# A Model to Long-Term, Multiarea, Multistage, and Integrated Expansion Planning of Electricity and Natural Gas Systems

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***Abstract*—A long-term, multiarea, and multistage model for the supply/interconnections expansion planning of integrated electricity and natural gas (NG) is presented in this paper. The proposed Gas Electricity Planning (GEP) model considers the NG value chain, i.e., from the supply to end-consumers through NG pipelines and the electrical systems value chain, i.e., power generation and transmission, in an integrated way. The sources of NG can be represented by NG wells, liquefied natural gas (LNG) terminals and storages of NG and LNG. The electricity generation may be composed by hydro plants, wind farms, or thermal plants where the latter represent the link between the gas and the electricity chain. The proposed model is formulated as a mixed-integer linear optimization problem which minimizes the investment and operation costs to determine the optimal location, technologies, and installation times of any new facilities for power generation, power interconnections, and the complete natural gas chain value (supply/transmission/storage) as well as the optimal dispatch of existing and new facilities over a long range planning horizon. A didactic case study as well as the Brazilian integrated gas/electricity system are presented to illustrate the proposed framework.**

***Index Terms*—Electricity systems, natural gas systems, operation and expansion planning of electricity systems, operation and expansion planning of natural gas systems.**

## NOMENCLATURE

*Indexes*

| | |
|---|---|
| $i, j, t, s$ | Index to subsystems, projects, stage of planning, and loads-block. |
| $S, T, I$ | Total number of loads-block, periods of planning horizon, and number of subsystems. |
| $J_i^G$ | Set of NG/LNG at subsystem $i$. |
| $J_i^{\rm FG}$ | Set of pipelines connected to area $i$. |
| $J_i^{\rm GST}$ | Set of NG/LNG storages at area $i$. |
| $J_i^{\rm UHE}, J_i^{\rm UTE}$ | Set of hydroelectric and no-hydroelectric power plants, respectively, at area $i$. |
| $J_i^{\rm UTE_{gas}}$ | Set of natural gas fired-power plants at area $i$. |
| $J_i^E, J_i^{FE}$ | Set of electricity generation plants ($J_i^E \in J_i^{\rm UHEOUTE}$) and transmission lines at subsystem $i$. |

*Parameters*

| | |
|---|---|
| $r$ | Discount rate in %. |
| $\phi e_{i,j}^t, \phi g_{i,j}^t$ | Annualized investment costs of generation plant project $j$ and NG/LNG supply/storage project $j$ at subsystem $i$ at stage $t$ in (US$), respectively. For existent facilities, this parameter is fixed in 0 US$ if in period $t$ its investment cost was totally recovered. |
| $\alpha e_{i,j}^t, \alpha g_{i,j}^t$ | Annualized investment costs of transmission line and gas pipeline project that connect the subsystems $i$ and $j$ at stage $t$ in (US$), respectively. |
| $\varphi e_{i,j}^t, \varphi g_{i,j}^t$ | Operation costs of electricity generation and gas production $j$ at subsystem $i$ at stage $t$ in US$/MWh and $/$\mathrm{Mm}^3/\mathrm{h}$ (millions of $\mathrm{m}^3\mathrm{h}$), respectively. |
| $\gamma e_{i,s}^t, \gamma g_{i,s}^t$ | Electricity and NG deficit cost at subsystem $i$ at stage $t$, during the load-block $s$ in US$/MWh and US$/$\mathrm{Mm}^3/\mathrm{h}$, respectively. |
| $\mu_{i,j}^t, \nu_{i,j}^t$ | Injection and withdrawal costs of NG/LNG storage $j$ at subsystem $i$ at stage $t$ in (US$/$\mathrm{Mm}^3/\mathrm{h}$), respectively. |
| $ic_{i,j,s}^{\min} ic_{i,j,s}^{\min}$ | Minimal and maximal bounds of injection of NG/LNG $j$ at subsystem $i$, at stage $t$ and during the load-block $s$ in $\mathrm{Mm}^3/\mathrm{h}$, respectively. |
| $wc_{i,j,s}^{\min} wc_{i,j,s}^{\min}$ | Minimal and maximal bounds withdrawal of NG/LNG $j$ at subsystem $i$, at stage $t$ and during the load-block $s$ in $\mathrm{Mm}^3/\mathrm{h}$. |
| $\sigma g_{i,k} \sigma e_{i,k}$ | Loss factor of NG and electricity energy interchange from subsystem $i$ to subsystem $j$ at stage $t$ in (%), respectively. |
| $v_{i,j,s}^0, v_{i,j,s}^{\rm Final}$ | Initial and final volume of NG/LNG at NG/LNG reservoirs in $\mathrm{Mm}^3$, respectively. |
| $v_{i,j,s}^{\min} v_{i,j,s}^{\max}$ | Minimal and maximal bounds of NG/LNG storage infrastructure $j$ at subsystem $i$ in $\mathrm{Mm}^3$, respectively. |

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$pg_{i,j}^{\min} pg_{i,j}^{\max}$ Minimal and maximal bounds of NG/LNG production infrastructure $j$ at subsystem $i$ in $\mathrm{Mm}^3/h$, respectively.

$pe_{i,j}^{\min} pe_{i,j}^{\max}$ Minimal and maximal bounds of electricity production plant $j$ at subsystem $i$ in MW, respectively.

$fg_{i,k}^{\max} fe_{i,k}^{\max}$ Maximal bounds of NG and electricity interchange from subsystem $i$ to subsystem $j$ in $\mathrm{Mm}^3/h$ and MW, respectively.

$\Phi_{i,s}^t$ Duration of load block $s$ at submarket $i$ at period $t$ in hours.

$\mathrm{Clinv}_{i,j}$ Total capital investment of NG or electricity infrastructure $j$ at subsystem $i$ in US$.

$\tau_{i,j}$ NG or electricity infrastructure lifetime in years.

$\mathrm{DG}_{i,s}^t$ NG/LNG demand at subsystem $i$, during the load-block $s$.

$\mathrm{DE}_{i,s}^t$ Power demand at subsystem $i$, during the load-block $s$.

$\rho g_{i,j} \rho e_{i,j}$ Participation factor of NG/GNL supply and power generation plants, $j$, respectively, at subsystem $i$ in %.

$Eh_{i,j}^t$ Mean energy supply to a hydrological mean scenario of hydroelectric power plant $j$ at subsystem during each period $t$ of planning horizon in MWh.

*Variables*

$xg_{i,j}^t$ State on/off (1/0) of NG/LNG supply project $j$, or NG/LNG storage project $j$, at subsystem $i$ during each period $t$ of planning horizon. For new projects, this variable is equal to 1 from the period $t$ which is decided to be built until its lifetime, 0 otherwise. For existent facilities, this variable is fixed in 1 from $t = 1$ until its lifetime, 0 otherwise.

$xe_{i,j}^t$ State on/off (1/0) of generation plant project $j$, at subsystem $i$ during each period $t$ of planning horizon. For new projects, this variable is equal to 1 from the period $t$ which is decided to be built until its lifetime, 0 otherwise. For existent facilities, this variable is fixed in 1 from $t = 1$ until its lifetime, 0 otherwise.

$xfe_{i,k}^t, xfg_{i,k}^t$ State on/off (1/0) of transmission line and gas pipeline project that connect the subsystems $i$ and $j$ at stage $t$. Equal to 1 if project is already built in $t$ and 0 otherwise.

$pe_{i,j,s}^t, pg_{i,j,s}^t$ Electricity energy and gas production of power unit and gas well $j$ at subsystem $i$, at stage $t$ and during the load-block $s$ in MWh and $\mathrm{Mm}^3/\mathrm{h}$, respectively.

$fe_{i,k,s}^t, fg_{i,k,s}^t$ Electricity energy and NG interchange from subsystem $i$ to subsystem $j$ at stage $t$ in MWh and $\mathrm{Mm}^3$, respectively.

$ic_{i,j,s}^t wc_{i,j,s}^t$ Injection and withdrawal of NG/LNG $j$ at subsystem $i$, at stage $t$ and during the load-block $s$ in $\mathrm{Mm}^3/\mathrm{h}$, respectively.

$dg_{i,s}^t, de_{i,s}^t$ Deficit of NG and electricity energy at subsystem $i$, at stage $t$ and during the load-block $s$ in $\mathrm{Mm}^3/\mathrm{h}$ and MWh, respectively.

$v_{i,j,s}^t$ Volume of NG/LNG at NG/LNG reservoirs.

## I. Introduction

THE physical and operative integration between the natural gas and the electricity sectors has sharply increased in the last decade due to the economic and environmental advantages of natural gas when compared to other fossil fuels. Additionally, combined cycle units feature distinct advantages for power generation such as high efficiency, fast response, and shorter installation time. As a consequence, all those attractiveness have encouraged increasing the investments in new gas-fired thermal units by market agents and governments in electricity production [1].

On the other side, abundant natural gas resources in many places, such as United States, Russia, Europe, and Latin America, favored gas-fired generation as a major factor in the overall growth of natural gas consumption. This consumption scenario is likely to keep growing due to the great number of unexplored natural gas reserves, ensuing increasing investments in natural gas infrastructures such as pipelines, compressors, and LNG terminals.

Traditionally, the power generation expansion planning of the electricity sector is defined as the problem of determining *which*, *where*, and *when* new generation/transmission installations should be constructed over a long range planning horizon. The main objective of this optimization problem is to minimize the total investment and operating costs in order to supply the electricity and gas demand following a set of technical criteria. In this traditional concept, the fuel supply at the thermal plants is considered as totally independent. Fuels like coal, oil, and nuclear are used without constraints either in transportation production or in storage. While the assumption of fuel supply adequacy can be accepted for more mature markets such as coal and oil, these assumptions do not hold for natural gas resources, mainly in countries where the gas industry is still at the beginning stage, like Brazil. Consequently, there is a clear interaction between the operation/expansion of natural gas supply/transport and the natural gas power plants operation and expansion, affecting the overall electrical power system operation and expansion and vice versa. In this context, it is very important to study expansion planning models that integrate the physical and economical aspects and interaction of operation and expansion of these two systems [1]–[5].

Several models have been proposed about the expansion planning of power systems based on deterministic criteria [6], [7]–[13]. Some of them deal with the multiarea power generation expansion problem [7], [9], [13]. More specifically, the work presented in [7], proposed by the Brazilian Research Center (CEPEL), formulated the long-term multiarea generation planning (MELP) and applied it to the Brazilian electric sector case. However, they all deal with just the electricity sector.

As for the natural gas sector, the expansion planning models are not abundant. Only a few examples could be mentioned, such as the computational model proposed in [14], which deals with the operation and expansion of natural gas infrastructures in a centralized way. Interesting computational (game-theoretic) complementary models addressing the operation and expansion of natural gas infrastructures under a competitive market environment and applied to Europe and North America were presented in [15]–[19].

Although the centralized approach seems at first sight not compatible with market structures, at least in the network industries, centralized expansion plans still have an important role, even if it is only an indicative one.

Several models appeared in the last years integrating two or more energy infrastructures in order to simulate and study their operation planning [3], [4], [20]–[23]. However, only the work presented in [1] and [24] addresses the issue of expansion (investment) and operation planning while considering multiple infrastructures.

This paper proposes a multiarea, multistage model (the GEP model) that integrates the long-term expansion planning of the electricity and natural gas systems. The presentation will proceed in two stages. Firstly, the natural gas infrastructure is modeled (gas wells, pipelines, gas storages installation, LNG installations, and transport), and the expansion problem is formulated as a multiarea, multistage model, i.e., the GP model. Secondly, an integrated multiarea and multistage expansion planning is formulated for both supply and transmission of gas natural and electricity systems. The consideration of transmission infrastructures and losses is very important to measure the locational operation impact and locational marginal costs impact of the power and gas expansion investment, obtaining more realistic results in both gas and electricity supply chains.

The paper is organized as follows: The proposed formulation of the GP and GEP models is described in Sections II and III, respectively. Section IV presents the numerical results corresponding to the application of these proposed models to a six-node system. Finally, Section V gives the results of the application of the GEP model to the Brazilian integrated gas and electricity system.

## II. Formulation of the GP Model

The GP model is an optimization tool for long-term expansion planning of natural gas supply and transport. It is structured as a long-term, multistage (dynamic), interregional, or multiarea optimization model, resulting in a large-scale mixed-integer programming model.

The supply chain for natural gas begins with producers that extract gas from either onshore, offshore reservoirs, or liquefied natural gas (LNG) re-gasification terminals. The transport of natural gas (NG) from production/supply sites to either storage facilities or directly to the consumption sectors (e.g., residential, commercial, industrial, and power generation) is made through pipelines. Meanwhile, the transport of LNG is typically made through LNG tankers or ships.

Natural gas is usually stored underground, in large storage reservoirs. There are three main types of underground storage: depleted gas reservoirs, aquifers, and salt caverns. In addition to the underground storage natural gas, it can also be stored as LNG which allows natural gas to be shipped and stored in liquid form occupying less volume [25].

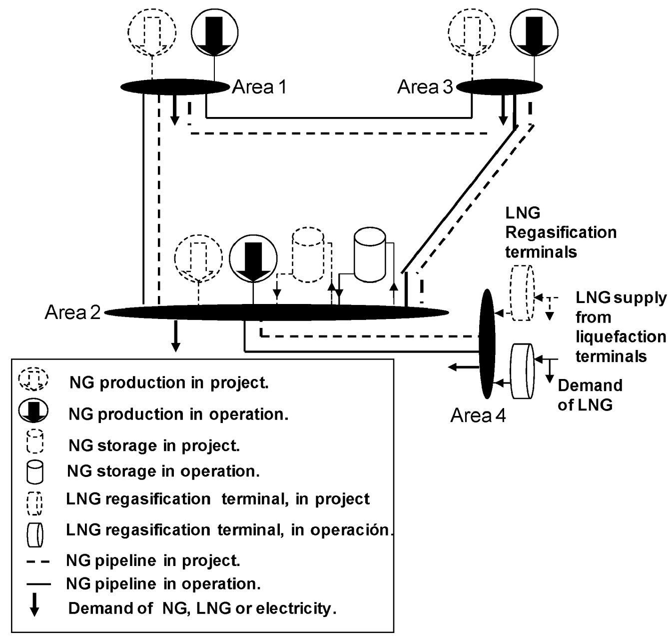



Fig. 1. Example of the expansion/operation of natural gas systems.

Natural gas storage plays a vital role in maintaining the reliability of supply needed to meet the demand of consumers. The storage of NG takes advantage of seasonal arbitrage by storing and injecting gas into storage in the low demand season and then withdrawing (or selling) it to consumers in the high demand season [15]–[18], [25]. For the Brazilian case which is illustrated in the next sections, the NG low demand occurs when there is plenty of water at the hydro-plants reservoirs and high demand when a drought period takes place.

To clarify how the natural gas system expansion planning was modeled in this paper, let us consider the example shown in Fig. 1. It presents areas or subsystems with projected or operational infrastructures such as NG producers, LNG suppliers, and NG storage facilities, usually located close to the load centers (at the area 2 in the example). The NG pipelines are responsible for the NG transportation. For the sake of simplicity, it is assumed that an LNG re-gasification terminal is operated in a similar way as an NG producer and it is continuously being supplied by LNG tankers from its respective LNG liquefaction terminal.

### *A. Modeling the NG and LNG Supply, Storage, and Transport*

The operation of NG production coming from NG wells and LNG re-gasification terminals is modeled in a similar way to a generation power plant, i.e., they have their supply bounded by its maximum and minimum production capacity.

The natural gas or LNG reservoir is illustrated in Fig. 2. Similarly to a water reservoir in a hydroelectric plant, the storage has an initial volume $(V_{O_{i,j}})$, the volume of NG/LNG injection $(ic^t_{i,j,s})$, and the volume of NG/LNG withdrawal $(wc^t_{i,j,s})$ which are constrained by their maximal and minimal bounds and by the maximal $(\mathrm{vmax}_{i,j})$ and minimal $(v\mathrm{min}_{i,j})$ capacity of the NG/LNG storage reservoir. Notice that differently from

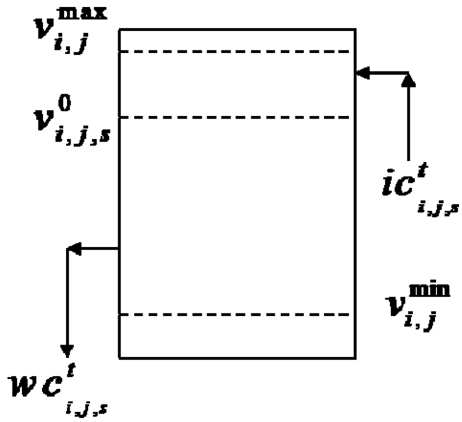



Fig. 2. Representation of natural gas storage reservoir.

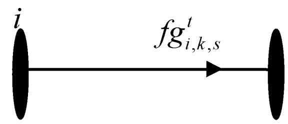



Fig. 3. Representation of natural gas transmission corridors.

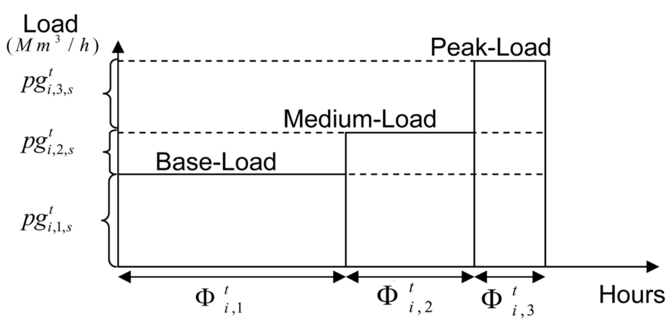



Fig. 4. Representation discretized gas load duration curve.

hydroelectric reservoirs, the injections and withdrawal operations cause injection and withdrawal costs.

The natural gas pipeline is modeled as an undirected arc, because the energy can flow in both directions. Fig. 3 shows an equivalent model where the natural gas flow variable $fg_{i,k,s}^{t}$ can assume both positive and negative values.

### *B. Modeling the Natural Gas Demand and Load Duration Curve*

Natural gas demand in each node of the system is represented through a load duration curve. A load duration curve provides a useful yearly summary (or period) of hourly fluctuations in natural gas demand. The discretized load duration curve shown in Fig. 4 divides the load demand into base-load, medium-load, and peak-load demands.

$pg_{i,1,s}^{t}, pg_{i,2,s}^{t}$, and $pg_{i,3,s}^{t}$ represent the types of natural gas supply or the gas supply mix, for example, NG from national wells, NG from wells located in others countries, LNG or NG from NG storage reservations, etc. The gas supply mix is allocated to meet the base, medium, and peak-load demands during the planning horizon. As for $\Phi_{i,1}^{t}, \Phi_{i,2}^{t}, \Phi_{i,3}^{t}$ they are the time periods of base, medium, and peak-load demands.

### *C. GP Model*

The GP model can be formulated as a least cost optimization problem described as follows.

*Objective Function:* The model considers the total present value of the sum of the equivalent annualized investment costs plus the annual operation costs. The equivalent annualized investment cost of an infrastructure $j$ of NG supply, storage, or transport at a subsystem $i$ is defined as

$$\phi g_{i,j}^{t} \text{ or } \alpha e_{i,j}^{t} = \frac{CInv_{i,j}}{anf_{i,j}} + (O\&\ MC)_{i,j}\left(pe_{i,j}^{\max}\right)\left(\Phi^{t}\right) \tag{1}$$

where $(O\&\ MC)_{i,j}$ represent the fix operation plus maintenance cost of an infrastructure $j$ expressed in US\$/MWh.

The annualized capital recovery factor $(anf_{i,j})$ is defined as

$$anf_{i,j} = \frac{1}{r} - \frac{1}{r(1+r)^{\tau_{i,j}}}. \tag{2}$$

The minimization of natural gas infrastructures investment plus operational costs is defined as

$$\begin{aligned}
&\text{GAS_COST} \\
&= \sum_{t=1}^{T} \frac{1}{(1+r)^{t-1}} \left[ \sum_{\substack{i=1,\dots,I \\ \forall j \in J_i^{G\cup GST}}} \phi g_{i,j}^{t} x g_{i,j}^{t} \right. \\
&\quad \times \sum_{\substack{i=1,\dots,I \\ \forall k \in J_i^{FG}}} \alpha g_{i,j}^{t} x f g_{i,k}^{t} + \sum_{\substack{i=1,\dots,I \\ \forall j \in J_i^{G} \\ s=1,\dots,S}} \varphi g_{i,j}^{t} p g_{i,j,s}^{t} \\
&\quad + \sum_{\substack{i=1,\dots,I \\ \forall j \in J_i^{GST} \\ s=1,\dots,S}} \mu_{i,j}^{t} i c_{i,j,s}^{t} + \sum_{\substack{i=1,\dots,I \\ \forall j \in J_i^{GST} \\ s=1,\dots,S}} \nu_{i,j}^{t} w c_{i,j,s}^{t} \\
&\quad \left. + \sum_{\substack{i=1,\dots,I \\ s=1,\dots,S}} \gamma_{i,s}^{t} d g_{i,s}^{t} \right].
\end{aligned} \tag{3}$$

The first term represents the annualized investment cost of gas production expansion, the second the annualized investment cost of gas interconnections expansion, and the third the operational cost of gas production. The fourth and fifth terms represent the operational cost of NG/LNG injection and withdrawal in NG/LNG storages. Finally, the sixth terms express the gas deficit cost.

*Constraints:*

- The construction of the total capacity of NG wells, pipelines, and LNG regasification terminals must be done in only one period of the planning horizon. These same equations give the state on/off of the projects along the planning horizon:

$$xg_{i,j}^{t} \leq xg_{i,j}^{t+1};\ t=1,\dots,T;\ i=1,\dots,I; \quad \forall j \in J_i^{G\cup GST} \tag{4}$$

$$xfg_{i,k}^{t} \leq xfg_{i,k}^{t+1};\ t=1,\ldots,T;\ i=1,\ldots,I; \quad \forall k \in J_i^{FG} \tag{5}$$

$$xg_{i,j}^{t},\ xfg_{i,k}^{t} \quad \in \{0,1\}. \tag{6}$$

- The supply of NG energy in each block of load duration curve, at each period and at each area, is

$$\sum_{\forall j \in J_t^G} pg_{i,j,s} + \sum_{\forall k \in J_t^{FG}} (\sigma g_{i,k} fg_{i,k,s}^t - fg_{k,i,s}^t) + \sum_{\forall j \in J_t^{\mathrm{GST}}} (wc_{i,j,s,t} - ic_{i,j,s} dg_{i,s}^t \geq \Phi_{i,s}^t DG_{i,j,s}^t;\ s=1,\ldots,S;\ i=1,\ldots,I;\ t=1,\ldots T. \tag{7}$$

- The NG/LNG balance constraint at NG/LNG reservoirs:

$$\begin{aligned} &v_{i,j,s}^t = v_{i,j,s}^{t-1} + e_{i,j,s}^t - w_{i,j,s}^t \\ &\text{If} \quad \mathrm{t}=1 \Rightarrow v_{i,j,s}^t = v_{i,j,s}^0 \\ &\text{If} \quad \mathrm{t}=\mathrm{T} \Rightarrow v_{i,j,s}^t = v_{i,j,s}^{\mathrm{Final}} \\ &\quad s=1,\ldots,S;\ j \in J^{\mathrm{GST}};\ i=1,\ldots,I;\ t=1,\ldots T. \end{aligned} \tag{8}$$

- The bounds of NG, LNG supply and NG transport:

$$pg_{i,j,s}^t - xg_{i,j}^t \Phi_{i,s}^t pg_{i,j}^{\max} \rho_{i,j} \leq 0 \quad t=1,\ldots,T;\ s=1,\ldots,S \quad j \in J^G;\ i=1,\ldots,I \tag{9}$$

$$pg_{i,j,s}^t - xg_{i,j}^t \Phi_{i,s}^t pg_{i,j}^{\min,t} \geq 0 \quad t=1,\ldots,T;\ s=1,\ldots,S \quad j \in J^G;\ i=1,\ldots,I \tag{10}$$

$$\left| fg_{i,k,s}^t \right| - xfg_{i,k}^m \Phi_{i,s}^t fg_{i,k}^{\max} \leq 0 \quad m=1,\ldots,T;\ s=1,\ldots,S \quad k \in J^{FG};\ i=1,\ldots,I; t=1,\ldots T. \tag{11}$$

- As for the bounds of NG storages:

$$v_{i,j,s}^t - xg_{i,j}^t \Phi_{i,s}^t v_{i,j}^{\max} \leq 0 \quad t=1,\ldots,T;\ s=1,\ldots,S \quad j \in J^{\mathrm{GST}};\ i=1,\ldots I \tag{12}$$

$$v_{i,j,s}^t - xg_{i,j}^t \Phi_{i,s}^t v_{i,j}^{\min} \geq 0 \quad t=1,\ldots,T;\ s=1,\ldots,S \quad j \in J^{\mathrm{GST}};\ i=1,\ldots I \tag{13}$$

$$ic_{i,j,s}^t - xg_{i,j}^t \Phi_{i,s}^t ic_{i,j}^{\max} \leq 0 \quad t=1,\ldots,T;\ s=1,\ldots,S \quad j \in J^{\mathrm{GST}};\ i=1,\ldots I \tag{14}$$

$$ic_{i,j,s}^t - xg_{i,j}^t \Phi_{i,s}^t ic_{i,j}^{\min} \geq 0 \quad t=1,\ldots,T;\ s=1,\ldots,S \quad j \in J^{\mathrm{GST}};\ i=1,\ldots I \tag{15}$$

$$wc_{i,j,s}^t - xg_{i,j}^t \Phi_{i,s}^t wc_{i,j}^{\max} \leq 0 \quad t=1,\ldots,T;\ s=1,\ldots,S \quad j \in J^{\mathrm{GST}};\ i=1,\ldots I \tag{16}$$

$$wc_{i,j,s}^t - xg_{i,j}^t \Phi_{i,s}^t wc_{i,j}^{\min} \leq 0 \quad t=1,\ldots,T;\ s=1,\ldots,S \quad j \in J^{\mathrm{GST}};\ i=1,\ldots I. \tag{17}$$

- Finally, the constraints of lifetime of the infra-structures are

$$\sum_{t=1}^{T} xg_{i,j}^t \leq \tau_{i,j}; \quad j=1,\ldots J;\ i=1,\ldots I \tag{18}$$

$$\sum_{t=1}^{T} xfg_{i,k}^t \leq \tau_{i,k}; \quad k=1,\ldots J;\ i=1,\ldots I. \tag{19}$$

## III. Formulation of the GEP Model

As mentioned in the introduction, several models have been proposed in the literature for the generation expansion planning of multiarea power systems. As a main contribution of this paper, this section integrates the multiarea power generation expansion planning model with the proposed GP model, obtaining a novel approach for the long-term multiarea, multistage integrated expansion planning of combined natural gas and electricity systems (GEP).

### A. GEP Model

Given that the equations for the electricity model are well known, they are not explained here and only added to the GP model. The integration model is built as follows.

*Objective Function:* The objective function is the minimization of the annualized investment plus operation costs. This includes the expansion of NG and electricity infrastructures, as well as their operating costs along the planning horizon:

$$\text{Min}: \sum_{t=1}^{t} \frac{1}{(1+r)^{t-1}} [\text{GAS\_COST} + \text{ELEC\_COST}]. \tag{20}$$

The sum of the annualized investment of the expansion of electricity infrastructures, considering their operational costs (MIN_ELEC), is given by

$$\begin{aligned} &\text{ELEC\_COST} \\ &= \sum_{t=1}^{T} \left[ \sum_{\substack{i=1,\ldots,I \\ \forall j \in J_i^E}} \phi e_{i,j}^t xe_{i,j}^t \times \sum_{\substack{i=1,\ldots,I \\ \forall k \in J_i^{FE}}} \alpha e_{i,k}^t xfe_{i,k}^t + \sum_{\substack{i=1,\ldots,I \\ \forall j \in J_i^{E-\mathrm{UTE_{gas}}} \\ s=1,\ldots,S}} \varphi e_{i,j}^t pe_{i,j,s}^t + \sum_{\substack{i=1,\ldots,I \\ s=1,\ldots,S}} \gamma_{i,j}^t de_{i,j,s}^t \right]. \end{aligned} \tag{21}$$

The first term represents the annualized investment cost of power generation expansion, the second the annualized investment cost of interconnections, the third the operational cost of power generation, and the fourth the electricity deficit cost. Notice that the third term, the variable fuel cost $(\varphi e_{i,j}^{t})$ of natural gas consumption of fired-power plants, are not considered, because this gas natural cost part is being considered implicitly in variable operation cost $(\varphi g_{i,j}^{t})$ of gas wells such as it is described in the GAS_COST (3).

*Constraints:*

— The operation of the total capacity of NG projects (wells, pipelines, and LNG re-gasification terminals), power generation plants, and transmission lines must be activated in only one period and the subsequent ones of the planning horizon. These same equations give the state on/off of the projects along the planning horizon:

$$xe_{i,j}^{t} \leq xe_{i,j}^{t+1};\ t=1,\ldots,T;\ i=1,\ldots,I;\ \forall j \in J_i^{E} \quad (22)$$

$$xfe_{i,k}^{t} \leq xfe_{i,k}^{t+1};\ t=1,\ldots,T;\ i=1,\ldots,I;\ \forall k \in J_i^{FE} \quad (23)$$

$$xe_{i,j}^{t}, xfe_{i,j}^{t} \quad \in \{0,1\}. \quad (24)$$

— The supply/demand balance of NG energy in each block of load duration curve, at each period and at each area is given by

$$\sum_{\forall j \in J_i^{G}} pg_{i,j,s} + \sum_{\forall k \in J_i^{FG}} (\sigma g_{j,i} fg_{j,k,s}^{t} - fg_{i,k,s}^{t}) + \sum_{\forall j \in J_i^{R}} (w_{i,j,s,t} - e_{i,j,s,t}) - \sum_{j \in J^{EG}} \eta_{i,j} pe_{i,j,s} + dg_{i,s}^{t} \geq \Phi_{i,s}^{t} DG_{i,s}^{t};\ s=1,\ldots,S;\ i=1,\ldots,I; t=1,\ldots T. \quad (25)$$

— As for the supply/demand balance of electricity energy in each block of load duration curve, at each period and at each area, (27) provides

$$\sum_{\forall j \in J_i^{E}} pe_{i,j,s}^{t} + \sum_{\forall k \in J_i^{FE}} (\sigma e_{j,i} fe_{j,k,s}^{t} - fe_{i,k,s}^{t}) \\ df_{i,s}^{t} \geq \Phi_{i,s}^{t} DE_{i,s}^{t} \\ s=1,\ldots,S;\ i=1,\ldots,I;\ t,\ldots T. \quad (26)$$

— Bounds of NG, LNG supply, NG transport, and NG storages facilities, as well as bounds of electricity energy supply and transmission facilities are modeled as

$$pe_{i,j,s}^{t} - xe_{i,j}^{m} \Phi_{i,s}^{t} pe_{i,j}^{\max} \leq 0 \\ m=1,\ldots,T;\ s=1,\ldots,S \\ j \in J^{\mathrm{UHE}};\ i=1,\ldots,I;\ t=1,\ldots T \quad (27)$$

$$\sum_{s=1}^{S} pe_{i,j,s}^{t} - xe_{i,j}^{m} Eh_{i,j}^{t} \geq 0 \\ m=1,\ldots,T;\ s=1,\ldots,S \\ j \in J^{\mathrm{UHE}};\ i=1,\ldots,I;\ t=1,\ldots T \quad (28)$$

$$pe_{i,j,s}^{t} - xe_{i,j}^{m} \Phi_{i,s}^{t} pe_{i,j}^{\max} \rho e_{i,j} \leq 0 \\ m=1,\ldots,T;\ s=1,\ldots,S \\ j \in J^{\mathrm{UHE}};\ i=1,\ldots,I;\ t=1,\ldots T \quad (29)$$

$$pe_{i,j,s}^{t} - xe_{i,j}^{m} \Phi_{i,s}^{t} pe_{i,j}^{\min} \geq 0 \\ m=1,\ldots,T;\ s=1,\ldots,S \\ j \in J^{E};\ i=1,\ldots,I;\ t=1,\ldots T \quad (30)$$

$$\left| fe_{i,k,s}^{t} \right| - xfe_{i,k}^{m} \Phi_{i,s}^{t} fe_{i,k}^{\max,t} \leq 0 \\ m=1,\ldots,T;\ s=1,\ldots,S \\ k \in J^{FE};\ i=1,\ldots,I;\ t=1,\ldots T. \quad (31)$$

— Constraints of lifetime of NG [(20)–(21)] and electricity infra-structures are

$$\sum_{t=1}^{T} xe_{i,j}^{t} \leq \tau_{i,j};\ j=1,\ldots J;\ i=1,\ldots I \quad (32)$$

$$\sum_{t=1}^{T} xfe_{i,j}^{t} \leq \tau_{i,j};\ j=1,\ldots J;\ i=1,\ldots I. \quad (33)$$

### B. Final Considerations

In summary, the GEP is a computational tool to determine the least-cost expansion of multi-regional hydrothermal (generation and interconnections) systems Integrating the NG and LNG supply, transport, and storage. It represents details of the gas/electricity system operation taking into account the expansion and operation constraints of the gas/electricity sectors simultaneously.

The GEP output includes:

— the optimal gas/electricity expansion plan: reinforcement schedule, installed capacity per stage, national and regional investment and operation costs, disbursement schedule, etc);

— the optimized dispatch of the gas/electricity system;

— marginal cost for each gas and power subsystem;

— internal and external gas/power exchanges.

In the GEP model, equilibrium occurs at the intersection of the inverse supply and demand curves, and thus that the equilibrium prices for each subsystem are equal to the marginal cost for each subsystem. From a different angle, the duality theory indicates that for each constraint of the GEP program, there is a dual variable. This dual variable (when an optimal solution is reached) is equal to the marginal change of the objective function per unit increase of the constraint's right-hand side.

However, a distinction is made between operation marginal and expansion marginal cost. The former involves only changes in the inputs power and gas production, while the latter allows all inputs, including capital items (new power plants, interconnections, gas wells, etc.), to vary along planning horizon.

In this paper, the marginal operation cost is calculated only optimizing the integrated gas/electricity dispatch, to each demand period. The marginal expansion cost is the dual solution of GEP model.

The GEP proposed models has been implemented in the General Algebraic Modeling System (GAMS) [29]. The computational implementation uses the CPLEX 11.0 solver. The GAMS

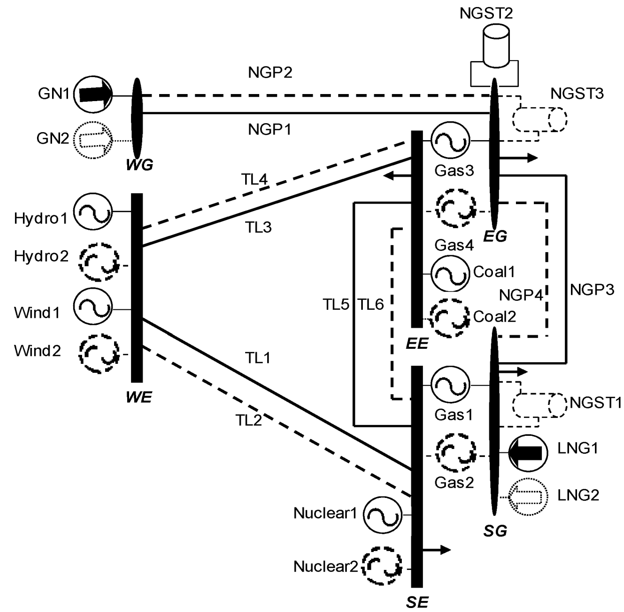



Fig. 5. Case study system.

system is a high-level modeling system for mathematical programming problems.

In this paper, two case studies were simulated. The first case is just a small example case with six areas; the second considers the large Brazilian gas/electricity system. For the small example and the Brazilian case, the CPU running time including the Matlab data reading, GAMS execution time, and Matlab printing and graphical plotting were under 5 s and 5 min, respectively. All the presented results were obtained running the study cases on a PC with a Pentium IV processor with 1 Gb of RAM at 2.99 GHz.

## IV. Case Study I

The proposed integrated gas/electricity expansion planning model is illustrated by a small example of the gas/electricity system depicted in Fig. 5.

Both the electricity and the gas systems have four areas or subsystems. The gas or electricity area infrastructures of natural gas, LNG supply, NG storage (NGST), and power generation, as well as their interconnections throughout pipelines (NGP) or transmission lines (LT) can be classified as in operation or as a project. The subsystems "West Electricity" (WE) and "West Gas" (WG) are electricity and natural gas production centers, respectively. The subsystems "East Electricity" and "South Electricity" (EE, SE), and "East Gas" and "South Gas" (EG, SG) are electricity and natural gas load centers, respectively. Notice that the natural gas-fired thermal power plants are located in the subsystems EE and SE. Relevant data of the case study are presented in the Appendix.

The total expansion and operation cost incurred to meet the demand growth in the natural gas and electricity sectors is 39 493 MUS$ (million dollars). The simulation encompasses the three load blocks and the five-year period of the planning horizon.

Fig. 6 shows the dispatch of natural gas of NG/LNG and gas stored to meet the NG demand, including NG demand of

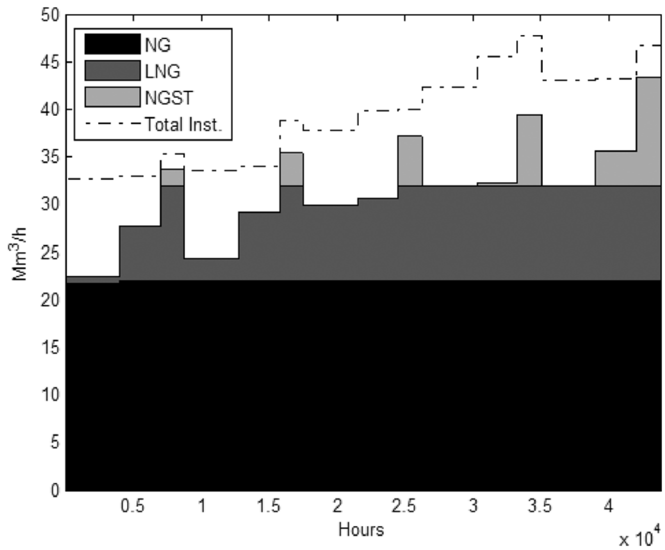



Fig. 6. Hourly dispatch throughout the planning horizon.

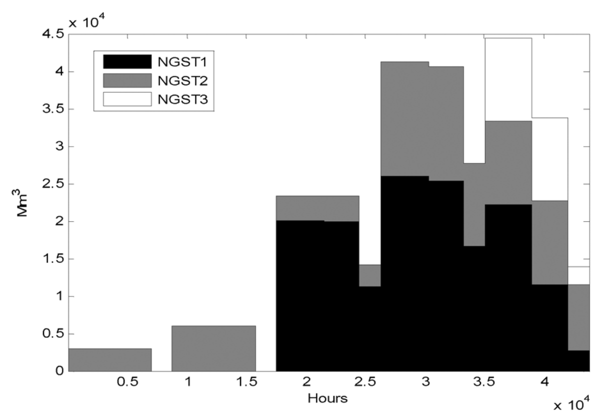



Fig. 7. Evolution of the volume of NG storage.

gas-fired power generation plants. It also shows the evolution of the total installed capacity of NG/LNG including the NG capacity of gas stored along the planning horizon. Fig. 7 shows the evolution of volume of NG stored during the planning horizon. From Figs. 6 and 7, notice that the volume (expressed in Mm3) of NG stored in load-block $(s-1)$ represents the NG capacity (expressed in Mm3/h) available in load-block $(s)$ which could be (or not) optimally used in this load-block $(s)$. For example, in period one, the capacity of gas stored during base and medium-load-block is optimally used in peak-load of this period.

According to optimal results, NG and LNG projects must be implemented in period one, whereas the pipeline projects NGP2 and NGP4 must be implemented in periods one and five, respectively. According optimal results, projects of NG storage infrastructures NGST1 and NGST3 must be implemented in periods three and five, respectively. In Fig. 6 one can note that the dispatch of natural gas follows the optimal merit order. It can also be observed that NG storage plays a vital role to meet the peak demand in all periods. Storage also provides part of the NG that is used to meet the middle load in periods four and five. Notice that, in these periods, the total capacity installed of NG/LNG is less than total NG demand. Figs. 6 and 7 show clearly that

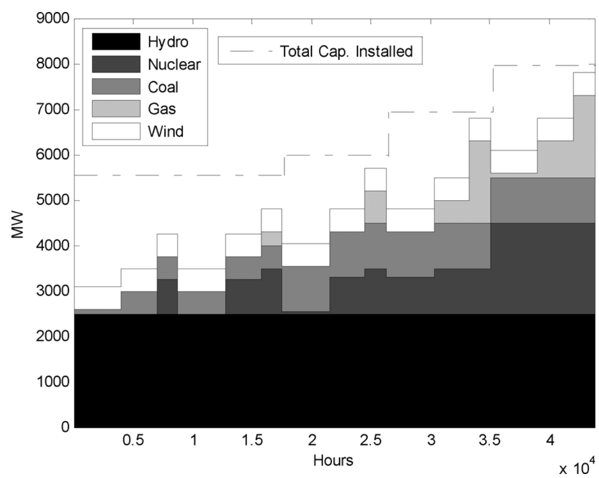



Fig. 8. Evolution of the total electricity dispatch.

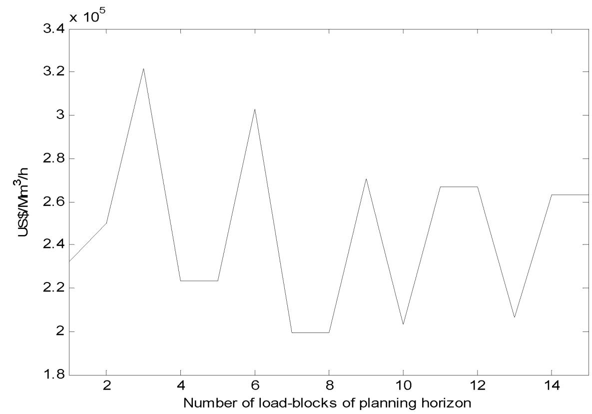



Fig. 9. Evolution of marginal expansion cost of natural gas in area SG.

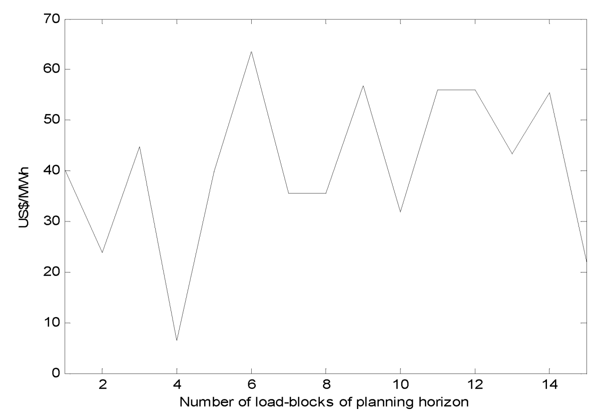



Fig. 10. Evolution of marginal expansion cost of electricity in area SE.

natural gas storage plays a vital role to ensure the security for the meet the gas demand (gas itself plus gas to gas-fired power generation units). Unlike water storage in hydrothermal plants, where the water affluence is exogenous and uncertain, in natural gas systems, it is possible to store NG/LNG intelligently/strategically, because it is an endogenous variable, as shown in Figs. 6 and 7. This represents a significant operational advantage of natural gas systems compared with hydrothermal systems.

Fig. 8 shows the optimal merit order of electricity dispatch by fuel. It also shows the evolution of the total installed generation capacity. According to the optimal results, the Hydro, TL2, and Wind2 projects must be implemented in period one, and the Coal2 project must be implemented in period three. The Gas2 and Gas4 projects in period four and the Nuclear2 project must be implemented in period five. Building hydrothermal plant Hydro2, TL2, and Wind2 in period one results more economical because their lower operational cost and they have a competitive expansion cost. Other power plants with more expensive operational/expansion costs, such as nuclear and gas-fired power plants, must be built later. Results may change if external environmental/social costs and impacts are internalized. However, discussing power system planning considering sustainable criteria is out of the scope of this paper.

Figs. 9 and 10 represent the expansion marginal cost of NG and electricity in the South area (SG/SE) as a function of the load level (three load blocks) along the all the five periods of the planning horizon (it is an total of 15 load-blocks). Notice that, in both cases, the marginal expansion cost may be higher or lower than the marginal operation cost depending on the considered load block. In this sense, one seeks the equilibrium between the operation and expansion marginal costs. When they are equal, the system is expanded optimally. An operation marginal cost higher than the planning one indicates that the system needs more expansion. On the other hand, a marginal operation cost lower than the planning marginal cost indicates that part of the system capacity is idle.

From Figs. 6 and 9, one can see that, for the base-load block of period one the natural gas has a expansion marginal cost lower than its operation marginal cost (280 000 US$/Mm3 which is the operational cost of LNG). Similarly, the NG expansion marginal cost during the peak-load of this same period one is lower than its operation marginal cost (330 000 US$/Mm3 which is the operation cost associated to NGST2). The marginal operational cost of 330 000 US$/Mm3 is obtained summing the operation marginal cost of the system in this load-block which is 280 000 (associated gas source LNG2 of the NGST2) plus the variable operation marginal cost of NGST2 which it is 50 000 (from Table VII). It is interpreted as a signal that the system needs additional NG capacity to meet additional NG load. These results show the strategic importance of considering the marginal expansion cost to the bulk power and NG systems expansion planning. A similar analysis can be done to the electricity sector considering the Fig. 10.

Fig. 11 shows the capacity expansion taking place if the hydroelectric project Hydro2 is not included in the expansion plan because a drought period during the entire planning horizon is forecasted for subsystem WE.

The capacity of the gas-fired plants is then doubled to compensate the forecasted lack of rain. As expected, Fig. 8 shows how the installed thermoelectric capacity and dispatch are increased compared to the base case represented in Fig. 7. The crisis caused by a deficit of electric energy is mitigated by the availability of natural gas. This example supports the idea that some sort of integral expansion planning is necessary. The analysis of extreme situations like this one reinforces the perception of the need to diversify the sources of electricity generation, thus

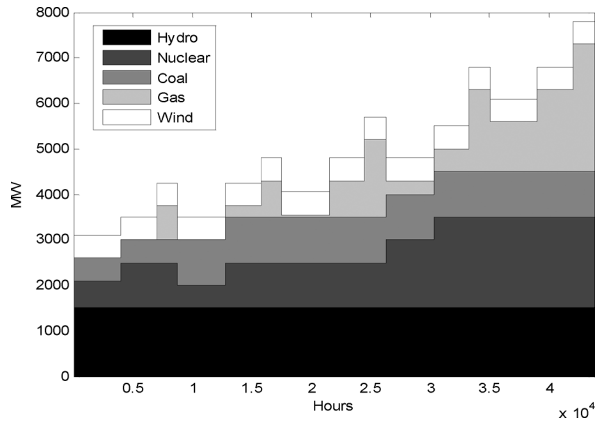



Fig. 11. Evolution of the total electricity dispatch for drought scenario.

TABLE I
SEPARATED AND INTEGRATED GAS/ELECTRICITY PLAN TO "DROUGHT" SCENARIO

| Total Operation and Investment Cost | Separated gas and electricity planning | Integrated Gas/Electricity planning |
|---|---|---|
| **Total Cost to gas sector in US$** | 2.8907e+011 | 2.9008e+011* |
| **Total Cost to Electricity sector in US$** | 7.9198e+009 | 5.2953e+009 |
| **Total Cost to Electricity and Gas sector in US$** | **2.9699e+011** | **2.9673e+011** |

*Including the investment cost necessary to meet the gas demand from gas-fired power plants.

reducing the dependence of electric power systems on natural gas and hydroelectric power. The impact of constraints on the capacity of production and transport of natural gas will also be analyzed in the next case.

Table I presents the results of the total costs when the expansion of the gas/electricity system is optimized considering the two structures together and separated. For the expansion of the electricity system the NG cost was set around 100 US$/MWh. The results represent the drought scenario. The cost of the integrated gas/electricity plan is cheaper than the gas and electricity plan executed separately. The saving is around 260 000 000 US$, which it represent a considerable amount of money in relative terms. Notice that in the integrated planning, the total cost to gas sector is more expensive than in the separated cost; it is due to the fact that in this cost is being included the investment plus operational cost necessary to meet the additional natural gas demand from gas-fired power plants. However, in integrated planning the total cost of electricity sector is cheaper than in the separated planning. Additionally only with the integrated planning is it possible to consider the pipelines capacity and gas wells capacity operation and expansion constraints which would represent the capture of gas/electricity long term supply security which could result in an additional cost.

## V. CASE STUDY II: THE BRAZILIAN CASE

The application of the proposed GEP model is now illustrated by using the Interconnected Brazilian natural gas and electricity systems (see Fig. 12). Both NG and electricity systems are physically linked through natural gas power plants. In Fig. 12, the symbol (→ NG, E, i) means that gas loads (NG) and gas-fired power plants (E) exist in area $i$ of the electricity system. For example, the symbol (→ NG, E,1) means that both the NG directed demand and the demand of gas-fired power plants connected to electricity area 1 exist in gas area BH. The full data used in this paper have been obtained from the Brazilian government energy report [26].

Brazil's electricity consumption is growing at a speedy pace, with growth rates over 5% that are requiring doubling installed generation capacity every ten years. This is the result of low per-capita electricity consumption levels (around 2000 kilowatt-hours, compared to 12 000 in the US and 6000 in Europe) combined with high economic and population growth. It is requiring, on average, around 3 GW of new generation capacity annually and around US$ 4 billion per year of investments in generation [26], [27].

The country has an installed generation capacity of 100 GW (2008), where hydro generation accounts for 85% of the total. Peak and average demand are close to 70 GW and 60 GW, respectively. The hydro system is comprised of several large reservoirs, capable of multi-year regulation, organized in a complex topology over several basins. Thermal generation includes nuclear, natural gas, coal, diesel, and biomass plants. In order to take advantage of the development of hydro generation and also to benefit from hydrological complementarities, the country became fully interconnected at the bulk power level by an 85 000 km meshed high-voltage transmission network [26], [27].

Brazil still has an undeveloped hydro potential of more than 150 GW. Most of it is located in the environmentally sensitive Amazon region, far from load centers and where mega hydro resources, such as the Belo Monte (area 6) project (11 GW), Madeira (area 7) river complex (7 GW) and Tapajos (area 8) river complex (11 GW), are being considered as expansion options. Actually, less than 30% of the country's hydropower potential is currently used [26], [27].

In Brazil, the introduction of NG in the energy matrix took place in an aggressive manner at the end of the 1990s, with the construction of the Bolivia-Brazil gas pipeline and the development of local production fields. Brazil has an aggregate average demand of 90 $\mathrm{Mm}^3$/day (2008). Gas demand by power generation plants accounts for around 40% of total demand. The remaining 60% corresponds to the NG demand of the industrial sectors and other users. NG consumption for industrial and automotive uses has grown at quite significant rates (induced by tax benefit policies, an increase in supply and low prices). In the electrical sector, installed gas thermal generation capacity also has grown quickly. Thus, it accounted in 2008 for some 12 GW. The supply of natural gas for thermal generation has been an object of concern by the authorities ever since the conception of the new model of the Electricity Sector. In an effort to increase the natural gas supply to the country, Petrobras (Brazilian State Oil Company) announced recently (2007) the construction of re-gasification stations, in order to be able to import LNG. The first ones began to operate in 2009 in the Southeastern (Guanabara with capacity of 20 $\mathrm{Mm}^3$/day) and Northeastern Regions (Pecem with a capacity of 7 $\mathrm{Mm}^3$/day).

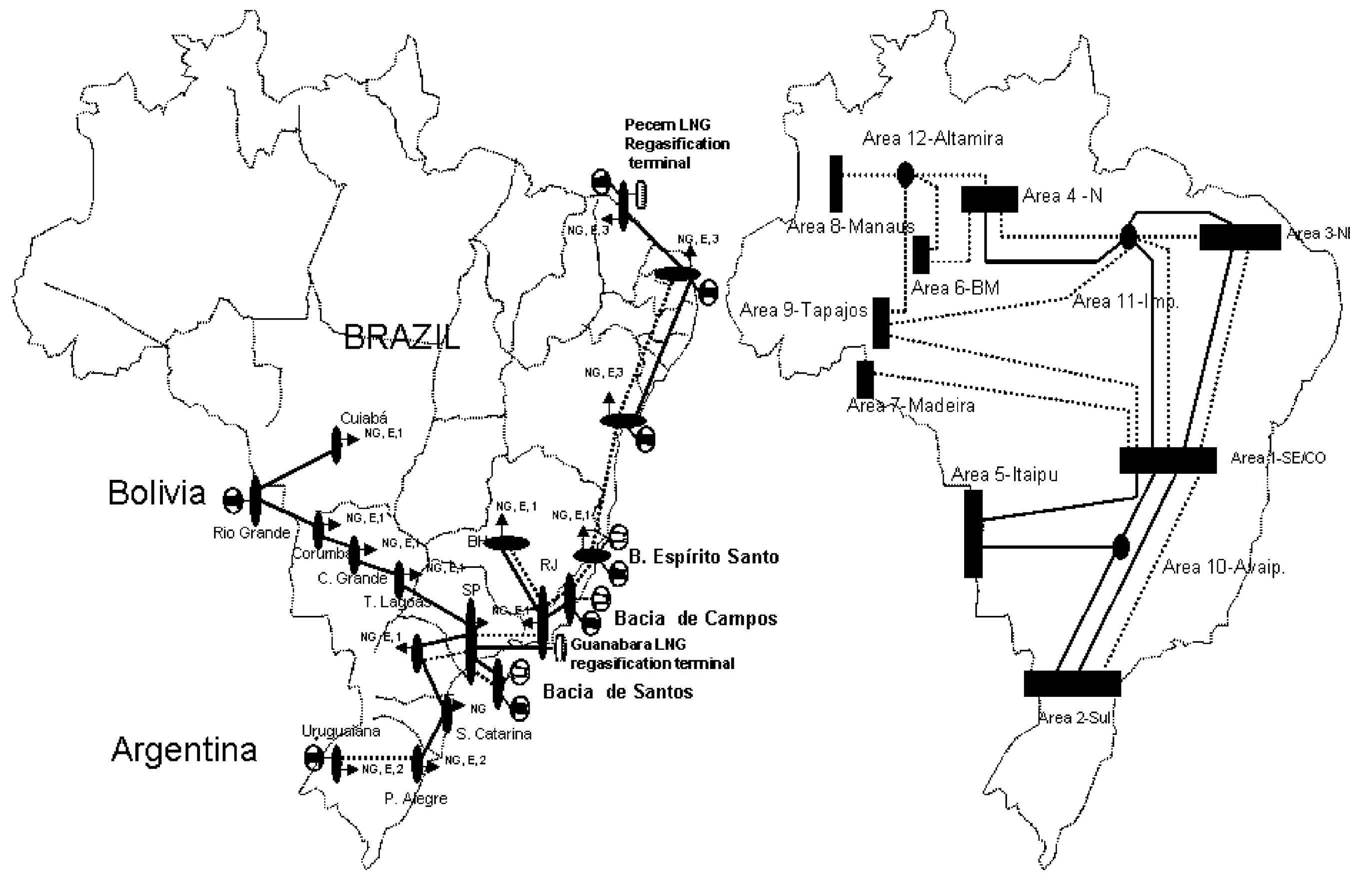



Fig. 12. Simplified representation of interconnected Brazilian natural gas and electricity system.

Gas imports would come from LNG exporters such as Trinidad & Tobago and Nigeria. Petrobras decided to install mobile floating storage regasification units (FSRU) [26], [28]. The government has planned to meet the increase in demand for electricity through the construction of new hydro generation as well as thermal generation and generation from renewable energy sources. Although in the future the energy matrix should become more diversified (including cogeneration, local coal, and gas), hydropower still is the cheapest expansion option and will be the focus of system's expansion plans over the next years. However, its environmental impact is the main obstacle to be the no construction for more generation capacity of this type. In Brazil, the electricity generation from natural gas represents only 5% of total power generation, though its contribution will increase up to 10% in the year 2020. This 10% should represent around 17 GW of generation capacity installed corresponding to gas-fired power plants. Consequently, gas demand for power generation will increase about 55 $\mathrm{Mm}^3$/day. For additional information, see [26].

The planning horizon (2009–2020) has been divided into 11 annual periods. The electricity system is comprised of 12 areas and 26 electric energy corridors (some sets of those circuits are represented just by an arc in Fig. 12). The natural gas sector is comprised of 18 areas and 22 gas pipelines, such as those shown in Fig. 12.

In the initial year of the planning horizon (2009) the electricity and NG average system demand is expected to be 60 GW each, while annual growth rate is expected to be 5.5% for a Gross Domestic Product growth rate of 5%, according the Brazilian government projections [30]. This is depicted in Figs. 13 and 14, where the NG demand does not include the consumption of gas-fired thermal units. Fig. 14 just shows the aggregated gas demand and gas demand in Rio de Janeiro and Sao Paulo; gas demand in others areas are not depicted because their values are small compared to those two. However into the model, gas demands of all areas were considered.

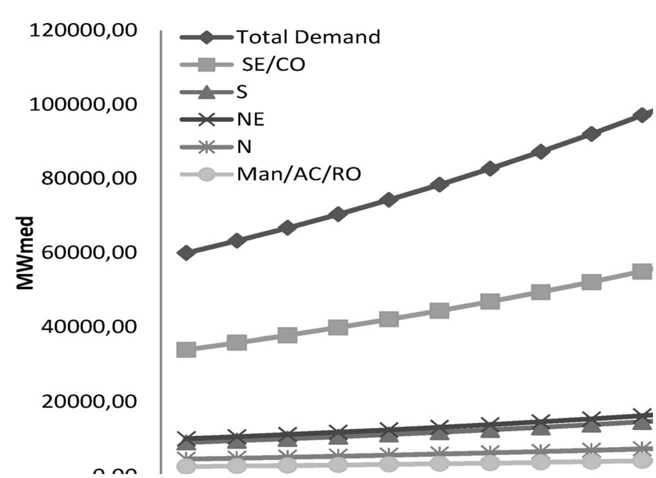
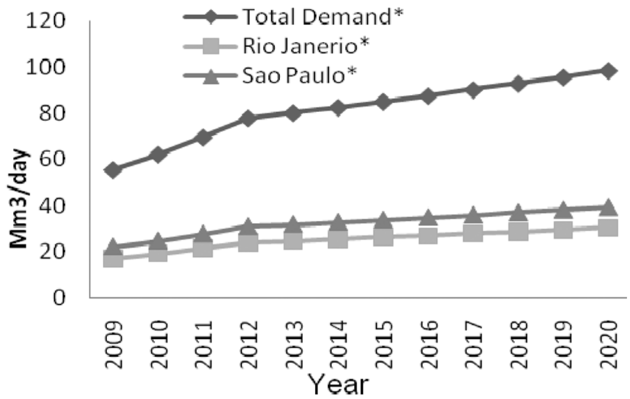



Fig. 13. Demand forecast for electricity.




*No include natural gas demand from natural gas fired power plants

Fig. 14. Demand forecast for natural gas.

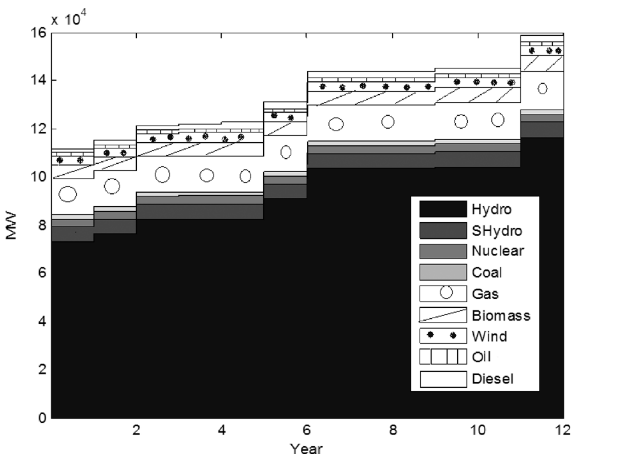



Fig. 15. Evolution of the total installed generation capacity in the Brazilian system by fuel type, throughout the planning horizon, for a hydrological mean scenario.

Fig. 15 shows the evolution of the total installed generation capacity by fuel type in the Brazilian electricity system throughout the planning horizon considering an average hydrological scenario. In this case, the Brazilian system electricity demand is met mainly using hydropower (around 82%) and biomass (around 3%) based power plants and a few power quantities (around 15%) from the existing thermal power generation. As expected, the model makes use of more economical options to meet the Brazilian demand growth. These include bigger hydropower projects (such as the first stage of the Rio Madeira, Belo Monte, and other hydropower projects) and small hydropower and biomass based power plants. In this "good" hydrological scenario case, electric energy corridors, such as the one from Madeira to SE/CO and that from Belo Monte to Subsystem N, are reinforced. Results show that generation dispatches as well as the installed capacity of no-hydropower plants, including gas-fired plants, are kept constant throughout the planning horizon. Despite this, the growth in demand for natural gas for industrial purposes (around 100 $\mathrm{Mm}^3$/day in 2020) requires the expansion of the Pecem and Guanabara LNG liquefied terminals, as well as carrying out the Campos, Santos, and Espiritu Santo Basins projects throughout the planning horizon.

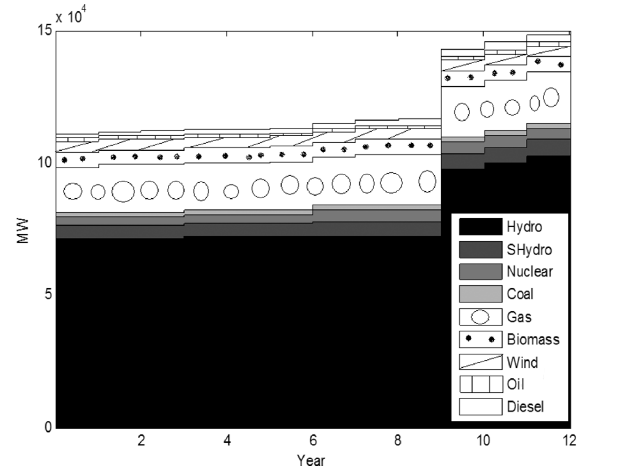



Fig. 16. Evolution of the total installed generation capacity in the Brazilian system by fuel type, throughout the planning horizon, for a critical hydrological scenario.

In this average scenario of water inflows, it is noted that the gas-fired power generation plants and transportation capacity are under-utilized during practically all the planning horizon. This problem may arise in hydro dominant systems, and may result in great economic losses for gas fired power producers, which normally have "take or pay" supply contracts. Thus, it is important to find a mechanism to mitigate this risk [28].

The simulation of a drought or hydrological critical scenario was performed and shows a decrease by 20% of hydropower production capacity with respect to the average hydrological scenario. Other scenario with similar impacts should be the no construction for the Belo Monte (11 GW), neither Tapajos (6 GW) or other large hydropower complexes, due to environmental oppositions. In this drought/environmental case, other fossil and renewable based sources power generations are expected to notably increase their participation in the power supply, as shown in Fig. 16.

For the critical hydrological scenario the gas-fired power generation capacity increases considerably to around 17 GW in year 2020. Remembering that the capacity installed in year 2009 is 12 GW, then, the gas-fired dispatch is increased in 5 GW from year 2009 until year 2020. Consequently, the demand of NG from these plants increases as well, reaching around 90 $\mathrm{Mm}^3$/day in 2020. In this case, the construction of most NG supply and transport capacity (NG/LNG) must take place in 2009 instead of 2012 for the average inflow case, as shown in Fig. 17.

For the critical hydrological scenario, NG/LNG supply projects that must be implemented considering the LNG gas terminals and natural gas exploration projects in the basin of *Santos* (3 $\mathrm{Mm}^3$/day), *Campos I* (24 $\mathrm{Mm}^3$/day), *Tupi/Jupiter* (26 Mm/day), *Espirito Santo* (10 $\mathrm{Mm}^3$/day) and other smalls projects. The NG exploration project in the Campos (24+26 $\mathrm{Mm}^3$/day) basin would be impossible to implement in three or four years. Thus, an NG deficit would exist in these years, yielding an electricity deficit around 10 GW in this critical hydrological/environmental scenario. The results show that around 20% of projected new NG capacity is not built because

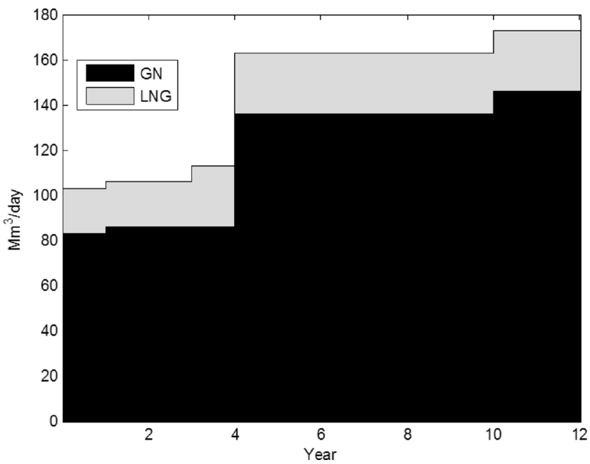



Fig. 17. Total installed capacity of NG/LNG for a dry or critical hydrological scenario.

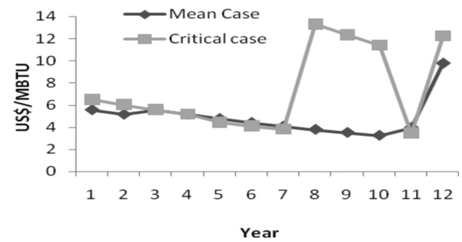



Fig. 18. Evolution of the marginal expansion cost of natural gas in the area "Rio Janeiro".

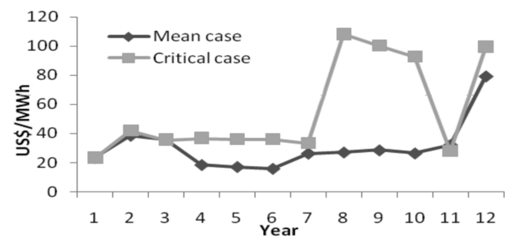



Fig. 19. Evolution of marginal expansion cost of electricity in area SE.

TABLE II
OPERATIONAL AND INVESTMENTS COSTS FOR HYDROLOGICAL AVERAGE AND "DRY" SCENARIOS

| Costs | Hydrological Mean scenario | Critical hydrological Scenario |
|---|---|---|
| Total Operation Cost in US$ | 1.8006e+011 | 2.0588e+011 |
| Total Investment Cost in US$ | 3.1809e+010 | 2.3197e+010 |
| Total Cost of Natural Gas Operation and Investment* | 5.6181e+010 | 7.5947e+010 |
| Total Cost Electricity Operation and Investment** | 1.5568e+011 | 1.5313e+011 |
| **Total Cost in US$** | **2.1186e+011** | **2.2908e+011** |

*Including the operation/investment costs in pipelines and NG/LNG projects necessary to satisfy the gas demand from natural gas-fired power plants.
**Not including the operation/investment costs in pipelines and NG/LNG projects necessary to supply gas to natural gas-fired power plants.

TABLE III
SEPARATED AND INTEGRATED GAS/ELECTRICITY PLAN TO "DRY" SCENARIO

| Total Operation and Investment Cost | Separated gas and electricity planning | Integrated Gas/Electricity planning |
|---|---|---|
| **Total Cost to gas sector in US$** | 5.0595e+010 | 7.5947e+010* |
| **Total Cost to Electricity sector in US$** | 2.0588e+011 | 1.5313e+011 |
| **Total Cost to Electricity and Gas sector in US$** | **2.5648e+011** | **2.2908e+011** |

*Including the investment cost necessary to met the gas demand from gas-fired power plants.

of the limited transport capacity of existing and projected pipelines. In order to meet the demand of electricity and NG using full NG capacity, the following options apply.

— The gas transport capacity of pipelines projected must increase by 20% (increasing their diameter).
— Mitigate the gas deficit under this critical scenario, by increasing additional 50% (26 $\mathrm{Mm}^3$/day) over the projected capacity of the LNG re-gasification terminals distributed along the Brazilian coast. This is obtained by means of additional pipelines.

The implementations of all the above measures are necessary for this critical hydrological scenario.

Table II presents the comparison of the operational and investments costs for the average and critical hydrological scenarios. As expected, the total cost of natural gas operation and investment in the critical scenario is higher than in the average scenario. It shows that the hydro power alternative is less expensive, but incorporates the risk of deficit, especially for the dry scenario.

Figs. 18 and 19 show, respectively, the evolution of the marginal expansion cost of NG and electricity for the SE/CO submarket. From these figures, one can see that electricity and gas follow the same trend in the average and in the critical cases. In the mean case, the marginal expansion cost in all periods is smaller than the operation cost (average values to gas and electricity are US$/MBTU 5 and US$/MWh 30, respectively), thus indicating the need of additional expansion of NG and power supply capacity. In the critical case, electricity marginal expansion costs are also smaller than operation costs in all periods of the planning horizon, thus indicating the need of expanding throughout the planning horizon.

Table III presents the results of the total costs when the expansion of the gas/electricity system is optimized considering the two structures together and separated. For the expansion of the electricity system, the NG cost was set around 60 US$/MWh, which is the average price of expanding the NG structures. The results represent the critical water inflow case. The cost of the integrated gas/electricity plan is cheaper than the gas and electricity plan executed separately. The saving is around $2.7400\mathrm{e}+010$ US$.

Although the difference in relative terms is not significant, the absolute gain is considerable, justifying the inclusion of the proposed method in the analysis of expansion alternatives of both electricity and natural gas systems.

Despite the above economical questions, the big advantages to consider an integrated gas/electricity expansion planning is its strategic and realistic contemplation of the interactions of both systems. One of the purposes could be to determine the least-cost expansion planning ensuring the long-term energy supply of both sectors. However, the integrated tool also would be useful to identify the strengths and weaknesses of both systems and the necessary corrective actions to maintaining the reliability of supply needed to meet the electricity and gas demand in long-term. These advantages of the integrated planning have an enormous value in terms of quality of solution of the expansion planning. The cost resulting is a more realistic cost compared to separate analysis.

## VI. Conclusion

This paper proposes a novel model to compute long-term multiarea expansion plan of natural gas systems: the GP model. It has been integrated into another model aimed at jointly computing the long-term, multiarea expansion plan of electricity and natural gas systems: the GEP model. The proposed models take into account jointly the natural gas value chain (i.e., the gas supply from the NG wells, or LNG terminals, the gas transport through NG pipelines, and the storage of NG and LNG) and the electricity value chain (i.e., power generation and transmission). The proposed model is formulated as a mixed-integer linear multistage optimization problem which minimizes the costs of investments plus operation.

In particular, the paper shows the importance of NG storage when hydro power is considered, because they act as a complementary energy source mitigating the risks derived from the water inflow uncertainties.

The results show that the integral gas/electricity expansion planning results in cheaper costs when compared to the disaggregated option. This validates the initial assumption that the aggregated vision seems more attractive. Among the remaining challenges, one that deserves special consideration is to make use of the results of an indicative centralized plan in a market-oriented environment.

The integrated expansion planning of gas and electricity has advantages when compared to separate planning, both in terms of quality and realism of the results. Integrated planning is capable to contemplate strategically both sectors simultaneously, in terms of operational and economical interactions, which with the traditionally separated gas and electricity analyses is impossible. This integrated planning model should be useful for energy companies and governmental agencies.

## Appendix
## Data of Case Study I

Table IV shows the operation and expansion characteristics of electricity generation plants. Table V shows the operation and expansion characteristics of electricity interconnections.

TABLE IV
Characteristics of Operation and Investment of Electricity Generation Plants

| Subs./Name | State* | Bound Min MW | Bound Max MW | Fuel(Variable)//Fix operation Cost in US$/MWh | Investment Cost in US$/kW | Annualized Investment plus (O&MC) Cost in Millions US$** |
|---|---|---|---|---|---|---|
| OE/Hydro1 | 1 | 0 | 1500 | 0/3.5 | - | 45.99 |
| OE/Hydro2 | 0 | 0 | 1000 | 0/3.5 | 2000 | 208.43 |
| OE/Wind1 | 1 | 0 | 250 | 0/3 | - | 6.57 |
| OE/Wind2 | 0 | 0 | 250 | 0/3 | 1200 | 33.23 |
| EE/Gas1 | 1 | 0 | 500 | 55/1 | - | 4.38 |
| EE/Gas2 | 0 | 0 | 500 | 55/1 | 700 | 35.49 |
| EE/Coal1 | 1 | 0 | 500 | 45/2 | - | 8.76 |
| EE/Coal2 | 0 | 0 | 500 | 45/2 | 1300 | 66.53 |
| SE/Nuclear1 | 1 | 0 | 1000 | 50/4 | - | 35.04 |
| SE/Nuclear2 | 0 | 0 | 1000 | 50/4 | 2000 | 212.81 |
| SE/Gas3 | 1 | 0 | 500 | 55/1 | - | 4.38 |
| SE/Gas4 | 0 | 0 | 500 | 55/1 | 700 | 35.49 |

*State: in operation=1, i n project=0
**using eq. (1); considering $r$=8%, $\tau_{i,j}$=30, and $\Phi^t$=8760

TABLE V
Characteristics of Operation and Investment of Interconnections of Electricity System

| Subs. From-To | Name | State | Bound Min MW | Bound Max MW | Length km | Invest. Cost US$/km MWh | Annualized Investment plus (O&MC) Cost in Millions of US$ |
|---|---|---|---|---|---|---|---|
| OE-SE | TL1 | 1 | 0 | 1000 | 1000 | - | 5 |
| OE-SE | TL2 | 0 | 0 | 1000 | 1000 | 500 | 55 |
| OE-EE | TL3 | 1 | 0 | 1000 | 1000 | - | 5 |
| OE-EE | TL4 | 0 | 0 | 1000 | 1000 | 500 | 55 |
| SE-EE | TL5 | 1 | 0 | 1000 | 1000 | - | 5 |
| SE-EE | TL6 | 0 | 0 | 1000 | 1000 | 500 | 55 |

TABLE VI
Characteristics of Operation and Investment of Natural Gas Wells

| Subs./Name | Type | State | Bound Min Mm3/h | Bound Max Mm3/h | Oper. Cost US$/Mm3/h | Investment Cost in Millions of US$/Mm3/h | Annualized Investment plus (O&MC) in Millions Of US$ |
|---|---|---|---|---|---|---|---|
| OG/GN1 | Onshore | 1 | 0 | 12 | 260000 | - | 5 |
| OG/GN2 | Onshore | 0 | 0 | 10 | 260000 | 200 | 105 |
| SE/LNG1 | Onshore | 1 | 0 | 5 | 280000 | - | 5 |
| / SE/LNG2 | Onshore | 0 | 0 | 5 | 280000 | 200 | 55 |

TABLE VII
Characteristics of Operation and Investment of Natural Gas Interconnections

| Subs. From-To | Name | State | Bound Min Mm3/h | Bound Max Mm3/h | Length km | Invest. Cost US$/km Mm3/h | Annualized Investment plus (O&MC) Cost Millions of US$ |
|---|---|---|---|---|---|---|---|
| OG-EG | NGP1 | Operation | 0 | 15 | 1000 | - | 5 |
| OG-EG | NGP2 | Projected | 0 | 15 | 1000 | 100000 | 105 |
| SG-EG | NGP3 | Operation | 0 | 15 | 1000 | - | 5 |
| SE-EG | NGP4 | Projected | 0 | 15 | 1000 | 100000 | 105 |

Table VI shows the operation and expansion characteristics of natural gas wells. Table VII shows the operation and expansion characteristics of natural gas interconnections. Table VIII shows the operation and expansion characteristics of natural gas

TABLE VIII
CHARACTERISTICS OF OPERATION AND INVESTMENT OF NATURAL GAS STORAGES

| Subs./ Name | State | Bound | | Oper. Cost US$ Mm3/h | Investment Cost in Millions of US$/Mm3 | Annualized Investment Cost plus (O&MC) In Millions of US$ |
|---|---|---|---|---|---|---|
| | | Min/Max Injection and withdrawal Mm3/h | Capacity Min/Max-Initial Volume in (Mm3) | | | |
| SG/NGST1 | 0 | 0/5 | 0/5000-0 | 5000 | 1 | 55 |
| EG/NGST2 | 1 | 0/5 | 0/5000-1000 | 5000 | - | 5 |
| EG/NGST3 | 0 | 0/5 | 0/5000-0 | 5000 | 1 | 55 |

TABLE IX
NATURAL GAS DEMAND

| Period or year | Gas Demand (Mm3/h) | | | | | |
|---|---|---|---|---|---|---|
| | SG | | | EG | | |
| | Base load Duration 4500 h | Middle load Duration 3000 h | Peak Load Duration 1260 h | Base load Duration 4500 h | Middle load Duration 3000 h | Peak Load Duration 1260 h |
| 1 | 15,84 | 19,80 | 23,76 | 5,94 | 7,92 | 9,90 |
| 2 | 16,63 | 20,79 | 24,95 | 6,24 | 8,32 | 10,39 |
| 3 | 17,46 | 21,83 | 26,19 | 6,55 | 8,73 | 10,91 |
| 4 | 18,34 | 22,92 | 27,50 | 6,88 | 9,17 | 11,46 |
| 5 | 20,22 | 25,27 | 30,32 | 7,58 | 10,11 | 12,63 |

TABLE X
ELECTRICITY DEMAND

| Period or year | Electricity Demand (MW) | | | | | |
|---|---|---|---|---|---|---|
| | EE | | | SE | | |
| | Base load Duration 4500 h | Middle load Duration 3000 h | Peak Load Duration 1260 h | Base load Duration 4500 h | Middle load Duration 3000 h | Peak Load Duration 1260 h |
| 1 | 2200,00 | 2500,00 | 3000,00 | 900 | 1000 | 1250 |
| 2 | 2500,00 | 3000,00 | 3300,00 | 1000 | 1250 | 1500 |
| 3 | 2800,00 | 3300,00 | 3700,00 | 1250 | 1500 | 2000 |
| 4 | 3300,00 | 3500,00 | 4300,00 | 1500 | 2000 | 2500 |
| 5 | 3800,00 | 4300,00 | 4800,00 | 2300 | 2500 | 3000 |

storages. Tables IX and X show the natural gas and electricity demand in each stage of the planning horizon, respectively.

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