TANDEM

Research and Innovation Action (RIA)

Start date : 2022-09-01 Duration : 36 Months

Sensitivity of the hybrid system techno-economic analysis to uncertain key parameters

Authors : Mr. Jussi-pekka IKONEN (VTT), Tomi Lindroos (VTT), Stéphanie Crevon (CEA), Gilles Lavialle (CEA)

TANDEM - Contract Number: 101059479

Project officer: Angelgiorgio IORIZZO

Document title	Sensitivity of the hybrid system techno-economic analysis to uncertain key parameters
Author(s)	Mr. Jussi-pekka IKONEN, Tomi Lindroos (VTT), Stéphanie Crevon (CEA), Gilles Lavialle (CEA)
Number of pages	82
Document type	Deliverable
Work Package	WP3
Document number	D3.3
Issued by	VTT
Date of completion	2024-10-18 16:20:36
Dissemination level	Public

Summary

Some sensitivity studies of the results will be performed considering uncertain key parameters

Approval

Date	By
2024-10-18 16:21:52	Mrs. Stephanie CREVON (CEA)
2024-10-18 21:59:20	Dr. Claire VAGLIO-GAUDARD (CEA)

TANDEM

D3.3 – Sensitivity of the hybrid system techno-economic analysis to uncertain key parameters

WP3 - Task 3.3

17/10/2024 [M26]

Jussi-Pekka Ikonen, Tomi J. Lindroos (VTT)

Stéphanie Crevon, Gilles Lavialle (CEA)

Funded by
the European Union

History

Date	Version	Submitted by	Reviewed by	Comments
11/10/2024	V1	Jussi-Pekka Ikonen	Ville Tulkki (VTT)	

Funded by the European Union

Table of Contents

Funded by the European Union

Abbreviations and Acronyms

Acronym	Description
ATR	AutoThermal Reforming
BESS	Battery Electric Storage Systems
BO DHN	Bohumin/Orlova District Heating Network
BOS	Balance Of System
CAPEX	CAPital EXpenditures
CC	Carbon Content
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture Storage
CHP	Combined Heat and Power
CI	Carbon Intensity
CR	Czech Republic
DC	District Cooling
DH	District Heating
DHN	District Heating Network
DHC	District Heating and Cooling
EA	Emission Allowances
EF	Environmental Footprint
EHB	European Hydrogen Backbone
E-SMR	European Small Modular Reactor
EU	European Union
GAMS	General Algebraic Modelling System
GWP	Global Warming Potential
HES	Hybrid Energy System
HOB-SMR	Heat Only Boiler – Small Modular Reactor
HP	Heat Pump
HTSE	High Temperature Steam Electrolysis
IRES	Integrated Renewable Energy System
LCA	Life Cycle Assessment
LCO	Levelized Cost Of
LCOE	Levelized Cost Of Electricity
LCOH	Levelized Cost Of Heat
$LCOH_2$	Levelized Cost Of Hydrogen
LTE	Low Temperature Electrolysis

Funded by the European Union

MILP	Mixed Integer Linear Programming
MPC	Model Predictive Control
MSR	Moravian-Silesian Region
NEA	Nuclear Energy Agency
N/A	Not Applicable
N.C.	Not Communicated
NGCC	Natural Gas Combined Cycle
NPV	Net Present Value
ODP	Ozone Depletion Potential
OPEX	OPerational EXpenditures
ORC	Organic Rankine Cycle
PEM	Proton Exchange Membrane
PV	PhotoVoltaic
RE	Renewable Energies
RED II	Renewable Energy Directive II
SEP	State Energy Policy
SMGR	Steam Methane Gas Reforming
SMR	Small Modular Reactor
SNG	Substitute Natural Gas
SOEC	Solid Oxide Electrolyser Cell
T DHN	Trinec District Heating Network
TURPE	Tarif d'Utilisation des Réseaux Publics d'Electricité
VRE	Variable Renewable Energy
WP	Work Package
WWHP	Waste Water Heat Pump

Funded by the European Union

Executive Summary

This deliverable (D3.3) is the third in a series of three reports, where D3.1 described the modelled systems and used tools and D3.2 provided the results from the main modelling cases of Hybrid Energy Systems (HES) with Small Modular Reactors (SMR). This deliverable provides a sensitivity analysis of the results obtained in D3.2 for Northern and Southern European cases, considering uncertain key parameters.

Northern European case:

The Northern European case studies SMR investments with the Backbone code from perspective of a district heating (DH) operator in the Helsinki metropolitan area. Deliverable D3.2 explored the potential and profitability of novel SMRs, revealing that while both reactor types (E-SMR and LDR-50) reduced reliance on fossil and biofuels. The LDR-50 produces only heat and allowed the operator to find profitability in the context of Helsinki metropolitan area. The E-SMR can produce heat and electricity. With the hypotheses from the Helsinki case study, it would not meet a district heating's operator profitability expectations. Indeed, the study takes the point of view of a district heating network operator, but does not look at the services rendered to the electricity grid or their remuneration. Since an E-SMR generates mainly electricity, its business model is highly dependent on the electricity market and the size of the power system. This deliverable continues with sensitivity studies on SMR specific economic and technological as well as city- and system level factors affecting the SMR investments. From the perspective of district heating operator, electricity and heat producing E-SMR was found unprofitable in most scenarios, however, this study does not consider the value coming from services electricity producers provide such as stability to the grid or energy security. The heat producing LDR-50 was found profitable in most scenarios. Both SMR technologies improved electricity supply of the studied area: E-SMR produced electricity and LDR-50 reduced the use of heat pumps and electric boilers. The sensitivity studies demonstrated that energy market conditions critically affect SMR investments. For instance, E-SMR found profitability in the high electricity price scenario of 2022, while LDR-50 was not profitable in the 2016 scenario where price of CO2 credits and fossil fuels were lower. The economic factors such as investment cost, operating costs and discount rate are also crucial, especially the investment cost for LDR-50. It must be noted that the Helsinki metropolitan area is quite small when compared to other capital regions in Europe. The city size is important in determining the energy demand, and E-SMR is quite big for the studied area while the smaller LDR-50 modules can be scaled better to fit smaller cities. Sensitivity analysis of E-SMR heat extraction rate showed improvements in plant performance and profitability, and heat production lead to an increased valuer in the business plan for the context of the study.

Funded by the European Union

Energy hub case:

Following D3.1 [1] that introduced the Southern European case as a virtual harbour located at Fos-sur-Mer in the Southern France, D3.2 [2] presented the results of a parametric optimization on CO_2 total emissions of a super-structure including several means to produce electricity, heat and hydrogen and pointed out four cases of interest – run0, 5, 7 and 13.

In the present deliverable D3.3, the Southern European case is analysed further with:

- Complementary studies on other ways to decarbonize the harbour such as the addition of a Carbon Capture Use and Storage (CCUS) or of an Organic Rankine Cycle (ORC).
- Sensitivity studies on price forecasts and on the main parameters of the SMR.

The figure below shows for all scenarios the $LCOH_2$ against the carbon intensity of hydrogen.

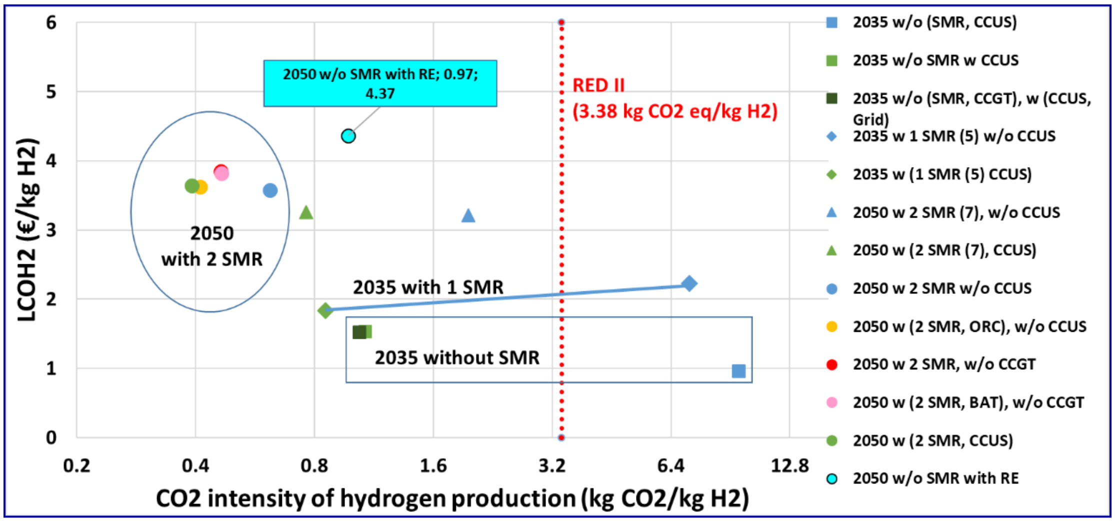


Figure ES 1: Summary of the architectures studied, LCOH2 and CO2 intensity of hydrogen

Equipping the CCGT and the SMGR with CCUS components results in decreasing CO_2 emissions at low extra cost. But the main disadvantage is the high carbon storage capacity needed for the 2035 scenarios, especially for “2035 without SMR” (18 Mtons of CO_2) and “2035 with 1 SMR” scenarios. For the “2050” scenario, adding a CCUS does not impact so much the LCOE and the $LCOH_2$ but it reduces the CO_2 intensity of electricity and hydrogen.

A price forecasts sensitivity was conducted to analyse the impact of the gas price (year 2019 and 2022) on the technical, economic and environmental results. The main conclusion that can be drawn from this sensitivity study is the less dependence to natural gas, the more robust the results in terms of LCOE and $LCOH_2$.

Funded by the European Union

The sensitivity analyses on the SMR main input parameters consisted in the evaluation of the NHES main results in the frame of the “2050 with 2 SMR and CCUS” on:

- The SMR economical parameters: CAPEX in the range [-20%, +20%] in relation with the 6050 €/MW reference data and variable cost (includes the uranium cost) in the range [5, 45] €/MWhe whereas the reference value is at 31.8 €/MWh.
- The SMR technical heat recovery parameter. D3.2 showed a too high heat recovery energy (9.26%): the heat excess was released outside the NHES. In the sensitivity runs, this parameter was reduced (from 9.26 to 8 and 7%).

The most influent is the SMR variable cost that leads to a deviation of [-23%, +11.3%] for the total costs of the NHES. Besides, the sensitivity conducted on the heat recovery rate of the SMR shows that there is a minimum to have a couple SMR – HTSE working properly (7%) but being a little bit higher than this minimum has a negligible impact on the results.

To conclude, in this deliverable, a new reference case for “2035 without SMR” scenario is presented including a CCUS for the CCGT and for the SMGR. This new reference leads to a couple (LCOE, CO_2 intensity of electricity) of (61.6 €/MWhe, 72.7 kg CO_2 eq/MWhe) and to a couple ($LCOH_2$, CO_2 intensity of hydrogen) of (1.53 €/kg H_2, 1.1 kg CO_2 eq/MWhe) considering a CO_2 transport and storage cost of 33 €/tons CO_2. It leads also to have 18 Mtons of CO_2 to store for the whole project duration.

The « 2035 with 1 SMR with CCUS » scenario is an interesting solution as the system can be decarbonized at about 44% compared to « 2035 without SMR with CCUS » scenario with a small decrease of the LCOE (-4.4 €/MWhe) and a small increase of the $LCOH_2$ (+0.3 €/kg H_2). However, the amount of CO_2 to be stored for the duration of the project is 11 Mtons of CO_2.

All the performed simulations show that the “2050 with 2 SMR” scenario give an autonomous NHES without commitment of external energy sources (gas and electricity) with realistic renewable production (the RE footprints) and without distant and massive storage (hydrogen and CO_2). The “2050 with 2 SMR maximizing decarbonisation without CCUS” scenario allows the system to be decarbonized at about 53% compared to « 2035 no SMR with CCUS » scenario with an extra cost of 5.1 €/MWhe for the LCOE and of 2 €/kg H_2 for the $LCOH_2$.

Keywords

SMR, Hybrid Energy Systems, District heating, Power supply, Energy Hub, Techno-economic and environmental study, Case study, Sensitivity study

Funded by the European Union

1 Introduction

The TANDEM (Small Modular ReacTor for a European sAfe aNd Decarbonized Energy Mix) project, funded by the Euratom programme, aims to facilitate the integration of Small Modular Nuclear Reactors (SMRs) into Hybrid Energy Systems (HES). Two hybrid energy systems have been configured in Work Package (WP) 1 to provide assumptions for the studies carried out in the other WPs. In WP3, these two HES have been derived into three study cases:

- Two study cases on the first HES configuration dedicated to supply district heating networks and power grids in Northern and Central Europe,
- One study case to generate heat and power while producing valuable commodities in an energy hub, particularly hydrogen, in Southern Europe.

In WP3, the TANDEM project delves into the operationality, profitability, and environmental impact of Hybrid Energy Systems (HES) with dynamic techno-economic and environmental assessments. To carry out these studies, appropriate tools are implemented, and special emphasis is placed on sharing the methodology of such assessments. For the Northern Europe case, the Backbone tool is used to conduct the techno-economic and environmental study, while the PERSEE tool is deployed for the Southern and Central Europe cases. Additionally, the operationality of the system is analysed using both the ECOSIMPRO tool or a coupling between the PERSEE tool and the Modelica open-source library developed in WP2.

The detailed description of the three study cases is the object of WP3/Task 3.1 and its associated deliverable gathers the description of each case and several techno-economic and environmental assumptions [1]. Task 3.2 is dedicated to the dynamic techno-economic and environmental assessment of the three study cases with the aim to provide tools and methodologies to study feasibility of HES integrating SMRs. Analysis of results along with the description of tools and methodologies implemented in the assessment are presented in Deliverable D3.2 [2]. The results on Key Performance Indicators (KPI) are strongly dependent on the assumptions used to model each case. Task 3.3 continues the study of HES by conducting sensitivity analyses of the results to the assumptions - related to economic and technological factors – and used in the assessment with Backbone and PERSEE for two of the case studies: the Northern European case and the Southern European case.

Chapter 2 of this report presents the results obtained for the Northern European case, while Chapter 3 covers the Southern European case. Both chapters include summary of results obtained in D3.2 and the methodologies used.

Funded by the European Union

2 Northern European case

2.1 General presentation of the case

2.1.1 Reminder of results presented in D3.2

The Northern European case studies the decarbonization of district heating and cooling (DHC) systems in the Helsinki metropolitan area with SMRs. Helsinki, the capital of Finland, and the neighbouring cities of Espoo and Vantaa, are all investigating different decarbonization strategies for their district heating (DH) systems, involving various combinations of heat pumps, heat storage, biomass, and waste heat. The need for decarbonization strategies is driven by the national and local policies to first phase out coal and then achieve carbon neutrality by 2030 [3] [4].

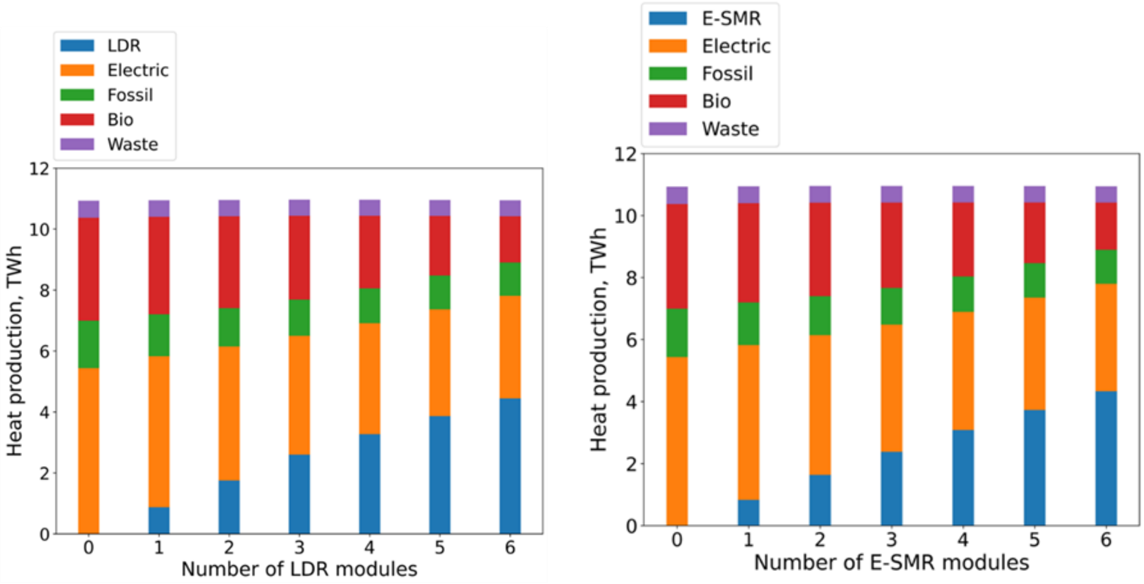
Decarbonization is not an easy task for the Finnish capital region. Finnish and Nordic power systems are relatively carbon-free, but the Finnish capital region depends heavily on fossil-fuelled power plants in the DH production due to high heat demand per km^2 and 10x difference in the heat demand between the summer base load and winter peak demand.

The role of SMRs in the production of dispatchable carbon-free district heating and the profitability of SMR investments have been studied in TANDEM/D3.2. Helen Ltd., a utility company operating in Helsinki, has publicly expressed their interest in SMRs, going so far as to launch a nuclear energy programme [5].

D3.2 was conducted from the perspective of a DH operator evaluating feasibility of SMR integration in the Helsinki metropolitan area. Two different SMR technologies were studied: the academic concept E-SMR, which produces both heat and electricity, and the VTT developed LDR-50, which is designed exclusively for heat production. In the study, the Backbone framework was used to model the SMR technologies into a city-level model of the Helsinki metropolitan area. Scenarios based on year 2030 were modelled with varying amounts of SMR modules implemented in the area.

The two SMR technologies are quite different from each other. E-SMR is much larger with capacity to produce both electricity and heat. LDR-50 produces district heat only in a very small unit size, emphasizing on simplicity in its design. Both technologies have potential for decarbonizing energy systems.

The study evaluated the optimal capacity, costs and emissions associated with each scenario. Increasing capacity increases the share of heat produced with SMRs (Figure 1) where the first units get the highest utilization rate as they can produce throughout the year. Additional units decrease the annual operation hours of SMRs as they are used only from autumn to spring, or only in winter.

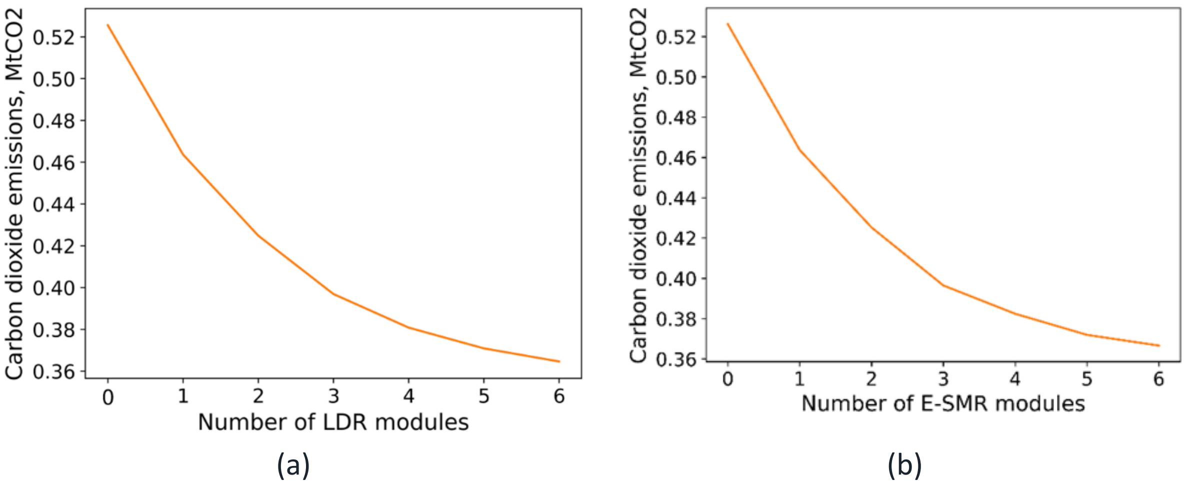


(a) (b)

Figure 1: Yearly heat production by fuel type for (a) LDR-50 and (b) E-SMR scenarios in the Helsinki metropolitan area.

DH system of Helsinki is mostly decarbonized already in the 2030 scenario (without any deployed SMR in the area) with 0.52 $MtCO_2$ emissions remaining compared to historical values of 3.2 $MtCO_2$ in 2019. The 2030 scenario assumes the phaseout of coal and significant reduction in the use of natural gas due to new investments to large heat pump capacities, storages, and biomass-fired units. The modelled SMR investments further decrease the fossil CO_2 emissions (Figure 2) and the remaining fossil fuel use happens during the peak heat demand in coldest winter weeks.

Funded by the European Union

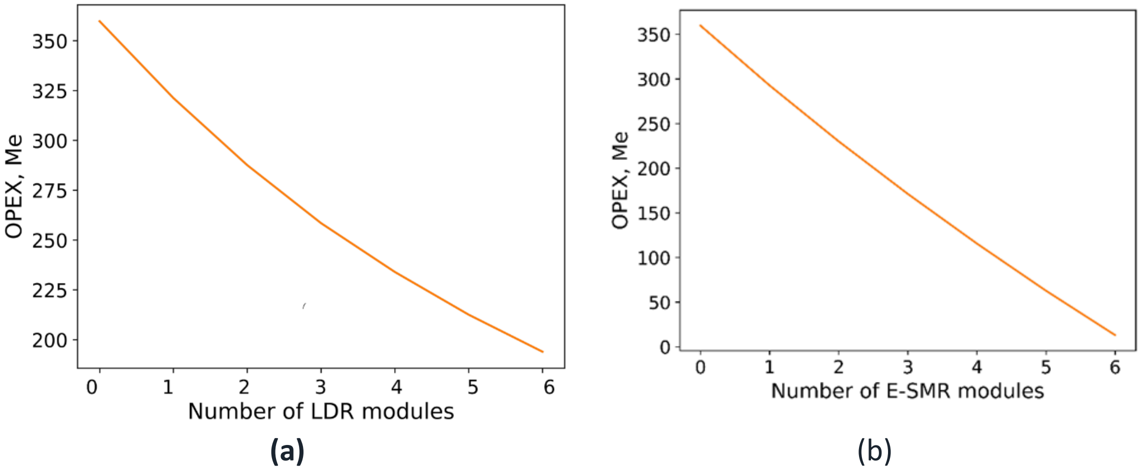


(a)

(b)

Figure 2: Yearly reduction of CO_2 emissions for (a) LDR-50 and (b) E-SMR scenarios in the Helsinki metropolitan.

Annual operational costs (fuel, CO_2 prices, unit level operational cost, cost/income from bought/sold electricity) also decrease with increasing SMR capacity due to low variable costs of SMRs (Figure 3). A large amount of E-SMRs could turn annual operational costs to profits due to sold electricity, but it is important to notice that this figure does not include investment costs.



(a)

(b)

Figure 3: Yearly reduction of system operational costs for (a) LDR and (b) E-SMR scenarios in the Helsinki metropolitan.

Figure 4 shows Net Present Value (NPV) calculation for E-SMR scenarios ranging from one to six modules and Figure 5 shows Internal Rate of Return (IRR) and NPV calculations for LDR-50 scenarios. The SMR investments were studied from the perspective of a district heating operator in the Helsinki metropolitan area. District heating operators prioritize heat production and sell

Funded by the European Union

electricity to the grid when it is profitable. Thus, city level heat demand is modelled, while electricity balance of Finland is not. Instead of modelling the electricity balance, electricity price based on time series data is used as a boundary condition for the model. The Northern European case does not look at the services rendered to the electricity grid or their remuneration by electricity producers. Since E-SMR generates mainly electricity, its business model is highly dependent on the electricity market and the size of the power system. To fully understand the potential of E-SMRs in the studied area, a more detailed study including the electricity balance would be required, which is beyond the scope of this work.

With the assumptions taken in the study, E-SMR did not meet the profitability criteria from a district heating operator’s point of view as the NPV of the SMR investment became negative. From the perspective of a DH operator, smaller baseload units like the LDR-50 were found profitable and the IRR was at its highest, 12 %, with a single SMR module (Figure 5). Due to the lower utilization rate of additional investments, the calculated IRR decreases when the unit count increases.

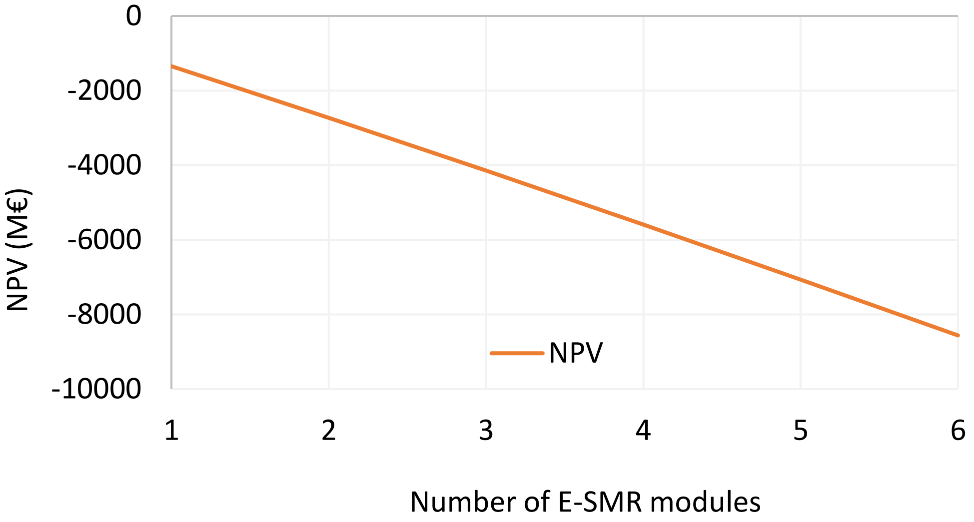


Figure 4: NPV as a function of number of E-SMR modules.

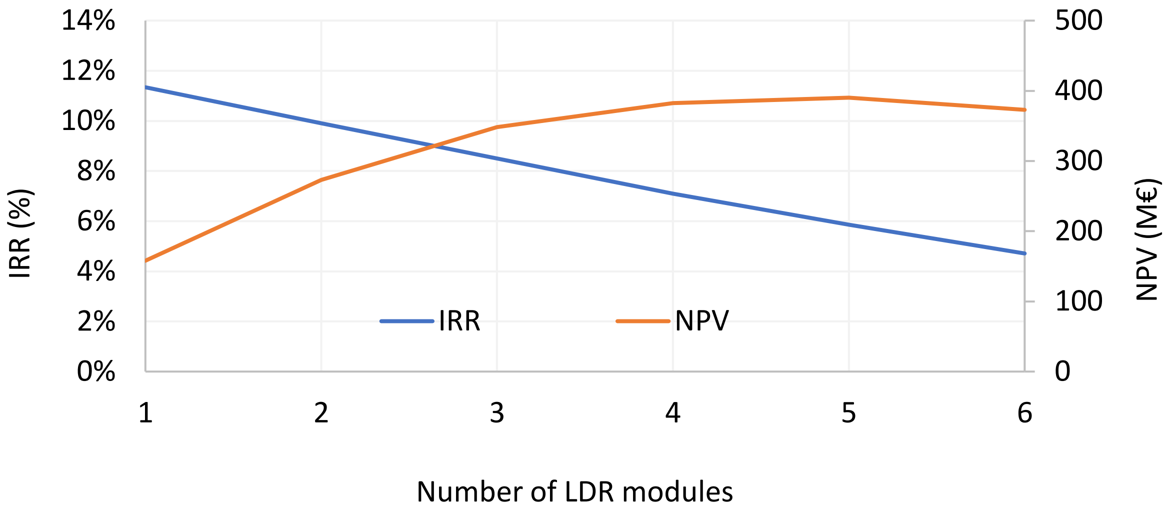


Figure 5: NPV and IRR as a function of LDR-50 modules.

2.1.2 Presentation of the sensitivity studies

This study continues the Northern European case investigation by performing sensitivity studies of the results to study assumptions used in D3.2 for the SMR scenarios. The most significant identified sources of uncertainty come from financial assumptions, technology specific assumptions, and city and system level assumptions. Each assumption category is discussed in detail in dedicated chapters.

The sensitivity studies were conducted for both SMR technologies, on a configuration with a single E-SMR unit and two LDR-50 units. Each parameter is modified to the Backbone model and then comparison between SMR scenario and a baseline scenario with no SMRs is compared to evaluate the impact of the studied parameter.

Most of the sensitivity studies are carried out by changing one input parameter at a time, with the exception of historical year sensitivity, that changes DH demand, prices, and hourly profiles at the same time.

2.2 Sensitivity study on economic assumptions

The main uncertainty sources on economic assumptions come from the variable operational cost, that covers also the fuel cost, investment cost, interest rate, construction time and economic lifetime. Table 1 lists the assumptions and the studied parameter range in the sensitivity analysis.

Parameters	E-SMR	LDR-50	Sensitivity analyses
CAPEX (€/kW_{th})	1905*	1500*	+/- 50 %
OPEX (€/MW_{th})	10.01**	6.3***	+/- 50 %
FOM (% of CAPEX)	0****	3	+/- 50 %
Construction time (years)	2	2	1-5 years
Economic lifetime (years)	20	20	+/- 30 %
Discount rate (%)	7	7	+/- 50 %
Value at the end of the economic lifetime (% of CAPEX)	23	23	+/- 30 %

** Costs correspond to the steam production capacity of the reactor*
*** OPEX for E-SMR combines variable cost of 24.4 €/MWhe and fuel cost 7.4 €/MWhe.*
**** OPEX for LDR-50 concerns all variable costs including fuel related costs*
***** E-SMR FOM is included in the CAPEX*

Table 1: Parameter range in the sensitivity analysis related to economic.

Economic assumptions impact mainly the financial indicators because SMRs typically have very low operation costs, and the assumed range of variable costs did not significantly reduce their annual operation hours. The NPV and IRR are calculated after the model run. Figures 6, 7, and 8 present the IRR of studied SMRS under the calculated sensitivity study on financial assumptions. The figures present only the IRR for clarity.

The cost of investment is an extremely significant factor for studied SMR technologies. For E-SMR, a 50% reduction in investment cost improved the IRR from -9.1% to -4.7%, while a 50% increase lowered it to -10.7%. In addition to the investment cost, operating cost and discount rate have similar impact on E-SMR. Economic lifetime of SMR investments was assumed to be only 20 years, while the SMRs are designed to last up to 60 years. Increasing the economic lifetime increases the IRR which is a very possible scenario for both E-SMR and LDR-50. Increasing the economic lifetime by 30 % to 26 years, the IRR of E-SMR rose to -7.3 %. Though, SMR operators most likely have to invest more money to renew systems as the nuclear power plant gets older.

Funded by the European Union

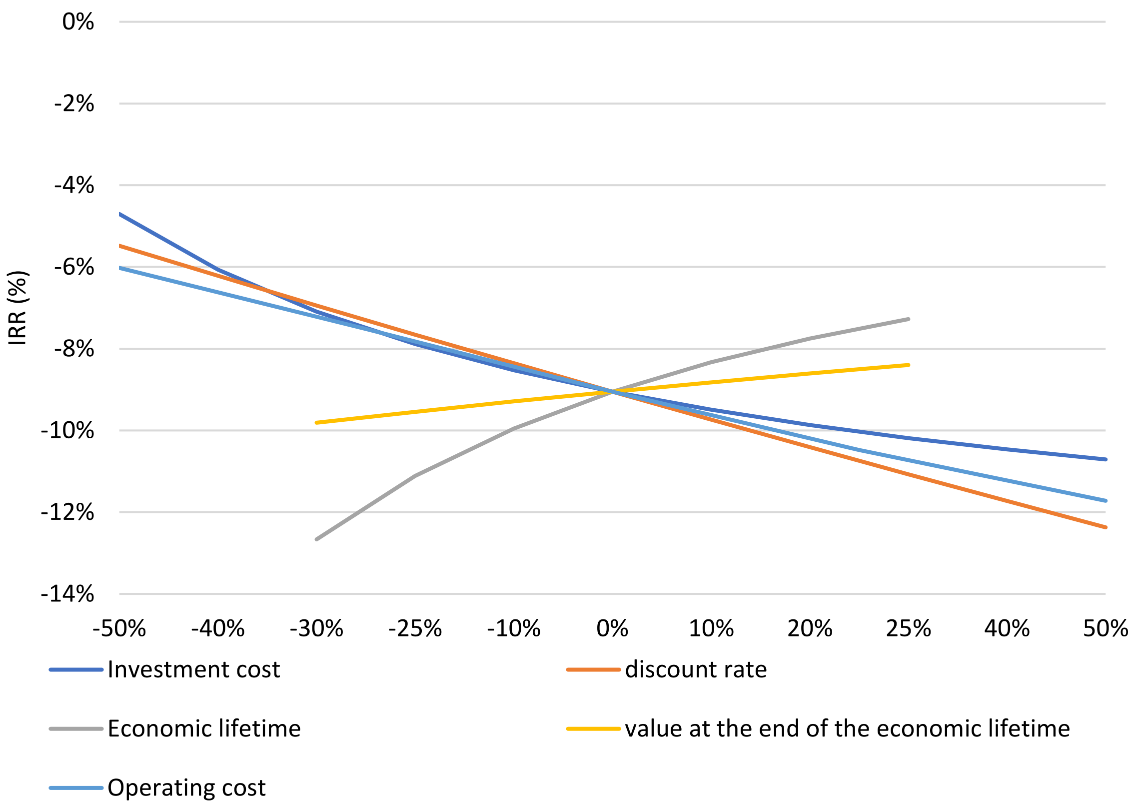


Figure 6: Sensitivity analyses related to E-SMR economic assumptions.

As said earlier, investment cost has significant impact on profitability of LDR-50. A 50% reduction in investment cost results in an increase of the IRR from 9.9% to 30.3%. Conversely, a 50% increase in investment cost reduces the IRR to 2.4%. See Figure 7 for clarity. Most SMR designs like LDR-50 and E-SMR use passive safety systems, which reduce the investment cost. In the current regulatory framework, it is possible that the passive safety systems need to be expanded with additional active safety systems which would increase the investment cost.

Funded by the European Union

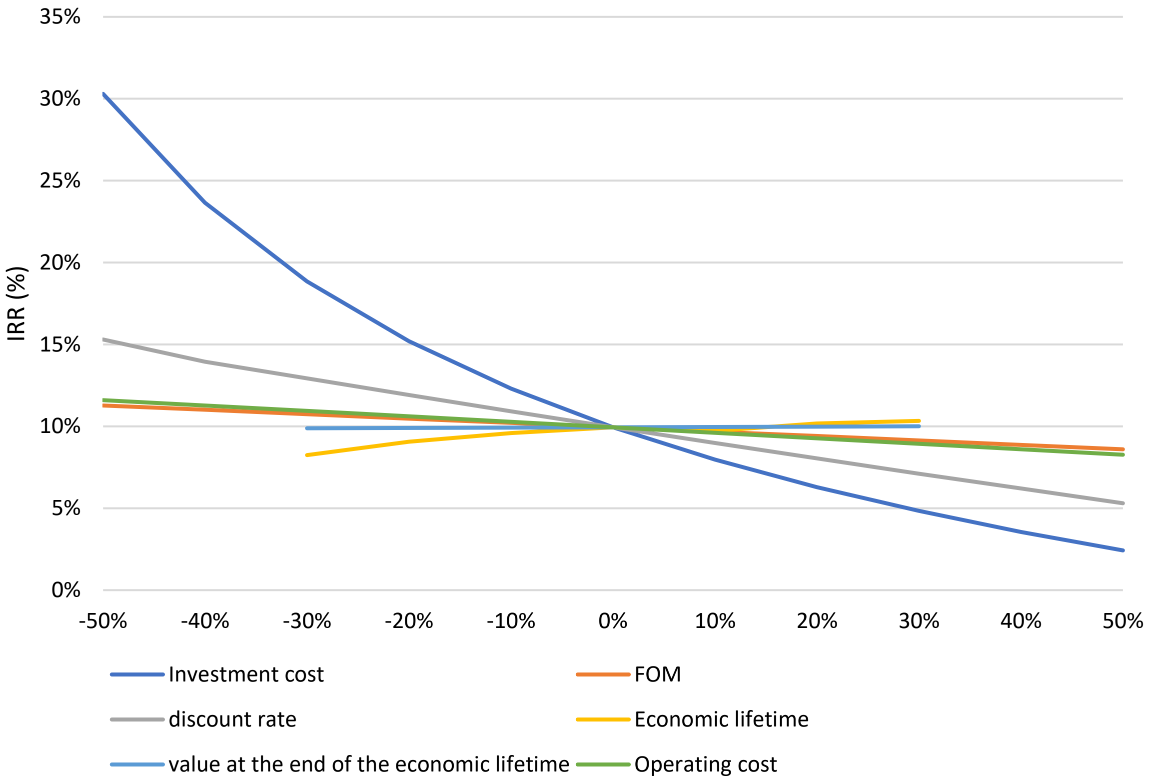


Figure 7: Sensitivity analyses related to LDR-50 economic assumptions.

Discount rate is another impactful factor for LDR-50 profitability along with operating cost and FOM. Economic lifetime has some effect, a 30 % decrease resulted in IRR of 8.2 %. Value at the end of economic lifetime has only small impact on LDR-50 profitability.

Construction time was assumed to be 2 years in the scenarios modelled in D3.2. As illustrated in Figure 8, any delays greatly impact the profitability of SMR investments. Each year of delay decreases the IRR of LDR-50 investment by approximately 1.5% and the IRR of E-SMR investment by around 1%. Delays are a well-known issue in the construction of Western nuclear power plants, with SMRs aiming to mitigate this issue through modularisation and simplification of systems. However, these benefits are not verified yet as not a single SMR has been constructed in a Western country.

Funded by the European Union

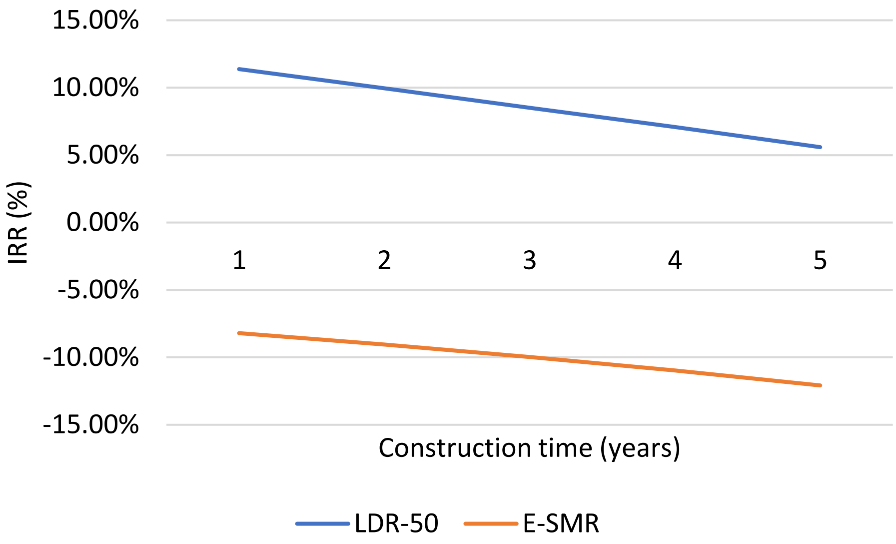


Figure 8: Sensitivity analyses to LDR-50 and E-SMR construction time.

2.3 Sensitivity study on E-SMR heat extraction rate

The SMRs had the lowest variable cost of the studied units in D3.2 and they were typically operated as much as possible according to the heat demand. For this reason, the unit specific parameters had much smaller role than normally, when units are typically switched on and off depending on a range of factors e.g. merit order of the units. The heat extraction in D3.2 was 10% for the E-SMR. In this document, we assume higher heat extraction rates. Thus, we study here a sensitivity analysis with the heat extraction rate ranging on 10-40%. See Figures 9 and 10.

Technology	E-SMR	LDR-50	modelled sensitivities
Reactor units in a single module	2	2	
Thermal power (MW)	1080	100	
District heat capacity (MW)	100	100	
Power generation capacity (MW)	340	-	
Minimum load (-)	0.4	0.2	
Electric efficiency (-)	0.315	-	
Heat extraction rate (%)	10%	-	10%-40%

Table 2: Technology-specific assumptions and modelled sensitivities

Funded by the European Union

The heat extraction rate was assumed to be 10 % for the E-SMR in Deliverable D3.2. As can be seen from Figure 9, increasing the heat extraction rate to 40 % raises IRR of single module E-SMR configuration by +5 % signifying its importance. Additionally, the increase in heat extraction rate reduces carbon dioxide emissions effectively. The yearly CO_2 emissions dropped from 0.47 $MtCO_2$ (10 % heat extraction rate) to 0.38 $MtCO_2$ (40 % heat extraction rate).

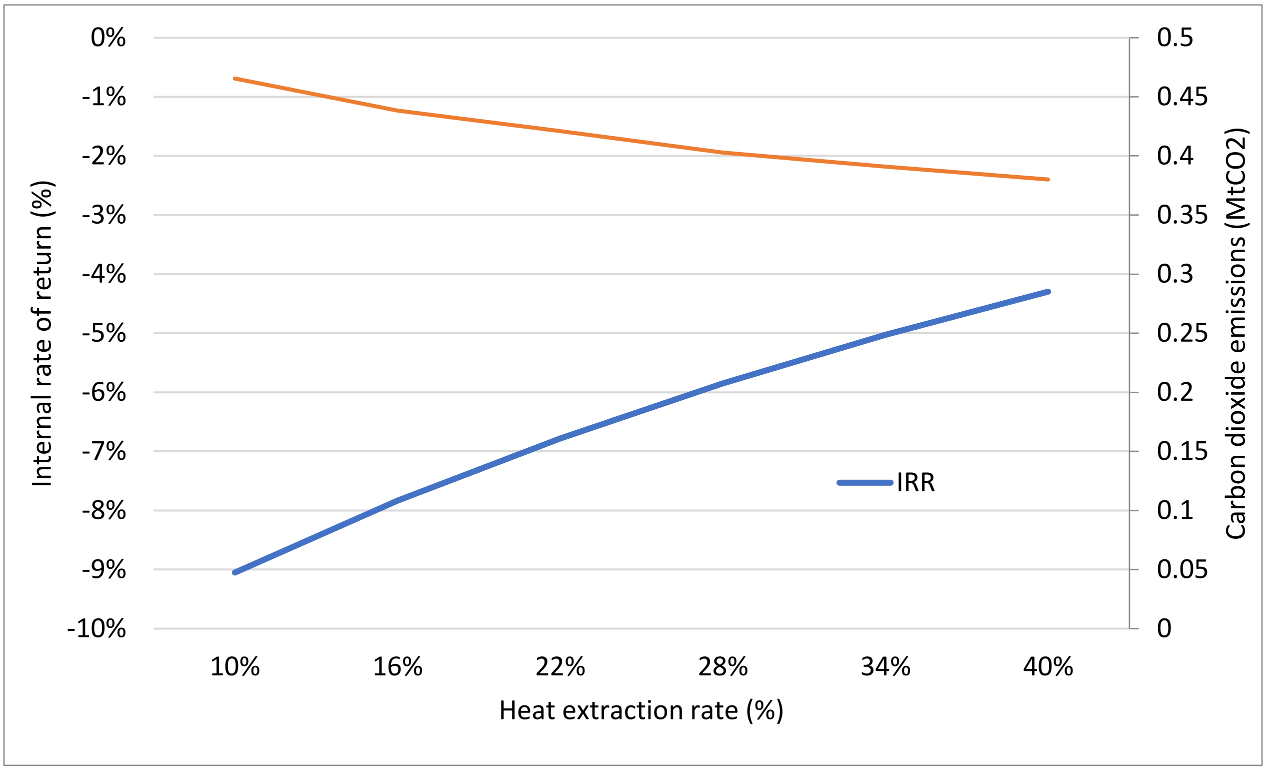


Figure 9: Internal rate of return and yearly reduction of CO_2 emissions as a function of heat extraction rate.

The higher heat extraction rate certainly improves the operational flexibility of E-SMR in the studied area as can be seen from Figure 10. Heat demand and electricity price fluctuate quite a lot in the Helsinki metropolitan area: both the heat demand and electricity price drop during the summer months. The increased heat production capabilities of E-SMR allows it to address a market with a higher value. While the increases in heat extraction rate reduces electricity production, both heat production and total energy production of E-SMR increased significantly. The yearly production of energy rose from 3.31 TWh (10 % heat extraction rate) to 4.95 TWh (40 % heat extraction rate).

Funded by the European Union

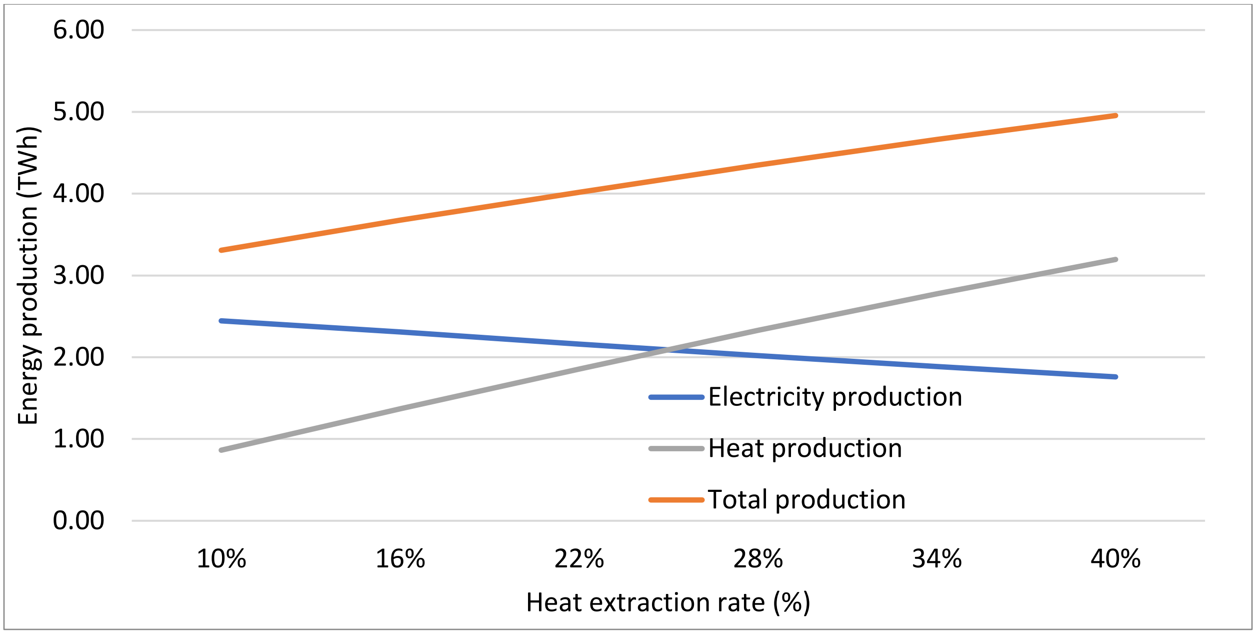


Figure 10: E-SMR electricity and heat production as a function of heat extraction rate

2.4 Sensitivity study on modelled year, city level assumptions, and prices

Finland and the Helsinki metropolitan area have strong seasonal fluctuations of heat demand and electricity price. In addition, there are significant variations in the prices depending on the year, due to hydro power availability, energy prices, and many other variables influencing the Finnish electricity price through Nordic power markets. We study these variables individually but also model three completely different time series years: 2019, 2016, and 2022. The time series came from the year 2019 to perform the studies in D3.2, but the year 2022 had relatively high electricity price and natural gas price while the year 2016 had slightly lower prices. Total DH demand varies by a few percents depending on the year.

	2016	2019	2022
Helsinki DH demand (TWh)	7.08	7	6.9
Capital region DH demand (TWh)	11.34	11.18	11.21
Average natural gas price (EUR/MWh)	22.2	28.9	113.6
Average coal price (EUR/MWh)	7.9	10.4	40.5
Average biomass price (EUR/MWh)	29.9	30.1	34.8
Average electricity price (EUR/MWh)	32.5	44	154
Average CO_2 price (EUR/tCO_2)	5.4	24.9	80.9

Table 3: Variation of annual demands and average prices in 2016, 2019, and 2022 to be considered in sensitivity analysis

Funded by the European Union

City and system-level assumptions include investments of other DH-operators as the DH grids are connected and can trade district heating, investments to DH interconnectors, and the development of DH demand. Few possible near-term investments are particularly significant in the capital region. Espoo has started the construction of large data centers and will utilize the low-temperature waste heat in district heating, but the final thermal power of those data centers is still unknown. Vantaa is planning to build a very large seasonal heat storage to store the excess heat from waste incinerator during the summer and use the stored heat in winter. This impacts the whole region as it would change the Vantaa from sellers during summer to buyer increasing also the production possibilities of SMRs in Helsinki. Sensitivity studies were modelled with following changes to the default model runs presented in D3.2.

- District heat transfer capacity between the modelled cities (+/- 50 %),
- Heat storage capacity of Vantaa (+/- 30 %),
- District heat demand of the modelled cities (+/- 10 %),
- DH from datacenter capacity in Espoo (+/- 40 %),

We also carry out additional sensitivity studies to biomass, natural gas, and CO_2 prices individually. These individual variable sensitivity studies are performed to assess their significance for E-SMR and LDR-50 results, but note that the fuel and CO2 prices are strongly linked to the price of electricity.

- Annual average electricity price (+/- 20 %),
- Biofuel price (+/- 25 %)
- Natural gas price (- 25 % / + 50 %)
- CO_2 price (- 30 % / + 60 %)

The results are presented in Figures 11 and 12. In Figure 11, fuel prices have surprisingly a high effect on results with LDR-50, while the size of datacenter and heat storage capacity barely have an effect on profitability of the technology. The sensitivity analysis to timeseries has a great impact, LDR-50 is unprofitable during timeseries year 2016. One significant factor for the sensitivity studies with a two module LDR-50 configuration is the district heat demand.

Funded by
the European Union

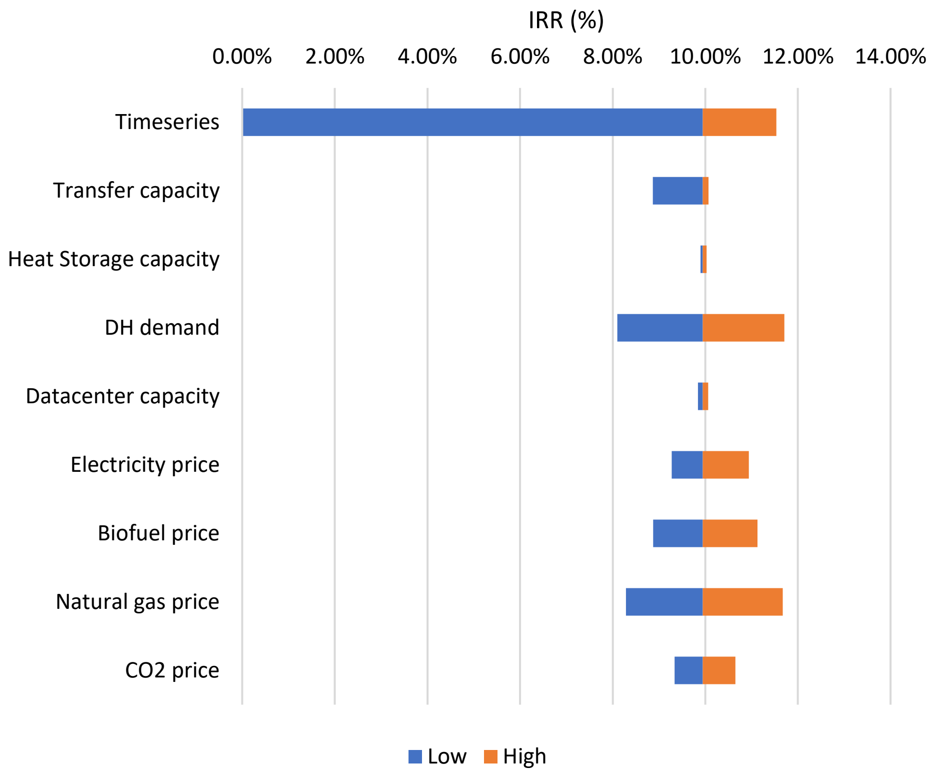


Figure 11: Sensitivity analyses to technological and economic factors for LDR-50.

Most factors regarding the DHC system have minimal impact on E-SMR results. In Figure 12, the sensitivity study to timeseries has the biggest impact and E-SMR is able to reach profitability with IRR of 7.9 % during timeseries year 2022 scenario. Also, the electricity price has notably a big impact on the single module E-SMR configuration since the E-SMR produces 90% of electricity. In the other sensitivities, the E-SMR would not meet a district heating operator's profitability expectations. The reader is reminded that the services for the electricity market and grid are not taken into account in this study. Note some modelling assumptions that can impact the profitability assessment: the SMR investments are modelled in this study with a city-level model and studied from DH operator's point of view. In a DH system, the operator must produce heat but can produce electricity when it is profitable. Instead of modelling the electricity balance, the city-level model uses electricity price based on the year 2019. This study does not look at the services rendered to the electricity grid or their remuneration by electricity producers. However, as E-SMR generates mostly electricity, its business model is highly dependent on the electricity market and the size of the power system. To fully understand the potential of E-SMRs a more detailed study including the electricity balance would be required, which is beyond the scope of this work.

Funded by the European Union

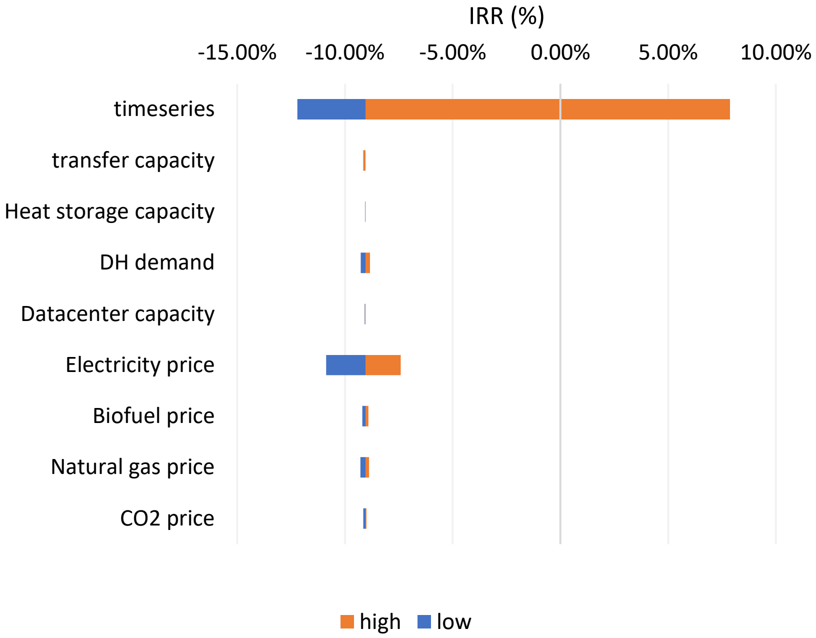


Figure 12: Sensitivity analyses to technological and economic factors of E-SMR.

2.5 Conclusions and discussion

The sensitivity studies conducted for the Northern European case provide insights into the technological and economic viability of the energy systems integrating SMRs. This sensitivity study focused on two SMR technologies: the E-SMR and the LDR-50, evaluating their technological and economic feasibility under various scenarios to identify key factors influencing their profitability. The Northern European case was studied from the perspective of district heating operator, and the sensitivity analyses were conducted for HES configurations with two LDR-50 modules and a single E-SMR module.

The sensitivity study to financial assumptions found the investment cost to be extremely significant factor affecting the profitability of both the LDR-50 and E-SMR technologies. For the LDR-50, a 50% reduction in investment cost resulted in a remarkable increase in the internal rate of return from 9.9% to 30.3%. Conversely, a 50% increase in investment cost reduced the IRR to 2.4%. Similarly, for the E-SMR, a 50% reduction in investment cost improved the IRR from -9.1% to -4.7%, while a 50% increase lowered it to -10.7%. These findings underline the importance of managing investment costs to enhance the financial attractiveness of SMR technologies.

Most often, novel reactor designs like the studied E-SMR and LDR-50 make use of passive safety systems instead of traditionally used active safety systems. The passive safety systems take

Funded by the European Union

advantage of natural forces such as gravity and natural heat convection, whereas active safety systems rely on active driving devices such as electrical or diesel motors. The passive safety systems reduce the costs of safety systems and their maintenance. However, safety demonstration of passive safety system is still under development, and nuclear regulators worldwide might be cautious of licensing these systems. Therefore, an increase in the investment cost of novel SMR technologies is quite possible if regulators ask for using active safety systems in combination with the passive safety systems.

Discount rates and operating costs also played important roles in determining the profitability for SMR technologies. A 50% decrease in the discount rate elevated the IRR for LDR-50 to 15.3% and for E-SMR to -5.5%. On the other hand, a 50% increase in the discount rate decreased the IRR for LDR-50 to 5.3% and for E-SMR to -12.4%. Operating costs exhibited a similar pattern; a 50% reduction raised the IRR for LDR-50 to 11.6% and for E-SMR to -6.0%, whereas a 50% increase reduced the IRR for LDR-50 to 8.3% and for E-SMR to -11.7%.

The significance of energy market conditions and demand fluctuations have to be highlighted in this study. The Finnish electricity and heat market have strong seasonal fluctuations, which might impact profitability of SMR investments drastically. Sensitivity analysis to timeseries years demonstrated this: year 2022 made E-SMR profitable with the IRR rising to 7.9 %, while LDR-50 was unable to make profit during year 2016 with the IRR decreasing to 0.01 %. Though, it has to be noted that the European energy crisis was in its worst condition during year 2022, elevating electricity prices to all-time highs. In 2016, the prices of CO2 and fossil fuels were much lower making the fossil fueled power plants more competitive. In the sensitivity study to prices of biofuel and natural gas, LDR-50 was found to be more sensitive, while E-SMR was not affected at all. Additionally, electricity prices and district heat demand were found to significantly impact the profitability of E-SMR and LDR-50. A 20% increase in electricity prices raised the IRR for a single E-SMR module to -7.4%. For the LDR-50, a 10% increase in district heat demand boosted the IRR to 11.7%.

Construction time and heat extraction rates were additional factors influencing the IRRs. Each year of delay in construction reduced the IRR for LDR-50 by approximately 1.5% and for E-SMR by about 1%. The latest construction projects of nuclear power plants in Western countries have experienced many delays. SMR designs are expected to alleviate this problem with modularization and simplification of components.

The heat extraction rate for E-SMR was assumed to be quite low, 10 %, in Deliverable D3.2. Increasing the heat extraction rate of E-SMR to 40 % increased the internal rate of return to -4.3 % and decreased the yearly CO_2 emissions in Helsinki metropolitan area to 0.38 $MtCO_2$.

Additionally, the higher heat extraction rate improved operational flexibility of the single module E-SMR configuration by boosting the yearly energy production from 3.31 TWh (10 % heat extraction rate) to 4.95 TWh (40 % heat extraction rate), helping E-SMR meet the fluctuating energy demand of Helsinki metropolitan area.

In conclusion, the Northern European case sensitivity studies provided valuable insights into the economic and technological factors affecting SMR profitability. The profitability of studied SMR investments, measured as NPV and IRR, were very sensitive on assumed economic parameters, especially the investment cost. The impact of energy market conditions should be studied thoroughly as the profitability of SMR technologies might switch drastically from unprofitable to profitable and vice versa. From the perspective of DH operator, LDR-50 was found to be profitable in most scenarios, while E-SMR would not meet the profitability conditions from the perspective of a district heating operator except during the timeseries of year 2022 scenario. Indeed, the study takes the point of view of a district heating network operator, but does not look at the services rendered to the electricity grid or their remuneration. Since the E-SMR generates mainly electricity, its business model is highly dependent on the electricity market and the size of the power system. Both SMRs improved supply of electricity: E-SMR produced electricity and LDR-50 reduced the use of heat pumps and electric boilers. Increasing the heat extraction rate of E-SMR showed improvements in plant profitability, but still, the heat extraction rate would have to be higher with the hypotheses of the case studies for the E-SMR to be profitable from the point of view of a district heating operator.

Helsinki metropolitan area is challenging environment for larger baseload units with its seasonal fluctuations: heat demand and electricity price drop quite a lot during the summer. However, integration to future energy systems such as electrolysers could alleviate this problem by increasing energy demand during summers, thus warranting further research on SMRs and nuclear power for decarbonization of energy systems.

3 Southern European case

3.1 General presentation of the case

3.1.1 Reminder of results of D3.2

The purpose of the Southern European case is to investigate the techno-economic and environmental profitability of a HES integrated SMRs in an industrialized harbour. Deliverable D3.1 [1] presents the main characteristics of the Southern European case: it is a virtual harbour located at Fos-sur-Mer in the Southern France. The location implies some of the boundary conditions like the Renewable Energies (RE) potential but a part of the perimeter is fixed arbitrarily. The purpose of the HES is to deliver electricity, heat and hydrogen to this industrial harbour but the electrical load as well as the hydrogen load are built for this case study. Real data of consumption for industry is difficult to obtain and even more difficult to share.

Deliverable D3.2 [2] included the study conducted for this case. From a super-structure that includes several means to supply the loads – including conventional electricity sources like Combined Cycle Gas Turbine (CCGT) or conventional hydrogen sources like Steam Methane Gas Reformer (SMGR) to low-carbon solutions like RE (PV, offshore wind turbines), SMR and Low Temperature Electrolysis (LTE) and High Temperature Steam Electrolysis (HTSE) – cases of interest are selected owing to a parametric optimization on CO_2 total emissions with PERSEE.

These four cases are highlighted in Figure 13:

- “2035 without SMR” scenario (run0).
- “2035 with 1 SMR” scenario (run5).
- “2050 with 2 SMR” scenario (run7).
- “2050 with 2 SMR maximizing decarbonisation” scenario (run13).

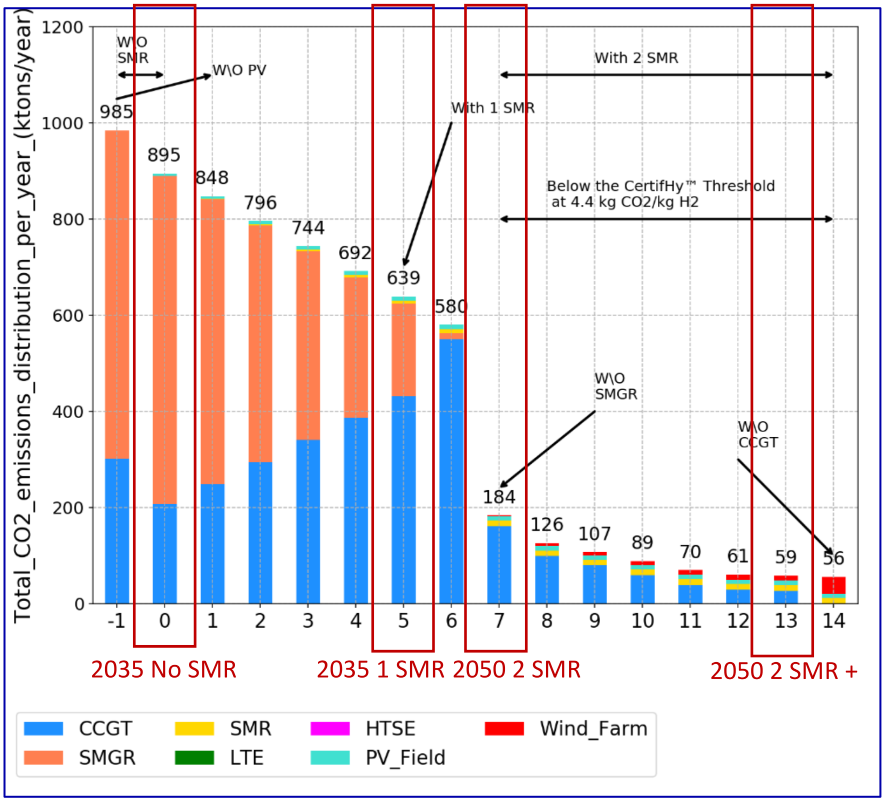


Figure 13: Summary of the results from D3.2 for the Southern European case

For each configuration, the size of all the HES components are provided and several economic and environmental KPIs are calculated: the total costs, LCOE, LCOH, $LCOH_2$ and total amount of

CO_2 emissions, carbon intensity of electricity, heat and hydrogen. The most decarbonized solutions include 2 SMRs and HTSE to supply the whole hydrogen demand.

To complete the study, it is necessary to conduct additional studies such as sensitivity analyses as the input are based on a lot of assumptions that may be questioned and complementary analyses of others architecture as the results suggested ways to improve the decarbonisation process.

3.1.2 Presentation of the additional studies

This document presents additional studies classified into two categories:

- Complementary analyses on “ways to improve the decarbonisation process”.

In section 3.2, other ways to decarbonize the virtual industrialized harbour located at Fos-sur-Mer are explored either on “2035” and “2050” scenarios with, in particular, the addition of a Carbon Capture Use and Storage (CCUS) or the addition of an Organic Rankine Cycle (ORC), an electrical battery or more RE and storages.

- Sensitivity analyses on the assumptions used for the input data.

In section 3.3, a sensitivity to price forecasts is conducted as natural gas is a key parameter in the optimisation process and the year 2019 is seen favourable whereas the year 2022 is less favourable. Finally, sensitivity studies to major parameters characterizing the SMR for the PERSEE study are conducted, that is to say to the CAPEX, the variable cost and on the heat recovery ratio.

3.2 Exploration of other interesting architectures

3.2.1 Adding a Carbon Capture, Utilization and Storage (CCUS) for CCGT and SMGR

The “2035 without SMR” case is partially based on conventional means to produce electricity and hydrogen. The size of the CCGT is 76 MW and hydrogen is fully produced by a SMGR with a maximal mass flow rate of 8257 kg H_2/h. Carbon Capture Utilization and Storage (CCUS) process could be considered for these two components.

There are different options to capture CO_2 either on CCGT or on SMGR. For example, according to European Industrial Gases Association AISBL (EIGA), there are three different options to capture CO_2 for a SMGR depending on where the carbon capture unit is located during the process [6]. CCUS presents the advantages of being relatively cheap and in case of refurbishment of an existing facility, there is no need to change the whole process allowing industrials to carry

Funded by the European Union

out their process as usual. Nevertheless, it leads to the question of CO_2 management as the potential for underground storage is limited.

The PilotSTRATEGY project [7] is investigating geological CO_2 storage sites in industrial regions of Southern and Eastern Europe to support the development of Carbon Capture and Storage (CCS). Detailed studies are carried out on deep saline aquifers in the Paris basin in France, the Lusitanian basin in Portugal and the Ebro basin in Spain. This project will also enhance the knowledge of CO_2 storage options in West Macedonia in Greece and Upper Silesia in Poland. The VASCO project [8], which lasts from 2010 to 2012, was a techno-economic study on the identification of CO_2 sources and the pooling of the capture, transport, and geological storage of CO_2 emissions from the industrial zone of Fos-sur-Mer, Beaucaire, Lavera, and Gardanne in France. First storage capacities have been calculated but there is a need of more precise parameters on site.

Table 4, Table 5 and Table 6 give respectively the technical, economic and environmental parameters used in the simulations for the CCGT equipped with CCUS or not, based on OECD reports [9] and [10].

Parameter name	Unit	Value without CCUS	Value with CCUS
Maximal power	MW	-350	
Efficiency	%	0.53	0.48

Table 4: Technical parameters of CCGT equipped with CCUS

Parameter name	Unit	Value without CCUS	Value with CCUS
Design lifetime	years	30	
CAPEX	€/MW_e	903 000	2 430 000
Variable cost	€/MWh_e	5.6	14

Table 5: Economic parameters of CCGT equipped with CCUS

CAPEX includes the equipment and the dismantling.

Parameter name	Unit	Value without CCUS	Value with CCUS
Embodied emissions	kg CO_2 eq/MW	-	-
Direct emissions	kg CO_2 eq/kg CH4	2.8464 (Gas burning)	0.5635

Table 6: Environmental parameters of CCGT equipped with CCUS

Table 7, Table 8, Table 9 and Table 10 give respectively the technical, economic and environmental parameters used in the simulations for the SMGR equipped with CCUS, based on IEA reports [11] and [12].

Funded by the European Union

Parameter name	Unit	Value without CCUS	Value with CCUS
Maximum capacity	kg H_2/h	8257	
Outlet pressure	bars	30	
SMGR Efficiency (LHV)	%	76	69
Electricity consumption	kWh/kg H_2	0.15	1.25

Table 7: Technical parameters of SMGR equipped with CCUS

Parameter name	Unit	Value without CCUS	Value with CCUS
Lifetime	year	20	
CAPEX	€/MW H_2 (LHV)	910 000	1 360 000
	€/(kg H_2/h)	30 330	45 328
OPEX	%CAPEX/year	4.7	3

Table 8: Economic parameters of SMGR equipped with CCUS

Parameter name	Unit	Value without CCUS	Value with CCUS
Embodied emissions	kg CO_2 eq/MW	-	-
CO_2 capture rate	%	-	90
Direct emissions	kg CO_2 eq/kg H_2	8.9	1

Table 9: Environmental parameters of SMGR equipped with CCUS

3.2.1.1 Studies on CCUS for the "2035 without SMR" scenario (run0)

In this section, first studies have been carried out to analyse the impact of the CCUS integration on the technical-economic and environmental results on the "2035 without SMR" scenario. Furthermore, a cost linked to CO_2 transport and storage is taken into account as an uncertain parameter. IEA considered 20 USD/tCO_2 for all regions in [11] and 33 USD/tCO_2 for Europe in [12]. Therefore, a sensitivity study to this parameter (from 20 to 200 €/tCO_2) is conducted. It can be noticed that IEA gives all costs in USD; for this study, a USD to Euro conversion is taken into account with a rate of 1. Table 10 gives the list of calculation runs.

An extra run (run0-TCO_2) is added to the comparison. No CCUS is considered for this case, only a tax on CO_2 emissions for the whole architecture equal to 200 €/tCO_2 is added in post-treatment.

Parameter name	Unit	Values						
run		run0	run0-CCUS					run0-TCO_2
CO_2 transport and storage cost	€/tCO_2	0	20	33	100	150	200	0
Carbon tax	€/tCO_2	0						200

Table 10: Studies on CCUS (run0), values of CO_2 CCUS and carbon tax considered

The Table 11 presents the main results of the CCUS and carbon tax sensitivity runs comparatively to the reference case (run0).

Funded by the European Union

	CO_2 emissions (ktons/year)	CO_2 captured (ktons/year)	Total Cost (M€)	LCOE (€/MWh)	$LCOH_2$ (€/kg H_2)	CI_E ($kgCO_2eq$ /MWhe)	CI_H₂ ($kgCO_2eq$ /kg H_2)
CCUS=20 €/tCO_2	126.07	888	1 836	58.17	1.41	72.69	1.08
CCUS=33 €/tCO_2			1 987	61.62	1.53	72.69	1.08
CCUS=100 €/tCO_2			2 766	79.45	2.19	72.69	1.08
CCUS =150 €/tCO_2			3 346	92.76	2.68	72.69	1.08
CCUS=200 €/tCO_2			3 927	106.06	3.18	72.69	1.08
Without CCUS	894.66	0	1 217	35.12	0.97	316.82	9.48
TCO_2=200 €/tCO_2 (without CCUS)			3 547	97.17	2.86	316.82	9.48

Table 11: Studies on CCUS (run0), main results

The Figure 14 presents the total CO_2 emissions for all cases. The CCGT-CCUS and SMGR-CCUS labels (in hatch colours) correspond to the CCUS terms while the CCGT and SMGR labels include only the CAPEX, OPEX and the direct CO_2 emissions. The total captured and stored carbon mass is about 888 ktons/year (run0 CCUS). The CO_2 emissions are then lower for cases with CCUS (126 ktons/year) compared with the “without CCUS cases” (895 ktons/year in the black circle symbols in the figure). It can be noticed that for a 20 years project the total captured CO_2 mass is 17754 ktons. The first results of the VASCO project, obtained with large uncertainties on the calculations, show that the onshore sites have significant storage capacities, ranging from approximately 80,000 to 180,000 ktons. The structure of offshore site presents much smaller volumes, mainly due to its shallow depth and thus the low value of CO_2 density.

The total cost of the project (Figure 15) is about more than two times higher when the system is equipped by CCUS while the assumption to pay a carbon tax at about 200 €/tCO_2 is comparable with a system equipped by a 150 €/tCO_2 CCUS

Funded by the European Union

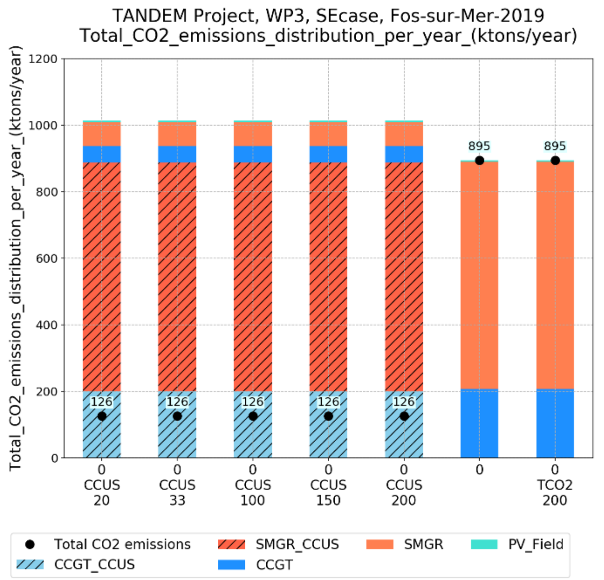


Figure 14: CCUS sensitivity on run0, yearly CO_2 emissions

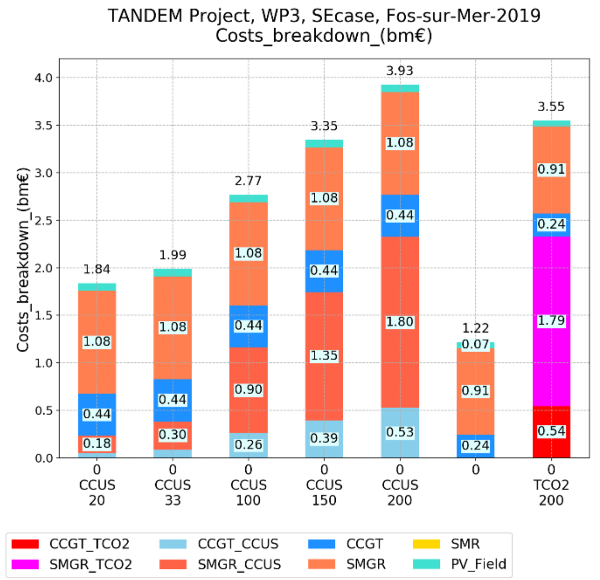


Figure 15: CCUS sensitivity on run0, cost breakdown

The Figure 16 shows the LCOE and $LCOH_2$. Same conclusions can be drawn. CCUS costs proposed by IEA will lead to about electricity and hydrogen 1.5 times higher than the reference case.

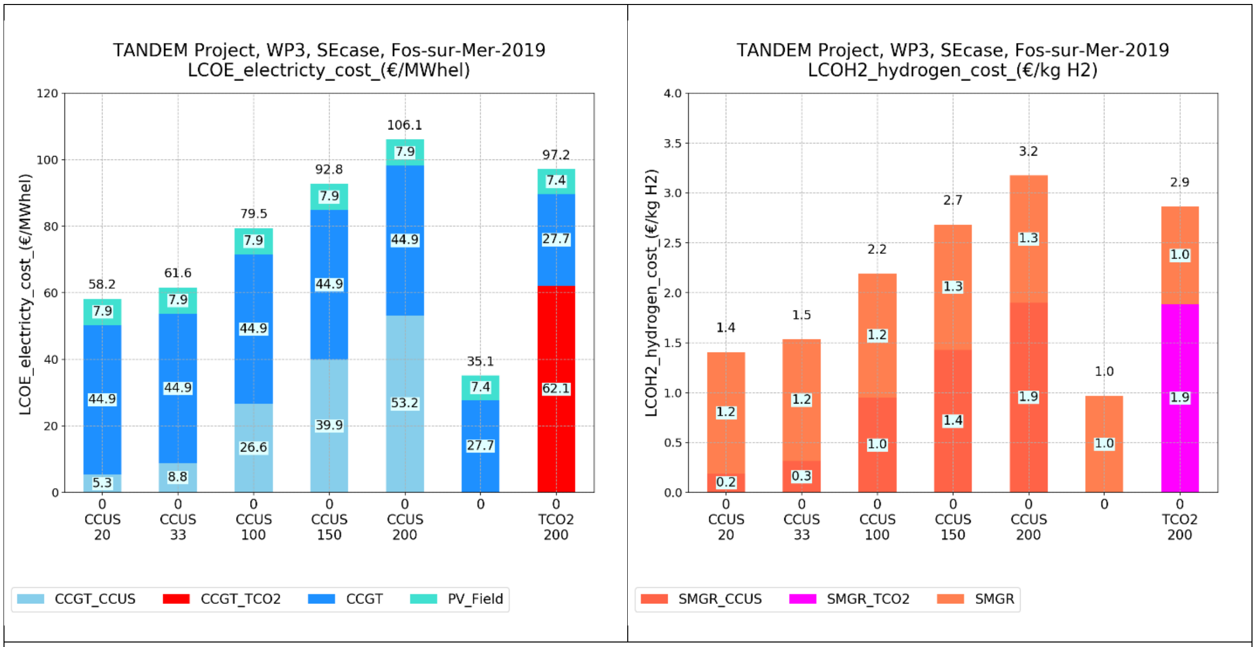


Figure 16: CCUS sensitivity on run0, LCOE and $LCOH_2$

The CO_2 intensity of electricity and hydrogen productions become about 4 times lower for electricity and 9 times lower for hydrogen in case of CCUS system. The CO_2 intensity of hydrogen

Funded by the European Union

becomes also lower than the CERTIFHy™ and the Renewable Energy Directive II (RED II) thresholds.

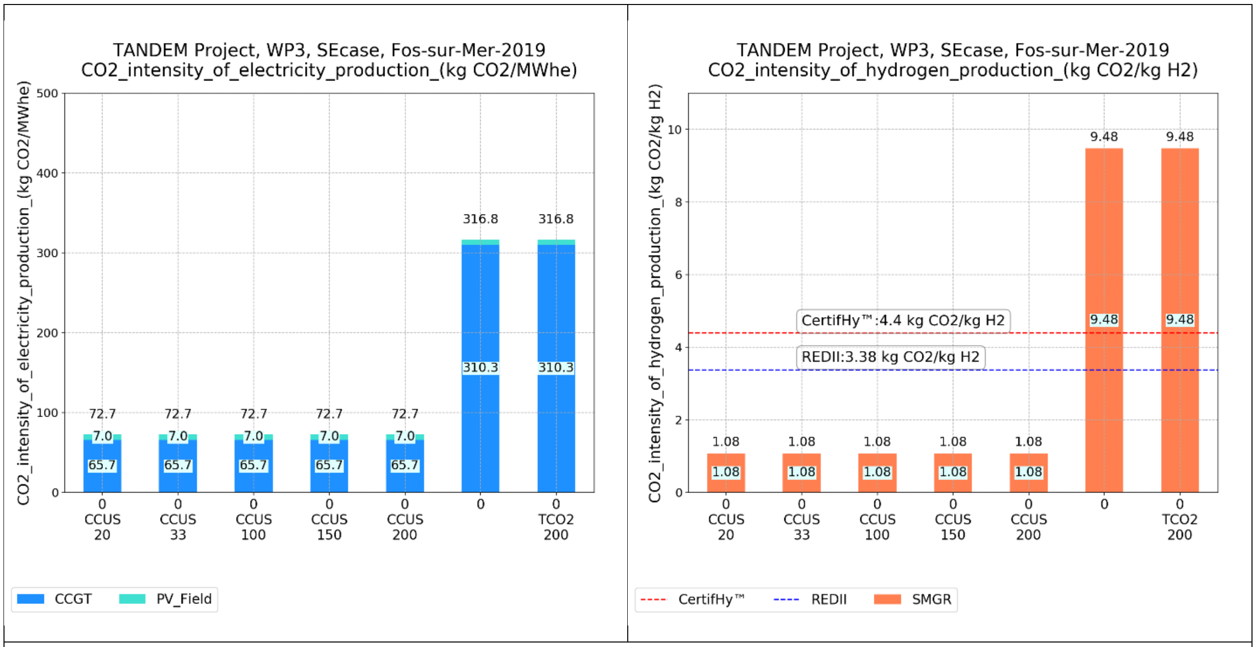


Figure 17: CCUS sensitivity on run0, CO_2 intensity of electricity and hydrogen

3.2.1.2 Adding the CCUS for all selected architectures

In the previous paragraph, studies have been carried out to analyse the impact of a CCUS implementation for the CCGT and SMGR in the frame of the “2035 without SMR” scenario (run0). The purpose of this section is to run the “2035 with 2 SMR” (run5) and “2050 with 2 SMR” scenario (run7 and 13) with the CCUS modelling. The cost of the CCUS is taken at the IEA 2050 proposal (33 €/tons CO_2). CCUS model and parameters are given in section3.2.1.

The CCUS cases are compared with the reference run0, 5, 7 and 13. The following Table 12 gives the main parameters of the runs. Each component is resized (except the number of SMR) and the operation is optimized. The total CO_2 emission is also optimized and only the case with the least CO_2 emission is presented.

It should be noticed that a **negative value** v for a PERSEE parameter means that this parameter is an optimization variable. Thus:

- The variable is optimized between 0 and $|v|$ (continuous variable and not integer variable).
- The parameter value is a result of the optimization.

Component	Parameter	Unit	Run0	Run5	Run7	Run13
CCGT	Maximal Power[1]	MW	-350			
SMGR	Maximal H_2 production	Kg H_2/h	-10 000		0	
SMR	Nb unit	-	0	1 (155 MWe)	2 (310 MWe)	
HTSE	Maximal power	MWe	-500			
H_2 Storage	Maximal capacity	tons	-160			
PV Field	Nb unit	-	-200			
Wind Farm	Nb unit	-	-80			

Table 12: Studies on CCUS implementation, main parameters

The Table 13 presents the main results of the CCUS cases comparatively to the reference cases (run0, 5, 7 and 13).

Parameter	Unit	run0	run0 CCUS	run5	run5 CCUS	run7	run7 CCUS	run13	run13 CCUS
SMR	-	0		1 (155 MWe)		2 (310 MWe)			
CCGT Power	MW	76.2	85.2	158	0	87.8	96.5	45.4	41.6
H_2 Storage Capacity	tons H_2	0		0		160	0	135	160
HTSE Power	MW	0		226	68	367	315	374	394
SMGR	kg H_2/h	8 254		2 327	6563	0			
PV Field (Nb unit)	-	96	116	200		200			
Thermal Storage Capacity	MWh	0							
Wind Farm (Nb unit)	-	0		0		4	0	18	20

	CO_2 emissions ktons/year	CO_2 captured ktons/year	Costs M€	LCOE €/MWh	LCOH €/MWh	$LCOH_2$ €/kg H_2	CI_E kg CO_2 eq /MWhe	CI_H kg CO_2 eq /MWhth	CI_H_2 kg CO_2 eq /kg H_2
Run0	894.7	**0**	1 217	35.12		0.97	316.82		9.48
Run0 CCUS	126.1	**887.7**	1 988	61.62		1.53	72.69		1.08
Run5	639.2	**0**	2 557	51.45	19.55	2.23	162.37	1.00	7.12
Run5 CCUS	70.9	**537.9**	2 638	57.24	19.55	1.84	8.18	1.00	0.85
Run7	184.0	**0**	3 663	61.20	19.55	3.21	50.88	1.00	1.96
Run7 CCUS	73.3	**211.1**	3 823	64.97	19.55	3.26	19.67	1.00	0.76
Run13	58.8	**0**	4 122	66.74	19.55	3.58	15.70	1.00	0.62
Run13 CCUS	37.5	**20.1**	4 235	68.49	19.55	3.65	9.85	1.00	0.39

Table 13: Studies on CCUS implementation, main results

The Figure 18 presents the total CO_2 emissions for all cases. The CO_2 emissions (the black circle symbols in the figure) are then lower for all cases with CCUS compared with the "without CCUS

---

[1] The maximal power is the result of the optimization between 0 and 350 MW.

cases". The total captured and stored carbon mass decreases from 888 for run0 CCUS to 20 ktons/year for run13 CCUS. For the 20 year lifetime project, the total captured CO_2 mass remains very high for run0 CCUS (18000 ktons) and run5 CCUS (11000 ktons), and is moderated in run13 CCUS (about 400 ktons). The total cost of the project (Figure 19) is higher when CCUS is included because of the CCUS cost.

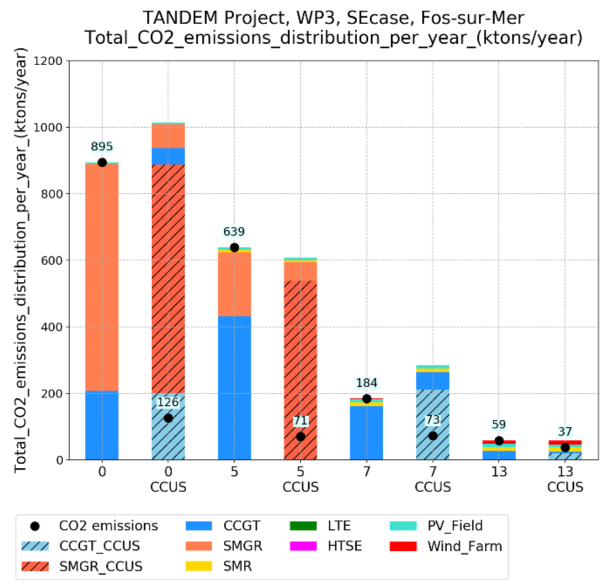


Figure 18: CCUS sensitivity for all cases, yearly CO_2 emissions

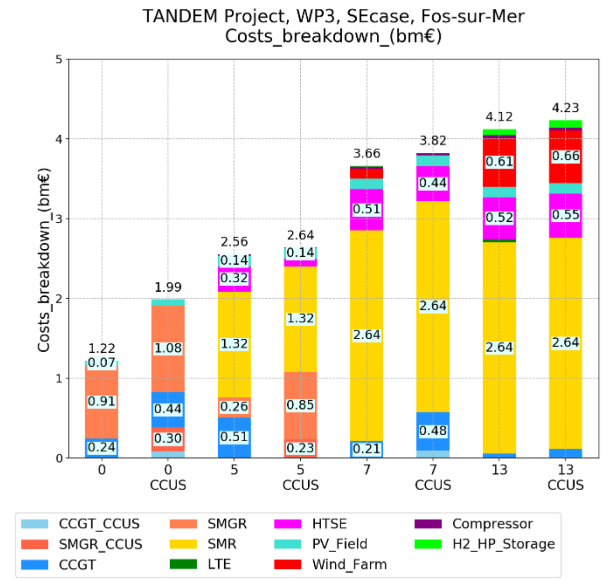


Figure 19: With CCUS sensitivity for all cases, cost breakdown

The Figure 20 and Figure 21 give the sizing of the electricity production components and the mean electricity power per component. For the "2035 without SMR" run0 and in case of CCUS as the carbon emissions are lower, the PERSEE optimisation process results in higher CCGT and PV commitments due to higher electrical needs for SMGR hydrogen production and lower SMGR efficiency (see Table 7).

For the "2035 with 1 SMR" (run5), adding a CCUS results in removing the CCGT because the amount of electricity coming from the SMR is enough (and even too much) to feed the electrical load and the hydrogen production means (SMGR and HTSE).

For "2050 with 2 SMR" scenario (run7 with CCUS), a lower wind farm size and HTSE and no hydrogen storage are calculated as the global flexibility of the system, in terms of electricity and hydrogens is ensured by the CCGT (equipped by a CCUS).

The solutions for the "2050 with 2 SMR" scenario with and without CCUS are very similar. The carbon emissions are lower in the case 'with CCUS'.

Funded by the European Union

Funded by the European Union. Views and opinions expressed are however those of the author(s) only and do not necessarily reflect those of the European Union or the European Atomic Energy Community ('EC-Euratom'). Neither the European Union nor the granting authority can be held responsible for them.

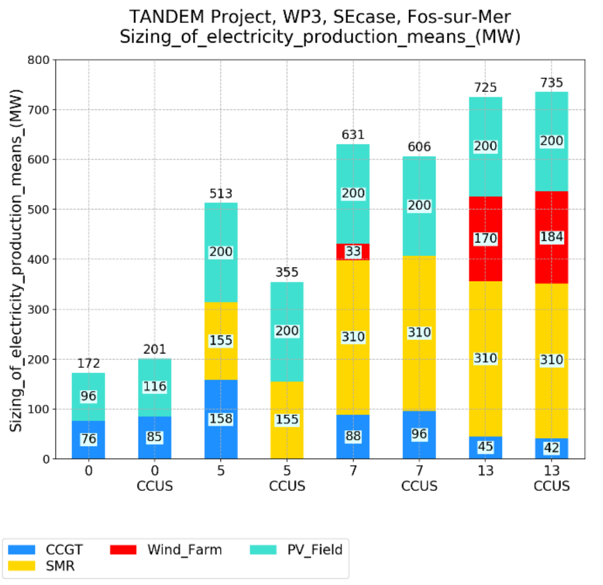


Figure 20: With CCUS sensitivity for all cases, sizing of electricity production means

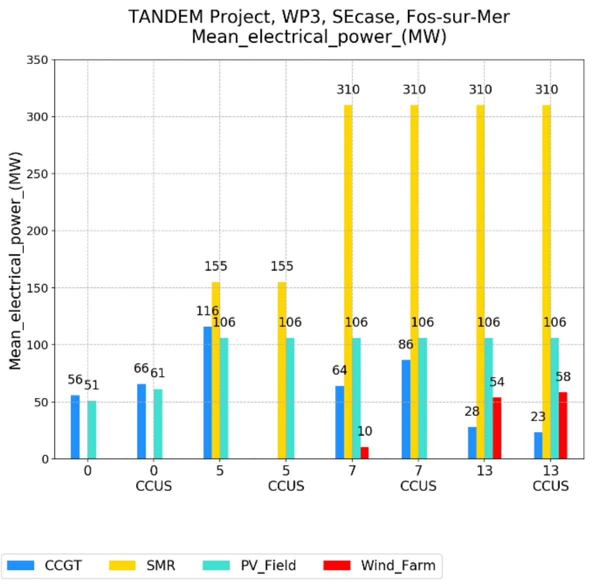


Figure 21: With CCUS sensitivity for all cases, mean electrical power

The Figure 22 shows the LCOE and LCOH$_2$. Same conclusions can be drawn. With CCUS, the electricity cost is slightly higher than in the references cases. But, for the “2035 with 1 SMR” scenario, run5, and as the SMGR contributes more to hydrogen because of lower CO$_2$ emissions with CCUS, the hydrogen cost becomes lower than for the “without CCUS” run5.

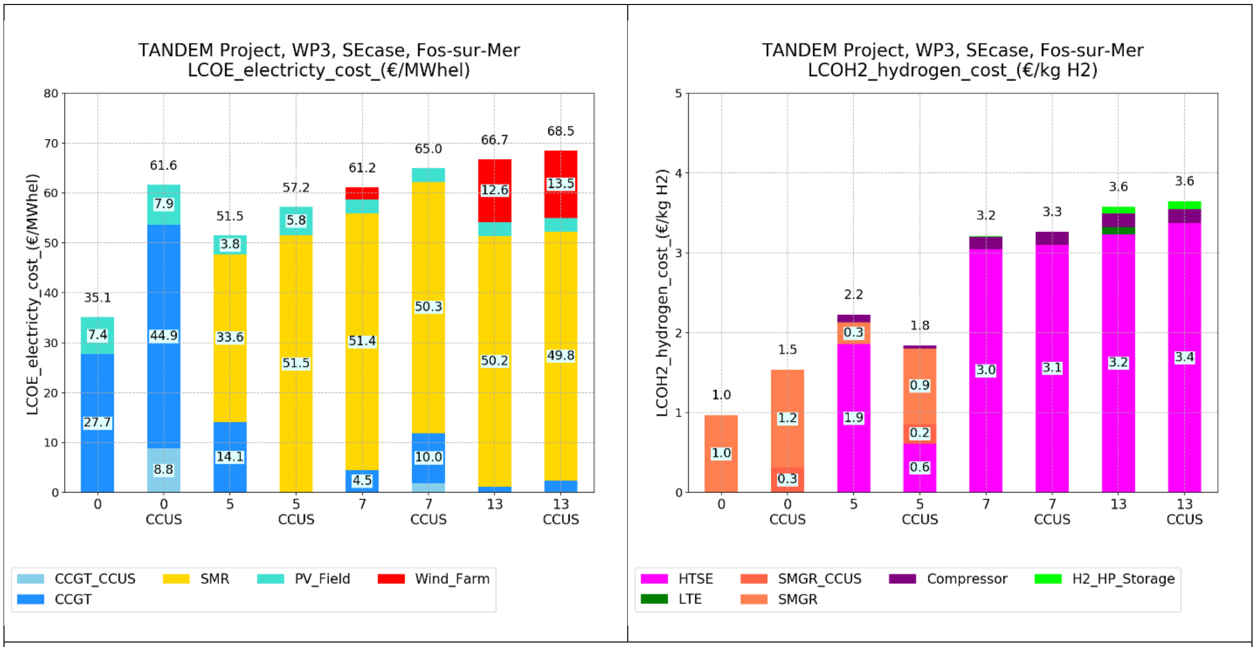


Figure 22: With CCUS sensitivity for all cases, LCOE and LCOH$_2$

3.2.1.3 Conclusions on the contribution of a CCUS

To conclude, these calculations show that equipping the system with CCUS for SMGR and CCGT components will reduce the CO_2 emissions with CO_2 intensity of products at very low rate. The counterpart is the increasing of product costs whereas the potentiality of high capacities of CO_2 underground storage is, at this time, not fully demonstrated as the one needed for the “2035 without SMR” configuration. CO_2 underground storage capacities needed for the “2050 with 2 SMR” scenarios are limited. The CCUS cost and the carbon tax are crucial parameters to evaluate more precisely the extra costs for the energy system.

3.2.2 Study on “2035 without SMR” scenario and replacing the CCGT by the national electrical grid

Another reference case that is worth analysing is the one where the CCGT is replaced with the French electricity network. In 2019, the electricity mix was mainly composed of nuclear at about 72.7%, of hydraulic power at about 10.3%, followed by fossil gas at about 7.0%, onshore wind at about 6.2% and solar at about 2.2%. Figure 23 presents both the time series of the SPOT prices in France in 2019 and the time series of the CO_2 intensity of the French electricity network in 2019.

The chosen case for replacing CCGT is the one where a CCUS is added to the SMGR with a CO_2 transport and storage cost for CCUS of 33 €/tCO_2.

Funded by the European Union

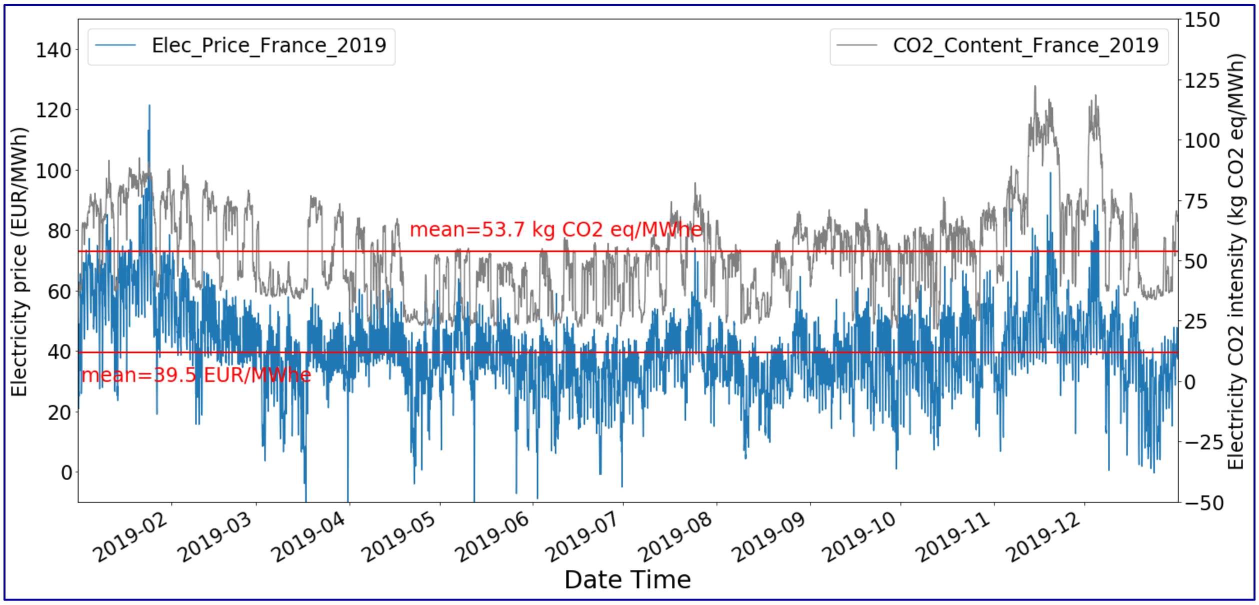


Figure 23: Time series of the electricity prices and CO_2 content of French electrical grid in 2019

In 2019, the average SPOT price was 39.5 €/MWhe and the mean CO_2 intensity of the electricity network was 53.7 kg CO_2 eq/MWhe.

Nevertheless, for consumers, the electricity price is composed of:

- The production cost. In this case, it will be assumed equal to the SPOT price.
- The marketing cost, neglected in this study.
- Tarif d'Utilisation des Réseaux Publics d'Electricité (TURPE): TURPE6 is calculated by taking into account different elements, such as network operating costs, investments necessary for increasing capacities, personnel costs and costs related to network maintenance. More details in appendix 5. Thus, in addition to the SPOT price, the consumer must pay about 37 €/MWhe.

Figure 24 shows the comparison of the cost breakdown between the case where the CCGT is replaced by the national electrical grid (run-4) and the reference case (run0 with CCUS) whereas Figure 25 shows the comparison of the total yearly CO_2 emissions between these two cases.

Funded by the European Union

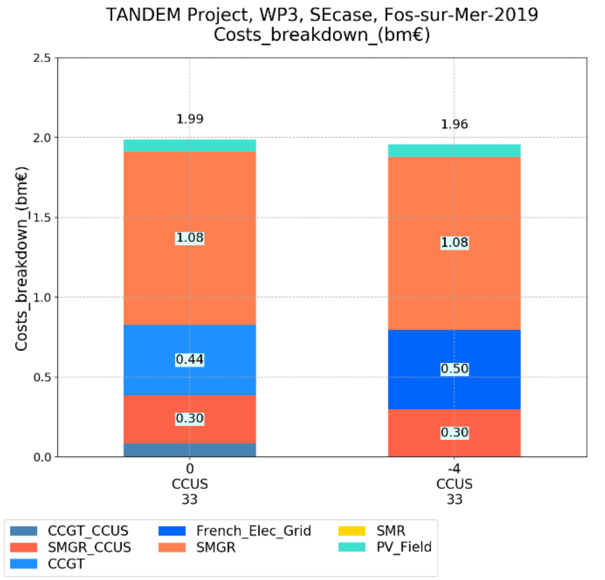


Figure 24: With electrical national grid, cost breakdown

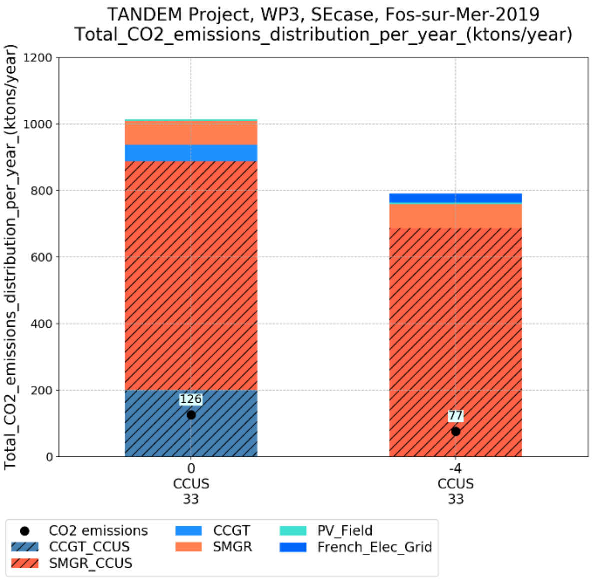


Figure 25: With electrical national grid, yearly CO_2 emissions

Replacing the CCGT by the national electrical network leads to a very small decrease of the total costs of the project of about 1.51% and to a decrease of the yearly CO_2 emissions of about 39.7%.

Figure 26, and Figure 27, and Figure 28 present the impact of replacing CCGT by national electrical grid on LCOE, CO_2 intensity of electricity, $LCOH_2$ and CO_2 intensity of hydrogen respectively.

Funded by the European Union

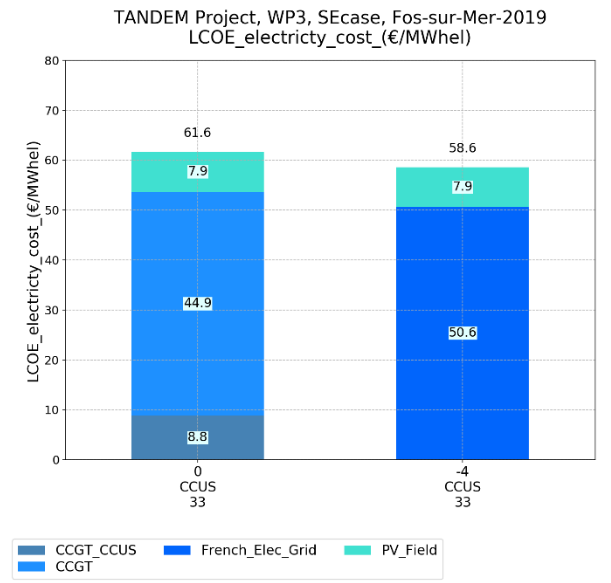


Figure 26: With electrical national grid, LCOE

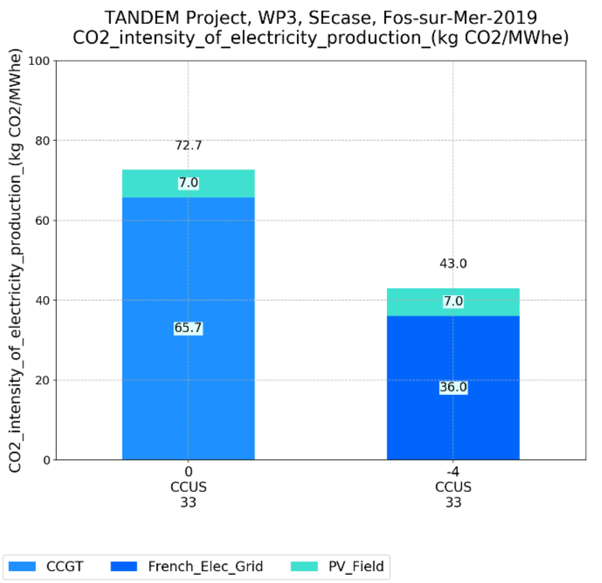


Figure 27: With electrical national grid, CO_2 intensity of electricity

The impact on the LCOE is a reduction of about 4.87% and the impact on the CO_2 intensity of electricity is a decrease of about 40.8%. Even if SPOT prices in 2019 were quite low, from a consumer point of view, building a new CCGT equipped with CCUS directly on site is almost more profitable than buying electricity to the grid. On the contrary, as the French electrical network is mainly based on nuclear, the CO_2 intensity of the electrical network is low so obviously using the electrical network is more interesting than building a new CCGT equipped with CCUS from a CO_2 point of view.

Funded by
the European Union

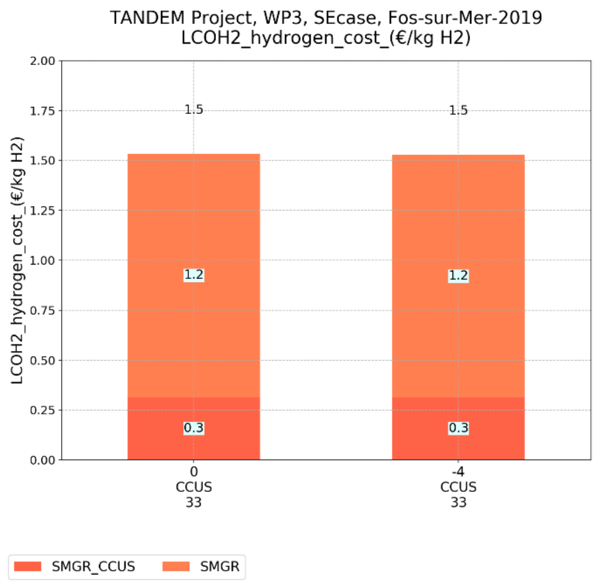


Figure 28: With electrical national grid, LCOH$_2$

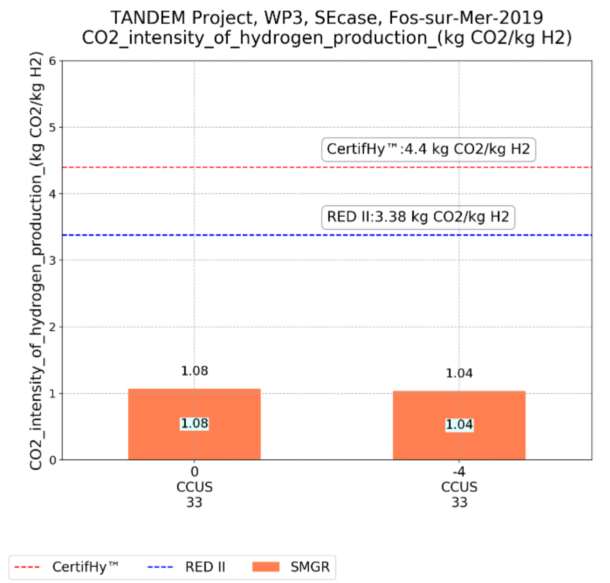


Figure 29: With electrical national grid, CO$_2$ intensity of hydrogen

Nevertheless, the impact on hydrogen is negligible as in this scenario, electricity and hydrogen are not correlated due to the fact that hydrogen is produced by a SMGR equipped with a CCUS.

3.2.3 Studies on "2050" scenarios

Two runs correspond to "2050" scenario:

- The run7 which corresponds to "2050 with 2 SMR" scenario.
- The run13 which corresponds to a "2050 with 2 SMR maximizing decarbonisation" scenario.

In these two runs, the hydrogen is supplied by a HTSE but despite the fact that there are 2 SMR units and renewable energies, the CCGT is still there to ensure the left electricity needs and the system flexibility. The idea in this section is to explore ways to remove this CCGT. Two extra studies are conducted:

- The first one relies on the use of the excess thermal heat produced by the SMR to produce more electricity using an Organic Rankine Cycle (ORC). About a 50 MWth power is released from the system to the outside and can be recovered to supply the ORC.
- The second one relies on the possibility to store in electrical battery the excess energy produced by the photovoltaic and wind productions and to release it during periods when CCGT is used.

A third analysis is run in order to analyse a **"2050 RE + Storages + LTE" scenario where no SMR is considered**; hydrogen then is produced with a Low Temperature Electrolysis (LTE); electrical batteries and hydrogen storage are used to ensure the electrical and hydrogen flexibilities.

3.2.3.1 Adding an Organic Rankine Cycle to the "2050 with 2 SMR" scenario

The work done for D3.2 deliverable showed a 50 MWth thermal energy is released and not used when 2 SMR are in operation. The purpose of this study is to convert this thermal excess in electrical power with an Organic Rankine Cycle (ORC) to limit the use of the CCGT.

The technical and economic parameters of the Organic Rankine Cycle (ORC) are based on several assumptions. The heat is available in the form of saturated steam at a temperature of 150°C and comes either from a steam extraction in the Rankine cycle of the SMR or from the output of the SMR. The targeted power of the ORC is 50 MWth. The corresponding steam mass flow rate is about 19 kg/s.

To fit with this need, the selected fluid is cyclopentane as it is a fluid adapted to the source temperature (critical temperature equals to 238°C) and with an operating pressure around 10 bar. Another reason is the fact that it is industrially available for sizes of several MW [13]. Furthermore, it is also a rather satisfactory fluid from an environmental point of view (no impact on Ozone Depletion Potential (ODP), low impact on Global Warming Potential (GWP), it does contain PFAS and it is not toxic). Nevertheless, it is inflammable [14].

The technical parameters of the ORC are calculated with the ECHTHERM tool [15]. The output electrical power is estimated to be 9 MWe that leads to an efficiency of 18%. In theory, the Carnot efficiency for a warm source at 150°C and a cold source at 20°C is 31%. The resulting Carnot factor of 0.58 which is quite high for an ORC can be explained by:

- The low temperature of condensing assumed to be the same as the cold source of the SMR,
- The size of the cycle that allows to take favourable assumptions on efficiencies and especially for the turbine.

Table 14, Table 15 and Table 16 give respectively the technical, economic and environmental parameters used in the simulations for the ORC, based on [16] and [17].

Parameter name	Unit	Value
Maximal power	MW	50

Funded by the European Union

Efficiency	%	18

Table 14: Technical parameters of ORC

Parameter name	Unit	Value
Design lifetime	years	20
CAPEX	€/MW_e	2 800 000[2]
OPEX	%CAPEX/year	2

Table 15: Economic parameters of ORC

Parameter name	Unit	Value
Grey emissions	kg CO_2 eq/MW	-

Table 16: Environmental parameters of ORC

The ORC case (run15) is compared with the run13. Table 17 gives the main parameters of the runs. For the run15, each component is resized (except the number of SMRs) and the operation is optimized. For the run15, the total CO_2 emission is also optimized and only the case with the least CO_2 emission is presented.

Component	Parameter	Unit	Run13=Ref	Run15 ORC
CCGT	Maximal Power	MW	-350	
SMGR	Maximal H_2 production	Kg H_2/h	0	
SMR	Nb unit	-	2 (310 MWe)	
HTSE	Maximal power	MWe	-500	
H_2 Storage	Maximal capacity	tons	-160	
PV Field	Nb unit	-	-200	
Wind Farm	Nb unit	-	-80	
ORC	Maximal Power	MWth	-	-100

Table 17: Study on heat recovery with ORC, main parameters

The Table 18 presents the main results of the ORC case (run15) comparatively to the reference case (run13).

Parameter	Unit	Run13=ref	Run15 ORC
SMR	-	2 (310 MWe)	
CCGT Power	MW	45.4	44.7
H_2_HP_Storage Capacity	tons H_2	135	160
HTSE Power	MW	374	367
PV_Field - Nb unit	-	200	200
Thermal_Storage Capacity	MWh		89
Wind_Farm - Nb unit	-	18	20
ORC Thermal Power	MWh_{th}	-	40

	CO_2 emissions	Costs M€	LCOE €/MWh	LCOH €/MWh	LCOH₂ €/kg H_2	CI_E kg CO_2 eq	CI_H kg CO_2 eq	CI_H2 kg CO_2 eq

---

[2] Installation factor at 1.4

	ktons/year					/MWhe	/MWhth	/kg H_2
Run13=ref	58.75	4 122	66.74	19.55	3.58	15.70	1.00	0.62
Run15 ORC	39.64	4 238	67.22	20.11	3.62	10.31	1.00	0.41

Table 18: Study on heat recovery with ORC, main results

Figure 30 and Figure 31 show the CO_2 yearly emissions and the electricity productions means. The use of ORC allows to reduce the CCGT commitment and so the equivalent CO_2 emissions. The CCGT lower commitment is replaced by a higher wind farm and the ORC electrical production.

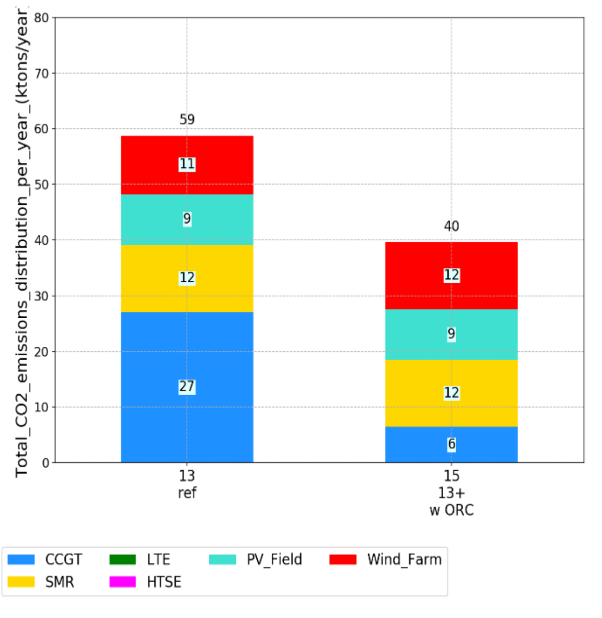


Figure 30: With ORC, CO_2 emissions per year

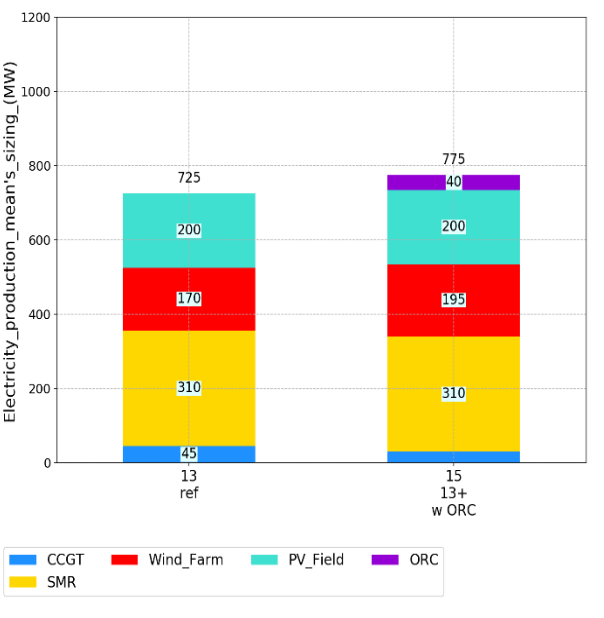


Figure 31: With ORC, Electricity production means

The Figure 32 shows the system cost breakdown. The total cost for both runs are very similar; the lower use of the CCGT is compensated by the ORC and thermal storage costs. The Figure 33 shows that the energy sent to the grids and not used in the system, demonstrates the local use of the recovered thermal energy to produce more electricity particularly when the wind farm and PV field productions are not sufficient. The electrical flexibility is ensured with a higher wind farm and the ORC with the help of the thermal storage.

Funded by
the European Union

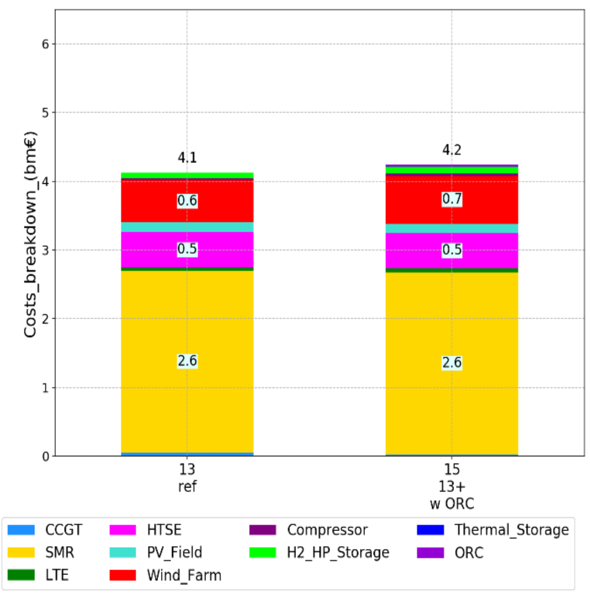


Figure 32: With ORC, Cost breakdown

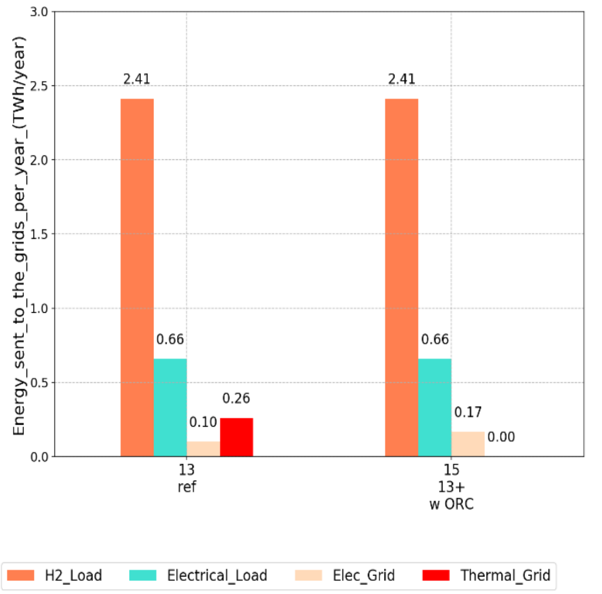


Figure 33: With ORC, energy sent to the grids

The Figure 34 shows the LCOE and LCOH$_2$. Results for run13 and run 15 are very similar. The ORC commitment, with a high operating time at 91%, does not lead to a higher electricity cost.

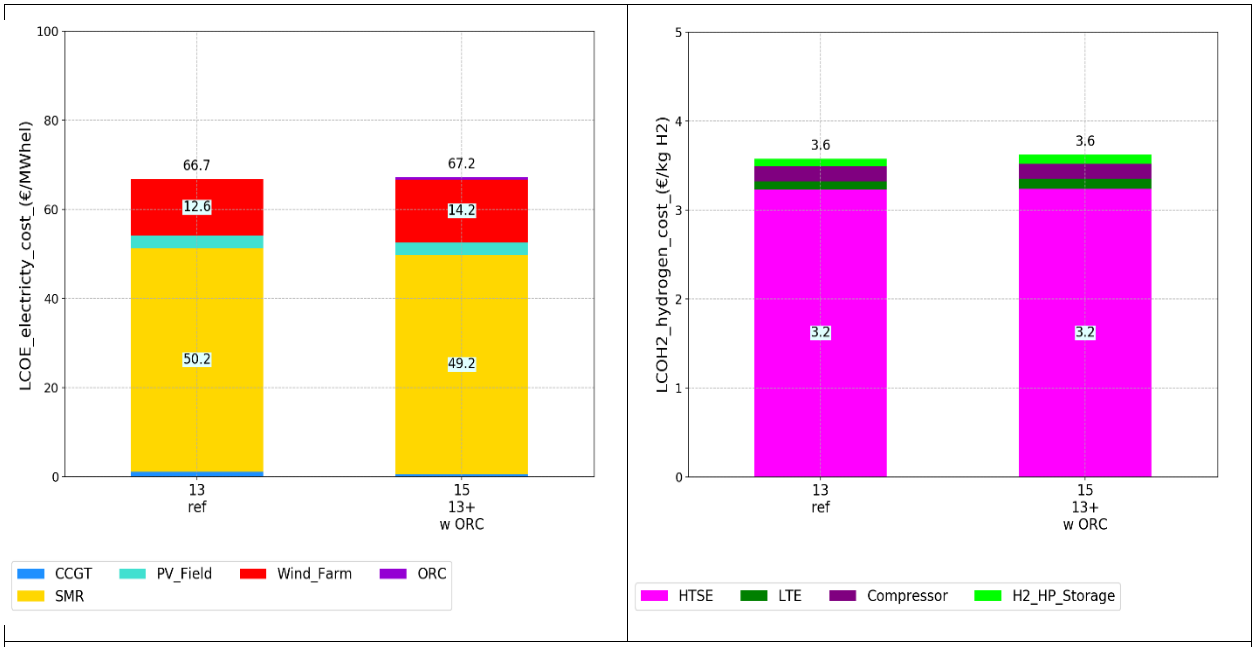


Figure 34: With ORC, LCOE and LCOH$_2$

The CO$_2$ intensity of electricity and hydrogen productions (Figure 35) are lower due mainly to the lower use of CCGT. It can be noticed that ORC embodied emissions have been neglected as no data are available.

Funded by the European Union

Funded by the European Union. Views and opinions expressed are however those of the author(s) only and do not necessarily reflect those of the European Union or the European Atomic Energy Community ('EC-Euratom'). Neither the European Union nor the granting authority can be held responsible for them.

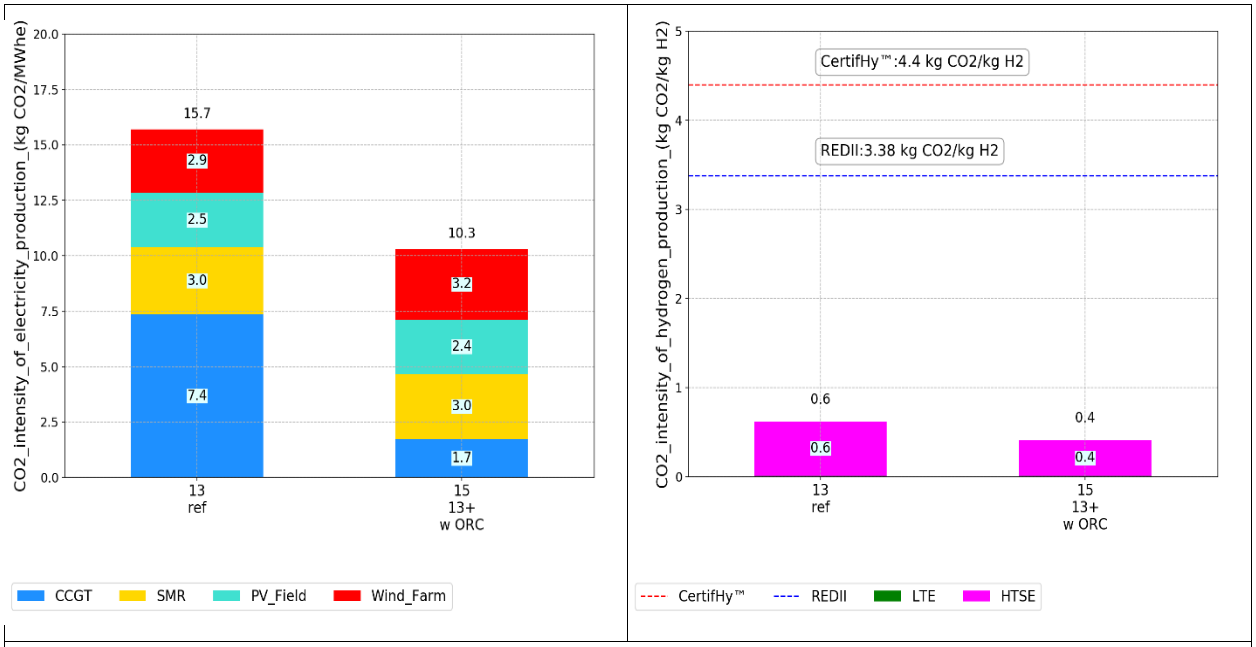


Figure 35: With ORC, CO_2 intensity of electricity and hydrogen production

3.2.3.2 Adding an electrical battery storage to the “2050 with 2 SMR” scenario

The purpose of this study is to store the electrical energy produced by the wind farm and the PV field to be used later when RE are not available (nights, winter, no wind). In the run13, CCGT with natural gas fuel are used during the unavailability of RE. In the sensitivity study, the compromise between the higher costs of RE productions (in particular due to oversizing) and the lower total emissions due to lower commitment of the CCGT will be analysed.

Table 19, Table 20 and Table 21 give respectively the technical, economic and environmental parameters used in the PERSEE calculations.

Parameter name	Unit	Value
Maximal capacity	MWh	-2 400
Maximal charge and discharge power	MW	50
Efficiency	%	100

Table 19: Technical parameters of the electrical storage

Parameter name	Unit	Value
Design lifetime	years	20
CAPEX	Power: €/MW	185 000
	Capacity: €/MWh	319 000
OPEX	Power: €/MW/year	4.6
	Capacity:€/MWh/year	8

Table 20: Economic parameters of the electrical storage

Funded by the European Union

Parameter name	Unit	Value
Embodied emissions	kg CO_2 eq/MW	14 500

Table 21: Environmental parameters of the electrical storage

The calculations (run16 and 17) with an electrical battery are compared with the run13 and the run 14 from D3.2, respectively. These two runs are "2050 with 2 SMR" scenarios that maximize the decarbonisation with the difference that run14 does not contain CCGT but a greater wind farm. The purpose is to analyse if adding electrical batteries will be economically and environmentally interesting (less CCGT and less wind energy share).

Table 22 gives the main parameters of the runs. For the run16 and 17, each component is resized and the operation is optimized. The total CO_2 emission is also optimized owing to several calculations and only the least CO_2 emissive calculation is given.

Variable	Unit	Run13 Ref	Run16 Ref+BAT	Run14 Ref wo CCGT	Run17 Ref wo CCGT+BAT
CCGT - Max Power	MW	-350		0	
SMGR - Max H_2 production	kg H_2/h	0			
SMR - Nb unit	-	2 (310 MWe)			
HTSE - Max power	MWe	-500			
LTE - Max power	MWe	-600			
H_2 Storage - Max capacity	tons	-160			
PV Field - Max Nb unit	-	-200			
Wind Farm - Max Nb unit	-	-80			
Electrical battery - Max Capacity	MWh	0	-2 400	0	-2 400

Table 22: Sensitivity studies on electrical batteries, main parameters

Table 23 presents the main results of the cases including an electrical battery (run16 and 17) comparatively to the reference cases (run13 and 14).

Component	Unit	Run13 Ref	Run16 Ref + BAT	Run14 Ref wo CCGT	Run17 Ref wo CCGT + BAT
CCGT Power	MW	45	20	0	
HTSE Power	MW	374	339	356	337
LTE Power	MW	33	40	28	0
H_2 Storage	tons	135	160		
PV Field (Nb unit)	-	200			
SMR (Nb unit)	-	2 (310 MWe)			
Wind Farm (Nb unit)t	-	53	75	180	168
Battery Optimal Capacity	MWh	0	100	0	224

Funded by the European Union

	CO_2 emissions ktons/year	Total costs M€	LCOE €/MWh	LCOH €/MWh	$LCOH_2$ €/kg H_2	CI_E kg CO_2 eq /MWhe	CI_H kg CO_2 eq /MWhth	CI_H_2 kg CO_2 eq /kg H_2
13=Ref	58.75	4 122	66.74	19.55	3.58	15.70	1.00	0.62
16 Ref + BAT	46.30	4 352	69.35	19.55	3.65	11.85	1.00	0.47
14 Ref wo CCGT	56.27	5 471	74.10	19.55	3.85	11.71	1.00	0.46
17 Ref wo CCGT + BAT	55.65	5 393	75.52	19.55	3.82	11.83	1.00	0.46

Table 23: Studies on electrical batteries, main results

Figure 36 and Figure 37 show the CO_2 yearly emissions and the total cost of the system. For the reference case (run16 and 17 with an electrical battery). Adding an electrical battery decreases the CO_2 emissions by about 12% (from 59 to 46 ktons/year) for an additional cost of about 8 %, mainly due to a lower CCGT and a higher wind farm. The electrical battery sizing is about 100 MWh with about a 2 hours autonomy. In run16, HTSE and LTE sizing is also lower as the system flexibility is larger.

For the run14 and 17, where the CCGT is removed, the yearly emissions and the total cost of the system are similar. But, in run17, the electrolysis sizing is lower and the wind farm is lower (-8%) as the system flexibility is improved.

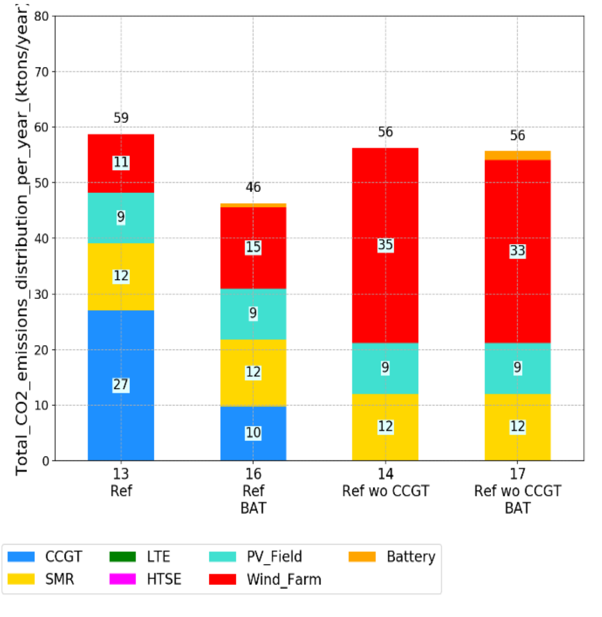


Figure 36: With BAT, CO_2 emissions per year

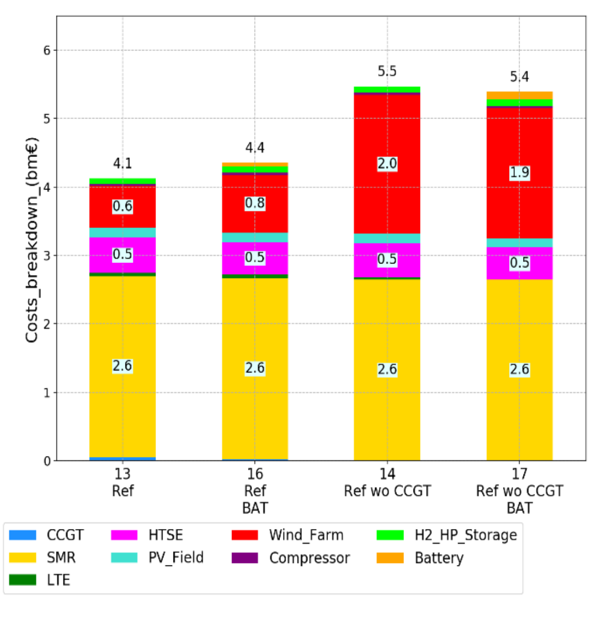


Figure 37: With BAT, cost breakdown

Funded by the European Union

Figure 38 shows the LCOE and LCOH₂. Including electrical batteries costs about +3% on electricity and hydrogen whereas CO_2 intensity are either improved (run16) or similar (run17), as it can be seen in Figure 39.

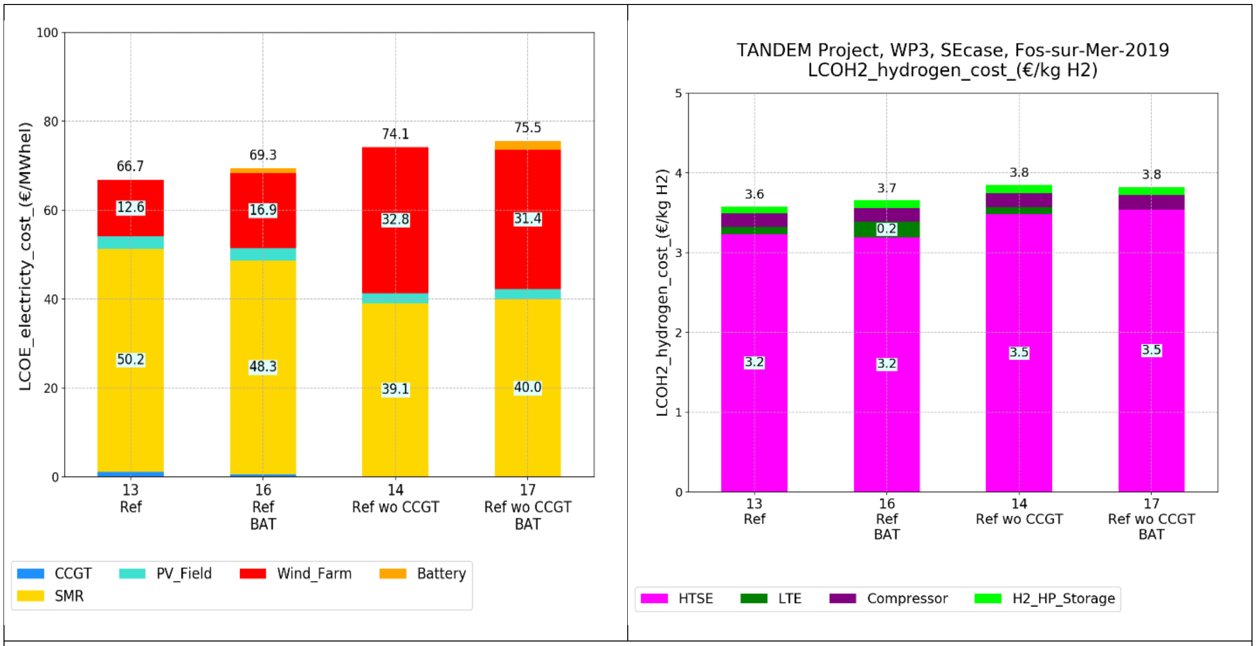


Figure 38: With BAT, LCOE and LCOH₂ costs

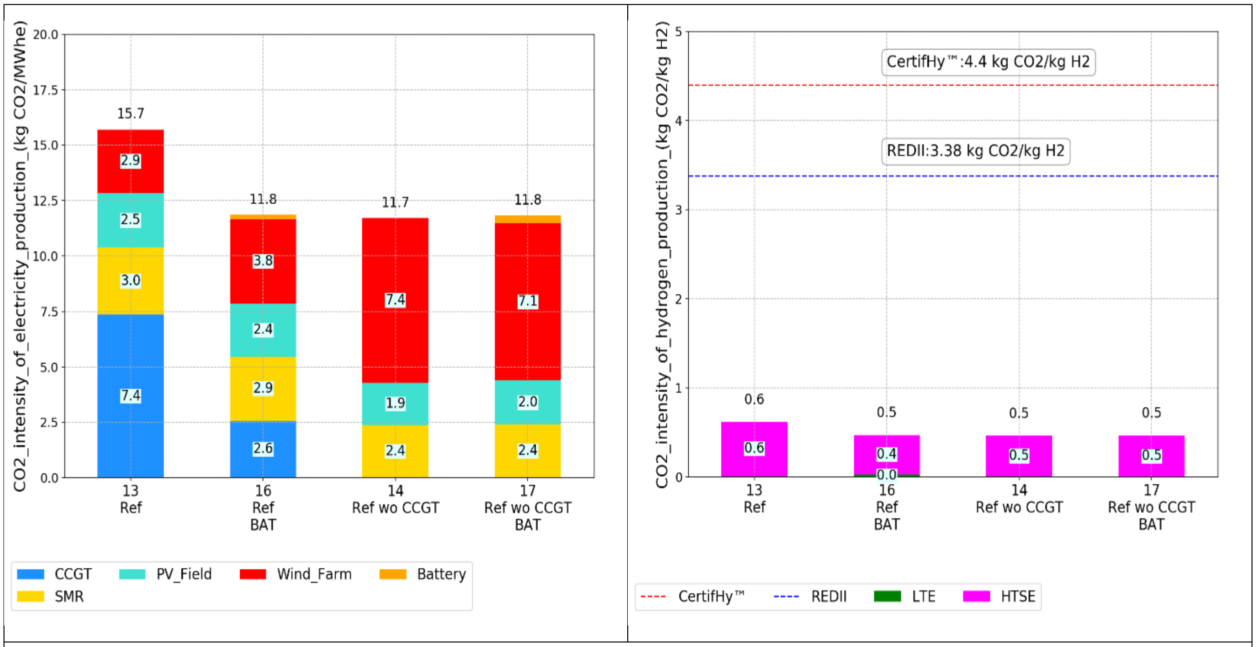


Figure 39: With BAT, CO_2 intensity of electricity and hydrogen production

Funded by the European Union

3.2.3.3 A “2050 without SMR” scenario but with RE, storages and LTE elements

In order to compare scenarios including solutions based on nuclear energy to scenarios based only on RE, a new architecture is built. This architecture includes PV, onshore wind and offshore wind as electricity producers coupled to a set of electrical batteries. Hydrogen is produced by a LTE and a salt cavern – connected through a pair of pipelines for supply and return – can be used to store hydrogen. Figure 40 shows the model of this architecture in PERSEE.

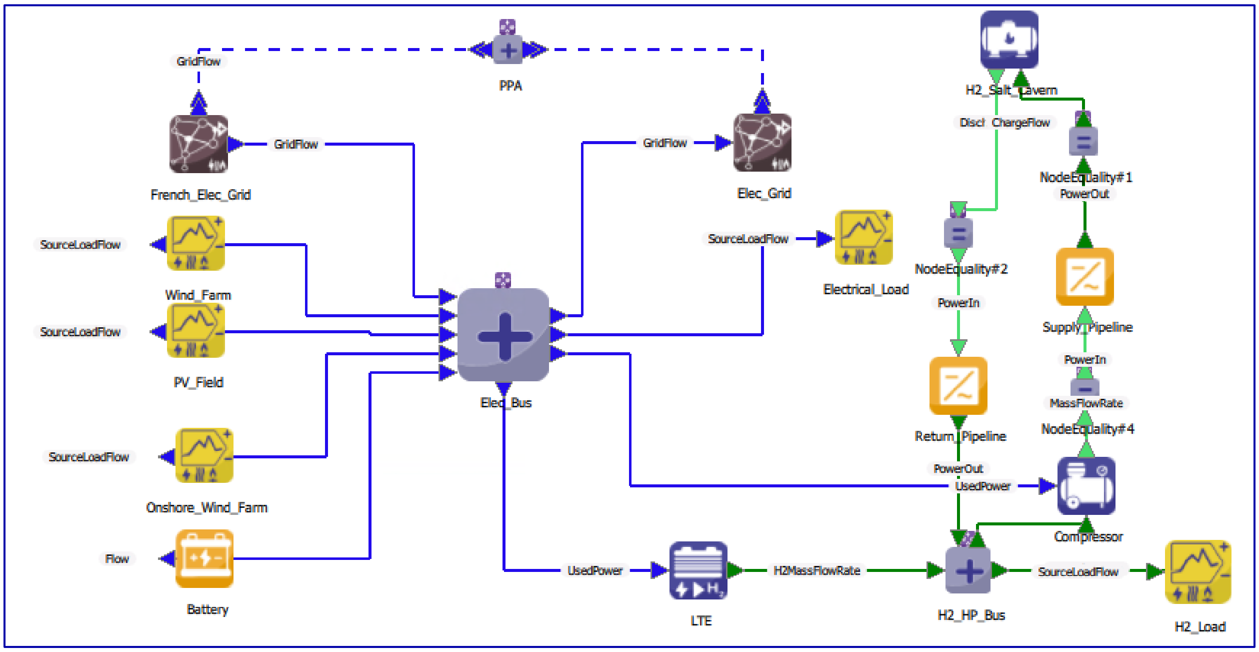


Figure 40: Scheme of the architecture of “2050 RE + Storages + LTE” scenario

Near Fos-sur-Mer, two salt caverns are located in Manosque, resulting in a hydrogen storage capacity of 6000 tons [18]. The distance between Fos-sur-Mer and the salt caverns is about 100 km. Two pipelines are required to transport hydrogen to and from the salt caverns (supply and return). Regarding the sizing of these two pipelines, several parameters are needed to calculate the diameter of the pipes:

- Maximal mass flow rate
- Temperature and pressure to evaluate the average density of hydrogen
- Velocity of hydrogen

The section S and thus the diameter can be calculated owing to the mass flow rate Q, the velocity v and the volumic mass ρ:

$$S(m^2) = \frac{Q\left(\frac{kg}{s}\right)}{\rho\left(\frac{kg}{m^3}\right) v\left(\frac{m}{s}\right)}$$

One criteria to size the pipeline is the velocity of the gas inside the pipeline. There is a limit beyond which the inner pipe might be damaged due to erosion. For natural gas, this limit is about 20 m/s according to [19]. Even if it can be a little bit different for hydrogen, this critical velocity is assumed for sizing the pipelines.

Regarding the pressure inside the pipelines, different ranges are envisaged in the open literature. European Hydrogen Backbone (EHB) [20] considers a range of 50 – 80 bar but higher ranges are considered in other studies like 60 – 90 bar [21] or even 70 – 100 bar [22]. For long distances, compressor stations are distributed regularly along the pipeline to maintain the pressure.

In this study, the pressure in the pipeline is assumed to be 100 bar. Thus, a compressor from 30 bar to 100 bar is required at the start of the supply pipeline. As the distance is only 100km, there is no additional compressor station along the pipeline. For the return pipeline, no compressor is considered at the input of the pipeline. It is a simplified assumption. The pressure inside the salt caverns depends on the state of charge. Different ranges of pressure can be found in the literature: according to INERIS [23]; the storage of pure H_2 in salt caverns currently exists at four locations (3 in the United States, 1 in the United Kingdom) with, for example, a pressure range of 55 - 152 bar at Moss Bluff salt cavern.

If a temperature of 20°C is assumed, the density of hydrogen at 100 bar is about 8 kg/m^3. Thus, in these conditions, the diameter is around 0.135m. In EHB, this diameter corresponds to small pipelines.

Regarding the potential of the RE, it is increased compared to D3.2: the PV field can reach 1,000 MWp and the offshore wind farm can reach 140 turbines. The techno-economic and environmental characteristics of the offshore wind farm and of the PV field are the same as in D3.2.

The techno-economic and environmental characteristics of the onshore wind farm are given in Table 24, Table 25 and Table 26.

Parameter name	Unit	Value
Nominal power	MW	4.28
Number of turbines	-	-60

Table 24: Technical parameters of the onshore wind farm

Parameter name	Unit	Value
Design lifetime	years	25
CAPEX	€/MW	1,318,000
OPEX	%/CAPEX/year	2

Table 25: Economic parameters of the onshore wind farm

Funded by the European Union

Funded by the European Union. Views and opinions expressed are however those of the author(s) only and do not necessarily reflect those of the European Union or the European Atomic Energy Community ('EC-Euratom'). Neither the European Union nor the granting authority can be held responsible for them.

CAPEX includes the CAPEX of the wind turbine, the CAPEX of the installation (preliminary studies, building permit, transportation, sea cables and so on), the CAPEX of the grid connection, the CAPEX of dismantling and a provision for contingencies.

Parameter name	Unit	Value
Embodied CO_2 emissions	kg CO_2 eq/MW_e	517 000

Table 26: Environmental parameters of the onshore wind farm

From IPCC [24], the direct CO_2 emission value is between 7 kg CO_2 eq/MWhe and 56 kg CO_2 eq/MWhe for wind onshore. Considering the assumptions taken in the study, the value is around 8.4 kg CO2 eq/MWhe.

An arbitrary location near Fos-sur-Mer is chosen for onshore wind and it results in the load factor given in Table 27. The load factor of offshore wind farm located in Mediterranean Sea near Fos-sur-Mer is also reminded.

	Fos-sur-Mer
Offshore wind farm Load factor (%)	31.7
Onshore wind farm Load factor (%)	35.3

Table 27: Comparison of load factors between onshore and offshore wind near Fos-sur-Mer

The techno-economic and environmental characteristics of the battery are the same as in section3.2. The techno-economic and environmental characteristics of the LTE are the same as in D3.2 (Proton Exchange Membrane (PEM) technology). The techno-economic characteristics of the salt caverns are provided in Table 28 and Table 29. The environmental aspects of the salt caverns are not considered.

Parameter name	Unit	Value
Maximal capacity	tons H_2	6 000

Table 28: Technical parameters of salt cavern

Parameter name	Unit	Value
CAPEX	€/kg H_2	30
OPEX	%CAPEX/year	2

Table 29: Economic parameters of salt cavern

The techno-economic characteristics of the compressor in the 30-100 bar range are given in Table 30 and Table 31. Again, the embodied emissions of the compressor are not considered.

Parameter name	Unit	Value
Inlet pressure	bar	30

Funded by the European Union

Funded by the European Union. Views and opinions expressed are however those of the author(s) only and do not necessarily reflect those of the European Union or the European Atomic Energy Community ('EC-Euratom'). Neither the European Union nor the granting authority can be held responsible for them.

Outlet pressure	bar	100
Compression rate (Outlet pressure/Inlet pressure)	bar	3
Number of stages	-	2
Hydrogen mass flowrate	kg/h	-20 000
Hydrogen thermal capacity	J/kg/K	14 400
Compression efficiency = Motor efficiency*Isentropic efficiency	-	0.63=0.9*0.7
Isentropic coefficient	-	1.4
Inlet temperature	K	293

Table 30: Technical parameters of the compressor

Parameter name	Unit	Value
Lifetime	-	10
CAPEX	€/kW	738
OPEX	%CAPEX/year	3

Table 31: Economic parameter of the compressor

The techno-economic characteristics of the pipelines are given in Table 32 and Table 33. Again, the environmental aspects of the pipelines are not considered.

Parameter name	Unit	Value
Maximal capacity	kg H_2	-20 000

Table 32: Technical parameters of hydrogen pipeline

Parameter name	Unit	Value
CAPEX	M€/km	1.5
OPEX	%CAPEX/year	0.9
Lifetime	year	40

Table 33: Economic parameters of hydrogen pipeline

A residual value is calculated due to the fact that the lifetime is 40 years whereas the project duration is 20 years.

Finally, the capacities of the RE are extended beyond the limits previously set and the possibility to conclude renewable Power Purchase Agreements (PPA) that fulfill the RED II conditions is also analyzed. It means that, in this case, PPA are signed between the LTE and the RE producers (PV field, onshore and offshore wind fields) to guarantee the electricity origin used to produce hydrogen on four criteria:

- **Renewability**: electricity should be limited to renewable energy sources only.
- **Temporal correlation**: the hydrogen is produced during the same calendar month as the renewable electricity until December 2029. After, the temporal correlation is reduced to one hour.
- **Geographical correlation**: the hydrogen production and power plants should be located in the same bidding zone.

- **Additionality**: the RE sources came into operation not earlier than 36 months before the installation producing the hydrogen and did not receive support in the form of operating aid or investment aid.

The main point is the temporal correlation: it means that the excess of electricity produced by the RE can be sold to the grid and the same amount of energy can be paid to the grid in the same month. Electricity is sold at SPOT price but when it is bought at a price that includes taxes, in the same way as the one defined in section3.2.2.

The “2050 without SMR” scenario but with RE, storages and LTE elements calculations (run20 and 21) are compared with the reference run13. Run20 is without PPA option when run21 is with a PPA. Table 34 gives the main parameters of the runs where negative values given in the table show the parameters to be optimized.

Variable	Unit	Run13 Ref	Run20 without PPA	Run21 with PPA
CCGT - Max Power	MW	-350	0	
SMGR - Max H_2 production	kg H_2/h	0	0	
SMR - Nb unit	-	2 (310 MWe)	0	
HTSE - Max power	MWe	-500	0	
LTE - Max power	MWe	-600	-1 200	
H_2 Storage - Max capacity	tons	-160	-6 000 Salt cavern	
PV Field - Max Nb unit	-	-200	-1 000	
Offshore Wind Farm - Max Nb unit	-	-80	-140	
Onshore Wind Farm - Max Nb unit	-	0	-60	
Electrical battery - Max Capacity	MWh	0	-4 800	
Compressor (1-30bars) Max H_2 flow	kg H_2/h	-10 000	20 000	
French electrical grid PPA	-	-	NO	YES

Table 34: Studies on “2050 without SMR” with RE, PPA and storages, main parameters

Funded by the European Union

Variable	Unit	Run13 Ref	Run20 without PPA	Run21 with PPA
CCGT Power	MW	45.3	0	
SMR - Nb unit	-	2 (310 MWe)	0	
HTSE power	MWe	374	0	
LTE power	MWe	32	1 099	1 169
H_2 Storage capacity	tons	135	6 000 Salt cavern	897 Salt cavern
PV Field Nb unit	-	200	1000	
Offshore Wind Farm Nb unit	-	18	53	45
Onshore Wind Farm Nb unit	-	0	60	
Electrical battery Capacity	MWh	0	970	44
Compressor (1-30bars) H_2 flow	kg H_2/h	9 806	20000	
French electrical grid PPA	-	-	NO	YES

	CO_2 emissions ktons/year	Total costs M€	LCOE €/MWh	LCOH €/MWh	$LCOH_2$ €/kg H_2	CI_E kg CO_2 eq /MWhe	CI_H kg CO_2 eq /MWhth	CI_H_2 kg CO_2 eq /kg H_2
13=Ref	58.75	4 122	66.74	19.55	3.58	15.70	1.00	0.62
Run 20 without PPA	101.32	5 368	59.14		4.96	23.16		1.12
Run 21 with PPA	90.11	4 751	49.30		4.37	20.13		0.97

Table 35: Studies on “2050 without SMR” with RE, PPA and storages, main results

Figure 41 shows the comparison of the cost breakdown between the “2050 RE + Storages + LTE” cases and the reference case and Figure 42 present the comparison of the total yearly CO_2 emissions between these three cases.

Funded by the European Union

Funded by the European Union. Views and opinions expressed are however those of the author(s) only and do not necessarily reflect those of the European Union or the European Atomic Energy Community ('EC-Euratom'). Neither the European Union nor the granting authority can be held responsible for them.

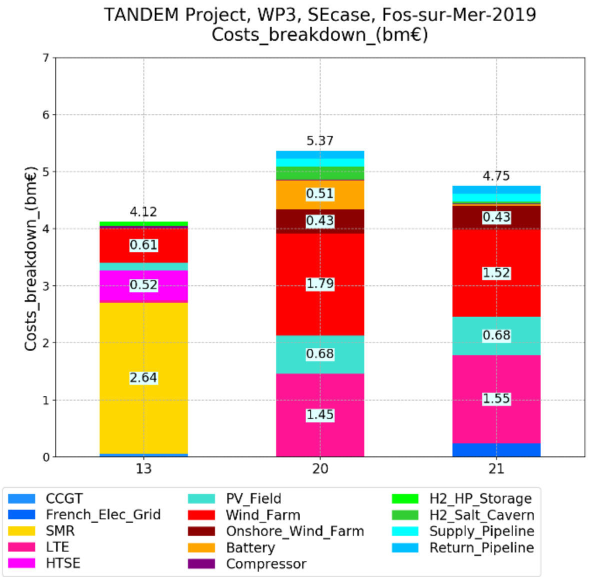


Figure 41: "2050 without SMR" scenario, cost breakdown

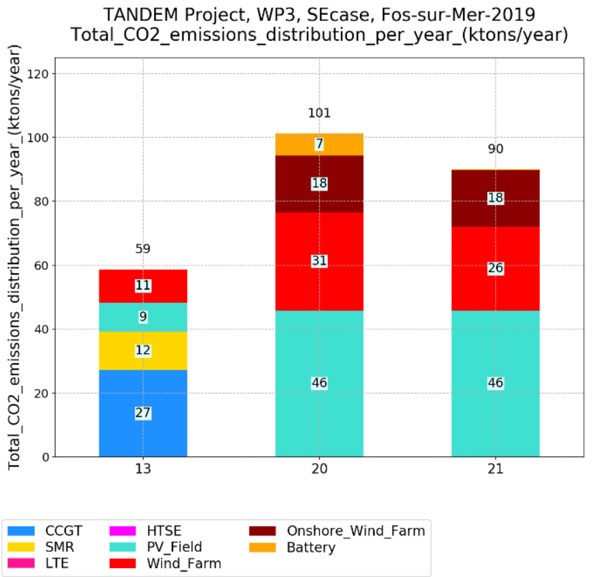


Figure 42: "2050 without SMR" scenario, yearly CO_2 emissions

Figure 43 and Figure 45 show the comparison of LCOE and $LCOH_2$ respectively between the "2050 RE + Storages + LTE" cases and the reference case whereas Figure 44 and Figure 46 present the comparison of CO_2 intensity of electricity and hydrogen respectively.

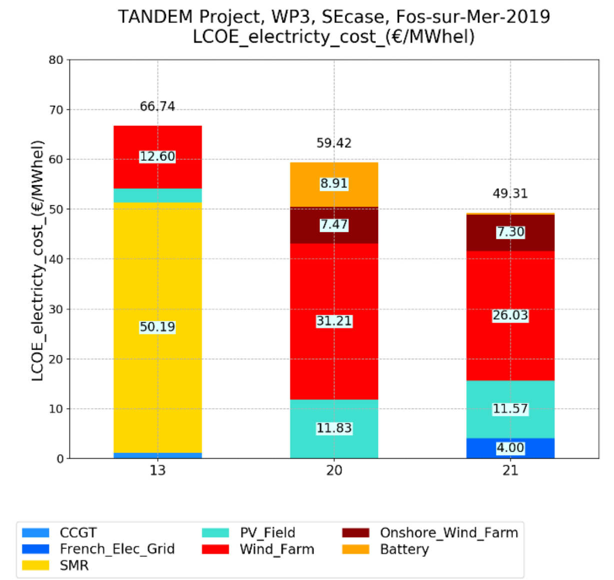


Figure 43: "2050 without SMR" scenario, LCOE electricity cost

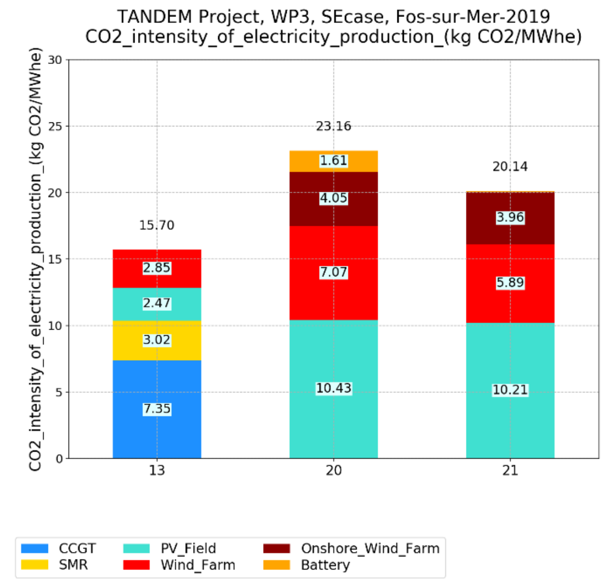


Figure 44: "2050 without SMR" scenario, CO_2 intensity of electricity

Funded by the European Union

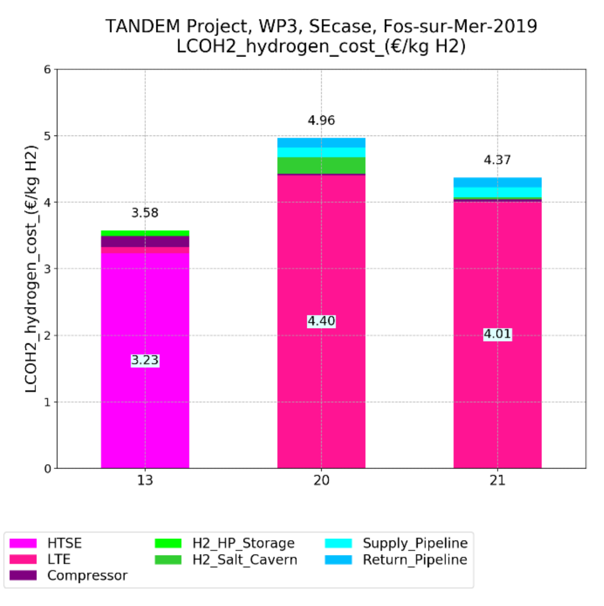


Figure 45: "2050 without SMR" scenario, $LCOH_2$ hydrogen cost

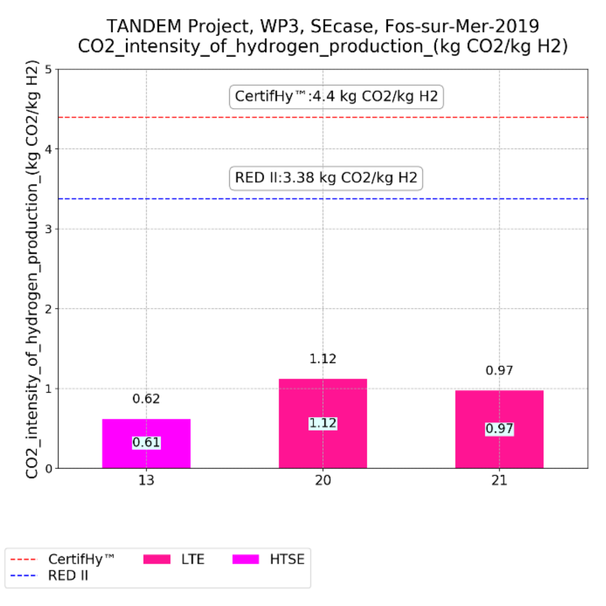


Figure 46: "2050 without SMR" scenario, CO_2 intensity of hydrogen

For the set of assumptions considered in this study, the "2050 without SMR" scenario appears to be less interesting than the "2050 with 2 SMR maximizing decarbonisation" scenario from both an economic and environmental point of views. One of the reasons is that renewable energy sources must be significantly oversized to meet a constant electrical load and a constant hydrogen load. PPA is used for 0.3 TWh/year and leads to a reduction of the number of offshore wind turbines installed. Nevertheless, several assumptions could be refined to improve a little bit the "2050 without SMR" scenario. First, neither size effect nor series effect is considered for PEM and PV whereas for such an amount of PEM modules installed, a cost reduction could be envisaged. In addition, a sensitivity study on the CAPEX of PEM and HTSE would be interesting as it is a strong and debatable assumption. Besides, in run 21, the size of the pipes and the compressor are not resized according to their usage, and given the use of the salt cavern in run 21, they are oversized.

3.2.4 Conclusions on the explored architectures

Deliverable D3.2 gave the first order of magnitude of electricity, heat and hydrogen prices and CO_2 intensity around base architectures. Other analyses were run to shed additional light on previous results:

- Equipping the CCGT and SMGR with CCUS components for 2035 and 2050 scenarios (run0, run5, run7 and run13)
- Using the electrical grid instead the CCGT for the "2035 without SMR" scenario.
- Improving the decarbonisation rate around the "2050" scenario by different means.

- Producing electricity and hydrogen with only RE with the help of hydrogen and electrical storages in the frame of the “2050 without SMR” scenario.

The Figure 47 shows for all selected scenarios the total cost against the carbon emissions of the HES (logarithmic scale base 2). The results of the “2035 without SMR”, “2035 with 1 SMR”, “2050 with 2 SMR”, “2050 with 2 SMR maximizing decarbonisation” scenarios are respectively shown with square, diamond, triangle and circle symbols. Simulations with CCUS are given in green colour. The two additional runs (“2035 without SMR and CCGT” and ‘’2050 without SMR”) are also reported in the figure.

Similarly, Figure 48 and Figure 49 show respectively the LCOE and $LCOH_2$ against the CO_2 intensity of each product.

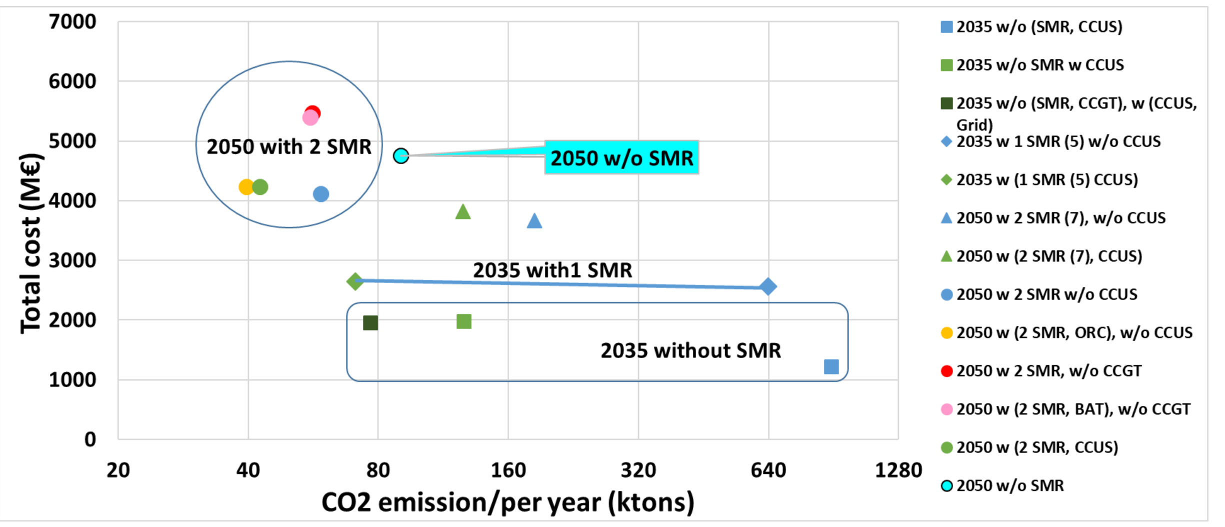


Figure 47: Summary of the architectures studied, cost and CO_2 emissions

Funded by the European Union

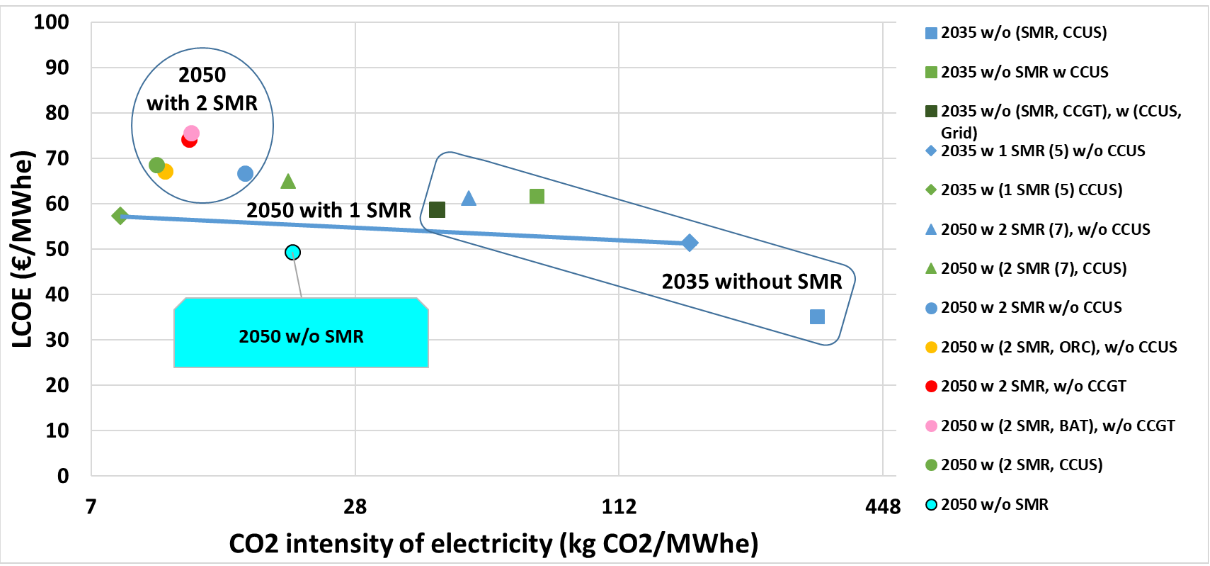


Figure 48: Summary of the architectures studied, LCOE and CO_2 intensity of electricity

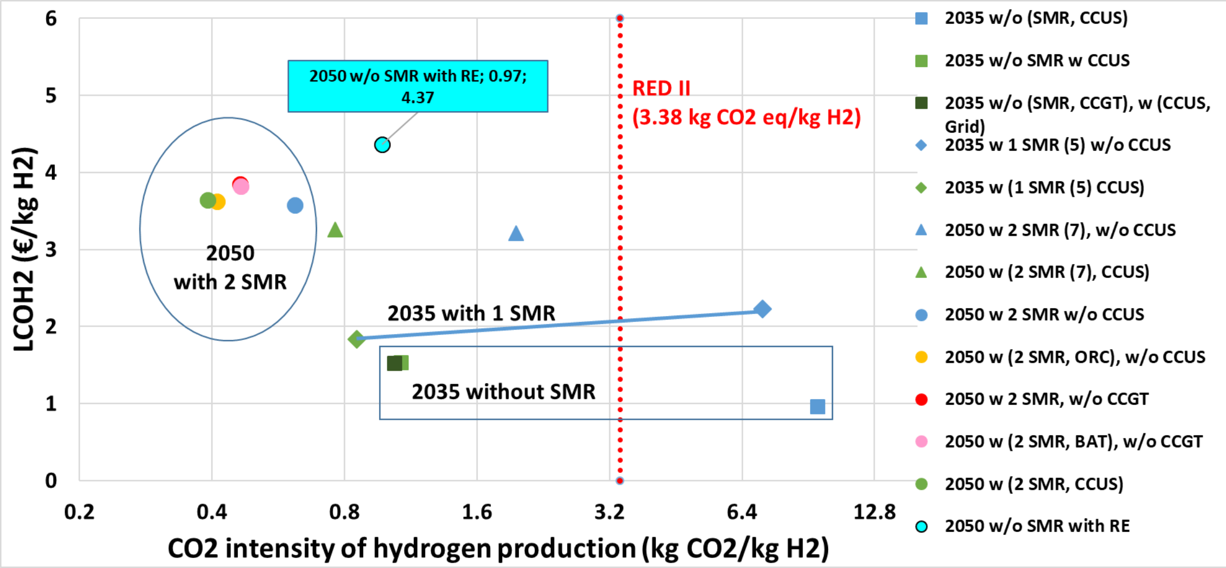


Figure 49: Summary of the architectures studied, $LCOH_2$ and CO_2 intensity of hydrogen

The following conclusions can be drawn from this exploration of other interesting architectures:

1. Except "2035 without SMR without CCUS" and "2035 with 1 SMR without CCUS" scenarios, all the scenarios provide hydrogen with a carbon intensity lower than the RED II threshold, even if the hydrogen produced could be considered as renewable only in "2050 without SMR" scenario according to RED II legislation as neither nuclear nor CCUS are allowed in the electricity supply of renewable hydrogen.

Funded by the European Union

2. Equipping the CCGT and the SMGR with CCUS components results in decreasing CO_2 emissions at low extra cost. But the main disadvantage is the high carbon storage capacity needed for the 2035 scenarios, especially for "2035 without SMR" and "2035 with 1 SMR" scenarios. For "2035 without SMR" scenario, equipping the CCGT and the SMGR with CCUS results in a higher LCOE of 61.6 €/MWhe (+75.5% compared to D3.2) for a CO_2 intensity of 72.7 kg CO_2 eq/MWhe (-77.1% compared to D3.2) and in a $LCOH_2$ of 1.5 €/kg H_2 (+58.7% compared to D3.2) for a CO_2 intensity of 1.1 kg CO_2/kg H_2 (-88.7% compared to D3.2). For the "2050" scenario, adding a CCUS does not impact so much the LCOE and the $LCOH_2$ but it reduces the CO_2 intensity of electricity and hydrogen.
3. Using the electrical grid instead of the CCGT equipped by CCUS for the "2035 without SMR" scenario gives similar economic results for better environmental results due to low carbon French electrical network.
4. The new reference for "2035 without SMR with CCUS" scenario is characterized by: a couple (LCOE, CO_2 intensity of electricity) of (61.6 €/MWh, 72.7 kg CO_2 eq/MWhe) and a couple ($LCOH_2$, CO_2 intensity of hydrogen) of (1.53 €/kg H_2, 1.1 kg CO_2 eq/MWhe) considering a CO_2 transport and storage cost of 33 €/tons CO_2. It leads also to have 17754 ktons of CO_2 to store for the whole project duration.
5. The « 2035 with 1 SMR with CCUS » scenario is an interesting solution as the system can be decarbonized at about 44% compared to « 2035 no SMR with CCUS » scenario with a small decrease of the LCOE (-4.4 €/MWhe) and a small increase of the $LCOH_2$ (+0.3 €/kg H_2). Nevertheless, the amount of CO_2 to be stored for the whole duration of the project is 10758 ktons of CO_2.
6. The "2050 with 2 SMR maximizing decarbonisation without CCUS" scenario allows the system to be decarbonized at about 53% compared to « 2035 no SMR with CCUS » scenario with an extra cost of 5.1 €/MWhe for the LCOE and of 2 €/kg H_2 for the $LCOH_2$.
7. Lower CO_2 emissions are obtained with the "2050 with 2 SMR" configuration. Among the proposed solutions to decarbonize even more the "2050" scenario, the implementation of an ORC seems to be a good option as it leads to a LCOE of 67.2 €/MWhe (+0.7% compared to D3.2) for a CO_2 intensity of 10.3 kg CO_2/MWhe (-34.3% compared to D3.2) and to a $LCOH_2$ of 3.6 €/kg H_2 (+1.3% compared to D3.2) for a CO_2 intensity of 0.4 kg CO_2 eq/kg H_2 (-33.6% compared to D3.2).
8. For the set of assumptions considered (which would need to be refined a little bit to be more accurate), the "2050 without SMR with RE" scenario results in similar results regarding electricity (LCOE and CO_2 intensity of electricity are quite close) but in worse values for hydrogen ($LCOH_2$ and CO_2 intensity of hydrogen higher than "2050 with 2 SMR" scenario).

Funded by the European Union

3.3 Sensitivities on robustness to main input data

The purpose of this sensitivity study is to analyse the impact of uncertainties linked to the price forecasts (gas, electricity prices) and the SMR main input data on PERSEE optimization results: the CAPEX, the variable cost (in which the fuel cost is a main parameter) and the heat recovery ratio. The sensitivity analyses are performed on the run13 corresponding to a “2050 with 2 SMR maximizing decarbonisation” scenario.

3.3.1 Sensitivity study to price forecasts

In the main study, the year 2019 is considered in the calculations. The objective of this sensitivity analysis is to study the impact of the gas price on the results mainly when CCGT and SMGR are used. Figure 50 and Figure 51 compare gas and electricity prices for Fos-sur-Mer in 2019 and 2022. It can be noticed that the gas price is about 6 times higher in 2022 (mean value at about 120 €/MWh) than in 2019 (20 €/MWh) with a large standard deviation.

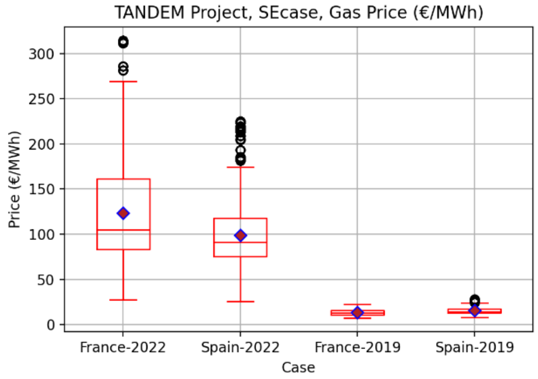


Figure 50: Gas price for France and Spain in 2019 and 2022

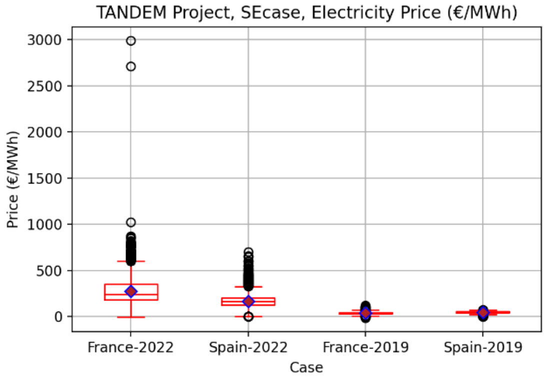


Figure 51: Electricity price for France and Spain in 2019 and 2022

The objective of the following sensitivity cases is to analyse the impact of the gas price on the results for the “2035 without SMR” scenario (run0 CCUS), and for the “2050 with 2 SMR” scenarios (run7 CCUS and run13 CCUS). The comparison is done when CCGT and SMGR are equipped with CCUS (the runs with CCUS are described in section 3.2.1 with the 33 €/tCO_2 CCUS price, value recommended by IEA for 2035).

PERSEE optimizations are performed by sizing the components (CCGT, PV field, wind farm and hydrogen storage) using either the 2019 or the 2022 gas price profiles. For the run0 CCUS, no SMR is modelled and for run7 CCUs and 13 CCUS, SMGR is not used. For run0 CCUs and run7 CCUS, the maximum value of the total CO_2 emissions is not imposed. In the run13 CCUS, a maximum of total CO_2 emissions is imposed. Only the least CO_2 emissive calculation run13 CCUS is given.

Table 36 presents the results of the sizing and Table 37gathers the main results.

Variable	Unit	0 2019	0 2022	7 2019	7 2022	13 2019	13 2022
CCGT with CCUS - Installed Size	MW	85.2	84.8	96.4	44.3	41.5	38.1
SMR - Installed Size	MW	0		310.			
H_2_HP_Storage - Storage Capacity	tons	0	160	0	160		
HTSE - Installed Size	MW	0		315.1	379.7	394.1	385.8
SMGR with CCUS - Installed Size	kg/h H_2	8 257	10 000	0			
Wind_Farm - Nb Unit	-	0	129	0	173	184	194
PV_Field - Nb Unit	-	116	165	200			

Table 36: Sensitivity on price forecasts, sizing results

Component	Unit	0 2019	0 2022	7 2019	7 2022	13 2019	13 2022
Total CO_2 emissions	ktons/year	126.1	110.6	73.3	38.4	37.5	37.5
Total costs	M€	1 990	7 490	3 820	4 350	4 230	4 360
LCOE	€/MWh	61.62	127.04	64.97	71.46	68.49	70.82
LCOH	€/MW	-	-	19.55	19.55	19.55	19.55
$LCOH_2$	€/kg H_2	1.53	6.39	3.26	3.74	3.65	3.72
CI_E	kg CO_2 eq/MWhe	72.69	40.91	19.67	10.14	9.85	9.80
CI_H	kg CO_2 eq /MWhth	-	-	1.00	1.00	1.00	1.00
CI_H_2	kg CO_2 eq /kg H_2	1.08	1.04	0.76	0.40	0.39	0.39

Table 37: Sensitivity on price forecasts, main results

For the run0 (without SMR and HTSE), the higher gas price results in higher RE production (wind and PV). Flexibility of the electrical supply is ensured by the CCGT but at lower rate for the 2022 case; CCGT is committed only at 54% in 2022 (87% in 2019, Figure 54). SMGR sizing is higher in 2022 (10000 kg H_2/h) at lower commitment rate (87% in 2022 and 100% in 2019) and the H_2 storage brings the flexibility of the hydrogen production. This lower use of natural gas results in lower CO_2 emissions in 2022 than 2019 (Figure 53).

Same conclusions can be drawn for the run7 (with 2 SMR and HTSE). In both calculation (2019 and 2022), the HTSE operating time is at 100% but at lower power in 2019. The H_2 storage is used only for the 2022 case. The CCGT is less used in 2022 (28%) than in 2019 (69%). For the run13, as the natural gas and CCGT are committed at very low rate, the two solutions (2019 and 2022) are very close.

Funded by the European Union

Figure 52 presents the total cost for all cases and shows that with SMR and HTSE (run7 and 13), the system cost becomes more independent of the gas price and relatively close to about 3.8-4.4 bm€.

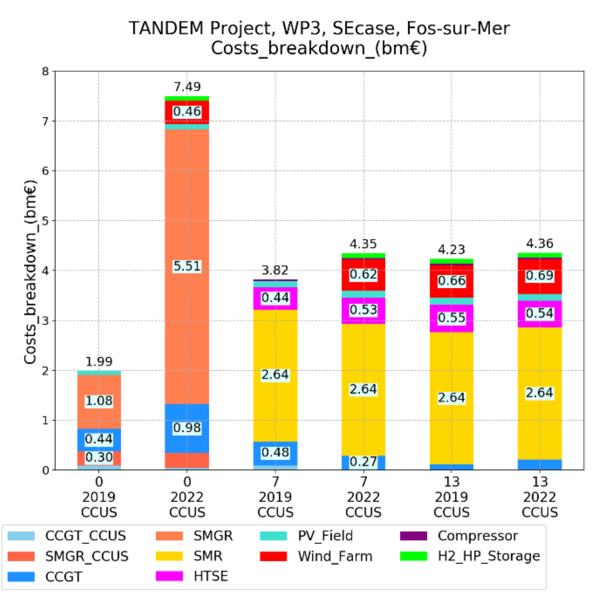


Figure 52: Gas price sensitivity, Total costs

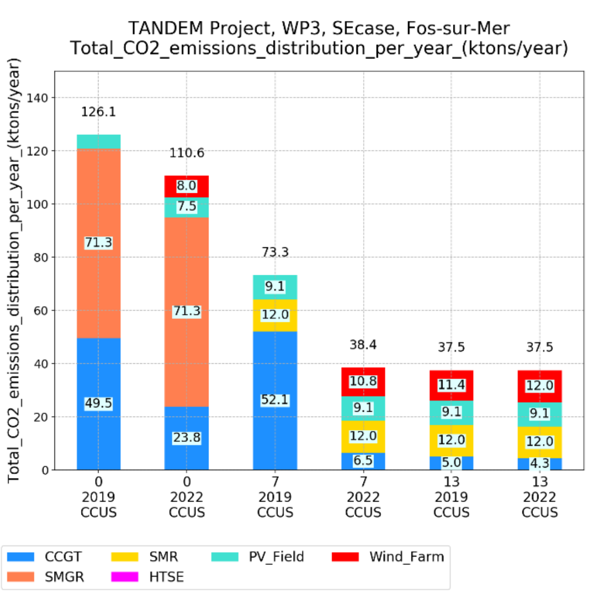


Figure 53: Gas price sensitivity, Total CO_2 emissions

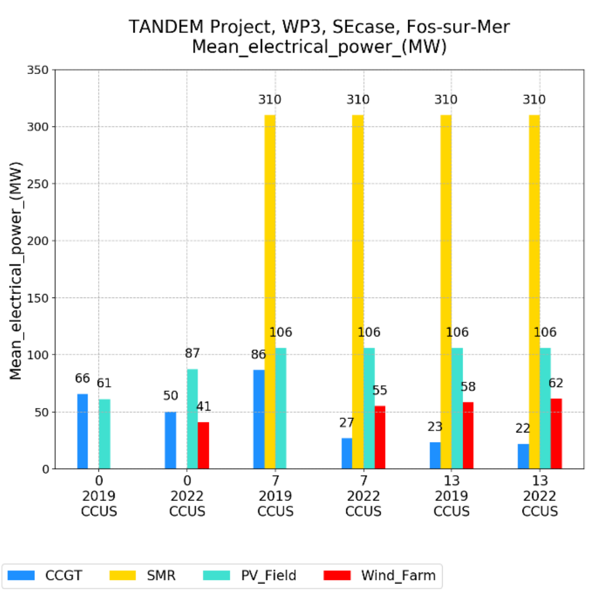


Figure 54: Gas price sensitivity, Mean electrical power

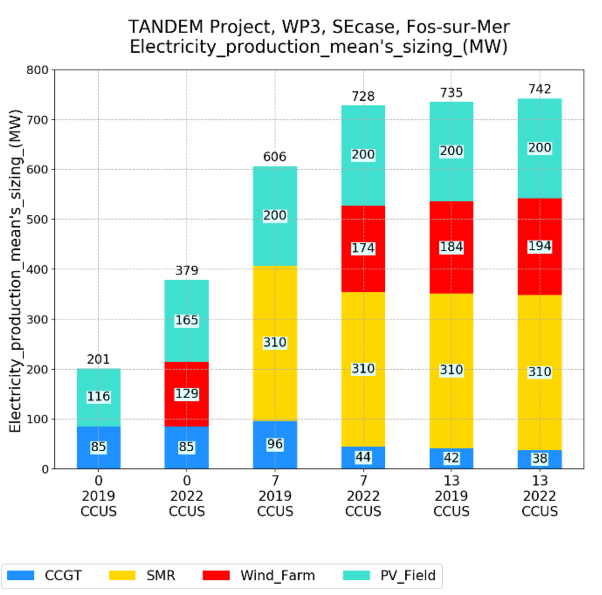


Figure 55:Gas price sensitivity, Electricity production means

Funded by the European Union

Figure 56, Figure 57 and Figure 58 give the cost and CO_2 intensity of electricity, hydrogen and thermal energy. Both prices and CO_2 intensities are less fluctuating on the external gas supply when SMR and HTSE are operating (run 7 and 13). When the CCGT is at very low rate (run13), CO_2 intensity of electricity is very low at a moderated price (about 70 €/MWhe). CO_2 intensity of hydrogen is always low compared to the RED II threshold but at lower rate when green hydrogen is produced with SMR and RE (about 0.4 kg CO_2/kg H_2 at about 3.7 €/kg H_2).

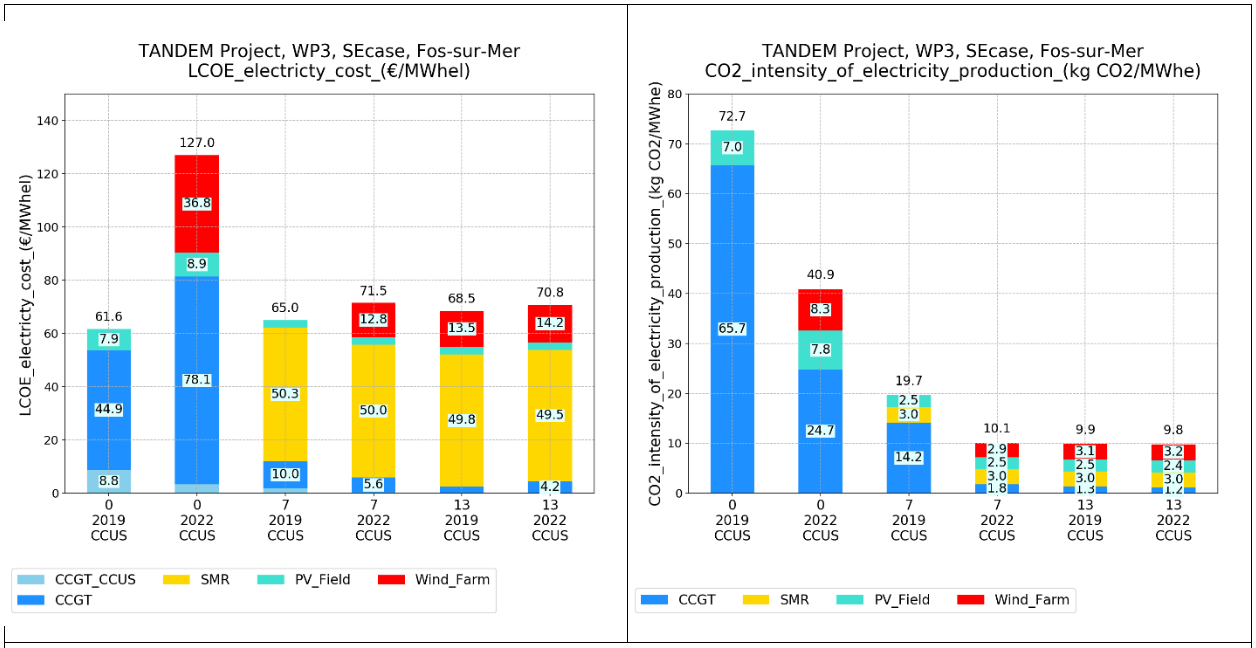


Figure 56: Gas price sensitivity, electricity cost and CO_2 intensity

Funded by the European Union

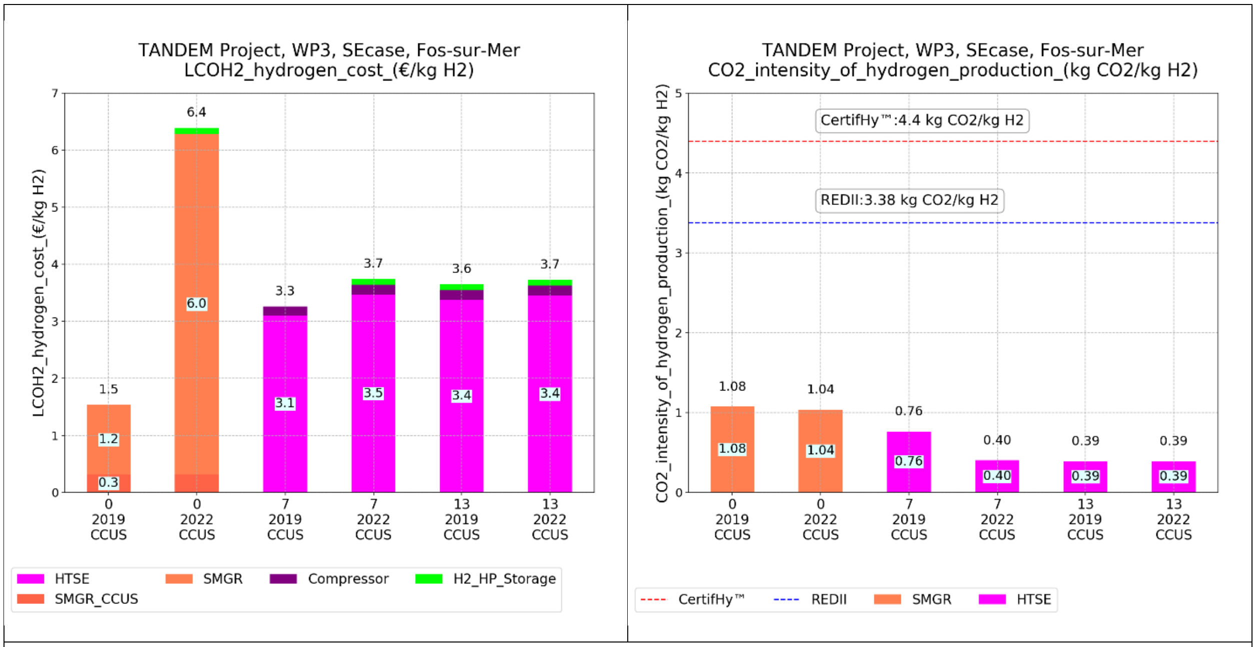


Figure 57: Gas price sensitivity, hydrogen cost and CO_2 intensity

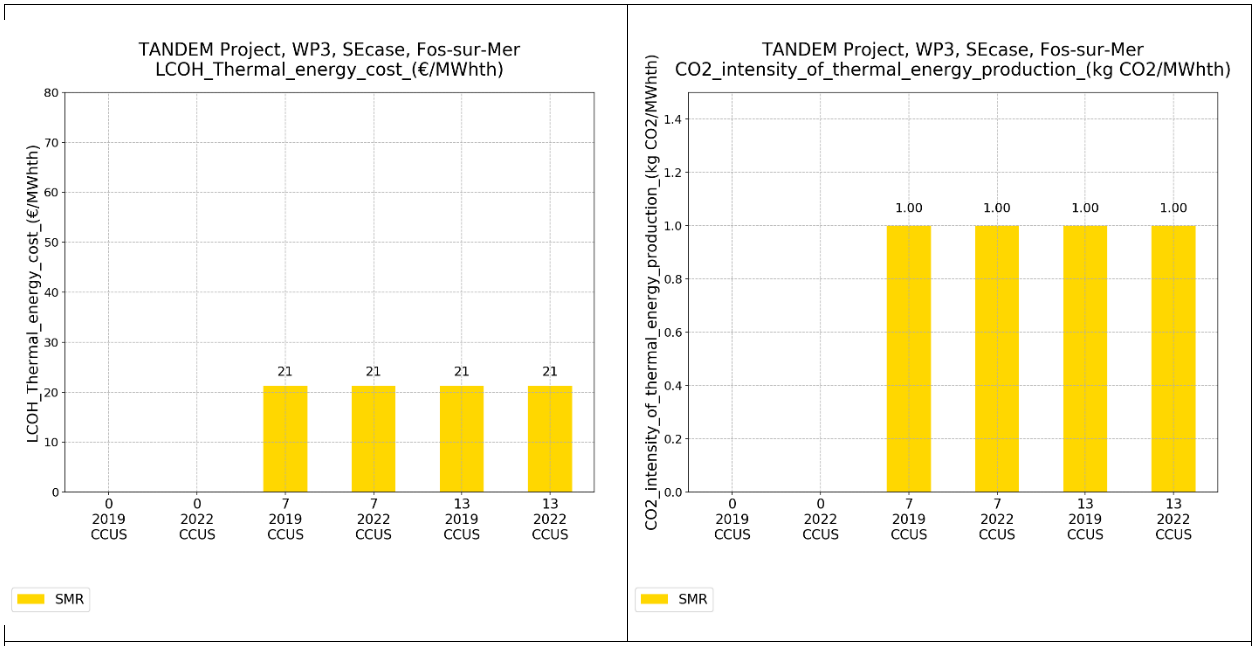


Figure 58: Gas price sensitivity, thermal energy cost and CO_2 intensity

Funded by the European Union

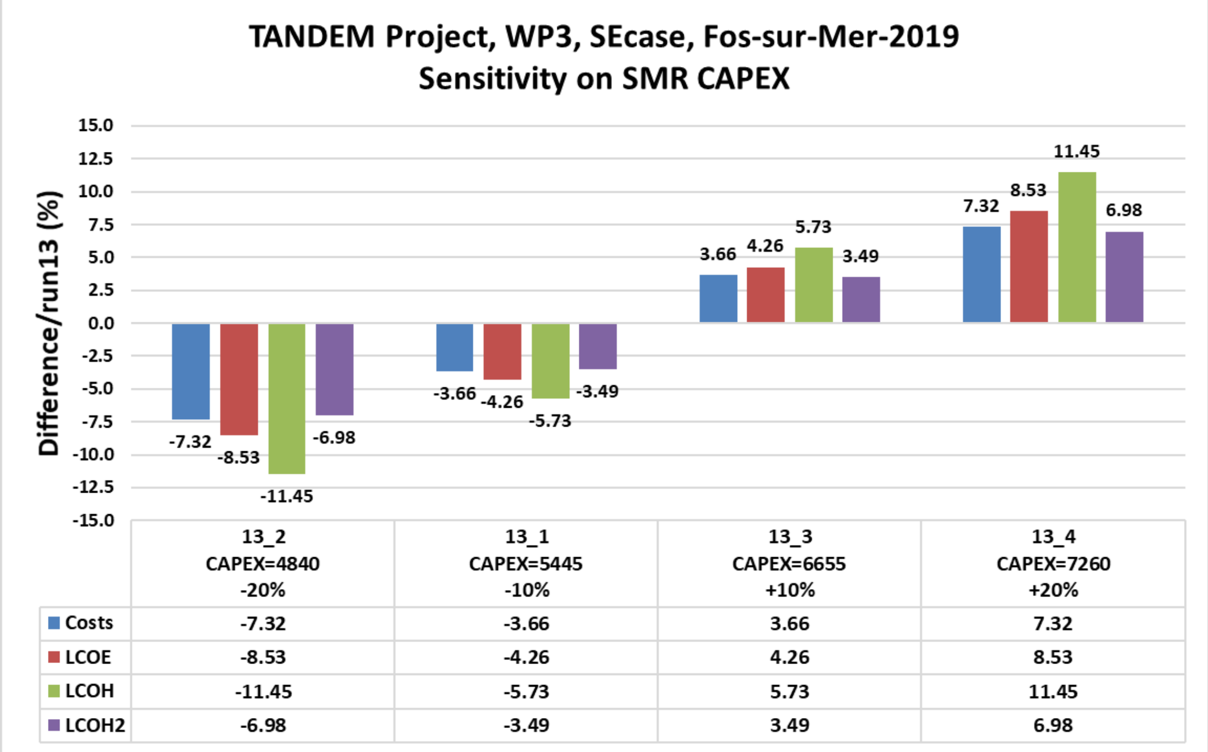
3.3.2 Sensitivity study to the SMR CAPEX

The reference CAPEX for a SMR is 6050 €/MW. The following sensitivity runs are conducted. For each run, the system is sized and optimized with 2 SMRs. Only the SMR CAPEX is changed. The total CO_2 emission is imposed at the reference run13 value.

Parameter name	Unit	Values				
SMR - CAPEX	€/MWe	4 840	5 445	6 050	6 655	7 260
Deviation from reference	%	-20	-10	0	+10	+20
		13_2	13_1	13	13_3	13_4

Table 38: Sensitivity on the SMR CAPEX

Results and comparison with the reference case are given in the Figure 59. The PERSEE process finds the same component sizing and only the SMR CAPEX and costs are updated compared with the reference run13. The [-20%, +20%] range for the SMR CAPEX leads to a deviation of [-8.5%, +8.5%] for the LCOE, [-11.4%, +11.4%] for the LCOH and [-7.0%, +7.0%] for the $LCOH_2$.



	13_2 CAPEX=4840 -20%	13_1 CAPEX=5445 -10%	13_3 CAPEX=6655 +10%	13_4 CAPEX=7260 +20%
🟦 Costs	-7.32	-3.66	3.66	7.32
🟥 LCOE	-8.53	-4.26	4.26	8.53
🟩 LCOH	-11.45	-5.73	5.73	11.45
🟪 LCOH2	-6.98	-3.49	3.49	6.98

Figure 59: Sensitivity on the SMR CAPEX

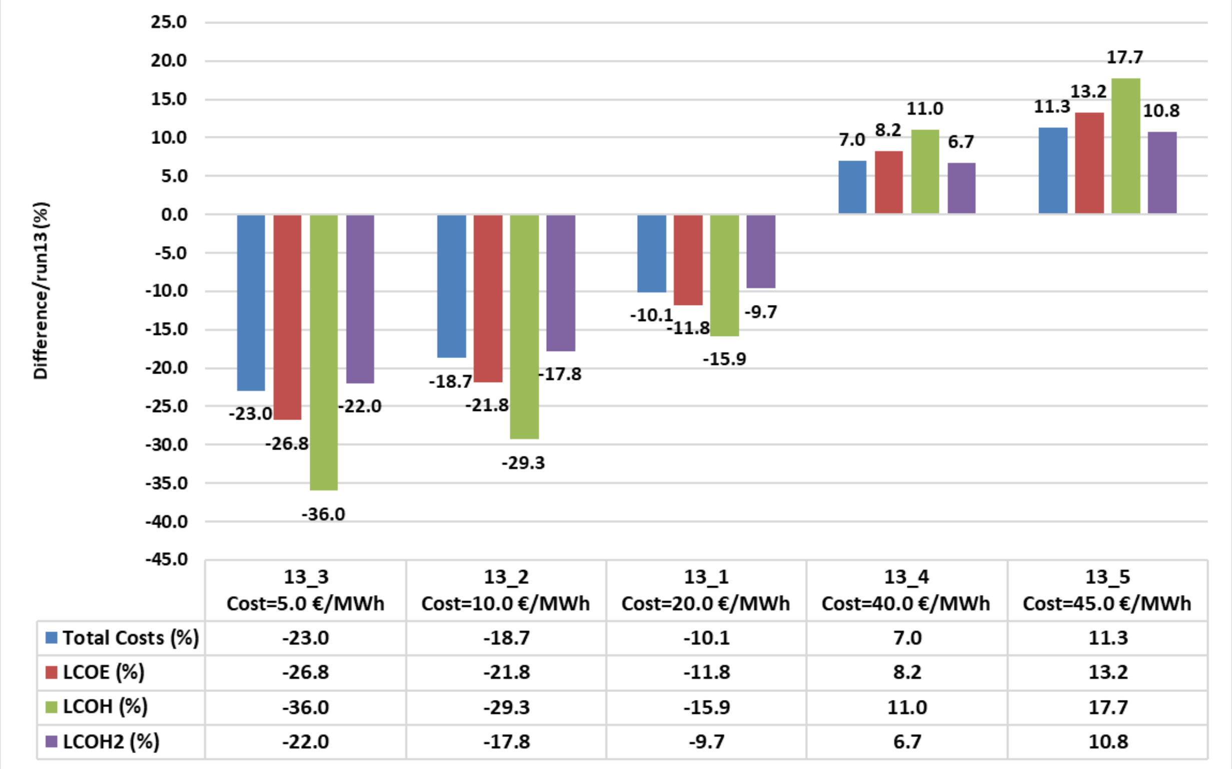
Funded by the European Union

3.3.3 Sensitivity study to the SMR variable cost

The reference variable cost for SMR is 31.8 €/MWhe. The following sensitivity studies are conducted. For each run, the system is sized and optimized with 2 SMR. Only the SMR variable cost is changed. The total CO_2 emission is imposed at the reference run13 value.

Parameter name	Unit	Values					
SMR – Variable cost	€/MWhe	5	10	20	31.8	40	45
Deviation from reference	%	-84.3	-68.6	-37.1	0	+25.8	+41.5
		13_3	13_2	13_1	13	13_4	13_5

Results and comparison with the reference case are given in the **Figure 60**. The PERSEE process finds the same component sizing and only the SMR variable and total costs are updated compared with the reference run13. The [5 €/MWe, 45€/MWe] range for the SMR variable cost – which corresponds to [-84.3%, +41.5%] compared to the reference value – leads to a deviation of [-26.8%, +13.2%] for the LCOE, [-36.0%, +17.7%] for the LCOH and [-22.0%, +10.8%] for the $LCOH_2$.



	13_3 Cost=5.0 €/MWh	13_2 Cost=10.0 €/MWh	13_1 Cost=20.0 €/MWh	13_4 Cost=40.0 €/MWh	13_5 Cost=45.0 €/MWh
🟦 Total Costs (%)	-23.0	-18.7	-10.1	7.0	11.3
🟥 LCOE (%)	-26.8	-21.8	-11.8	8.2	13.2
🟩 LCOH (%)	-36.0	-29.3	-15.9	11.0	17.7
🟪 LCOH2 (%)	-22.0	-17.8	-9.7	6.7	10.8

Figure 60: Sensitivity on the SMR variable costs

Funded by the European Union

3.3.4 Sensitivity study to the SMR heat recovery rate

The reference SMR heat recovery rate is 9.26% and corresponds to about 100 MWth (for run13). At the same time, the thermal power needed by the HTSE to produce the hydrogen is about 70 MWth (hydrogen production at 8760 kg/h). The purpose of the following sensitivity study is to analyse the decreasing of the SMR heat recovery rate and the equivalent electricity production increase and the technical, economic and environmental consequences on the system sizing and operation. The following table proposes the sensitivities to be evaluated and the thermal and electrical power and the electrical efficiency associated to the heat recovery rate (Hr_rate).

Parameter name	**Unit**	**Values**		
run		**13_2**	**13_1**	**13**
SMR – Heat recovery rate (Hr_rate)	**%**	**7.00**	**8.00**	**9.26**
Deviation from reference	**%**	**-24.4**	**-13.6**	**-**
Thermal power	MW	75.6	86.4	100
Electrical power	MW	317.3	314.0	310.0
Electrical efficiency		0.293	0.290	0.287

Figure 61: Sensitivity on the SMR heat recovery rate, main parameters

The PERSEE process is performed by sizing the CCGT, the PV field, the wind farm, the HTSE and the hydrogen and thermal storages and by optimizing the operation. The following table shows the sizing and the main results obtained by PERSEE.

Parameter	**Unit**	**13_2 Hr_rate=7.00%**	**13_1 Hr_rate=8.00%**	**13 Hr_rate=9.26%**
CCGT - Optimal Size	MW	46.1	44.7	44.0
H_2 Storage - Storage Capacity	tons H_2	102.4	136.0	149.4
HTSE - Installed Size	MW	388.6	385.8	385.3
PV Field - Nb unit	-	200	200	200
Thermal Storage - Storage Capacity	MWh	186.9	0	0
Wind Farm - Nb unit	-	15	17	19

Parameter	**Unit**	**13_2 Hr_rate=7.00%**	**13_1 Hr_rate=8.00%**	**13 Hr_rate=9.26%**
Total costs	bm€	4.042	4.076	4.139
LCOE	€/MWh	66.60	66.70	66.97
LCOH	€/MWh	21.72	19.89	19.55
$LCOH_2$	€/MWh	3.54	3.55	3.56
CI_E	kg CO_2 eq/MWhe	15.74	15.69	15.59
CI_H	kg CO_2 eq/MWhth	1.00	1.00	1.00
CI_H_2	kg CO_2 eq/kg H_2	0.61	0.61	0.61

Figure 62: Sensitivity on the SMR heat recovery rate, main results

Funded by the European Union

Figure 63 and the Figure 64 show respectively the total emissions per year in the system and the electricity mean sizing. As planned, the sum is identical for the three runs (run13 and the two sensitivities). The breakdown of the CO_2 emissions is representative of the PERSEE cost minimization and the maximum constraint of the CO_2 emissions. As the SMR electrical production is higher, the SMR CO_2 emissions increase The minimization of cost leads to a smaller wind farm.

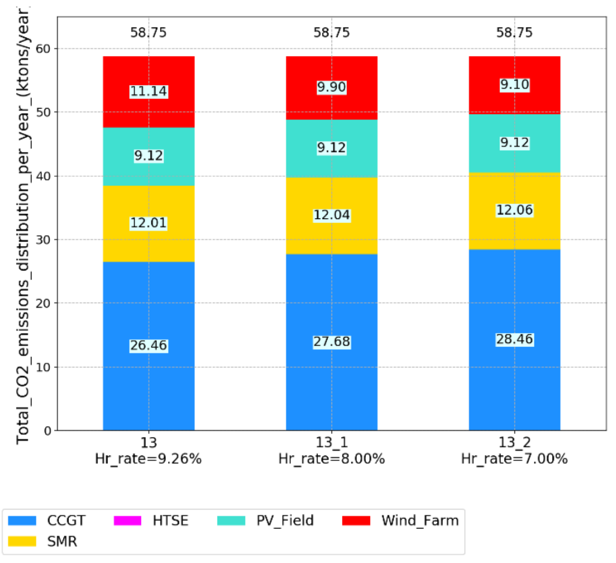


Figure 63: Sensitivity on SMR heat recovery rate, CO_2 emissions per year

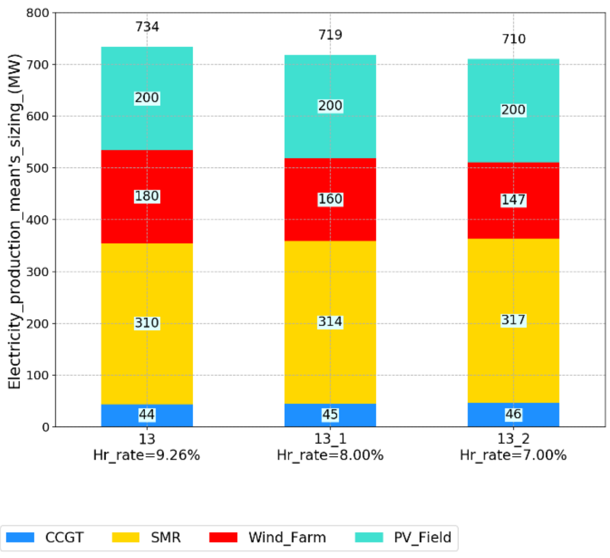


Figure 64: Sensitivity on SMR heat recovery rate, Electricity production means

The following figures (Figure 65, Figure 66 and Figure 67) illustrate the consequently cost and CO_2 intensities of the products (electricity, hydrogen and thermal energy). Electricity and hydrogen production costs slightly decrease as the wind farm is smaller. Thermal energy cost is higher for the 13_2 (7% heat recovery rate) as a thermal storage is added. CO_2 intensity of electricity is higher as CCGT commitment is greater than in the reference run. CO_2 intensity of hydrogen and thermal energy are very similar.

Funded by the European Union

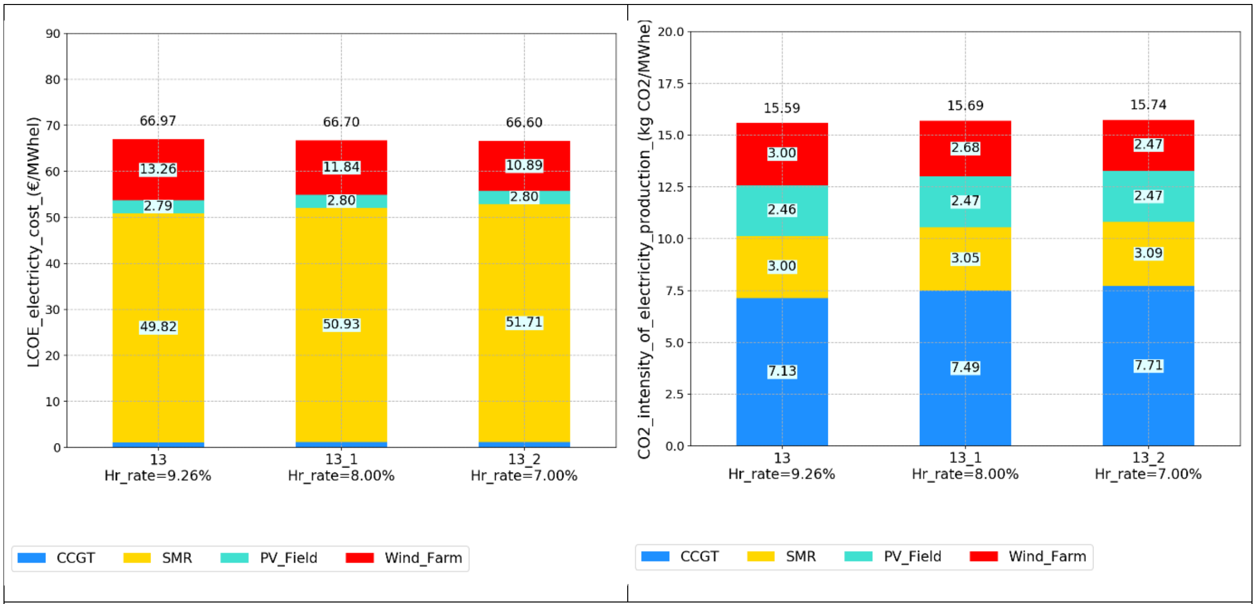


Figure 65: Sensitivity on SMR heat recovery rate, LCOE and CO_2 intensity

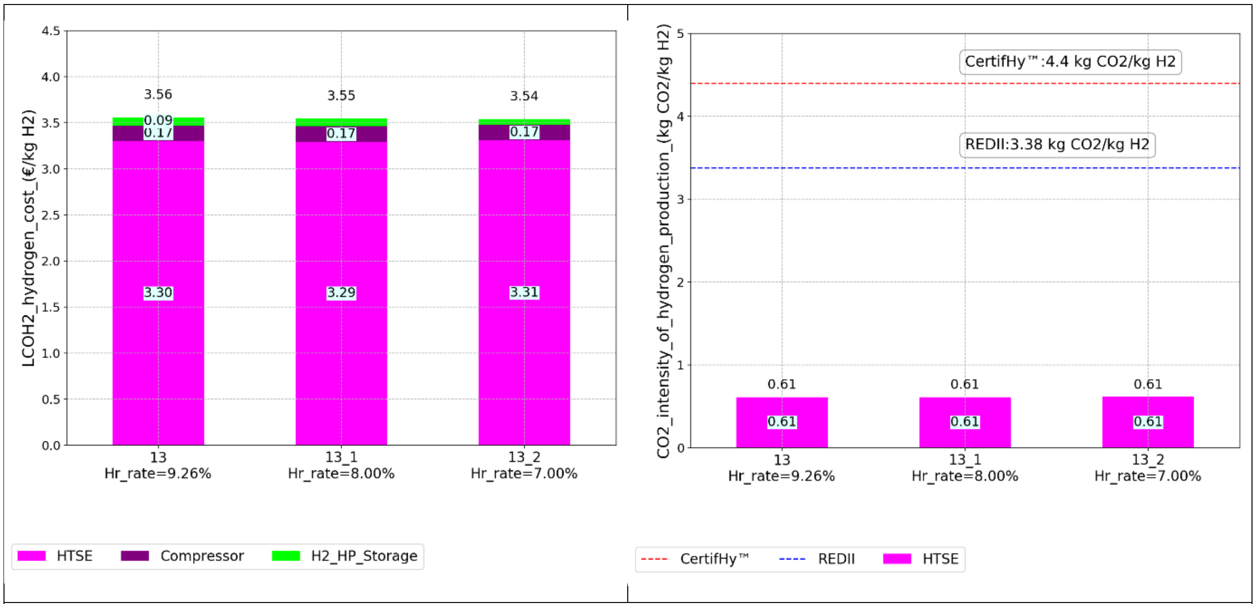


Figure 66: Sensitivity on SMR heat recovery rate, $LCOH_2$ and CO_2 intensity

Funded by the European Union

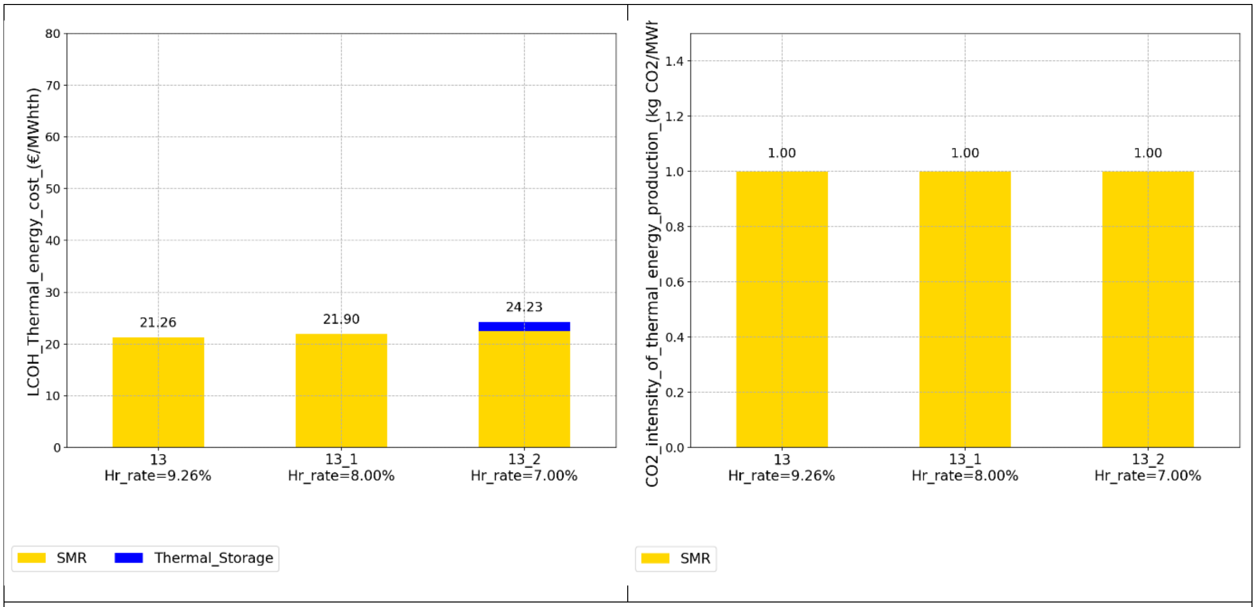


Figure 67: Sensitivity on SMR heat recovery rate, LCOH and CO_2 intensity

As a conclusion, the impact of decreasing the SMR heat recovery rate is negligible for the HES considered in this study. The SMR heat recovery cannot be strongly reduced as the HTSE thermal energy need is about 50 MWth. The lower value of the SMR heat recovery is about 7% considering this particular NHES.

3.3.5 Conclusions on the sensitivity analyses

In addition to analyses of other architectures aimed at improving the HES decarbonisation, sensitivity studies to price forecasts and key SMR input parameters were conducted.

The objective of the price forecasts sensitivity case was to analyse the impact of the gas price (year 2019 and 2022) on the technical, economic and environmental results of the selected scenarios. The results of the PERSEE optimization process is given in Figure 68. In all scenarios, the higher the gas price is, the less CCGT and SMGR are used. CO_2 emissions are then reduced but the total cost is higher and mainly for the “2035 without SMR” scenario. The less dependent to natural gas the system is, the more robust the results are in terms of LCOE and $LCOH_2$. As the HES is considered as islanded from the electrical network in most of the cases, it is not impacted by the potential increase of SPOT prices but only by the increase of natural gas prices.

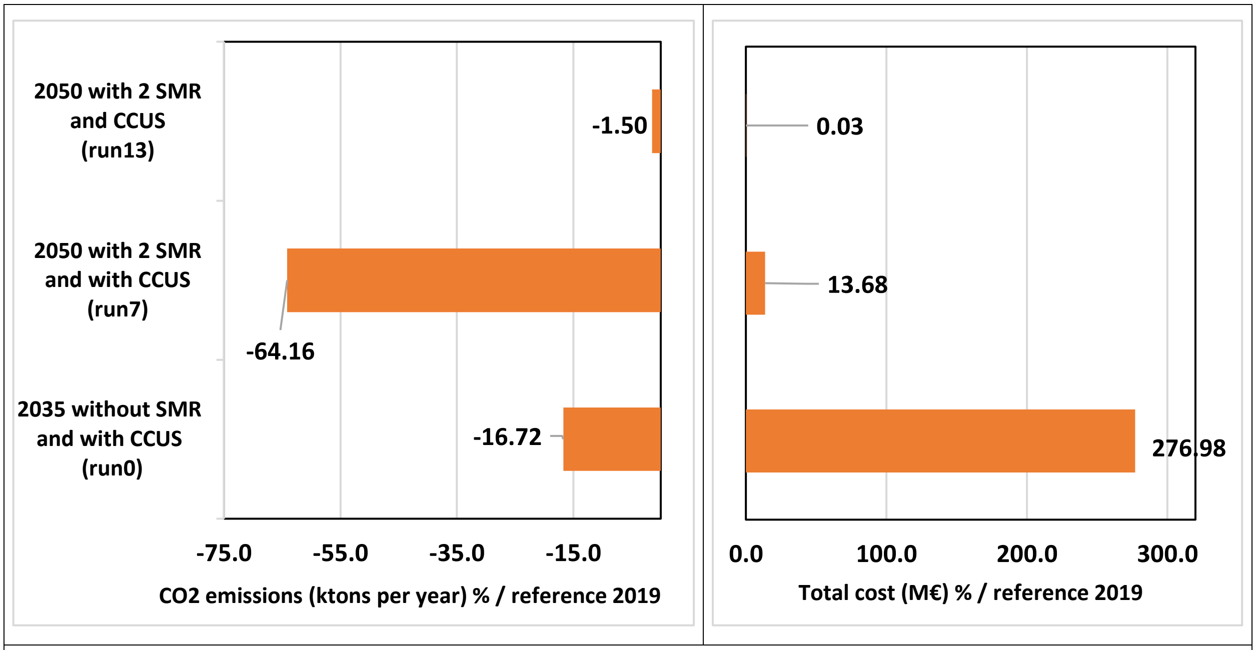


Figure 68: Sensitivity analyses on price forecast, CO_2 emissions and total cost

The sensitivity analyses to the SMR main input parameters consisted in the evaluation of the HES main results in the frame of the "2050 with 2 SMR and CCUS" on:

- The SMR economical parameters:
    - CAPEX in the range [-20%, +20%] in relation with the 6 050 €/MW reference data
    - Variable cost (includes the uranium cost) in the range [5, 45] €/MWhe whereas the reference value is at 31.8 €/MWh.
    - The SMR technical heat recovery parameter. D3.2 showed a too high heat recovery energy (9.26%): the heat excess was released outside the HES. In the sensitivity runs, this parameter was reduced (from 9.26 to 8 and 7%).

Figure 69 summarizes the sensitivity studies conducted on the main parameters of the SMR.

Funded by the European Union

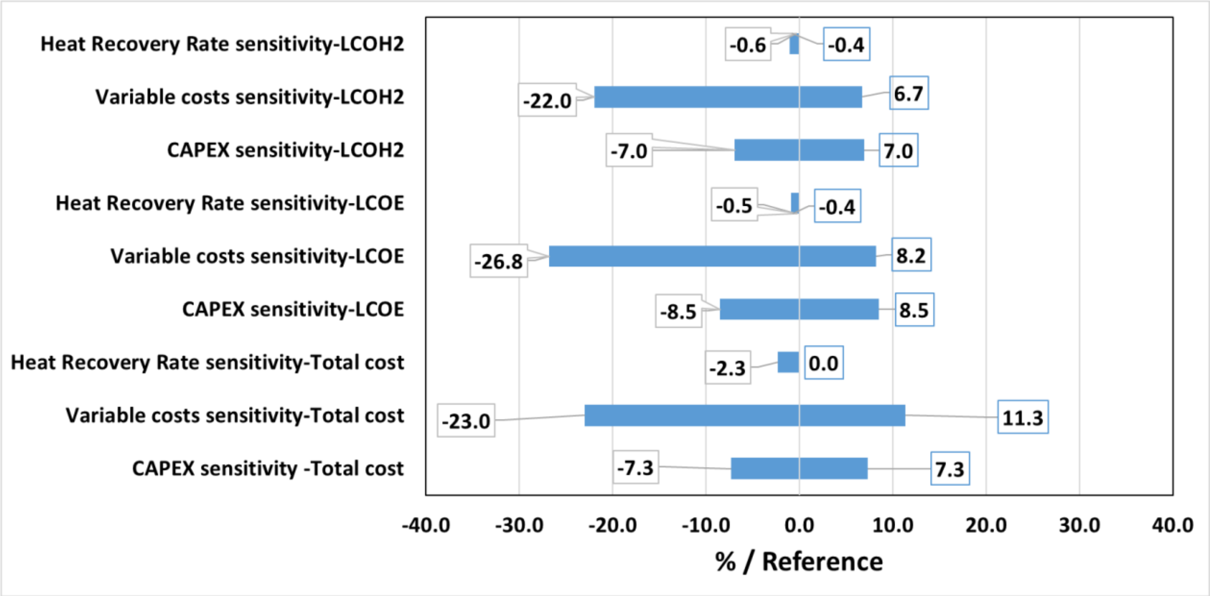


Figure 69: Sensitivity analyses on SMR input data, total cost, LCOE, LCOH$_2$ for “2050 with 2 SMR” scenario

The PERSEE optimization process did not change the sizing of the HES. Only the SMR and total costs are impacted. Sensitivities to SMR input data have more impact on electricity production cost than on the hydrogen cost. Among the selected parameters and ranges, the most influent is the SMR variable cost that leads to a deviation of [-23%, +11.3%] for the total costs of the HES.

Finally, the sensitivity conducted on the heat recovery rate of the SMR shows that there is a minimum to have a couple SMR – HTSE working properly (7%) but being a little bit higher than this minimum has a negligible impact on the results. Decreasing the heat recovery rate results in reducing the total cost.

4 Conclusions

4.1 Main conclusions on the Northern European case

As detailed in Deliverable D3.2, the Northern European case was studied from the perspective of a district heating operator in the Helsinki metropolitan area. While we model the district heat balance, we use electricity prices instead of modeling the electricity balance. The DH operator must produce heat while electricity is generated whenever it is profitable to be sold at the Nordic electricity market. Sensitivity analyses conducted in the Northern European case are performed on two LDR-50 modules and a single E-SMR module configurations.

Funded by the European Union

The model is based on current investment plans of companies in the Helsinki metropolitan area for the year 2030. The SMR technologies studied are still under development, with technological and economic parameters derived from current estimations. Therefore, the projected future scenario is subject to numerous changes and should be updated as necessary. The sensitivity analyses in this deliverable aim to study the potential impacts of foreseeable changes, such as variations in the capacity of planned data centers and heat storage facilities in the studied area, as well as changes in technological and economic factors affecting the SMR investments.

The Northern European case sensitivity studies provided valuable insights into the economic and technological factors affecting SMR profitability. Table 39 presents the summary of the modelled economic studies and the summary of their results. The variable cost of SMRs is quite low and the model utilized the SMR investments as much as possible reducing the use of fossil fuels and biomass. From the perspective of district heating operator, The E-SMR producing 10% of heat and 90% electricity would not meet the expectations for profitability for a district heating operator with the electricity profile and prices from the Helsinki case study . Furthermore, this study does not consider the value coming from services electricity producers provide such as stability to the grid or energy security. The heat producing LDR-50 was found profitable in most scenarios. Both SMR technologies improved electricity supply of the studied area: E-SMR produced electricity and LDR-50 reduced the use of heat pumps and electric boilers.

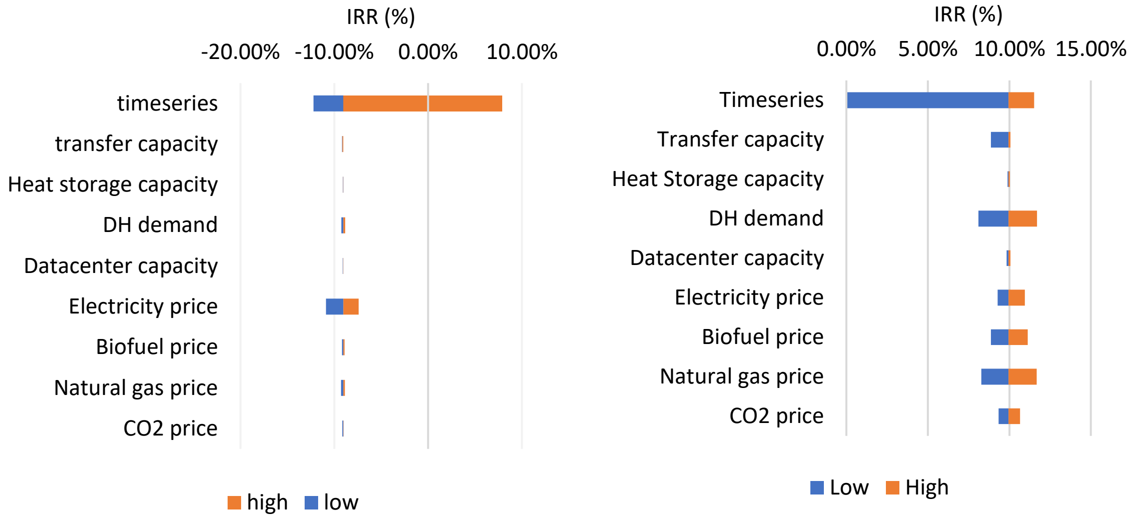
		E-SMR	LDR-50
	Sensitivity	IRR (%)	
Baseline SMR scenario	-	-9.1	+9.9
Investment cost	+ 50 % … -50 %	-10.7...-4.7	+2.4...+30.3
Operating cost	+ 50 % … -50 %	-11.7...-6.0	+8.3…+11.6
FOM (% of CAPEX)	+ 50 % … -50 %	-	+8.6…+11.6
Construction time	1–5 years	-8.2…12.1	+11.4…+5.6
Economic lifetime	+ 30 % … -30 %	-7.3...-12.7	+10.3…+8.2
Discount rate	+ 50 % … -50 %	-12.4...-5.5	+5.3…+15.3
Value at the end of the economic lifetime (% of CAPEX)	+ 30 % … -30 %	-8.4...-9.8	+9.9…+10.0
Heat extraction rate	+ 40 %	-4.3	-

Table 39: Economic and unit level sensitivity studies modelled for E-SMR and LDR-50 and the summary of their results.

Summary of E-SMR and LDR-50 results for modelled city- and system-level sensitivity analyses can be seen from Figure 70. The impact of energy market condition is extremely critical for SMR investments and should be studied thoroughly. Sensitivity analysis of timeseries years demonstrated this fact as E-SMR was able to find profitability in timeseries year 2022 scenario

Funded by the European Union

while LDR-50 went unprofitable during timeseries year 2016 scenario. However, it must be noted that the year 2022 had extremely high electricity prices and the year 2016 had lower prices for natural gas, biomass and CO2 credits. The economic factors such as investment cost, operating costs and discount rate are also crucial, especially the investment cost for LDR-50. Most SMR designs rely on passive safety systems, and the current regulatory framework might demand use of active safety systems to comply with safety regulations increasing the investment cost of SMRs.



(a) E-SMR (b) LDR-50

Figure 70: E-SMR and LDR-50 internal rate of return in modelled city- and system-level sensitivity analysis

It must be noted that the Helsinki metropolitan area is quite small when compared to other capital regions in Europe. The city size is important in determining the energy demand, and E-SMR is quite big for the studied area while the smaller LDR-50 modules can be scaled better to fit smaller cities. Sensitivity analysis of E-SMR heat extraction rate showed improvements in plant performance and profitability, and higher heat production lead to an increased value in the business plan for the context of the study. Helsinki metropolitan area is challenging environment with its seasonal fluctuations, however, integration to future energy systems such as electrolysers or direct air capture units could alleviate this problem by increasing the energy demand during summers, thus warranting further research on SMRs and nuclear power for decarbonization of energy systems.

4.2 Main conclusions on the Southern European case

Deliverable D3.2 gave the first order of magnitude of electricity, heat and hydrogen prices and CO_2 intensity around base architectures. Other analyses were run to shed additional light on previous results:

- Equipping the CCGT and SMGR with CCUS components for 2035 and 2050 scenarios (run0, run5, run7 and run13). It led to establish a new reference for "2035 no SMR" scenario.
- Using the electrical grid instead the CCGT for the "2035 without SMR" scenario.
- Improving the decarbonisation rate around the "2050" scenario by different means.
- Producing electricity and hydrogen with only RE with the help of hydrogen and electrical storages in the frame of the "2050 without SMR" scenario.

All the performed simulations show that the "2050 with 2 SMR" scenario give an autonomous HES without commitment of external energy sources (gas and electricity) with realistic renewable production (the RE footprints) and without distant and massive storage (hydrogen and CO_2).

4.3 Common findings from the cases and differences between the cases

Both case studies supplement and deepen the analysis in D3.2 by studying the impacts of alternative or supplementary investment options, and studying the impacts of price sensitivities and SMR parameter sensitivities.

A common conclusion was that other investments and investment options in the system have a significant impact on the outcome. This impacts especially the Northern European case where three DH utilities have transfer connections between the grids and investments of one company impact the profitability of the investments of other companies. Southern European case studied a large range of possible technologies for the HES architecture and different available technologies can lead to very different optimized capacities.

Another major common finding was the impact of used prices and time series year. Particularly 2022 had very high electricity and natural gas prices significantly impacting the investments in both cases. In reality, the investments would see many different years and the assessment could be made by using these example years with certain probabilities.

Both case studies also highlight the importance of economic assumption and high sensitivity of E-SMR study to assumed variable costs and investment costs. The Northern European case study shows that LDR-50 study was less sensitive to assumed variable cost, but very sensitive to assumed investment cost.

Funded by the European Union

Two major differences in the methodology between the studies were that Northern European case study assumed an existing system while Southern European case study optimized the whole capacity, and that the Northern European case modelled only the balance of heat while Southern European case modelled the balance of electricity, heat, and hydrogen. The approach of Northern European case study leads to smaller differences between the studied cases as most of the system is already existing and the same between the runs. On the other hand, the approach of Southern European case study can lead to a situation where assumptions on, e.g. hydrogen storage, might be more meaningful than assumptions on the SMR.

A significant different in the sensitivity analysis was that Northern European case benefited from the higher heat extraction rate of the E-SMR while a smaller heat extraction rate was better in the Southern European case.

Funded by the European Union

5 Appendix: TURPE calculation

TURPE6 is considered by taking into account three components: annual management component (CG), annual counting component (CC) and annual withdrawal component (CS). Medium voltage (HTA) is considered even if the power required by the electrical consumers is higher than the limit of 40 MW and it is assumed that the consumer does not inject power. For CS, only active power is considered and it is assumed that the power subscribed is respected.

$$CG = 399.48\ €/year$$

$$CC = 339.96\ €/year$$

$$CS = b_1 * P_1 + \sum_{i=2}^{5} b_i * (P_i - P_{i-1}) + \sum_{i=1}^{5} c_i * E_i$$

CS is more complicated to calculate. Five time windows are considered. In TURPE6, the windows are not defined at a national level anymore. Thus, the time windows of TURPE5 are assumed. There is a fix part linked to the power subscribed for each time window and a variable part linked to the energy consumed during each time window. To simplify, only one power is considered: the maximum power provided by the CCGT (even if it is not optimal) and the profile of the CCGT found in 3.2.1 is used to calculate the variable part linked to energy.

At the end, CG, CC and CS are divided by the total amount of energy produced by the CCGT in 3.2.1 to easily provide the TURPE6 to PERSEE.

Taxes: TVA is not considered as it can be refunded for companies. Only excise and transport tariff contribution are considered. In 2023, the excise is 20.5 €/MWh and CTA is 21.93% of the fix part of the TURPE for client connected to the distribution network.

6 Bibliography

[1] S. Crevon, G. Lavialle, A. Ruby, G. Cardoso, A. Goicea, F. Vobr, L. Zezeula, J.-P. Ikonen and O. Soppela, “D3.1 Definition of case studies for techno-economic analysis including some environmental aspects,” 2023.

[2] S. Crevon, G. Lavialle, T. Lindroos, J.-P. Ikonen, L. Zezula and F. Vobr, “D3.2 Presentation of dynamic techno-economic analysis for each study,” 2024.

[3] UNFCC, “Adoption of the Paris agreement Conference parties its twenty-first session,” 2015. [Online]. Available: Adoption of the Paris agreement Conference parties its twenty-first session.

[4] Statistics Finland, “Greenhouse Gas Emissions in Finland 1990 to 2019,” 2021. [Online]. Available: https://stat.fi/media/uploads/tup/khkinv/fi_nir_eu_2021_2023-03-15.pdf.

[5] Helen, “Helen proceeds towards non-combustion by launching a nuclear energy programme,” 2024. [Online]. Available: https://www.helen.fi/en/news/2024/helen-proceeds-towards-non-combustion-by-launching-a-nuclear-energy-programme.

[6] EIGA, “Overview of hydrogen production methods”.

[7] European Union’s Horizon 2020 programme, “The PilotSTRATEGY project (2021-2026),” [Online]. Available: https://pilotstrategy.eu/about-the-project. [Accessed 10 08 2024].

[8] BRGM, “Identification des sites potentiels de stockage de CO2 dans le Sud Est de la France et première estimation des capacités (projet VASCO - 2012),” 2012.

[9] OECD, ““Projected costs of generating electricity 2010 Edition”,” 2010.

[10] OECD, ““Projected costs of generating electricity 2015 Edition”,” 2015.

Funded by the European Union

[11] IEA, “The future of hydrogen,” 2020.

[12] IEA, Global Hydrogen Review, 2023.

[13] DECAGONE, 2024. [Online]. Available: https://decagone.eu/.

[14] N. Tauveron, D. Haubensack, P. Dumoulin and N. Alpy, “Hydrogen production by high temperature steam electrolysis coupled with a small modular reactor: cross-comparison between various thermal architectures,” in *ICONE-31*, 2024.

[15] ECHTHERM, 2024. [Online]. Available: https://greth.fr/echtherm/.

[16] S. Lemmens, “Cost Engineering Techniques and Their Applicability for Cost Estimation of Organic Rankine Cycle Systems,” *Energies,* 2016.

[17] M. Raya and A. Garcia-Prat, “Conceptualization of the public webtool for feasibility assessment of the CHEST system,” 2021.

[18] IFP Energies Nouvelles, “Launch of the FrHyGe project, an underground hydrogen storage demonstrator,” [Online]. Available: https://www.ifpenergiesnouvelles.com/article/launch-frhyge-project-underground-hydrogen-storage-demonstrator.

[19] G. Nasr and N. Connor, “Natural Gas Engineering and Safety Challenges: Downstream Process, Analysis, Utilization and Safety,” *Springer International Publishing.*

[20] European Hydrogen Backbone (EHB), “European hydrogen infrastructure vision covering 28 countries,” 2022.

[21] P. Castello, E. Tzimas, P. Moretto and S. D. Peteves, “Techno-economic assessment of hydrogen transmission and distribution systems in Europe in the medium and long term”.

Funded by the European Union

[22] O. Kanz, F. Brüggemann, K. Ding, K. Bittkau, U. Rau and A. Reinders, “Life-cycle global warming impact of hydrogen transport through pipelines from Africa to Germany,” *Royal Society of Chemistry,* vol. 7, no. 13, pp. 3014-3024.

[23] INERIS, “Maîtrise des risques liés au stockage souterrain de l'hydrogène,” 2023.

[24] S. Schlömer, Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P.Eickemeier, B. Kriemann, J. Savolainen, C. v. Stechow, T. Zwickel and J. Minx, “Annex III: Technology-specific cost and performance parameters. In: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change,” Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 2014.

[25] MIT, Czech SMR Roadmap Applicability and Contribution to Economy, 2023.

[26] MIT, State Energy Policy of the Czech Republic, 2014.

[27] MIT, MF, National Action Plan for the Development of the Nuclear, 2015.

[28] ČEPS, Hodnocení zdrojové přiměřenosti ES ČR do roku 2040, 2022.

[29] Photovoltaic Geographical Information System; https://re.jrc.ec.europa.eu/pvg_tools/en/tools.html#api_5.1.

[30] Renewables.ninja, https://renewables.ninja/.

[31] Siemens Energy, Large-scale industrial heat pumps, https://www.siemens-energy.com/global/en/home/products-services/product-offerings/heat-pumps.html.

[32] MIT, The Czech Republic’s Hydrogen Strategy, July 2021.

[33] W. Combaluzier, N. Tauveron, M. Beaughon et A. Serafino, «Decision-making matrix for the selection of mixture in ORC application,» chez *ORC2023 conference*, Sevilla, 2023.

Funded by the European Union

[34] A. d. Angelis, M. Frignani, C. Liegeard, J.-B. L. Velasco, P. Amphoux, F. David, M. M. Asenjo, V. Amzecua Pérez, M. Minchole Lapuente, O. Sevbo, A. Rantakaulio, K. Värri and &. all, “TANDEM D1.2 - Description and techno-economic characterization of the hybrid system components,” 2023.

Funded by
the European Union