Seventh LACCEI Latin American and Caribbean Conference for Engineering and Technology (LACCEI'2009)
"Energy and Technology for the Americas: Education, Innovation, Technology and Practice"
June 2-5, 2009, San Cristóbal, Venezuela.

Design of Ideal Power Systems

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ABSTRACT

This paper is inspired in the concept that an electrical power system can be designed ideally, following a function that relates all the decision variables in the same domain, only constrained by a set of restrictions, that could be reached by using an integral AC optimal power flow, knowing the demand to supply and the availability of primary energy resources. A mathematical model is proposed to take into account aspects of reliability, quality, environment, and cost that all applied on a power system model, define the design of an optimal system. A prototype tool has been developed and already used in some scenario exercises of the Venezuelan National Grid, revealing its potentialities in the conjoined generation and transmission expansion planning.

Keywords: Planning, OPF, Expansion, Reduced Gradient, Marginal Cost

1. INTRODUCTION

There is a broad spectrum of problems in an electrical power system that can be solved taking the concept of an ideal system as theoretical frame. An integral expansion planning is one of them, where the generation and the transmission systems must be harmonically complemented. An integral AC optimal power flow (IOPF) is introduced herein as a special variation of an OPF where the objective function includes both investment and operation costs. On this comprehensive optimisation, the equations have been adapted to the real problem in AC so that the physical laws are satisfied fully and not approximately as in DC power flows. Furthermore, reliability, quality, environment and cost criteria complying with the regulation and other policies could be considered in the final design. The aim is to obtain an adequate power system, so flexible as to face with the unforeseen, that allows supplying reliable and economical electricity of good quality on the sensible basis of sustainable use of natural resources.

One of the challenges of this approach may be finding an optimal solution that already considers the basic requirements for power system stability apart from the others. Traditionally, this feature is only studied after selecting a final design by means of complex simulations. The results of these additional analyses could cause modifications in the original chosen design and make it move away from the optimum.

Although power system stability implies phenomena of different nature (IEEE/CIGRÉ, 2004), the steady-state stability (as representative of rotor angle stability) could be considered in the optimization problem by formulating angular restrictions to the nodal voltages as first step. Voltage phase angle criteria require, however, being studied deeper.

Additionally, the need of reactive compensation can be also included in the integral formulation of the optimisation problem.

As an ideal power system is a future system by nature, the intrinsic uncertainties related to the electrical demand and the primary energy resources availability must be sorted out in order to maintain its effectiveness. This is out of the scope of this work though.

Instead, a suitable statistic model of the hourly curves of demand for each load substation can be implemented with no major difficulty, preserving the validity of the proposal on a deterministic approach.

The use of ideal power systems in the expansion planning could ease the definition of not only the horizon scenario but the development stages.

2. DEFINING AN IDEAL SYSTEM

The proposed ideal system concept has the particularity of always being within the limits of what is achievable. It is not utopia because it takes into account the existing elements of the real current system, the supplies of primary energy and the other restrictions of the problem, including the geographic elements. All this is considered to find the better possible system in agreement with the established objective function. The solution of the involved optimisation process could be called *Target System*.

If the equations for solving the problem are complete, and all restrictions are covered, an objective function that represents the global costs could be adequate. Thus, the *Target System* is the one that fulfils all conditions imposed at minimum cost.

The *Target System* is a feasible network since it was built from the current grid, overseeing the future, and taking into account the energy availabilities.

3. PRIMARY RESOURCES AND LOAD DEMAND

The dynamic development of a power system pretends to guarantee all the time that the grid can produce and take the energy from the place where it is generated to the place where the load demand exists. These locations, simplified into two sides: Primary Resources and Load Demand, are not so flexible, therefore, they have an important impact in the spatial power system expansion, not to mention, in the size and technical characteristics. There are few aspects to optimise with regard to primary sources and load demand when planning the power system expansion.

The exploitation of primary resources with potential for producing energy depends on the location where they exist naturally amid other factors. In so cases, it is possible to generate energy far from the main resources are (e.g. fossil fuels) but a new variable must be included: the transport, which alters the cost structure significantly. Conversely, hydroelectricity is more attached to the place where the dam or water reservoir is. That is the particular case in Venezuela, where about 70% of the total electrical energy is provided by the set of cascading hydro power centrals in the Caroní river basin, located in the south-east while the main load sinks are 1,000 km far in the north-west. Not in vain, the Venezuelan National Grid has long corridors at voltage levels as high as 765 kV. With load and generation sites so differentiated, in the past, the expansion of the Venezuelan National Grid was focused only on the addition of new transmission lines.

Load centres are close related with the social and economic development. Load forecasting is vital for the power system planning. In the last decades, only with the expected maximum load in a year, the planner built scenarios under conservative approaches, but today, other aspects are available as the location and the consumption pattern. Local demand at substation node is provided on the hourly, daily, monthly, and yearly basis. In fact, the total demand of an electrical area could be obtained as an hourly aggregation of the local demand for all the load nodes of such an area without applying adjusting factors.

In summary, primary resources and load demand can be considered as inputs for the optimal power system expansion problem.

4. PUBLIC POLICIES AND DESIGN CRITERIA

The Regulation conditions the power system expansion to certain extends since the main criteria must be agreed before planning. Spinning reserve, objective power factor, voltage limits, power transfer limits, quality of service, security reactive power, etc, are some of the many design factors that planners expect to be well defined by the regulator. Equally important are the policies for fuel, environment, primary resources, efficiency, renewable energy, technology, tariffs, and the economic regime.

A *target system* must consider all these public policies and criteria. In fact, they are inputs for the optimal power system expansion problem.

5. STANDARD TECHNOLOGY

A power system expansion can be developed by using different generation and transmission technology and with a standard design which has been the result of a long-term strategy. Issues as substation layout, voltage levels, HVDC transmission ties, type of thermal power plant, standard sizes of generation units, standard sizes of transformer units, etc, are part of the inputs for the optimal power system expansion problem as well.

6. PRINCIPLES FOR AN OPTIMAL EXPANSION

An optimal power system expansion should be the balance of four design factors at least as represented in Figure 1. They are: *Security and Reliability* which corresponds to traditional technical specifications of the classic methodology; *Quality of the Electrical Service* which is a current requirement often treated once the power system is in service despite the design could have already considered it; *Environment Protection and Sustainability* which is a global requirement; and *Cost*. Only the latter can be optimised, for the Security, Quality, and Environment should not be negotiable on a rigorous approach.

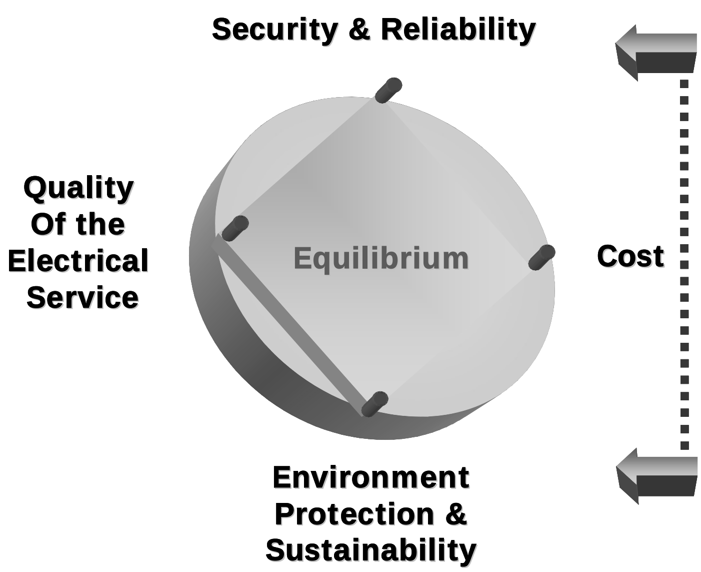

Figure 1: Design Requirements for a Power System Expansion

7. THE INTEGRAL OPTIMAL POWER FLOW

The optimisation problem should be ampler to cover all the aspects involved in the power system design and not only, in the power system operation as in the traditional use of the optimal power flow.

Thus, it is proposed an Integral Optimal Power Flow that takes into account not only the Operations Costs but the Capital Costs of Investments for both Generation and Transmission as shown in Figure 2.

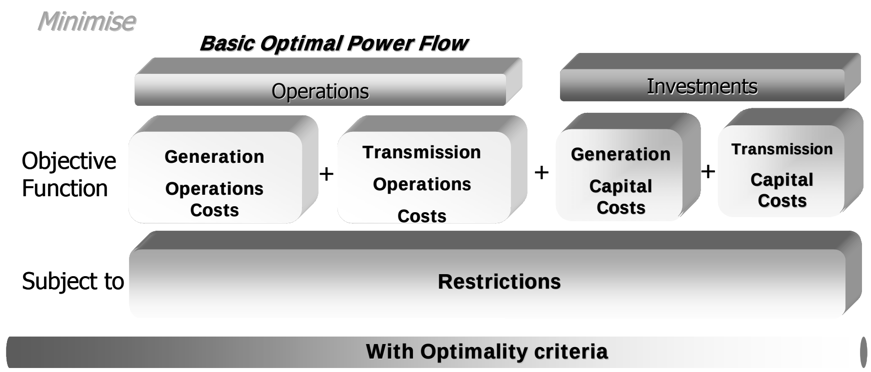

Figure 2: Design Requirements for a Power System Expansion

8. PROBLEM FORMULATION

Such an Integral Optimal Power Flow can be implemented at first, knowing that the operating costs for transmission, as a good approximation, can be considered constant and included in the cost of transmission investment. The Integral Optimal Power Flow could evolve from that of Figure 2 to this of Figure 3.

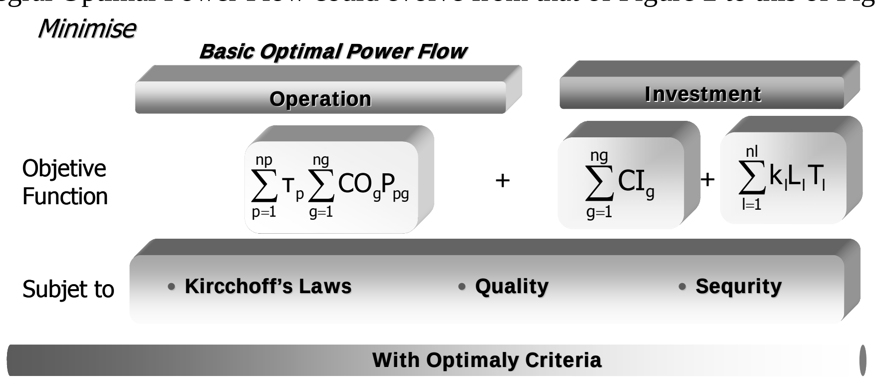

Figure 3: Integral OPF ignoring Transmission Operation Costs

The Operation Costs would be represented by the Fuel Costs of the generation units. The Capital Costs would keep the costs of the new generation plus those of new transmission investments. The current infrastructure the capital of which has been already fully discounted should not contribute in the global costs for optimization.

The formulation is as follows (G. Barreto-Mederico et al, 2006):

$$\mathrm{Min} \sum_{p}^{np} \tau_p \sum_{g}^{ng} CO_g P_{pg} + \sum_{g}^{ng} \frac{k_g}{N} Pm_g + \sum_{l}^{nl} \frac{k_l}{N} L_l Tm_l \tag{1}$$

Subject to:

$$P_{g\min} \le P_{pg} \le P_{g\max} \tag{2}$$

$$Q_{g\min} \le Q_{pg} \le Q_{g\max} \tag{3}$$

$$V_{\min} \le V_{pi} \le V_{\max} \tag{4}$$

$$\delta_{\min} \le \delta_{pi} \le \delta_{\max} \tag{5}$$

$$P_{pg} + \sum Pvin_{pi} - D.Act_{pi} = 0 \tag{6}$$

$$Q_{pg} + \sum Qvin_{pi} - D.Reac_{pi} = 0 \tag{7}$$

Where:

τ_p	Demand block durations
p, g, l, i	Demand blocks, generators, transmission lines, and nodes index, respectively
np, ng, nl, ni	Total number of demand blocks, generators, transmission lines, and nodes, respectively
CO	Unitary operation costs including O&M
P_{pg}	Generator power delivery in each block of demand
N	Numbers of periods in the year according to the demand time scale (e.g.: yearly: N =1; monthly: N =12; daily: N =365; hourly: N =8760)
k_g	Annualized marginal cost for the installation of one KW at one node (US$/kW-year)
Pm_g	Maximum power required of each generator, among all generator power of each demand block
Tm_l	Maximum capacity required of each line, among all line power capacities resulting at each demand block
L_l	Length of each line
k_l	Annualized marginal cost for the construction of one Kilometre of transmission line (US$/MW-Km-year)
P_{min}, P_{max}	Minimum and maximum limits for the active power that can be delivered to the system by each control-active element (e.g. A generator)
Q_{min}, Q_{max}	Minimum and maximum limits for the reactive power that can be delivered to the system by each control-active element (e.g. A generator, a SVS, an area interchange bus)
V_{pi}	Magnitude of the voltage resulting at each demand block (p.u.)
V_{min}, V_{max}	Minimum and maximum limits for the voltage magnitude at each node (p.u.)
δ_{pi}	Phase Angle of the voltage at each node resulting at each demand block (radians)
δ_{min}, δ_{max}	Minimum and maximum limits of the phase angle of the voltage at each node (radians)
$Pvinc_{pi}$, $Qvinc_{pi}$:	Active and reactive power flows resulting at each demand block, of all the links associated with each node, respectively (MW/MVAr)
$D.Act_{pi}$, $D.Reac_{pi}$	Active and reactive power for the load demand at each node for each demand block, respectively (MW/MVAr)

The equations include explicitly the transmission investment costs. On the other hand, the transmission operation costs can be represented either as a constant or as a percentage of such investment costs. Due to the low dependency on the transmission lines power flows, the transmission operation costs are not included explicitly in the function.

In general, incorporating transmission costs to the optimisation problem gives some benefits to the design as follows:

- A balanced distribution of the generation, provided multiple primary energy resources are available in the system
- Losses reduction
- Increase of the system stability

On the side of the generation, the investment and operation costs are also included in the problem formulation. That makes them work as an instantaneous financial analyzer where the decision making by itself is part of the design process. Conversely, the traditional planning methodology considers the financial analysis only after defining a set of expansion options of the power system.

As the investment costs are calculated on the basis of the maximum capacities dispatched among the values obtained in each demand block, a frank competition between operation costs and investment costs of the same equipment is established.

Notice that the power generation obtained in each demand block corresponds to the capacity dispatched, being the maximum of them the installed capacity at the end. The operation costs are accumulative and depend on the capacities dispatched while investment costs depend on the installed ones. These operation costs are related to the energy produced in the whole load curve with a determined amount of fuel.

From long time ago, it is known the relationship between the set of angles of the voltage at any node and the steady state stability of a power system design (Evans, R et al, 1997). Some authors have researched about the possibility to retake the simple stability limit approach for two-node power system to explain more complex situations (Xue, Y. et al., 1994), but this requires deeper studies. However, the inclusion of restrictions to the voltage phase angles in the problem formulation helps evaluating the robustness of the resulting transmission links, and subsequently, the power system stability at a basic level.

9. COST MODEL FOR TRANSMISSION LINES

The costs of transmission are modelled by means of the adjustment of a function that represents the annualized long term marginal cost (ALTMC) for the construction of a kilometre of line referred to its capacity. This function can be as precise as available data of installed lines are. Anyway, only is the part related to costs that varies with the transmission capacity required (G. Barreto-Mederico et al, 2006). Figure 4 shows a function, fit according to the costs of transmission lines in the Venezuelan National Grid. The function was built using data for lines at different voltages, something that could be very useful later for inferring the adequate voltage level for a new transmission link.

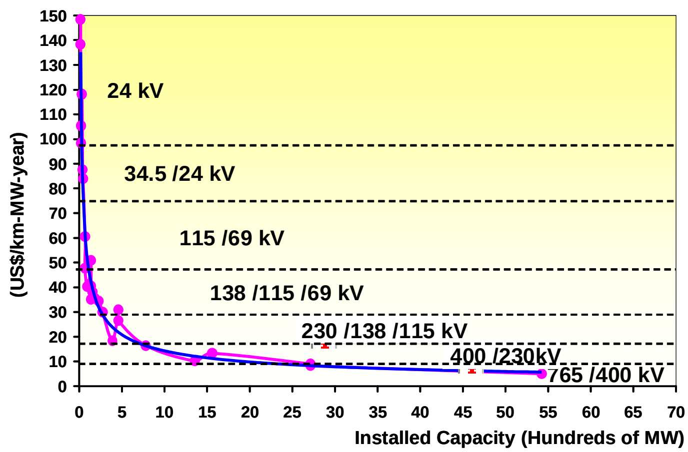

Figure 4: Annualized Long Term Marginal Cost per length unit (ALTMC) for Transmission Lines.

10. MODEL FOR GENERATION COSTS

The generation costs represent the cost derivative of all generation equipment participating in the optimisation process. Each generation unit can have two cost functions: one associated to the necessary investment for its installation in certain locality, and the other, related to the fuel consumption. The variable costs for operation and maintenance should be added to all this.

10.1 INVESTMENT COSTS

The greater installed capacity is, the lower marginal cost is. This reveals the presence of economy of scale in the generation investments. The example of Figure 5 shows the behaviour of the generation long-term marginal costs (GLTMC) for gas turbines in both open cycle (OCGT) and combined cycle (CCGT) according to data collected from Gas Turbines World Handbook Magazine, 2004-2005, 206.

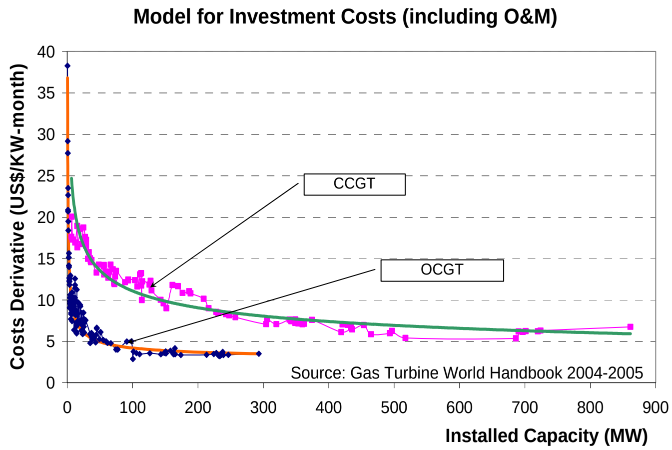

Figure 5: Generation Long Term Marginal Costs (GLTMC).

The marginal cost trend of Figure 5 would lead to concentrate generation in great blocks in opposition to the dispersion effect that would impose the participation of transmission costs in the optimisation function. This is an advantage of the conjoined generation and transmission expansion approach. The optimal expansion must result from the equilibrium between generation and transmission.

10.2 OPERATION COSTS

Although the model is similar to that of the investment costs, the calculation of the operation costs is variable according to the power dispatch for each demand block. The variability of fuel costs in the time scale could introduce uncertainty in the results though.

Figure 6 shows an example of the behaviour of the operation costs for OCGT and CCGT in the horizon year 2020 with a scenario of natural gas at a cost of 2.39 US$/MMBTU. Depending on the fuel cost, a generation technology could be more or less convenient.

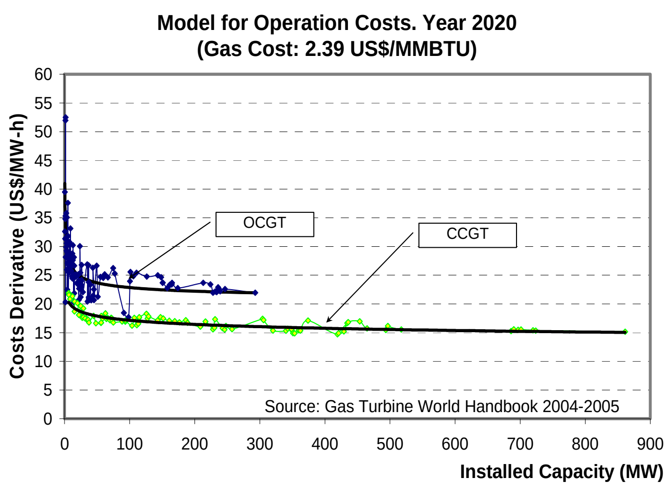

Figure 6: Short Term Marginal Cost (STMC) for Generators.

11. ELECTRICAL AND ECONOMIC SIGNALS

Depending on the optimization solving method, sensitivities and other indicators are provided. The correct interpretation of these signals, which could have either an economic origin or an electrical one, could guide the decision making process when planning a power system expansion.

Two of these signals are: *Reduced Gradients* associated to the movement of the State variables, and *Local Marginal Costs*, related to the problem restrictions (Rau, Narayan S, 2003).

In the process for designing an optimal power system expansion, sensitivities to active and reactive power injections, and to voltage magnitudes and phase angles, are of the type of reduced gradients. During the convergence, these variables could change to a condition of "binding" after reaching a bound of the solution region. In such a case, sensitivities are tripped indicating with their sign and magnitude how the modification of this bound would impact in the objective function. For example, in the case of global costs minimisation with a maximum limit for a generation offer in "binding" condition, a negative sensitivity would indicate the convenience of generation increment at that node since the objective is the reduction of costs.

Sensitivities to restrictions at nodes (i.e Kircchoff's laws) or any active and reactive power flow balance at a particular node are representative of the type of Local Marginal Costs. For example, for the same case of costs minimisation, Load demand marginal cost would represent the variation of the global costs with an increment of the load demand at that node.

In summary, the reduced gradients are useful for new generation sitting and sizing while marginal costs can be used for the process of creating new links. It has been found that joining a node with higher load demand marginal cost to another with lower cost reduces the marginal cost of the first one, provided the building of the associated link is feasible. In fact, a convergence criterion for links addition in a power system expansion could be based on reaching the same nodal costs in all the nodes. There may be no reason to join two nodes if they have the same marginal cost.

Table 1 shows the sensitivities to active power balance at all the nodes in the Mid-Eastern power system of Venezuela.

Table 1: Sensitivities to the Nodal Active Power Balance in the Venezuela Mid-Eastern Power System without any expansion

Node	Active Power (MW)	Sensitivity ($/MWh)
P.E.Z._115	10.00	25.22
P.E.Z._230	0.00	25.35
CAMATAGUA_115	23.12	27.17
SOMBRERO II_115	28.00	27.95
S.J. MORRO_230	0.00	28.06
S.J._MORROS_115	125.00	28.09
S_GERONIMO_115	39.71	28.64
ARAGUA_230	0.00	28.64
La_Horqueta_230	0.00	28.64
S. TERESA_230	0.00	28.64
S_GERONIMO_230	0.00	28.64
S_TERESA_115	161.31	28.68
ARAGUA_115	113.24	28.77
VICTORIA_115	58.60	28.96
El_Mácaro_230	0.00	29.00
VICTORIA II_230	0.00	29.08
R_CHICO II_230	0.00	29.11
V_CURA_II_115	108.79	29.22
P_NEGRO_115	60.31	29.23
VA_PASCUA_115	114.12	29.23
SOCO_115	85.54	29.41
VI_CURA_115	98.27	29.55
CAGUA_115	137.40	29.56
R_CHICO II_115	0.00	29.61
R_CHICO I_115	70.70	29.65
CABRUTA_230	0.00	29.69
MARIPOSA_115	56.18	29.77
CABRUTA_115	32.74	29.78
TACARIGUA_15	21.93	30.07
CAUCAGUA_115	64.99	30.09
ALTAGRACIA_115	17.88	30.34
TEJERIAS_115	67.39	30.64
HIGUEROTE_115	65.12	30.83
L_PIJIGUAOS_230	0.00	31.67
L_PIJIGUAOS_115	26.87	31.84
P_AYACUCHO_115	77.30	37.23
CALABOZO_230	0.00	39.35
CALABOZO_115	93.23	40.06
S_FERNANDO_230	0.00	43.43
GORRIN_115	16.08	44.11
S_FERNANDO_115	178.11	44.25

Table 1 has been sorted from the higher sensitivity to the lower one. It is less costly to increment the generation in PEZ 115 kV than to do it in the node San Fernando 115 kV according to these values. If it were possible, the building of a link between these nodes could make lower the cost difference, and even reduce the global costs in spite of adding new investments; however, it does not look feasible geographically, much less economically, joining the end nodes PEZ 115 kV to San Fernando 115 kV but others with a great cost difference between them, as shown in the frequency distribution of Figure 7.

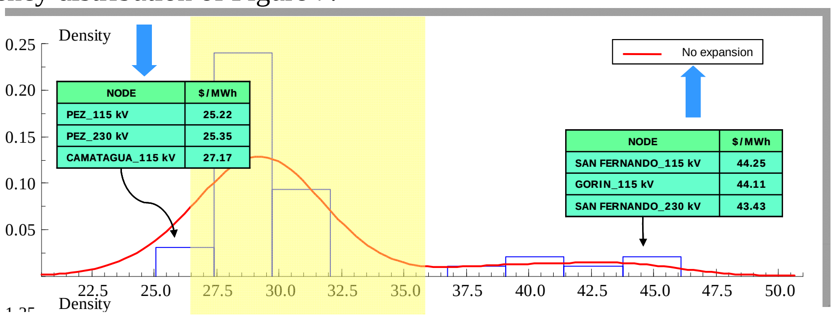

Figure 7: Frequency probability distribution of the sensitivities to nodal Active Power Balance in the Venezuela Mid-eastern power system.

Planner can be guided by these signals combining the real physical limitations up to find gradually a convenient transmission expansion, as the example of Figure 8, where it was possible to propose a link between the nodes El Sombrero II 115 kV (27.95 US$/MWh) and Calabozo 115 kV (40.06 US$/MWh).

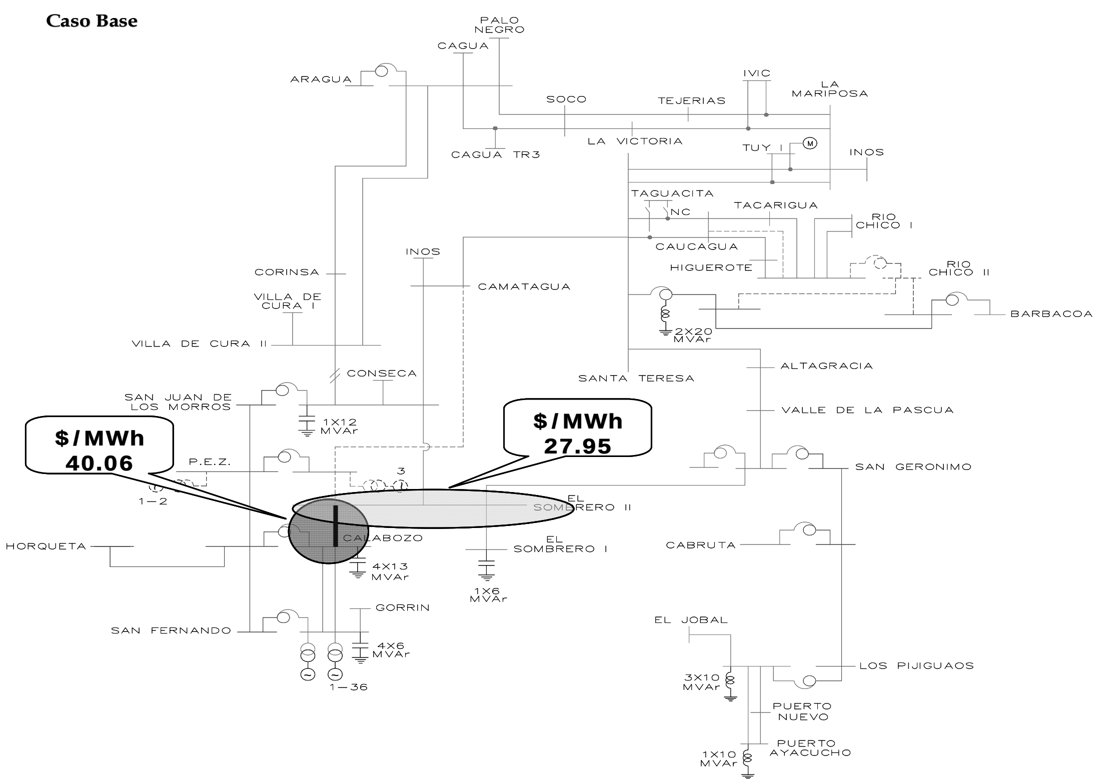

Figure 8: Addition of a new link between El Sombrero II 115 kV and Calabozo 115 kV following the sensitivities to nodal Active Power Balance in the Venezuela Mid-eastern power system.

The addition of a new link reduced the global costs of the system from 30.82 US$/MWh to 29.59 US$/MWh as a consequence of an integral optimisation that takes into account the impact of the transmission on the generation as shown in Table 2.

Table 2: Reduction of global costs when a new line El Sombrero II – Calabozo 115 kV is added in the Venezuela Mid-Eastern Power System

	No Expansion		With a New Link	
	US$/h	**US$/MWh**	**US$/h**	**US$/MWh**
Operation Cost	36,602.92	18.75	34,243.82	17.54
Generation Capital Cost	22,141.38	11.35	21,898.25	11.22
Generation Total Cost	58,744.30	30.10	56,142.07	28.76
Transmission Total Cost	1,403,39	0.72	1,614.42	0.83
Power System Total Cost	**60,148.99**	**30.82**	**57,756.49**	**29.59**
Losses	51	144	60	53

12. CONCLUSIONS

In this paper, it has been presented the fundaments of a new planning methodology for expanding progressively a power system towards an ideal system by using an integral optimal power flow that takes into account the generation and transmission system at the same time, considering both the capital costs and the operation costs. The analyses of the sensitivities, product of the process of convergence, can guide the planner to devise the most adequate expansion, capable to reduce with investment the global costs of the power system.

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