Energy analysis of a CCGT power plant integrated to a LNG regasification process

Diogo Angelo Stradioto[a], Marina Fonseca Seelig[b], Paulo Smith Schneider[c]

[a] APS Soluções em Energia, *Porto Alegre, Brazil, diogo@apsengenharia.com.br*
[b] Department of Mechanical Engineering UFRGS, *Porto Alegre, Brazil, marinaseelig@mecanica.ufrgs.br*
[c] Department of Mechanical Engineering UFRGS, *Porto Alegre, Brazil, pss@mecanica.ufrgs.br*

Abstract:
This paper examines the performance of a combined cycle gas turbine plant (CCGT) when integrated to the cold energy released during the regasification process of liquefied natural gas (LNG). A growing number of LNG import terminals supply regasified natural gas for power generation, with an adjacent CCGT plant providing an anchor market for the facility itself. Two integration alternatives with mutual energetic gains are proposed and simulated, and compared to a reference case without any use of the LNG cold potential. The first alternative consists on exchanging heat among LNG and the Brayton cycle air intake. The second one adds a novel recovery opportunity by exchanging heat with the Rankine cycle condenser. On both cases, heat from the CCGT is rejected to a lower temperature level than the one of the regular dead state. From the regasification side, the process is performed without any help of extra external energy. Both integration alternatives led to an electrical efficiency enhancement when comparing to the non-integrated cycle: 6.32% and 9.09%, respectively. The energy return on investment (EROI) of each alternative is also analyzed and gains of 12.92% and 18.57% are predicted via simulation.

Keywords:
LNG, Liquefied Natural Gas, EROI, Energy Return on Investment, Plant Integration, Regasification.

1. Introduction

Natural gas is seen as a cleaner burning alternative to other fossil fuels, and has an expanding role in power production [1]. Options for exporting natural gas from stranded oil and gas fields to markets include pipelines, liquefied natural gas, compressed natural gas, gas to liquids, gas to solids, and gas to wire, the first two being the common methods of transport [2]. Liquefied natural gas (LNG) is ideally transported in cryogenic tankers by road, ships and rail wagons, playing a key role bringing gas to the market when distance or natural obstacles make pipeline transport not possible. The increasing supplies of LNG accompanied by the increased flexibility in LNG trade are adding security to gas supply [3].

The LNG chain consists basically of gas production, liquefaction, shipping, and regasification. The liquefaction process transforms natural gas into liquid by cooling it to -163°C, after which it is stored until it can be shipped on board LNG tankers to the import terminal, where the cold liquid is warmed back into gas and sent into the pipeline system as fuel [4]. Due low temperatures involved, a significant quantity of cold energy is available during the regasification process, and the majority of current LNG import terminals do not make use of it: this energy is simply dissipated to the environment via air or sea [5].

Most NG reserves are offshore and away from demand sites. The storage and transportation of NG is a critical technology and cost issue. Pipelines represent a security risk and are not always feasible or economical. They are often limited by a limited amount of NG that can be transported. Alternately, an attractive option is to liquefy NG at -163 °C at the source and then transport it as liquefied natural gas (LNG) by specially built ships or tankers that are essentially giant floating flasks. When liquefied, the volume of natural gas reduces by a factor of about 600 at room temperature, which facilitates the transport of NG. In fact, LNG is the most economical way for transporting NG over distances more than 2200 miles onshore and 700 miles offshore [6]. LNG provides an excellent example of design for logistics. Because major end user markets of Asia, Europe, and North America are thousands of miles away from the major exporting countries such as Indonesia, Qatar, Trinidad, among others, LNG is becoming an increasingly global energy option and considered as the fuel for the future.

A growing number of LNG import terminals supply regasified natural gas for power generation with an adjacent natural gas driven power plant, providing an anchor market for the LNG receiving facility itself [4]. An interesting use for LNG cold energy is inlet air cooling to power generation gas turbines: cooler air has a higher density and thus, for a fixed volumetric flow rate, a larger mass enters the air compressor of the gas turbine, increasing power output. Sharratt [5] explains that in a combined cycle gas turbine plant (CCGT) a further enhancement is possible by chilling also the cooling water used in the steam condenser downstream of the turbine generator, lowering the steam condensing pressure, increasing power generation further. As heat is exchanged, LNG is warmed, thus other interesting integration is using this machinery residual heat in LNG vaporization: a cogeneration plant for the simultaneous generation of electricity and regasification of LNG, as revised by Morosuk and Tsatsaronis [7]. According to these authors, the concepts based on combined cycles for cogeneration systems are discussed only in recent publications, as in Shi *et al.* [8], where an integrated advanced thermal power system was proposed to improve the performance of a conventional 200 MW CCGT power plant by inlet air cooling and compressor inter-cooling with LNG cold energy utilization, using the latent heat of spent steam from a steam turbine and the heat extracted from the air during the compression process to vaporize the LNG. Net electrical efficiency was increased by 2.8% and overall work output by 76.8 MW, while delivering 75.8 kg/s of natural gas to the supply system.

Sharratt [5] pointed out that the performance gain of such enhancing integrations depend on the value of the surplus of the exported energy, as the cost of both the LNG import terminal and the power plant will increase, so that the return on investment (ROI) must be analysed. In this paper, the energy return on investment (EROI) replaces the monetary ROI of such integrations as an assessment parameter. According to Weißbach et al. [9], the EROI is a very important parameter in investment decision in energy sector as it describes the overall life-cycle efficiency of a power supply technique, independently from temporary economical fluctuations or politically motivated influences, which can distort the perception of real proportions.

The present work is about the energy integration of LNG import terminals to adjacent power plants, aiming mutual profits for both systems. There are several opportunities for performance enhancement and clever use of the residual non-workable energy from the power plant side into the regasification process, as well as the very low temperature of that last system can change the temperature level of the environment, the restricted dead state. The performance of a regular CCGT plant is examined when integrated to the cold energy released during the LNG regasification process, turning otherwise waste heat into electricity. Two integration alternatives are compared, and the energy return on investment is analysed, which is an original approach.

2. Supply Chain Of LNG

The Figure 1 shows the supply chain of LNG in details. Streams of mass and energy are depicted, taking into account that the supply chain begins right after the extraction pit of Natural Gas, where methane (CH_4) is separated from the other components of the mixture, and CH_4 is pressurized to be send to the liquefaction process, where it is again purified. Liquefaction is achieved at a temperature of about – 163ºC, demanding a high amount of energy, and it is labeled as

Liquefied Natural Gas (LNG), although being pure methane. At that point, LNG is ready for delivery overseas. The last procedure to be considered in the chain is the LNG regasification process, performed with the aid of external heat from sea water.

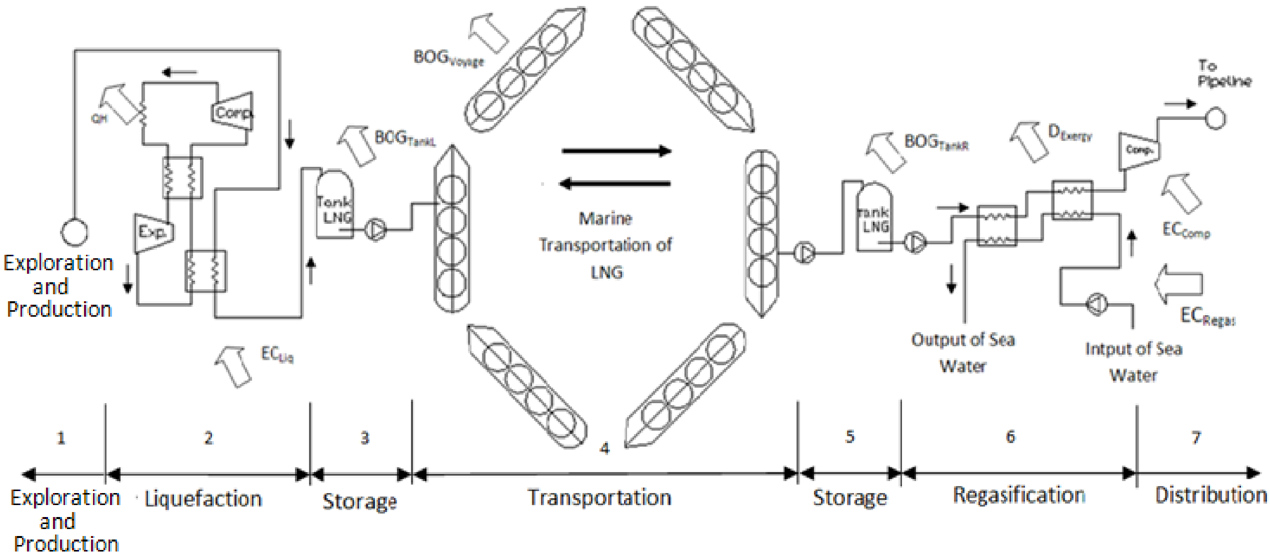

Figure 1. Supply Chain of LNG

Figure 2 shows the exergetic along the supply chain of LNG. It starts at zero at the dead state and will suffer increases or decrease, in each stage, in accordance with the generation or destruction of exergy. The destruction of exergetic in the cycles of exploration and purification are neglected.

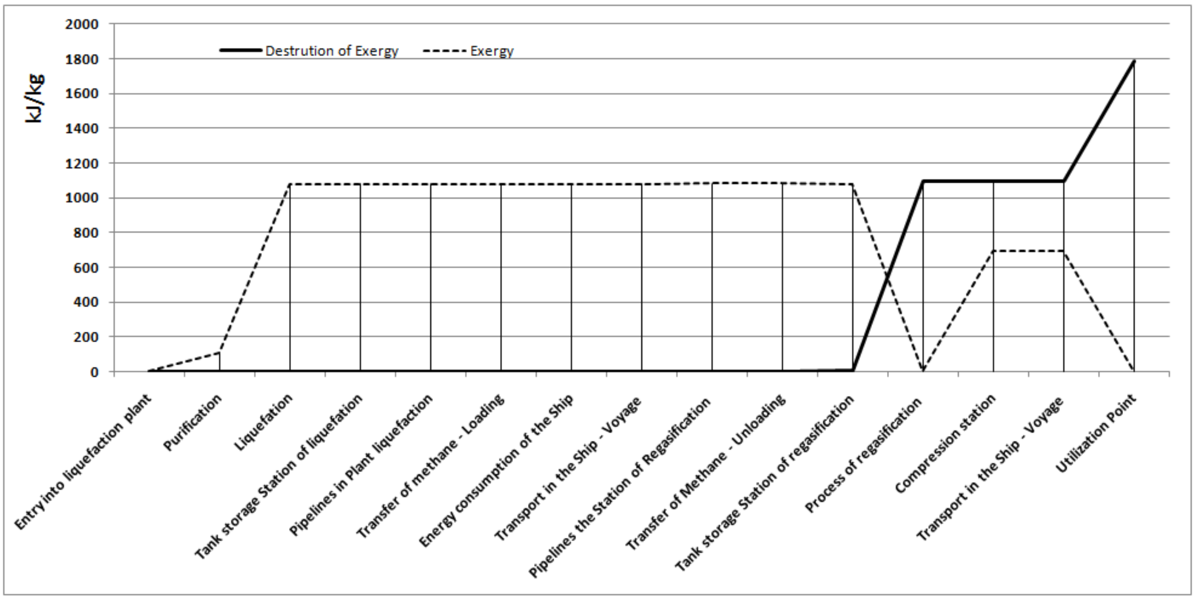

Figure 2. Exergy and exergy destruction along the Supply Chain of LNG

The substantial increment of exergy in the stream takes place at the liquefaction process and pressurization of methane, and its destruction is occurs at the regasification process and point of utilization.

The destruction of exergy occurs mainly on two points, the first and most significant is the regasification plant, destroying 1078 kJ/kg of methane, due to heat exchange be made with sea water, and the second point is the change in pressure throughout valves next to the points of use.

3. Description of integrated cycles

A conventional non-integrated CCGT power cycle was modelled and two integration alternatives were proposed with the aim of mutually increasing the efficiency of both the power system and the regasification process separately, and therefore the overall performance. Figure 1 shows the three simulated schemes, listed in Table 1.

Table 1. Simulated schemes for performance analysis

System	Description
Reference	Reference non-integrated or stand-alone CCGT power plant
Alternative 1	LNG integrated to the Brayton cycle inlet air cooling
Alternative 2	LNG integrated to both the Brayton cycle inlet air cooling and the Rankine heat rejection to the environment

The reference CCGT power plant is a regular combined Brayton-Rankine cycle without any integration to the LNG regasification process, and natural gas is supplied from a pipeline. Natural gas is supplied to the gas turbine at point 30 (green line), air flows from points 1 to 7 (blue lines, the Brayton cycle working fluid), flue gas flows from points 8 to 14 (red lines), and the Rankine plant working fluid circulates in cycle from points 15 to 28 (the brown lines). On the reference case, water is the Rankine working fluid and heat is exchanged to the environment against another liquid water stream at the condenser.

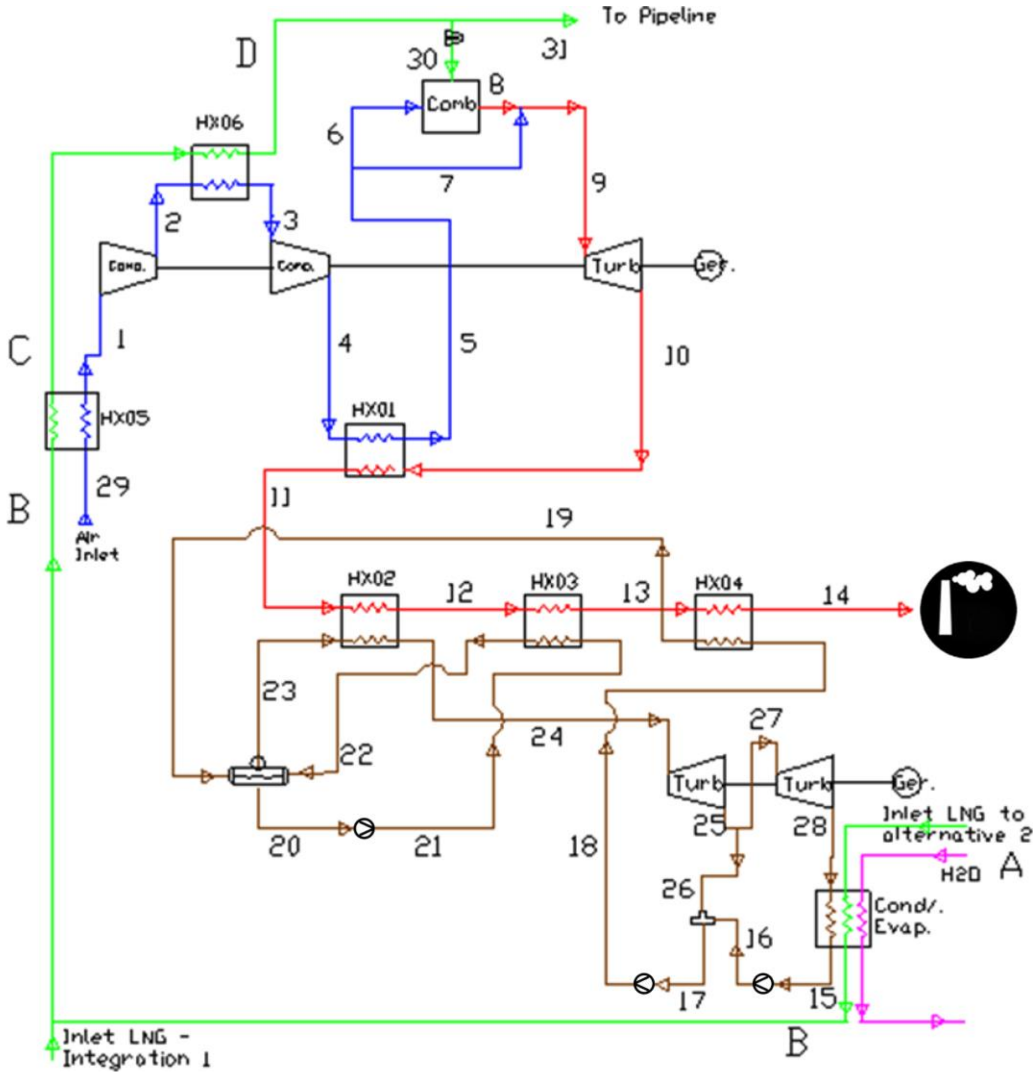

Fig. 3. Scheme of the conventional CCGT power plant and LNG regasification integration alternatives

Integration alternative 1 uses LNG cold energy integrated at the Brayton inlet air cooling, at the HX05 heat exchanger (points B to C) and HX06 (points C to D). Heat exchanger HX05 acts as an evaporator as it turns LNG into gas and the second one acts as an intercooler, heating the natural gas. Heat integration in alternative 2 starts at Rankine cycle heat rejection to environment. At the condenser unit, LNG changes phase from liquid to gas from point A to B, while the cycle working fluid is condensed at a lower temperature level than the regular dead state. Rankine cycle working fluid (water) is condensed at a lower temperature because the pressure has been lowered in this alternative to take advantage of the available lower temperature heat sink. Natural gas at low temperature is again exchanged against the air intake flow of the Brayton cycle. Heat exchanger HX05 is a sensible heat exchanger, without fluid phase change (points B to C), and HX06 (points C to D) still acts as an intercooler.

The main modelling assumptions were: steady state regime; air is modelled as an ideal gas with neglected humidity; LNG is assumed to be pure methane; pressure drop and heat loss along the pipe of hydraulic circuit are neglected. Brayton cycle power was fixed to 30 MW, working with 20.5 bar air pressure after the second compression stage and 1246°C|1519.15K flue gas temperature at the expansion turbine inlet. The efficiency of the air compressor and the pumps were assumed 0.85 and the isentropic efficiency of both turbines were assumed 0.88. Heat exchanger efficiencies were assumed 0.99. Table 2 shows the state and mass flow rate of all streams for the reference (Ref.) cycle and its two integration alternatives (Int. 1 and 2). System simulation was performed with aid of IPSEpro simulation software (http://www.simtechnology.com).

Table 2. Thermodynamic state and mass flow rate of the working fluids in respect to the points indicated in Figure 1 for the reference cycle and the two energy integration alternatives

Point	Fluid	Temperature (K)			Pressure (bar)			Mass flow rate (kg/s)		
		Ref.	Int. 1	Int. 2	Ref.	Int. 1	Int. 2	Ref.	Int. 1	Int. 2
A	LNG	NA	NA	110.55	NA	NA	1.01	NA	NA	22.44
B	GN/LNG	NA	110.55	203.05	NA	1.01	1.01	NA	6.24	22.44
C	Gas	NA	127.54	234.15	NA	1.01	1.01	NA	6.24	22.44
D	Gas	NA	298.15	298.15	NA	1.01	1.01	NA	6.24	22.44
1	Air	298,15	245.12	280.47	1.01	1.01	1.01	86.15	63.94	70.21
2	Air	551,96	382.97	437.69	7.50	7.00	7.00	86.15	63.94	70.21
3	Air	551,96	339.30	372.46	7.50	7.00	7.00	86.15	63.94	70.21
4	Air	769,02	571.04	624.52	20.50	20.50	20.50	86.15	63.94	70.21
5	Air	793,15	785.15	785.15	20.50	20.50	20.50	86.15	63.94	70.21
6	Air	793,15	785.15	785.15	20.50	20.50	20.50	29.52	21.66	23.44
7	Air	793,15	785.15	785.15	20.50	20.50	20.50	56.63	42.26	46.77
8	CP	2614,46	2601.15	2609.25	20.50	20.50	20.50	31.15	22.90	24.78
9	CP + Air	1519,15	1519.15	1519.15	20.50	20.50	20.50	87.78	65.16	71.56
10	CP + Air	842,37	834.74	834.48	1.10	1.10	1.10	87.78	65.16	71.56
11	CP + Air	820,06	648.03	685.51	1.10	1.10	1.10	87.78	65.16	71.56
12	CP + Air	725,48	628.47	647.99	1.10	1.10	1.10	87.78	65.16	71.56
13	CP + Air	453,15	453.15	443.15	1.10	1.10	1.10	87.78	65.16	71.56
14	CP + Air	398,15	398.15	398.15	1.02	1.02	1.02	87.78	65.16	71.56
15	Water	362,16	354.07	293.15	1.00	0.60	0.10	13.94	5.93	9.12
16	Water	362,16	354.07	293.15	10.00	10.00	10.00	13.94	5.93	9.12
17	Water	368,45	359.36	319.35	10.00	10.00	10.00	13.94	6.33	9.71
18	Water	368,45	359.36	319.35	95.00	95.00	95.00	13.94	6.33	9.71
19	Water	435,63	442.52	416.56	95.00	95.00	95.00	13.94	6.33	9.71
20	Water	580,57	580.50	580.43	95.00	95.00	95.00	13.94	6.33	9.71
21	Water	580,57	580.50	580.43	95.00	95.00	95.00	13.94	6.33	9.71
22	Water	585,25	584.21	583.82	95.00	95.00	95.00	13.94	6.33	9.71
23	Water	580,54	580.46	580.39	95.00	95.00	95.00	13.94	6.33	9.71
24	Water	673,15	628.15	653.15	95.00	95.00	95.00	13.94	6.33	9.71
25	Water	453,03	453.03	453.03	10.00	10.00	10.00	13.94	6.33	9.71
26	Water	453,03	453.03	453.03	10.00	10.00	10.00	1.04	0.4	0.59
27	Water	453,03	453.03	453.03	10.00	10.00	10.00	12.90	5.93	9.12
28	Water	372,75	359.07	293.95	1.00	0.60	0.10	12.90	5.93	9.12
29	Air	298,15	298.15	298.15	1.01	1.01	1.01	86.15	63.92	70.21
30	Gas	298,15	298.15	298.15	21.00	21.00	21.00	1.632	1.24	1.34
31	Gas	NA	298.15	298.15	NA	1.01	1.01	NA	5.0	21.10

4. Cycle performance

The energetic performance η of the CCGT and its two alternatives of connection to LNG is given by

$$\eta = \frac{\dot{E}_{TOT}}{(\dot{m}_{30}LHV)_{NG}} \tag{1}$$

where the denominator is the only energy input of the system, the product of the natural gas flow rate $\dot{m}_{30}$ (kg/s) to its Lower Heating Value *LHV*, assumed as 50 MJ/kg. The net output $\dot{E}_{TOT}$ (MW) is given by

$$\dot{E}_{TOT} = \dot{W}_{Brayton} + \dot{W}_{Rankine} + \dot{E}_{Reg} \tag{2}$$

where $\dot{W}_{Brayton}$ and $\dot{W}_{Rankine}$ are the net electrical output power from the combined systems (MW). The last term $\dot{E}_{Reg}$ of this equation stands for the LNG regasification heat rate (MW), supplied by heat rejection by the CCGT on both coupling alternatives, given by

$$\dot{E}_{Reg} = \dot{m}_{31}(h_{31} - h_{LNG})/1000 \tag{3}$$

$\dot{E}_{Reg}$ is an extra gain for the coupled systems and correspond to the heat rate of regasification of the natural gas flow rate surplus $\dot{m}_{31}$, ready to be piped outside the power plant at point 31. The non-integrated CCGT displayed null values for this stream as there is no energy recovery, and it assumed different amounts according to the type of integration. Data on that equation are the enthalpy of regasified natural gas at point 31 (h_{31}= -20.8 kJ/kg @[*P*= 21 bar, *T*=25.0°C|298.15K]) and LNG enthalpy (h_{LNG}=-911.9 kJ/kg @[*P*= 21 bar, *T*= -162.6°C|110.55K]). Table 3 brings the most relevant results for the reference cycle and its coupling alternatives.

Exergy efficiencies of the cycle are given by

$$\varepsilon_{Ecycle} = \frac{\dot{W}_{liqB} + \dot{W}_{liqR} + \dot{m}_{31}(E_{LNG}^{PH} - E_{31}^{PH})}{\sum Ex_E} \tag{4}$$

E^{PH} is the physical exergy in the methane, and Ex_E is the sum of the chemical exergy (E^{CH}) in the stream 30 (combustor) and physical exergy in stream B. Entry exergy is given by

$$Ex_E = \dot{m}_{30}E_{NG}^{CH} + \dot{m}_B(E_{LNG}^{PH} - E_{31}^{PH}) \tag{5}$$

Figure 4 shows energy inputs and outputs of cycles.

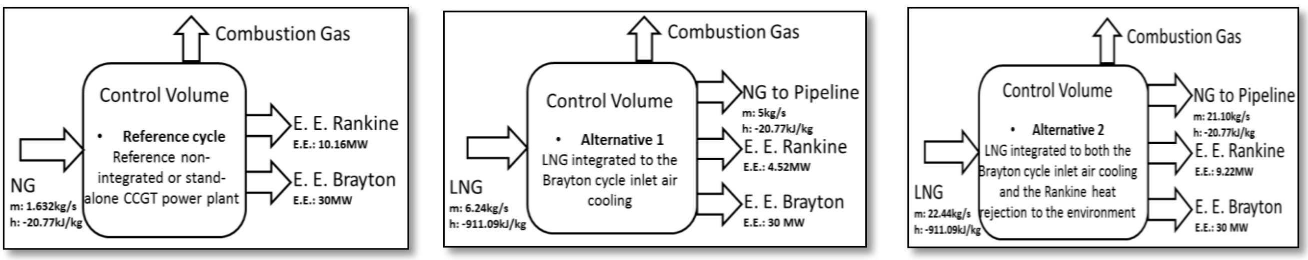

Fig. 4. Control volume of the conventional CCGT power plant and LNG regasification integration alternatives

Table 3. Main system outputs for the reference CCGT and the two proposed integration alternatives depicted in Figure 1 (fixed value)*

#	Output	Reference	Integration 1	Integration2
1	Inlet air temperature at Gas turbine, Point 1 [°C, K]	25.00 298.15	-28.00 245.15	7.30 280.45
2	$\dot{W}_{Brayton}$[MW] *	30.00	30.00	30.00
3	$\dot{W}_{Rankine}$[MW]	10.16	4.52	9.22
4	$\dot{W}_{Brayton} + \dot{W}_{Rankine}$ [MW]	40.16	34.52	39.22
5	$\dot{E}_{Reg}$[MW] (Eq. 2)	NA	4.46	18.80
6	$\dot{E}_{TOT}$[MW] (Eq. 3)	40.16	38.98	58.02
7	Net electrical efficiency [%]	49.22	55.54	58.31
8	Net energetic efficiency [%] (Eq.1)	49.22	62.76	86.34
9	Net exergy efficiency [%] (Eq. 4)	47.07	57.55	67.13
10	Fuel consumption [kg/s]	1.632	1.242	1.344
11	Specific power output [MW/kg_{fuel}]	24.61	27.79	29.18
12	Regasification capacity [kg/s]	0	8.15	27.00
13	Ratio of regasified to consumed natural gas	NA	4.00	15.70
14	Increased of efficiency [%]	NA	6,32	9,09

Brayton cycle net power output was set to the fixed value of 30 MW (line 2). Combined Rankine cycle net output (line 3) depended on the amount of flue gases that were discharged by the gas turbine. The highest net output for that cycle was obtained for the reference cycle, as it consumed the highest amount of fuel (line 9), and therefore producing more fuel gases. When observing the net electrical efficiency (line 7), the integration strategies achieved higher performances, as the fuel consumption dropped when both Brayton and Rankine cycles worked on a lower environmental temperature. Heat exchanged by both cycles was symbiotically employed to bring LNG back to the gas phase and furthermore to heat it up to the regular dead state. Regasification energy rate $\dot{E}_{Reg}$ (line 5) represents an avoided energy and was considered as a useful energy output of the system. Energetic efficiency (line 8) went from approximately 50% for the reference cycle up to 86% when considering both the performance gains of the power cycles and the avoided energy of the LNG regasification process. Heat exchange process was able to deliver to the pipeline four times more natural gas than the consumed amount to the power system in alternative 1, and more than 15 times in alternative 2 (line13).

Figure 5 allows following the air temperature profile along the gas turbine, from the environment (point 29) until the regenerator heat exchanger HX01 (point 4), before the combustion chamber intake. Throughout that path, LNG was heated and regasified (points B to C) and then superheated (point C to D). Natural gas enthalpy change was about 14,300 $kJkmol^{-1}$, or 900 $kJkg^{-1}$.That amount of energy would otherwise be given by an auxiliary system on a non-coupled plant. From the Brayton cycle side, the temperature drop on HX05 and HX06 lead to a gain in compression performance. In the reference plant, air was admitted at the compressor intake (point 1) at 25°C|298.15K and again at the second intake (point 3) at approximately 300°C|573.15K. The air temperature at these same points drop to -28°C|245.15K and 66°C|339.15K in alternative 1 and 7°C|280.15K and 99°C|372.15K in alternative 2.

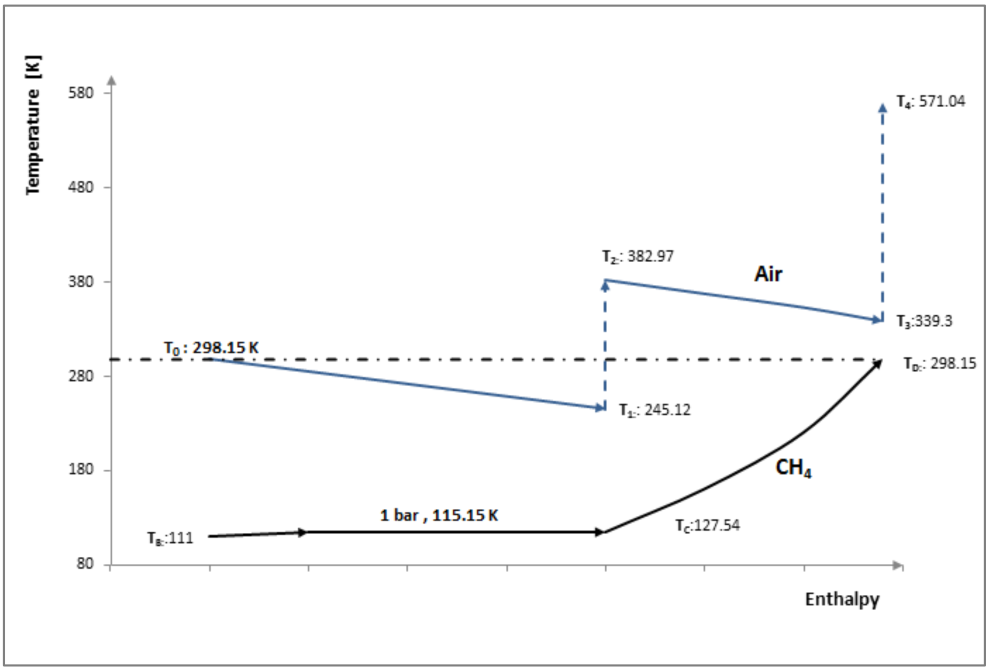

Fig. 5. Enthalpy change of methane along the regasification process followed by the Brayton inlet air temperature profile for the integration alternative 1

Figure 6 adds the Rankine cycle behavior to the one presented formerly, focused on integration alternative 2. The rejection temperatures drop lead to a lower condensation pressure that is the main reason to the gain in conversion performance of the cycle. On the reference plant, the working fluid temperature was set to about 80°C|353.15K (points 15 and 28, Figure 3 or Table 2), and these same points were lead to operate at about 20°C|293.15K due to the integration with the LNG regasification. Although there was a significant increase in cycle efficiency, there was a reduction on net power output on the Rankine cycle for both integration alternatives. The Rankine cycle depended on the heat recovery from the Brayton cycle flue gases (HX02, 03 and 04), which had been reduced as the fuel consumption was improved after the integration strategies.

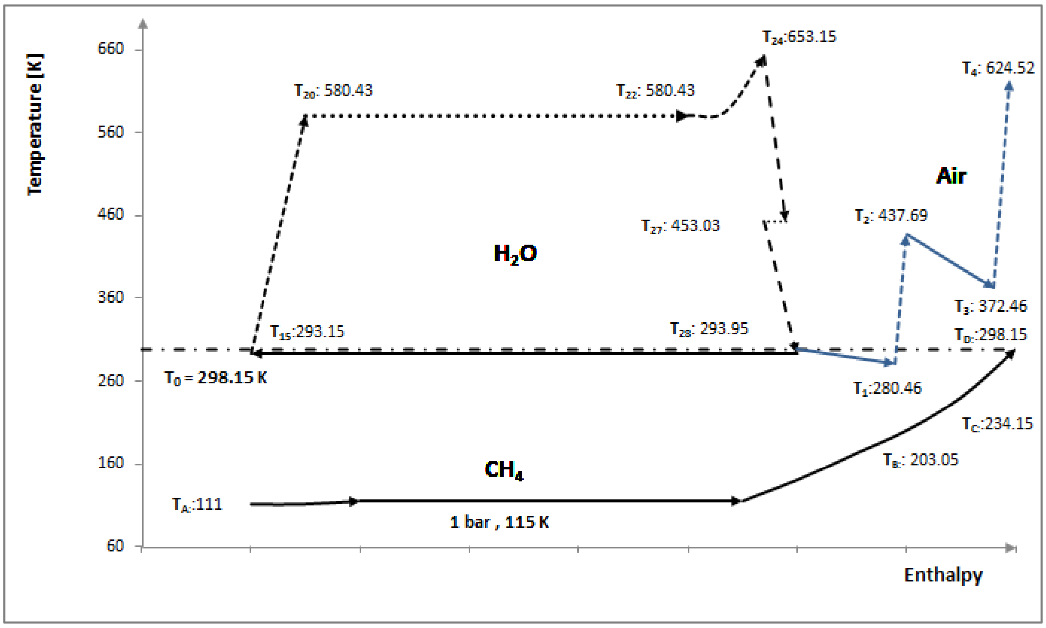

Fig. 6. Enthalpy change of methane along the regasification process followed by the Brayton inlet air temperature profile and the Rankine water temperature profile for the integration alternative 2

5. Energy return on investment of the integrated alternatives

The *EROI* of a power plant is the ratio of usable energy returned by the plant along its lifetime to the overall invested energy needed to make this energy usable [8]. The returned energy is the product of average power P times assessed elapsed time t. Invested energy has a fixed part for construction and deconstruction E_{fix}, and a variable time dependent amount P_I, that stands for maintenance and fuel provisioning.

$$EROI = \frac{Pt}{E_{fix}+P_I t} \tag{6}$$

According to Weißbach *et al.* [9], for most power plants, energy invested in maintenance and fuel provision during plant lifetime is small when comparing to the fixed demand and the energy output. Gas fired power plants are an exception, with energy demand dominated by P_I, in extraction and refining of natural gas. In order to know P_I, the LNG chain must be analyzed.

In the present work, the focus was the EROI gain of the proposed integrations. The energy required for provisioning fuel for the three simulated plant scenarios was considered the same. Although the reference plant needs an additional regasification system, according to [7] the energy consumption of the regasification process with open rack vaporizers is approximately 28.8 kJ/kg for driving the sea water circulating pumps. This number is negligible when compared to the energy consumption of the liquefaction process, 1800 kJ/kg according to [9].

As P_I was considered the same in all scenarios, the EROI gain of the proposed integrations will be the power output enhancement. As fuel consumption is different in each simulation, the specific power output must be considered. As on Table 3, it was 24.61 MW/kg_{fuel} for the reference plant, 27.79 MW/kg_{fuel} for integration 1 and 29.18 MW/kg_{fuel} for integration 2. Thus, integration 1 leads to a 12.92% gain in the EROI when comparing to the EROI of the reference plant, and integration 2 leads to an 18.57% gain in the EROI when comparing to the EROI of the reference plant. This is an important parameter in investment decision in energy sector.

6. Conclusion

Two alternatives for LNG cold energy integration to a regular combined cycle power plant were examined: LNG integrated to the Brayton cycle inlet air cooling, and LNG integrated to both the Brayton cycle inlet air cooling and the Rankine heat rejection to the environment. Both integration alternatives lead to an electrical efficiency enhancement when comparing to the non-integrated cycle: from 49.22% for the reference case to 55.54% for alternative 1 and 58.31% for alternative 2, a gain of 6.32% and 9.09%, respectively. When considering the overall performance, which includes the thermal energy for LNG regasification, alternative 1 reached 62.76% and alternative 2 reached 86.34% considering a 1^{st} law efficiency analysis. Exergy efficiency improved from 47.07% in reference case to 57.55% and 67.13% for alternatives 1 and 2 respectively. The energy return on investment of each alternative was also enhanced by 12.92% and 18.57%, respectively.

Acknowledgments

Authors acknowledge the financial support: Seelig acknowledges CAPES (AUX-PE-PNPD 2503/2009), Smith Schneider acknowledges CNPq (PQ 305357/2013-1).

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