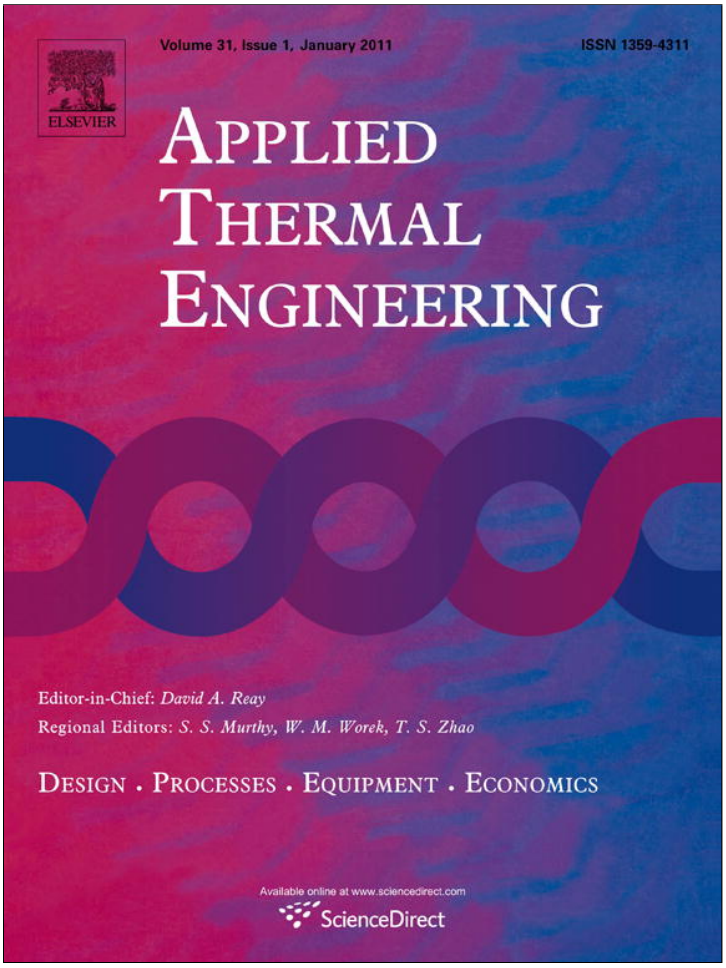
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Line-pack management for producing electric power on peak periods

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ABSTRACT

The distribution of natural gas is carried out by means of long ducts and intermediate compression stations to compensate the pressure drops due to friction. The natural gas compressors are usually driven by an electric motor or a gas turbine system, offering possibilities for energy management, one of these consisting in generating energy for use in-plant or to commercialize as independent power producer. It can be done by matching the natural gas demand, at the minimum pressure allowed in the reception point, and the storage capacity of the feed duct with the maximum compressor capacity, for storing the natural gas at the maximum permitted pressure. This allows the gas turbine to drive an electric generator during the time in which the decreasing pressure in duct is above the minimum acceptable by the sink unit. In this paper, a line-pack management analysis is done for an existing compression station considering its actual demand curve for determining the economic feasibility of maintaining the gas turbine system driver generating electricity in a peak and off-peak tariff structure. The potential of cost reduction from the point of view of energy resources (natural gas and electric costs) is also analyzed.

1. Introduction

The Brazilian energetic scenery was characterized in 2001 by a serious deficit in the electricity offer. As the great majority of Brazilian electricity is generated by hydroelectric power stations, which are strongly dependent on weather, the relatively dry period verified in 2000–2001 and the depletion of accumulated water resulted in the electric crisis. Furthermore, some Brazilian regions were not completely interconnected at that time; therefore, in the crisis period, the electric surplus eventually available in one region could not be transported to a scarcely provided region.

In the years 2001–2002, several new hydraulic and thermoelectric plants were planned; some of them were constructed and are nowadays operating as reserve margin for the interconnected system. Nowadays, the Brazilian generating matrix is based on 74% of hydroelectric power systems, and according to BIG [1], 21.5% of thermoelectric power systems and the remaining part is due to nuclear, wind and small hydro power generation. Thermoelectric power generating systems are based on natural gas burning, except for some deficit periods, in which fuel oil is burnt. It must be mentioned that the Brazilian electricity network is far more developed than the gas network, and although natural gas reserves were recently discovered, the Bolivia–Brazil pipeline is actually the way by which thermal power generation was expanded.

The line-pack management of pipelines for producing electricity in the daily peak period to be offered to the grid, exploiting the storage capacity of long ducts, is proposed in this paper as an opportunity of economic dispatch; it is also as a way to partially overcome the electric system uncertainties, because this proposal stimulates the distributed generation.

2. State-of-the-art review

In compression plants, natural gas is transported through pipelines by means of compressors driven by electric motors or gas turbines. Distances in the range of 150–200 km between compression stations and duct diameter around 500 mm are commonly recommended. Compression stations receive the natural gas at approximately 5.9 MPa and discharge it at 10.2 MPa. The maximum compressor capacity must be at least equal to the peak demand. These facts allow that, in a period of low natural gas (NG) demand, the compressor keeps sending a volume that exceeds the demand, thus increasing the pressure in the duct and storing some amount of gas, as described by Balestieri et al. [2]. This is referred as line-pack.

Line-pack is the storing of natural gas inside the pipeline network by boosting the line pressure above the delivery pressure. The line-pack is useful to reduce abrupt changes on compressor

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Nomenclature

CD	cycles duration, hour
EC	electric cost produced by the gas turbine driver, US $/MWh
E_{cp}	economy per cycle for the period with peak tariff, US $/MWyear
E_{sp}	economy per cycle for the period without peak tariff, US$/MWyear
EPV	electricity present value per MW (based on mean demand), US$/MWyear
F	ratio between the present cost and alternative cost, [-]
FT	filling time, hour
K	maximum flow coefficient, m^2
$\dot{m}$	mass flow, kg/s
NG	natural gas, [-]
NGC	natural gas cost, US$/million BTU
N_{cp}	numbers of cycles in days with peak tariff, [-]
N_{sp}	numbers of cycles in days without peak tariff, [-]
NGPV	natural gas present value per MW (based on mean demand), US$/MWyear
OPEC	electricity cost for the off-peak period, US$/MWh
PEC	electricity cost for the peak period, US$/MWh
P	static pressure, MPa
R	ratio between OPEC and PEC, [-]
RR	ratio of electric energy produced and off-peak electric cost, [-]
TEC	total storage capacity, m^3
TP	hours per day of peak period (3 hours in), hour/day
ρ	specific density, kg/m^3

load but may also serve, in special circumstances, to allow the gas to be transported for a period that depends on the duct size and pressure, consumer demand and minimum acceptable pressure.

Some line-pack schemes consider that transmission capacity and supply capacity are matched and the transmission system cannot be used for diurnal storage, and in some other situations the transmission system can be used both for transporting gas from the supply sources to the end-users and to balance the fluctuations in demand that occur during the day. Cornot-Gandolphe [3] reports that in the United Kingdom line-pack represents up to 3% of total demand, but in Spain the figure is 0.4%.

For analyzing the feasibility of a line-pack proposal, Suna et al. [4] developed an integrated decision support system for the optimization of natural gas pipeline operations in which both expert systems and operations research techniques were used to model the operations of the gas pipelines. For determining the state of the line-pack of the pipelines and recommending the control commands to be issued, a line-pack expression as a function of the average pressure between compressor discharge pressure and the customer end-point delivery pressure was developed for the gas pipeline in the St. Louis East area, which is one subsystem for supplying natural gas to meet the demand of two geographical areas, Hudson Bay and Nipawin.

The convergence of interests for the gas and electricity industries, particularly in developed markets of the US, the UK, and parts of Europe, was stated by Malecek [5] in a report whose objective was to evaluate the extent to that which convergence is occurring in developing countries. Brazil was selected as a case study to determine how this convergence might occur in a developing country, and one of the conclusions was that there are immediate opportunities for gas-fired power generation near gas transmission pipeline routes. Some other information about Brazilian natural gas power generation may be seen at Szklo and Tolmasquim [6].

Al-Salamah et al. [7] included the storage analysis in the context of a study that represents the inter-dependency between natural gas supply and electricity supply in the Gulf region. The gas model there described is a mixed integer programming model for assisting the Gulf countries in their planning of the new gas infrastructure and provide least cost analysis in the long term expansion of their facilities.

Carter and Rachford Jr. [8] presented several line-pack management strategies for attending some possible future scenarios, such as uncertain peaking power plant loads, low and high load forecasts based on historic estimates of weather forecast uncertainties, compressor outage events, and even different possible marketing and contractual alternatives available. Some other literature studies, such as that of Roy-Aikins [9], were presented for pipelines applications in Kenya.

3. System concept

In a typical operation, the natural gas compressor fits the gas demand curve by varying its speed. The discharge pressure also varies because of pressure drops in the pipeline. The upper horizontal line in Fig. 1 represents the maximum compressor capacity, expressed as equivalent kW. The variable line represents the instantaneous gas demand, also expressed as equivalent kW. The mean power demanded for natural gas compression is represented by the lower dotted horizontal line.

The compressor generally fits the gas curve by varying its speed. The discharge pressure also varies since the pressure drops in the duct. The shaded area may be associated to an amount of energy available to the compressor driver (here named dynamic storage) for other uses, such as to drive an electric generator or to maintain the compressor at its full capacity, the excess of gas being stored in the duct (static storage). The first alternative is operationally more complex because the stocked gas must be enough to supply the demand for producing a stable electric energy, even when it is above the mean demand. The second option allows to stop the compressor and to couple the driver to an electric generator, when convenient.

If the compressor driver is an electric motor, the gas storage in the off-peak tariff period associated to the stopping of the motor in the peak period tariff may be convenient. In the turbine gas driver case, the same advantages are present, with the eventual additional advantage that the cost of storage is natural gas based, normally a cheaper option, instead of electric energy based. When the driver is an electric motor, the investment probably will be lower and the costs of electricity and gas have a fundamental role in the decision to adopt or not the proposal.

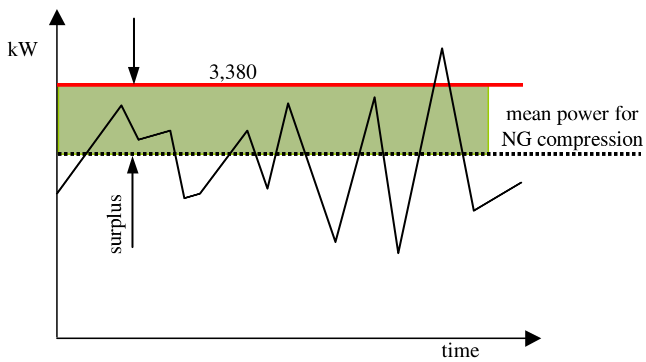

Fig. 1. Qualitative curves of mean and instantaneous demands.

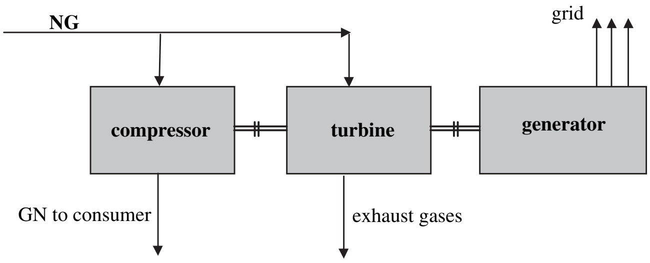

Fig. 2. Mechanical coupling.

A coupling system, which allows a quick and reliable change of the operation mode, is necessary in the gas turbine case. Figs. 2 and 3 indicate two possibilities: the mechanical and electric coupling, respectively.

If the dynamic storage is considered and electrical coupling is employed, a device to control the frequency must be provided between the generator and the electric motor (i.e., a frequency converter, not shown in Fig. 3). In a similar way, this device must be employed in the mechanical coupling. This frequency control is needed due to the variable speed operation of the compressor and represents an additional cost to the system.

For this reason, the static storage concept is preferred; in this case, the compressor variable speed only affects the filling time of the duct to eventually drive an electric generator at constant speed during the storage time. This solution must be carefully implemented, considering that it implies on assuring certain logistic conditions, as described below.

For a compression station network (Fig. 4), when duct 2 is full-filled or packed, the compressor of station B can stop and the natural gas is transported to station C by the potential pressure energy in duct 2. During this period, the compressor unit can drive an electric generator. A mass balance indicates a problem with the handling of the incoming natural gas from station A. To overcome that, there are two possibilities: to store natural gas also in duct 1 or stopping the compressor in station A; this will create problems to an eventual plant upstream station A. As can be seen, the application of the storage concept involves a strategic analysis of a network of plants and a synchronized operation. In this paper it is analyzed the static storage condition, assuming that all upstream station or plant B correlated problem was solved.

4. Storage capacity modeling

The storage capacity is the mass (or volume, Sm^3) that the duct or pipeline contains and can be used in a satisfactory way by the consumer, say a downstream station C in Fig. 4; the unit Sm^3 is the *standard conditions volume*, calculated for a fixed quantity of mass with temperature of 20 °C and a pressure of 101 kPa. In Fig. 5, the pressure profile along the duct is represented for some operational conditions.

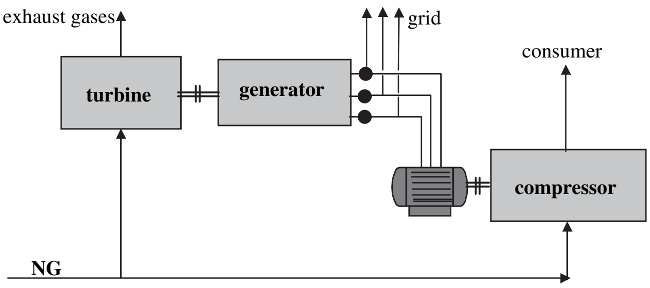

Fig. 3. Electric coupling.

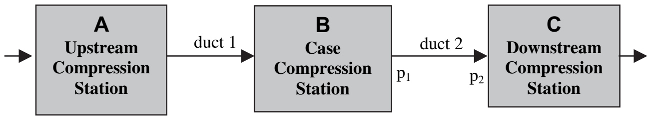

Fig. 4. Compression station network.

According to More [10], the pressure drop p_1-p_2 is calculated by using an appropriate method and the pressure profile can be considered a right line for the mass flow and duct dimensions; the Weymouth expression was utilized for the evaluation of pressure drop in the present case study; for Coelho and Pinho [11], this method is less accurate compared to the other formulations, but as this equation overestimates the pressure drop calculation, it is frequently used in the design of distribution networks. In Fig. 5, line 1 indicates a lower pressure drop relatively to line 2; line 3 represents the case of no flow, i.e., the compressor had charged the duct at the maximum permissible pressure during a period of null natural gas demand by station C. This situation will be denominated as full-filling case. When the duct is operating according to the line 1 profile and the compressor is stopped, an equilibrium pressure is admitted and its value can be estimated by the mean value between p_1 and p_2. This will be called the operational filling case.

The storage capacity depends on the consumer demand, which is normally variable. The assumptions for a reasonable model are:

- There is a minimum constant demand when using the storage capacity;
- It is possible to determine a minimum admissible pressure p_2 to allow the operation of Station C;
- When operating according to the storage capacity, the pressure remains uniform along the duct;
- Natural gas can be considered an ideal gas with the appropriated compression factor.

It can also be considered that the discussion about hourly and daily balancing regimes described in GTE [12] is minimized by the simplicity of natural gas network here considered, that involves a little number of companies connected to a single duct. The information presented in Table 1 was used to calculate the storage capacity.

The storage capacity can be estimated for many operating conditions and minimum acceptable pressure p at the inlet of station C. An internal operating pressure p_3 in plant C and a maximum flow coefficient K in a virtual inlet control valve are supposed, so the estimation of the minimum acceptable p_2 can be done when the minimum acceptable demand is established, i.e., it is considered that in normal operation this virtual valve operates partially closed, depending on the required flow and on the pressure p_2. When the stored gas is taken from the duct and the pressure is up to decrease, the valve is opened until its maximum

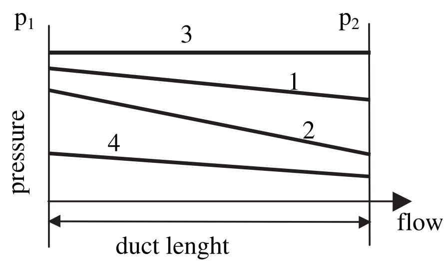

Fig. 5. Pressure profile on pipeline.

Table 1
Natural gas and pipeline data.

Pipeline			
Length: 180 km		Diameter: 0.5 m	Volume: 35,000 m^3
Natural gas			
$R = 415.1$ J/kg K	$\rho_n = 0.8939$ kg/Nm^3	$\rho_s = 0.8316$ kg/Sm^3	Operating temperature = 27 °C
Natural gas demand (Sm^3/h)			
Maximum		Medium	Minimum
193,400		125,000	65,000

aperture, determining the minimum suitable p_2. Fig. 6 shows this proposed control system.

The mass flow is determined by

$$\dot{m} = K\sqrt{(p_2 - p_3)\rho_2} \qquad (1)$$

By imposing p_3 and considering multiple operational conditions, such as different compressor discharge pressure and demand, it is possible to determine p_2 using the pressure loss in the duct, and therefore to estimate K values. For the maximum value calculated for K, it is possible to estimate the minimum p_2 to provide the minimum required demand.

5. Filling required time calculation

As the natural gas compressor is operated in the off-design condition, it is necessary to evaluate its response to the mass flow variation. Fig. 7 presents the efficiency curves assumed for the natural gas compressor considered in this case-study. The compressor curves of Fig. 8 show that it is possible to provide the same demand by using different discharge pressures and compressor speed. The dotted line is the preferred mode of operation for the required flow (160,800 kg/h or 2,890 Am^3/h) and the actual suction pressure of 5.8 MPa, for which the efficiency is the maximum, according to Fig. 7 (the unit Am^3 means *actual volume*, i.e., the volume corresponding to a fixed quantity of mass at actual suction temperature and pressure, adopted to be 30 °C and 5.8 MPa in this case-study).

In Fig. 8, point 1 indicates the flow reduction process by means of pressure augmentation and constant speed (at 11,163 rpm); point 2 shows the process when the discharge pressure is maintained and the speed is reduced to the dotted line rotation. The power consumption in case 2 is lower than in case 1, as also seen in Fig. 8, confirming that the efficiency is better in case 2. In practice, the flow reduction is obtained by a combination of speed reduction and a variation of discharge pressure.

The filling process during operation is only possible if the demand is lower than the compressor capacity and the speed compressor is raised. A possible filling process is indicated by the wide arrow in Fig. 8; the filling time can be calculated by using this new capacity minus the demand, and the initial and final mass in the duct, keeping the initial pressure drop because it is mainly dependent on the demand. This is illustrated in Fig. 9, in which line 1 is the initial condition and lines 2 to 4 indicate the rise of pressure in the duct, maintaining the pressure drop due to demand. Line 4 represents the profile for maximum filling, limited to the maximum compressor discharge pressure p_1 or the maximum duct admissible

Fig. 6. Suggested control system.

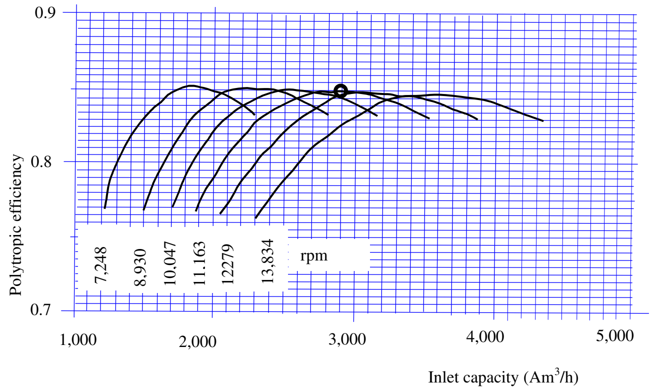

Fig. 7. Compressor performance curves: efficiency x capacity.

pressure. Line 5 is the idealized profile, in which the pressure is homogeneous and equal to the mean value between p_1 and p_2 in the first moment.

6. Economic evaluation

The economic evaluation here presented is based on the electricity and on the natural gas costs, comparing the present cost value of electricity with the present cost of the alternative proposed. In this article, it is considered two possibilities for the compressor driver, an electric motor and a natural gas turbine. Each case is studied independently.

6.1. Electric motor driver case

According to Fig. 8, it is reasonable to assume a relatively linear relationship between the shaft power consumed and natural gas delivered by the compressing system, especially for the lower

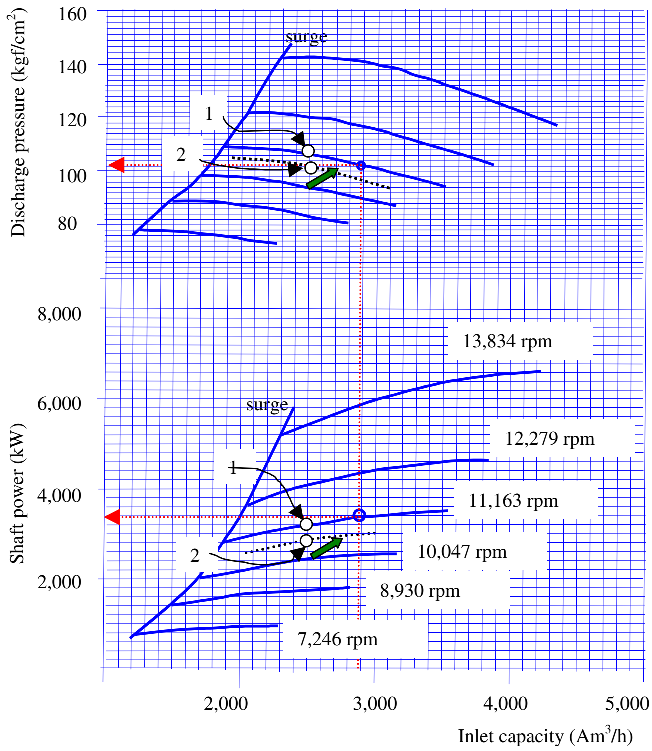

Fig. 8. Compressor performance curves: power and pressure x capacity.

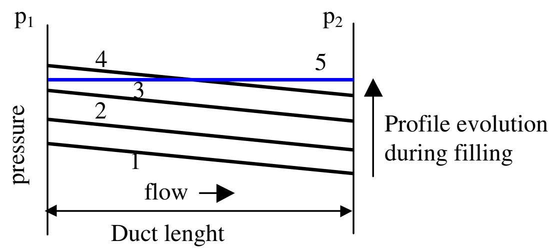

Fig. 9. Pressure profile during filling.

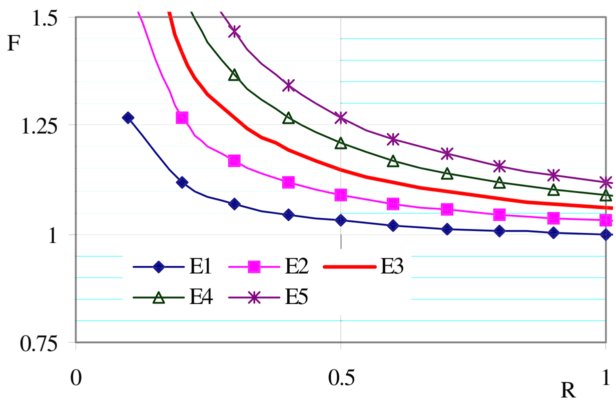

Fig. 10. Economy ratio for electric motor driver.

speeds, that are in fact considered in this analysis. When the natural gas demand is low, it is possible to store natural gas in the pipeline, in a daily basis, in a volume enough to permit stopping the electric motor in the peak period tariff. There is no advantage to maintain the compressor (and motor) in standby out of the peak period because the electricity economy will be cancelled in the next duct filling process.

The present annual cost per MW of consumed electricity is given by Eq. (2) and the cost of the alternative option, i.e., the cost of consumed electricity for storing natural gas is expressed by Eq. (3).

$$\mathrm{EPV} = \{(24-\mathrm{TP})\cdot\mathrm{OPEC}+\mathrm{TP}\cdot\mathrm{PEC}\}\,261+104\cdot24\cdot\mathrm{OPEC} \quad (2)$$

$$\mathrm{NGPV} = 365.24.\mathrm{OPEC} \quad (3)$$

in which OPEC and PEC are the electricity cost in US$/MWh for the off-peak period and peak period, respectively; TP is the hours per day of peak period (in Brazil, it takes 5 h for the whole electric system, with the imposition of 3 h to industrial and commercial consumers) and the numbers 261 and 104 correspond to the days per year with and without peak period, respectively.

The ratio between the electric present cost and the alternative present cost, *F*, is given by Eq. (4).

$$F = 0.0298\left\{(24-\mathrm{TP})+\frac{\mathrm{TP}}{R}\right\}+0.2849 \quad (4)$$

the F ratio is quite similar to the one presented by Milosevic and Cowart [13], the price equivalent efficiency (PEE) of generating power. According to these authors, this is an economic indicator for cogeneration viability as a function of power and fuel pricing and, by definition, is the ratio of fuel to power price.

Fig. 10 presents the economy ratio for different values of *R* (in Brazil, the ratio between electricity off-peak and peak costs ranges from 0.5 to 0.8). Curves E1 to E5 correspond to TP equal to one to 5 h, in steps of 1 h, respectively. The shape of the curves are coherent with *R*, meaning that the higher the difference between peak and off-peak costs (i.e., the lower *R*), the higher the economy. The calculus has considered the storage a possible condition for all the days of the year.

Table 2 indicates the estimated values for different operational conditions, calculated for compressor pressure of 8.0 MPa and 0.9 MPa, for mass flow from 80,000 $\mathrm{Sm^3/h}$ to 170,000 $\mathrm{Sm^3/h}$; it is possible to conclude that if the typical demand is around 125,000 $\mathrm{Sm^3/h}$, as indicated in Table 1, this assumption is appropriate, specially because for three operation hours (TP), it is not necessary to fulfill the duct. The relative economy may be calculated by using F factor according to Eq. (5).

$$\mathrm{Economy}(\%) = \left(1-\frac{1}{F}\right)\cdot 100 \quad (5)$$

6.2. Gas turbine driver case

As in the preceding item, a linear relationship between the shaft power consumed and natural gas delivered by the compressing system was here accepted. The alternative of producing electricity in the gas turbine mover is only commercially interesting if it is more attractive than the electricity acquired from the grid.

6.2.1. Gas turbine electricity cost

The gas turbine data sheet indicates that 12,323 kW of fuel are needed for a shaft power of 3,380 kW. Considering that the gas turbine operates at full load in the storage period, its operational cost may be estimated as expressed in Eq. (6), and the cost of electricity produced by the gas turbine driver is presented in Eq. (7).

$$\mathrm{Hourly\ cost} = 41.9\cdot10^6\cdot\mathrm{NGC}\left[\frac{\mathrm{US\$}}{\mathrm{h}}\right] \quad (6)$$

$$\mathrm{EC} = \frac{41.9\cdot10^3}{3,380}\cdot\mathrm{NGC}\left[\frac{\mathrm{US\$}}{\mathrm{MWh}}\right] \quad (7)$$

Table 2
Storage capacity of duct, required filling time and cycle duration (all in hours).

Flow ($\mathrm{Sm^3/h}$)	Compressor pressure 8.0 MPa			Compressor pressure 9.0 MPa		
	Storage capacity (h)	Required filling time (h)	Cycle duration (h)	Storage capacity (h)	Required filling time (h)	Cycle duration (h)
80,000	18.88	6.79	25.67	24.73	3.39	28.12
90,000	18.64	7.47	26.11	24.52	3.73	28.25
100,000	18.36	8.30	26.66	24.28	4.15	28.43
110,000	18.05	9.34	27.39	24.01	4.67	28.68
120,000	17.71	10.68	28.39	23.71	5.34	29.05
130,000	17.33	12.46	29.79	23.38	6.23	29.61
140,000	16.92	14.95	31.87	23.02	7.47	30.49
150,000	16.46	18.69	35.15	22.63	9.34	31.97
160,000	15.96	24.92	40.88	22.2	12.46	34.66
170,000	15.41	37.39	52.8	21.74	18.69	40.43

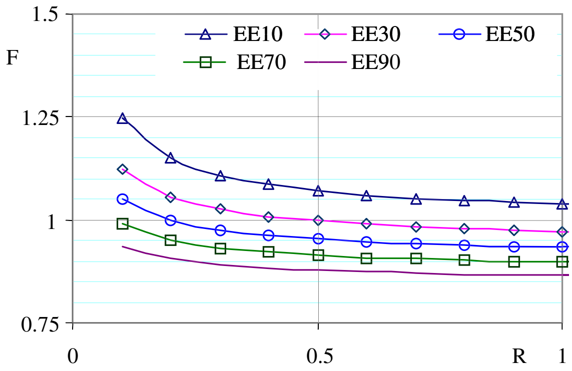

Fig. 11. Economy ratio for gas turbine driver, scenario 1.

in which NGC is the natural gas cost in US$ per million BTU, which was estimated to be 3 US$/MMBTU for Brazilian conditions. Considering the uncertainty and variability of energy cost, it is possible to evaluate two scenarios, as described below.

6.2.2. Scenario 1 (OPEC < EC < PEC)

In this scenario, the cost of electricity produced is between off-peak and peak tariffs, so the storage is only of interest when the focus is in the peak period. The annual economy is calculated according to Eq. (8), and it is assumed that it is possible to store natural gas all the days which presents electricity peak tariff.

$$\text{Economy} = 261 \cdot \text{TP} \cdot (\text{PEC} - \text{EC}) \tag{8}$$

A factor expressed by the ratio between the electric present value and natural gas present value, *F*, may be calculated as presented in Eq. (9) as the ratio between the conventional use of energy from the grid (Eq. (2)) and the cost of the alternative (Eq. (2)–Eq. (8)). In this case, the factor *F* is calculated according to Eq. (9), in which RR is the ratio between the electric energy produced and off-peak electric cost (EC/OPEC) and *R* is equal to the ratio between OPEC and PEC. If the natural gas price is 3 US$ per million BTU, EC is 37 US$/kWh, a cost higher than the peak period (reference values are 23.90 US$/MWh for off-peak and 34.70 US $/MWh for peak tariff). In this case, the alternative consisting of using the gas turbine to produce electricity must be discarded.

$$F = \frac{\{(24 - \text{TP}) \cdot R + \text{TP} \cdot \text{IP}\} \cdot 261 + 104 \cdot 24 \cdot R}{\{(24 - \text{TP}) \cdot R + \text{TP}\} \cdot 261 + 104 \cdot 24 \cdot R - 261 \cdot \text{TP} \cdot (1 - R \cdot \text{RR})} \tag{9}$$

Fig. 11 presents factor *F* for RR ranging from 1 to 9 and is performed with TP = 3 h (curve EE10 means RR = 1, EE30 means RR = 3, and so on). Note that for a reference *R* value of 0.5, the *F* factor is lower than the case of electrical driver in Fig. 10, for RR = 1.

6.2.3. Scenario 2 (EC < OPEC < PEC)

This scenario, in which the value of off-peak tariff ranges from the cost of electricity produced to the peak tariff, is more complex to be analyzed because both the total storage capacity (TEC) and the filling time (FT) in hours must be simultaneously considered. Filling and storage time are not cost dependent, but they are function of the physical characteristics of the process, such as pressure drop in duct, pressure p_1, and demand and compressor capacity. According to Sections 2 and 3, TEC and FT are determined for several operational conditions. As shown in Table 2, the cycle duration (CD) is higher than one day, and it is necessary to calculate the number of cycles per year, separately for the days with and without peak load tariff.

The variables relative to the number of cycles per year for days with peak tariff (N_{cp}) and for days without peak tariff (N_{sp}) are given by Eqs. (10) and (11), respectively.

$$N_{cp} = \frac{261 \cdot 24}{\text{CD}} \tag{10}$$

$$N_{sp} = \frac{104 \cdot 24}{\text{CD}} \tag{11}$$

The cost savings per cycle for the period with peak (E_{cp}) tariff is given by Eq. (12) and for the period without peak tariff (E_{sp}) by Eq. (13).

$$E_{cp} = (\text{OPEC} - \text{EC}) \cdot (\text{TEC} - \text{TP}) + (\text{PEC} - \text{EC}) \cdot \text{TP} \tag{12}$$

$$E_{sp} = (\text{OPEC} - \text{EC}) \cdot \text{TEC} \tag{13}$$

In these equations, TEC is considered to be lower than 24 h in every case and the use of storage is planned to include the peak tariff period. The economy factor (*F*) in this scenario is expressed by Eq. (14), considering that the economy obtained per cycle in peak periods is given by dividing Eq. (2) by the alternative present cost (in this case, Eq. (2) less Eq. (10) multiplied by Eq. (12) less Eq. (11) multiplied by Eq. (13)).

$$F = \frac{\{(24 - \text{TP}) \cdot R + \text{TP} \cdot \text{IP}\} \cdot 261 + 104 \cdot 24 \cdot R}{\{(24 - \text{TP}) \cdot R + \text{TP}\} \cdot 261 + 104 \cdot 24 \cdot R - N_{CP} \cdot (R - R \cdot \text{RR}) \cdot (\text{TE} - \text{TP}) + (1 - R \cdot \text{RR}) \cdot \text{TP} - N_{SP} \cdot (R - R \cdot \text{RR}) \cdot \text{TE}} \tag{14}$$

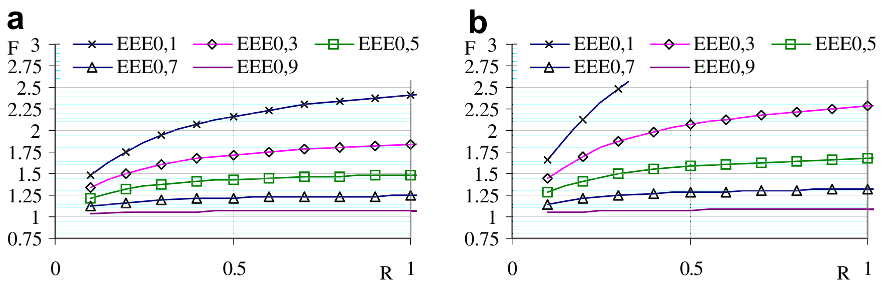

Fig. 12. Economy factor for gas turbine driver, scenario 2, 80,000 S m^3/h: a) 8.0 MPa b) 9.0 MPa.

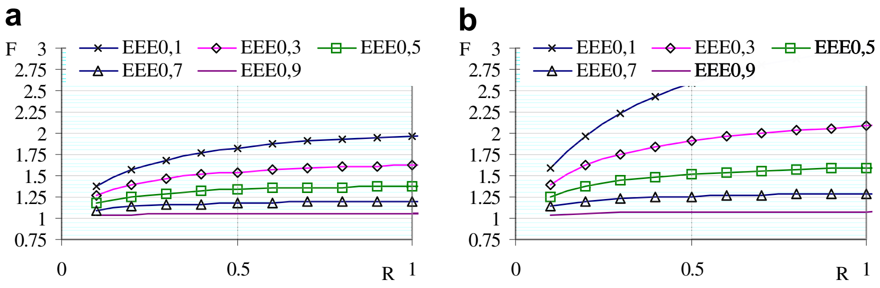

Fig. 13. Economy factor for gas turbine driver, scenario 2, 120,000 S m^3/h: a) 8.0 MPa b) 9.0 MPa.

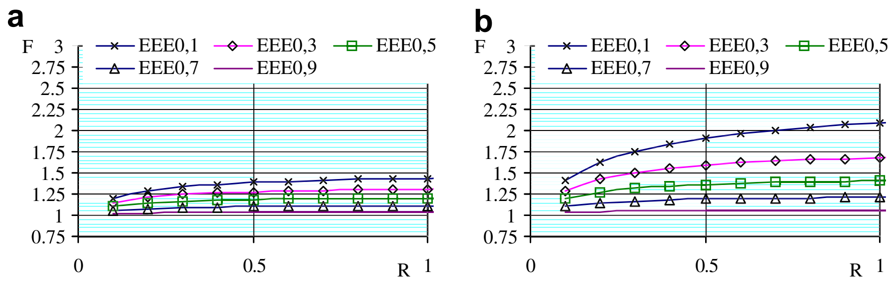

Fig. 14. Economy factor for gas turbine driver, scenario 2, 160,000 S m^3/h: a) 8.0 MPa b) 9.0 MPa.

Figs. 12–14 present the economy factor F for three natural gas flow and two outlet compressor pressure p_1. As expected, for the same level pressure, the factor F decreases with the natural gas flow due to a higher pressure drop that conduces to a lower mean pressure in the pipeline. For the same natural gas flow, the factor F increases with the augmentation of pressure, as the mean pressure also increases, resulting in more natural gas accumulated inside the duct (curve EEE0,1 means RR = 0.1, EEE0,3 means RR = 0.3, and so on).

A comparison among some of the investigated conditions is presented in Fig. 15 for a peak period (TP) of 3 h. For the gas turbine driver scenario 1, it was considered RR = 5 (curve EE50) and RR = 1 (curve EE10). For the gas turbine driver scenario 2, a natural gas flow of 120,000 S m^3/h and a compressor pressure of 9.0 MPa were considered for RR = 0.5 (curve EEE0,5).

When the cost of electricity produced from natural gas storage is between OPEC and PEC (curves EE50 and EE10), the advantages only occur for OPEC <<< PEC, i.e., for $R <<< 1$, and the same is applicable in the case of electric motor driver (curve E3). Curve EEE0,5 is not presently applicable because when using a cost of US$ 3 per million BTU and the actual turbine efficiency, EC > PEC and the alternative has no advantage.

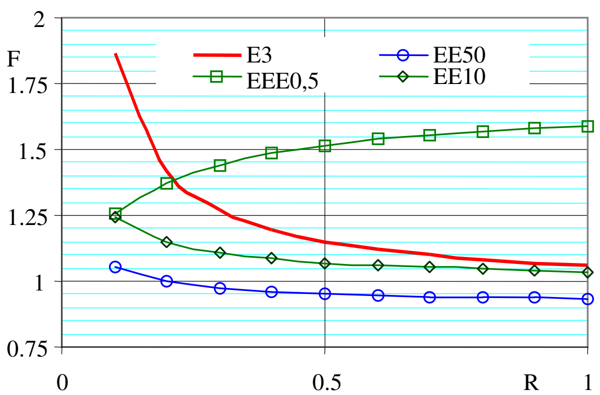

Fig. 15. Comparison of alternatives.

7. Conclusions

The economy factor presents higher values for the electrical driver when the turbine electricity cost is between OPEC and PEC, and normally a decision adopted with focus in the electric driver case is based on a more reliable scenery since today, in Brazil, the relation between OPEC and PEC is well known, while the cost of natural gas is not so predictable.

According to Fig. 15, the percentage of economy is around 5% when the compressor driver is a gas turbine and the cost of electricity produced by the turbine lies between OPEC and PEC, for a factor $R = 0.5$. In the case of an electric motor compressor driver, the economy is around 13% and in an "idealized" case in which the cost of the electricity produced by the gas turbine is a lower OPEC, this economy is 33% if the cost is one half of OPEC (EEE0,5 ⇒ RR = 0.5)

The storage procedure proposed in this work may be applicable only after a verification of electricity and natural gas cost which can be increased by an eventual additional operating and capital costs. In practice, this method seems to be suitable to be adopted when the driver is an electric motor. On the top of this, the storage concept implantation claims a strategic planning, to be made in conjunction with the other correlated plants or stations.

The possibility of using a heat recovery steam generator for cogeneration purposes in the case of gas turbine driver is not affected when employing the storage potential. In the case of combined cycle application, the electric output of this cycle will be variable, being necessary to analyze if natural gas storing can bring some inconvenience. As the duct will be subject to different operational conditions, studies about the mechanical effects in the duct and compressor applying the line-pack procedure here proposed must be carried out.

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