DEMOSOFC

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Cost/benefit analysis of the system

Task T2.5: Cost/benefit analysis of the system

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Abstract:

The investment costs of the components of DEMO plant have been calculated, as well as the costs occurring during the operations. The cost estimation has only involved the new pieces of equipment used for moving, cleaning and converting biogas into heat/power.

A mathematical model has been formulated in order to perform an optimization analysis to obtain the optimal scenario in which the plant may work with the minimum total costs. The results are presented in terms of energy flows and costs and show the best operational decisions on an hourly basis which minimize total operating costs. The operating decisions are: the status of operation of each fuel cell (on/off as well as operating regime), level of biogas in the gas holder, flow rate of biogas to each cell, flow rate of biogas unexploited or burned in the boiler, flow rate of natural gas as well as the electricity imported from the grid.

The base case scenario refers to the configuration in which the plant works at its nominal capacity and specifically three modules of SOFCs – coupled to one heat exchanger each – are fuelled by the biogas (obtained by anaerobic digestion), previously cleaned through a siloxanes and sulphur removal system.

In addition to the base case simulation, further simulations have been made and for each the optimal solution have been obtained, adapting the mathematical model when necessary. The additional scenarios that have been simulated are:

- Addition of one module of SOFC;
- Sludge pre-thickening;
- Alternative energy market;
- Alternative technologies.

Each scenario has been individually compared to the base case and an overall comparison only in terms of costs is presented.

Keyword list: biogas, SOFC, mathematical, system design, techno-economic analysis, WWTP, optimization.

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1. **Purpose of this document**

The core part of this task consists in the formulation of a mathematical model in order to minimize the costs of the operations of DEMO plant.

The cost appraisal of the DEMO has been estimated from using the thermal load, the electrical demand of the plant as well as the biogas rate provided by SMAT and POLITO.

The mathematical model was implemented in the software GAMS®, which performs a simultaneous assessment of all the possible solutions in terms of operating strategies according to the features of the plant. The optimization provides the minimum costs that can occur in the wastewater treatment (WWTP) in Collegno on the basis of the operation of the SOFC modules.

This document presents a list of scenarios as agreed with POLITO and SMAT to allow a comprehensive evaluation of the possible alternative in which the DEMO plant can operate.

2. **DEMO cost estimation**

In this section, the cost estimation of both investment and operating costs is presented. The investment costs of the equipment are estimated following the procedure proposed by Timmerhaus et al. [1]. The replacement costs are calculated only for certain components, such as fuel cells and adsorbents. These costs are supposed to occur every three years.

The analysis of the operating costs is carried out by the software GAMS®, since they are the decision variables in the mathematical model.

The year 2015 was used as a reference for the techno-economic appraisal and strategic optimisation of the plant. As such, the hourly biogas flow as well as the electricity consumption and heat load as recorded by SMAT in 2015 was used as inputs onto which the optimisation was carried out.

The biogas produced from anaerobic digestion flows first into a gasholder that redirects it to the different components according to the operations and requirements of the plant. The biogas can be sent to the fuel cells (*BG Fuel Cell*) – to produce electricity and heat – or to a boiler (*BG boiler*) – for direct combustion – in the case it does not match specific requirements in terms of flow rate. The biogas can also be flared to the environment whether it exceeds the maximum capacity of the gasholder.

In the case in which the production of biogas does not meet the thermal demand both through the SOFC system and the combustion in the boiler, it is necessary to withdraw natural gas from the network and burn it in the boiler.

In *Figure 2.1* the schematic representation of the gases flowing into the plant is shown.

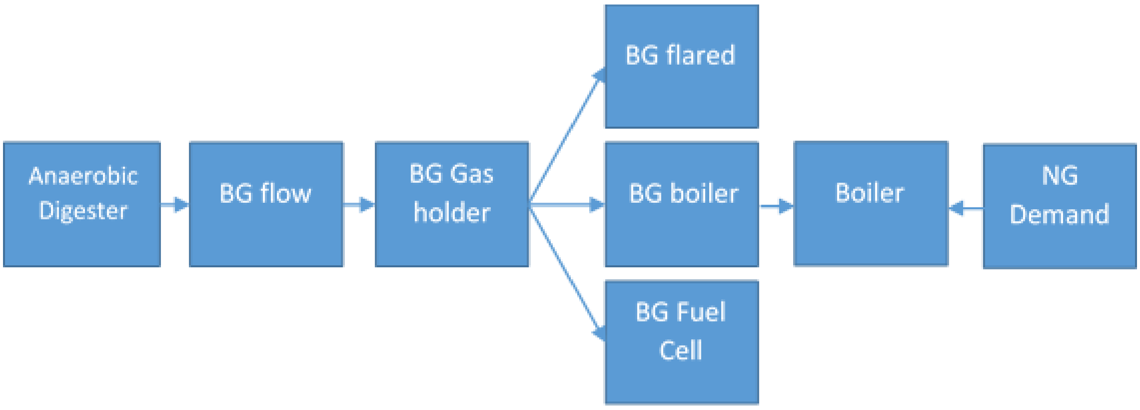


Figure 2.1 Gas scheme

Investment costs

Only the equipment newly installed and not previously existing is part of the analysis. These components are highlighted in the boxes in *Figure 2.2* with a blue code each:

- B → blower;
- CH1 → chiller before biogas clean-up;

- CU1 → Si/S removal system, including 4 columns and the adsorbent;
- CU2 → scavenger, including 2 columns and the adsorbent;
- K → compressor;
- CH2 → chiller after the biogas clean-up;
- SOFC → fuel cell modules (SOFC1, SOFC2, and SOFC3);
- HEX → heat exchangers for heat recovery (HEX1, HEX2, and HEX3).

The approach described in Timmerhaus et al. [1] was used to estimate the purchased cost of a component through plots, scaled according to the size range and the type of equipment.

All the costs in [1] are provided in USD 2002. A conversion to euros at the average exchange rate of year 2015 is applied [2]. Investment costs have been updated from the reference year (2002) to 2015, taking into account inflation and deflation. In order to do so, the Chemical Engineering plant cost index (CEPCI) is used to scale year 2002 to 2015 [3].

$$CEPCI_{2002} = 390.4$$

$$CEPCI_{2015} = 547.4$$

$$Purchased\ cost_{2015} = Purchased\ cost_{2002} \cdot \left(\frac{CEPCI_{2015}}{CEPCI_{2002}}\right) \quad (2.1)$$

In addition to the purchase cost, further costs need to be added in order to include installation costs and expenditures occurring during the construction of a plant.

In order to obtain the final cost, the procedure proposed by the National Energy Technology Laboratory (NETL) is used [4]. The method is based on five levels of cost:

- BEC – Bare Erected Cost;
- EPCC – Engineering, Procurement, and Construction Cost;
- TPC – Total Plant Cost;
- TOC – Total Overnight Capital;
- TASC – Total As-Spent Capital.

The bare erected cost corresponds to the purchase cost obtained in *Equation 2.1*. Starting from the BEC, the final cost of the equipment (TASC) was calculated adding mark-ups as represented by a certain percentage of the base cost. The structure assumed for this estimation is schematised in *Table 6.1* in the *Appendix*.

The cost estimation of the equipment is summarised into *Table 2.3,* with the main characteristics of each component.

The adsorbents used for the removal of the siloxanes and the sulphur in the biogas are activated carbons – as proposed by POLITO. The cost of the adsorbents is obtained following the investigation of Babel et al.

[5]. Each reactor of this system was assumed to contain 250 kg of activated carbons, whose estimate cost was approximately 260 [€] per column.

Once the biogas is clean, it is possible to feed the SOFC system.

The costs of the fuel cells were provided by CONVION in terms of both investment and stack replacement as well as stack environment, process and automation, power conversion and grid interface. Below the estimation is reported in *Table 2.1* and *2.2*.

Item in cost breakdown	amount for 3 modules [€]	amount for 1 module [€]	[€/kW]
Stacks	1,554,048	518,016	8,885.4
Stacks replacement	599,808	199,936	3,429.4
Rest of the system	572,544	190,848	3,273.6
TOT	2,726,400	908,800	15,588.3

Table 2.1 Estimation of the cost of the stacks [11]

"Rest of the system" cost breakdown	amount for 3 modules [€]	amount for 1 module [€]	[€/kW]
Stack environment	194,664	64,888	1,113.0
Process + automation	320,625	106,875	1,833.2
Power conversion and grid interface	57,255	19,085	327.4
TOT	572,544	190,848	3,273.6

Table 2.2 Estimation of the cost of the "rest of the system"[11]

As it is possible to notice from *Table 2.3*, the components that require considerable investments are the Si/S removal system and the fuel cell modules, due to their size, the materials involved, and the complexity of the technology.

The total estimate investment cost is 3068742 [€]. The breakdown of investment costs can be found in the *Appendix A.*

Regarding the replacement costs of DEMO plant, only the costs related to the fuel cells and the adsorbents are calculated in this analysis. The replacement of the rest of the equipment is supposed not to occur before the 20 years of plant lifetime. On the contrary, the fuel cell modules and the adsorbent require to be replaced approximately every 3 years.

For the estimation of the cost for the replacement of the stack and the rest of the system the value provided in *Table 2.1* and *2.2* were used. It was supposed that the cost of the reformer catalyst is included.

Concerning the adsorbents replacement, it is supposed to occur approximately every 3 years, as for the fuel cell stacks. The cost is evaluated following the same procedure of the cost estimation related to the Si/S removal system, which includes the activated carbons. Thus, the cost is retrieved from Babel et al. [5] and annualized to year 2015. The total estimate replacement cost is 601,802 [€] every three years.

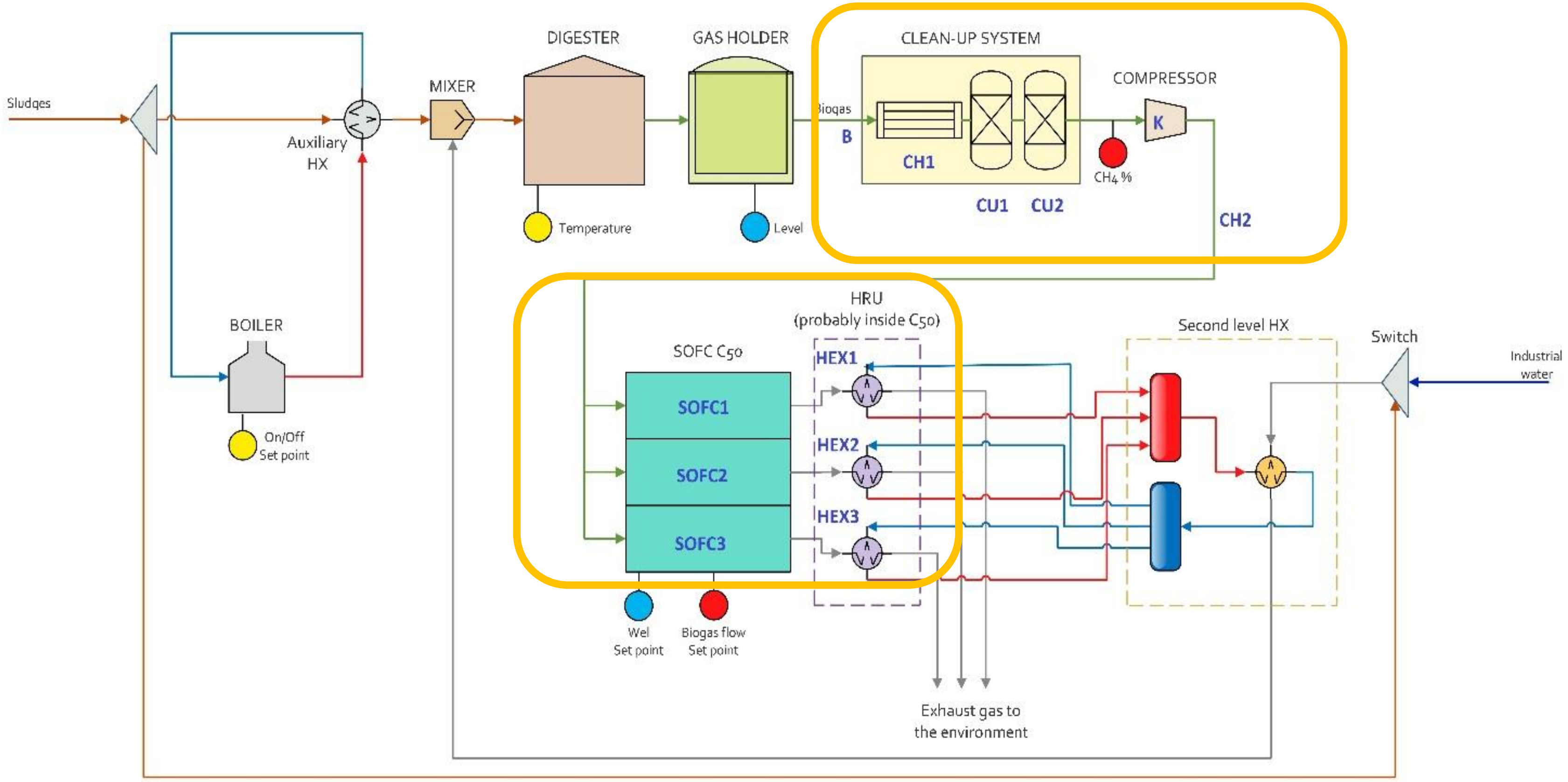


Figure 2.2 Highlighting of the equipment included in the investment cost estimation

Component	Code of the component	Typology	Capacity		Size exponent for scaling	$\frac{\text{CEPCI}_{2015}}{\text{CEPCI}_{2002}}$	Exchange rate 2015 [$/€]	Purchased cost [€]	TASC [€]
Blower	B	Centrifugal blower	Flow rate [m^3/s]	0.02	0.59	1.4	0.902	5,661.4	11,280.4
Chiller 1	CH1	Industrial refrigeration	Cooling power [kW]	0.73	0.62	1.4	0.902	2619.1	5,218.6
Si/S removal system	CU1	(4) Packed columns	Height [m]	2	0.5	1.4	0.902	23,770.7 (95,082.70)	47,363.2 (189,452.6)
Scavenger	CU2	(2) Packed columns	Height [m]	2	0.5	1.4	0.902	23,770.7 (47,541.4)	47363.2 (94,726.3)
Compressor	K	Rotary compressor	Flow rate [m^3/s]	0.019	0.79	1.4	0.902	12,866.4	25,636.3
Chiller 2	CH2	Industrial refrigeration	Cooling power [kW]	4.55	0.62	1.4	0.902	82,149	16,236.9
Heat exchanger	HEX	Floating-head	Area [m^2]	4.4	0.6	1.4	0.902	4,192.6	8,353.8

Table 2.3 Estimation of the investment costs with the method of Timmerhaus et al. [1]

Operating costs

The costs linked to the operation of the DEMO plant have been modelled including:

- Operating costs – every year;
- Maintenance – every year;

The operating costs are composed by the following terms:

- Grid costs (electricity and natural gas from the network);
- Carbon costs (since the energy bought from the network is subjected to fees due to carbon emissions);
- Start-up and shutdown costs.

For a more detailed explanation of the mathematical model used to obtain them, refer to the *Appendix A*.

The electricity costs include also the costs related to the electricity consumption of the various components that are installed in the new plant layout, i.e. components in the biogas clean-up system.

In order to calculate these costs, for each electricity-consuming component a unitary energy consumption value (UEC) is calculated as ratio of the component's electrical energy and the fuel energy consumed as function of the flow rate entering the component.

In the *Appendix*, *Table 7.2* shows the unitary energy consumption values for the biogas clean-up system.

As it is possible to notice from the table, the component with the highest UEC value is the biogas compressor, which requires more electrical power than the rest of the equipment.

In addition to the gas and electricity costs, the plant faces the costs due maintenance of the equipment.

With the regard to the maintenance costs, they are calculated as a percentage of the investment costs, occurring every year.

$$AM_i = 2\% \cdot InvestmentCost\ [€/y] \quad (2.2)$$

In the mathematical model, the maintenance costs are entered as inputs.

The overall costs are 61,375 [€] per year.

The cost estimation that has been carried out both for investment and operating costs is based on literature sources or assumptions, therefore it is retained that the analysis may have a 30% uncertainty regarding the provided values.

3. **Optimization**

In this section, the optimization of the lifetime costs of DEMO plant is presented. It is explained the aim of the optimization and the software used to run it. Moreover, the mathematical formulation is described. The description of the model is organized in the formulation and description of the objective function and afterwards in the formulation of the energy balances on which it is based. All the variables and symbols contained in the equations are reported in the nomenclature in the *Appendix A*.

Optimizing the performance of a plant allows working in the optimal scenario. Even though the size and the layout of DEMO plant are already set, it is important to verify that the new equipment will be used at its fullest potential. Afterwards, it is important to verify its operation: working below the optimum results in higher expenditures and exposes the equipment to premature wear.

Further scenarios are investigated:

- Addition of one module of SOFC;
- Sludge pre-thickening;
- Alternative energy market;
- Alternative technologies.

In order to run the optimization, it is necessary the use of a software in which the model is solved. GAMS (*General Algebraic Modelling System*) was chosen as the most suitable software to fulfil this analysis. It is a high-level algebraic modelling system for large scale optimization and it is specifically designed for modelling linear, nonlinear and mixed integer optimization problems.

For the use of the software and its grammar formulation, see GAMS user’s guide [6].

Mathematical formulation

The model is structured on equations and energy balances that lead to obtain the objective function (i.e. total annual costs), following the main mathematical structure proposed by Hawkes et al. (2009) [7].

The optimal solution provides the outputs in terms of hourly energy flows:

- biogas that flows into the gasholder;
- biogas that is sent to the fuel cells;
- biogas that is sent to the boiler;
- biogas that is flared;
- natural gas from the grid;
- electrical and thermal output per module of fuel cell and operating regime;
- electricity from the grid;

and costs:

- costs of the natural gas from the grid;

- costs of the electricity from the grid;
- carbon costs due to the purchase of energy from the grid;
- start-up and shutdown costs;
- total annual costs due to operations;
- total costs of the plant at the end of its lifetime.

For the formulation of the model different decision variables are identified. These quantities are controlled in the optimization model and are manipulated in order to search for the values that produce the optimal scenario. They are calculated in all the possible solutions in order to obtain the optimal objective function.

The aim of this optimization is to minimize the overall costs during plant life, which is identified as sum of fixed costs – the investment costs – and of costs varying with the operation and occurring every year – i – (maintenance, operations, replacement).

$$\text{minimize} \rightarrow PlantCost = InvestmentCost + \sum_i (AM_i + OP_i + ReplacementCost) \cdot df_i \; [€] \quad (3.1)$$

In order to reduce the computational burden and focus on the operational optimisation of the fuel cells in one year, a decomposition strategy was applied. Accordingly, the running operating costs have been optimised for one year only and replicated for the life time of the fuel cells. As such, the optimization is run in the software for the reference year only and then replicated over the entire lifetime of the plant. The minimum cost for the plant during its lifetime is provided after having solved the objective function, which is then multiplied over the lifetime of the plant together with the maintenance and replacement costs. The investment costs are added to this summation in the end.

The approach was supported on the assumptions of periodic boundary conditions on the gas holder storage levels from one year to the next one as well as constant fuel cell performance during the plant life time (i.e. neglecting the degradation).

Both for electricity, heat and biogas, energy balances are formulated. For each one, constraints are set in order to give boundaries of operation during the compilation of the software.

Constraints

In addition to the material and energy balances, specific constraints are used to model the fuel cells:

- Minimum uptime and minimum downtime: in order to prevent any damage due to thermal stress during transition from one operating regime to another, the fuel cell modules are forced to be stay up for a minimum time t_{up}, once there are on and to stay down for a certain minimum time t_d, once they are shut down. The formulation of this constraint follows the one proposed by Novak et al. [8]. The minimum uptime and downtime are considered to last over a period of 24 hours;

- Ramp modulation: the rate of change of the electrical output of the SOFC modules is constrained due to risk of mechanical and thermal stress. The value for the modulation ramp is assumed 40 [kW/h];
- Star-up and shutdowns: the heat-up of the cold system to full load takes approximately 24 hours; therefore, it is hypothesized to incur in start-ups and shutdowns of minimum 24 hours each.

Constraints to the fuel cell operation which derive from the rest of the plants, are:

- Minimum and maximum gasholder capacity: respectively 300 m^3 and 1400 m^3. When the biogas exceeds the upper limit, it is flared into the external environment. On the other hand, when it does not reach the minimum level of the gasholder capacity, it is necessary to resort natural gas from the network, which is burnt into the boiler;
- Boiler maximum capacity: assumed 1600 [kWh] in order to cover the maximum picks of biogas flow rate;
- Gasholder periodic condition: the same gas level is imposed at the end of each year, therefore the energy balances are written for one year only. In order to express this assumption, the gasholder is subjected to the periodic condition:

$$GasHolder_{t_1} = GasHolder_{t_{8760}};$$

- Biogas compressor's stop: the biogas compressor stops for maintenance every six months for ten hours. Therefore, the electricity output is set 0 from hour 4380 until 4389 – approximately after six months during the year.

The formulation of the model can be found in the *Appendix A*.

4. **Results**

In this section, the results of the optimisation of the operational strategies for the DEMO plant are presented in terms of energy flows and costs for each of the different scenarios that are investigated. The first scenario is the base case, where the plant operates in the nominal capacity. The other scenarios are presented as a comparison to the base case.

Base case scenario

The plant in the base case woks in the following configuration:

- Number of cells: 3;
- Input biogas flow rate per cell: 19.3 [kg/h];
- Operating regimes of the fuel cells: 100-50% and 40-30%;
- Electrical efficiency per operating regime: 53.8% for regime 100-50% and 41.2% for regime 40-30%;
- Thermal efficiency per operating regime: 79% for regime 100-50% and 91.3% for regime 40-30%.

The software provided the costs occurring during the operations in the optimal scenario in order to minimize the total lifetime costs of the plant.

The results are presented in terms of both energy flows – with the regard to the energy balances formulated in the model – and costs. The latters are presented both for the reference year (operating costs) and for the lifetime of the plant (total costs). *Table 4.1*, *4.2*, and *4.3* summaries the results obtained.

	Share	[MWh]	Hours
BG in boiler	26.3%	990.04	6427
BG fuelling FC	66.4%	2498.38	8734
BG unexploited	7.4%	277.72	2413
BG flow	100%	3766.1	8760
FC electricity output	22.6%	1313.51	8734
Grid electricity demand	77.4%	4388.72	8760
Electricity demand	100%	5702.23	8760
FC thermal output	67.9%	2027.57	8734
NG demand	4.0%	118.49	1848
BG boiler	28.2%	841.54	6427
Digester demand	100%	2987.59	8760

Table 4.1 Energy flows during the operation of the plant and hours of operation per each energy flow in the optimal scenario

	Share	[€/y]
NG Costs	6.3%	49,953.5
Grid Electricity Costs	86.5%	681,073.2
Carbon Costs	7.2%	56,512.9
Start-up/Shutdown	0.01%	45.8
Operations Costs	100%	787,585.4

Table 4.2 Costs occurring during the operation of the plant in reference year

	Share	[€]
Investment	26.0%	3,068,742
Operation	56.9%	6,705,158.2
Replacement	12.7%	1,491,125.7
Maintenance	4.4%	522,518.6
Plant costs	100%	11,787,545

Table 4.3 Total costs occurring during the lifetime of the plant

From *Table 4.1*, it is possible to notice that the fuel cells cover almost the 23% of the electricity demand of the plant, thus in order to cover the remaining demand it is necessary to buy electricity from the network for most of the time. The contribution of the fuel cells to the electricity demand of the plant is represented in *Figure 4.1*.

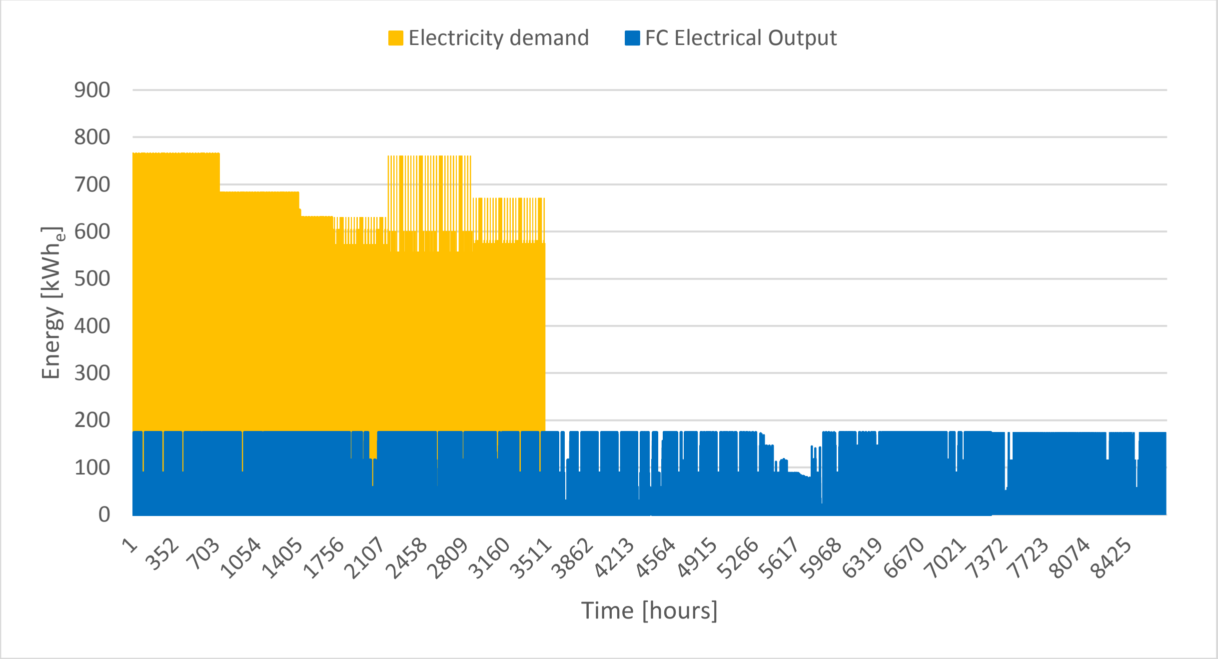


Figure 4.1 Fuel cells electrical output and electrical plant demand during the reference year

Regarding the thermal demand, the fuel cells cover the 68%. The remaining needs are satisfied by the boiler, which burns mainly biogas, thus only a small amount of natural gas would be bought from the grid. The contribution of the fuel cells to the thermal demand of the plant is represented in *Figure 4.2*.

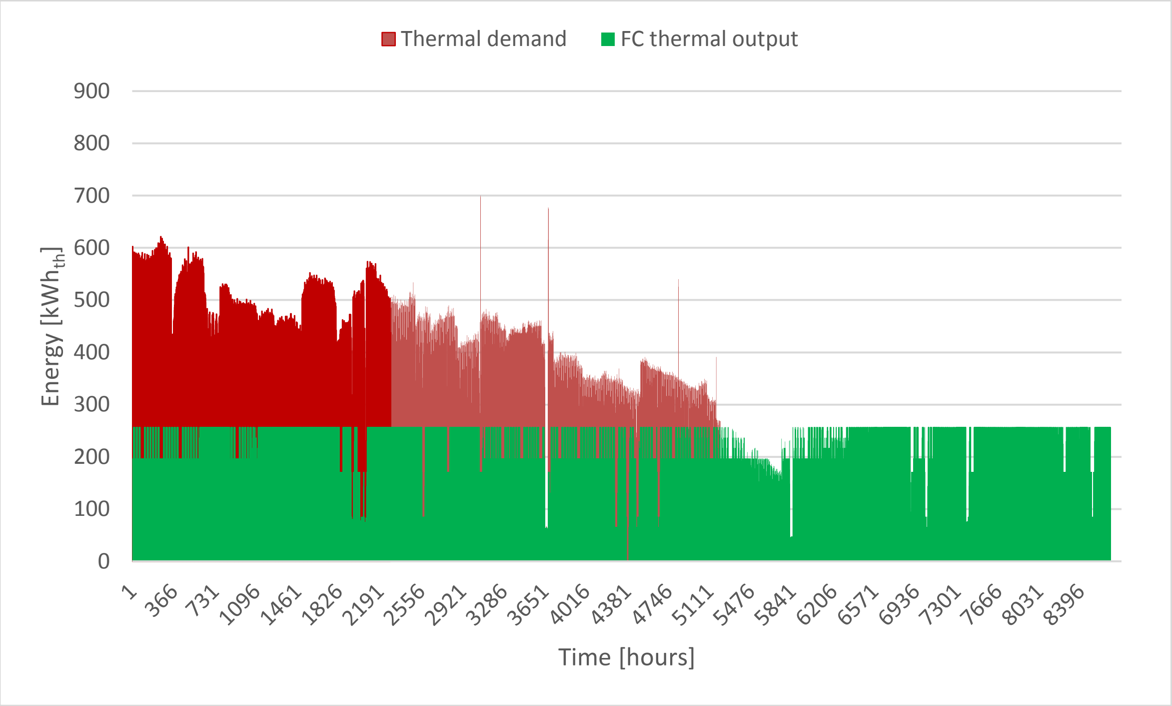


Figure 4.2 Fuel cells thermal output and digester thermal demand during the reference year

Regarding the costs occurring during operations, *Table 4.2* shows that the majority is represented by the electricity bought from the network, since the fuel cells can cover only less than 30%. Start-ups and shutdowns do not require high costs for the plant. The total shutdown of all the modules occur 2 times a year, respectively when the biogas compressor stops for maintenance every 6 months and at the end of every year, for maintenance of the fuel cells.

During the operations, the use of the fuel cells is modulated on two different regimes of operability: 100-50% and 40-30%, therefore each module can work in a different regime from the other modules at the same time and they can be alternatively switched off. In *Figure 7.1* (in *Appendix A*) the operations in terms of electricity produced by the three modules are shown. As it is possible to notice, one module is kept ON for a longer time than the others, in order to guarantee continuity of operation.

With regard to the total plant costs at the end of its lifetime, the majority is represented by the costs due to operations, which represent the 57% of the total share. The costs occurring for replacement and maintenance have a smaller impact.

Addition of one module of SOFC

In the following scenario the possibility of adding one module of SOFC is simulated and optimized.

Table 4.4 and *4.5* below summarise the results obtained from the optimization in terms of costs occurring during the operations of the plant in the reference year and of total costs at the end of the lifetime of the plant.

	3 modules [€/y]	4 modules [€/y]
NG Costs	49,953.5	40,490.3
Grid Electricity Costs	681,073.2	643,603.0
Carbon Costs	56,512.9	53,330.9
Start-up/Shutdown	45.8	80.1
Operations Costs	787,585.4	737,504.2

Table 4.4 Base case and case with 1 module added in terms of costs of operations

	3 modules [€]	4 modules [€]
Investment	3,068,742	3,976,808.0
Operation	6,705,158.2	6,278,789.2
Replacement	1,491,125.7	1,986,520.8
Maintenance	522,518.6	677,136.2
Plant Costs	11,787,544.6	12,919,250.0

Table 4.5 Base case and case with 1 module added in terms of total costs

The costs related to the purchase of energy from the network are therefore lower than the base case, since more energy is provided by the SOFC plant. The total plant costs after 20 years are higher, due to the substantial investment of the installation of one more C50 module.

Sludge pre-thickening

In this scenario, the possibility of an additional sludge thickening into the wastewater treatment plant is analysed, since it would significantly reduce the thermal demand of the digester.

Currently a gravel filter – one of the most commonly used thickening processes – already exists and provides sludge with a solid concentration of 1.91% (mass basis).

The plant upgrade is analysed in two different cases – dynamic and centrifugal thickening –, which would respectively bring to obtain a total suspended solid (TSS) percentage from 1.91% to 5% or 8%, according to the type of technology used for thickening the sludge. From the sludge flow in 2015, an annual profile was estimated on an hourly basis, considering a reduction in the mass flow replicating the increase in the TSS percentage.

The plant in the dynamic configuration presents lower capital costs and power consumptions than that in the centrifugal configuration. On the contrary the heat needs of the digester are higher than the case with centrifugal thickener.

The investment costs of these plants are calculated using the method proposed by Timmerhaus et al. [1], so as for the components of the biogas clean-up system.

Table 4.6 and *4.7* show the costs in the case these systems are installed and added to the plant.

The costs of the operations are higher, due to the power consumptions of the thickening system; thus more electricity needs to be bought from the grid, as well as more carbon emission are released. On the contrary the thermal needs are completely satisfied by the plant itself.

	Base case [€/y]	Dynamic thickening [€/y]	Centrifugal thickening [€/y]
NG Costs	49,953.5	0	0
Grid Electricity Costs	681,073.2	746,655.5	757,750.2
Carbon Costs	56,512.9	60,775.2	61,671.0
Start-up/Shutdown	45.8	70.3	95.7
Operations Costs	787,585.4	807,500.9	819,516.9

Table 4.6 Base case and dynamic sludge pre-thickening case in terms of costs of operations

	Base case [€]	Dynamic thickening [€/y]	Centrifugal thickening [€/y]
Investment	3,068,742	3,068,742	3,183,754.0
Operation	6,705,158.2	5,569,591.9	6,977,009.5
Replacement	1,491,125.7	1,491,125.7	1,491,125.7
Maintenance	522,518.6	522,518.6	542,101.9
Plant Costs	11,787,544.6	10,651,978.3	12,193,991.1

Table 4.7 Base case and dynamic sludge pre-thickening case in terms of total costs

Alternative energy market

In this scenario, the same plant of the base case is optimized considering the price of electricity and gas of United Kingdom in 2015. In order to provide a comprehensive description of the UK market, the possibility of selling electricity to the network was included in the mathematical model.

Table 4.8 and *4.9* present the comparisons between the Italian and British markets in terms of operations costs during the reference year and total plant costs. For each term the costs are lower in the British market than the base case. Moreover the software revealed no convenience in selling electricity to the grid in these operative conditions.

The costs for the British market are retrieved from "UK Government - Gas and electricity prices in the non-domestic sector" [10] and then converted from GBP to EUR in order to have a direct comparison.

	IT market [€/y]	UK market [€/y]
NG Costs	49,953.5	7,483.97
Grid Electricity Costs	681,073.2	591,253.1
Carbon Costs	56,513.0	55,424.4
Start-up/Shutdown	45.8	40.7
Operations Costs	787,585.4	654,202.17

Table 4.8 Italian and British energy markets in terms of costs of operations

	IT market [€]	UK market [€]
Investment	3,068,742	3,068,742
Operation	6,705,158.2	5,569,591.9
Replacement	1,491,125.7	1,491,125.7
Maintenance	522,518.6	522,518.6
Plant Costs	11,787,544.6	10,651,978.3

Table 4.9 Italian and British energy markets in terms of total costs

Alternative technologies

In this scenario, two different technologies are analysed in order to compare their operations to those of the CHP SOFC.

In the first scenario, no CHP system is included. Thus, the thermal needs are satisfied only by a boiler burning both biogas and natural gas and the electrical ones are covered only by direct connection to the electricity network.

Investment, maintenance, and replacement costs are not taken into account, since no SOFC CHP system is installed.

In the second scenario, the SOFC CHP is replaced by a µ Gas turbine CHP system and the boiler can still serve part of the thermal needs. The µGT is assumed to have the same size (174.9 kW) of the SOFC plant, while the electrical efficiency is assumed 22% and the power to heat ratio 0.6 [9]. The electric yield value is assumed very low, since no biogas clean-up system is included in the analysis.

The cost of investment is assumed 2500 [\$/kW$_e$], from the estimation of the "Catalogue of CHP technologies" [9].

In the case of µGT CHP, the software revealed that the optimal solution excludes the use of such a system. This probably relates to the lack of incentives to electricity sold to the grid in the Italian framework. The results for the "Boiler only" case are reported in *Table 4.10* and *4.11.*

	Base case [€/y]	Boiler only [€/y]
NG Costs	49,953.5	45,274.4
Grid Electricity Costs	681,073.2	876,823.9
Carbon Costs	56,512.9	71,926.9
Start-up/Shutdown	45.8	0.0
Operations Costs	787,585.4	994,025.1

Table 4.10 Base case and "Boiler only" case compared in terms of operation costs

	Base case [€]	Boiler only [€]
Investment	3,068,742.0	0
Operation	6,705,158.2	8462696.036
Replacement	1,491,125.7	0
Maintenance	522,518.6	0
Plant Costs	11,787,544.6	10,651,978.2

Table 4.11 Base case and "Boiler only" case compared in terms of total costs

5. **Concluding remarks**

The optimization has been applied to seven different scenarios, whose operations were simulated in the software GAMS. Each simulation allowed to evaluate the system in several respects. In particular, all the scenarios have been individually compared to the base case, highlighting the benefits and the disadvantages.

The overall results are presented in the following table, in terms of percentage changes of all the scenarios from the base case.

	UK energy market	Boiler only	Dynamic thickening	Centrifugal thickening	4 SOFC modules
NG Cost	-85.0%	-9.4%	-100.0%	-100.0%	-18.9%
Grid Electricity Cost	-13.2%	+28.7%	+9.6%	+11.3%	-5.5%
Carbon Cost	-1.9%	+27.3%	+7.5%	+9.1%	-5.6%
Start-up/Shutdown	-11.1%	-100.0%	+53.7%	+109.2%	+75.2%
Operations Costs	-16.9%	+26.2%	+2.5%	+4.1%	-6.4%
Investment	-	-100.0%	+2.3%	+3.8%	+29.6%
Operation	-16.9%	+26.2%	+2.5%	+4.1%	-6.4%
Replacement	-	-100.0%	-	-	+33.2%
Maintenance	-	-100.0%	+2.3%	+3.8%	+29.6%
Plant costs	-9.6%	-28.2%	+2.1%	+3.5%	+9.6%

Table 5.1 Overall percentage changes from the base case

COMMENT #1: You should find a way to combine together operations costs and plant costs in a single figure-of-merit (e.g., the Net Present Value of the plant). Otherwise it is not clear which is the 'best plant configuration' really.

From *Table 5.1 and Figure 5.1*, it is possible to notice that in the case of sludge pre-thickening the need of thermal energy for the anaerobic digester is completely satisfied by the plant itself, since 97% (99% in the centrifugal configuration) of the demand is covered by the heat recovery system of the SOFCs. The remaining needs are covered by the boiler through biogas combustion. The overall operating costs, as well as the total plant costs, are 2% (3-4% in the centrifugal configuration) higher than the base case.

In the case of centrifugal thickening, the software revealed that a significant amount of biogas results to be flared (60%), which represents a waste of exploitable energy.

Based on the above considerations, a system upgrade might be reasonable in the case of installation of the dynamic thickening system.

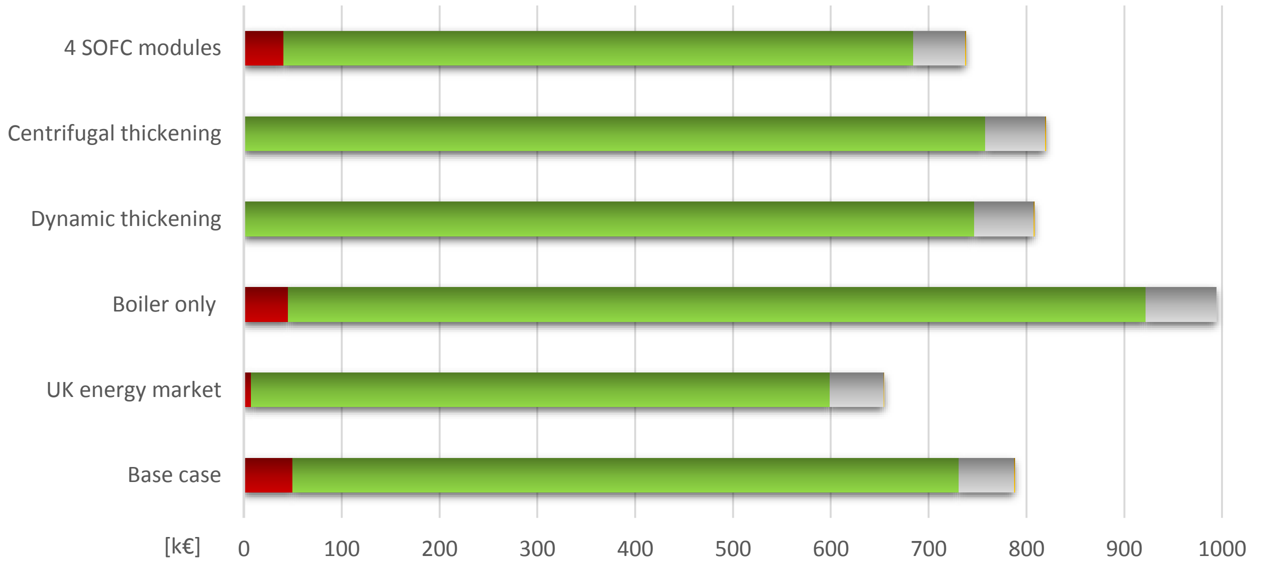
The addition of one module to the SOFC would make the system energetically more independent than the base case, but it would also increase of about 10% the final cost of a plant at the end of its lifetime. Although the final costs increase, there is a decrease of annual costs related to operations. If the investment costs of the cells decreased, this scenario would probably be more suitable than the base case.

Another interesting result is represented by the scenario where the SOFC system is excluded, thus the boiler is used to cover part of the heat demand and the electrical energy is totally supplied by the network. Although no investment is required, the plant would incur in higher operating costs (+26%) due to greater dependence on the network, as well as more carbon emissions and the related costs (+27.3%).

The optimal case proves to be the same plant configuration of the base case, but in a more convenient energy market, such as the British one.

Further sensitivities analysis may be required in order to analyse the operation in different configurations, such as increased number of the modules in order to cover the electricity demand and the addition of one module to the SOFC plant but in a different energy market.

In addition, a sensitivity analysis on the cost of carbon may be performed in order to evaluate the weight of this cost on the optimization.



	Base case	UK energy market	Boiler only	Dynamic thickening	Centrifugal thickening	4 SOFC modules
🟥 NG Cost	49.953,5	7.484,0	45.274,4	0,0	0,0	40.490,2
🟩 Grid Electricity Cost	681.073,2	591.253,1	876.823,9	746.655,5	757750,2	643.603,0
▨ Carbon Cost	56.512,9	55.424,4	71.926,9	60.775,1	61671,0	53.330,9
🟨 Start-up/Shutdown	45,8	40,7	0,0	70,3	95,7	80,1

Figure 5.1 Comparison in terms of operations costs of the different scenarios

6. **References**

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7. **Appendix**

A. DEMO costs estimation

The table below reports the structure assumed in order to estimate the final cost of a component, starting from the Bare Erected Cost (BEC), which is the purchase cost. As mentioned in the description of the cost estimation, the structure follows the method of the National Energy Technology Laboratory (NETL) based on six levels of cost [4].

EPCC	$BEC \cdot (1 + 10\%)$
Process Contingency	$EPCC \cdot (1 + 10\%)$
Project Contingency	$Process\ Contingency \cdot (1 + 30\%)$
TOC	$Project\ Contingency \cdot (1 + 20.2\%)$
TASC	$TOC \cdot (1 + 19.6\%)$

Table 7.1 Structure for the estimation of TASC

Table 7.2 reports the unitary energy consumptions (UEC) for each component. This value is expressed in terms of electricity consumed and energy of the biogas feeding the component. These values have been used in the analysis in order to calculate the electrical needs of the plant they are part of. They are part of the electrical balance formulated in *Appendix D*.

Component	UEC [kWh_e/kWh_f]
Blower	0.0011
Chiller 1	0.0007
Compressor	0.0177
Chiller 2	0.0050

Table 7.2 Unitary energy consumptions per component in the biogas clean-up system

B. Operations of the fuel cells

In the figures below, the operations in terms of electricity produced by the three modules of fuel cells are represented both all together (*Figure 7.1*) and individually (*Figure 7.2*, *7.3*, and *7.4*). As it is possible to notice, the electrical output may change from one module to another. Moreover the cells can work in different operative regimes, according to the biogas flow that fuels them.

The individual representation of each module shows that one module over the others (*N1*) works for a higher number of hours, guaranteeing continuity of operation.

The breakdown of the energy produced by each modules is reported in *Table 7.3*.

Module	[MWh_e]
N1	432.3
N2	428.7
N3	427.9
TOT	1,289.0

Table 7.3 Energy production of each module of fuel cell

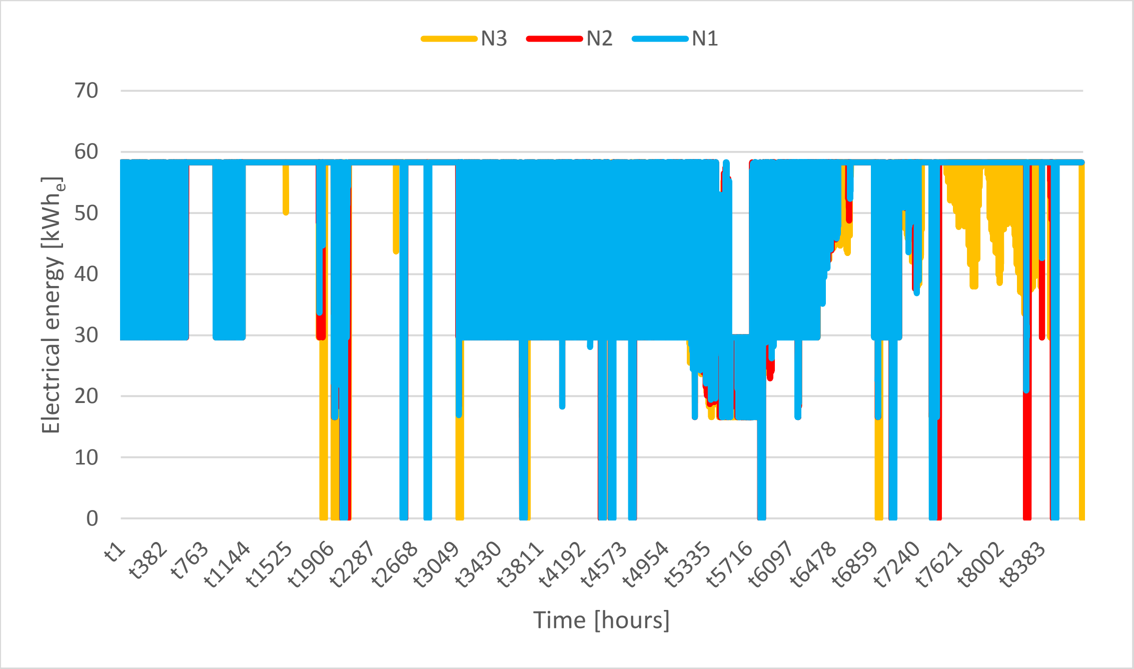

Figure 7.1 Operation of the 3 modules of SOFCs in the base case scenario

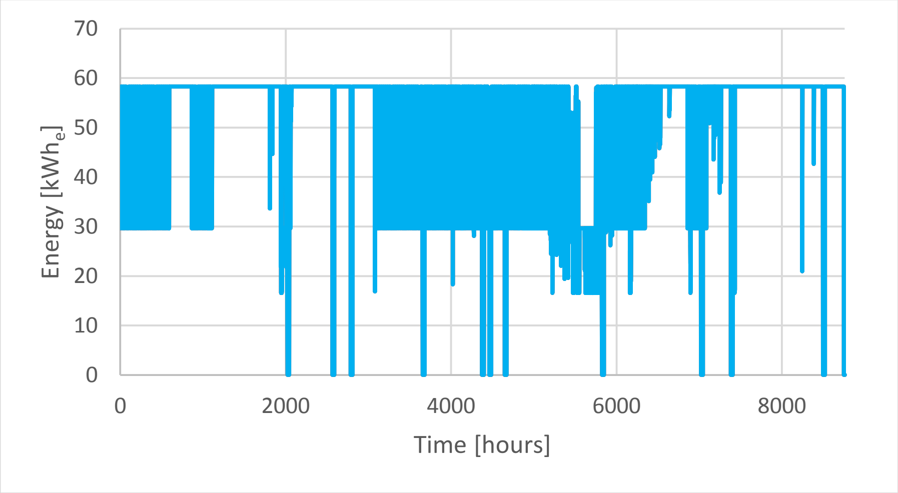

Figure 7.2 Electrical output of fuel cell N1

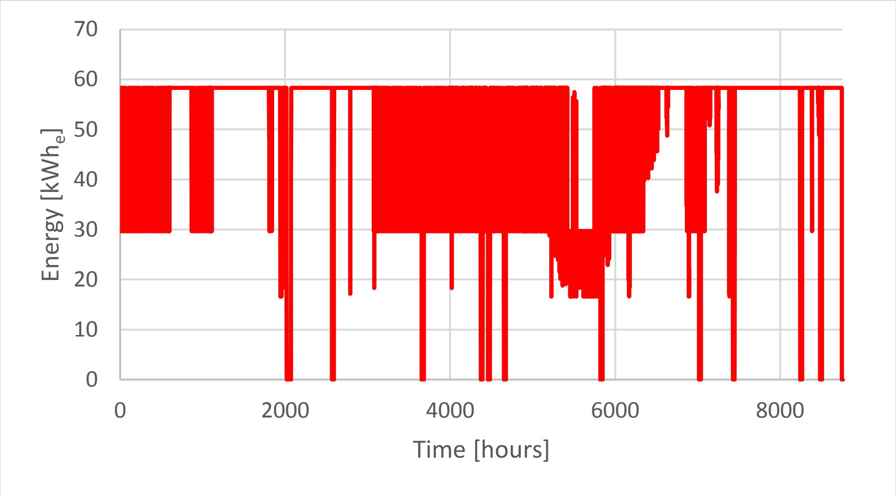

Figure 7.3 Electrical output of fuel cell N2

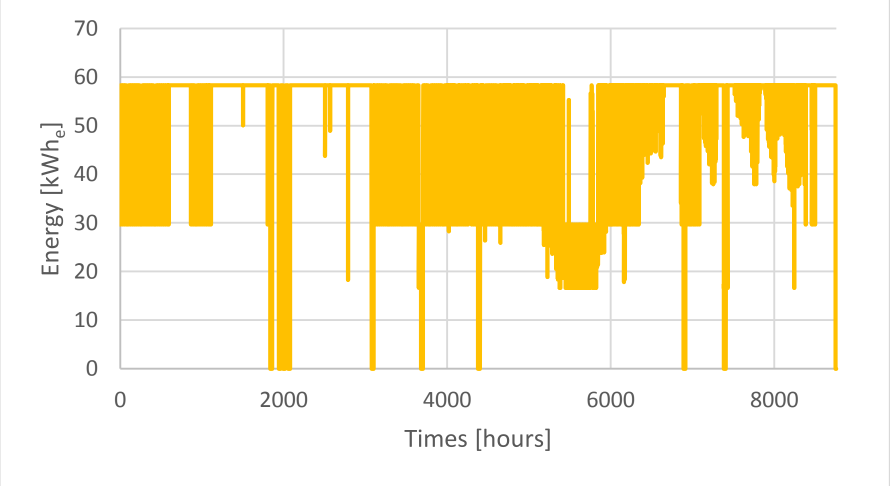

Figure 7.4 Electrical output of fuel cell N3

C. Nomenclature

Objective function

OP_i	Total operating costs occurring every year [€/y]

Sets

f	Fuel cell $[N1, N2, N3]$
i	Years $[1 * 20]$
r	FC operating levels
t	Hours per year $[t1 * t8760]$
τ_d	Subset for the minimum downtime

Constants

$AECost$	Auxiliary equipment purchase costs [€]
$BCap$	Boiler capacity $[kWh_f]$
BG_{nom}	Nominal energy flow of biogas entering the fuel cell $[kWh_f]$
CH_1Cost	Purchase cost of the chiller 1 before the clean-up of the biogas [€]
CH_2Cost	Purchase cost of the chiller 2 after the clean-up of the biogas [€]
CO_2UC	Carbon unit cost $[€/kg_{CO_2}]$
$CUCost$	Purchase cost of the clean-up system (Si/S reactors and scavenger) [€]
μ_b	Boiler efficiency $[kWh_{th}/\ kWh_{NG}]$
$FCcost$	Fuel cell investment cost [€]
$FCRC$	Fuel cell replacement cost [€]
γ	Gas price $[€/kWh]$
$GasHolderLL$	Lower limit of the capacity of the gasholder $[kWh]$
$GasHolderUL$	Upper limit of the capacity of the gasholder $[kWh]$
$GridEmFact$	Electricity emission factor $[kg_{CO_2e}/kWh_e]$
$HEXCost$	Purchase cost of the heat recovery heat exchangers [€]
$InvestmentCost$	Investment cost of the fuel cells and the auxiliary equipment [€]
$KCost$	Purchase cost of the compressor [€]
MH	Maximum number of hours per year $[h]$
$NGEmFact$	Natural gas emission factor $[kg_{CO_2e}/kWh_f]$
N_{FC}	Fixed number of modules of fuel cell
P_{ass}	Energy absorbed by the fuel cells when switched on $[kWh_e]$
P_{nom}	Nominal energy of the fuel cell $[kWh_e]$

sd	Unit shutdown cost [€]
t_d	Minimum down time of fuel cell $[h]$
UEC_{Bl}	Unitary energy consumption of the blower $[kWh_e/kWh_f]$
UEC_{CH_1}	Unitary energy consumption of the chiller 1 before the clean-up $[kWh_e/kWh_f]$
UEC_{CH_2}	Unitary energy consumption of the chiller 2 after the clean-up $[kWh_e/kWh_f]$
UEC_K	Unitary energy consumption of the compressor $[kWh_e/kWh_f]$
UIC	Unitary investment cost of the fuel cell stack $[€/kW]$
URC	Unitary replacement cost of the fuel cell stack $[€/kW]$

Parameters

$ADRC_i$	Adsorbent replacement cost $[€/y]$
AM_i	Maintenance cost of the fuel cell and the rest of the equipment, expressed as a percentage of the total investment cost [€]
$BGflow_t$	Biogas supplied from digester $[kWh]$
$D_{max,r}$	Maximum electric output of the fuel cell per operating regime r $[kWh_e]$
$D_{min,r}$	Minimum electric output of the fuel cell per operating regime r $[kWh_e]$
df_i	Discount factor [%]
DTL_t	Digester thermal demand $[kWh_{th}]$
$\eta_{FC,r}$	Fuel cell electrical efficiency per regime r $[-]$
ϵ_t	Vector of electricity price from grid $[€/kWh_e]$
$ElectricityConsumed_t$	Electricity consumed at the plant in the current layout $[kWh_e]$
$ReplacementCost_i$	Total replacement cost of the fuel cell, the reformer catalyst and the adsorbent in the clean-up system [€]
su	Unit start-up cost vector $[€/kWh_e]$
$\tau\varepsilon_r$	Fuel cell thermal efficiency $[kWh_{th}/\ kWh_f]$

Binary variables

$\alpha_{t,r,f}$	Binary variable: 1 if cell *f* operates in regime *r* and in period *t* $[-]$
$u_{t,f}$	Binary variable: 1 if cell *f* operates in period *t* $[-]$

Decision variables

$a_{t,r,f}$	Piecewise electrical output of fuel cell f in regime r and period t $[kWh_e]$
$P_{t,f}$	Piecewise electrical output of fuel cell f in period t $[kWh_e]$

$BGboiler_t$	Biogas burnt in the boiler $[kWh]$
$BG\ FC_t$	Biogas energy flow used to fuel the fuel cell $[kWh]$
$BGunexploited_t$	Biogas energy flow that is flared when it exceeds the capacity of the gas holder $[kWh_f]$
$Boiler_t$	Natural gas and biogas energy flow in the boiler $[kWh_f]$
CO_2Cost_t	Carbon cost related to NG burnt and electricity gained from the grid [€]
$ElectricityConsumed_t$	Electricity consumed in the plant $[kWh_e]$
$ElectricityCost_t$	Cost of electricity bought from the grid $[kWh_e]$
$FC\ ElectricityOutput_t$	Electrical output of the fuel cell $[kWh_e]$
$FC\ ThermalOutput_t$	Thermal output of the fuel cell $[kWh_{th}]$
$GasHolder_t$	Biogas energy flow that remains inside the gasholder $[kWh_f]$
$GridCost_t$	Costs related to the use of NG and electricity from the grid [€]
$GridElectricityDemand_t$	Electricity demand (bought from the grid) $[kWh_e]$
$NGcost_t$	Cost of the natural gas from the grid [€]
$NGDemand_t$	Natural gas demand (from the grid) $[kWh_f]$
$SDCost_{t,f}$	Costs of shutting down the fuel cell [€]
$SUCost_{t,f}$	Costs of starting up the fuel cell [€]

D. Mathematical model

$$PlantCost = InvestmentCost + \sum_i (AM_i + OP_i + ReplacementCost_i) \cdot df_i \ [€]$$

$$InvestmentCost = FCcost + AE\ Cost \ [€]$$

$$FCcost = N_{FC} \cdot UIC \cdot P_{nom} \ [€]$$

$$AE\ Cost = BCost + CH_1\ Cost + CU\ Cost + K\ Cost + CH_2\ Cost + HEX\ Cost \ [€]$$

$$AM_i = 2\% \ \cdot \ InvestmentCost \ [€/y]$$

$$OP_i = \sum_t \left(GridCost_t + CO_2Cost_t \ + \sum_f SUCost_{t,f} + SDCost_{t,f} \right) [€/y]$$

$$GridCost_t = NGCost_t + ElectricityCost_t \ [€]$$

$$NGcost_t = NGDemand_t \cdot \gamma [€]$$

$$ElectricityCost_t = GridElectricityDemand_t \cdot \epsilon_t \ [€]$$

$$\begin{aligned} CO_2Cost_t = CO_2UC \\ \cdot (NGDemand_t \cdot NGEmissionFactor + \ ElectricityDemand_t \\ \cdot GridEmissionFactor) \ [€] \end{aligned}$$

$$ReplacementCost_i = FCRC + ADRC \ [€/y]$$

$$FCRC = N_{FC} \cdot URC \cdot Pnom \ [€]$$

<u>*Thermal energy balance*</u>

$$Boiler_t + FC\ ThermalOutput_t - DTL_t = 0 \ \ [kWh_{th}]$$

$$Boiler_t = (NGDemand_t + BGboiler_t) \cdot \mu_b \ \ [kWh_{th}]$$

$$BGflow_t - BGunexploited_t - BGboiler_t - BG\ FC_t = GasHolder_t - GasHolder_{t-1} \ \ [kWh_f]$$

$$BG\ FC_t = \sum_{r,f} \frac{a_{t,r,f}}{\eta_{FC,r}} \ \ [kWh_f]$$

$$FC\ ThermalOutput_t = \sum_{r,f} \frac{a_{t,r,f} \cdot \tau\varepsilon_r}{\eta_{FC,r}} \ \ [kWh_{th}]$$

<u>*Electrical energy balance*</u>

$$\begin{aligned} GridElectricityDemand_t + FC\ ElectricityOutput_t - \left(UEC_K + UEC_{ch_2}\right) \cdot BG\ FC_t - (UEC_b + UEC_{ch_1}) \\ \cdot BGflow_t - ElectricityConsumed_t = 0 \ [kWh_e] \end{aligned}$$

$$FC\ ElectricityOutput_t = \sum_{r,f} a_{t,r,f} \ \ [kWh_e]$$

Equipment capacity constraint

$$P_{t,f} \leq P_{nom} \cdot u_{t,f}\ [kWh_e]$$

Rump modulation

$$\sum_r a_{t,r,f} - a_{t-1,r,f} \leq r_{up}\ [kWh_e]$$

Minimum up, minimum down time

$$u_{t-1,f} - u_{t,f} \leq 1 - u_{\tau,f}, \qquad \tau = t+1, \dots, min(t + \tau_d - 1)$$

$$u_{t-1,f} - u_{t,f} \geq - u_{\tau,f}, \qquad \tau = t+1, \dots, min(t + \tau_d - 1)$$

Power constraint

$$\sum_r a_{t,r,f} = P_{t,f}\ \ [kWh_e]$$

Regime constraint

$$D_{\mathrm{max,r}} \cdot \alpha_{t,r,f} \geq a_{t,r,f}\ [kWh_e]$$

$$D_{\mathrm{min,r}} \cdot \alpha_{t,r,f} \leq a_{t,r,f}\ [kWh_e]$$

Start-up/shutdown

$$SUCost_{t,f} \geq su_t \cdot (u_{t,f} - \sum_\tau u_{t-\tau,f})$$

$$SDCost_{t,f} \geq sd \cdot (u_{t-1,f} - u_{t,f})$$