where c is the time of construction, d is the utility's lifetime, h is the planning horizon, t relates the exercised moments, and j is the interest rate.

[14] We use standard financial mathematics and assume the utility's investment sunk cost can be financed in equal payments during its lifetime. We also compute the expenditures incurred before the operation time.

4. The risk premium associated to these investments is beyond the scope of this study. We have adopted the discount rate of 15% / year which, according to other studies[15] is the appropriate discount rate for investment in power supply generation.

5. Our alternative COD model assume a simplified electrical system, composed by a consumer, a Hydropower plant equivalent to the total hydropower generation and a Thermopower plant. We do not consider transmission constraints, neither the power losses.

6. We define the λ parameter as a shift on the system balance[16].The expansion is modeled as an addition to the initial system capacity:

$$H_t^* = H_0 + \lambda\ (H_t - H_0)$$

$$G_t^* = G_0 + \lambda\ (G_t - G_0)$$

- H_0 and G_0: current power supply capacity.
- H_t*and G_t*: future expected power supply capacity.

For a given set of parameters "ψ" that characterizes the model, the COD determines the optimal dispatch for a Hydropower plant (u_{zt}^{y}) and Thermopower plant (g_{zt}^{y}) for each possible scenario (state of nature "z") and time period "t" that minimizes the system operation cost. The COD also determines the spot price s_{zt}^{y} as the system marginal operation cost . Therefore we can evaluate the Power Utility's instantaneous revenue r_{zt} of a power or plant for each state (scenario) and period of time, as well as the transition probability function $\pi(z^*,t+1|u_{zt},z,t,\psi)$ between consecutive states "z".

2.2.1 Structure of the Power Utility Revenue

As mentioned before, part of the Power Utility's income is earned on the long-term energy supply contracts, which yields a fixed value (fixed price x fixed energy amount = $P.q^c$).

However, the actual generation (g^d for a Thermopower and u^d for a Hydropower) may be greater or less than the amount that is settled in the contract (q^c). The difference is sold / bought on the spot market, respectively. This difference (q^d - q^c) is called the "spot market adjustment portion".

The Thermopower Utility's net revenue (r_g) is the balance of this income minus the operation costs, which is the product of the production (g^d) and marginal cost (c):

$$r_g = P.q^c + (g^d - q^c).s - g^d.c$$

Thermopower plants, especially those driven by turbines, have a limited economical and/or technologically feasible operation range, usually from 70 to 100% of its nominal capacity. To allow for this limitation, the Thermopower Utility may declare a fraction (1 - q^f) of its capacity as "inflexible". This inflexible portion capacity has a priority dispatch, as if it had no cost.

[15] Coopers & Lybrand Report (1997) on Brazilian Electrical Framework reform.

[16] For λ = 1, the system's deficit probability is less than 5%.

The Thermopower plant generation (g^d) is the dispatch of the inflexible and flexible portions, as:

$$g^d = (1 - q^f) + q^f.g/G$$

Where g is the dispatch and G is the thermo capacity of a flexible system.

Therefore, the Thermopower's net revenue can be expressed as:

$$r_g = P.q^c + ((1 - q^f) + q^f.g/G - q^c).s - g^d.c$$

For a Hydropower, the net revenue (r_u) expression is equal to its income, since there are no operating (fuel) costs:

$$r_u = P.q^c + (u^d - q^c).s$$

The Hydropower plant generation (u^d) is the dispatch of flexible portion, as

$$u_d = u/H$$

Where u is the dispatch and H is the hydo capacity system.

The table below depicts the Power Utility's net revenue as a function of its contracted capacity (q^c) and also of its flexibility (q^f) for the Thermopower Utility.

Tab.1: Utility's Net Revenue (extreme cases)

q^c	q^f	Thermopower	Hydropower
1	0	P - c	-
1	1	P – s + (s - c).g/G	P – s(1-u/H)
0	0	s - c	-
0	1	(s - c).g/G	s .u/H
g^d, u^d	1	(P - c).g/G	P.u/H

The equations below summarize the instantaneous net revenue r^y_{zt} and the expected revenue R^y_{zt}, for a given set of parameters ψ = (q^f,q^c,ψ*,P), where ψ* are COD model parameters determined and ρ* is the appropriated discount rate:

$$r^y_{zt} = P.q^c + s^y_{zt}\ (1 - q^f + q^f\ g^y_{zt} / G^y_t - q^c) - c_{zt}.(1 - q^f + q^f.\ g^y_{zt} / G^y_t\ ) \text{ .... (Thermopower)}$$

$$r^y_{zt} = P.q^c + s^y_{zt}\ (u^y_{zt} / H^y_t\ - q^c) \text{ .... (Hydropower)}$$

$$R^y_{zt} = r^y_{zt} + \rho * \sum_{z*\in Z*} R^y_{z*t+1}\ .\pi(z*,t+1|u_{zt},z,t,\psi)$$

2.2.2 The Investment Option Valuation

For each type of power plant, and for each pair of scenario (z), and time period (t), the investor calculates the option value $\tilde{O}^y_{zt}$ and decides whether to keep the option alive, delaying the investment, or to exercise it, realizing the investment (paying the exercise price), in which case the investor would receive the future revenue, estimated by its expected value ($R^y_{z,t}$).

The option value at each time period is the highest value between investment's expected Net Present Value ($R^y_{z,t}$ - k_t) and the value of postponing the investment, keeping the option alive, and receiving the corresponding interest (ρ* $\tilde{O}^y_{z,t}$):

$$O^y_{z,t} = max[\, R^y_{z,t} - k_t,\ \rho * \ E\{\tilde{O}^y_{z,t+1}\}\,] \ \ \forall t, \forall z$$

$$\text{where: } E\{\tilde{O}^y_{z,t+1}\} = \sum_{z^* \in Z^*} O^y_{z^*,t+1}\ \pi(z^*, t+1 \mid u_{z,t}, z, t, \psi)$$

Dynamic Programming, using the following boundary condition, for the final period, can solve this recursive Bellman equation:

$$\tilde{O}^y_{z,T} = max\ [\, R^y_{z,T} - k_T,\ 0]$$

This investment option corresponds to a multi-stochastic American call option. Its exercise is optimal when it is deep in the money ($R^y_{zt} - k_t > \rho * \tilde{O}^y_{zt}$):

- $I^y_{zt} = 1$ if $R^y_{zt} - k_t > \rho * \tilde{O}^y_{zt}$
- $I^y_{zt} = 0$ otherwise

Where I^y_{zt} is the investment exercise indicating variable

The proportion (p_t) of states at time "t" when the option would be exercised is a relevant measure of how effective is the regulatory policy for inducing investments on power generation. For instance, if p_t is zero, the regulation is so adverse that no investments would occur in that time period in any of the possible scenarios. If $p_t = 1$, the regulation is so attractive that the investments would occur on every possible scenario.

The seasonality of the power demand and affluence affects the proportion p_t, and therefore insets a bias towards a particular period regarding the investment committing. Since the regulatory policy should not rely on a particular period, we have defined p_t as the higher proportion of scenarios that the investment would occur during a period of one year (moving average):

$$p^y_t = \max_{i \in [1,12]} \{ \textstyle\sum_z I^y_{z,t+i} / N_z \}$$

3 Results

We have run a test case for a Thermopower plant, using natural gas on combined cycle, with an efficiency of 7000 MMBTU/MWh, supposing the natural gas price = 2.9 US$/MMBTU, thus having an operating cost of US$ 22/MWh, including a non-fuel variable cost of US$2/MWh[17]. The investment amounts to 650 US$/kW, with an opportunity cost (discount rate) of 15% / year. This Thermopower plant would have a 90% load factor.

The following sections show the effect of the Energy Deficit Cost (β), and of the long-run contracts price (P) on the investment attractiveness, i.e., on the proportion of scenarios "p(P,β)" when the investment would be committed during the first year of the planning horizon, considering three different types of economical uncertainties.

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[17] Operational cost = 2.9 US$/MMBTU * 7000MMBTU/MWh + 2 US$/MWh = US$22.3/MWh

3.1 Effect of Energy Deficit Cost (β)

The influence of β on the attractiveness of the investments is more pronounced when all produced energy is sold on the spot market and the System is under an energy deficit situation, or when it is very likely. Therefore, we have studied the case where the Thermopower Utility operation is 100% flexible ($q^f = 1$), and both the Thermopower and the Hydropower would sell all produced energy on the spot market ($q^c = 0$).

The results are parameterized according to the expansion degree (λ),described in section 2.2. When λ = 1, the system is balanced, i.e. the supply power generation is equal to the expected demand of energy, and energy deficit probability is ≤ 5%). When λ < 1.0, the system capacity is under the required level and similarly, when λ > 1. Table 2 shows the results for both types of power plants, considering the affluence as the only source of uncertainty. The level of β on January 2001 was US$342/MWh[18].

Tab.2: Option Exercise Proportion (%)

	Thermopower Plant			Hydropower Plant		
β (US$/MWh)	λ = 0.9	λ = 1.0	λ = 1.1	λ = 0.9	λ = 1.0	λ = 1.1
342	23	20	13	15	10	10
684	25	21	18	24	21	18
1368	27	22	19	26	22	19

The results show that:

1. The Energy Deficit Cost (β) is not effective to attract investments, neither on Thermopower nor on Hydropower plants.
2. The system expansion degree, which is a function of the investment level, has a strong influence on investment decision, as 10% variations around the balance situation are equivalent to 100% variation on Energy Deficit Cost.

3.2 Effect of the Normative Value

The effect of the Normative Value upon the investments can be observed by inspecting the critical (minimum) long-run energy price (P_c) required for the exercise of the investment option and comparing to its current value to check how effective is it to attract new investments. The simulations were done setting the Energy Deficit cost (β)on the current level of January 2001(≈US$342/MWh).

Table 3 shows the critical (minimum) long-run energy price P_c required for immediate investments in Thermopower plants. Three uncertainties combinations were considered: the “Standard”, adopted on the model currently being applied for the COD, supposes that affluence is the uncertainty; in the “Fuel” model both affluence and natural gas price are uncertain; and finally, in the “Demand” model both affluence and the energy demand are uncertain. The results are shown for a balanced system (λ = 1).

Tab.3: Critical Price (P_c) for a Thermopower Plant - (US$/MWh)

q^c	q^f	Revenue	Standard	Fuel	Demand
1.0	0	P – c	38	53	38
1.0	1	P - s + (s - c).g/G	39	54	46
0.5	1	0.5(P - s) + (s - c).g/G	54	69	57
g^d	1	(P - c).g/G	66	81	> 100

[18] R$684/MWh, US$1.00 ≈ R$2.00

The results show that:

1. The lowest critical price (US$38/MWh), for a fully inflexible operation, fully contracted revenue and considering the affluence as the only economical uncertainty, is roughly equal to the current Normative Value (US$38.69/MWh).So the current policy does not prompts the Thermopower Utilities to deal in the spot market and have a flexible operation. These consequences depress the energy market and system efficiency.
2. The highest critical prices occur when the contracted energy is equal to the dispatched generation, showing the revenue uncertainty burden for the Utility.
3. The second lowest critical price (US$39/MWh) is almost equal to lowest one, and occurs for a fully flexible, fully contracted revenue. The only difference between this case and the one with the lowest critical price, is the flexibility level, showing that the Utility's operation flexibility does not affect the critical price, and that the long term contracts effectively hedge the Utility exposition to the spot price.
4. As the Utility increases its exposition to the spot price, the critical price required to commit the investment also increases.
5. The uncertainty in natural gas price ("Fuel" model) increases the critical prices. The first line of Table 3 shows an increase of 40% comparing to case 1.
6. The uncertainty on demand ("Demand" model) increases the critical price for the flexible operation mode. The second line of Table 3 shows an increase of 18% comparing to case 1.

Table 4 shows the critical long-run energy price P_c required to have immediate investment in Hydropower plants, considering the affluence as the only source of uncertainty and a balanced system (λ=1). The results are presented for several investment cost levels (α), compared to a Thermopower plant with same capacity for the "Standard" model case.

Tab.4: Critical Price (P_c) for Hydro Plant - (US$/MWh)

q^c	$\alpha = 2$	$\alpha = 3$	$\alpha = 4$	Thermopower "Standard" model P_c
1	117	141	166	39
0.5	85	133	182	54
$u^d \vert g^d$	63	94	126	66

Table 5 present the Hydropower / Thermopower investment cost ratio (α) that would lead to the same critical price (P_c).

Tab.5: Hydro Plant investment compatible to the thermal P_c

q^c	$P_c^{Standard}$	$\alpha \mid P_c^{Standard}$	P_c^{Fuel}	$\alpha \mid P_c^{Fuel}$
1	39	<1	54	<1
0.5	54	1.4	69	1.7
u^d	66	2.1	81	2.6

The results show that:

1. The Hydropower / Thermopower investment cost ratio (α) increases with the uncertainty of the revenue, i.e., it increases when the contract level (q^c) decreases and also when economical uncertainties as "Fuel" model are considered.

2. Considering the contract level as one ($q^c = 1$), Hydropower is not competitive related to Thermopower, since is very unrealistic that the Hydropower cost is less than the Thermopower one. For that case Table 4 shows that a critical price P_c for Hydropower is about three times the Thermopower one
3. The "spot market adjustment portion" can be viewed as a hedge mechanism that benefits the Thermopower but not the Hydopower.

According to the Brazilian Power System Expansion Plan for the 1999/2008 decade, the planned Hydropower plants have a Hydropower / Thermopower investment cost ratio (α) between 2 and 4. Therefore, for the current electrical system conditions, we can conclude that the planned Hydropower plants are not competitive, since they would require a higher Normative Value than the Thermopower plant to attract investments.

3.3 Effect of the Natural Gas Price Uncertainty

The current policy[19] has established a natural gas supply policy and a Tariff adjustment , which eliminate both the exchange rate (US$/R$) risk and the Natural Gas price uncertainty for the Thermopower plants that shall go into in operation until June 2003[20].

Since the time to build a typical Thermopower plant is around 2 years is about the time yet left[21] for the expiration of this benefit, there is not option to delay the investment, and the decision shall be taken based only on the Net Present Value (NPV), i.e., the investment would be realized in the scenarios that would yield a positive NPV.

The regulation effectiveness regarding the investment attraction can be assessed by the Critical Price required for immediate investment in three cases: A) affluence and natural gas cost (price and exchange variation[22]) are uncertain; B1) only the affluence uncertainty is considered; and B2) affluence and demand uncertainty are considered. The results are shown on Table 6, considering the current (as of January 2001) Energy Deficit cost (≈US$342/MWh).

Tab.6: Critical Price (US$/MWh) X Uncertainties

q^c	q^f	Revenue	A	B1	B2
1.0	0	P - c	49	39	39
1.0	1	P – s + (s - c).g/G	58	40	40
0.5	1	0.5 (P - s) + (s-c).g/G	63	53	53

The results show that:

1. The new natural gas supply policy (B1) reduces the critical price required to realize the investment between US$10 and US$18, when compared to the case when the Natural Gas price is uncertain (A)

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19 Regulation MME/MF/nº 176, June 2001

20 This benefit is part of a set of government actions to overcome the undergoing energy shortage.

21 As of December 2001.

22 The uncertainty coming from the exchange rate was considered by increasing in 10% upon the natural gas price uncertainty. This is a simple way to consider the exchange rate risk. Actually, the exchange rate risk is not symmetric and a jump diffusion process would model it more accurately.

2. The new policy (B1) yields a critical price (US$39/MWh) that is roughly equal to the current Normative Value (US$38,69/MWh), when the production is fully contracted ($q^c = 1$). So, for investment on the studied Thermopower plant, the current policy would be effective only in this case.;
3. As for the other cases, because the Critical Price (P_c) is greater than the current Normative Value, the investment will not be granted in all scenarios. However, the investments will take place for the current situation of almost energy deficit. In the cases of fully contracted production ($q^c = 1$), lines 1 and 2 of Table 6, the investment would be committed in 53% or 20% of the scenarios, respectively, including those scenarios representing the current level of the energy storage. The uncertainty on the demand of energy (B2) does not change these results.

4 Conclusions and Final Remarks

The results found in this study must be seen with caution. The hypothesis made about the parameters, the stochastic process specifications and estimates are relevant issues. Nevertheless, it provides some useful insights:

1. A regulation policy based only on as increase on the Energy Deficit Cost is not effective to attract the required investments in power generation;
2. Under the current policy, regarding the Natural Gas price variation compensation, the investment in Thermopower plants seems to be feasible. This policy has reduced the Critical Price (P_c) that turns out to be roughly equal the current Normative Value (US$38.69/MWh);
3. Under a non-compensation for fuel price variation policy, the Normative Value shall be higher, as this study has indicated a minimum value of US$ 46/MWh, for flexible operation and considering the demand uncertainty;
4. An agent totally exposed to the spot market, i.e., without long term contracts to sell its production, is vulnerable to the system shortage degree that is subject to other investors actions.
5. The flexible operation of Thermopower plants does not increase the critical price, and optimizes the system operation. The revenue uncertainty can be hedged by long-term contracts;
6. As of the current conditions of energy system status and Regulatory Policy, the Hydropower plants are not competitive to Thermopower plants, since they require a higher long-run energy price to attract investment
7. The Normative Value shall match the Critical Price required for immediate investment.

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Appendix : The Centralized Optimal Dispatch Model

The optimal dispatch is determined using the standard algorithm of dynamic programming explained on Bertsekas(1995) known as “Recourse Problem” which derives for each states and period of time the optimal dispatch and the marginal cost of system operation.

Our model is different related to the model used by the Brazilian Integrated Power System Operator is based on Pereira (1989); Pereira, Oliveira,Costa, Kelman (1984); Pereira, Pinto (1985), which apply the “Wait and See” approach[23] and do not deal with others economical uncertainties except the hydrological one.

Assuming that:

- The affluence (a_t) follows the mean reverting process described in eq.A2, with long-run mean $\bar{a}_t$, representing the long-run affluence at time t, with the drifit seasonally adjusted;
- Natural gas price (c_t) follows the mean reverting process represented by eq.A3 with long-run price $\bar{c}$;
- The demand for energy (d_t) follows standard geometric brownian motion described by eq. A4, and the drift rate is seasonally adjusted.
- Hydro-electrical balance eq. A5 is the sum of the energy volume (v_t) stored in reservoir with the difference between seasonally affluence adjustment and the total hydro dispatch (u_t) and the overflowing amount (v_t).
- According to eq.A10, the demand for energy (d_t) is supplied by the sum of the optimal hydro and Thermopower dispatch, (u_t) and (g_t). The excess of demand is supplied by the dispatch (f_t) of a hypothetical Thermopower plant of infinite supply capacity and operational cost (β) times higher than the usual Thermopower plant.
- The maximum Thermopower and hydropower supply G_t and H_t respectively.
- The maximum capacity of energy stored in reservoir is Vt.

The optimal dispatch problem is to determine the hydro and Thermopower optimal dispatch at each time and for each state, $\{u\}=\{u_1(z_1), u_2(z_2),..... u_T(z_T)\}$, in order to minimize the system operation cost W_{zm}.

$$W_{zm} = \text{Min}_{\{u\}} \sum_{t=m}^{T} E_t \{w_{zt}(u_{zt})\} e^{-rt} \quad \forall z \in Z$$

[23] The “ Wait and See” approach determines the optimal dispatch and the associated variables for each stochastic process realization. The optimization procedure is performed for each realization and the optimal dispatch is calculated as an average. To better details about the differences between this approach and the one known as “Recourse Problem” see Birge and Louveaux (1997), chapter 4 first paragraphs.

Subject to:

$$w_{zt}(u_{zt}) = c_{zt}\,(g_{zt} + \beta.f_{zt}) \quad \text{(A1)}$$

$$\Delta a_{zt} = \varphi(\bar{a}_t - a_{zt-1}) + \sigma_a\, e_a \quad e_a \sim N(0,1) \quad \text{(A2)}$$

$$\Delta c_{zt} = \eta(\bar{c} - c_{zt}) + \sigma_c\, e_c \quad e_c \sim N(0,1) \quad \text{(A3)}$$

$$\Delta d_{zt}/d_{zt} = \mu + \sigma_d\, e_d \quad e_d \sim N(0,1) \quad \text{(A4)}$$

$$\Delta v_{zt} = (a_{zt}\, S_{a(t)} - u_{zt} - x_t) \quad \text{(A5)}$$

$$0 <= u_{zt} <= \mathrm{Min}\{v_{zt}, H_t\} \quad \text{(A6)}$$

$$0 <= g_{zt} <= G_t \quad \text{(A7)}$$

$$0 <= f_{zt} \quad \text{(A8)}$$

$$0 < v_{zt} < Vt \quad \text{(A9)}$$

$$d_{zt}\, S_{d(t)} = u_{zt} + g_{zt} + f_{zt} \quad \text{(A10)}$$

$w_{zt}(u_{zt})$ is the instantaneous system operational cost given the state $z=(v,a,d,c) \in Z$, for each time t, u_{zt} is the control variable representing the hydro-electrical dispatch and r represents the inter-temporal discount rate.

In this stochastic optimal control problem, variables such as Thermopower optimal dispatch (g_{zt}), the proportion of energy supplied on deficit situation (f_{zt}) and the overflow level x_t can be determined by the hydro-electrical optimal dispatch (u_{zt}).

Table bellow presents the parameter estimates

Thermopower operational cost	US$22.3/MWh
σ_c: Natural gas price Std.Dev.	15
η: Speed reversion coefficient for natural gas price	0.86
σ_a: Affluence Std.Dev.	87
φ : Speed reversion coefficient for affluence	0.11
μ : Demand drift rate	6% p.a.
σ_d: Demand Std.Dev.	3.5% p.a.
r : discount rateo	10% p.a.
T : planning horizon	10 years