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Load following of Small Modular Reactors (SMR) by cogeneration of hydrogen: a techno-economic analysis

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ABSTRACT

Load following is the possibility for a power plant to adjust its power output according to the demand and electricity price fluctuation throughout the day. In nuclear power plants, the adjustment is usually done by inserting control rods into the reactor pressure vessel. This operation is inherently inefficient as nuclear power cost structure is composed almost entirely of sunk or fixed costs; therefore, lowering the power output, does not significantly reduce operating expenses and the plant is thermo-mechanical stressed. A more attractive option is to maintain the primary circuit at full power and use the excess power for cogeneration. This paper aims to present the techno-economic feasibility of nuclear power plant load following by cogenerating hydrogen. The paper assesses Small Modular nuclear Reactors (SMRs) coupled with: alkaline water electrolysis, high-temperature steam electrolysis, sulphur-iodine cycle. The analysis shows that in the medium term hydrogen from alkaline water electrolysis can be produced at competitive prices. High-temperature steam electrolysis and even more the sulphur-iodine cycle proved to be attractive because of their capability to produce hydrogen with higher efficiency. However, the coupling of SMRs and hydrogen facilities working at high temperature (about 800 °C) still require substantial R&D to reach commercialisation.

KEYWORDS

SMR; Load following; Cogeneration; Hydrogen; Economics; Feasibility study

LIST OF ACRONYMS

AWE = Alkaline Water Electrolysis

DCF = Discounted cash flow

CAPEX = CApital Expenditures

HTGR = High-Temperature Gas Reactor

HTSE = High-Temperature Steam Electrolysis

LF = Load Following

LWR = Light Water Reactor

NPP(s) = Nuclear Power Plant(s)

NPV = Net Present Value

OECD = Organisation for Economic Co-operation and Development

OPEX = OPeration EXpenditures

R&D = Research & Development

SI = Sulphur-Iodine thermochemical

SMR(s) = Small Modular Reactor(s)

WACC = Weighted Average Cost of Capital

1 Introduction

1.1 The need for load following

The global demand for energy will increase by 48% from 2012 to 2040 primarily due to non-OECD countries [1]. The journey towards sustainable energy production, therefore, faces several challenges, with the contribution of different technologies to achieve this long-term goal. Nuclear Power Plants (NPPs) can be deployed along with renewable power plants to achieve the long-term perspective of sustainable development [2], [3].

Due to the predominance of fixed costs, NPPs are considered a base load power technology [4]. NPPs have a lower marginal production cost than gas or coal. Since the demand for electricity changes continuously during a single day, the adjustment on the offer-side is usually obtained by manoeuvring gas or coal power plants. This is done since the 70s and it is still mostly the case nowadays. However, given the expected substantial introduction of intermittent sources of energy (i.e. solar, the wind), NPPs need to be able to follow the load as stressed by OECD/NEA [5]:

"a unit must be capable of continuous operation between 50% and 100% of its nominal power (P_n), [...]. Load scheduled variations (should be) *2 per day, 5 per week and 200 per year"*.

Therefore NPPs planned today, and operating in the time frame 2025 – 2100 need to have the manoeuvrability described in [5]. Several modern NPP designs implement enhanced manoeuvrability, with the possibility of planned and unplanned load-following in a wide power range and with ramps of 5% of nominal power rate per minute [5]. This is, for example, the case of France, while older reactors in other countries (e.g. USA) have more limited manoeuvrability. For example the standard Russian design "VVER – 1000" can perform ramps of 3-4% their power rate per minute if the reactor is in the 10-70% of the fuel cycle or 1%-1.5% their power rate per minute if the reactor is in the 70-100% of the fuel cycle [5].

1.2 Challenges in load following using nuclear power plants

Currently, NPP follows the electricity demand (from now on "Load Following" - LF) by modifying the reactivity within the core, e.g. by inserting control rods made of neutrons absorbers into the coolant [6]. By doing so, the power is reduced, with a waste of potential energy and a thermomechanical stress on the plant. Moreover, the typical cost breakdown of producing electricity with NPP is [4]:

- Investment, including interest: 59%
- Operation and maintenance: 25%
- Fuel (uranium mining, conversion, enrichment, fabrication): 12%
- Waste management and decommissioning: 4%

Besides investment costs, operation & maintenance costs (mainly personal and insurance) are fixed and independent of the power rate. Therefore unlike fossil-fuelled power plants, there is not a relevant cost saving in operating an NPP at a lower power level due to the substantially fixed nature of nuclear costs. Again, opposite to conventional gas-fired plants, where fuel accounts for approximately 70%-80% of the generation cost, nuclear fuel accounts for only about 12% of generation costs [4]. Due to the complexity of the neutron dynamics within the core (fission, absorption by all reactor materials, capture reactions, leaks, poisoning, etc.), the proportionality between power produced and fuel consumed is not linear [6]. A lower power rate does not translate into an equivalent fuel saving. Consequently running a power plant at 50% of its power does not save more than few percentages of its operating cost, while the loss of revenue is proportional to the electricity not produced.

1.3 Load following by cogeneration

As presented in [7] the fundamental idea of the "LF by Cogeneration" is to meet electricity market demand fluctuation and avoid an economic penalty at the same time. In this configuration, the NPP would work at its nominal power all the time, leaving the primary circuit conditions unchanged. Cogeneration is therefore intended as the production of electrical energy and another valuable product output [8], [9]. During the high load/high price hours (usually day-time) the nuclear thermal power is entirely converted into electricity to the grid, while during hours of low demand/low price (usually night-time) the excess thermal energy would produce a valuable by-product. The coupling is particularly virtuous for those co-products that are storable, that require large amounts of energy (heat or electricity) and for which the energy supply represents a significant component of production cost [7].

Virtually *every* facility which requires electricity could be coupled with a standard NPP to support the LF if:

- The power demand is in the region of 500 MW_e – 1 GW_e;
- There is an abundance of “input material” to be processed;
- There is relevant market for the end product;
- It can work at full power during the night, and operate at a much lower load during the day. This means that the co-product is storable and daily power cycles do not damage the facility in the long term;

In this paper, we investigate the case of co-production of hydrogen as recommended in [7]. Since electricity can be more easily transmitted than heat, the proximity with the NPP is not imperative for a hydrogen facility using electricity only. Conversely, the coupling with a hydrogen facility using thermal energy has tighter requirements. An auxiliary facility thermally coupled with an NPP operating in LF mode should:

- Be located reasonably close to the NPP;
- Need a thermal power in the region of 1.5-3 GW_{th};
- Require adequate temperature.

Most of the Light Water Reactors (LWR - accounting for 89% of the global nuclear capacity [10]) operate in the region of 300 °C; while future high-temperature reactors might operate at higher temperature, for instance, 500 °C for the sodium-cooled fast reactors and 900 °C for high-temperature gas reactors (HTGR) [11] like the GTHTR300C [12], [13]. The NPP temperature is a key parameter because, as later explained (section 2.2), higher the temperature more types of cogenerating facilities are available.

1.4 Why SMRs might be an ideal candidate technology

Small Modular Reactors (SMRs) are a relevant technology for the LF because the overall power at the site level is fractioned. As explained in [6] and further developed in [7] a key advantage of adopting multiple SMRs instead of a single large reactor is the intrinsic modularity of an SMR site power output. It is possible to operate all the primary circuits of the SMR fleet at full capacity and switch the thermal power of some of them only, for the cogeneration of suitable by-products. The same could be made with a single large reactor, i.e. some thermal power could be diverted and channelled to the cogeneration process, but getting some steam out of the secondary circuit would compromise the efficiency of the electricity conversion and this would translate into a technical and economic inefficiency. With multiple SMRs, the LF strategy is realised at the site level, rather than at single plant level, by diverting 100% of the electricity (or 100% of the thermal power) generated by some SMRs to cogeneration purposes and let the remaining SMRs produce power for the electricity market at full regime; in this way the optimal fine tuning of the secondary power circuit is not compromised. Either in the case of full electricity conversion or in full cogeneration operation mode, the efficiency would be maximised, letting the secondary circuits working by-design: indeed, some SMRs could run at the full nominal power and maximum conversion efficiency, while some other would give up producing electricity.

The size of the cogeneration facility is optimised according to the thermal power rate made available by the SMRs. E.g. considering four SMRs, the electric power rates at site level would be approximately 0%, 25%, 50%, 75% and 100% corresponding respectively to the following cases: none of the four SMRs produces electricity for the grid, or alternatively, one, two, three or all SMRs produce electricity for the grid. These steps in power rate could be made available by SMRs, with gas plants providing further fine matching with the electricity market demand. By using smaller SMRs, the possible power rates steps could be made smoother.

For the sake of clarity, let's compare a site with four "independent SMRs of 250 MWe" versus a site of same total power (1000 MWe) produced by a single large reactor. If during the night, the power needs to be reduced by about 50%, two SMRs can be disconnected from the grid and used for the cogeneration of other products, while the two remaining will continue to produce electricity at full power rate and maximum efficiency. In the case of a 1000 MWe, the 50% power reduction will cause some components (e.g. pumps and turbine) to work outside the most efficient operating conditions, with a lower efficiency of the electricity conversion. Therefore, when operating in LF mode, the four SMRs would be more efficient than a single stand-alone LR, at the plant level.

1.5 Aim and structure of the paper

Following the preliminary analysis of [7], the co-production of hydrogen seems a good candidate technology for coupling with nuclear power, but the topic is under-researched. This paper fills this gap assessing the technical and economic feasibility of coupling hydrogen production facilities with SMRs.

This paper aims to present the techno-economic feasibility of SMRs performing the LF by cogenerating hydrogen. Specifically, the paper assesses the case of multiple SMRs coupled with three alternative hydrogen production facilities: alkaline water electrolysis, high-temperature steam electrolysis, sulphur-iodine cycle.

The rest of the paper is organised as follows: Section 2 presents the literature review about candidate technologies for both hydrogen facilities and SMRs. In 2.1 the paper focuses on the most relevant aspects of the hydrogen production and market. In 2.2 it presents the three most relevant technologies that can be coupled with SMRs to perform the "LF by cogeneration". These three technologies will be analysed and compared throughout the paper. Section 3 explains the overall research method. Section 4 reports the technical verification of coupling SMR with a hydrogen-producing facility on the basis of the literature and experts' interviews. Section 5 details a novel economic appraisal of the technically feasible solutions. The results from these economic calculations are original from this research. Section 6 summarises the most salient conclusions and provides insights for future works.

2 Literature review

2.1 The market for hydrogen

The hydrogen world consumption is about 85 million tonnes, growing steadily [14]. This market might increase dramatically if technologies such as fuel-cell vehicles would be widely used [15]. Indeed the "hydrogen economy" is getting higher visibility and stronger political support [16]. Nowadays, hydrogen finds many applications as a chemical product for [17]: ammonia synthesis, methanol synthesis, direct reduction of iron ore, fossil fuel processing (hydrocracking), Fischer-Tropsch hydrocarbon synthesis, methanation in long-distance energy transportation, hydrogasification. Ammonia is the most important product, used as fertiliser and in the petroleum industry. In the future, hydrogen might be utilised for ground transport, aviation, marine applications, and railroad transport. If the whole demand of hydrogen was satisfied by water electrolysis, with an energy input of 48.2 MWh/ton [15], then 4097x 10^3 GWh of electricity would be necessary for its production. Considering that a standard 1 GWe NPP can produce up to 8,760 GWh/year, almost 500 large NPPs would be required to produce the same amount of hydrogen. This is more than the global NPP installed capacity in 2018.

2.2 Hydrogen production methods overview

Nowadays, the breakdown of the hydrogen production methods is [18]:

- Steam Methane Reforming: 48%
- Oil/Naphtha Reforming: 30%
- Coal Gasification: 18%
- Water Electrolysis: 4%

The vast majority of hydrogen comes from fossil fuel because the energy demand in their process is much lower than in water electrolysis [18]. Hydrogen can also be produced by several other methods (thermolysis, radiolysis, thermochemical cycles, photolysis et al.), but the status of economics and technology readiness prevented so far their large-scale application [19].

The water electrolysis is the only non-fossil process giving a sensible contribution to the industrial production of hydrogen. This method has "abundant material as input" (water) and a large increasing market as output (see section 2.1). Requiring a significant amount of energy, hydrogen from water is an ideal candidate for the LF application. According to the experts' opinions and to the literature [17] Alkaline Water Electrolysis (AWE) is the standard technology among those that use electricity as the unique energy input. High-Temperature Steam Electrolysis (HTSE), and Sulphur-Iodine thermochemical (SI) cycle are the two most promising technologies among those that make use of heat.

Therefore this paper investigates:

- AWE as proven, short-term, electricity only application;
- HTSE as medium-term heat and electricity application;
- SI as long-term, mostly thermal power application.

2.2.1 Low-temperature electrolysis: Alkaline Water Electrolysis (AWE)

The AWE consists in the decomposition of water molecules, under an electric field generated between two electrodes immersed in an electrolyte. The process occurs in installations commonly called electrolyzers. An electrolyser cell consists mainly of the water medium, the electrodes and the diaphragm, which separates the cell into two compartments, anode and cathode, where the two semi-reactions (reduction and oxidation) take place [20]. The electricity creates an electric field over the electrolyte, which forces the negative ions (anions) to move towards the anode (positive pole) and positive ions (cations) to the cathode (negative pole). Hydrogen and oxygen develop separately on two electrodes. AWE is the most common technology for the large-scale application. The electrical input is 3.5 [kWhe/Nm^3] in theoretical conditions [26] however in real life real life operations, considering a reasonable efficiency for industrial applications, a more reasonable value is 3.8 - 4.4 [KWhe/Nm^3] according to [20] or 4.3 - 4.7 [kWhe/Nm^3] according to [27]. Several studies assert that AWE is not economically competitive against hydrocarbon-based technologies because of the electricity cost [21], [22]. In these studies, the electricity accounts for about 75% of the hydrogen generation cost [15]. However, these studies consider an average annual cost of the electricity or a combination with must-run power sources (like wind or photovoltaic) [23], [24]. These studies do not consider the variation of the electricity price over the day. They assume to feed the AWE with electricity at "market price", regardless its hourly variable value.

The novelty of this study is that the AWE cogeneration process is assumed to work only during the period of low electricity market price, typically during the night-time. Assuming a "carbon-free electricity" generation portfolio, i.e. a mix of nuclear and renewable, the electricity production will be independent of the demand, creating an excess of energy during the night. The idea of using "the surplus of electricity" is among the key innovative contributions of this paper, as well as taking advantage of the SMRs plant modularity to produce different power rates with optimal conversion efficiency.

2.2.2 High-Temperature Steam Electrolysis (HTSE)

It is possible to reduce the electricity required for the electrolysis by increasing the temperature of the process. At the temperature of 2,500 °C, the electricity is unnecessary because water breaks down into hydrogen and oxygen through thermolysis [25]. For the whole range of temperatures between 0 and 2,500 °C, the energy input is a combination of electricity and heat. The electrical and thermal energy inputs for the HTSE at 850 °C (a typical value) are respectively 2.5 [kWh_e/Nm^3] and 0.92 [kWh_t/Nm^3] [26]. A solid oxide electrolyser cell is the standard technology for HTSE. Since the HTSE is a high-temperature application, the ideal solution is the coupling with high-temperature, GEN-IV SMRs [28], [29]. HTSE is in the R&D phase, and most of the high-temperature SMRs are at the prototype/pilot phase.

2.2.3 Sulphur-Iodine thermochemical cycle (SI)

In the SI process, the sulphuric acid is heated to approximately 900 °C producing hydrogen through a series of reactions described in [26]. This process is still under R&D, and different options are considered [19], [30]. Within this process, the hydrogen is produced with an overall efficiency of about 45% using thermal energy only [31]. Because sulphuric acid and other elements are very corrosive, the selection of the structural materials is a relevant research topic [32] [33]. Notably, R&D on the SI cycle is carried out in the USA, France, South Korea and Japan [34]. Recently, researchers successfully demonstrated a stable and continuous hydrogen evolution at laboratory scale [12]. [13] describes the technical aspects of coupling a SI facility with high-temperature SMR design, such as the HTGR. The HTGR generates up to 300 MW_e at 45-50% thermal efficiency by a direct cycle gas turbine power conversion system and potentially up to 1.4 million Nm^3 hydrogen/day at about 45%

efficiency with an SI process. The reactor has 600 MW_t thermal power and 850~950 °C reactor outlet temperatures, ideal for the SI. Using an intermediate heat transport loop, a share of the HTGR heat is the input of the adjacent hydrogen facility. As for HTSE, the hydrogen facility should be sited close to the reactor building to reduce thermal loss and pipeline cost [13].

2.3 Other revenues: reserve services and energy storage

The coupling of a SMR with a facility producing hydrogen could allow the SMR to sell electricity for balancing service. Each country has its balancing service market; the UK market is selected as a reference because of the public availability of information and previous studies [35], [36]. In the UK the "National Grid" procures balancing services to balance demand and supply and to ensure the security and quality of electricity supply across the UK transmission system. The National Grid manages the balancing service either accessing to sources of extra power generation or demand reduction, to deal with unexpected demand increase and generation unavailability. Different sources require different time scales to be ready to deliver the services and different price [37]. The most important reserves for this studies are the so-called "Fast Reserves" and "Short Term Operating Reserves" [36]. Fast reserves are used to control frequency variations arising from sudden and unpredictable changes in generation or demand. Active power delivery must start within 2 minutes of the dispatch instruction, and the reserve energy should be sustainable for a minimum of 15 minutes; it must be able to deliver a minimum of 50MW [38]. *"Providers of the service will receive an Availability Fee (£/h) for each hour in a Tendered Service Period where the service is available. A utilisation fee (£/MW/h) is payable for the energy delivered"* [38].

For Short Term Operating Reserve the minimum capability requirements are [39]:

- 3MW minimum power generation;
- 240 minutes maximum response time, although typical contracts are for 20 minutes or less;
- Delivering the contracted MW for a continuous period of minimum 2 hours;
- Not more than 1200 minutes as recovery period after the reserve provision;
- Being able to deliver at least three times per week.

There are two forms of payment that National Grid makes as part of the Short Term Operating Reserve. *"Availability Payments (£/MW/h): service providers are paid to make their unit/site* *available for the [Short Term Operating Reserves] service within an Availability Window. Utilisation Payments (£/MWh): service providers are paid for the energy delivered as instructed by National Grid. This includes the energy delivered in ramping up to and down from the Contracted MW level"* [39]. This paper assesses the economic relevance for SMR coupled with a hydrogen facility operating in the reserve market, assuming the market prices in the UK. Regarding the technical aspects is unclear if a stand-alone SMR can adjust its power output, on a regular basis, in the timeframes required. Conservatively the paper considers this options for AWE only. In case of AWE, the SMR produces electricity 100% of the time, so the Short Term Operating Reserves and Fast Reserve service is provided by simpling disconnecting or reducing the power in one (or more) of the electrolyser modules. This electrical switch operation is compatible with the requested flexibility timeframe.

3 Methodology

This research is based on two steps.

1. The technical verification of the possible coupling solutions, on the basis of the literature and experts' interviews (Section 4).
2. A novel economic appraisal of the technically feasible solutions. The results from these economic calculations are original from this research (Section 5).

3.1 General framework for the economic analysis

Traditional methods for project economic appraisal are based on the Discounted Cash Flow (DCF) analysis that is grounded on the estimation of costs and revenues over the facility life. A detailed and clear explanation of the DCF analysis in energy and research facility is available in [40]. This section explains the equations used in the research presented in this paper. Because of the time value of money, each cash flow produced during the plant lifetime is discounted back to current value, using the formula:

$$PV_t = \frac{FV_t}{(1 + WACC)^t} \quad (1)$$

Where:

FV = future value of the cash flow;

PV =present value of the cash flow;

WACC (Weighted Average Cost of Capital) = discount rate per time period, i.e. weighted average remuneration rate expected for the financing sources mix invested in the project;

t = number of the time periods.

The project Net Present Value (NPV) is the sum of the PVs of all the cash inflows and cash outflows over the life of the project:

$$NPV = \sum_{t=0}^{T} PV_t = \sum_{t=0}^{T} \frac{FV_t}{(1 + WACC)^t} \quad (2)$$

Therefore the DCF analysis calculates future free cash flow projections (revenues and costs) and discounts them in a lumped NPV, which is used to evaluate the capability of the project of generating net economic value for the investors.

If the discounted cash inflows are higher than the all the discounted costs, then the NPV is positive, and therefore the investment is considered “profitable”. A heuristic decision maker rule is, therefore, to invest in the project (i.e. building the hydrogen cogeneration facility) if NPV is positive. Therefore the NPV is usually a synthetic value calculated as the lump sum of the annual net cash flows over the entire life cycle of the facility (i.e. “T” in the equation 2 is the total number of years and “t” is the year index). The following charts in Figure 1 and Figure 2 show the cumulated net cash flows calculated at each year of the life cycle of the facility. The value in the final year is the NPV of the overall project. An important indicator related to the DCF is the “Payback time”. The Payback time is the length of time (usually years) required to recover the cost of an investment.

The main limitation of the aforementioned NPV method is that all costs and revenues over the facility lifecycle should be estimated with reasonable confidence. This is possible for the case of AWE, but not for HTSE or SI. When key data are missing it is common practice to reverse the equation: the NPV calculation can be implemented in a spreadsheet and, with a “goal seek function” assuming NPV = 0, it is possible to calculate breakeven values of the key variables, (e.g. the construction capital cost) that are the threshold values for the technology profitability. Table 8, Table 9 and Table 11 are built with this criteria and provide a complete sensitivity analysis respect to different parameters.

3.2 Key Hypothesis for the economic analysis

The goal of this economic analysis is to support the investment appraisal of building a hydrogen production facility for the LF. This paper assumes that the decision to build the SMR is already taken. In the perspective of the SMR owner, the paper assesses the chance to add economic value by building a hydrogen production facility coupled with the SMR, to perform the LF with the help of the cogeneration process. Therefore the economic analysis focuses only on the hydrogen production facility and is presented in differential terms compared to the case of a SMR 100% dedicated to the electricity production for the grid.

Compared to a SMR full-electricity operation mode, the analysis considers three main elements:

- Revenues: from the sale of hydrogen and from backup capacity (Fast Reserve and Short Term Operating Reserves – for AWE only).
- Capital expenditures (CAPEX), including all the costs to design and build the hydrogen production facility.
- Annual operation expenditures (OPEX), including all the costs to run the hydrogen production facility, i.e. personnel, materials & spare parts. We assume that the OPEX expenditures include the "opportunity cost" from the loss of the electricity sales.

Since the analysis is differential to the full-electricity operation mode, revenues from electricity sale are not considered. Conversely, the paper considers the "opportunity cost" of giving up the revenues from electricity sales, to use the nuclear thermal power to produce hydrogen. The "opportunity cost" is not a cash cost, but a loss of revenue and is equal to the wholesale price of electricity (0.05 €/kWh) when the SMRs are in LF mode. As presented later, the "opportunity cost" is a very important parameter driving the overall economics.

The paper also assumes that the electricity sold to the grid by the combined nuclear-hydrogen plant is roughly 100% SMR site nominal power during the day (8.00 am to 12.00 pm), and roughly 50% during the night (0.00 am to 8.00 am). This is called "Base Case 8" i.e. a case with 8 hours of low electricity demand and price. A sensitivity analysis is performed on a "Base Case 12", that assumes a longer 12 hours night (8 pm – 8.00 am).

4 Technical verification

Table 1 lists the key characteristics of a typical LWR SMR [41] (according to the IRIS reactor concept [42]), and an HTGR SMR (according to the GTHTR300 [12]) resized to 335MW$_e$ for a fair comparison.

PLEASE INSERT TABLE 1 HERE

Table 1: SMRs technical characteristics [34], [31]

Assuming that the electricity required by the grid is roughly 100% SMRs nominal power during day-time and roughly 50% at night-time the power available night-time for the cogeneration auxiliary facility will be 670 MW$_e$ from both IRIS and GTHTR300 designs, or 2000 MW$_t$ and 1456 MW$_t$ from the IRIS and GTHTR300 sites respectively. The power split between the grid and the hydrogen production facility, for each case, is calculated as follows:

1. During the night, 50% power is diverted to the hydrogen facility.
2. If the SMRs cannot provide the necessary enthalpy to the cogeneration process, natural gas is burned to increase the steam temperature.
3. The ratio between the nuclear and the natural gas thermal contribution is determined by the enthalpies (i.e. by temperatures reached in the two thermal power sources).

4.1 Alkaline Water Electrolysis

4.1.1 Choice of the electrolyser module

Alkaline electrolysers are a standardised item and several manufacturers are available. The efficiency of an electrolyser measures the rate of hydrogen production per unit of electrode active area; it is inversely proportional to the cell potential, which is determined by the current density [43]. Consequently, a higher voltage would result in more hydrogen production, but at a lower efficiency. Typically, the cell voltage is about 2 V, but a lower nominal voltage (as low as 1.6 V) can be used to raise the efficiency. Currently, commercial large-size electrolysers have electric power inputs usually between 0.35 MW$_e$ and 3.35 MW$_e$. Considering that the cogeneration facility has to absorb all the excess power coming from the SMR, the AWE facility will be composed of several electrolysers cells (or modules).

[15] presents a list of electrolysers models, technical data on efficiency degradation (typically between 0.25 to 1.00 %/year) and stack lifetime (between 78,840 to 96,000 hours). According to [20] [27], the energy input varies from 3.8 KWh_e/Nm^3 to 4.7 KWh_e/Nm^3. After several interviews with electrolyser manufacturers, the researcher selected a standard module with a size of 2.2 MWe and an electricity consumption of ranging from 3.8 to 4.4 KWh_e/Nm^3 with 4.3 KWh_e/Nm^3 as the expected value. This module is the NEL A. 485, produced by NEL Hydrogen [27] with the features presented in Table 2

PLEASE INSERT TABLE 2 HERE

Table 2: AWE technical parameters [27] [15]

It is necessary to take into accounts some degradation of the electrolyser efficiency, i.e. the energy required to produce 1 Nm^3 of hydrogen increases. According to the experts he efficiency degradation ranges between from 0.7% to 1.5 %/year, with an expected value of 1.0 %/year. After ten years, the excessive degradation of performance requires a replacement of the electrolysers stacks. The availability of the electrolysers is typically high (about 98%) since there are no moving parts. The planned maintenance can mostly be done during the day-time with a negligible impact on the production.

4.1.2 Sizing the Alkaline Water Electrolysis facility

Since the available power from the SMRs is approximately 670 MWe, 304 electrolyser units are installed. During the night the electrolysers operate at their maximum operating load. On the opposite, according to alkaline electrolysers manufacturers, the repeated shutdown of the AWE facility during day-time would cause a rapid degradation of the electrolysers performances. Therefore, following the manufacturer's recommendations, the paper assumes that the minimum operation level for the AWE facility is 20% of its nominal capacity. Considering the reserve market, the dynamic response becomes essential in the case of “Fast Reserve Operation” and “Short Term Operating Reserve”. According to electrolysers manufacturers, in the event of a request, electrolysers can be rapidly brought to the minimum operating level and the electricity made available to the grid within two minutes, without damaging the AWE system.

4.2 High-temperature steam electrolysis facility

Currently, there are no commercial HTSE facilities in operations. Therefore it is not possible to refer a “standard” set of input data. Efficiency degradation is one of the most serious problems affecting the HTSE and is highlighted in Table 3. Moreover, LWR SMRs (like IRIS) cannot supply a steam temperature high enough for the HTSE. Therefore, natural gas could be burned to increase the steam enthalpy. The techno-economic feasibility of this facility might be challenging. On the contrary, the steam produced by HTGR SMR (like GTHTR300) complies with the requirement in terms of temperature, and therefore no extra heating source is necessary. The stack lifetime is hardly predictable at this stage of knowledge, so a sensitivity analysis will be done on this parameter (see section 5).

Also in this case, the repeated shutdown of the facility during day-time would cause a rapid degradation of the electrolysers performances. Therefore the paper assumes that the minimum operation level for the HTSE facility is 20% of its nominal capacity. Table 3 presents the key technical parameters of the HTSE. The HTSE requires a combination of electric and thermal energy (about 2.5 kWh_e + 0.92 kWh_t) [26]; therefore electricity is largely the most important input for the HTSE as well. The HTSE is still in the R&D phase, and its key challenge is the fast degradation issue.

PLEASE INSERT TABLE 3 HERE

Table 3 HTSE technical parameters

4.3 Sulphur-iodine cycle thermochemical facility

All the considerations about uncertainties on technical parameters applicable to the HTSE apply to the SI as well. The thermal energy input of the SI cycle is 5.99 KW_t/Nm^3. The need for a heat transfer fluid at 850°C, makes the usage of an LWR reactor unrealistic since the enthalpy of the steam is by far too low for the process. Therefore this work focuses on the coupling of SI with HTGR. Whether an SI facility would be flexible enough to perform LF is not an easy question to answer. Realistically, this facility would present the typical problems of thermal inertia and low flexibility, which characterise large thermochemical facilities. However, the process is under R&D, and there is not enough information to confirm nor dismiss this assumption. Moreover to avoid the thermal dynamic stress a conservative hypothesis and in analogy with the AWE and HTSE, a load factor of 20% has been assumed for the day-time operation. The SI process requires thermal energy only: 5.9 kWh_t/Nm^3 [26]. Table 4 presents the key technical parameters of an SI facility.

PLEASE INSERT TABLE 4 HERE

Table 4: Sulphur-Iodine facility model technical parameters

5 Economic analysis

5.1 Alkaline water electrolysis facility

5.1.1 Cost analysis

The AWE capital cost ranges between 1,000 to 1,200 €/kW$_e$, but it is expected to decrease to 760—1,100 €/kW$_e$ in the next years [44]. A more significant cost reduction is expected in the medium term, which could be fostered by the growing penetration of hydrogen as a fuel in the automotive market. The expected capital cost in the long term is 600 €/kW$_e$, with an optimistic forecast of 370 €/kW$_e$ [44]. Much of the cost reduction will come from an improved supply chain and from increased production volumes with more cost-efficient production techniques [44]. Substantial capital cost reductions are possible by the economy of scale applied to larger auxiliary systems shared by electrolysers. [45] reports that the scaling of compressors, gas holding tanks, transformers and balance of plant equipment might reduced capital cost at 60% or 25% of its current value. All this considered and following discussions with the manufacturers we assumed an interval from 730 to 880 €/KW$_e$ as CAPEX cost.

Considering OPEX, the stack replacement is the substitution of the electrolyser components where the electrochemical reactions take place. Stack cost typically represents about the half of the overall costs of the alkaline electrolysis [44]. According to the vendors, the AWE system lifetime is estimated to 40 years, but the stacks have to be replaced every ten years. According to [44], other OPEX ranges between 2%-5% of the CAPEX, while manufacturers suggested that for the middle term a value of around 1.0% and 1.5% is more reasonable.

5.1.2 Inputs

In this research, revenues come from:

- The hydrogen sale
- The electricity sold as Short Term Operating Reserve or Fast Reserve (*Utilisation Payments*)
- The payment for the plant *Availability* related to the Short Term Operating Reserve only.

The costs are represented by CAPEX and OPEX (including the electricity opportunity cost) as aforementioned discussed. Table 5 summarises the annual costs and revenues from the participation to the Short Term Operating Reserve and the Fast Reserve markets, assuming 50% reduction in the electricity supply to the grid during 8 hours night-time.

The CAPEX values are reported in Table 6. As for the OPEX and Stack Replacement, the expected values are derived from the literature [44] and the interviews with some manufacturers. The WACC - Discount Rate is 5% as suggested by [40].

PLEASE INSERT TABLE 5 HERE

Table 5: Cost and Revenues description during different operation periods, for Short Term Operating Reserve and Fast Reserve

PLEASE INSERT TABLE 6 HERE

Table 6: AWE Inputs from [44] **and the interviews with the manufacturers**

The electricity price changes over the day as well as over the year. The electricity price distribution of the UK Day Ahead electric market is available from [46], [47]. The hydrogen selling price is very complex to define since it is usually not traded, but produced and consumed in situ [48]. A reference price provided by experts is around 0.30 - 0.40 €/Nm^3.

5.1.3 Results

Figure 1 gives a long-term perspective showing that with a hydrogen price of 0.30 €/Nm^3 the NPV is negative for all the scenarios; therefore the hydrogen production is not economically viable in the long term. Considering a hydrogen price of 0.40 €/Nm^3, the three scenarios present very different results: indeed, in the "optimistic case" the Payback Time is about nine years; in the "expected scenario" is 25 years, while the "pessimistic scenario" forecasts a non-profitable investment (Payback Time never occurs).

Figure 2 gives a short-term perspective showing the hydrogen/electricity breakeven prices, according to the two Base Case scenarios: Base Case 8 and Base Case 12, i.e. when the hydrogen is produced respectively for 8 or 12 hours/day. Considering, for instance, the "Expected Base Case 8" the figure reveals that the production of hydrogen is reasonable when the demand and price for electricity is particularly low. In fact, given a certain Hydrogen price, there is a break-even price for electricity, above which it becomes more profitable to produce electricity. For instance, if the price of Hydrogen is 0.30 €/Nm^3, the electricity breakeven price is about 0.05 €/KWh$_e$. In other words at hydrogen 0.30 €/Nm^3 and electricity 0.05 €/KWh$_e$ is economically equivalent, in the short term, to produce hydrogen or electricity.

Data and consequent revenues for Short Term Operating Reserve and Fast Reserve are presented in Table 7 (with original data converted in €).

PLEASE INSERT FIGURE 1 HERE

Figure 1: NPV for the Base Case 8 operation, taking the Hydrogen price at 0.40 €/Nm^3 (solid line) and 0.30 €/Nm^3 (dotted line).

PLEASE INSERT FIGURE 2 HERE

Figure 2: Deterministic Breakeven Hydrogen price depending on electricity Price: Expected value, Optimistic and Pessimistic curves. Base Case 8 and Base Case 12 operation mode. BC = Base case. Operating life 20 years

PLEASE INSERT TABLE 7 HERE

Table 7: Short Term Operating Reserves and Fast Reserve - Revenue calculation (data converted in €)

The Short Term Operating Reserve operation gives a weak extra value to the investment, due to the lower unit economic value is given to this reserve type compared to the Fast Reserve. The Fast Reserve operation is more profitable (from 3.5 M€/y for availability to 7 M€/y for utilization), provided that the efficiency degradation is relatively low. However, these values do not substantially change the overall economics of the facility.

5.2 High-temperature steam electrolysis facility

5.2.1 Inputs

The only relevant differences respect to the DCF model of the AWE investment case are:

- The natural gas fuel cost (LWR + Natural Gas case);
- The reserve market is not considered because the flexibility of the HTSE facility is not known yet.

Since the HTSE technology is not ready for commercialisation, the economic analysis will provide a plausible CAPEX for the HTSE model, to be compared with some information provided by the literature. Thus, for this technology (as well as for the SI cycle in section 5.2.2), the most interesting research output is the break-even CAPEX. This is the maximum cost for an HTSE module, which would let a minimum required profitability (i.e. 5% WACC) and justifies the construction of this facility. Mathematically, the breakeven corresponds to a NPV equal to zero, i.e. the investment returning a profitability rate which is exactly equal to the WACC.

5.2.2 Results

Table 8 shows the results of the coupling the HTSE facility with an IRIS SMR and a superheater. Results are given in terms of breakeven capital costs, that is the minimum WACC for the hydrogen cogeneration facility that makes the investment profitable, given the electricity and hydrogen market prices. Table 9 refers to the coupling between the HTSE facility and an HTGR. The two cases (IRIS + Natural Gas; HTGR) produce very similar results. The difference is due to the additional cost of the natural gas presented only in the first case. The values have a trend:

- The values increase with the increase of the hydrogen price, which is the most important variable since it is the only revenue. The correlation is almost direct: increasing the hydrogen price, the breakeven capital cost increases by roughly the same percentage.
- The values decrease with the increase in the electricity price. The reason is that if the price of electricity is high the "opportunity cost" of producing hydrogen increases; therefore the production of hydrogen is convenient only if capital cost of the facility is low.
- The values decrease with the efficiency degradation increase. If the facility degrades quickly, it is convenient to build the facility only if the CAPEX cost "is low". In particular is important to keep the degradation under 8%-10% per year.

PLEASE INSERT TABLE 8 HERE

Table 8: HTSE + External Heater Breakeven Capital Cost, in the case of coupling between the HTSE facility and an LWR, with the Steam Superheating provided by natural gas (Neg = Negative NPV)

PLEASE INSERT TABLE 9 HERE

Table 9: HTSE Breakeven capital cost, in the case of coupling between the HTSE facility and an HTGR (Neg = Negative NPV)

5.3 Sulphur-Iodine cycle thermochemical facility

5.3.1 Inputs

The relevant differences of the HTSE DCF model from the previous ones are:

- No Stack replacement cost, because of the different nature of the facility;
- No natural gas fuel cost, because the LWR+Natural Gas case is considered unfeasible (see section 4.3);

The economic inputs for the SI cycle DCF are listed in Table 10

PLEASE INSERT TABLE 10 HERE

Table 10: SI cycle Deterministic DCF Inputs

5.3.2 Results

Table 11 shows the results of the SI facility and an HTGR coupling. The table is conceived in the same way as the HTSE case; the only difference is represented by the OPEX costs expressed as a percentage of the CAPEX in place of the efficiency degradation rate. Most of the comments made for the HTSE case remain valid here: the electricity price is a key driver, and the efficiency degradation must be carefully assessed since above 8%-10% per year the investment might be hardly profitable.

PLEASE INSERT TABLE 11 HERE

Table 11: Sulphur-Iodine Breakeven Capital Cost, according to hydrogen price, electric price and OPEX cost scenarios (Neg = Negative NPV)

5.4 Discussion and summary of the results

If the hydrogen price is low (below 0.15 €/Nm^3) and electricity above 0.06 €/kWh$_e$, both the HTSE and SI processes are not competitive as is. It is necessary need to decrease their capital cost to become a profitable investment.

With a hydrogen price of 0.30 €/Nm^3 and an electricity price of 0.06 €/kWh$_e$ the HTSE begins to be profitable if the efficiency degradation rate is between 2%/year and 5%/year. With these market prices for hydrogen and electricity, the SI facility is always a profitable investment. The SI facility is potentially profitable even for medium-high electricity prices as far as the hydrogen price reaches 0.15 €/Nm^3 and OPEX costs are lower than 6%.

The HTSE becomes profitable with hydrogen prices above 0.30 €/Nm^3, particularly if efficiency degradation rate remains below the 5-10 %/year. In the case of 20 % efficiency loss per year, the HTSE struggles to be competitive. Table 12 summarises all these results.

PLEASE INSERT TABLE 12 HERE

Table 12: Summary of the results

6 Conclusions e future developments

NPPs have been historically used for base load electricity production. However, the energy portfolios evolution towards increasing share of renewables and the new requirements set by institutions, will require NPPs to be able to work in LF mode. NPP, including SMRs, are capital intensive, and almost all of their costs are fixed or sunk costs. Therefore, this paper proposes to use the excess energy available during periods of low demand / low electricity price (usually night-time) to produce hydrogen as a valuable by-product.

Three different hydrogen production electrolysis technologies have been investigated: AWE, HTSE and the SI. Among these, AWE is the only one commercially developed. HTSE and the SI are at different stages of R&D.

Considering the technical aspects, the paper shows that the AWE, as an electric application, is a flexible technology that can be easily coupled with SMRs. The investment can be profitable, mostly depending on electricity and Hydrogen prices. With AWE, the Short Term Operating Reserve is sustainable for electrolyzer and does not damage the facility. Fast Reserve operation puts a strain on the electrolyzer, which however is capable of performing fast shutdown and rapid recovery. This operation would reasonably cause an increase of the efficiency degradation, and given the limited contribution to the overall economics, the investor should carefully consider this option and carry out further research for an informed decision.

HTSE is mostly an electric application even if requires thermal power. HTSE can be coupled with an HTGR, but this SMRs concept still requires substantial R&D. The coupling of HTSE with a LWR SMR might be technologically challenging due to the difference in temperature between the steam produced by the SMR and the cogeneration process requirements. The LF with HTSE might also be challenging because the capability of the 850 °C operating facility to adapt to periodical changes in power input need further investigation. However, the feasibility of this coupling cannot be excluded a priori. Moreover, the modular nature of the facility (made by hundreds of HTSE) could be an advantage.

The SI facility uses predominantly thermal power and can be coupled with an HTGR for cogeneration purposes. The coupling with an LWR and a natural gas burner is not feasible since the natural gas heating system should provide at least 1,000 MWth. The use of a LWR as a thermal power source seems unrealistic, since the steam enthalpy is too low respect to the SI operating conditions. Also, the SI facility and the HTGR are in their R&D stage.

Considering the economic aspects, this research shows that the production of hydrogen with an AWE facility is profitable if the hydrogen price is at least hydrogen price of 0.40 €/Nm^3 and the electricity price (i.e. the opportunity cost) is relatively low. This applies in particular when the period of “low price” is longer: the 12 hours low price scenario is considerably more profitable than the 8 hours low price scenario. The Short Time Reserve operation gives a weak extra value to the investment, while the Fast Reserve operation gives a more significant additional value to the investment, as far as the electrolysers efficiency degradation rate is low (<2% per year). However, the reserve market, with the typical value of the UK scenario, does not significantly change the overall project economics. It is interesting to note that HTSE becomes profitable for high hydrogen prices, i.e. in the range of 0.30 - 0.45 €/Nm^3 or above, but only if efficiency degradation rate keeps below 5-10 %/year. The SI is potentially very profitable, meaning that its capital cost can be higher than a water electrolyzer, even for medium-high electricity prices, as far as the hydrogen price reaches 0.30 €/Nm^3. Therefore there is an economic rationale for a SMR to co-generate hydrogen for LF purposes if the price of electricity is low enough during night-time. Moreover, the development of more advanced technologies, such as SI, that use thermal energy only, is interesting from the technical-economic point of view, since the conversion loss from thermal to electric power is avoided.

This research paves the way for a number of future developments. Regarding the technical aspects, the most innovative, are related to the further development of SI facility and HTGR. Regarding the economic aspects, the next step is to develop a Monte Carlo analysis with a real options approach. This would allow to better quantify the risks in the investment and the value of the degrees of freedom available to the investor. Regarding the policy aspects, the study of the contracting schemes to enable the most reasonable risk allocation among the stakeholders involved would be of extreme interest. Under this perspective, particularly relevant would be the proposal of a government scheme to foster the construction of a pilot facility and, eventually, the commercial production of the facilities investigated in this research.

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Figures and tables

TABLE 1

	LWR	HTGR
Thermodynamic efficiency	33%	46%
1 SMR nominal Electric Power [MW_e]	335	335
Number of SMRs in the site	4	4
Overall *electric* power available night-time [MW_e]	670	670
Overall *thermal* power available night-time [MW_t]	2,000	1,456
Load Factor	95%	95%

TABLE 2

	Optimistic	**Expected value**	**Pessimistic**
Initial energy Input per Nm^3 [kWh_e/Nm^3]	3.8	4.3	4.4
Efficiency degradation_ Full operation	0.7%	1.0%	1.50%
Efficiency degradation_ Fast Reserve operation [%/y]	Expected value *90%	Scenario variable: {2%; 5%; 10%; 20%}	Expected value *110%
Stack power [MWe]	2.2		
Nominal Generation capacity [Nm^3/h]	485.0		
Stack lifetime [h]	87,600 (10 years)		
Availability [h/y]	8,585		

TABLE 3

	Expected value
Initial Electric Energy Input per Nm^3 [kWh_e/Nm^3] [26]	2.5
Efficiency degradation: scenario variable [%/y]	{2%;5%;10%;20%}
Stack power [MWe]	2
Nominal Generation capacity [Nm^3/h]	800
Availability [h/y]	8,585
Operating range (day - night) as explained in 4.1.2	20%—100%

TABLE 4

	Expected value
Thermal Energy Input [kWh_t/Nm^3]	5.99
Power Input [MW_e]	1454
Nominal Generation capacity [Nm^3/h]	242,700
Facility lifetime [y]	20
Availability [h/y]	7,008 (80%)
Operating range (day-night)	20%—100%

TABLE 5

	Operation set up	Cost items	Revenues items	Hours
Short Term Operating Reserves	Day operation: (279 electrolyzers at 20%)	Electricity used: 122 MW	Hydrogen production (from 122 MW)	5,840
	Availability – ready state (25 electrolyzers at 100%)	Electricity used: 55 MW	Hydrogen production (from 55 MW) Availability payment	3,864
	Electricity sale - Short Term Operating Reserve	Hydrogen Not produced (from 55MW)	Utilization payment: electricity sold on Short Term Operating Reserve market	78
Fast Reserves	Day operation: (259 electrolyzers at 20%)	Electricity used: 114 MW	Hydrogen production (from 114 MW)	5,840
	Availability – ready state (45 electrolyzers at 100%)	Electricity used: 99 MW	Hydrogen production (from 99 MW) Availability payment	4,223
	Electricity sale - Fast Reserve	Hydrogen Not produced (from 99MW)	Utilisation payment: electricity sold on Fast Reserve market	365

TABLE 6

	Optimistic	Expected value	Pessimistic
CAPEX [€/kW_e]	730	810	880
OPEX [% CAPEX]	1.0%	1.25%	1.5%
Variable non electrical cost [% total costs]	0.9%	1.0%	1.1%
Stack Replacement [% capex]	45%	50%	55%
Hydrogen price [€/Nm^3]	0.30 or 0.40 in Figure 1, calculated as breakeven in Figure 2		
Electricty price [€/kWh_e]	Sentitivity analysis: {0; 0.02; 0.04; 0.06; 0.08; 0.10}		
Discount rate	5%		

TABLE7

		Availability (contracted)	Utilization	Not Contracted
Short Term Operating Reserve Data from [39]	Hours per year	3,864	78	4,818
	Unitary payment [€/MWh]	3.36	212	0
	Total year revenue for 55 MW_e [k€]	714	909	0
Fast Reserve Data from [38]	Hours per year	4,223	365	4,912
	Unitary payment For a 99 MW Reserve Facility	814 [€/h]	192 [€/MWh]	0
	Total year revenue for 99 MW_e [k€]	3,551	7,000	0

TABLE 8

		HTSE + External Heater BREAKEVEN CAPITAL COST [K€/(Nm^3/h)]: IRIS+Natural Gas											
		Hydrogen price [€/Nm^3]				Hydrogen price [€/Nm^3]				Hydrogen price [€/Nm^3]			
		0.15	0.15	0.15	0.15	0.30	0.30	0.30	0.30	0.45	0.45	0.45	0.45
	Efficiency degradation [%/year]	2%	5%	10%	20%	2%	5%	10%	20%	2%	5%	10%	20%
ELECTRICITY price [€/kWh_e]	0.02	2.79	2.32	1.73	1.09	6.48	5.41	4.05	2.55	10.17	8.49	6.36	4.01
	0.04	1.37	1.12	0.82	0.52	5.06	4.21	3.13	1.97	8.75	7.29	5.44	3.43
	0.06	Neg	Neg	Neg	Neg	3.60	2.97	2.19	1.38	7.29	6.06	4.50	2.84
	0.08	Neg	Neg	Neg	Neg	2.13	1.73	1.24	0.79	5.82	4.82	3.55	2.24
	0.10	Neg	Neg	Neg	Neg	0.69	0.51	0.31	0.20	4.38	3.60	2.62	1.66

TABLE 9

		HTSE BREAKEVEN CAPITAL COST [k€/(Nm³/h)]: HTGR											
		Hydrogen price [€/Nm³]				Hydrogen price [€/Nm³]				Hydrogen price [€/Nm³]			
		0.15	0.15	0.15	0.15	0.30	0.30	0.30	0.30	0.45	0.45	0.45	0.45
	Efficiency degradation [%/year]	2%	5%	10%	20%	2%	5%	10%	20%	2%	5%	10%	20%
ELECTRICITY price [€/kWh$_e$]	0.02	2.82	2.35	1.75	1.10	6.51	5.43	4.06	2.56	10.20	8.52	6.38	4.02
	0.04	1.29	1.05	0.76	0.48	4.98	4.14	3.07	1.94	8.67	7.22	5.39	3.40
	0.06	Neg	Neg	Neg	Neg	3.40	2.80	2.06	1.30	7.09	5.89	4.37	2.76
	0.08	Neg	Neg	Neg	Neg	1.82	1.47	1.03	0.66	5.51	4.55	3.35	2.12
	0.10	Neg	Neg	Neg	Neg	0.26	0.15	0.03	0.03	3.96	3.24	2.35	1.49

TABLE 10

	Value
CAPEX [k€/(kilo Nm³/h)]	Research goal
OPEX [% capex]	Different scenarios texted: 2.5%; 5%; 7.5%; 10%
Variable non electrical cost [% capex]	1%
Hydrogen price [€/Nm³]	Different scenarios texted: 0.15; 0.30; 0.45
ELECTRICITY price [€/kWh$_e$]	Different scenarios texted: 0.02; 0.04; 0.06; 0.08; 0.10
DISCOUNT RATE	5%

TABLE 11

		SULPHUR-IODINE BREAKEVEN CAPITAL COST [k€/(Nm³/h)]											
		Hydrogen price [€/Nm³]				Hydrogen price [€/Nm³]				Hydrogen price [€/Nm³]			
		0.15	0.15	0.15	0.15	0.3	0.3	0.3	0.3	0.45	0.45	0.45	0.45
	Fixed OPEX [€/kWh]	2.5%	5.0%	7.5%	10.0%	2.5%	5.0%	7.5%	10.0%	2.5%	5.0%	7.5%	10.0%
ELECTRICITY price [€/kWh$_e$]	0.02	4.5	3.6	3.0	2.6	9.3	7.5	6.3	5.4	14.2	11.5	9.6	8.3
	0.04	2.9	2.3	1.9	1.7	7.7	6.2	5.2	4.5	12.6	10.2	8.5	7.3
	0.06	1.2	1.0	0.8	0.7	6.1	4.9	4.1	3.5	10.9	8.8	7.4	6.4
	0.08	Neg	Neg	Neg	Neg	4.4	3.6	3.0	2.6	9.3	7.5	6.3	5.4
	0.1	Neg	Neg	Neg	Neg	2.8	2.2	1.9	1.6	7.6	6.2	5.2	4.4

TABLE 12

Hydrogen Production Method	Process Temp.	Energy Input [kWh/Nm³]	SMR coupled	Technical feasibility	Economic profitability
Alkaline Water Electrolysis (AWE)	80 °C	4.3 kWh$_e$ Electricity only	LWR	All Feasible	Depends on electricity and Hydrogen prices. All electric sources are equivalent. No advantage with SMR
			HTGR		
High-Temperature Steam Electrolysis (HTSE)	850 °C	2.5 kWh$_e$ + 0.92 kWh$_t$ Mostly electricity	LWR + External Heater	Feasible in theory, Extra Heating required → natural gas solution. Technical challenges HTSE under R&D.	Depends on CAPEX, in electricity and Hydrogen price scenario
			HTGR	HTSE and HTGR under R&D	Depends on CAPEX, electricity and Hydrogen price scenario
Sulphur-Iodine Thermochemical cycle (SI)	850 °C	5.9 kWh$_t$ Thermal energy only	LWR	Not Feasible. 4 GWh$_t$ of natural gas heating required and very large heat exchanger	---
			HTGR	SI cycle and reactor under R&D	Depends on CAPEX, in electricity and Hydrogen price scenario. In general electricity price might be 0.06 €/kWh$_e$ or less and the Hydrogen price 0.3 €/Nm³ or more.

FIGURE 1

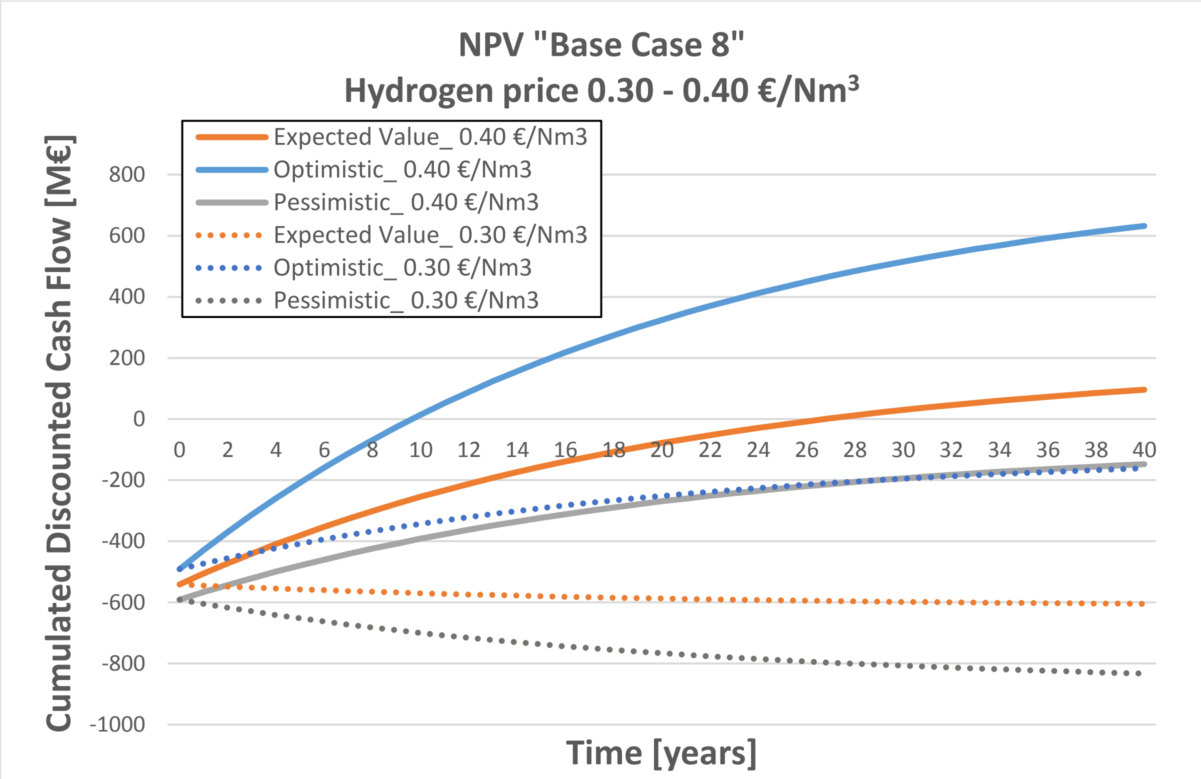

FIGURE 2