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NC2I-R D411 Economic assessment and business modelling

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Summary

The European Commission is looking at cost-efficient ways to make the European economy more climate-friendly and more energy efficient. The European Commission has with its Roadmap set ambitious targets that, by 2050, the EU should cut its emissions to 80% below 1990 levels through domestic reductions alone.

In order to meet the targets for emission reductions CO_2 free and cost efficient technologies are needed to secure the cost competitiveness of European industries. The European economy has already seen the outsourcing of process industry into countries with less stringent environmental constraints. The nuclear co-generation demonstration aims to prove a concept for a CO_2-lean, competitive and reliable energy source for the process industry which could at the same time reduce CO_2 emissions, increase security of supply and secure the cost efficient energy source for the industry.

This report is an outcome of the preliminary economic assessment that has been carried out as a part of the Nuclear Cogeneration Industrial Initiative project. The task has been cooperated with tasks related to European sites mapping which has helped to finetune the business model options identified and the preliminary assessment has been provided as an input to demonstrator specifications and to enable to update and improve possible business models.

The evaluation of the industrial sector showed that an HTR (High Temperature Reactor) could fullfil EU requirements in CO_2 emissions reductions by serving process industry with continuous heat and electricity delivery to its processes. The chemical industry is foreseen to offer the best opportunities for the implementation of high temperature nuclear cogeneration in the near term. The chemical industry already uses cogeneration, the required temperatures correspond to the output of an HTR and the power capacity of several parks is large enough to be compatible with the size of an HTR. There is also a strong willingness to decrease the CO_2 emissions. In addition, moving toward nuclear cogeneration could be of strategic interest in order to increase independence from fossil fuel imports (especially gas) and also reduce uncertainty to price volatility with a long-term stability with a local heat production.

The hydrogen production, the CTL (Coal To Liquid) and the CCS (Carbon Capture and Storage) technologies were identified as potential applications for high-temperature nuclear cogeneration in a longer term. Suitable process have process temperatures between 450°C and 800°C which are compatible with an HTR's output temperature. The CCS technologies could be applied to highly-emissive industries such as the chemical, steel, cement and refining industries.

The economic assessment has identified the economic and financial parameters impacting the profitability of nuclear cogeneration. The assessment showed that with the prevailing price levels the HTRs are not competitive as electricity-only power plants against hydro, coal or large nuclear power plants. The HTR cogeneration can reach the level of profitability if it replaces gas-fired heat boilers and if the electricity production from the HTR plant is replacing the electricity purchase from the grid when the transmission costs and possibly also renewables tax can be avoided. The most critical parts affecting the feasibility of the plant are the availability of the plant, interest rate, investment costs, and heat prices.

Higher heat price adds a significant NPV increase to the project. Heat price is mainly affected by alternative production costs for heat i.e. costs of coal, oil and gas as well as by CO_2 costs.

Design adaptation and licensing costs may challenge the viability of an HTR cogeneration project. A licensing process based on a generic design assessment should strongly favour such project and therefore a

standardization of regulation and licensing procedures at European level should be one of the main priorities when developing the HTR concept further.

The best near-term opportunities can be found from HTR powering a chemical park. Integration of nuclear actors downstream in the value chain as Energy Manager would mean that the counter parts for a chemical park would be less numerous and it could concentrate on its core business. The energy manager could also be in charge of additional services e.g. waste management and raw material supplies enabling the industry to outsource all the activities that are not part of their core business. A successful business concept requires a long-term energy delivery to the site which would for one guarantee the high availability of the HTR and the payback of the investment. Therefore the size of the selected reactor should be a good fit with the heat demand of industrial customer or the nearby city in the case of district heating.

Poland would be an excellent country for a demonstration although there are no commercial-scale nuclear power plants in operation. Poland has notable coal and chemical industry besides the energy knowledge and CTL and the CCS technologies could be interesting CO_2 free technologies for the future. By adding nuclear to an energy mix, Poland could also decrease its dependency on imported fuels and increase the security of its energy supplies. Also one of the most influential factors for the HTR plant feasibility in Poland is the possibility to use the produced electricity on site, instead of selling it to the grid.

There is a current trend towards emission-free generation, that could be the initiator of a strong CO_2 policy. Profitability of an HTR significantly increases with higher CO_2 prices, and would be a credible alternative, from both technical and economic aspects, especially for clusters where coal is the primary fuel source. Risks of new technology and markets can be shared through long-term contracts or by sharing the ownership with relevant parties. With nuclear cogeneration from HTR different needs of the market players can be met. The process industry needs CO_2 free electricity and heat to its processes with competitive price level, utility needs the electricity to be delivered to its customers and in some locations also district heat. A vendor of HTR technology needs a demonstrator for its technology to prove the suitability of an HTR in a long-term energy efficient and CO_2 free energy production.

Approval

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Table of contents

1 Introduction

Process industries continuously optimize strategies to be able to thrive. New industrial plants are built close to fossil resources. The European economy has already seen the outsourcing of process industry into countries with less stringent environmental constraints. With a nuclear co-generation demonstration, Europe has an opportunity to create a CO_2-lean, competitive and reliable energy alternative for process industry. It will strengthen the position of industry in Europe and assist it in global competition, and help maintaining the positive contribution that industry has to European economy and way of life.

This report is an outcome of the task of the preliminary economic assessments that has been carried out as a part of the Nuclear Cogeneration Industrial Initiative project. The task has been cooperated with other tasks related to European sites mapping which has helped to finetune the business model options identified and the preliminary assessment has been provided as an input to demonstrator specifications and to enable to update and improve possible business models.

The economic assessment has identified the economic and financial parameters impacting the economic viability of nuclear cogeneration. The basis for this work has been the EUROPAIRS market study and pre-economic viability assessment. The economic and financial parameters has been defined and sensitivity analyses has been produced on these factors.

In order to assess the condition for competitiveness of nuclear cogeneration, an economic model was issued in this work. The purpose was to evaluate the influence of the main economic parameters for an HTR project. This evaluation aims to provide inputs and justifications for the specification of a demonstrator. This demonstrator shall consist of an industrial process coupled to a nuclear heat source and shall demonstrate the viability in terms of technology, economy and safety. It is focusing on the use of HTR technology, drawing from the large European experience. Optimally, this demonstrator would be a first-of-a-kind, after which the next steps to deployment are taken on a commercial basis by duplication with minor adjustments. The financing of a nuclear cogeneration plant, and of a commercial plant (NOAK), has also been addressed in this task.

Apart from the Chinese HTR-PM project currently under construction, no high temperature reactors have been constructed for more than a decade. Therefore, almost no empirical technical and economic data exists for HTRs. However, to ensure a consistent basis for the economic evaluation of a HTR for industrial cogeneration, this work creates a reference case based upon technical and economic data.

2 Industrial process heat market

2.1 Introduction

During the EUROPAIRS project, a market study was conducted to describe the industrial heat market in Europe. The utilisation of heat in different industries was depicted and quantified. The industries included:

- Oil refining & chemical sector
  - Oil refining sector
  - Chemical clusters
  - Ammonia, urea and fertilizers industry
  - Soda ash production
- Industrial gases
  - Hydrogen production
  - Air gases production (oxygen, nitrogen, argon)
- Pulp and paper industry
- Metals and minerals
  - Alumina and aluminium production
  - Iron and steel industry
  - Lime industry
  - Glass, cement, ceramics and non-ferrous metals (Lead, zinc)

Industrial heat market offers opportunities to HTR applications. The purpose of this section is to:
- Update the previous heat market study: what is the situation for the applications identified 4 years ago? Several innovations were expected; are they developed? Do they have an impact on the profile of the heat industry?
- Identify new applications that might be developed in the timeframe 2030-2050 and will represent a heat market for High Temperature (HT) nuclear cogeneration.

This section aims at giving an overview of the current market applications with mainly qualitative and some quantitative information. The update of the market study identifies the applications for which changes have been observed and new potential applications.

2.2 Main conclusions of EUROPAIRS heat market study

The EUROPAIRS study conducted between 2009 and 2011, revealed that the European industrial heat market is large, ranging from 2 526 to 3 091 TWh/y (corresponding to an equivalent 289 GWth to 353 GWth). Approximately 25% to 30% of the market is externalised in the form of co-generation and the remaining 70% to 75% is consumed in embedded process burners and boilers. Quantitatively, the heat market is more important at temperatures below 550°C and above 1 000°C.

Europe is an attractive market since it has experience in commercialising nuclear co-generation and good industrial infrastructures with strong companies. Furthermore, the European energy policy context promotes and tries to develop alternative low-carbon solutions.

The industrial heat market was segmented as follows:
- The plug-in segment: it covers all existing cogeneration plants supplying one or more industrial facilities.
- The extended segment: it covers all boilers and burners operated internally within an industrial facility and/or embedded directly into the production processes

Two hypothetical submarkets were identified:
- Polygeneration refers to the co-production of base-raw materials beyond the sole cogeneration of heat and electricity, such as industrial gases (e.g. hydrogen, oxygen).
- Pre-heating considers the share of the extended market that could be technically externalised if a low-carbon, competitive high temperature steam was available.

Based on roadmaps delivered by the European Commission and interviews conducted with experts from different industries' European platforms, the following applications were identified as of interest for the purpose of this update: the steel industry, the chemical industry, the production of hydrogen, the Coal-To-Liquids (CTL) process and the development of Carbon and Capture Storage technologies.

2.3 STEEL

2.3.1 Reminder EUROPAIRS

The steel industry is not included in the plug-in market but nuclear energy may be used in existing furnaces supplying syngas from nuclear assisted Steam Methane Reforming (SMR) or partial oxidation. Another possible outlet considered for nuclear energy was heat used for air-preheating and oxygen production through high temperature processes.

Finally, breakthrough concepts were mentioned, especially the ones developed under the ULCOS (Ultra Low CO_2 Steelmaking) consortium but the use of heat in these concepts was not investigated.

2.3.2 Evolution

The reduction of CO_2 emissions in the steel industry requires new processes. Indeed, over the past 40 years, the European steel industry has decreased its CO_2 emissions from 50% to 60%, reaching high level of energy conservation. Further reductions are only possible through innovative processes. These processes are investigated in a large R&D program called ULCOS initiated in 2004. After years of research, 3 main paths are under consideration to reduce CO_2 (Birat, 2009):

- Shift away from coal, called decarbonising, in which carbon would be replaced by hydrogen and/or electricity
- Introduction of the Carbon Capture and Storage (CCS)
- Use of sustainable biomass.

These different pathways led to the development of several innovative processes. The most promising one is called the **Top Gas Recycling Blast Furnace** (TGR-BF). The TGR-BF relies on the separation of the off gases on top of the blast furnace so that the useful components can be recycled back into the furnace and used as a reducing agent (ULCOS, 2015). According to a workshop organised by the IEA in 2013, the likely requirement for additional heat is high. The redesign of the blast furnace (BF) removes the availability of BF gases for on-site heat and power production whilst simultaneously increasing the power and heat demand for cooling and compression (IEA, 2013).

After a successful test facility in Sweden (32t/d), the concept was supposed to be scaled-up at 1Mt/d on the site of Florange. However, due to current economic context of the steel industry in Europe (the European production of steel has decreased of about 15% since 2007, before the financial crisis (OECD, 2014)), the project was stopped - no industrial actors being willing to finance a large scale innovative process. Nevertheless, the technology still presents great advantages for the objective of reducing CO_2 emissions.

Other processes are also under investigation

- The HIsarna process, based on bath-smelting, combines coal preheating and partial pyrolysis in a reactor, a melting cyclone for ore melting and a smelter vessel for final ore reduction and iron production. As the coal usage is reduced, the CO2 emissions are reduced as well. The energy of the HIsarna off gas is recovered in a waste heat boiler. Heat and electricity can then be reused in the process (ULCOS, 2015). Currently the HIsarna process is being tested in a pilot facility in the Netherlands, the initial investment being much lesser than the one for TGR-BF due to a smaller scale demonstration.
- The ULCORED process is based on Direct-Reduced Iron (DRI) produced from direct reduction of iron ore by a reducing gas produced from natural gas. The reduced iron is in a solid state and for melting it, an Electric Arc Furnace (EAF) is required (ULCOS, 2015). Thus, high amount of electricity is required. The ULCORED process is today quite left out, the pilot phase being constantly postponed.
- The ULCOWN/ULCOLYSIS processes are based on the electrolysis of iron ore. This concept allows the transformation of iron ore into metal and gaseous oxygen using only electrical energy (ULCOS, 2015). This concept is the least advanced; it was proven at a laboratory scale but no industrial pilot demonstration is expected before 2020-2030.

2.3.3 Potential for high-temperature nuclear cogeneration

In the frame of the ULCOS project, different innovations are being developed for the manufacturing of iron. The development of the most advanced one, the TGR-BF, is currently stopped because of the economic context of the iron industry. Compared to the others, the TGR-BF is the process that requires the most additional heat.

However, even if the other processes require more electricity than heat, in any case the iron industry could be interested by a nuclear heat, either as a potential heat source for the fusion energy or for other steps in the iron making process (lamination, reforming, etc.). The temperature required for the iron manufacturing is at least 1,000°C but nuclear heat at 800°C can act as a pre-heating energy completed by another source of heat (high-temperature heat pump for example).

2.4 CHEMISTRY

2.4.1 Reminder EUROPAIRS

The chemical industry was considered as a preferred application for the implementation of the HTR technology for several reasons:

- The heat market in Europe for the chemical industry is large, estimated at 52 102 GWh/y (EUROPAIRS, 2011).
- The great majority of the chemical parks in Europe already have cogeneration plants, mostly powered by natural gas or coal. The chemical industry is part of the plug-in market (applications that already use cogeneration plant to power the plants) which makes the implementation of an HTR cogeneration easier.
- The required temperature of process heat is compatible with the output temperature of an HTR (between 450°C and 550°C).
- The chemical industry is organised in clusters or parks on which several industries can be implemented. The resulted power capacity is large and compatible with the power capacity of an HTR (between 100MWth and 500MWth).
- The chemical parks already use boilers and burners which can be useful during the operation and maintenance of a nuclear reactor, to maintain a power source for the park.

2.4.2 Evolution

The profile of industrial chemistry will not radically change in the 2030-2050 timeframe. Of course, there is a rise of consciousness to reduce Greenhouse Gas (GHG) emissions and save energy. This evolution will lead to changes within one cluster but the number of clusters and their respective size should be similar to the present ones. The evolutions that are forecasted in the next 20 years are the following (SPIRE 2030, 2013):

- The development of energy harvesting and re-use of waste heat through low and high temperature heat pumps.
- The use of more efficient systems and equipment, which requires tore-think design of process equipment and systems that can be integrated as a novel component in existing processes (e.g. new furnaces, ovens, grinding techniques, etc.).
- Development of the Carbon and Capture Storage (CCS) techniques (see dedicated section)
- Optimum design for electrical generation system by integrating renewable energy Combined Heat and Power (CHP) & storage systems.
- Combining heating hybrid alternative ways of high temperature technology using electricity and biomass.

The evolutions presented **above show a willingness to make a better utilisation of energy through energy harvesting, re-use of waste and storage, a need to improve processes and equipment to avoid losses and improve energy efficiency and finally, a move from fossil fuels towards more renewable and low-carbon energy sources.** However, nuclear energy and its advantages are not well known by the chemical industry's stakeholders and a dialog must be opened (probably through the NC2I Business Group).

2.4.3 Potential for High-Temperature cogeneration

Today, the energy issue is crucial for the European chemical industry. To remain competitive, the chemical industry will have to make modifications into internal processes to increase its energy efficiency. However, the size and location of the chemical parks are not forecasted to change. A shift towards more renewable energy is considered (wind, solar, biomass). Nuclear cogeneration is also a possible solution for the future chemical industry's requirements, especially in terms of GHG emissions' reductions.

2.5 Hydrogen, H2

2.5.1 Reminder EUROPAIRS

The hydrogen market was considered as a viable market in the EUROPAIRS study. Indeed, hydrogen is used in multiple applications, mainly in refineries but also in the ammonia production or in the chemical industry. The current hydrogen production is above 65 million tons per year (IEA, 2007). Moreover, the emerging market using hydrogen in fuel cells is increasing; hydrogen consumption for non-traditional applications is estimated to grow from 0.168 million ton in 2013 to nearly 3.5 million tons in 2030 (Navigant Research, 2014).

The main producing route for hydrogen is the steam methane reforming (SMR) since it is by far the most competitive technology, but numerous other producing routes exist. Two were particularly of interest during the EUROPAIRS study: the high temperature electrolysis and the thermo-chemical cycles.

The **SMR process** requires process heat between 700 and 800°C, which might be compatible with an output temperature of an HTR. The **electrolysis** can take place at low temperatures but, in this case, the electricity requirement is so high that this solution cannot be economically competitive. On the contrary, in the high temperatures range of 800-1000°C, electricity input could be about 35% lower than that of conventional electrolysis (IAEA, 2013).

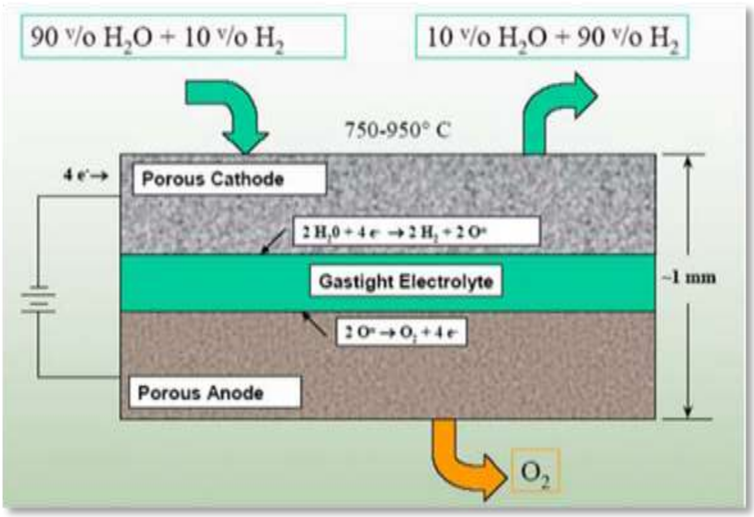

Figure 2-1. Schematic of a planar steam electrolysis cell (IAEA, 2013)

The last technology considered in the EUROPAIRS study was the **thermochemical cycles**. It consists of a series of thermally driven chemical reactions where water is decomposed into hydrogen and oxygen at moderate to high temperatures. The most promising process is the sulphur-iodine (S-I) process, in which three chemical reactions are conducted, as shown below:

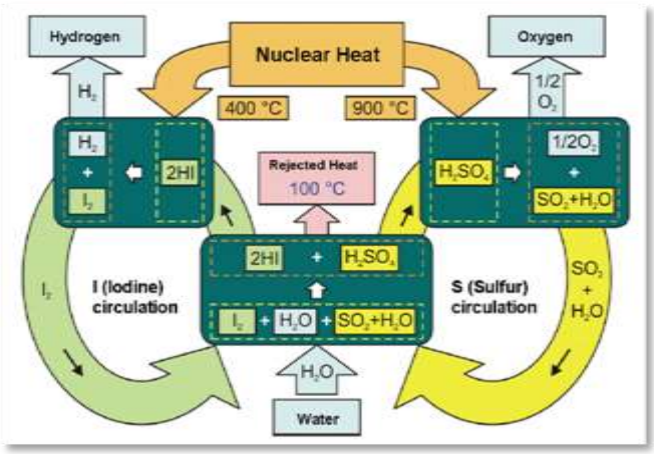

Figure 2-2. Schematic of the S-I thermochemical water splitting cycle (IAEA, 2013)

In this thermochemical cycle, on one hand, heat is required at 400°C to split hydrogen iodide into hydrogen and iodine; heat at 900°C is required on the other hand to recover sulphur dioxide.

2.5.2 Evolution

Projects on innovative production processes for hydrogen are still ongoing and are gathered under the umbrella of the FCH-JU platform (Fuel Cells & Hydrogen – Joint Undertaking). The FCJ-JU platform was established in May 2008 as a public-private partnership between the European Commission, European industry and research organisations, to accelerate the development of fuel cell and hydrogen technologies. On 6th May 2014, **the Council of the European Union formally agreed to continue the FCH-JU Initiative under the EU Horizon 2020 Framework Programme.** The budget allocated to the phase 2014-2020 reaches a total budget of 1.33 billion €, provided on a match basis between the European Commission, industry and research (FCH-JU, 2015).

The projects of the second phase of FCH-JU (FCH 2) are separated into two pillars:

- Innovation Pillar 1: FCH Technologies for Transportation Systems
- Innovation Pillar 2: FCH Technologies for Energy Systems

The second pillar is also divided into two areas: the hydrogen production from renewable electricity for energy storage and grid balance, and the hydrogen production with low carbon footprint from other resources and waste hydrogen recovery.

The HT water splitting and the HT electrolysis constitute the main technologies of the second areas. The Technology Readiness Level (TRL) for both technologies was estimated at 3 at the end of 2012.

2.5.3 Potential for High-Temperature Cogeneration

The context of hydrogen production has not much changed since the EUROPAIRS market study. **The main production process used to produce hydrogen is the Steam Methane Reforming process. Research on other innovative processes, especially HT water splitting and HT electrolysis is being conducted.**

High Temperature nuclear cogeneration could be used in the three processes mentioned above: SMR, HT electrolysis and HT water splitting (thermo-chemical cycles).

2.6 Coal-To-Liquid, CTL

2.6.1 Applications

The Coal-To-Liquid application is a relatively new technology. Today, liquid fuels from coal appear as a viable alternative to conventional oil products. Indeed, Liquid fuels from coal present interesting advantages by providing ultra-lean transport fuels for use in the existing vehicle fleet. These coal-to-liquid fuels would be delivered through existing infrastructure. Moreover, the Coal-derived fuels are sulphur-free, low in particulates, with low levels of oxides of nitrogen. The main drawback of the use of coal-to-liquid fuels is the carbon dioxide emissions. CTL partisans claim that they can be reduced with the use of carbon capture and storage.

Other minor applications concern cooking (for ultra-clean coal derived fuels), stationary power generation and the chemical industry (in this case, the liquid is used as feedstock).

2.6.2 Context & trends

After the 1980s, a number of demonstration CTL units have been built worldwide, with extensive work in Japan and in the US. In Europe, most of the research programs were carried out in Germany and in the UK. Much of this work was stopped in the 1990s because of the relatively low oil price. Over the past years, because of the increasing level of oil prices, coal liquefaction has been reconsidered and several units are now under construction or planned in various countries.

China is the most advanced country with a program including: the Shenhua Direct Coal Liquefaction (DCL) plant with a capacity of 6 kt coal per day (1.4 GWth) producing 1 Mt/y of liquid products (operation tests completed in 2008); the Yitai Indirect Coal Liquefaction (ICL) plant (0.22 GWth) producing 160.000 t/y of liquid products (operation tests in April 2009); and several additional ICL plants being planned or built (IEA ETSAP, 2010).

In the US, the market for coal liquefaction depends on future policies regarding CO_2 emissions. Facilities without CO_2 capture and storage are unlikely to be commissioned, although highly desired for improving supply security for transport fuels and reducing oil import dependence. A large CTL plant that was planned to be operational by 2011 for producing fuels for the US army has been cancelled for safety and environmental reasons (IEA ETSAP, 2010).

Nowadays, the world's CTL production capacity is estimated at around 15GWth and is almost entirely located in South Africa (DOE, NETL, 2007).

2.6.3 Production routes

Two main processes are used today for coal liquefaction: the Direct Coal Liquefaction (DCL) and the Indirect Coal Liquefaction (ICL).

Direct Coal Liquefaction (DCL)

This process involves dissolving coal in a solvent at high temperature and pressure (around 450°C and 170 bar). A hydrocracking step follows the first dissolution (i.e. hydrogen is added over a catalyst).

There are two main variants of Direct Liquefaction Processes, depending on whether or not the initial dissolution of the coal is separated from the conversion of the dissolved coal into distillable liquid products.

- A single stage liquefaction process provides distilled liquids (distillates) through one primary reactor or reactor chain.
- A two-stage process provides the distillates through two reactors or reactor chains. The first reaction dissolves the coal either without a catalyst or with a low activity disposable catalyst, producing heavy coal liquids. In the second reactor, further treatments using hydrogen and a high-activity catalyst are used to produce additional distillates.

The Shenhua Group Corporation started the construction of the world's first commercial direct coal liquefaction plant in 2003. It is now operating and produces around 1,000 kta of fuel oil per year (China Shenhua Coal to Liquid & Chemical Engineering Company, 2012).

The main advantage of the DCL process is that liquid yields can be in excess of 70 % of the dry weight coal feed, with thermal efficiencies of around 60-70 (IEA ETSAP, 2010).

Indirect Liquefaction

Indirect liquefaction involves two major steps in the process

- The gasification of coal leading to the complete breakdown of the coal structure using steam. This first reaction is performed at very high temperature and pressure (800°C-1,000°C, 10-100 bars).
- The Fischer-Tropsch (FT) synthesis which transforms synthetic gas into hydrocarbons. Depending on the final products desired (gasoline or diesel), the FT synthesis operates at different temperatures between 200°C and 350°C. A Methanol synthesis can be used as an alternative route to the FT synthesis.

The ICL process is currently used in the SASOL Secunda CTL plant in South-Africa, producing 150,000bbl/d of liquid fuels and petrochemicals from coal (IEA Coal Research, 2009).

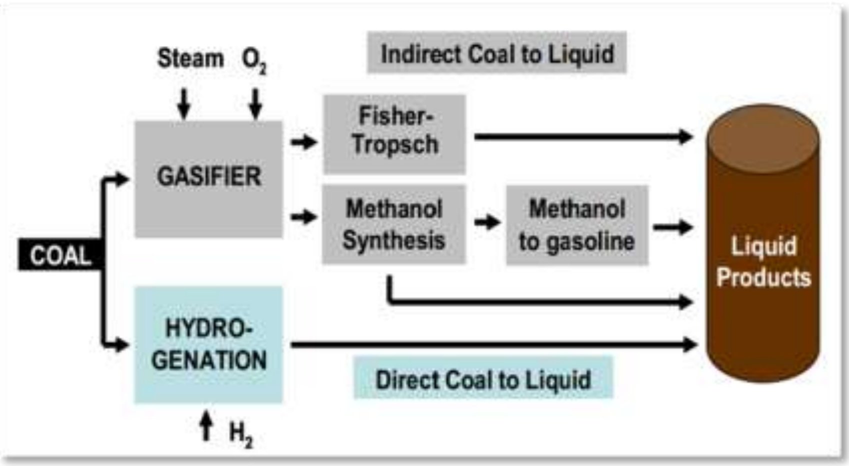

Figure 2-3. Principal process routes for the production of liquid fuels from coal (IEA ETSAP, 2010)

2.6.4 Heat demand profile

The heat demand depends highly on the process used for coal liquefaction.

Indeed, the DCL process requires heat at 450°C while the ICL process requires steam at 800°C for the first gasification, the second step being performed between 200°C and 350°C.

2.6.5 Opportunities for high-temperature cogeneration

The CTL technology does not represent for now an opportunity for nuclear cogeneration since only one industrial plant is in operation in South-Africa. However, due to the increasing price of oil in the last 10 years, there has been **a revival of interest over the last few years concerning the coal liquefaction.**

Nevertheless, this process is under development; the required amount of heat needs to be further investigated to determine whether or not a nuclear reactor could power a CTL plant. Like for the oil refining industry, the presence of hydrocarbons close to a nuclear reactor may raise safety issues that constitute a negative point when comparing nuclear cogeneration to cogeneration based on other fuels. **Moreover, if the efficiency of a cogeneration plant is demonstrated, nuclear cogeneration will have to face the coal-cogeneration competition. Indeed, in a CTL plant, coal used as feedstock would perfectly be used as fuel for the cogeneration plant (it would make easier logistics and safety issues).**

The Indirect Coal Liquefaction process requires steam at 800°C and so, could be compatible with HTRs' output temperature (depending on HTR's characteristics). **The Direct Coal Liquefaction requires temperatures around 450°C** and could represent as well a potential application for HTR (temperature similar to the chemical industry).

2.7 Carbon Capture and Storage, CCS

2.7.1 Applications

CCS refers to the capture, transport and storage of CO_2 that would be otherwise have been emitted from commercial facilities excluding the power sector. Once captured, the CO_2 is either geologically stored to permanently isolate the CO_2 from the atmosphere, or can be utilised in industrial applications.

The main industries that are looking at these technologies are:

- Refining
- Chemicals
- Cement
- Iron and Steel

Indeed, these sectors are projected to increase their combined emissions by one third by 2050, being responsible for between 21 and 23% of global CO_2 emissions under current policies. Moreover, these sectors are affected by the existing climate mitigation policies and thus must face the prospect of regulatory costs, calculated according to their emissions intensities. As a result, the CCS solution represent for these sectors a crucial opportunity to cuts in emissions and they all have political and economic motives for developing this technology.

2.7.2 Context & Trends

The reduction of CO_2 emissions has become a major environmental issue. The CCS technology provides a complementary solution to renewable or nuclear energy sources.

The US oil industry has already been transporting and injecting CO_2 for several decades to enhance oil recovery. The first CO_2 pipeline was commissioned in 1972 in the US, where there are now more than 6000km of CO_2 pipelines.

According to the Global CCS Institute, there are **13 large-scale CCS projects in operation worldwide and 9 under construction** (Global CCS Institute, 2015). The CCS technology is quite a trendy technology insofar as these 22 projects represent an increase of 50% in the number of large scale CCS projects since 2010. In Europe, the UK has strong experience in the CCS technology applied to the oil sector with North Sea oil and gas operations. In April 2012, the UK government launched the new **CCS Commercialisation programme** and the UK CCS Roadmap to support practical experience in the design, construction and operation of CCS.

CCS in the power industry is also a reality as it has been demonstrated in the world's first large-scale power sector CCS project in Canada operational since October 2014 – the Boundary Dam Integrated Carbon

Capture and Sequestration Demonstration Project. The CCS is coupled to a refinery and uses the post-combustion capture technology.

2.7.3 Technical solutions

There are three main generic types of CO_2 captures (CCSa, 2015):

Pre-combustion

This technique implies converting fuel into a mixture of hydrogen and carbon dioxide using one of a number of processes such as “gasification” or “reforming”. The CO_2 is then separated from the hydrogen and ready for transport and storage. The hydrogen may then be used as fuel or for electricity production.

Figure 2-4. Pre-combustion process (CCSa, 2015)

Post-combustion

In this technique, CO_2 is captured from the exhaust of a combustion process by absorbing it in a suitable solvent. The absorbed CO_2 is liberated from the solvent and is compressed for transportation and storage. Other methods for isolating CO_2 exist and include adsorption/desorption processes, high-pressure membrane filtration and cryogenic separation.

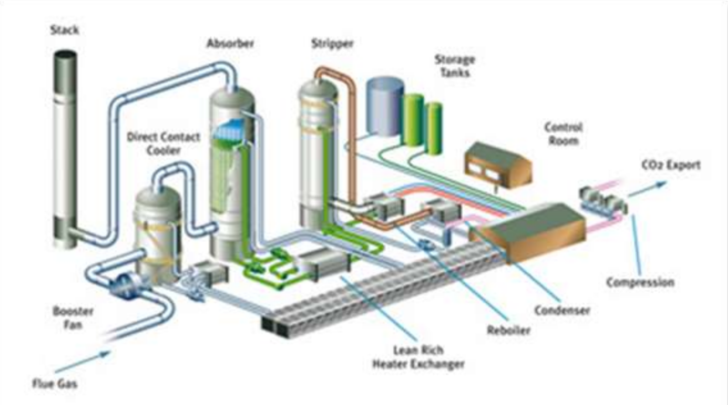

Figure 5: Post-combustion process (CCSa, 2015)

Oxy-fuel

In the process, the fuel is burnt into an air enriched in oxygen (the oxygen is separated from air prior to combustion). This oxygen-rich, nitrogen-free atmosphere enables a final flue-gas mainly composed of CO_2 and H_2O, and thus produce a more concentrated CO_2 stream, easier to purify.

Figure 2-6. Oxy-fuel process (CCSa, 2015)

2.8 Opportunities for high-temperature cogeneration

The CCS technology is not an industry in itself but is meant to be coupled to an industry to reduce the CO_2 emissions. The coupling of the CCS technology may change an industrial process and modify its requirements in terms of heat and energy.

Chemical industry

The chemical industry is highly diverse and gathers several thousands of products. CCS studies in the chemical industry focus on a small number of energy intensive processes that generate large quantities of CO_2, especially the production of ammonia, methanol and Bulk High Value Chemicals.

The CO_2 emissions for the methanol and ammonia production mainly come from the production of hydrogen. The pre-combustion technology is the preferred option to reduce CO_2 emissions during this step. However, the investment cost is important. In Europe, the ammonia production plants are rather small and the integration of CO_2 capture appears attractive and economically viable only in large coal-based plants, such as in China or in South-Africa. The methanol production plants are larger and highly suitable for carbon capture, especially the ones based on coal (IEA, 2013). The additional requirement of heat resulting from the CCS technology is low and does not represent a significant change in the heat requirement in general (the chemical industry and especially the methanol production already being a potential application for high-temperature cogeneration).

Finally, **the production of Bulk High Value Chemicals including the production of ethylene by naphtha cracking presents interesting opportunities for high-temperature cogeneration. Indeed, the carbon capture in naphtha crackers is possible by flue gas scrubbing (post-combustion process) and would require additional heat supply (in the order of magnitude of 100MW) (IEA, 2013).**

Steel industry

Concerning the steel industry, all the innovative processes include the CCS technology. The opportunities for HTRs were presented in the steel section.

Cement industry

The cement industry, releasing large amounts of CO_2 would benefit from the CCS technology. Two processes are considered for carbon capture. The first one, the post-combustion process consisting in flue gas scrubbing is more advanced and may require an additional steam supply capability from a new and dedicated CHP plant. Indeed, the increase in energy consumption for this carbon capture technology is estimated between 30% and 103% (IEA, 2013). Furthermore, the flue gas scrubbing would have to process approximately one ton of CO_2 for each ton of cement produced, highly raising capital and operational costs. **This might double the cost of cement production, making it hardly economically viable, especially in the current context of the cement industry** (the construction crisis resulting in a price war for cement).

The second technique to apply CCS to the cement industry is to use oxy-firing process to obtain a nearly pure CO2 stream from the calcination process. Oxy-firing requires a relatively capital-intense Air Separation Unit (ASU) to supply the oxygen but this occupies a smaller space on site than the equivalent footprint that the CO2 absorbers for flue gas scrubbing. **The energy consumption would increase by 13%** (IEA, 2013) **but mostly in the form of electricity, to supply the ASU and CO2 compressor.**

CCS technology applied to the cement industry does not constitute a potential application for HT nuclear cogeneration since the only economically viable technology, the oxy-firing process requires extra-energy only in the form of electricity.

Refining

In the refining industry, the reduction of CO_2 emissions can be achieved at three different levels:

- Hydrogen production
- Fluid Catalytic Crackers (FCC)
- Process heaters

The CO_2 reduction for hydrogen production is mainly investigated through innovative processes such as the High Temperature Electrolysis, different from the current widely used Steam Methane Reforming (see dedicated section on Hydrogen production). The addition of a CCS technology to an SMR plant could be achieved by adding an additional CO_2 separation step to the Pressure Swing Absorption (PSA) process, which aims at separating hydrogen from CO_2. This addition would be costly and would not capture CO_2 from the flue gases of the reformer furnace. To do so, partial oxidation approaches could be preferred to SMR as all CO_2 emissions could be captured together.

FCC is used to break the long-chain molecules into shorter molecules suitable for transport fuels. Applying CCS to FFC involves flue-gas scrubbing. **This addition of a post-combustion process and the heat-consuming solvent regeneration step, may require a new or larger CHP plant if sufficient excess heat was not available onsite** (IEA, 2013).

Process heaters can be numerous on a refinery site (20 to 30 with a power capacity ranging from 20 to 250MW). Just like for FCC, applying CCS to process heaters involves flue gas scrubbing and a large requirement of additional heat, possibly supplied by an additional CHP plant. However, to limit the costs, process heater emissions must be grouped together in a single stack.

Applying CCS to refineries would increase the heat requirement of a site through the addition of flue gas scrubbing to FCC and process heaters. However, the carbon capture activities in the refining sectors appear to be less well-developed than in other highly emitting sectors such as cement or steel. Furthermore, **the additional heat requirement would probably be supplied by burning gaseous and liquid components of the oil being refined as it is currently the case in most of refineries; the entry barriers for nuclear energy are then still difficult to overcome.**

2.9 Conclusion

Since the end of the EUROPAIRS project, several innovative processes for the industries considered in the market study have been developed and potential new applications have been identified. The chemical industry still presents the best opportunities for the implementation of HT nuclear cogeneration. Indeed, this industry already uses cogeneration, the required temperatures correspond to the output of an HTR and the power capacity of several parks is large enough to be compatible with the size of an HTR. Moreover, there is a strong willingness to decrease the CO2 emissions. To do so, processes will integrate more efficient components, waste heat will be recovered and energy harvesting system will be developed. However, the profile of the chemical industry (the size and location of the parks) will remain the same and no completely breakthrough innovative process is upcoming.

The development of innovative processes in the steel industry in the frame of the ULCOS programme has been delayed because of the current context of the steel industry in Europe (decrease of the sales and production). The most advanced one, the TBF-GR requires additional amount of heat but the demonstration project is currently stopped.

The hydrogen production mainly uses the SMR process, which is a possible application for HT nuclear cogeneration. Research is ongoing and budgets will be allocated to projects developing the innovative processes: HT electrolysis and cater splitting (thermochemical cycles).

Finally, the CTL and the CCS technologies have been investigated as potential applications for HT nuclear cogeneration. Depending on the process used, CTL requires temperatures between 450°C and 800°C which are compatible with HTR's output temperature. This application is particularly of interest for Poland which has important resources of coal and is a possible host-country for the commissioning of a HTR demonstrator. The CCS technologies could be applied to highly-emissive industries such as the chemical, steel, cement and refining industries. The most heat-consuming process is the flue gas scrubbing using solvent regeneration (post-combustion process) requiring several dozens of MWth of additional heat.

3 Energy supply through High Temperature Reactor

The reference case is a helium cooled modular high temperature reactor using Pebble bed fuel with a thermal output power of 500 MWth (2 reactors of 250 MWth each). The principal setup can be seen in the following figure:

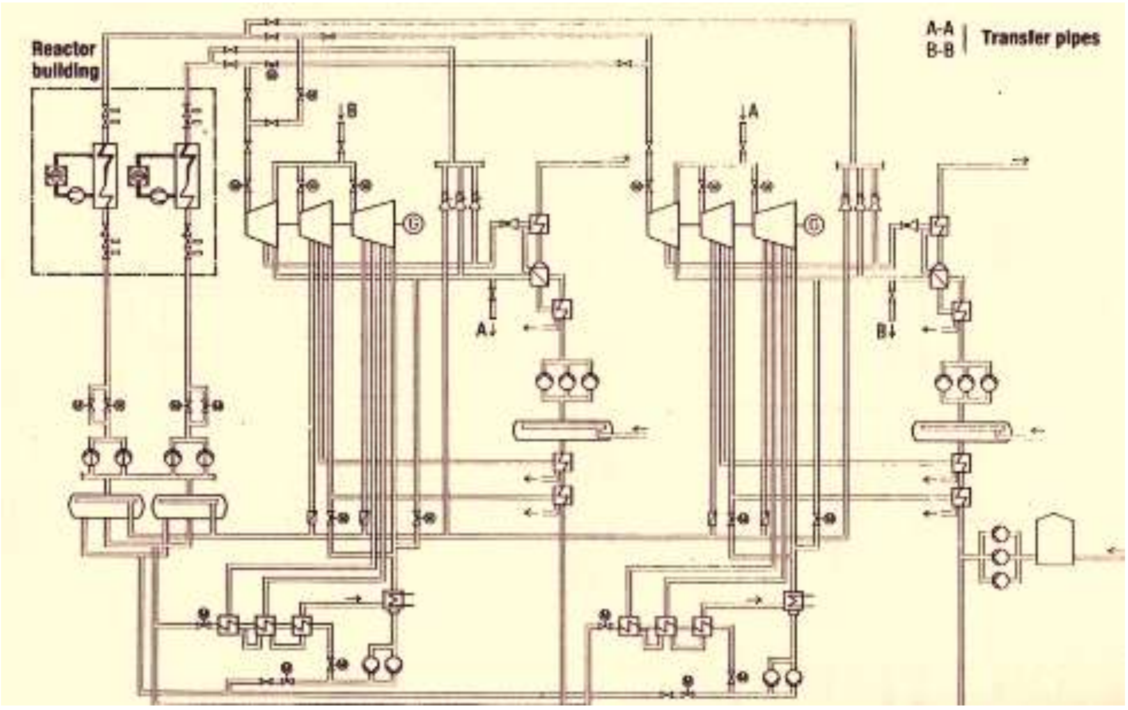

Figure 3-1. Process flow diagram of a helium cooled modular high temperature reactor using pebble bed fuel

The technical characteristics and financial figures of the reference case HTR have been extrapolated and updated on the basis of the analysis of a cogeneration project HTR-MODULE 200 in the 1990ies, delivering power and process steam for chemical complexes.

Characteristics and costs for building and operating a HTR-plant are described in the report (AREVA GmbH, 2014) "Cost Assessment HTR-MODULE 250", provided in the frame of NC2I project. A process flow diagram of an HTR used in cogeneration is presented in the following figure.

4 Economic Assessment

4.1 Energy and CO2 emission prices

In order to evaluate the revenue streams, forecast for energy (electricity and heat) and emission prices (CO2) are needed. Several publications present scenarios on evolution of energy and CO2 prices, such as:

- EU Energy, Transport and GHG Emissions, Trends to 2050, European Commission, 2013
- World Energy Outlook (edition 2014)

These different energy prices scenarios have to be adapted for specific simulations related to a HTR plant for process heat within Europe.

A schematic break-down of an end consumer bill for electricity and natural gas is presented hereafter:

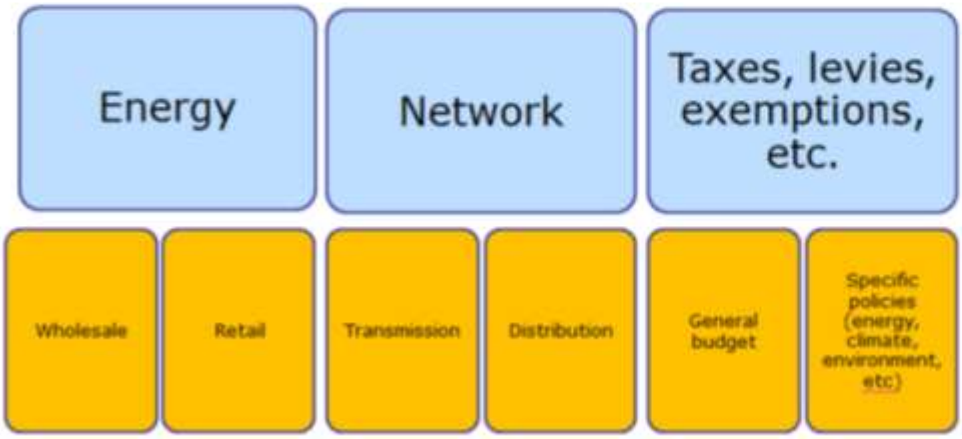

Figure 4-1. A schematic break-down of an end consumer bill for electricity and natural gas

The wholesale element covers the costs to deliver the energy product on the grid. It covers all direct costs related to the construction, operation and decommissioning of energy generating units.

The retail element covers costs related to the sale of energy products to final consumers, including (but not limited to) portfolio management (size and structure of client base), personnel, IT, overheads, insurance for imbalance, etc.

The transmission and distribution elements include infrastructure costs (maintenance and grid expansion), system services (costs by use or by availability), network losses and other charges such as stranded costs, public service obligations, policy support to certain technologies, etc.

Finally, the elements related to taxation policy can be grouped along several criteria to two or more sub-categories.

- Recoverable taxes or levies include full or partial recovery of taxes paid on purchases, either as a payment or as an offset against taxes owed to the tax authorities (e.g. VAT is a recoverable tax).
- Partially recoverable taxes include a combination of taxable and exempted levels of consumption.
- In the case of non-recoverable taxes or levies, the full amount of collected proceeds is transferred to the tax authorities. This distinction is important when it comes to retail prices for different types of final consumers of electricity and natural gas. For example, the tax-related elements for households would most often be non-recoverable whereas at least some part of the taxes and levies companies that are paid by companies would be recoverable and companies may further benefit for some special exemption regime.

4.1.1 Electricity prices

In the case of electricity, some chemical companies may have cogeneration units and produce their own electricity, and therefore strongly reduce transmission and distribution costs. Therefore, prices will be comprised between the wholesale price and the electricity price for industries (exclude VAT and other recoverable taxes in the case of industry, as well as industry exemptions). In many counties a small grid fee exists for the electricity input to the grid which generally needs to paid also for electricity produced for own consumption.

Table 4-1. Forecasted electricity prices

	2015	2020	2030	2040	2050	Source
Av. electricity price (€'10/MWh)		172	172		169	(European Commission, 2013)
Electricity price for industries (pre-tax) (€'10/MWh)		118	108		99	(European Commission, 2013)
Wholesale electricity price (€/MWh)	47-50	54-59	54-72		50-119	(A. Schroder, T. Traber, C. Kemfert, 2013)

Sources:
EU Energy, Transport and GHG Emissions, Trends to 2050 (European Commission, 2013)
Climate policy and technology scenarios until 2050 in the model EMELIE-ESY, (A. Schroder, T. Traber, C. Kemfert, 2013).

In addition, electricity prices present some variations between European countries.

As a conclusion, it is proposed to evaluate different scenarios, in a range defined by:
- Wholesale electricity price
- Electricity price for industries

4.1.2 Heat prices

Heat revenues are calculated on the basis on an equivalent fossil heat source. Construction and operation costs are chosen based on Fortum's experience and average costs on the market and are presented in Chapter 4.2 Process heat costs for concurrent technology.

Document (EUROPAIRS, End-Users Requirements for Process heat Application with Innovative nuclear Reactor for Sustainable energy Supply, 2011) states that main fuels for plug-in market are gas and coal. Therefore, scenario with oil as a fossil fuel will not be studied in this report (although is it possible to run such simulations with the model).

4.1.3 Fuel prices

Gas prices

Forecasted gas prices are summarized in the following table.

Table 4-2. Forecasted gas prices

		2015	2020	2030	2040	2050
IEA 2009	Reference scenario	58	67.18	77.84		
IEA 2009	Lower prices sensitivity case	45.8	48.75	54.24		
IEA 2009	Higher prices sensitivity case	73.9	87.17	101.5		
(European Commission, 2013)	Reference scenario	68	80	83		81

Sources:
World Energy Outlook (International Energy Agency, 2009) ($'08/boe)
EU Energy, Transport and GHG Emissions, Trends to 2050 (European Commission, 2013) ($'10/boe)

Coal prices

Forecasted coal prices are summarized in the following table.

Table 4-3. Forecasted coal prices

		2015	2020	2030	2040	2050
IEA 2014	New policies		101	108	112	
IEA 2014	Current policies		107	117	124	
IEA 2014	450 Scenario		88	78	77	
(European Commission, 2013)	Reference scenario	138.9	143.71	153.3		191.6

Sources:
World Energy Outlook, (Internation Energy Agency, 2014)($'08/t)
EU Energy, Transport and GHG Emissions, Trends to 2050 (European Commission, 2013) ($'10/boe)

4.1.4 CO_2 prices

Forecasted carbon prices are summarized in the following table.

Table 4-4. Forecasted prices for CO_2

		2015	2020	2030	2040	2050
IEA 2014	New policies		22	37	50	
IEA 2014	Current policies		20	30	40	
IEA 2014	450 Scenario		22	100	140	
(European Commission, 2013)	Reference scenario	5	10	35		100

Sources:
World Energy Outlook, (Internation Energy Agency, 2014)($'08/t)
EU Energy, Transport and GHG Emissions, Trends to 2050 (European Commission, 2013) ($'10/boe)
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4.2 Process heat costs for concurrent technology

For the purposes of feasibility assessment of HTR cogeneration, process heat production costs in conventional boilers and in a Combined-Cycle-Gas-Turbine (CCGT) plant are also evaluated and compared to steam prices generated in the HTR. Heat-Only-Boilers (HOBs) are individual boilers delivering steam or hot water at a specified pressure and temperature. The fuel is burned in the furnace section and the heat is used to boil water in the boiler section which is then distributed to end consumers. HOBs using gas as a fuel source are common heat sources in industrial applications. In many cases they are also used as a back-up source of process heat.

Combined-Cycle-Gas-Turbine (CCGT) plant is a gas-fired plant consisting of a gas turbine generator that generates electricity. The residual heat in hot exhaust gases is used to make steam to generate additional electricity via a steam turbine. As the steam can be taken from the process at different temperature and pressure levels the power-to-heat ratio in CCGT depends on how much steam will flow and expand in the the steam turbine. In this study only a reference price for a steam output at a low temperature is calculated.

4.2.1 Investment costs

Investment costs have been evaluated as average investments to boilers that generate approximately 100 MW (or 360 GJ/h). Investment costs vary a bit between medium (e.g. 16 bar) and high (e.g. 80 bar) pressure steam where within medium pressure steam the investment costs are a bit higher. In this study it has been estimated that they are 25 per cent higher. The investment costs are presented in Chapter 4.2.3 Heat production costs.

4.2.2 Operation and maintenance costs

Operation and maintenance costs consists of personnel costs as well as fixed and variable operation and maintenance costs. The costs have been estimated for different heat production technologies and they are presented in Chapter 4.2.3 Heat production costs.

4.2.3 Heat production costs

Table 4-5 summarizes the technical characteristics, environmental emissions and costs of gas boilers and CCGT that are alternative means to produce the steam or heat needed in the process industry compared to the HTRs.

Table 4-5. Technical characteristics, environmental emissions and costs of alternative steam production

Technology	HOB	HOB	CHP (CCGT)
Technical data			
Fuel	Natural gas	Coal	Natural gas
Capacity, GJ/h	360	360	360 (+85 MW electricity)
Efficiency, %	92	87	90
Technical lifetime, a	20	20	20
Construction time, a	1	2	3
Environmental data			
SO_2 (mg/Nm3)*	35	850 (2000)	35
NO_X (mg/Nm3)*	150 (300)	400 (600)	50 (300)
Dust (mg/Nm3)*	5	50 (100)	5
CO_2 (kg per GJ fuel)	55	95	55
Financial data			
Spesific investment, €/kW_{th}	150	520	500
Fixed O&M (% of initial investment per year)	1.2	1.2	1.2
Variable O&M, €/MWh	0.5	1.6	0.5

*LCPD emission limit values for existing and new plants (50-100 MWth), limits for existing plants in paranthesis. Source: Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from Large Combustion Plants

The estimated heat production costs in the heat-only-boilers and gas-fired CCGT in 2030 are presented in the following figure. The fuel and emission prices used in the figure are the prices of base scenario and they are presented in more detail in Chapter 4.1 Energy and CO2 emission prices.

The heat production costs of a CCGT power plant which produces both heat and electricity have been estimated by using the methodology of alternative electricity production for the division of costs. Here the alternative production costs for electricity have been the market price of electricity.

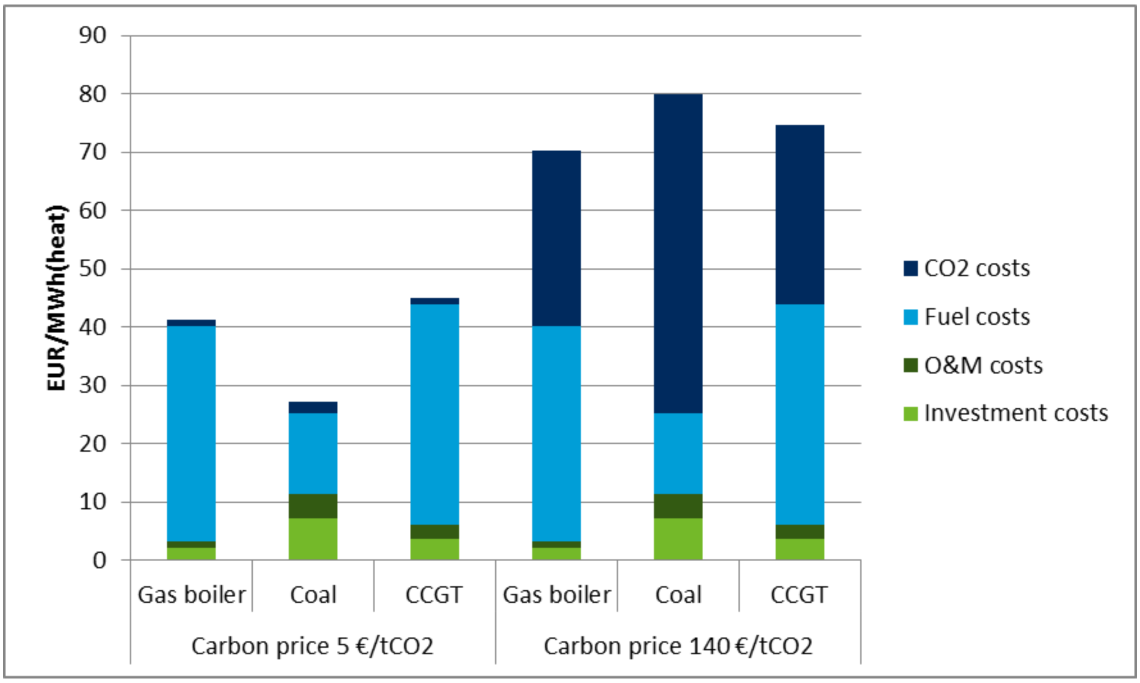

Figure 4-2. Heat prices in the alternative means to produce the steam or heat needed in the process industry compared to the HTRs in 2030 (basic scenario)

Calculations for an equivalent heat price (€'14/MWh) give the prices presented in the following table.

Table 4-6. Equivalent heat prices with low and high carbon price

	Coal	Gas
CO2 prices low (5€/t)	27	41
CO2 prices high (140€/t)	80	70

It is proposed to evaluate a scenario based on a heat price of 40€/MWh, with a variation in the range [-50%, +100%], covering all forecasted evolutions for fuel and CO2 prices.

4.3 Economic assessmentof HTR

Several parameters may affect the economics, especially for long-term project such as building a nuclear power station. The present chapter aims proposing variation ranges for the parameters impacting the business case.

4.3.1 HTR construction costs

Data provided in the report (AREVA GmbH, 2014) "Cost Assessment HTR-MODULE 250" are based on the analysis of an HTR-MODULE 200. Although this design was not build at this time, it went through most of the design and licensing steps:

- Basic and detailed design
- Component design, testing and R&D work for some critical issues
- Licensing process according to Germany's regulations
- Design according to chemical complex needs

Total investment overnight cost is evaluated 931 M€ for 2x250 MWth, resulting in a cost of 1861 €/kW.i (note: overnight costs often relate to electrical installed power. In the case of a HTR, overnight cost relates to the thermal installed power. For a plant producing electricity only, this would result in an overnight cost of 4380 €/kWe.i (≈ 5700 $/kWe.i), similar to current constructions in OECD).

Data from the World Nuclear Association (www.world-nuclear.org) about ongoing projects with Light Water technology show that:

- Costs for current nuclear project are significantly increased along the construction period (mostly due to financing cost incurred by delay during construction)
- Overnight costs are largely influenced by the region hosting the project

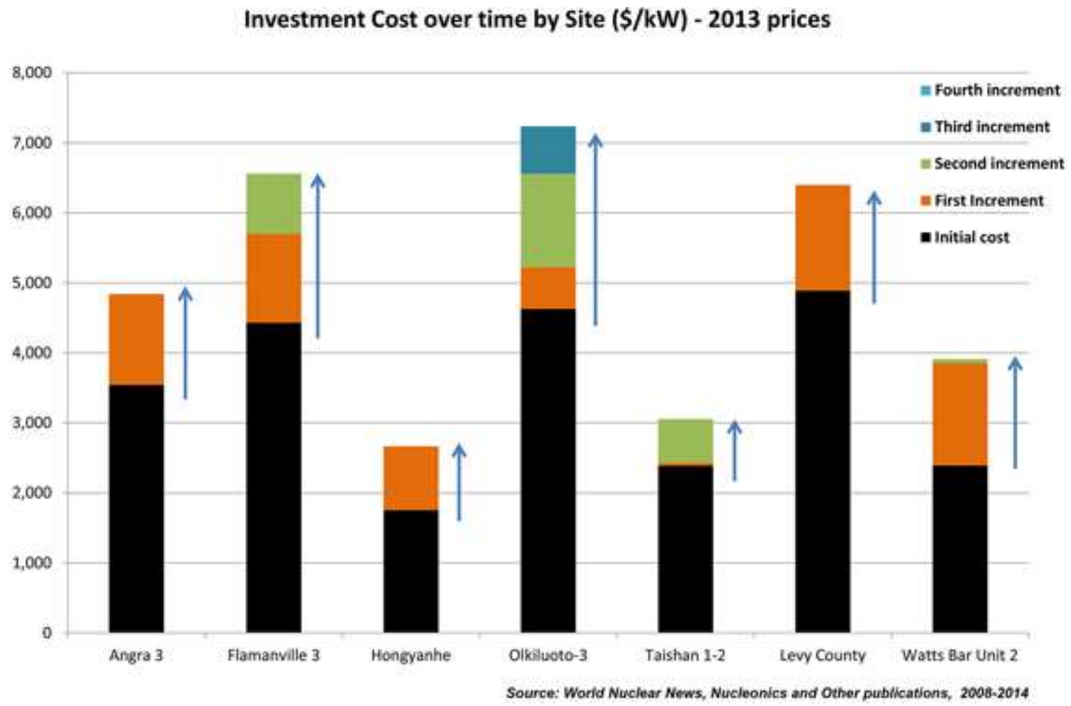

Figure 4-3. Total investment overnight cost of ongoing projects with Light Water technology

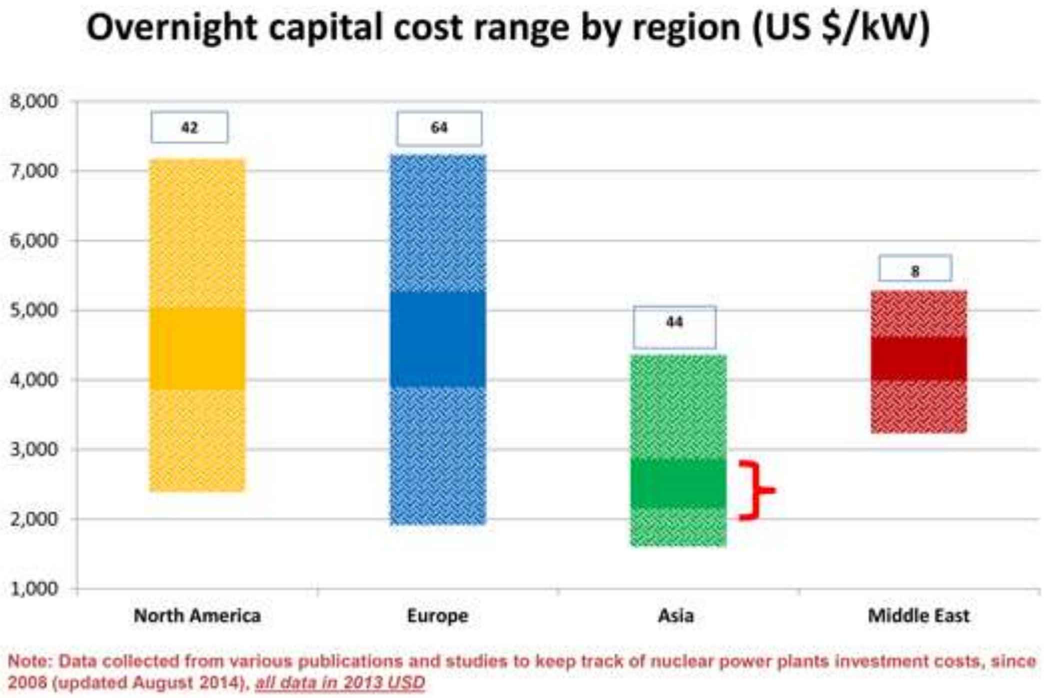

Figure 4-4. Overnight capital cost range by region

In comparison to ongoing projects, the following aspects impact construction costs:

Positive impact (reduce risks)	- Inherent safety, reducing number of safety components and therefore reducing licensing risks - Smaller power level: o Construction should be simplified o Required investment minimized, lower financial impact of delays - Modular construction, improving learning curve
Negative impact (increase risks)	- Limited or outdated regulatory framework, to be potentially developed for a given project - First-Of-a-Kind risks - Limited supply-chain, to be developed for HTR specifics

As conclusion, it is proposed to evaluate different scenario in the range [-30% ; +30%] for overnight costs.

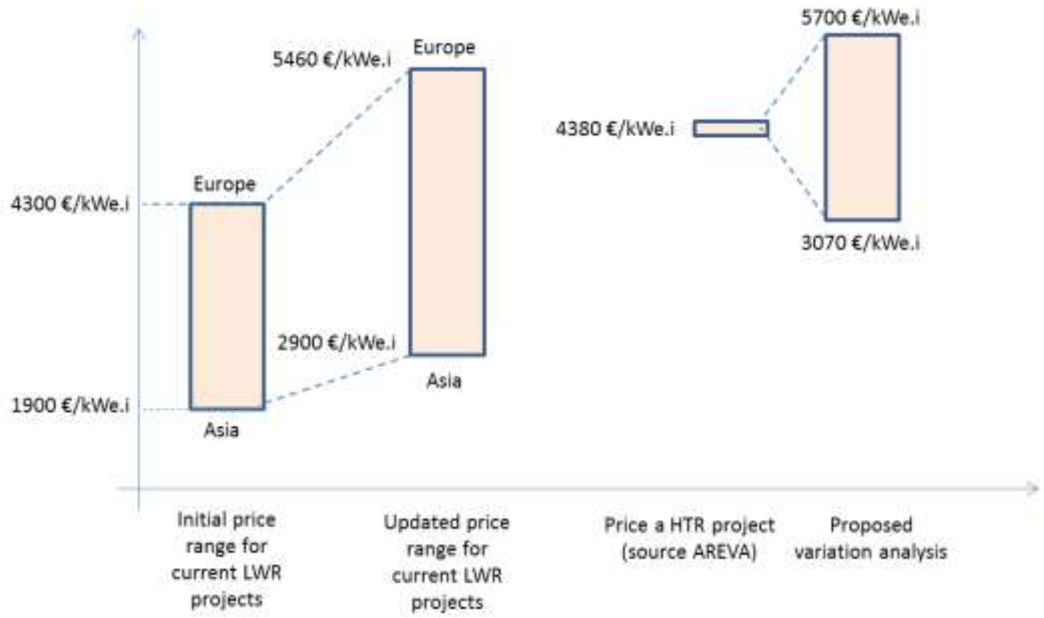

Figure 4-5. Variation analysis of overnight costs

4.3.2 HTR Operation and Maintenance costs

Data provided in the report (AREVA GmbH, 2014)"Cost Assessment HTR-MODULE 250" proposes figures for:

- Operation costs (number of staff and average salary)
- Annual Maintenance cost
- Insurance cost

Based on these figures, O&M costs are evaluated 23,4 M€/year, or 6,24 €/MW (14,6 €/MWe when converted to electricity).

Literature review on current operating plants gives an overview of O&M costs (fuel excluded) for large reactors:

- Report on the cost of nuclear generation (French government („Cour des Comptes“), 2012) evaluates O&M costs up to 16,8 €(2010)/MWh for EDF fleet.

- Nuclear Energy Institute (Nuclear Energy Institute) evaluates O&M costs up to 12,7 €(2012)/MWh for US plants.
- UK Department of Energy and Climate Change (Department of Energy and Climate Change - UK, 2011) evaluates O&M costs up to 14,7 €(2013)/MWh
- Projected Costs of Generating Electricity (OECD/NEA, 2010) evaluates O&M costs between 8 €/MWh (Large reactors in China) and 29,8 €/MWh (440 MWe reactors in Hungary)

In comparison to running plants worldwide, the following aspects may impact O&M costs:

Positive impact (reduce costs)	- Inherent safety, reducing number of safety components and therefore reducing maintenance on safety systems
Negative impact (increase costs)	- Regulatory framework might require dedicated functions (e.g. security people) not covered in the reference scenario - Average yearly staff cost higher that the reference scenario - Higher maintenance cost for components operating under higher conditions (high temperatures)

As conclusion, it is proposed to evaluate different scenario in the range [0% ; +100%] for O&M costs.

4.3.3 HTR decommissioning costs costs

Data provided in the report "Cost Assessment HTR-MODULE 250" (AREVA GmbH, 2014) evaluates a dismantling cost of 115 M€ for the plant, equivalent to 0,77€/MW (or 1,8 €/MWe when converted to electricity).

Literature review on current operating plants gives an overview of dismantling costs for large reactors:

- Report on the cost of nuclear generation (French government („Cour des Comptes"), 2012) compares different evaluations for dismantling worldwide, with costs varying from 310 M€/reactor (France) to 1068 M€/reactor (Germany).
- Nuclear Energy Institute (Nuclear Energy Institute) evaluates dismantling costs between 230 M€ and 385 M€ for US plants.

In comparison to running plants worldwide, the following aspects may impact dismantling costs:

Positive impact (reduce costs)	
Negative impact (increase costs)	- Dismantling of large graphite quantities still investigated

As conclusion, it is proposed to evaluate different scenario in the range [0% ; +200%] for dismantling costs.

4.3.4 HTR fuel costs

Data provided in the report "Cost Assessment HTR-MODULE 250" (AREVA GmbH, 2014) evaluates a fuel cycle cost of 7,23 €/MW (or 17,1 €/MWe when converted to electricity).

Literature review on current operating plants gives an overview of fuel costs for large reactors:

Report Projected Costs of Generating Electricity 2010 Edition (OECD/NEA, 2010) evaluates fuel costs between 6,07 €/MWh and 8,9 €/MWh.

In addition, World Nuclear Association (www.world-nuclear.org) lists current tax specifically applied on nuclear fuel :

Country	tax detail (for 2012)	2012 paid (estimate)
Belgium	Nuclear tax of 0.5 Euro cents/kWh	€479 million*
France	Tax on basic nuclear installations	€350 million**
Germany	€145 per gram of fissile uranium or plutonium fuel loaded into reactor. This translates to 1.4 Euro cents/kWh (2012 nuclear generation of 100 billion kWh)	€1400 million***
Sweden	Nuclear tax of 0.67 Euro cents/kWh. (63.5 billion nuclear kWh generated in 2012)	€424 million***
UK	0.61 Euro cents /kWh† Climate Change Levy on business and industry (70 billion kWh 2012 nuclear generation, 60% UK business consumption)	€256 million***
Total		€2909 million

Following aspects may impact fuel costs:

Positive impact (reduce costs)	Variations in uranium prices may have positive impact on fuel prices Deployment of HTR fleets
Negative impact (increase costs)	Variations in uranium prices may have negative impact on fuel prices Fuel tax on nuclear fuels

As conclusion, it is proposed to evaluate different scenario in the range [-30% ; +100%] for fuel costs.

4.3.5 HTR lifetime

Data provided in the report “Cost Assessment HTR-MODULE 250” (AREVA GmbH, 2014) evaluates lifetime of 40 years.

Following aspects may impact lifetime of the plant:

Positive impact (Increase lifetime)	Lifetime extension (as performed for current plant, although feasibility is not demonstrated yet for HTRs)
Negative impact (Reduce lifetime)	Political decision to shut down nuclear plants Technical problem leading to early closure of the plant Lifetime of the chemical complex (end-user)

As conclusion, it is proposed to evaluate different scenario in the range [-30% ; +30%] for plant lifetime.

5 Sensitivity analysis

5.1 Other parameters analysed in the sensitivity analysis

5.1.1 HTR Availability

Data provided in the report “Cost Assessment HTR-MODULE 250” (AREVA GmbH, 2014) evaluates availability up to 85%.

It is proposed to evaluate different scenario in the range [-20% ; +10%] for plant availability.

5.1.2 Construction time and delay during commissioning

Data provided in the report “Cost Assessment HTR-MODULE 250” (AREVA GmbH, 2014) states a construction time of 4 years. It is propose to evaluate longer construction time [0, +2 years], and also potential delays during commissioning [0, + 2 years].

5.1.3 Tax rate

Tax rate is country specific.

It is proposed to evaluate different scenario in the range [- 10 % ; 40%]

5.1.4 Interest rate

Reference scenario is based on a reference rate of 8%.

It is proposed to evaluate different scenario in the range [-20 % ; + 50%]

5.1.5 Design and Licensing phase

Reference scenario is based on a design that is already developed and licensed.

It is proposed to evaluate different scenario requiring some time and adaptation work for design and licensing phase, with the following variations:

- Design and licensing duration: [0 ; + 5 year]
- Design and licensing cost: [0; + 300 M€]

5.1.6 Summary of the reference case and variations

Figures used for calculations are summarized in the following table.

Table 5-1. Figures used in the economic assessment for HTR cogeneration

Item	Reference scenario	Variation min	Variation max	Min value	Max Value
HTR construction costs	930,8 M€	- 30 %	+ 30 %	651.6	1210.0
O&M costs	23,4 M€/year	0	+ 100 %	23.4	46.8
Decommissioning costs	115 M€	0	+ 200 %	115	345
Fuel costs	27,1 M€/year	- 30 %	+ 100 %	19.0	54.2
Lifetime	40 years	- 30 %	+ 30 %	28	52
Electricity price	50 €/Mwe	0	+ 100 %	50	100
Heat price (incl. CO2)	40 €/MW	- 50 %	+ 100 %	20	80
HTR Availability	85 %	- 20 %	+ 10 %	0.68	0.94
Construction time	4 years	0	+ 50 %	4	6
Delay during commissioning	0 years	0	+ 2	0	2
Tax rate	20 %	- 10 %	+ 40 %	18	28
Interest rate	8 %	-30 %	+ 50 %	5.6	12
Design and licensing duration	0 years	0	+ 2	0	2
Design and licensing cost	0 M€	0	+ 300	0	300

5.2 Calculation results

5.2.1 HTR availability

According to the following graph, availability has a major influence on the NPV. Therefore, the highest availability shall be expected from the design.

Figure 5-1. Sensitivity of Net Present Value (NPV) to the availability of HTR

5.2.2 Heat price

The following graph presents the evolution of NPV when varying the heat price.

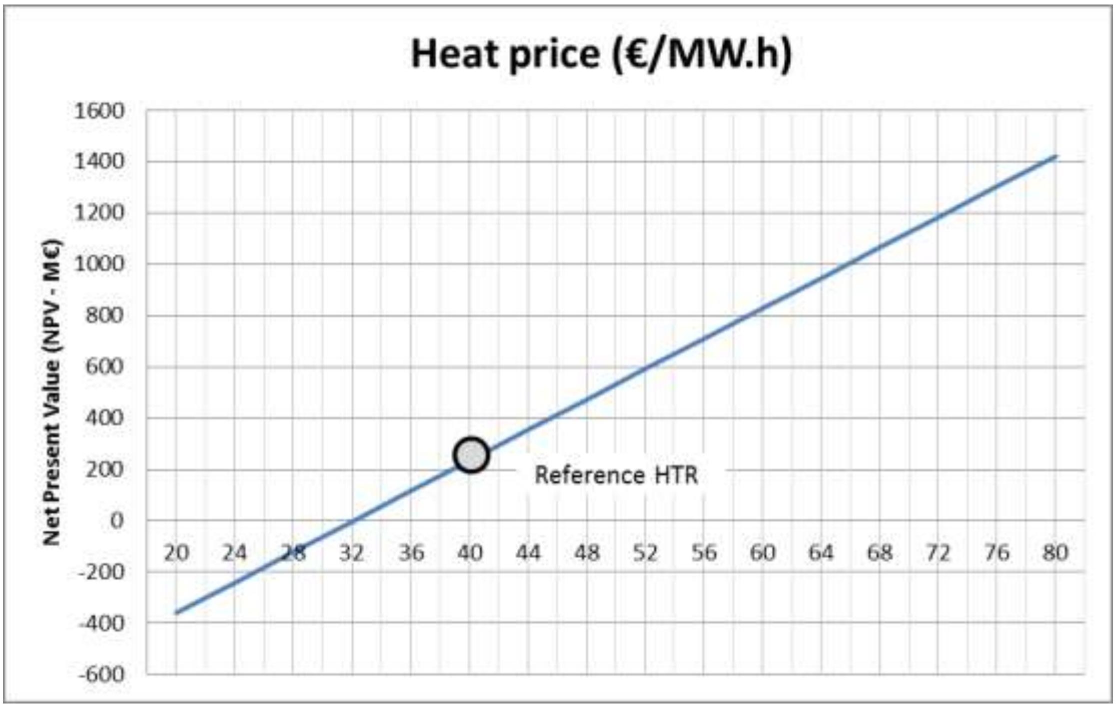

Figure 5-2. Sensitivity of NPV to the heat price

This heat price is calculated integrating the fuel price (gas or coal), OPEX and CAPEX for standard plants, and CO2 penalty. In the current situation, heat production with low prices for coal and CO2 (Heat price≈ 25€/MWh) does not favor HTR. However, the reference HTR can compete with heat production based on gas (Heat price ≈ 40€/MWh).

CO2 has a high influence on the heat production price, and its evolution is likely to be more important than fuel costs (CO2 costs are strongly dependent on the energy policies, when fuel prices are forecasted with a low variation rate).

5.2.3 Electricity price

The following graph presents the evolution of NPV when varying the electricity price.

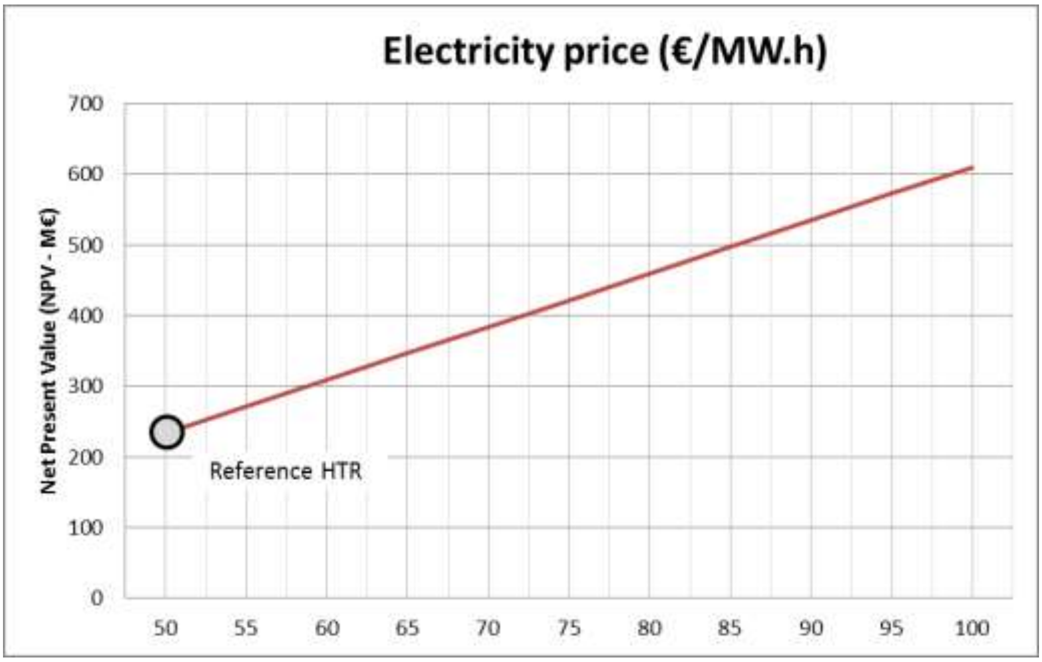

Figure 5-3. Sensitivity of NPV to the electricity price

Assumption for the reference case is a cost for electricity equal to the wholesale price (penalizing assumption). One can see the positive influence of an increase in the electricity (typically in a configuration where the end-user buys electricity from the grid, instead of producing in cogeneration mode).

5.2.4 HTR construction costs

The following graph presents the evolution of NPV when varying the construction cost.

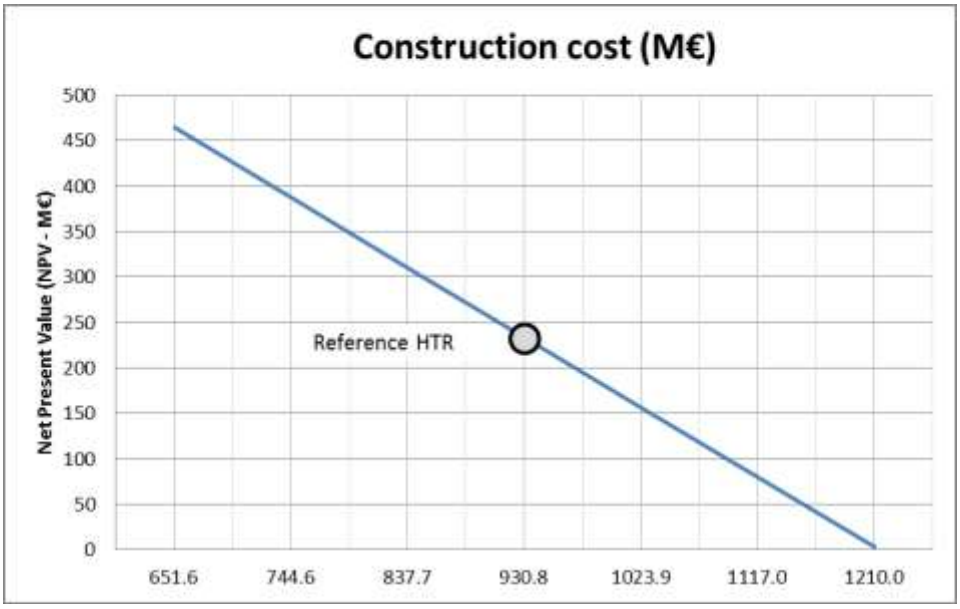

Figure 5-4. Sensitivity of NPV to the construction costs

A variation of 30% in the construction cost jeopardizes the economics of an HTR project. However, it should be reminded that figures used are based on a First-Of-a-Kind project, already integrating a risk related to construction.

5.2.5 Operation and maintenance cost

The following graph presents the evolution of NPV when varying the O&M costs.

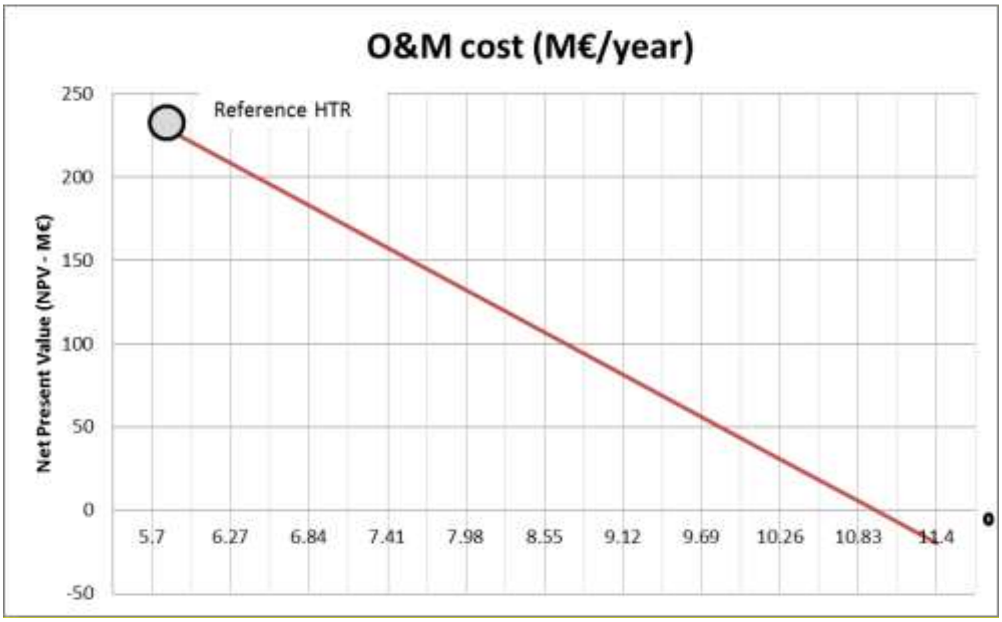

Figure 5-5. Sensitivity of NPV to the O&M costs

One can see the high influence of O&M cost on the economics. This can be explained by the relatively low power level of the plant, and the limited scale effect.

For a given project, it will be important to validate that assumptions of the reference HTR are applicable (staffing, average salary, maintenance..).

5.2.6 Fuel cost

The following graph presents the evolution of NPV when varying the fuel cost.

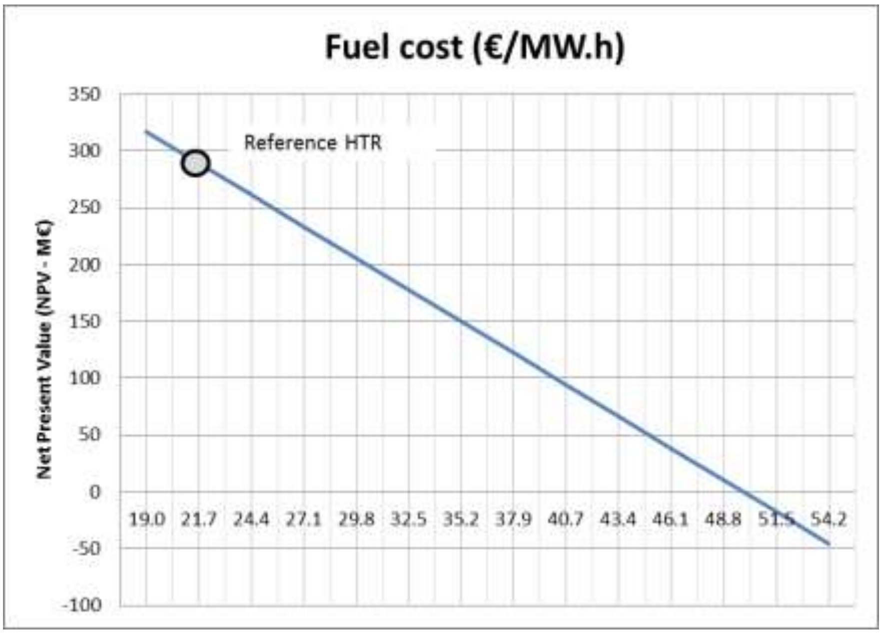

Figure 5-6. Sensitivity of NPV to the nuclear fuel costs

Fuel cost is usually of low influence in nuclear generation. For the reference HTR, it is also mentioned that Uranium and separation work prices are assumed to be a 50/50 mix of spot and long-term contract prices, lowering the risk.

However, specific tax on nuclear fuel could have a negative on the profitability of a HTR project.

5.2.7 Interest rate

The following graph presents the evolution of NPV when varying the interest rate.

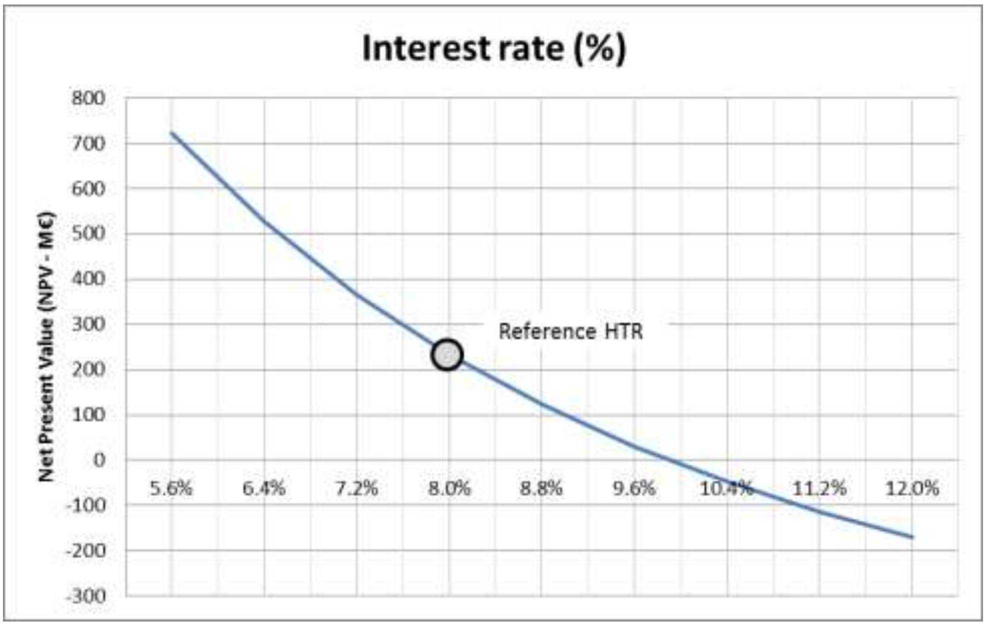

Figure 5-7. Sensitivity of NPV to the interest rate

As seen on the graph, interest rate is one of the most influent parameter.

5.2.8 Lifetime

The following graph presents the evolution of NPV when varying the plant lifetime.

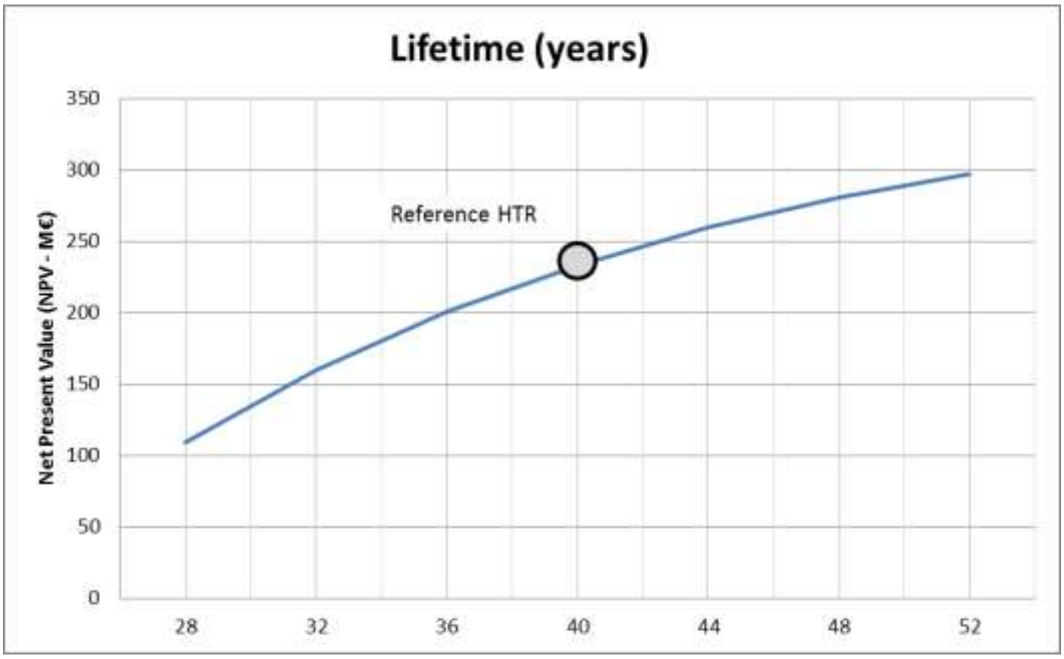

Figure 5-8. Sensitivity of NPV to the lifetime of the HTR

As seen on the above graph, a quite large variation in the lifetime has no dramatic effect on the economics of the project.

This can be understood by looking at the additional cash flows caused by a longer lifetime. They occur far in the future and are, therefore, heavily discounted.

5.2.9 Decommissioning costs

The following graph presents the evolution of NPV when varying the decommissioning costs.

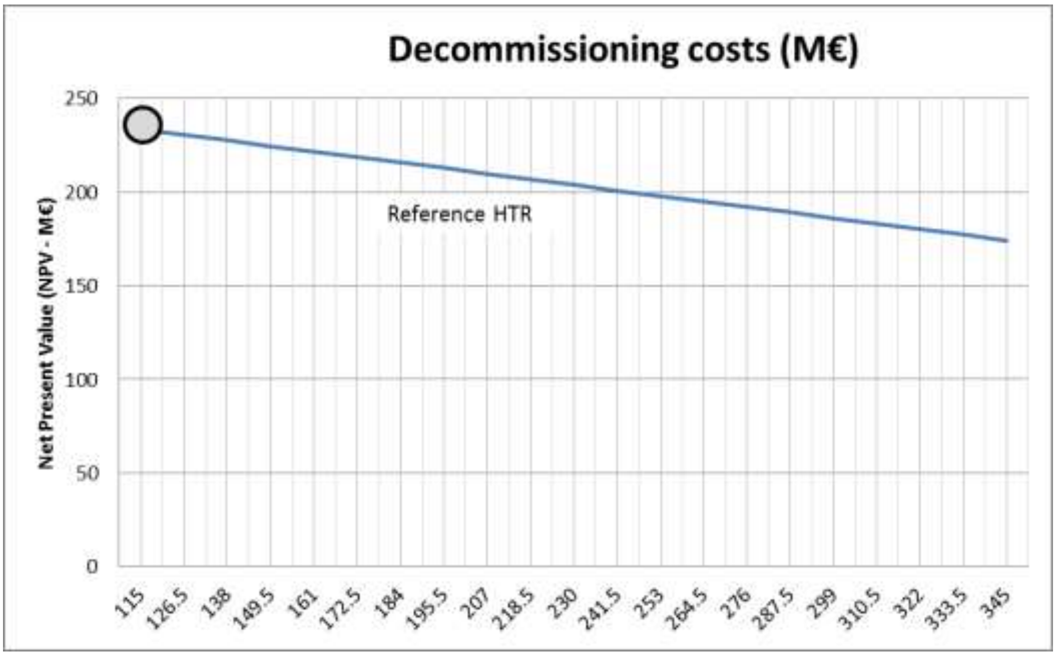

Figure 5-9. Sensitivity of NPV to the decommissioning costs

As seen on this graph, a quite large variation in the decommissioning costs has no dramatic effect on the economics of the project.

Same as lifetime, this can be understood by looking at the provision for decommissioning. They occur far in the future and are, therefore, heavily discounted.

5.2.10 Tax rate

The following graph presents the evolution of NPV when varying the tax rate.

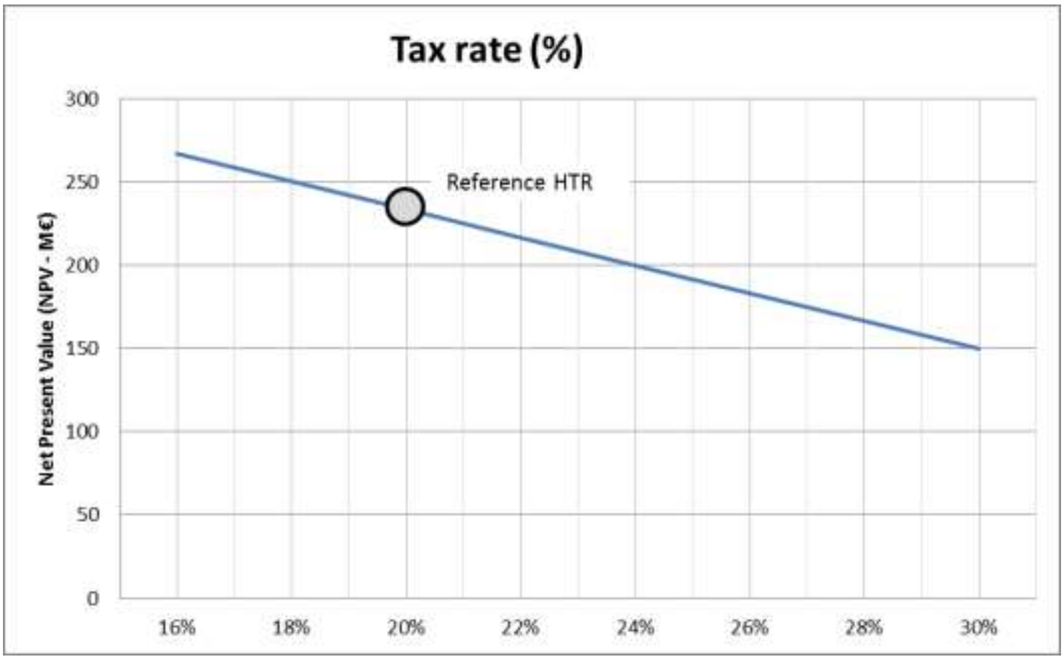

Figure 5-10. Sensitivity of NPV to the tax rate

As seen on this graph, a quite large variation in the tax rate has no dramatic effect on the economics of the project.

5.2.11 Construction time and delay during commissioning

The following graph presents the evolution of NPV when varying the construction time or suffering delays before commercial operation.

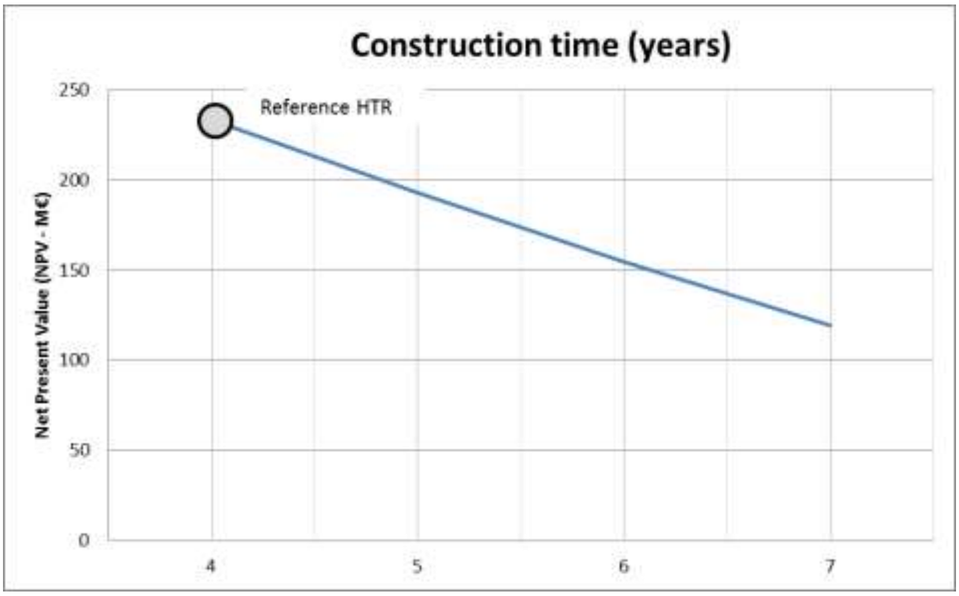

Figure 5-11. Sensitivity of NPV to the construction time

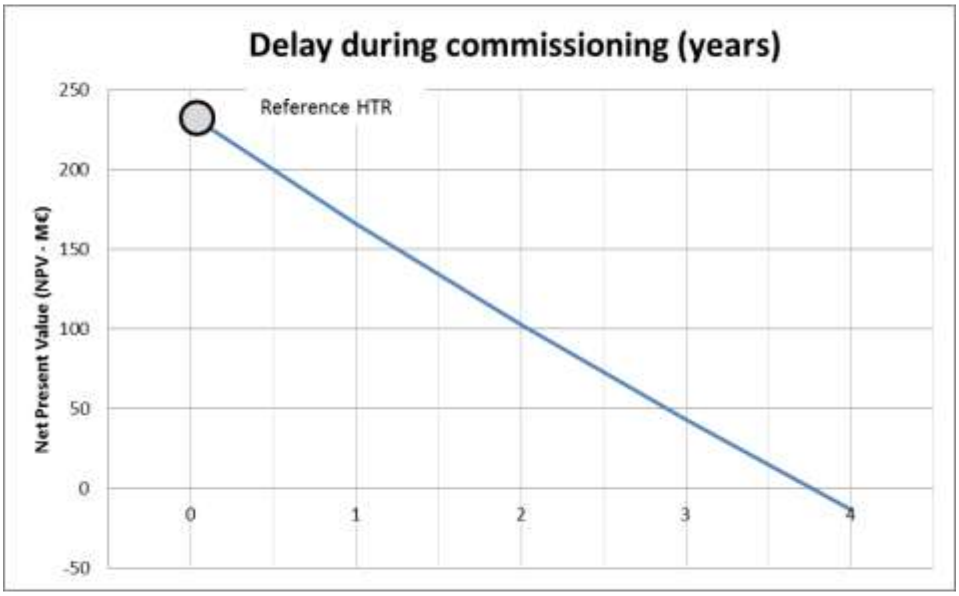

Figure 5-12. Sensitivity of NPV to the delay in commissioning

One can see that a longer construction time leads to a lower NPV, however still positive.

A delay before commercial operation in the same order of magnitude challenges the profitability.

Indeed, the more time goes, the more revenues are heavily discounted, when expenses for construction occur in the first years.

5.2.12 Design adaptation and licensing costs

For the reference HTR, it is assumed that the design is already developed and requires no design adaptation. It is quite likely that some design work will be needed for:

- Adaptation to current norms and regulations
- Adaptation to local conditions for a given site
- Licensing in the host country, when different from the reference case
- Adaptation to the chemical process, when different from the reference case

For this simulation, an average 100 M€/year in engineering work has been assumed.

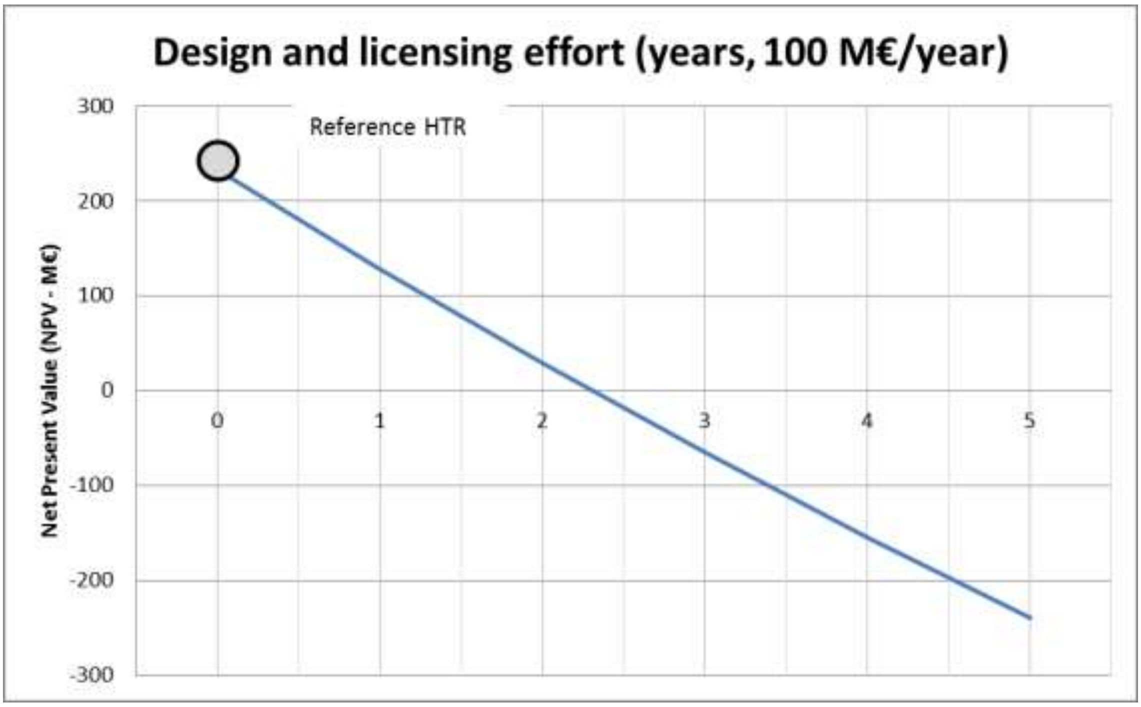

Figure 5-13. Sensitivity of NPV to the adaptation and licensing costs

As seen on this graph, a HTR project alone would not be profitable when supporting large costs for design and licensing.

However, cost related to site adaptation and a significant part of the licensing cost could be covered. A licensing process based on a generic design assessment should therefore strongly favour such project.

6 Adaptation of the scenario for Poland

In order to assess the condition for competitiveness of nuclear cogeneration, evaluation tools are needed:

- Cost model for an HTR project: Based on information related to nuclear project (provided by vendors and/or from company's knowledge), or in order to perform sensitivity analysis, input parameters for the financial assessment of the project will be calculated.
- Economic model: Based on aforementioned parameters, Net Present Value (NPV) and Internal Rate of Return (IRR) will be calculated for comparison with a fossil-fuel based alternative.

A generic analysis was provided in the frame of NC2I (ETG GmbH, 2015), in order to identify the most influent parameters of the business case for an HTR project.

This report proposes to adapt the HTR reference case to Poland-specific characteristics.

6.1 Input data for a scenario adapted to Poland

As mentioned in (ETG GmbH, 2015), no high temperature reactors have been constructed for more than a decade. Therefore, almost no empirical, technical and economic data exists for HTRs.

Data used in the reference case were updated from previous projects investigated in the 90' in Germany.

Proposing an adaptation to a case in Poland is a difficult exercise, as many additional factors differ from the reference scenario, and therefore increase the result uncertainty.

Following paragraphs list the main source of uncertainties identified during the reference case adaptation.

6.1.1 Currency

The currency in Poland is the Zlotys, when inputs for the reference case are calculated in Euros. Technical disposition and financial instruments exist to limit currency risks; however such mitigation may have a large impact on the different costs:

- Construction costs (CAPEX), e.g. depending of the share of the construction or procurement localized in the host country
- Operation costs (OPEX), e.g. depending on the operating model, the assistance requested during the first years of operation
- Fuel cost, especially when fuel supply and fabrication is imported from other countries.

6.1.2 Cogeneration support

Some governmental dispositions are currently supporting energy production, with incentives depending on the fuel and also the efficiency (to favor high-efficiency cogeneration) with so-called "Rainbow certificates".

More information can be found on the URE (Urzędu Regulacji Energetyki) website:

http://www.ure.gov.pl/download/2/241/Polish_support_schemes_for_renewable_and_cogeneration_so.pdf

Cogeneration based on Uranium is currently not covered in this policy. A comparison with other energies might be distorted as this support represents a quite significant part of the incomes: for gas cogeneration, the support reached in the last years up to 30 €/MWh. Although attractive, CHP support system will last only until 2018 and there is a significant uncertainty regarding the value of support, as the certificates are traded on the power exchange. Overall, energy regulations are still not in the final shape as some laws are being updated creating uncertainty..

6.1.3 Licensing and Regulatory framework

The reference case was based on the licensing framework for Germany. Although we can expect a more standardized licensing framework in the future, experience from past projects have shown that national regulator may have different or additional requirements, compared to European visions developed in the frame of e.g. WENRA.

In addition, non-nuclear regulations -more often country-specific- may require significant design changes, and therefore additional costs (design or construction).

6.1.4 Contractual setup for the project

The Nuclear Energy Project Implementation Organization (NEPIO) may have different approaches for project implementation (e.g. Full turnkey, multi-lot approach…) with significant impact on the project cost. In addition, endorsement of specific risks might be way for supporting bankability of a project by reducing financial burden for the investors. Such initiatives are currently not defined.

6.2 Economic parameters

The general framework of the project is comparable to the one described for the reference case (detailed in ETG GmbH, 2015 § 2 General description of the economic model).

The reference case presented in ETG GmbH, 2015 was related to a real-case configuration investigated in the 90' in Germany. The site mapping in Poland (Deliverable D4.21 in NC2I) as not identified any similar configuration (387 MW of steam production, 98 MW of electricity production).

Parameters that are specific to Poland-case are detailed hereafter. All other parameters –not specifically described- are considered identical to the reference case.

6.2.1 Heat price used in the scenario

In D4.21 European site mapping most of the chemical complexes with energy needs in the range of [160 – 550] MWt are fuelled by coal. Current coal price are quite low (around 60 $/t, eq. 6,9 €/MWh). Given the current situation, commercial operation date for a project will not happen before 2020. It is proposed then proposed to use prices forecast from the World Energy Outlook (edition 2014).

Intercontinental Exchange website (www.theice.com) provides prices for CO2 emissions (6,99 €/t on the 23.03.2015). In order to evaluate a maximum range of variation, "450 Scenario" data provided in World Energy Outlook, 2014 will be used.

As comparison, heat price from gas is calculated with average gas price form S2-2014 available from the European Commission (D4.21 European site mapping).

Table 6-1. Heat prices used in the scenario for Poland

Scenario	Current CO_2 (7€/t)	High CO_2 (30 €/t)
Gas (35.9 €/MW.h)	43.5 €/MW.h	48.4 €/MW.h
Coal (12.3 €/MW.h)	27.3 €/MW.h	36.3 €/MW.h

The resulting price for heat price considered in the revenue stream will be [27 ; 48] €/MW.h.

6.2.2 Electricity price used in the scenario

Polish electricity prices from the European Commission data in 2014 states an average price for electricity of 83,3 €/MWe.h (Excluding VAT and other recoverable taxes and levies) during S2 2014. A precise breakdown to identify the different costs is not possible. However, it is reasonable to consider that the price breakdown is the following: 70% for commodity, 15% Grid Costs and 15% additional fee (including renewables contribution).

Accordingly, the range for electricity price considered in the revenue stream will be [58 ; 83] €/MWe.h.

6.2.3 Tax rate

Tax rate used in Poland is 19%.

6.3 Summary of the Polish case and variations

Figures used for calculations are summarized in the following table:

Table 6-2. Sensitivities of the economics of HTR cogeneration in Poland

Item	Reference scenario	Variation min	Variation max	Min value	Max Value
HTR construction costs	930,8 M€	- 30 %	+ 30 %	651.6	1210.0
O&M costs	23,4 M€/year	0	+ 100 %	23.4	46.8
Decommissioning costs	115 M€	0	+ 200 %	115	345
Fuel costs	27,1 M€/year	- 30 %	+ 100 %	19.0	54.2
Lifetime	40 years	- 30 %	+ 30 %	28	52
Electricity price	58 €/MW_e	0	+ 50 %	58	87
Steam price (incl. CO2)	27 €/MW_{th}	0 %	+ 80 %	27	48.6
HTR Availability	85 %	- 20 %	+ 10 %	0.68	0.94
Tax rate	19 %	0 %	0 %	19	19
Interest rate	8 %	-30 %	+ 50 %	5.6	12
Design and licensing duration	0 years	0	+ 2	0	2
Design and licensing cost	0 M€	0	+ 300	0	300

6.4 Calculation results

NPV calculation shows a negative value of -88.1 M€, under the assumptions of the case described here above. Thus, the project decreases the shareholder value and therefore should not be carried out.

Same as for the HTR reference case, most influent factors are:

- Interest rate
- Availability
- Heat price
- Electricity price
- HTR costs

Once again, these results should be taken carefully, especially because the general framework for supporting high-efficiency cogeneration is not taken into account in the calculations.

In addition, some initiatives to reduce risk or ensuring value for investor could help decreasing the expected interest rate, and therefore increase the project value.

Other parameters such as energy independence or job creation, depending on political support for implementing a nuclear project, could help increasing project's value.

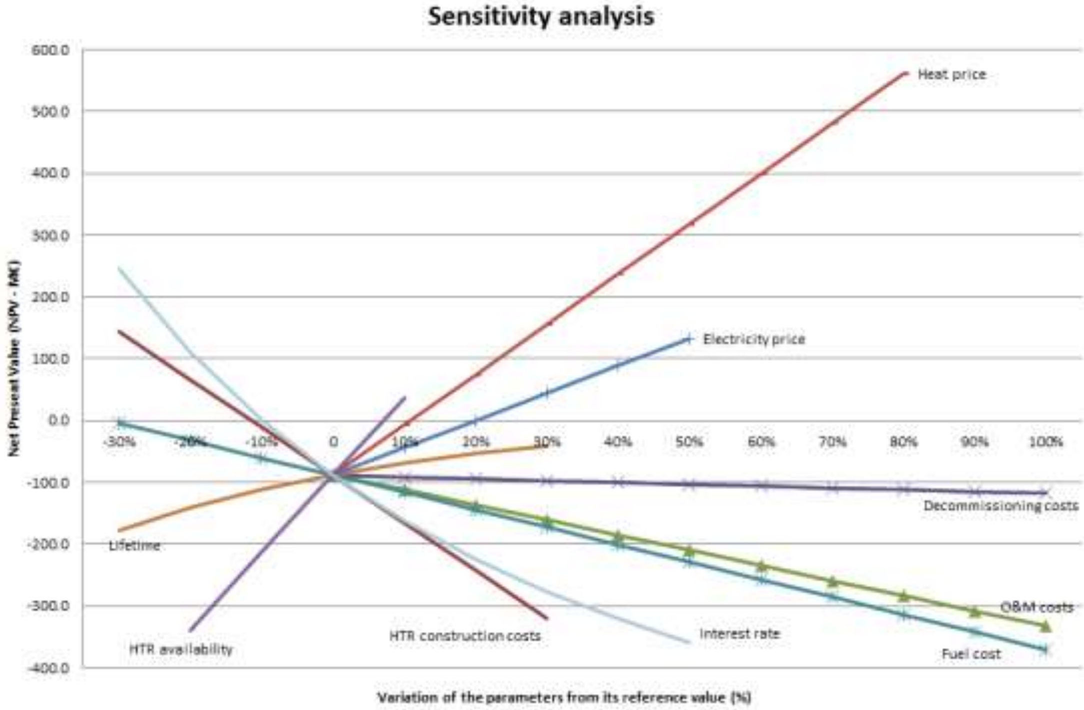

Figure 6-1. Sensitivity of NPV of HTR cogeneration in Poland

6.4.1 Interest rate

The reference interest rate used in the simulation (8%) leads to a negative NPV.
The IRR of the reference case is 7,2%.

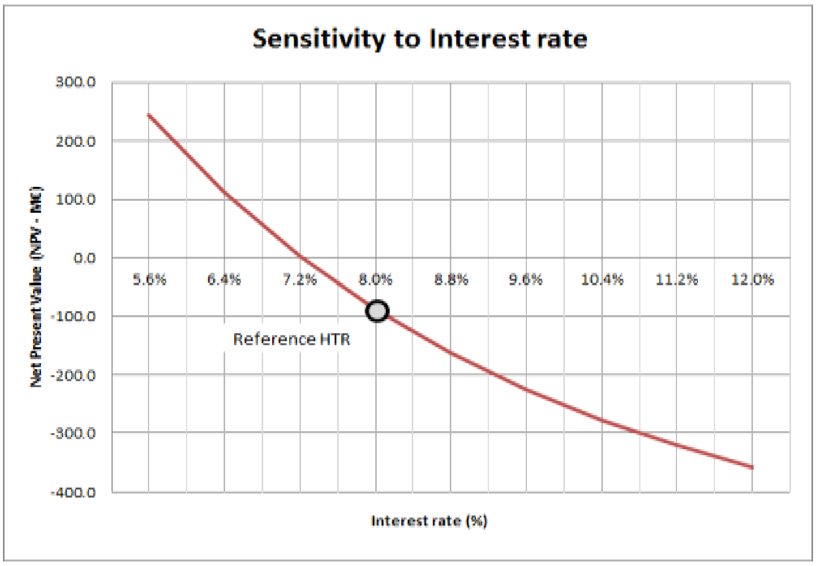

Figure 6-2. Sensitivity of NPV to the interest rate

6.4.2 Energy prices

The reference energy prices used in the simulation (27 €/MW.h for heat, 58 €/MWe.h for electricity) leads to a negative NPV.

Most influent factor for electricity is the use of electricity onsite, instead of selling it to the grid. Case by case studies should be investigated to maximize it.

Related to heat price, the most influent factor would be a policy penalizing CO2 emission, significantly increasing profitability for clusters where coal is the primary fuel source.

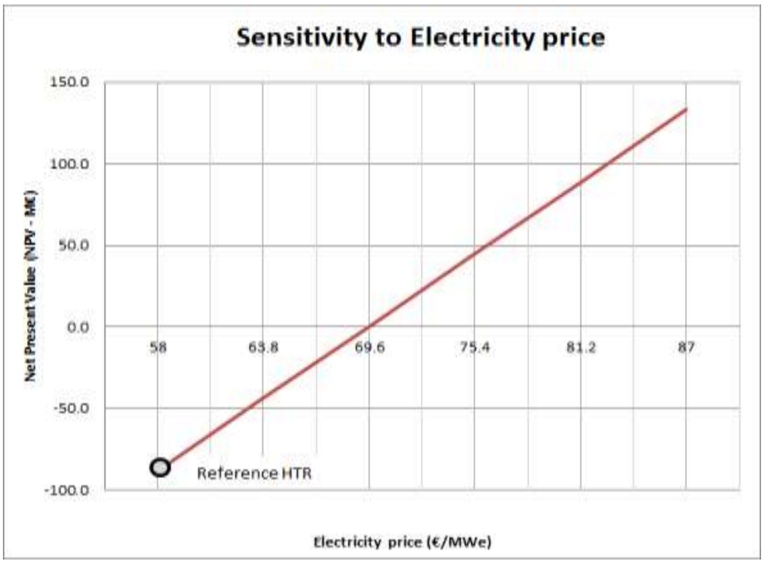

Figure 6-3. Sensitivity of NPV to the electricity price

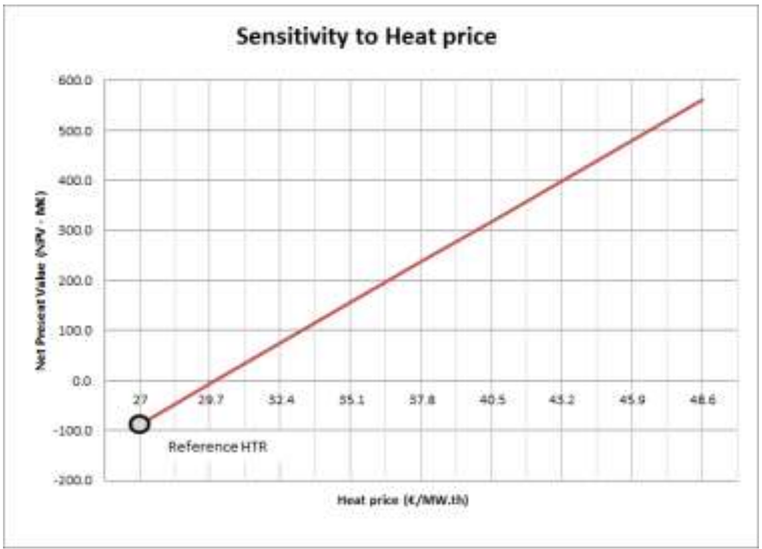

Figure 6-4. Sensitivity of NPV to the heat price

7 HTR Business Models

7.1 Business model overview

Objectives and methodology

This section aims at completing the Economic Assessment conducted in part 3 by providing a big picture of the stakeholders involved in the nuclear cogeneration project for a chemical park, and the interactions between these actors. The objective is to understand how these stakeholders interact with each other, what are the flows exchanged and what constraints are added by the implementation of a nuclear installation on a chemical park. The purpose of this section is then a qualitative understanding of the business operating within a chemical park, the quantitative investigation being described in part 3.

The methodology used is to reach this objective is to understand first the standard Business model of a chemical park and the Business model of a nuclear power plant. Then, the Business Model of a chemical park powered with a nuclear cogeneration installation is described and the boundary conditions are identified. Finally, different options and risks are investigated.

Definition

There is no one definition of a Business Model. Porter (Porter, 2001) explains that the definition of a 'business model' is murky at best and "most often, it seems to refer to a loose conception of how a company does business and generate income". The definition given by Timmers (Timmers, 1998) constitutes a good starting point to understand the concept behind the words 'Business model': "An architecture for the product, service and information flows, including a description of the various business actors and their roles; and a description of the potential benefits for the various business actors; and a description of the sources of the incomes."

Many other definitions of a business model exist in the literature and they converge towards a way to describe how a company operates and logic to create a value for customers in a market segment and how they capture this value in a financial income stream to make a profit (Morris, Schindehutte, & Allen, 2005) (Casadeus-Masanell, 2011). A Business model can also be seen as a story of how the business works according to Magretta (Magretta, 2002). Osterwalder (Osterwalder, 2004) tries to clarify the concept of a business model by saying: "So differently put the business model is an abstract representation of the business logic of a company. And under business logic I understand an abstract comprehension of the way a company makes money, in other words, what it offers, to whom it offers this and how it can accomplish this".

There are different business model tools that enable to map how a company create value and generate revenue from this value. The most famous one, and widely used by the companies is the **Business Model Canvas** developed by Osterwalder and Pigneur in 2010 (Osterwalder & Pigneur, Business Model Generation, 2010). The canvas can be described as a dashboard resuming the main characteristics of the company into 9 building blocks:

Figure 7-1. Business Model Canvas. Source: Osterwalder and Pigneur, 2010

The 9 blocks to describe a business model according to Osterwalder are the following:

- The **Value Proposition** is the set of products and services that add value for the specific customers.
- The **Customer Segments** define the different groups of people or organisations that the stakeholder aims to reach and serve.
- The **Channels** describe how the stakeholders communicate with and reach customers in order to deliver their value proposition.
- The **Customer Relationships** are the types of relationship a stakeholder establishes with his customers.
- The **Revenue Stream** represents the cash a company generates from the sale of value to his customers.
- The **Key Resources** are the most important assets required to make the business model work.
- The **Key Activities** are the most important things a company must do to make its business model work.
- The **Key Partners** represent the network of suppliers and partners that will make the business model work.
- The **Cost Structure** describes all costs incurred to operate the business model.

The advantages of this tool are the widespread use of the Canvas in innovation management and the different levels of detail that the tool allows according to the use: one visual and conceptual while the other one is more deep and analytic. The disadvantages are the restrictive scope to company internal logic only and the lack of tangible product presented. This tool is the one used in this study.

Business case:

In this study, we will consider the case of a chemical park being coupled to a HTR. The HTR delivers heat and electricity to the chemical industries on the park and distributes the extra-energy to the grid.

Boilers and burners are also located on the park and represent additional power sources.

7.2 Current situation

7.2.1 Ecosystem maps

Numerous chemical parks are located in Europe today; more than a hundred were mapped in the deliverable D4.21 *"European sites mapping"*. This large number of sites comes along with different types of organisation/structures of the chemical parks. Nevertheless, most of the energy management structures within a park can be described thanks to the two following ecosystem maps:

Case n°1: No integration

This situation corresponds to a chemical park in which the different activities regarding the energy management are clearly separated between the different stakeholders.

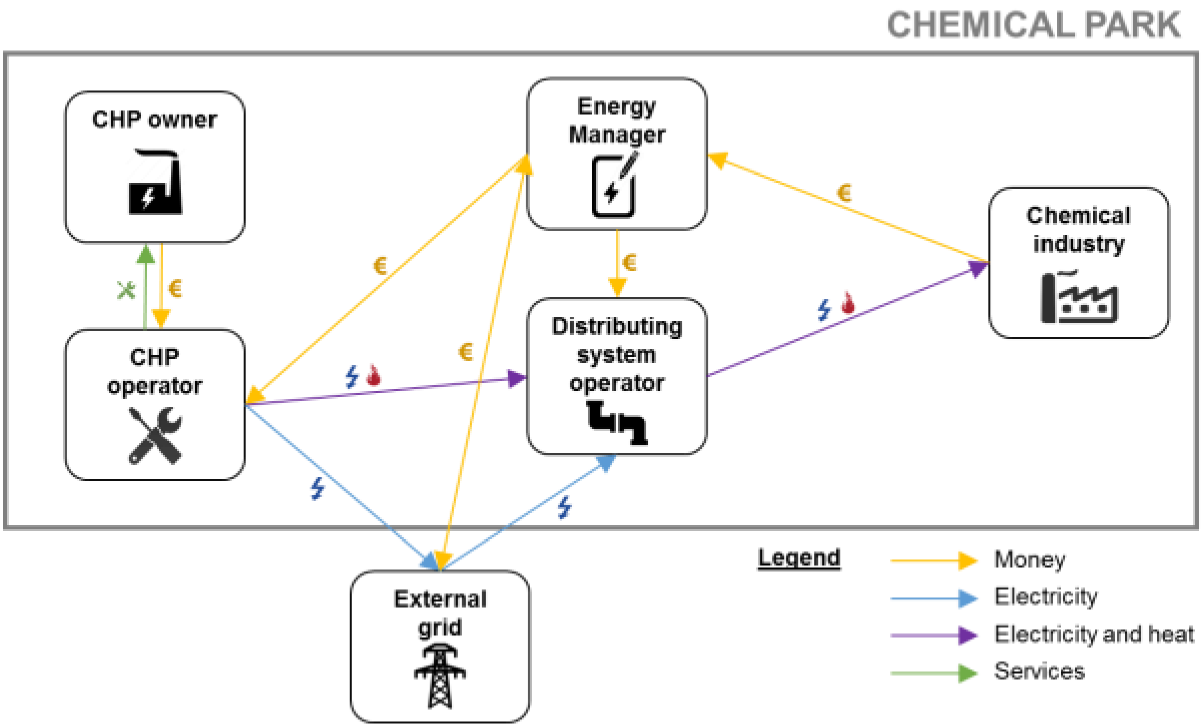

Figure 7-2. Ecosystem map of a non-integrated chemical park

The stakeholders included on such a non-integrated chemical park are the following:

The **Chemical industries** are the end-users of the park. They produce on the site their chemical products and perform R&D. They buy energy delivered by the Distributing system operator to the Energy Manager.

The **Energy Manager** negotiates contracts between energy producers and industries and ensures the continual energy delivery. It only deals with contracts and negotiating but works in close collaboration with the Distributing System operator who deals with the technical engineering required. To ensure the best competitive energy prices, the Energy Manager might buy electricity from the grid.

The **CHP owner** owns the energy production facility and is responsible for the initial investment of the CHP plant but does not operate it and is not responsible of the management of the CHP plant on a day-to-day basis. That is why, the CHP owner only interacts with the CHP operator.

The **CHP operator** operates the energy production facility. It produces electricity and heat but is not in charge of the distribution. Depending on the market conditions, the electricity produced can be distributed to the end-users through the Distributor system operator or can be released to the grid.

The **Energy distribution system operator** operates the pipelines and the whole distribution system between the CHP plant and the end-users. It is in charge of delivering the electricity and heat produced by the plant to the industries.

The **Utility (external grid)** intervenes depending on the selling conditions of the electricity market. The energy manager might want to buy electricity from the Grid rather than using the one produced by the CHP plant. Occasionally, it buys the electricity produced by the CHP plant (depending on the marketing conditions).

The Chemelot park[1] located in the Netherlands constitutes one example of a chemical park in which each stakeholder is clearly identified. USG (Utility Support Group) provides utilities at Chemelot. It buys in utilities such as steam, water and electricity for distribution onsite and delivery to its customers. EdeA operates installations producing and distributing steam, electricity, various types of water and air and technical gases for the plants at the Chemelot site.

[1] http://www.chemelot.nl/

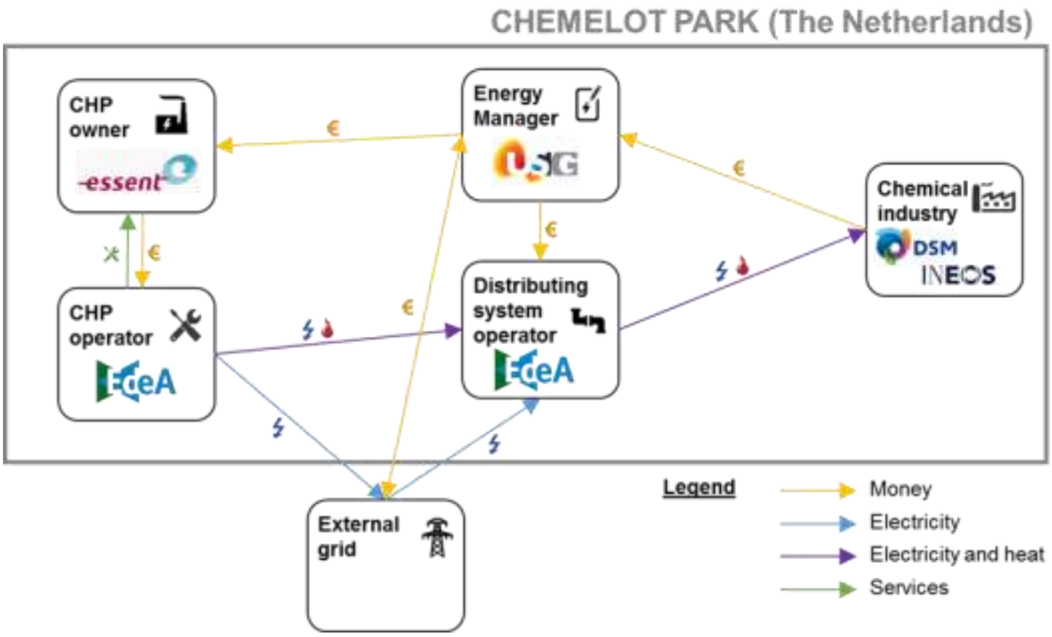

Figure 7-3. Example of a non-integrated chemical park

In addition to utilities, the Energy manager can provide also other services: ensure safety and security, take care of waste management, training management, offers training for employees, etc. This is for example the case of Currenta on the site Chempark-Leverkusen.

Case n°2: Energy stakeholders integration

In some cases, al the stakeholders involved in the production, the delivering and the commercialisation of the energy are integrated. As a result, the energy manager, the CHP owner, the CHP operator and the Distributing system operator represent only one actor: the **integrated Energy Manager**. The ecosystem map is then simplified since only three types of stakeholders intervene:

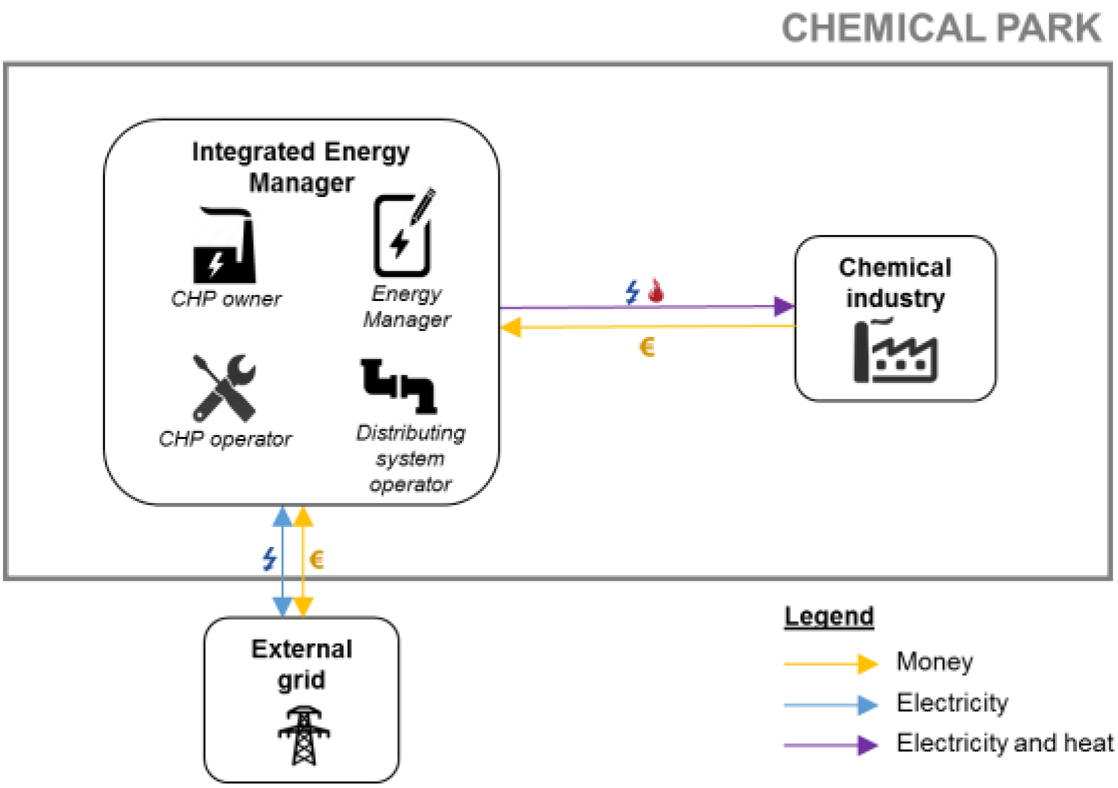

Figure 7-4. Ecosystem map of a chemical park with an integrated energy manager

Companies such as Sembcorp, Nuon and Getec intervene as integrated energy managers for different chemical parks in Europe. For example, Sembcorp provides centralised utilities, energy and steam to industries in Singapore, the United Kingdom (Saltend Chemical Park), Asia and the Middle East. Their main advantage is that the service they provide is their core business, they already have the competencies to operate, distribute energy and negotiate contracts to fit perfectly the customers' requirements.

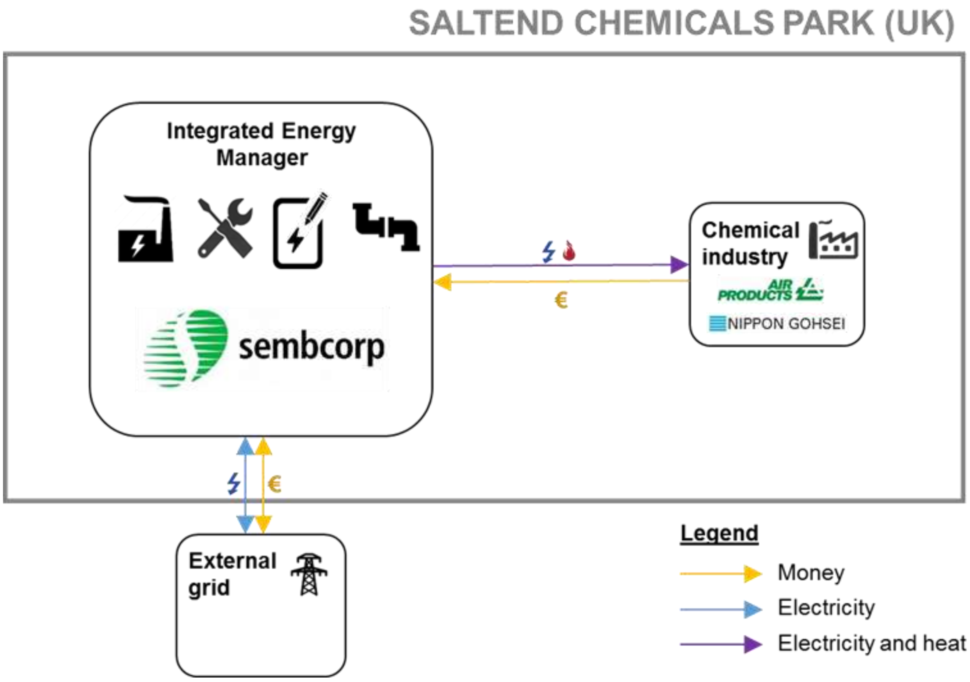

Figure 7-5. Example of an integrated energy manager in a chemical park

Case n°3: Integration of a chemical industry

In the 1980s-1990s, several chemical industry invested in land, especially in Germany to develop chemical parks. Now, they lease the land in the park and are involved in the management and operation of the park. The main advantage for large chemical industries to own their chemical park is the possibility to make decisions that correspond to their requirements concerning important issues (source and technical characteristics of energy, investment, gas pipelines, etc.).
In such cases, chemical industries own the CHP plant and the distribution system. The operation of the installations is either outsourced or conducted by a subsidiary of the chemical industry.

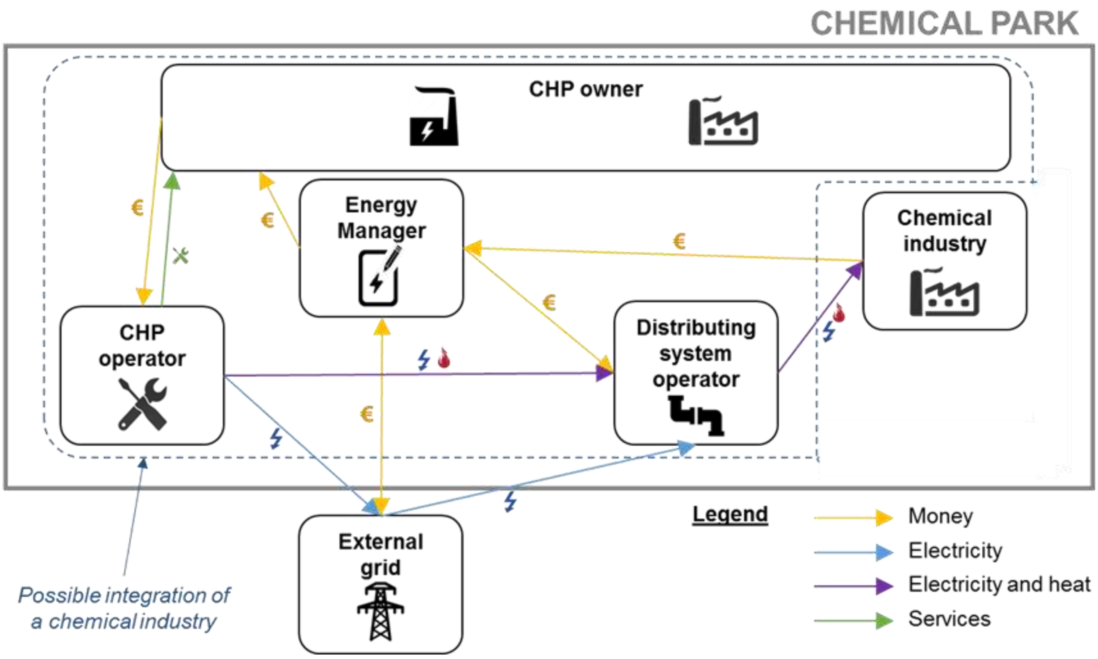

Figure 7-6. Ecosystem map of a chemical park in case of integration of the chemical industry

For example, the company Evonik-Degussa, leader in specialty chemicals, owns the Marl Chemical Park in Germany. The Marl Chemical Park's energy needs are covered by the power and steam co-generation of one site-owned gas and two coal power stations. The plants and the distribution systems are operated by Infracor GmbH, a wholly subsidiary of Degussa (Chemsite Initiative, 2006).
Another example of a chemical industry integration is the Bayer Bitterfeld Park. Bayer Bitterfeld GmbH is a wholly owned subsidiary of Bayer AG. Since 1992, Bayer Bitterfeld GmbH operates the Bayer Bitterfeld Park. Bayer Bitterfeld GmbH owns a power and natural gas supply network, but does not operate it. Indeed, the operation of the plants is ensure by EVIP GmbH while the distribution system as well the overall energy management on general (negotiation of contracts, prices, etc.) is ensured by the company Currenta (Bayer Bitterfeld GmbH, 2013).

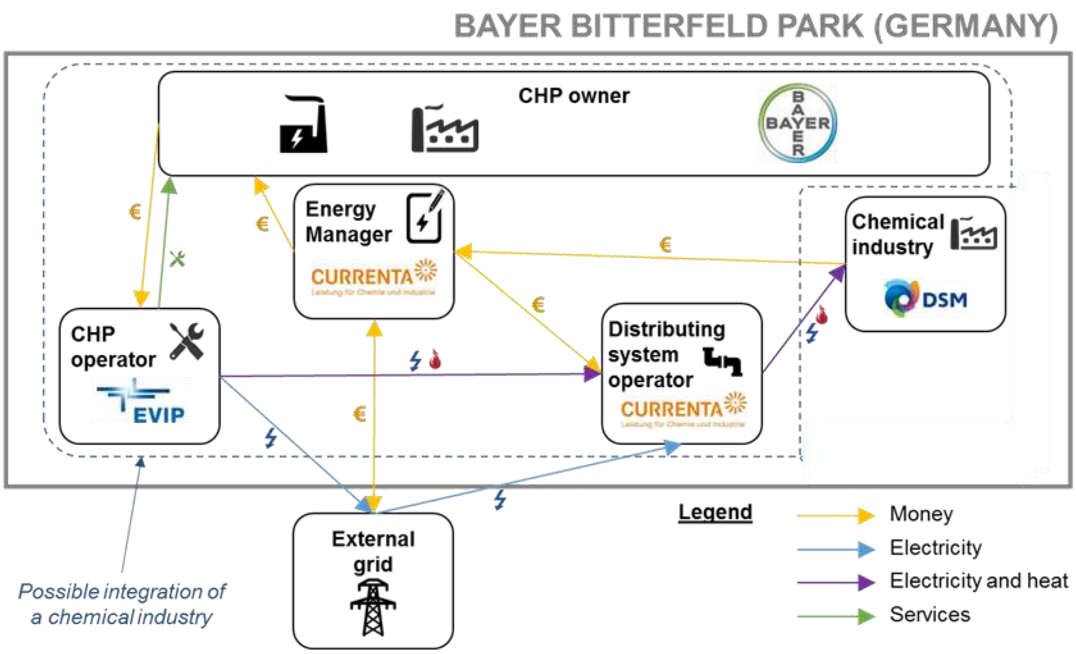

Figure 7-7. Example of an integration of a chemical industry within a park

7.2.2 Business model canvas

To understand better the role and the interactions between the different stakeholders, the Business Model canvas from Osterwalder are described below for key actors.

The Chemical industry

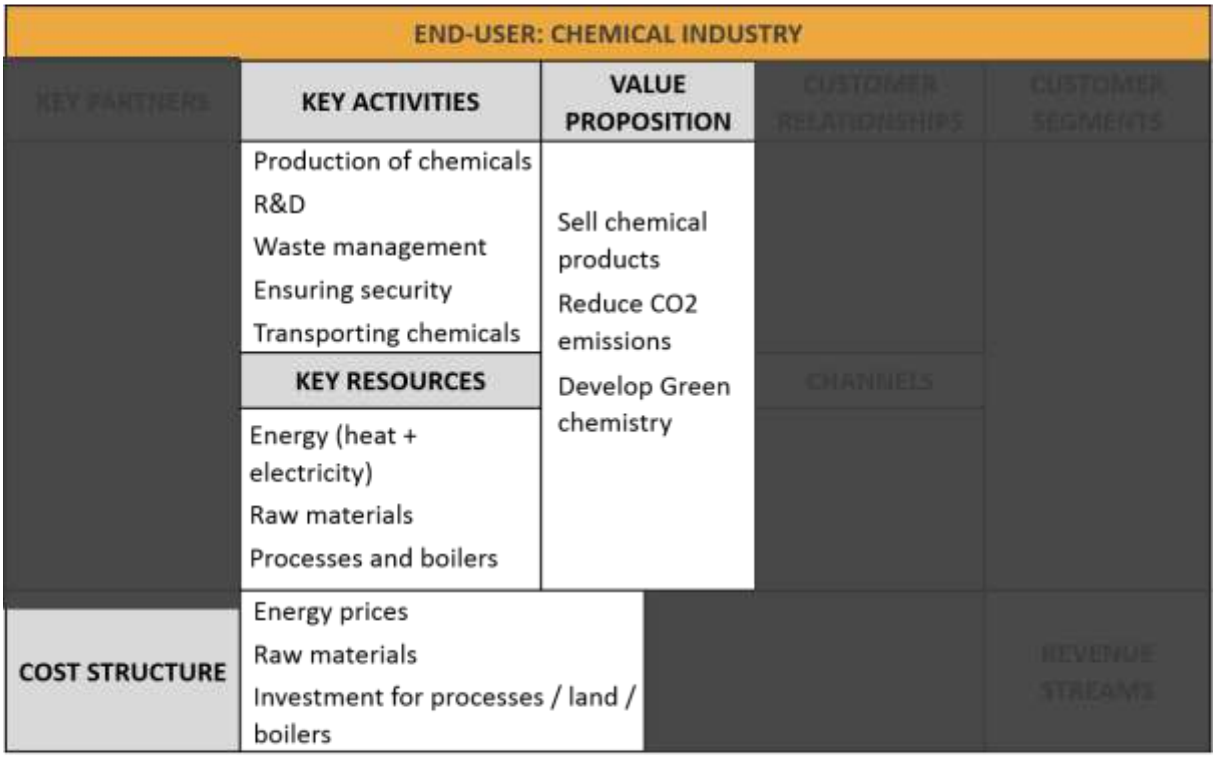

Figure 7-8. Business model canvas for a chemical industry

The value proposition of a chemical industry is to produce and sell chemical products without neglecting several external conditions such as the environment or the safety, more and more important for industries. Chemical parks presents several advantages to maximise this value proposition. Indeed, chemical parks enable the chemical industries to focus more on their core business by dealing for them with subsidiary issues such as the energy sourcing or waste management. The energy manager of the park takes care of the contracts while the CHP operators and the Distribution system operator handle the technical issues to deliver the heat and electricity with the given constrains. The energy is key for chemical industries. Indeed, energy represents in average 50% and can go up to 80% of the production cost (IEA, 2008). Chemical parks give the opportunity to outsource the energy management to a third-company whose only activity is to ensure best competitive energy costs. This outsourcing enable the industries to put all their resources on their core business, e.g. producing chemicals and conducting R&D. The integration of the energy manager with the CHP owner, and the CHP and distributing system operators (case n°2) does not affect much the Business model canvas of the chemical industry. In both cases, concerning the energy management, the industry interacts only with one actor.

Energy Manager

Case 1: no integration

CASE N°1: NON-INTEGRATED ENERGY MANAGER				
KEY PARTNERS	**KEY ACTIVITIES**	**VALUE PROPOSITION**	**CUSTOMER RELATIONSHIPS**	**CUSTOMER SEGMENTS**
CHP owner Distributing system operator Utility (external grid)	Negotiates contracts with industries Buys electricity from the grid	Ensures the supply of heat and electricity 24-7 with given characteristics (V, T°, P, etc.) Supplies energy at best prices	Enables the chemical industries to focus on their core business	Industries located on the park
	KEY RESOURCES		**CHANNELS**	
	Negotiation skills Juridical workforce		Direct relationships (onsite)	
COST STRUCTURE	Energy bought from CHP operator	Contracts from industries Money from surplus electricity to the grid	**REVENUE STREAMS**	

Figure 7-9. Business model canvas for a non-integrated energy manager

When the Energy Manager is not integrated (case n°1), the Energy Manager is in charge of the estimation of the demand, negotiation of the contracts with industries, ensuring to buy the electricity at the lowest prices (balancing between the CHP plant and the Grid). The resources of the Energy Manager is then mainly then a qualified workforce since the technical engineering required is taken care by its key partners (CHP operator, and the Distributing System operator).

Case 2: Integrated Energy Manager

In case n°2, where all the energy actors are integrated, the business model canvas is modified.

CASE N°2: ENERGY MANAGER INTEGRATION				
KEY PARTNERS	**KEY ACTIVITIES**	**VALUE PROPOSITION**	**CUSTOMER RELATIONSHIPS**	**CUSTOMER SEGMENTS**
External grid	Negotiates contracts with industries Buys electricity from the grid Operates CHP plant and distribution network	Ensures the supply of heat and electricity 24-7 with given characteristics (V, T°, P, etc.) Supplies energy at best prices	Enables the chemical industries to focus on their core business	Industries located on the park
	KEY RESOURCES		**CHANNELS**	
	Negotiation skills Juridical workforce Distributing system Technical workforce CHP plant		Direct relationships (onsite)	

COST STRUCTURE	Energy bought from CHP operator Coupling system investment CHP investment O&M CHP costs	Contracts from industries Money from surplus electricity to the grid	**REVENUE STREAMS**

Figure 7-10. Business model canvas for an energy manager integration

The right section of the Canvas does not change with the integration: the value proposition remains the same as well as the customers. However, since the energy manager is more integrated, the range of its activities is larger and the partners required are less numerous. The resources include now infrastructures and technical workforce.

In some cases, the energy manager is also in charge of additional services such as waste management and raw material supplier. Once again, it enables the chemical industries to outsource all the activities that are not part of their core business. For example, the society Currenta in Germany plays numerous roles in the Chemparks Leverkusen and Dormagen.

7.3 Ownership models for NPP

Economic analyses for the HTR-used for cogeneration were calculated to identify the major factors that influence the economics of HTRs in-integrated processes. The analyses were based on a simplified business model in which a single entity owns and operates the industrial and associated HTR plants. In this chapter it is reviewed how the different business models can impact the economics or risks of the HTRs used for cogeneration.

Possible models for the ownership and construction of industrial HTR cogeneration can be:

- Standalone entity or NPP built & operated by electricity utility
    - Utility Control
    - EPCM Contract
    - EPC Contract or Turn-Key Project
- Multiple Owners or Group Financing
- Vendor Financing
- Build-Own-Operate (BOO)
- Lease-to-Own

The identified models are not covering all possible models for the ownership, but a list of models that exist within nuclear sector. The models are presented in a simplified way to describe the main differences from the ownership and financing perspective. The following main roles can be identified:

- Industry and other end users
- Vendors (Technology and system providers)
- Energy utilities
- Contractors
- Operator i.e. O&M company
- Lenders

It is important to notice that in some models the previous roles overlap as an energy company may be a supplier, leasing company, and/or an O&M service provider.

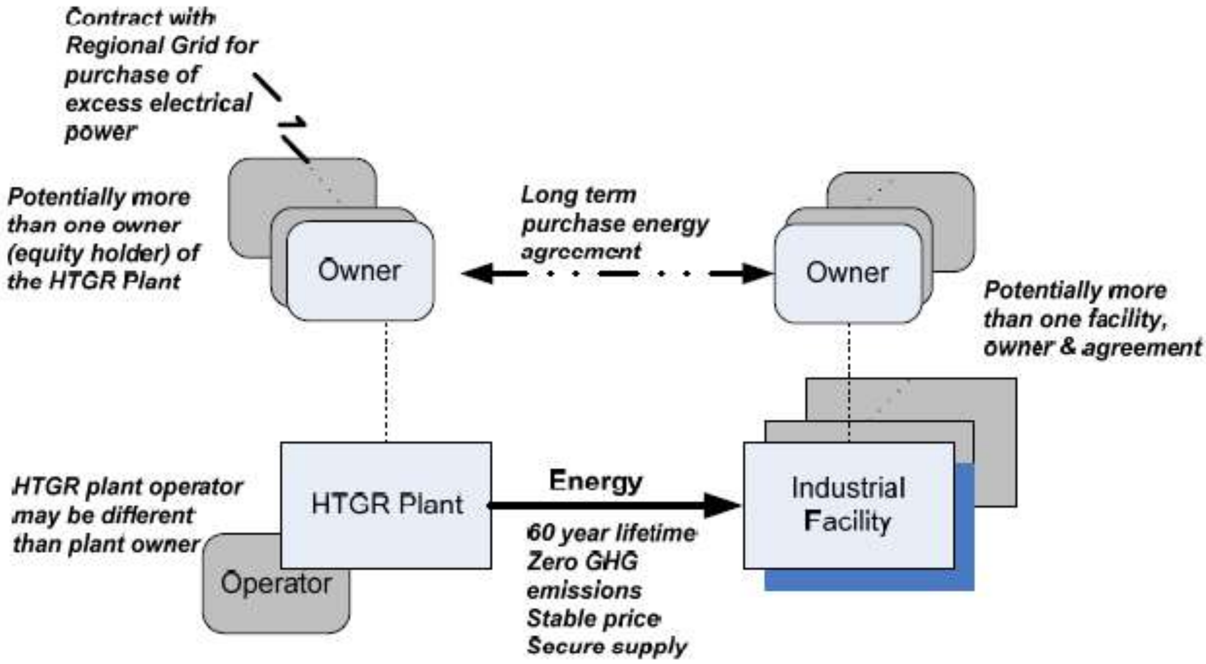

Figure 7-11. Interacting parties in HTR (or HTGR) plant operation *(Source: INL, Next Generation Nuclear Plant Project Evaluation of Siting an HTGR Co-generation Plant on an Operating Commercial Nuclear Power Plant Site, October 2011)*

7.3.1 Standalone entity

In the basic business model the HTR plant is assumed to be a standalone entity owned by a utility company. It is assumed that the owner of the HTR plant would enter into long term energy supply agreements with the industrial facility or facilities. The excess electricity would be sold to the electricity markets or to regional utilities with similar terms than the ones with industrial contracts. To achieve the suitable economic feasibility, these agreements need to ensure the full use of HTR plant's energy at a high capacity factor over the 40 year lifetime of the plant.

The owner could also be the industrial plant itself producing heat and electricity to its own need. In the case of nuclear cogeneration, however, it is unlikely that an industrial company would solely make the investment to the technology as a very specific knowledge on the technology and energy sector is needed. Therefore it is assumed that the industrial plant is not the sole owner of the plant.

Typically, energy supply contracts will only extend for several years. In general they contain clauses for price adjustments over this period, (e.g. to account for inflationary factors) and provisions for continuation. It is important that such contracts between the cogeneration plant and the energy off-takers provide adequate incentives for continuing these contracts over the life time of the plant. This is necessary because nuclear plants have high capital costs but very low operating costs. During the period of capital recovery, capital recovery makes up to 60-70% of the operating costs. Accordingly, achieving the required internal rate of return on equity relies on long term operation with a high capacity factor.

Utilities can have different strategies for the project contracting. The commercial arrangement defines who carries different risks in the project. In projects under utility's control the vendors are contracted separately, they are in a direct contract with the utility and contractor manages his scope and responsibility directly towards the utility. In this model the majority of the risks lie on owner's due to obligation to coordinate all the contracts and performance project management and success lies on the utility. The performance, cost, and schedule risk depend on the skills of owner's personnel and how well they integrate the work of the contractors.

In an EPCM (Engineering, Procurement and Construction Management) contract the EPCM contractor takes responsibility for the provision of engineering and design services, generally acting as an agent of the owner, and manages and supervises the procurement and construction phase. Generally an EPCM contractor does not assume time, cost and quality risk for the project but the project owner carries the risks.

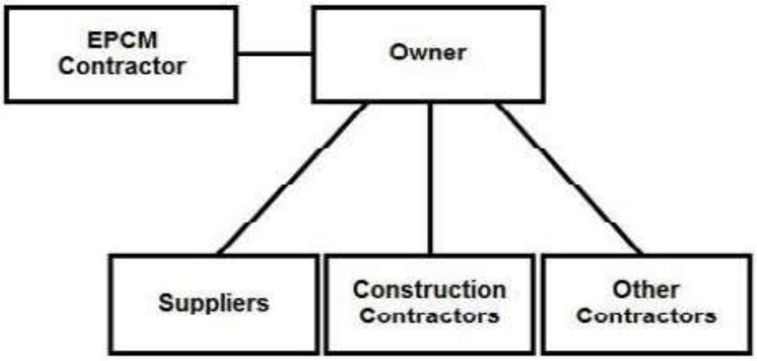

Figure 7-12. The basic structure for an EPCM delivery model *Source: Dawson, B. 2011*

Engineering, procurement and construction (EPC) contracts are a common form of contracting on large-scale and complex projects. Under an EPC contract a contractor is obliged to deliver a completed project from design to the owner on a turn-key basis. The contractor must deliver the facility for a guaranteed price by a guaranteed time and it must perform on a predefined level. An EPC contractor generally carries the schedule, cost and performance risk for the project.

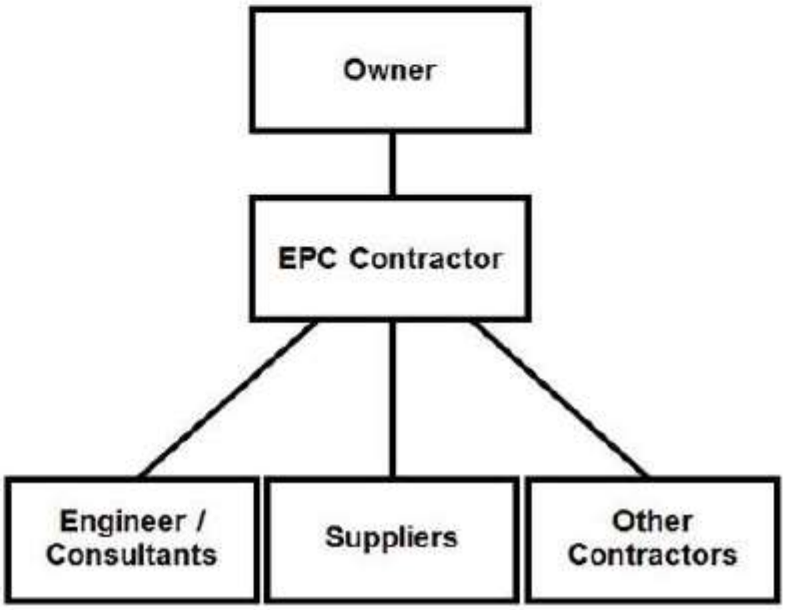

Figure 7-13. The basic structure for an EPC delivery model *Source: Dawson, B. 2011*

7.3.2 Multiple Owners or Group Financing

Multiple entity ownership could be used to share the investment and market risks with several owners. As the interests how to operate the plant between different type of owners e.g. industry and utility may differ from time to time clear rules need to be make on cost allocation and if conflicts of interest occur e.g. while defining the optimal time for maintenance breaks and while defining whether to produce electricity or heat or both.

In the history several nuclear sites have been built as a shared investment of several stakeholders. In Germany e.g. E.On Kernkraft is a shareholder in several nuclear plants which have two or multiple owners (e.g. Gundremmingen) and E.On is also operating some of its co-owned plants (e.g. Brokdorf, Grohnde, Isar-II/Ohu). The owners have typically been utility companies or local city owned energy companies.

Mankala model

There are examples of industrial cogeneration plants in Finland where the industrial CHP plant is co-owned with the industrial owner and with the local utility or electricity partner. The CHP plant provides the industrial plant electricity and heat to its process needs and electricity and heat to the municipal owner and electricity to the possible electricity partner. This type of concept is generally based on the so-called 'Mankala principle' where shareholders hold a right to a certain amount of energy output of the Mankala plant, corresponding to their shareholding The similar structure exists in nuclear sector also although there the ownership involves only ownership to the electricity generated by the Mankala owned company.

Mankala is a widely used business model in the Finnish electricity sector, whereby a limited liability company is run like a zero-profit-making co-operative for the benefit of its shareholders. The model has been successfully applied to allow shareholders to join their resources to acquire a particular resource, typically a generation asset. The company operates as a zero-profit cooperative and supplies electricity and/or heat to shareholders at cost price. The owners of a Mankala company are committed to the company as electricity off-takers and at the same time they commit to cover their share of the actual costs of the Mankala company. By this way the Mankala company is not exposed to market risks, as these are taken by the end users. The structure is attractive for banks, as several creditworthy owners or end users will ensure the long term cash flow, and as a result the project company can be heavily leveraged. However, the structure is heavy, entails extensive legal and financial arrangements and documentation, and therefore high transaction costs.

The Mankala model is not based on a specific law, but rather, it is established on a case by-case basis through the company's Articles of Association and Shareholders' Agreement. TVO and PVO are the best known Mankala companies in Finland.

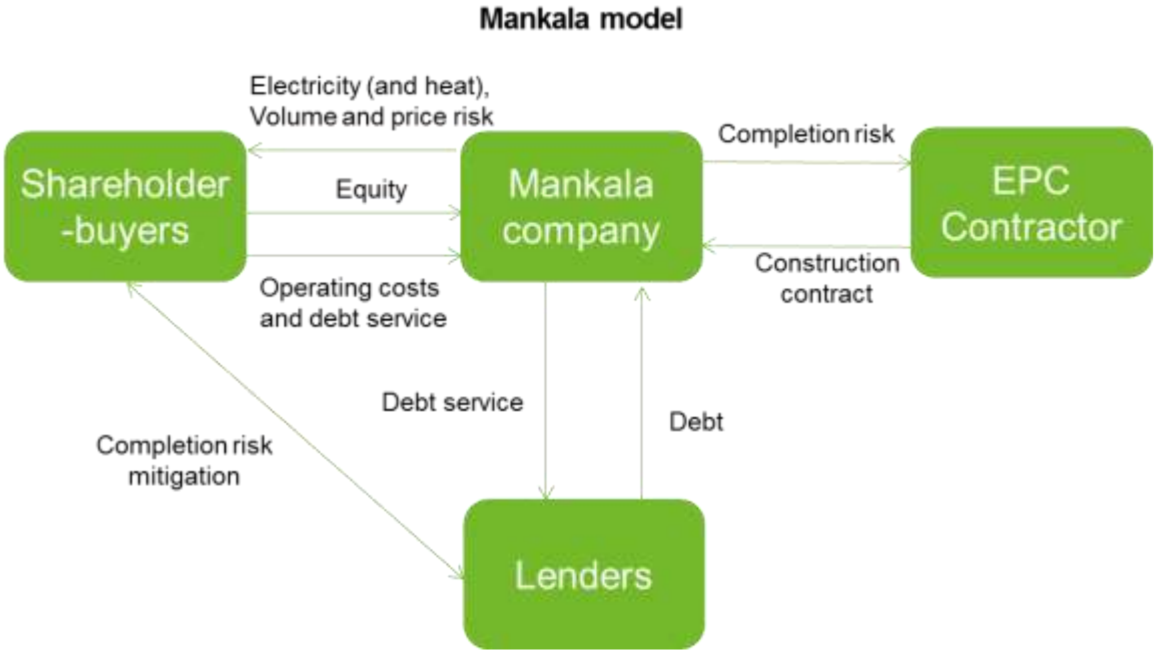

Figure 7-14. The basic structure for a Mankala model

In the Mankala Model, multiple investors diversify the risk and the construction risk is usually limited by entering into an EPC contract with the contractor. Generally part of project equity and loans are provided by the large companies. Long-term power purchase agreements from large customers ensure a stable future revenue stream from the project.

Vendor financing

Vendor financing is an option to finance the project and it is independent from the final ownership model. However, here it is listed as another option of shared ownership between the vendor and other shareholders. Vendor finance can refer to different financing options including vendor arranged credit, vendor provided credit, and vendor equity. In vendor arranged credit, the vendor facilitates financing from sources such as relationship banks and export credit agencies. Vendor arranged credit does not appear on the vendor's balance sheet. Vendor provided credit is often short-term, such as construction loans.

In vendor equity financing vendors (nuclear reactor/NSSS suppliers) get a share of future net income generated by the nuclear power project. From a risk perspective, vendor equity is a riskier than lending or selling. Vendor finance can be relatively expensive compared to cost of capital from other sources. Project developers need to have a to look at the vendor's cost of capital, the cost of equity, and the cost of borrowing.

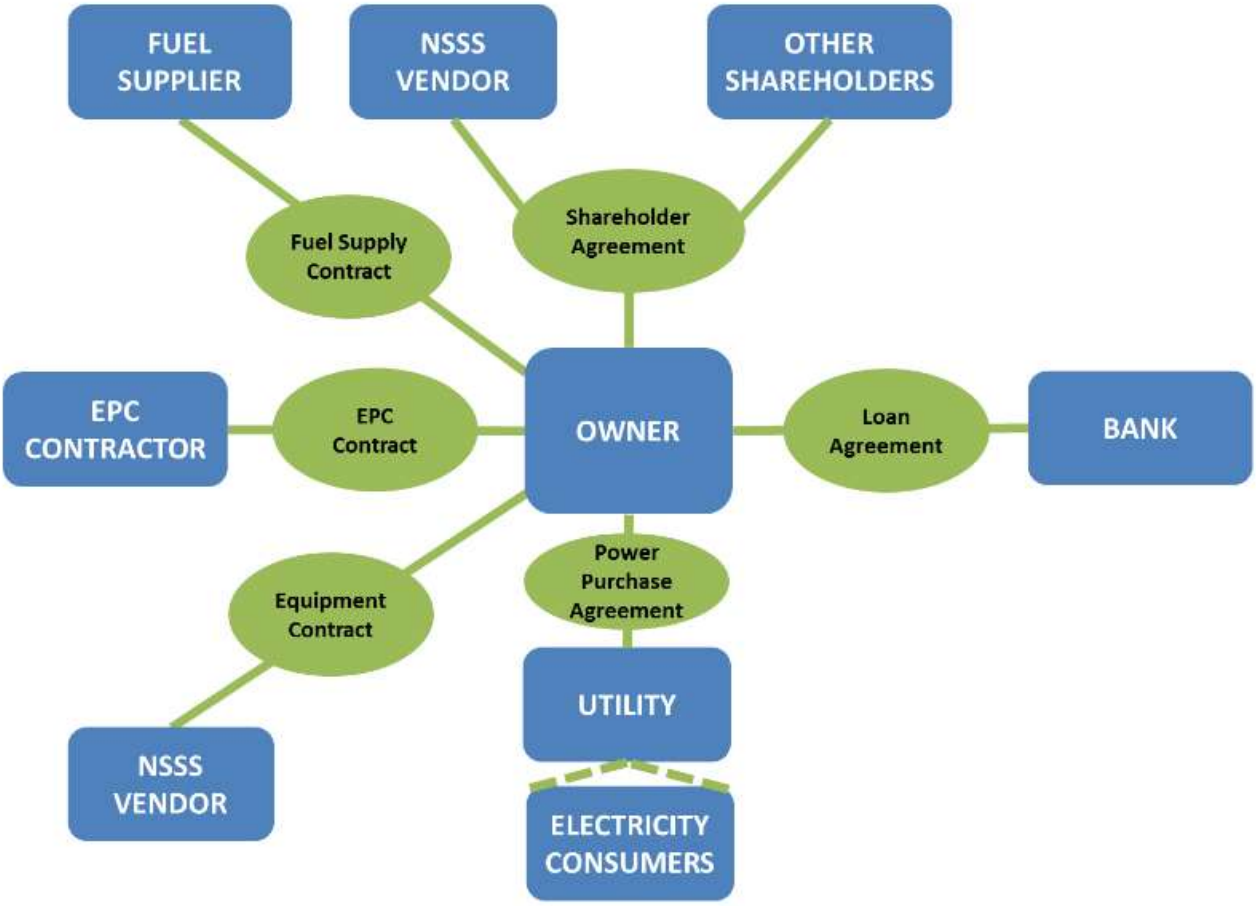

Figure 7-15. Vendor Equity Financing

Source: Financing Nuclear Power Projects: New and Emerging Models, IFNEC Finance Workshops and Panel Session, 2014

In nuclear sector there are some examples of Vendor Equity Financing. Lithuania sought equity investors for Visaginas in early 2011, and Hitachi GE offered to take an equity stake. The United Arab Emirates contract provides for equity shares for Emirates Nuclear Energy Corporation (ENEC) and Korea Electric Power Corporation (KEPCO). In November 2012, the board of directors of KEPCO resolved to invest US$ 1.04 billion in Barakah One Company in exchange for 18 percent equity interest in the company. Actual capital contribution is scheduled to be made in April 2018. AREVA will have 10 percent equity in Hinkley Point C. EDF will have 45-50 percent, China General Nuclear Cooperation and China National Nuclear Corporation will have 30-40 percent, and others potentially ~15 percent.

7.3.3 Build-Own-Operate (BOO)

A Build-Own-Operate (BOO) approach is a third-party ownership model, in which the nuclear facility is built, owned, and operated by the third party e.g. a vendor. BOO model is quite common in the power generation sector. With a BOO contract, the investor is responsible for design, construction, operation, maintenance, and decommissioning. The funding comes from investor's own assets and the investor owns the project outright and retains the operational risks and all of the operating revenues. Therefore the investor gets the benefits of any residual value of the project. This framework is typically used when the physical life of the project coincides with the concession period. A BOO scheme involves large amounts of finance and long payback period.

More countries are looking to build their first nuclear power plant and the BOO model is seriously being considered for its benefits such as training, experience, and financial support. Rosatom Overseas, a subsidiary of Russia's State Atomic Energy Corporation ROSATOM, is using the ‘build own operate’ (BOO) model to build Turkey’s first NPP, based at Akkuyu in southern Turkey. Construction is to start in 2015.

However, if a country wants to start developing its own nuclear industry the BOO model might not be the most optimal. On the other hand, “certain countries, such as the US, have laws which restrict ownership of strategic assets including nuclear power plant and therefore the BOO model might not be possible.

7.3.4 Lease-to-Own

Some technology providers have chosen to act as lessors towards their clients, thus promoting the sales of the equipment. In the model the technology supplier retains the ownership of the equipment during the leasing period. Supplier or vendor finance has been typical in energy sector especially for new technologies. As the market matures, the business typically becomes more demand driven, meaning for example more active role and ownership by traditional energy companies, institutional investors and end users.

The specific challenge in the supplier leasing model is that technology suppliers or system providers seldom want to be involved in the ownership of the energy generation assets, if not specifically required. Leasing of the equipment instead of sales ties extensive amount of capital, and can become a financial burden for the supplier.

In this model the technology supplier makes an equipment supply agreement with the customer, who in turn makes a leasing agreement with a mainstream leasing company and, if needed, an O&M agreement with the supplier (or a separate O&M company). In the leasing model the equipment is typically transferred to the customer with minimal or no residual value in the end of the leasing period.

7.4 Concept for cogeneration

7.4.1 Business model of an HTR coupled to a chemical park

As described in previous sections, there are numerous possible combinations between the existing business models of a chemical parks and the ownership model of a NPP. Nevertheless, the ecosystem map would likely be close to the case n°1 (no integration) of the Business model of a chemical park. Indeed, due to the large initial investment which represents a HTR, the CHP owner will likely be a consortium (made of technology provider, utility, etc.), whereas the role of the operator is very specific and required highly-qualified competences in the nuclear field.

From a business point of view, the main advantages of the implementation of the HTR is to ensure a fixed energy price and the security of supply. These advantages make the role of the Energy Manager of the park easier: the market conditions are simplified and the best energy prices for industries is easier to ensure.

In most chemical parks, the role of the Energy Manager is key since it is the decision-making entity which chooses the energy source. The NC2I Business Group should also include this type of stakeholders to understand precisely their needs and requirements.Business model components in the cogeneration model

The main aspects of the business model components discussed in Chapter 7.1 Business model overview have been compared against the different ownership models of nuclear cogeneration. There are some differences in customer segments as in some areas owners are also the customers for the end products and in e.g. cost structure.

Table 7-1. The main aspects of the business model components

	Standalone entity	Multiple Owners		Build-Own-Operate (BOO)	Lease-to-Own
		Mankala company	Vendor Financing		
Customer segments	Industrial heat and electricity customers, electricity market, district heating	Joint owners, electricity markets	Industrial heat and electricity customers, electricity market, district heating	Industrial heat and electricity customers, electricity market, district heating	Industrial heat and electricity customers, electricity market, district heating
Customer relationships	Business-to business relationship	Business-to business relationship	Business-to business relationship	Business-to business relationship	Business-to business relationship
Channels	Direct sales (long-term), electricity markets	Delivery of energy (marketing is not needed)	Direct sales (long-term), electricity markets	Direct sales (long-term), electricity markets	Long-term agreements
Value proposition	Long-term energy contracts	No energy market risks	Long-term energy contracts	Long-term energy contracts	Long-term energy contracts
Key activities	Energy production	Energy production, participating investors	Energy production	Designing, constructing, investing and operating the plant	Designing, constructing, investing and operating the plant
Key resources	Energy production equipment	Energy production equipment	Energy production equipment	Energy production equipment	Energy production equipment
Key partnerships	Buyer- supplier relationships	Involved shareholders	Joint ventures, buyer- supplier relationships	Strategic alliance with the utility, buyer- supplier relationships	Strategic alliance with the utility, buyer- supplier relationships
Revenue streams	Heat and electricity sales	Shareholders covering actual costs (no taxable profit)	Heat and electricity sales	Heat and electricity sales	Leasing fee
Cost structure	Cost-driven	Same price for all owners	Cost-driven	Cost-driven	Cost-driven

7.4.2 Roles and risks in the ownerships models

The roles and responsibilities differ depending on the ownership model between the main participants: energy utility, industry and vendors. The following tables show the simplified division of the roles between the different participants according to their ownership.

Table 7-2. Main roles in the ownerships models

Roles	Standalone entity	Co-owned generation plant	Build-Own-Operate (BOO)	Lease-to-Own
Utility	Full ownership	Partial ownership	Purchasing energy	Purchasing energy
Industry	Purchasing energy	Purchasing energy / Partial ownership	Purchasing energy	Purchasing energy
Vendor	Sell equipment and services	Sell equipment and services / Partial ownership	Full ownership	Fixed-term ownership

The risks falling on different ownership models depend on the markets, delivery of the nuclear plant and on the ownership model. The level of risk has been estimated for the main parties in the following table. The final risk level depends greatly on the market prices, regulation and contracts that are consummated.

Table 7-3. Level of risk for different parties in the ownerships models

Roles	Standalone entity	Co-owned generation plant	Build-Own-Operate (BOO)	Lease-to-Own
Utility	Depends on a market, may be high	Moderate	Low	Low
Industry	Low	Moderate	Low	Low
Vendor	May be high (turnkey delivery)	May be high (turnkey delivery) / Moderate (ownership)	Depends on a market, may be high	Depends on a market, may be high

There are several possibilities for a business model to be created round HTR cogeneration. The role of an Energy Manager is important as it negotiates contracts between energy producers and industries and ensures the continual energy delivery. The energy manager also works in close collaboration with the distribution system operator and in order to ensure the best competitive energy prices, the Energy Manager might also buy electricity from the grid.

If the energy manager is more integrated with the CHP owner, and the CHP and distribution system operators, the range of its activities is larger and the partners required are less numerous. The energy manager could also be in charge of additional services e.g. waste management and raw material supplies enabling the industry to outsource all the activities that are not part of their core business.

Shared ownership model is a possibility to involve industrial customers to be part of the cogeneration concept. As energy generation is not their core business it is unlikely that they would invest on their own to nuclear technology requiring a lot of specific technological know-how but as a partial owner they can share the risk of the investment and in return receive a long-term energy delivery at competitive prices.

7.5 Nuclear cogeneration market and potential opportunities

The precondition for a successful cogeneration from HTR is to have the site close to the consumption i.e. to the industrial process or district heating network. Especially when it comes to the delivery of high temperature steam the range of delivery should be minimised. High temperature steam cannot be delivered for long distances but the sites need to be close to each other in order to ensure the high quality steam to meet the process requirements.

District heat can be delivered from longer distances meaning that the nuclear site can be sited further from the inhabitation. The distance is limited by the feasibility of the pipeline from the plant to the district heating network. The further the transportation distance the more expensive the pipeline is and the district heat delivered results in higher pumping costs and may require additional heating to the wished delivery temperature.

While the heat shall be produced close to where it is consumed the electricity may be easily exported to the grid. Electricity markets have deregulated in the Europe and excess electricity can be sold at the market price to the markets. The heat produced by nuclear cogeneration must match the heat demand of the industry where it is located and therefore also the plant size should match with the industry demands. However, as HTRs are quite small in sizes they can be quite easily be matched with the heat demands of local industry and by having several modules the security of supply can be increased.

Clear opportunities that have been identified for nuclear cogeneration are:

- Integration of nuclear actors downstream in the value chain for chemical parks as integrated Energy Manager. Indeed, companies such as EDF already have the knowledge of electricity transport and dealing with companies for electricity contracts. They have the competencies to negotiate and study market price to ensure best electricity price to the industries.
- Energy storage: to be economically viable it is more than likely that the capacity of the HTR will be a few hundreds of MWe. Many European parks have an electrical demand below 200MWe. To optimize the use of the HTR, energy storage is a solution and an opportunity. Energy consists in using the extra energy by storing it under another form. The technical solutions which can be

considered are the production of hydrogen and the Coal-To-Liquid process. In both of these cases, energy vectors, whether it is hydrogen or liquid fuels, are produced.

- Development of district heating: once again, in order to optimize the use and the capacity of the HTR, steam produced by the reactor could be used to supply heat to a town located close to the chemical park. It would require technical adjustments since the steam temperature used in district heating infrastructures cannot excess 120°C (Mayor of London, 2013)and the output temperature of the HTR is around 750°C. The addition of district heating in the applications of HTR involves a new enter – a local utility - in the Business model of the HTR (see dedicated part).
- Development of new chemical parks: this situation corresponds to the situation in Piketon, USA. The Piketon site is a former nuclear site example on which the NGNP Industry Alliance plans to develop an HTR. In a longer-term view, the HTR could be coupled to industries or other renewable sources.

8 Conclusions

The European Commission is looking at cost-efficient ways to make the European economy more climate-friendly and more energy efficient. In order to meet the targets for emission reduction CO_2 free and cost efficient technologies are needed to secure the cost competitiveness of European industries. The nuclear co-generation demonstration aims to prove a concept for a CO_2-lean, competitive and reliable energy source for the process industry which could at the same time reduce CO_2 emissions, increase security supply and secure the cost efficient energy source for the industry.

A suitable industrial sector for the nuclear co-generation is the process industry which requires constant heat and electricity to its processes. The chemical industry presents the best opportunities for the implementation of high temperature nuclear cogeneration. The sector is suitable as it already uses cogeneration, the required temperatures correspond to the output of an HTR and the power capacity of several parks is large enough to be compatible with the size of an HTR. There is also a strong willingness to decrease the CO_2 emissions. It is expected that the profile of the chemical industry (the size and location of the parks) will remain the same as nowadays and no completely breakthrough innovative process is upcoming.

In the steel industry many processes require high temperature steam above 700°C. The development of innovative processes in the steel industry in the frame of the ULCOS programme has been delayed due to the decreased sales and production of the steel industry in Europe. The most advanced one, the TBF-GR (Top Gas Recycling Blast Furnace) requires additional amount of heat but the demonstration project is currently stopped.

The hydrogen production mainly uses the Steam Methane Reforming (SMR) process, which is a possible application for high temperature nuclear cogeneration. Research is ongoing and budgets will be allocated to projects developing the innovative processes: HT electrolysis and cater splitting (thermochemical cycles).

The CTL (Coal To Liquid) and the CCS (Carbon Capture and Storage) technologies were identified as potential applications for high-temperature nuclear cogeneration. Depending on the process used, CTL requires temperatures between 450°C and 800°C which are compatible with HTR's output temperature. This application is particularly of interest for Poland which has important coal resources and is a possible host-country for the commissioning of a HTR demonstrator. The CCS technologies could be applied to highly-emissive industries such as the chemical, steel, cement and refining industries. The most heat-consuming process is the flue gas scrubbing using solvent regeneration (post-combustion process) requiring several dozens of MW_{th} of additional heat.

The economic assessment showed that with the prevailing price levels the HTRs are not competitive as electricity only plants compared to hydro, coal or large nuclear power plants. The HTR cogeneration can reach the level of profitability if replacing gas-fired heat boilers and if the electricity production from the HTR plant is replacing the electricity purchase from the grid when the transmission costs and possibly also renewables tax can be avoided. Electricity purchase cost including grid fees and possible taxes that can be avoided should be at least 50 €/MWh. The economics of nuclear cogeneration with HTR are affected by construction and operation costs, availability, fuel costs and market prices. The most critical parts that affect the feasibility are the availability of the plant, interest rate, investment costs, and heat prices. The higher the price received for the heat produced, the higher the NPV is for the project. Heat price is mainly affected by alternative production costs for heat i.e. fuel costs for coal, oil and gas as well as by CO_2 costs.

Design adaptation and licensing costs may challenge the viability of a HTR cogeneration project. A HTR project alone would not be profitable if it needs to support large costs for design and licensing. However, cost related to site adaptation and a significant part of the licensing cost could be covered. A licensing process based on a generic design assessment should strongly favour such project and therefore a standardization of regulation and licensing procedures should be one of the main priorities when developing the HTR concept further.

At the moment the coal price is quite low as well as emissions allowance prices. This means that the alternative ways to produce heat with conventional fuels is still quite cheap which weakens the profitability of nuclear cogeneration. Therefore changes in the prevailing market conditions that increase the economics are needed. Those changes would be an increase in fossil fuel prices and/or increase in CO_2 prices and increase in electricity prices. Other reasons which promote nuclear cogeneration are a target to radically reduce the CO_2 emissions in energy production and in industrial processes as well as emphasis on security of supply.

Increased share of nuclear generation would reduce the need for imported fuels like natural gas and would result in increased share of ingenuous fuel usage in the European Union. Nuclear energy would also be a way to strengthen the security of energy supply as electricity is produced domestically with domestic labour, the availability of the plant is generally high, uranium procurement is secured with globally distributed supplies, and nuclear energy is capable of providing large amounts of baseload power at stable costs and would be unaffected by a sudden tightening of restrictions on the emission of greenhouse gases.

The best near-term opportunities can be found from HTR powering a chemical park. Integration of nuclear actors downstream in the value chain as Energy Manager would mean that the counter parts for a chemical park would be less numerous and it could concentrate on its core business. The energy manager could also be in charge of additional services e.g. waste management and raw material supplies enabling the industry to outsource all the activities that are not part of their core business.

A successful business concept requires long-term energy delivery to the site which would guarantee the high availability of the HTR and the payback of the investment. Therefore the size of the selected reactor should be a good fit with the heat demand of industrial customer or the nearby city in the case of district heating.

The risks of developing a new concept relate to e.g. design completion, regulatory assessment and approvals, vendor and contractor performance and construction quality. These risks can be minimized with close connection with the regulator, by emphasizing on plant design and performance and by selecting partners having similar experience of past projects. Contractual models like EPC (Engineering, Procurement and Construction) can minimize the cost related risk on the construction work although the risk premium associated with the contract might be high. The operational risks can be minimized thanks to inherent safety features of HTRs. In addition, an optimized plant performance is possible, by sharing the energy market risks between heat and electricity, or adapting to the demand by switching production between heat and electricity.

The risks can also be minimized by shared ownership model. Multiple owners can share the risk of increased interest rate, investment costs and if the owners of the plant are also the energy off-takers from the plant the long-term energy deliveries can be secured. For a newcomer countries without NPP in operation different shared ownership models with the industry or the vendor might be suitable to lower the risk and to increase the knowledge base during the project.

Poland with its notable coal and chemical industry would be an excellent country for a demonstration. Although there are no commercial scale nuclear power plants in operation in Poland has the needed industrial sector and the needed energy knowledge. CTL and the CCS technologies could be interesting CO_2 free technologies for the future. Nuclear energy could also strengthen the security of energy supply with domestic electricity generation requiring domestic labour. The availability of the nuclear plant is generally high and nuclear plant produces large amounts of baseload power at stable costs. Most influential factor for the feasibility of a HTR plant from the electricity point of view is the use of electricity on site, instead of selling it to the grid. In order to increase the competitiveness of the heat price from HTR the most influential factor would be a policy penalizing CO_2 emissions, which would significantly increase profitability of HTR cogeneration for clusters where coal is the primary fuel source.

Abbreviations

Abbreviation	Signification
ASU	Air Separation Unit
BF	Blast Furnace
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
COD	Commercial Operation Date
CTL	Coal To Liquid
DCF	Discounted Cash Flow
DCL	Direct Coal Liquefaction
DRI	Direct Reduced Iron
EAF	Electric Arc Furnace
EUR	European Utility Requirements
FCC	Fluid Catalytic Crackers
FCH-JU	Fuel Cells & Hydrogen – Joint Undertaking
GHG	Greenhouse Gas
HT	High Temperature
HTR	High Temperature Reactor
IAEA	International Atomic Energy Agency
ICL	Indirect Coal Liquefaction
IRR	Internal Rate of Return
LWR	Light Water Reactors
MWe	Electrical Megawatt
MWth	Thermal Megawatt
NEPIO	Nuclear Energy Project Implementation Organization
NPP	Nuclear Power Plant
NPV	Net Present Value
SMR	Steam Methane Reforming
TGR-BF	Top Gas Recycling Blast Furnace
TRL	Technology Readiness Level
WANO	World Association of Nuclear Operators

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