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Examining the Technoeconomics of Nuclear Hydrogen Production and Benchmark Analysis of the IAEA HEEP Software

IAEA

International Atomic Energy Agency

EXAMINING THE TECHNOECONOMICS OF NUCLEAR HYDROGEN PRODUCTION AND BENCHMARK ANALYSIS OF THE IAEA HEEP SOFTWARE

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The Agency's Statute was approved on 23 October 1956 by the Conference on the Statute of the IAEA held at United Nations Headquarters, New York; it entered into force on 29 July 1957. The Headquarters of the Agency are situated in Vienna. Its principal objective is "to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world".

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FOREWORD

Hydrogen, the lightest of the elements, holds great promise for humanity. The hydrogen economy concept is fast becoming a reality. In addition to the 60 million tonnes of hydrogen consumed annually worldwide today, mainly as feedstock by the petroleum and chemical industries, hydrogen is increasingly being used as fuel in the residential, commercial and transport sectors, and its use for power generation is anticipated. In Japan alone, demand for hydrogen is projected to approach 25 million tonnes annually by 2050.

More than 95% of the hydrogen used today is produced from fossil fuels (oil, gas and coal) and thus involves adverse effects such as resource depletion and environmental impacts due to the emission of greenhouse gases.

One of the IAEA's statutory objectives is to "seek to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world". One way to achieve this objective could be through hydrogen production from nuclear energy on a scale comparable with nuclear power generation. The strong and growing interest of Member States in a potential future role for hydrogen in national energy economies, including production from nuclear energy, has prompted the IAEA to launch an active project on the subject, including meetings for information exchange on the status and future challenges of nuclear hydrogen production; assessment of technoeconomic aspects of production; and the development of an analytical tool to assist Member States in such an assessment. The objectives and outputs of this project are closely aligned with the Sustainable Development Goals adopted in 2015.

The present publication documents the results of an IAEA coordinated research project on the technoeconomics of producing hydrogen using nuclear energy. Launched in September 2012, the project has created a platform for information exchange among 11 Member States; assessed technical and economic aspects of nuclear hydrogen production, including case studies of various scenarios and comparison with conventional and renewable options; improved understanding of the practical challenges involved; and, on the basis of the project's outcome of the, recommended follow-up activities such as developing a road map and addressing socioeconomic aspects of nuclear hydrogen deployment and application. The country reports submitted by the participating Member States on the outcomes of their activities during the project are available on the CD-ROM attached to this publication. The project also helped validate the IAEA's Hydrogen Economic Evaluation Program (HEEP), which allows analysis of various options for a future hydrogen economy. As part of the project,generic benchmark analysis has been performed for various scenarios of hydrogen production and against other codes built on different platforms and models, thus helping to improve HEEP.

This publication was compiled by Xing L. Yan of the Japan Atomic Energy Agency based on evaluations of officially issued reports and published papers as well as contributions provided by the experts listed at the end of the publication. The IAEA officer responsible for this publication was I. Khamis of the Division of Nuclear Power.

CONTENTS

SUMMARY

The potential of nuclear hydrogen production is increasing as marked by continued progresses achieved in research, development and deployment of pertinent nuclear reactor and process technologies in Member States and by the growing interest of Member States in the future roles of hydrogen in national sustainable energy strategies. Moving forward in the active programme of assisting Member States in considering non-electric applications of nuclear energy including nuclear hydrogen production, IAEA launched a Coordinated Research Project (CRP) during September 2012 through December 2015, which carried out the following activities:

- Established an effective platform to promote information exchange and international collaboration among Member States on hydrogen production using nuclear power.
- Assessed various options of hydrogen production including related transportation and storage and the techno-economics of hydrogen production using nuclear power.
- Performed benchmark analysis of the Hydrogen Economic Evaluation Programme (HEEP), a first-of-a-kind software developed previously by IAEA. HEEP allows analysing various options of hydrogen production for future energy economy and has become an international tool in use by Member States.
- Performed economic case studies of the selected nuclear hydrogen technologies applying a suite of analytical capabilities of the HEEP and under the representative financing conditions of participating Member States.

MAJOR CONCLUSIONS

As described below, the major conclusions address the four topics of the CRP: Information exchange and international collaboration, Assessing options and techno-economics of nuclear hydrogen production, benchmarking of the HEEP software and technology-based case studies on nuclear hydrogen production cost.

Information exchange and international collaboration

The CRP proved to have offered a successful platform for information exchange and research collaboration on nuclear hydrogen production among Member States. It gathered a group of eleven strong participating countries from all continents of the world. The group includes countries currently active at various levels of research and development ranging from the newcomer such as Algeria and Indonesia to the most developed such as China and Japan.

The CRP held research coordinated meetings annually, where the Chief Scientific Investigators (CSIs), in rare cases their representatives, of the participating Member States exchanged information on national activities and updated results of research and development on nuclear hydrogen production in general and economics assessment in particular. It is worth noting that Germany and the United States brought to the CRP the experience gained through the German PNP (prototype nuclear process heat reactor including development of nuclear steam reforming of methane) and the American NHI (Nuclear Hydrogen Initiative of investigating a range of thermochemical, electrolytic and hybrid options). The information developed and the lessons learned in these legacy national projects proved extremely useful. In fact, they provided design bases for some of the case studies performed by all participants.

The period of the CRP also saw some of the most exciting progresses being made in the participating Member States. China was building a prototype HTGR reactor plant, and shared the practical design and cost input. Japan built an engineering test loop for autonomous high temperature thermochemical production of hydrogen and exchanged the knowledge and its design data and cost estimate of commercial systems.

The last section of the Summary summarizes the major accomplishments and benefits received by the participating Member States. Detailed description of the activities and outcome through the implementation of the CRP can be found in the individual country reports available on the CD-ROM attached of this report.

Assessing options and techno-economics of nuclear hydrogen production

The CRP assessed various technological and economical aspects of potential nuclear hydrogen production options including cogeneration option. The reactor technologies assessed include the large light and heavy water reactors, small modular reactors and next generation high temperature gas cooled reactors. The hydrogen production processes examined include conventional water electrolysis, high temperature steam electrolysis, steam reforming, thermochemical cycle and hybrid cycle.

Cost of nuclear hydrogen production is found to vary not only among the technologies and the processes considered but also with the methods of integrating these technologies and processes and with such key performance indicators as thermal efficiency and operation life cycle of a technology or a process. Moreover, the financial parameters typically used to fund a nuclear project are country specific and can vary in considerable ranges. Table 1 provides the financial values typically used in the participating Member States. Note that the discount rate in Argentina case is reset to an effective value of zero because HEEP does not accept a discount rate smaller than inflation rate. The equity to debt ratio, borrowing interest, discount rate, inflation rate, and plant operating years are found to wield more heavily on final hydrogen cost than the depreciation period and tax rate. The hydrogen cost calculated using the country specific set of financial values can differ by as much as 20-40%. More details will be described later.

TABLE 1. COUNTRY SPECIFIC FINANCIAL PARAMETERS

	Algeria	Argentina	Canada	China	Germany	India	Japan	Korea, Republic of	Pakistan
Discount rate (%)	6	5	2	12	10	12	3	4	8
Inflation rate (%)	1	9.5	2	2	1.66	5.65	0	2	5
Equity:Debt ratio (%)	70:30	70:30	50:50	30:70	50:50	30:70	0:100	50:50	20:80
Borrowing interest (%)	6	30	7	5	5.5	10.5	3	10	8
Tax rate (%)	1.5	10	30	15	28.2	30	1.4	10	0
Depreciation period (year)	20	20	30	20	20	20	20	20	20

Benchmark analysis of the HEEP software

The CRP performed the benchmark of the HEEP for various scenarios of nuclear hydrogen production including related storage and transportation. Table 2 defines the five generic cases of nuclear hydrogen production as provided by IAEA. They cover various combinations of reactor technologies and hydrogen processes. The study of these cases allows validating the reliability of the HEEP software in not only predicting the cost of a nuclear production system but reflecting the sensitivity to technical and financial conditions under which such nuclear project is to be deployed.

TABLE 2. GENERIC CASES USED FOR HEEP BENCHMARK

	Case 1	Case 2	Case 3	Case 4a	Case 5
Nuclear plant	APWR	APWR	APWR	HTGR	HTGR
Number of reactors	2	2	2	2	2
Rating per reactor	359.5 MW(e)	719.0 MW(e)	1117.1 MW(e)	546.5 MW(th)	630.7 MW(th)
Hydrogen plant	CE	CE	CE	HTSE	S–I
Number of units	1	1	1	1	1
Hydrogen rate	4 kg/s	8 kg/s	12.43 kg/s	4 kg/s	4 kg/s

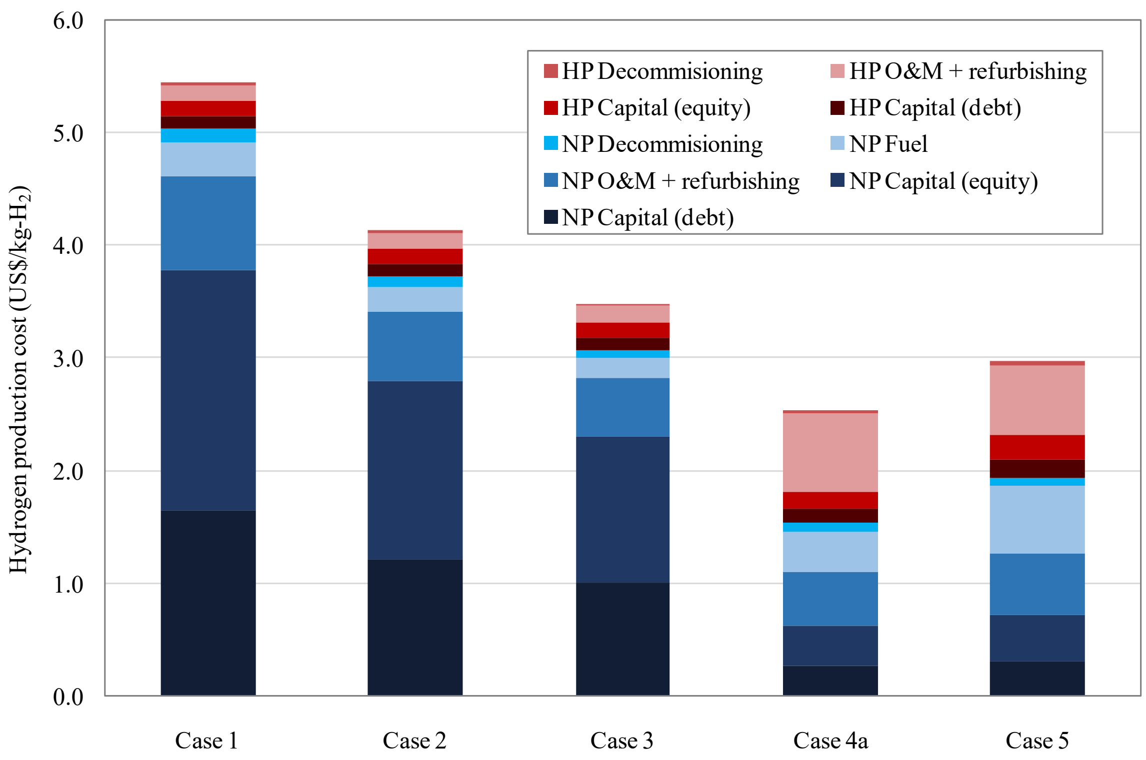


FIG. 1. Levelized hydrogen generation cost for generic cases (HEEP default financial values).

Figure 1 shows the result of levelized cost of hydrogen calculated by HEEP using the code`s default financial parameters as listed in Table 3. For the three generic cases of light water reactor combining Generation-III APWR with conventional electrolysis (CE), about 90% of the final hydrogen production cost is seen coming from the nuclear plant cost as would be expected of the greater complexity and capital investment involved with building and operating the nuclear plant relative to the conventional electrolysis plant. The HEEP is also shown to correctly predict the expected economy of scale expected from the nuclear plant. The levelized production cost is estimated to be US \$5.46/kg-H_2 for the 2×360 MW(e) APWR+CE plant with a production rate of 4.0 kg/s hydrogen while that from the 2×1117 MW(e) APWR+CE plant with a rate of 12.43 kg/s hydrogen is reduced to US \$3.49/kg-H_2. In contrast, there appears to be no significant effect of economy of scale associated with the electrolysis plants as they build on standardized modular electrolyzer units to tailor to the scale of production requirement.

TABLE 3. HEEP DEFAULT FINANCIAL PARAMETERS

Discount rate (%)	5
Inflation rate (%)	1
Finance Equity:Debt ratio (%)	70:30
Borrowing interest (%)	10
Tax rate (%)	10
Depreciation period (year)	20

For the remaining two cases of Generation IV HTGR based production, HEEP can predict the lower levelized cost of hydrogen as expected of the advanced methods of production. An important contribution to the lower cost of the HTGR-based production is the higher thermal efficiency of hydrogen production achieved in the high temperature process methods. The efficiency is about 52% for HTGR-HTSE of Case 4a and 46% for HTGR-SI of Case 5, comparing to about 26% for the APWR-CE cases.

Figure 2 shows the variation band of hydrogen production cost for the generic cases calculated by HEEP using the default and country-specific sets of financial values. Several observations can be made here. First, the HEEP is shown able to respond to the wide range of financial conditions used by the Member States. Furthermore, the HEEP results obtained with the default set of financial values are representative of the average of all country specific results. Despite of the obvious disparity of country specific financial values assumed, the cost ranking displayed in Fig. 1, which is obtained with the default financial values, remains the same among all countries. This suggests that the default set may represent an international average basis for nuclear project financing. The APWR-based conventional electrolysis plants of Cases 1-3 (due to the fact that the final hydrogen product cost depends heavily on nuclear plant cost), appear more sensitive to the financing conditions than the HTGR-based plants of Cases 4a 5, where reactor and hydrogen plants tend to weigh similarly on the final hydrogen cost. The difference in final hydrogen cost is about 40% for the APWR-based cases due to the wide range of the country specific financing conditions considered, whereas such difference is reduced to roughly a half for the HTGR-based cases.

Rather good agreement is obtained in benchmark against H2A and G4-CONS, the two widely used codes developed on different platforms for hydrogen cost estimation. The agreement is excellent for the APWR-based Cases 1-3, and within 20% for the HTGR-based Cases 4a and

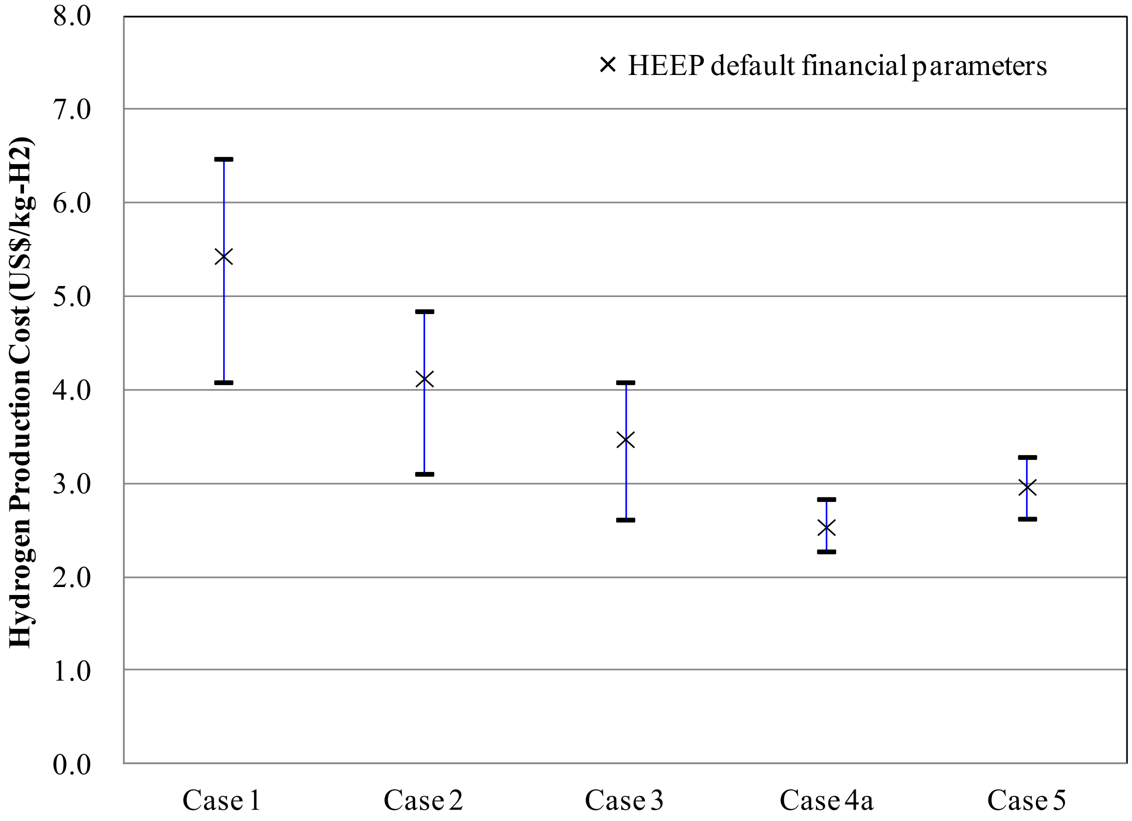


FIG. 2. Hydrogen cost band in the range of financial parameters used in Member States.

5, as shown in Table 4. The agreement is more difficult to obtain against ASPEN PLUS, a general process analysis code not specific to hydrogen production, because of the difference in model treatment. The ASPEN PLUS computes costs on equipment levels from a built-in database whereas HEEP relies on user inputs. When the design parameters are adjusted to be equivalent, the agreement may be improved between the two codes.

TABLE 4. COMPARISON OF HYDROGEN COST ESTIMATES BY HEEP AND OTHER CODES

Unit: US $/kg-$H_2$

	Case 1	Case 2	Case 3	Case 4a	Case 5
HEEP	5.44	4.13	3.48	2.54	2.97
H2A	5.32	4.03	3.39	2.21	2.53
G4-ECONS	5.41	4.17	3.39	2.58	2.47

A similar benchmark conclusion can be drawn based on the additional case studies carried out by Japan and Germany. Using respective proprietary codes, Japan found the HEEP results to be within 15% of its own code's results, whereas Germany reported nearly identical calculation results of hydrogen production cost between HEEP and its code for a HTGR SMR system.

Technology-based case studies

Techno-economics of four technology-based cases for nuclear hydrogen production have been studied in detail. The respective technology concepts and design data as required for HEEP input are provided by the participating Member States as identified in Table 5.

The four cases are performed by having each participating country conduct HEEP calculations applying the same technical data for both the nuclear and the hydrogen plant but selecting the respective country's set of financial parameters (Table 1) to estimate hydrogen generation costs.

Case A provided by Canada is based on the Enhanced CANDU6 or EC6 reactor. The hydrogen production method is the 5-step Copper–Chlorine (Cu–Cl) hybrid cycle. Since the cycle operates around 550°C, heat pump is employed for upgrading nuclear heat of about 300°C to the required temperature of the cycle. The assumed efficiency of the cycle is about 40.5%. Fig. 3 summarizes the hydrogen production cost of EC6 under country specific financial parameters. The high decommissioning cost of 14.75% and the long decommissioning period of 50 years assumed lead to large contributions of decommission costs to the total hydrogen cost. This is further inflated by the low discount rate assumed in the results by Argentina and Canada (see Table 1) relative to those by the other countries.

Case B provided by China is based on the prototype 250 MW(th) pebble-bed HTR-PM currently under construction in China. The reactor outlet temperature is 750°C. The hydrogen production is based on the ongoing research results of the Sulfur–Iodine (S–I) thermochemical process investigated by the Tsinghua University. The electricity required is assumed to be obtained from the grid. The process efficiency is 38.6%. Fig. 4 summarizes the hydrogen production cost of HTR-PM under country specific financial parameters. Note that the exceptional low value obtained by Pakistan is due to the assumption of zero refurbishment cost used in Pakistan estimation.

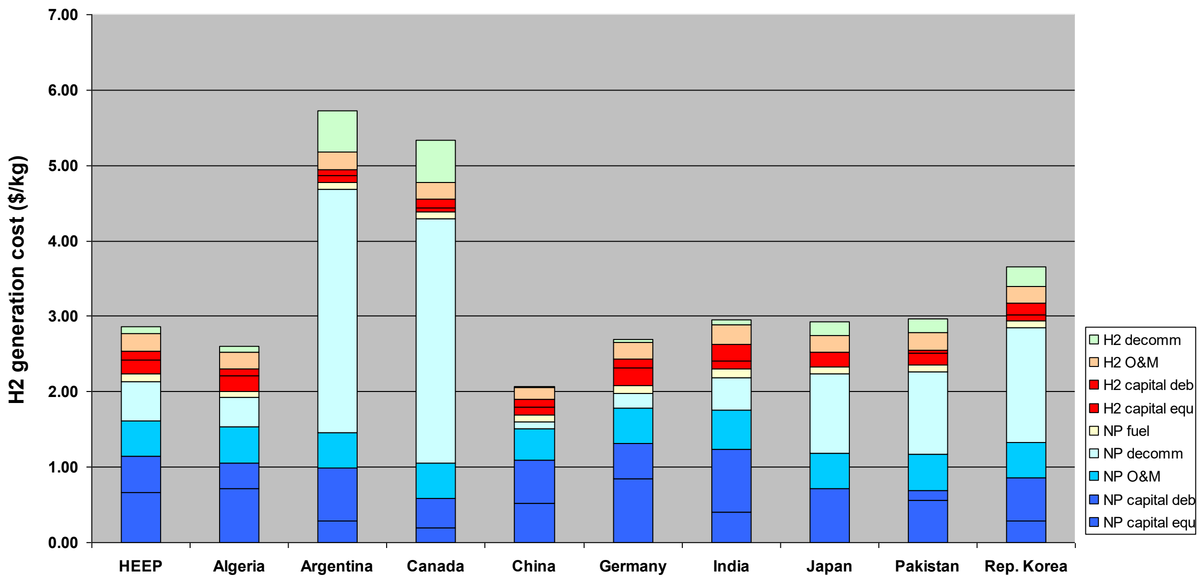


FIG. 3. Hydrogen production cost of Case A estimated by Member States.

TABLE 5. TECHNOLOGY-BASED CASE STUDIES PERFORMED

	Case A	Case B	Case C	Case D
Plant design	EC6 (Canada)	HTR-PM (China)	HTR-Module (Germany)	GTHTR300C (Japan)
Nuclear plant	APWR	HTGR	HTGR	VHTR
Number of units	4	2	2	1
Thermal rating/unit (MW(th))	2084	250	170	600
Heat output/unit (MW(th))	159.58	250	117	170
Electricity output/unit (MW(e))	629.88	0	21.3	204
Hydrogen plant	Cu–Cl	S–I	SMR	S–I
Number of units	1	2	2	1
Heat input/unit (MW(th))	638.36	250	117	170
Electricity input/unit (MW(e))	273.25	20.0	21.3	25.4
Hydrogen rate/unit (kg/s)	4.25	0.68	1.74	0.77

Case C is based on the 170 MW(th) pebble-bed HTGR design called HTR-Module developed in 1980s. With its outlet temperature of 950°C, the reactor delivers the heat at 810°C required for the steam–methane reforming (SMR) process. The electricity required is obtained from the grid. The cost of methane assumes a price of US $32.60/MWh. The SMR process efficiency is 48.8%. Fig. 5 shows the results of hydrogen costs for HTR-Module as estimated by the participating Member States under the respective country specific financial parameters. Clearly visible is the large contribution from hydrogen plant O&M cost, which includes the cost of methane feedstock at the German natural gas price. Such price is not necessarily representative for other countries.

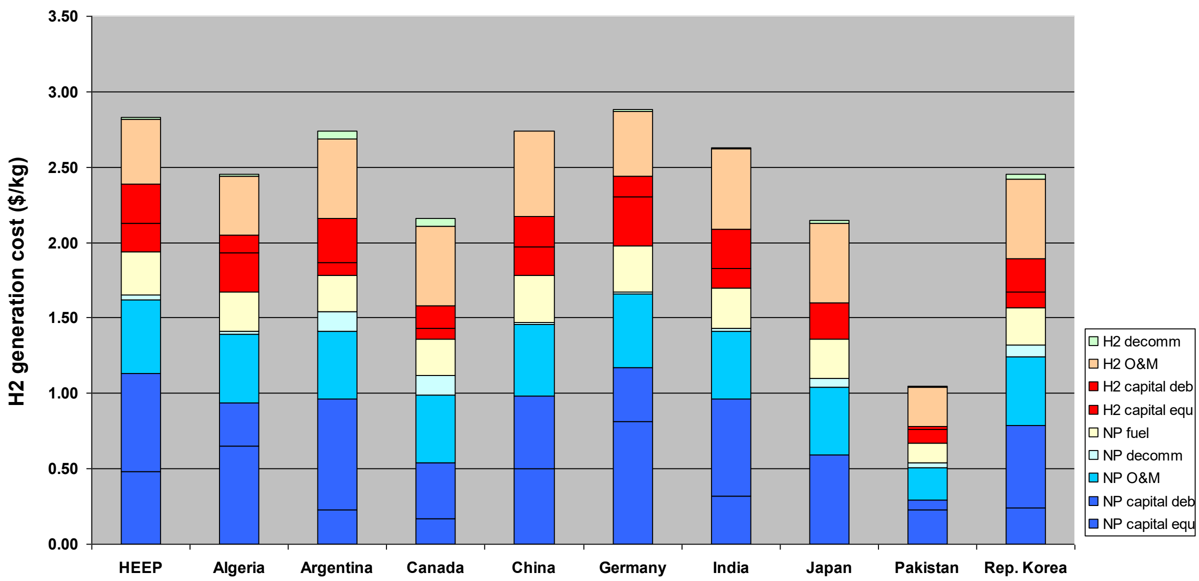


FIG. 4. Hydrogen production cost of Case B estimated by Member States

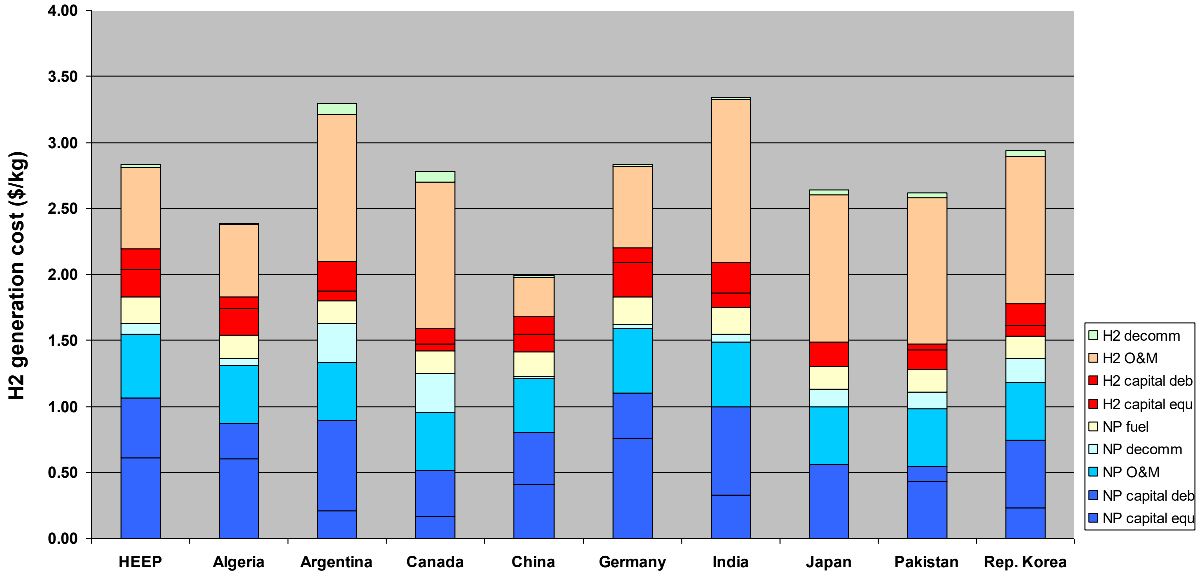


FIG. 5. Hydrogen production cost of Case C estimated by Member States

Case D is based on the commercial 600 MW(th) prismatic VHTR design GTHTR300C being developed by Japan Atomic Energy Agency. The reactor with outlet temperature of 950°C cogenerates both the process heat at 900°C and the electricity required for the S–I process. The S–I process efficiency is estimated at 49.2%. Fig. 6 summarizes the results of hydrogen costs for GTHTR300C as estimated under the respective country specific financial parameters.

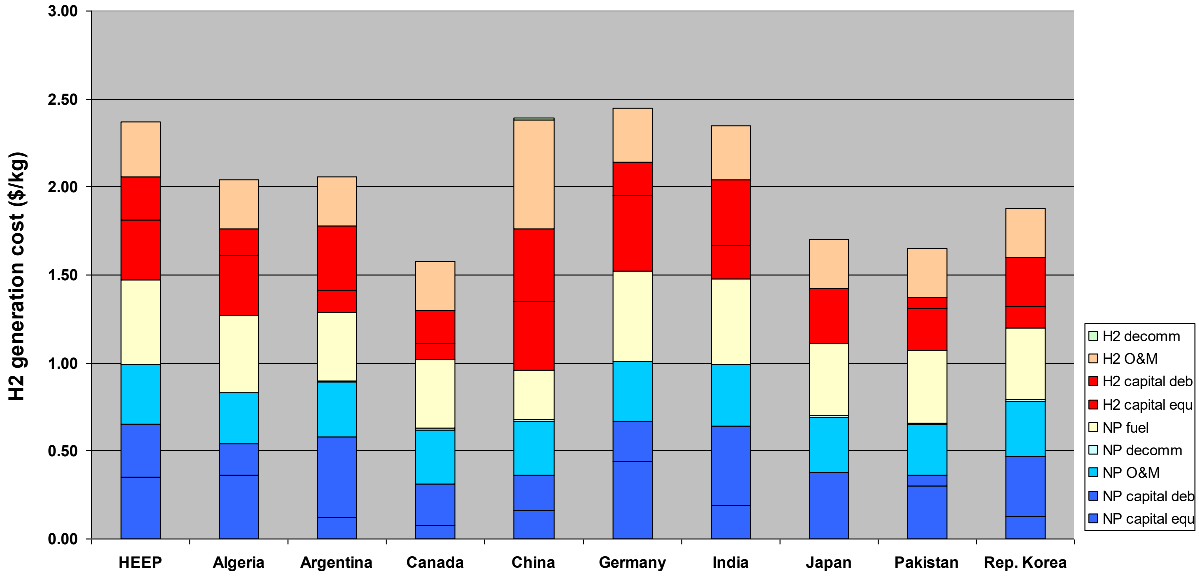


FIG. 6. Hydrogen production cost of Case D estimated by the Member States

In addition to the result for each case, the general conclusions that can be derived from the four technology-based case studies are as follows:

- HEEP results provided by the participating countries for the four technology cases compare well with each other. The exception is for the EC6 case (Fig. 3) where the results estimated by two participants are almost double as the others.

- HEEP results with the default set of financial parameters are typically well within the range of the other countries' results, meaning that the HEEP default set represents a good average basis for cost assessments, similar to the earlier conclusion in the HEEP benchmarking of the generic cases.

- The cost ranking is found rather consistent among all the countries. Japan's case GTHTR300C plus S–I ranks the lowest cost of being less than US \$2.50/kg-H_2 from the results of all countries. China's case HTR-PM ranks the next lowest cost of below US \$3.00/kg-H_2. This holds true also for most results for Canada's case EC6, but with exceptions. The results range from US \$2 to 3.3 /kg-H_2 for Germany's case HTR-Module.

- These results suggest that nuclear hydrogen production is potentially cost competitive compared to conventional steam reforming, coal gasification or water electrolysis using renewable energy sources

SUMMARY OF MAJOR ACHIEVEMENTS

Listed below is a summary, as provided by Member States, of the major contributions made and benefits received through participation of the CSIs and their research collaborators in the CRP. The detailed country reports are available on the attached CD-ROM.

Algeria

Highlight of contributions made

Our contribution has been two-fold: first it has been on nuclear hydrogen production cost estimation, and then it has been on solar hydrogen cost estimation. Our actions have been:

- HEEP benchmarking and hydrogen production analysis, in which we have treated the generic cases and the national cases designated by the CRP.
- Solar hydrogen production for the case of concentrated solar energy, namely CPV and to some extend CSP. The main goal of this second work is twofold:
  - First to compare the cost of hydrogen production using nuclear energy to hydrogen production using solar energy;
  - Second to possibly extend the capability of HEEP to include solar techniques

We have also:

- Presented and discussed nuclear-based hydrogen production cost results during the research coordinated meetings;
- Presented and discussed our comparison of the nuclear-based hydrogen costs to those obtained using environment friendly hydrogen production techniques such as solar-based techniques;
- Participated and contributed to the technical meetings on benchmark analysis of the IAEA HEEP software;
- Summarized important results in annual and final reports to the CRP;
- Contributed to the IAEA TECDOC;
- Made recommendations for future coordinated research activities.

Highlight of Benefits received

– Opportunity to discuss and exchange information with experts in the field of hydrogen as an energy carrier. This could lead to networking and long-lasting collaboration in the field.
– Possibility in contribution in improving HEEP capability by expanding HEEP capabilities to include cost evaluation of hydrogen production based on other environmental friendly techniques, such as solar-based techniques.
– Having attracted and trained students on hydrogen as an energy carrier.
– Publication of journal papers and communication on issues of hydrogen production.

Argentina

Highlight of contributions made

This project contributed significantly in this mainstream through a well-designed theoretical and experimental and economic program addressed to elucidate the kinetics and mechanisms of thermochemical reactions at the Laboratory scale, in order to find the optimum conditions for increasing the efficiency of these cycles with the objective of a future scaling up of the experimental facility.

Through the benchmark analysis, HEEP software behaved as a suitable and friendly analysis tool for obtaining valuable information about techno-economics on nuclear hydrogen production although several features of the software should be further improved. Parametric calculations carried out by changing finance parameters as allowed in HEEP gave insights to the great influence on the levelized cost of hydrogen production of discount rate, inflation rate, borrowing interest and tax rate, which proved very important for the calculations with Argentina data.

Highlight of benefits received

During this project one doctoral thesis was finished and another was initiated. Some publications in papers and meetings were made and further publications will be presented with the thesis results.

The CNEA has two other important national projects related with hydrogen, one is the hybrid fuel HYDROGAS as a bridge with the future pure hydrogen automotive fuel and the other is the development of PEM fuel cell which requires pure hydrogen and can be used for different daily purposes. Other important decisions in the economy of energy must be taken by the government but the sign of hydrogen future is manifest by today's general plans

It is expected that the results of this research would give impulse to the growing of hydrogen economy, which is associated with a cleaner technology and a sustainable energy source all through the world. But especially throughout the remote desert regions of our country like the vast Patagonia extended at the south and the highest Norther Puna.

The potential of these technologies, of which nuclear power could play a major role in the market for hydrogen production and would drive in our country the interest in the design and construction of the Advanced High Temperatures Reactors, is another example of the application of nuclear technology in uses for the peace.

Canada

Highlight of contributions made

Canada has successfully completed all the objectives originally proposed, including:

- To extend the database of HEEP to consider moderate temperature thermo-chemical cycles such as Copper–Chlorine and hybrid hydrogen process at lower temperature.
- To improve the pre-processing of HEEP in order to provide enough flexibility for the user, in terms of input data and constraints in both technical and economic aspects of generation, storage and transportation.
- To modify the execution module for calculating the operational parameters in addition to levelized cost for generation, storage and transportation of produced hydrogen.
- To improve the analysing capabilities of HEEP, adding comprehensive modelling and analysis of a Cu–Cl hydrogen production plant based on thermodynamics, energy, exergy, exergoeconomic, efficiency and life cycle assessment;
- Identified several issues with HEEP and recommended several improvements to be made in HEEP.
- To made a comparative study of the Cu–Cl cycle with other methods such as high temperature steam electrolysis, conventional electrolysis and steam reforming, and other potential thermochemical cycles by considering important technical features of different categories of plants and facilities.
- To conduct additional studies to cover Mg–Cl cycle and other cycles with CANDU Gen-IV SCWR and compare them with Cu–Cl, S–I and Hy-S cycles.

Highlight of benefits received

The major achievements and benefits include:

- Made 10 peer-reviewed journal publications, 1 book chapter and 6 conference papers, specifically related to Cu–Cl cycle, HEEP and HEEP use. These are identified at the end of the TECDOC.
- Trained 2 doctoral students and 1 Master student.
- Obtained critical NPP data from various Canadian organizations to incorporate into the modelling studies and HEEP analyses.
- Presented the modelling and HEEP analysis results in 6 international conferences.
- Completed generic case studies in coordinated efforts with other countries.
- Studied Cu–Cl (3 step), Cu–Cl (5 step), Hy-S and S–I cycles with CANDU Gen-IV SCWR for hydrogen production cost, cost share of NPP and H_2 plant, etc.
- Studied heat upgrade options for the CANDU reactors to increase the temperature to the desired cycle temperatures for thermochemical/hybrid cycles.

China

Highlight of contributions made

As a leader in the development of HTGR technologies, China has shared the information on the progress of the prototype HTR-PM plant construction and that of the associated R&D on nuclear hydrogen production in INET with the other participating countries of the CRP. The information has proved useful to assist in other Member States in their studies. Specific contributions include:

- Designed and provided to IAEA a new technology case of nuclear hydrogen production for the HEEP based on the HTR-PM and the S–I process. The case was used by all other participating Member States to study the cost of nuclear hydrogen production.
- Performed benchmarking exercise of HEEP including sensitivity analysis and compared the results with other countries.
- Completed and validated a simulation model of the S–I process for heat and mass balance as well as efficiency calculations.
- Prepared a final report of China's contributions to the CRP which presents the progress of R&D on nuclear hydrogen production in China, including description on the models, facilities, experimental results, and the R&D plan.

Highlight of benefits received

- Enhanced capability of techno-economics evaluation for nuclear hydrogen production.
- Obtained a preliminary economic data of nuclear hydrogen, which will be used as a basic reference for introduction to the public as well as the policy maker.
- Gave a lecture of introducing HEEP to university students.
- Published several peer-reviewed journal papers on nuclear hydrogen production. A paper on cost estimation of nuclear hydrogen production is under preparation.

Germany

Highlight of contributions made

Several persons learned to handle the HEEP software, accumulated experience, conducted studies with the code, and gave recommendations on how to further improve the model. This IAEA tool has presented itself as a valuable means for the comparison of different primary energy sources including nuclear, solar, and conventional sources of different hydrogen production technologies, and different sets of economic parameters.

Main results achieved were two comprehensive studies conducted by bachelor students. Apart from the two benchmark exercises conducted within the frame of the HEEP CRP (generic cases, technology-based cases), additional cases were investigated. One study treated a comparison of conventional hydrogen production methods with those that are assisted by nuclear heat and power. The comparison is still in favour of the conventional method. This even holds if the capture and storage of CO_2 during the production process is taken into account showing that under current conditions, this is an inefficient regulation tool. A comparison was also made with regard to solar primary energy.

Comparing the outcome with what was suggested in the beginning, we have to admit that the proposal was too ambitious, partly even not feasible (like analysis of German hydrogen market structure). Brainstorming sessions condensed the original program to what was deemed feasible in due time, and also fit into the work profile of the institute at the RWTH Aachen.

Highlight of benefits received

The major benefits received through the participation in the CRP include the two Bachelor thesis completed in 2013 and 2015 respectively at the Technical University (RWTH) Aachen, Germany.

India

Highlight of contributions made

Bhabha Atomic Research Centre (BARC) of India has contributed to the CRP by participating in the activity of "benchmarking exercises through international collaboration to validate HEEP and establish HEEP database".

The primary objective of this activity was to validate models used in the HEEP through extended benchmarking exercises. Other objectives were (a) to enhance robustness and user-friendliness of the HEEP, and (b) to generate database in the form of library of files compatible with HEEP.

The work plan to meet these objectives included (i) collection of input data affecting hydrogen cost for identified cases through support from other participating organizations of this CRP, (ii) estimating hydrogen cost using HEEP for identified cases (iii) compile the information collected in the form of a database compatible with HEEP for identified cases, (iii) identify other similar software tools for estimation of hydrogen cost (iv) estimate hydrogen cost using these software tools and compare results, (v) obtain feedback from HEEP users, and (iv) incorporate modifications in HEEP to enhance robustness and user-friendliness.

During the first year of the CRP, India contributed in the preliminary modelling of the five generic cases for benchmarking. These five cases were modelled using HEEP as well as another software tool H2A. The results of HEEP and H2A were compared. The features of HEEP and H2A were also compared to justify the small difference in the results obtained. This exercise not only validated mathematical models used in HEEP but also demonstrated various features of HEEP.

During the course of CRP, feedback was received from the users of HEEP to incorporate certain modifications in the software to enhance its robustness and user-friendliness. Most of the suggestions have been incorporated. The information on the parameters affecting hydrogen cost was provided by various participating organizations to this CRP. This information has been compiled in the form of a library of files compatible with HEEP.

Highlight of benefits received

In the second year of the CRP, a parametric study was carried out using HEEP to assess the effect of source of energy on hydrogen production cost. In this parametric study, variation in two parameters viz. (a) rate of purchase of electricity from market and (b) thermal efficiency of nuclear power plant, if generating and supply electricity for hydrogen generation was assessed. Results of this parametric study were presented in IAEA Workshop on "Assessment of Non-Electric Applications of Nuclear Energy" held between 9 to 11 September 2013.

Training was given to various groups in BARC on evaluation of hydrogen generation cost using the HEEP code.

Indonesia

Highlight of contributions made

Indonesia has contributed a study of the HTGR-based steam–methane reforming for hydrogen production process. SMR is commercially used in fertilizer industry in Indonesia. In order to coupling it to the HTGR, several components such as IHX, helium purification system, several cooling systems, temperature and pressure control system, helium flow control system and additional safety system with nuclear heat.

The hydrogen production cost of the above HTGR+ SMR plant is calculated with the use of HEEP and another code. The difference in final hydrogen cost is about 25%, which are thought to come from the difference in some data input of power plant parameters.

Details of the study are presented in the final report as the contribution to the CRP.

Highlight of benefits received

- Improvement of knowledge and skill of human resources of Indonesia in use of HEEP programme, especially in our group at BATAN;
- Exchanging information and experience with researchers of participating Member States;
- Improve of the capacity building of our institution.

Japan

Highlight of contributions made

Nuclear hydrogen production technologies developed in Japan, including the relevant design and cost database of the HTTR, the S–I process, the commercial GTHTR300C plant, are provided as input to the techno-economics study of the CRP. Specifically, major contributions include

- Reviewed and shared the research materials including computational models, technology and cost database as input to the CRP participants;
- Designed a generic case and a technology case of nuclear hydrogen production models and provide them for calculations by the CRP participants;
- Performed the extensive benchmark analysis of the HEEP on the five generic cases;
- Performed the benchmark of the HEEP against the JAEA's internal code;
- Performed case studies using the HEEP on the four technology-based country-specific cases;
- Suggested various improvements to the HEEP and recommended future research activities for consideration by the IAEA;
- Elected by the participating Member States, the CSI of Japan chaired the RCMs and facilitated the information exchanges and studies among the Member States.

Highlight of benefits received

- Developed a network with the experts in other Member States;
- Improved the capability and usability of the HEEP as a tool for in-house research;
- Developed a journal paper on the economics of hydrogen production through collabourative research in the CRP.

Pakistan

Highlight of contributions made

Hydrogen production by nuclear power for the cost of production, storage and transportation has been assessed. The hydrogen production technologies assessed include Sulfur–Iodine (S–I), high temperature steam electrolysis (HTSE) and steam–methane reforming (SMR) coupled with the 2×250 MW(th) pebble bed modular nuclear reactor, at core outlet temperatures 950°C, 850°C and 900°C, respectively. Hydrogen produced using coal gasification is also assessed for comparison. Costs of these hydrogen production options have been developed including sensitivity analysis on some assumed parameters. In addition to country case study, benchmark analysis of IAEA model was performed on selected hydrogen production processes. The results of these studies are reported in the final country report to the IAEA.

Highlight of benefits received

The HEEP benchmarking exercise provided confidence in the in-house software being used for techno-economic analysis of energy projects. HEEP is a valuable tool that improved analytical capabilities of the study team in techno-economic analysis of alternative hydrogen production options.

The CRP provided opportunities to present and discuss the results of the country case study with experts from other countries. Feedback from these experts was valuable in refining the techno-economic analysis of nuclear hydrogen production. The study results also provide important information to support policy decisions regarding energy/electricity planning in the country.

Republic of Korea

Highlight of contributions made

- Introduced to the Member States theG4-ECONS software developed by GEN-IV EMWG (Economic Modelling Working Group) as an alternative economic evaluation program for nuclear systems;
- Ran GEN4-ECONS program for the five generic cases provided by IAEA for the benchmarking of HEEP;
- Ran GEN4-ECONS program for the three country specific cases provided by Japan, China and Germany and compared the results with those obtained from the HEEP;
- Validated the HEEP program by confirming that 1) the results from two programs HEEP and GEN4-ECONS are within a 2~9% for all five generic cases and 2) the results are within tolerable error bound of 2~12% for three country specific cases;

– Discussed various experience and insights gained from the benchmarking and the case studies with the Member States, including potential improvements to the HEEP;
– Highlighted the impact of the financial parameters, especially discount rate and inflation rate on the hydrogen production cost.

Highlight of benefits received

– Exchanged information on the issues of nuclear hydrogen production with the other Member States. In particular, assistance was received from the other participants in the performance of the CRP studies.
– Expanded networking with the international research experts on the subject.

United States of America/Republic of Korea

Highlight of contributions made

The analysis of Bunsen reaction indicated that by increasing the temperature in the Bunsen reactor, the conversion can be slightly improved and the pressure has no effect on the reaction. Further, analysis of available detailed data on Bunsen reaction was performed which identified key parameters and their ranges for optimized performance of the reaction section.

Modelling and dynamic simulation of coupled high temperature pebble bed modular reactor (PBMR) and Sulfur–Iodine thermochemical process based hydrogen plant was developed. The simulation results identified key safety parameter for operational transients and accidents in such coupled system. The economic analysis was performed on cost of hydrogen production with the PBMR coupled S–I plant. Both the nuclear reactor and the chemical plant are capital intensive so the hydrogen cost is found to be a strong function of interest rates as well as capital recovery factors.

Highlight of benefits received

The research in the CRP involved participation of 3 undergraduate students, 2 graduate students, and 1 post-doctoral researcher and 1 visiting scholar. In particular, the training of 5 students on the technology of hydrogen generation and economic analysis is a significant benefit.

The work has resulted in publication of 5 journal papers on technology development of S–I cycle.

1. INTRODUCTION

The interest in developing and deploying hydrogen production using nuclear energy is increasing. This has led the IAEA to carry out an active programme on the subject including the present CRP, the results of which are presented in this report. The scope of the CRP covers information exchange and research collaboration benefiting Member States, and economics assessment on nuclear hydrogen production including sensitivity to important technical aspects of integrating nuclear reactors with hydrogen plants. The CRP performs benchmark of the HEEP software previously developed by JAEA as an assessment tool and detailed case studies for some promising integrated systems identified by the CRP participants for hydrogen production using different types of nuclear reactors and hydrogen production processes.

1.1. MOTIVATION OF THE CRP

1.1.1. Increasing role of hydrogen for sustainable development

The world population expanded by 25% in the last 20 years. Standing at 7.3 billion in 2015, it is expected to reach 9.7 billion in 2050 [1]. In the meantime, the standard of living has received a major lift mostly in developing countries. The world average gross domestic product (GDP) per capita has more than doubled in the recent two decades [2].

The expansion of the population and economy is fuelled by 40% increase in energy demand during the same period. According to IEA, the world total primary energy production is 13 600 Mtoe in 2013, of which fossil fuels accounted for 81.6%. Between 2012 and 2013 alone

, production of coal increased by 4.6%, oil by 0.5% and natural gas by 2.7%. Neither the trend nor the degree of the present dependence on fossil energy is sustainable due to resource depletion and adverse environmental impact.

Hydrogen has the potential to be an alternative fuel because it can be produced in large quantity and used in places where fossil fuels are used but without emitting carbon dioxide. Hydrogen economy is a concept of using hydrogen on a comparable scale as fossil fuels are used in today's hydrocarbon economy.

Hydrogen economy is a fast-growing reality in many countries, mostly evident in the residential and transport sectors. In Japan, marketing of residential stationary fuel cell units such as ENE-FARM began in 2014, followed by fuel cell cars in 2015. The demand for hydrogen as transport fuel is forecast to be 56 million metric tonnes annually in 2030 and grow to 330 million metric tonnes in 2050 in Japan. In contrast, the present worldwide consumption of hydrogen in 60 million metric tonnes of hydrogen, consumed annually worldwide, mainly in the industrial sector. More than 95% of the hydrogen used today is produced by striped molecular hydrogen off oil, gas or coal. Such way of production inherits the adverse effects of consuming fossil fuels.

Reflecting the past trends and the energy and environmental policies in place today, global fossil energy consumption will increase by 1.3-fold from 2013 to 14.7 billion tonnes of oil equivalent in 2040, meeting 78% of world primary energy demand. The associated global

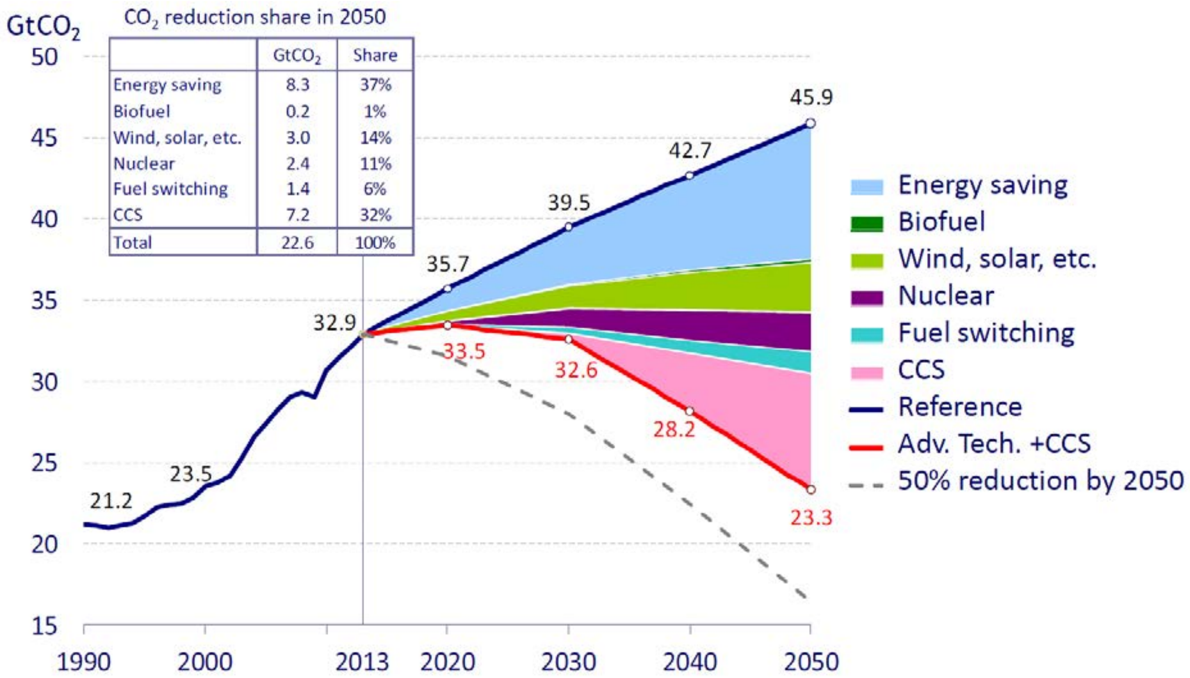


FIG. 7. Global CO_2 emission and Advanced Technologies Scenario to reduce emission [3].

CO_2 emission from the consumption of fossil fuels increases by 39% in 2050 from the 2013 level of 32.9 Gt. In this scenario marked as reference in Fig. 7 [3], which is similar to the global GHG emissions projected based on the INDCs at the 2015 United Nations Climate Change Conference held in Paris, France in December 2015, the atmospheric concentration of CO_2-equivalent will reach 760-860 ppm in 2100 with the resulting average temperature change to be 2.8-4.0°C from the 1850-1900 period.

Through implementing a mix of advanced technological options, on both demand and supply sides such as energy conservation through continued efficiency improvement, significant increase in low-carbon technologies including renewable energy, fossil energy with CCS, and increase in nuclear energy, CO_2 emission instead of increase would be reduced to 23.3 Gt in 2050. The atmospheric concentration of CO_2-equivalent will be 540-600 ppm with the average temperature change to be 1.7-2.4°C. In this scenario, both increasing and emerging utilization of nuclear power is anticipated. Specifically, nuclear power generation would be expected to rise from 389 GW(e) in 31 counties today to 618 GW(e) in 2040 in 39 countries in 2040. The nuclear energy will contribute to 11% of the reduction needed in 2050.

To halve the CO_2 emission from the current level by 2050 (see the dashed projection in Fig. 7) to achieve the goal of UN Framework on Climate Change (UNFCC) of limiting the global warming below 2.0°C, proactively developing innovative technologies is required. Here, implementation of large-scale hydrogen energy production, distribution, and applications is one of the stated national strategies in many Member States to fulfil the national CO_2 reduction goals in 2050. Some highlights are given below.

TABLE 6. PRIMARY ENERGY CURRENT & FORECAST DEMAND IN JAPAN

Unit: Mtoe/year

	2010 [4]	2013 [5]	2030 [6]	2050 [7]
Fossil fuel	431.0	462.0	344.0	114.1
Renewable**	8.4	8.6	20.1	72.6
Nuclear**	24.8	0.8	20.1	47.7
Hydrogen	0.0	0.0	0.6	**73.3**
Total	464.1	471.4	384.3	307.8

** Values for renewable and nuclear are amount of electric power generated

1.1.1.1.Outlook of hydrogen energy economy in Japan

Japan's energy mix drastically shifted in the earlier 2010s as fossil fuel replaces nearly all of nuclear capacity suspended in the wake of the Fukushima nuclear incident in March 2011. Japan has limited domestic energy resources and depends on imported fossil fuel for more than 90% of its primary energy demand in 2013 (Table 6). Japan is the world's largest liquefied natural gas importer, second-largest coal importer behind China, and third-largest consumer and net importer of oil behind the US and China.

Japan's CO_2 emission has increased since 1990 (Table 7) and ranked the world's 5th-largest emitter in 2013. Joined by other 195 developed and developing countries at the COP21, Japan has committed as the INDC of reducing greenhouse gas (GHG) emissions by 26% in 2030 below the 2013 level. In longer-term, the April 2012 Basic Environment Plan of Japan has set the goal of reducing CO_2 emission by 80% below the 1990 level.

TABLE 7. JAPAN`S CO_2 EMISSIONS TILL 2013 & EMISSION REDUCTION GOALS

Unit: Million t-CO_2

				COP21 INDC of Japan (December 2015)	Basic Environmental Plan of Japan (April 2012)
Year	1990	2005	2013	2030	2050
Energy-related CO_2 emission	1070	1290	1334	1,042 (26% of 2013 level)	214 (80% of 1990 level)

The government's Basic Energy Strategy enacted in April 2014 has emphasized a balanced energy of energy security, economic efficiency, environment and safety, the so-called 3E+S principle. As shown in Table 6, primary energy consumption is expected to decline as a result of continued progress in energy efficiency in a maturing economy and decreasing population.

In particular, fossil energy consumption will gradually and significantly be cut. CCS will be implemented not only in power generation plants of existing and new fossil-fired plants), but also industrial sectors such as steel and cement factories.

Significant use of hydrogen is considered an important option of future energy mix to achieve the ambitious CO_2 reduction target in 2050. The option is important as an alternative both to overcome the limit of CCS that could be deployed in the country and to reduce the risk of price uncertainty of other energy options.

Table 8 shows the medium projection of hydrogen demand in transport and other major sectors of economy in Japan. The demand of 25.2 million metric tonne in 2050 would account for 28% of the 300 Mtoe primary energy demand in that year. A current plan envisions for this demand to be met chiefly by reforming fossil fuels such as through large-scale gasification of coal. [6]. Noting that the country is devoid of indigent resource of fossil fuels, Japan would still depend on overseas coal or import of hydrogen to meet the majority of future hydrogen demand under this plan. To augment the 3E+S principle of Japan's Basic Energy Policy, Japan Atomic Energy Agency is engaging in research and development of reactor and process technologies to enable secure, safe, cost-efficient, and emission-free nuclear hydrogen production. More detail of JAEA activities can be found in the country report.

TABLE 8. MEDIUM PROJECTION OF HYDROGEN DEMAND IN JAPAN

Unit: million metric tonne/year

<table>
<tr><th></th><th>2030 [6]</th><th>2040 [7]</th><th>2050 [7, 8]</th></tr>
<tr><td>Transportation</td><td>0.5</td><td>1.5</td><td>2.6</td></tr>
<tr><td>Industries</td><td rowspan="2">0.1</td><td rowspan="2">1.3</td><td>0.8</td></tr>
<tr><td>Residential</td><td>7.5</td></tr>
<tr><td>Power</td><td></td><td>8.3</td><td>11.6</td></tr>
<tr><td>Others</td><td></td><td></td><td>1.3</td></tr>
<tr><td>Total</td><td>0.6</td><td>11.1</td><td>23.7</td></tr>
</table>

1.1.1.2.Hydrogen energy outlook in the Republic of Korea

Current hydrogen demand is mainly from oil refinery and chemical industries. Hydrogen is mostly produced by steam reforming using the fossil fuel heat that emits large amount of greenhouse gases. Today in the Republic of Korea, about 1.3 million metric tonnes of hydrogen is produced annually, mainly through by-production, and consumed at oil refinery industries. In 2040, as projected by the hydrogen roadmap 25% of total hydrogen demand will be supplied by nuclear hydrogen, which amounts to around 3M tonnes/year, even without considering the hydrogen iron ore reduction market. The demand for hydrogen, mainly FCV, FC for power generation (150 MW(e) FC power generation instalment in the Republic of Korea in 2014) and hydrogen steelmaking, is expected to be 0.8 million tonnes per year in 2030. Minus the by-production hydrogen capacity in the country, which is expected to remain relatively constant over the time, additional supply routes have to be developed for 0.7 million tonnes per year. The country is looking to a strategy of diversified hydrogen supply, consisting of 40% steam–methane reforming, 30% nuclear production, 25% renewable, and 5% other sources.

1.1.1.3.Hydrogen energy outlook in the United States of America

The United States of America currently consumes more than 11 million metric tonnes of hydrogen per year. Refinery and fertilizer are the two largest users of hydrogen. Out of which 5 million tonnes of hydrogen were consumed on-site in oil refining, and in the production of ammonia and methanol. A small fraction, 0.4 million tonnes were an incidental by-product of the chlor–alkali process. Refinery demand for hydrogen has increased as demand for diesel fuel has risen both domestically and internationally, and as sulfur-content regulations have become more stringent. EIA data show that from 2008 to 2014 the demand of hydrogen for refineries rose from 2.24 million tonnes of hydrogen per year to over 3.5 million tonnes per year while the production at refinery has more or less at 2.67 million per year until now since several years [9, 10]. The difference is being met through hydrogen purchased from merchant suppliers rather than from increased hydrogen production on-site at the refinery.

For the future demand of hydrogen transportation sector seems the most ideal sector in a vision to transit to hydrogen economy given its advantage in terms of CO_2 reduction potentials. Hydrogen for stationary applications as well as bus and government fleets are defined possible end-use areas. By 2020, 1.5 trillion kW·h of additional electricity generation capacity will be needed in the U.S. If 10% of added generation (150 billion kW·h) is to be met from hydrogen, 10 MT of hydrogen would be required. The forecast for US net hydrogen demand for light duty vehicles (LDVs) is shown in Table 9 [11]. By 2030, 20% of total vehicle miles are assumed to be fuelled by hydrogen which is around 16 million tonnes. By 2040, nearly 78% of total vehicle miles are run by hydrogen vehicles, creating a demand for 64 million tonnes of hydrogen. Starting in the late 2030s, hydrogen vehicles dominate all new vehicles markets. Hence, by 2050 all vehicle miles are made by hydrogen-fuelled vehicles, corresponding to a demand of 100 million tonnes.

TABLE 9. US CURRENT AND FUTURE HYDROGEN DEMAND FOR LIGHT DUTY VEHICLES

Year	Hydrogen Demand for transportation (Million Tonnes)	Net Including transportation and refinery and others (Million Tonnes)
2015	0	11
2020	10	21
2030	16	27
2040	64	64
2050	100	100

Table 10 provides further details on how this demand can be met. In particular, each resource is assumed to provide 20% of the total future hydrogen demand (i.e. almost 13 million tonnes of hydrogen each).

Out of 280 million LDVs on road by 2020, 2 million of them (0.7%) are estimated to be hydrogen fuel cell vehicles (HFCVs). In a decade, they could reach up to 25 million. By 2050, 80% of new vehicles entering the LDV fleet could be HFCVs. The study concludes that the government cost to support a transition to a hydrogen economy where fuel cell vehicles would become competitive with gasoline-powered vehicles would be roughly US $55 billion from 2008 to 2023. One factor that may reduce the cost of hydrogen is the potential synergies between transportation sector and stationary applications. In the near term, hydrogen production through electrolysis can supply hydrogen where natural gas or other sources are unavailable. In the longer term, after 2025, cogeneration of low---carbon hydrogen and electricity may be an option. Hydrogen production and delivery systems that are taken into account in the study are shown in Table 11.

TABLE 10. SAMPLE SCENARIO FOR US DOMESTIC HYDROGEN PRODUCTION OPTIONS AND RESOURCE NEEDS

Carbon Neutral Resource	Needed for Hydrogen	Availability of Fuel	Current Consumption	Increase in Consumption with H2 production (Factor times current)
Gasification and Reforming				
Biomass	140–280 MT/yr	Between 512 and 1300 MT/yr	190 MT/yr	1.7–2.5
Coal (with sequestration)	110 MT/yr	268 000 MT of estimated recoverable reserves	1100 MT/yr	1.1
Water Electrolysis				
Wind	200 GWe	2300 GWe	10 GWe	28
Solar	260 GWe	5400 GWe	371 GWe	700
Nuclear	80 GWe	0.345 MT	100 GWe	1.8
Thermo-Chemical				
Nuclear	110 GWth	0.345 MT	310 GWth	1.3

Hydrogen demands for future are presented in Table 12. By 2020, only 0.7% of cars are assumed to be running on hydrogen, generating a demand for 0.5146 million tonnes of hydrogen. By 2035, the share of hydrogen fuelled cars reaches 18% of the total car fleet, requiring a supply of 13.87 million tonnes of hydrogen. By 2050, 60% of the total fleet runs on hydrogen, generating a demand for 43.8 million tonnes of hydrogen.

TABLE 11. HYDROGEN SUPPLY PATHWAYS

Resource	Hydrogen Production Technology	Hydrogen delivery Methods
Natural Gas	Steam methane reforming (SMR) (onsite)	N/A
	SMR (central plant)	Liquid hydrogen, compressed gas tuck, pipeline
Coal	Coal Gasification with capture and sequestration	Liquid hydrogen, compressed gas tuck, pipeline
Biomass	Biomass gasification	Liquid hydrogen, compressed gas tuck, pipeline
	Onsite ethanol reforming	N/A
Electricity	Water electrolysis (onsite)	N/A

TABLE 12. TYPE OF HYDROGEN SUPPLY OVER TIME

	2010	2035	2050
No. of cars served	1.8 million (0.7%)	61 million (18%)	219 million (60%)
Infrastructure capital cost	$2.6 billion	$139 billion	$415 billion
Total no. of stations	2112 (all onsite SMR)	56 000 (40% onsite SMR)	180 000 (44% onsite SMR)
No. of central plants	0	113 (20 coal, 93 biomass)	210 (79 coal, 131 biomass)
Pipe length (miles)	0	39 000	80 000
Hydrogen demand (tonnes per day)	1410 (100% NG)	38 000 (22% NG, 42% biomass, 36% coal)	38 000 (31% NG, 25% biomass, 44% coal with CCS)

Hydrogen energy outlook in Pakistan

At present, hydrogen demand in Pakistan is around 1.3 million tonnes per year. Fertilizer sector is the major producer and consumer of hydrogen in the country. Increases in both cultivation area and fertilizer intensity in agriculture are expected to further increase the demand of hydrogen in this sector. The hydrogen demand of fertilizer industry is estimated to be doubled by 2050 assuming an increase in cultivated area from current 22.0 million hectares to 23.5 million hectares and fertilizer intensity from 175 nutrient kilograms per hectare to 350 nutrient kilograms per hectare. Table 13 shows the estimated hydrogen demand in fertilizer, transport and other major sectors of the economy by 2050 in Pakistan.

TABLE 13. PROJECTIONS OF HYDROGEN DEMAND FOR PAKISTAN

Unit: kilotonne/year

Year	2030	2040	2050	
Fertilizer industry	1913	2294	2476	Ammonia based fertilizers
Transport	538	1505	3484	Fuel cell / IC engine road vehicles
Oil refining	42	51	57	Petroleum refining only
Other uses	30	49	80	Steel, textile, food oil, pharmaceutical, glass, etc.
Total	2523	3900	6097	

Transport sector has a large potential of hydrogen use in the country. The transport sector of Pakistan is well acquainted with the use of compressed natural gas (CNG) as fuel. More than 2.8 million vehicles are fitted with CNG cylinders [12] and there is a well-established network of CNG filling stations in the country. This sector consumes 8% of country's natural gas and currently it is experiencing supply shortage. Pakistan depends on imported petroleum fuels for 80% of its oil needs and transport sector contributes 51% in the demand of oil in the country [13]. Transition of transport sector from petroleum to hydrogen fuel will reduce reliance on natural gas and oil. The transition to hydrogen fuel is assumed to start by 2025 when fuel cell technology will be deployed in various countries. Hydrogen demand will gradually build-up to replace 20% of transport fuels by 2050. The hydrogen supply infrastructure is assumed to replace the oil and CNG fuels 7% by 2030, 13% by 2040 and 20% by 2050.

Currently, hydrogen is mainly produced and consumed in fertilizer industry through steam reforming of natural gas and in short term, this will continue to be produced by the same method. Pakistan has large coal resource, 186 billion tonnes, with heating value range from 6200 to 11 000 BTU/lb. Government has planned to exploit the resource on large scale for power generation. In medium term, it is likely that hydrogen production through gasification of indigenous coal will be an economical option.

To meet the long-term hydrogen demand in the country, additional technologies and processes, including nuclear energy, would have to be used for hydrogen production. It is expected that high temperature reactor (HTR) for hydrogen production would be commercially available beyond 2025. Therefore, along with coal gasification, nuclear power based hydrogen production technologies are expected to penetrate the hydrogen market at large scale in the country.

1.1.1.4.Hydrogen demand outlook in China

Hydrogen is mainly used as chemical raw materials. Around 80% of hydrogen is used for ammonia synthesis, which is much high than 60% of the world level. The second largest H_2 demand is from upgrading of crude oil. As the oil quality deteriorated, more and more hydrogen will be used for hydrogenation splitting and refining of oil, to obtain high quality gasoline and diesel to decrease the environmental impact caused by vehicles. Another important demand of H_2 is from the synthesis of methanol from syngas (CO and H_2). In addition, in some other processes, including coal to oil, F-T synthesis, methanation, hydrogen is also need in large amount. Beside application as chemicals, liquid hydrogen is also used as rocket fuel in aerospace industry.

Recently, fuel cell and related vehicle technology made great progress, which presents a huge potential demand for hydrogen. In addition, if it can be supplied in large amounts and at reasonable cost, hydrogen may be widely used in metallurgy for production of direct reduction iron, dramatically decreasing CO_2 emissions in the steel industry.

The demand of hydrogen in the future in China will be increased continuously. The actual demand in 2012 was about 16 million tonnes. It is estimated to steadily increase to 23 million tonnes by 2017. The longer term hydrogen demand is forecast to increase with the continual expansion of the Chinese economy. Table 14 shows the projection of hydrogen demand for China in medium scenario.

TABLE 14. MEDIUM PROJECTION OF HYDROGEN DEMAND FOR CHINA

Unit: million metric tonne/year

Year	2030	2040	2050	
FCV	0.3	1.5	6.0	
Stationary FC	0.1	1.0	3.5	Power and heat
Household			0.8	
Commercial			0.4	
Industrial			2.3	
Power generation	0.0	4.0	10.0	
Industries	20.0	25.0	30.0	Ammonia, methanol, refinery, steel making
Total	20.4	31.5	53.0	

1.1.2. The potential of nuclear hydrogen production

Development of innovative nuclear hydrogen production methods as an expanded area of nuclear energy utilization that offers a zero-emission energy strategy of scale and cost similar to the role of nuclear power generation today is being undertaken in many Member States with the aim to potentially contribute to meeting the significant outlook for hydrogen energy for sustainable development of national economy towards fulfilling national CO_2 reduction goals in 2050. The following are selected case studies performed by Member States.

1.1.2.1. Japan

A Generation-IV VHTR reactor, known as GTHTR300C, is being developed in Japan for potential commercial deployment of 2025. As detailed in Section 2.1.1.2, the GTHTR300C is a multi-purpose reactor with design flexibility to generate electric power, hydrogen or cogenerate both products. The pre-licensing basic design of the reactor has been completed.

Three cases of hydrogen production based on this particular Generation-IV VHTR reactor design are evaluated. They are depicted in Fig. 8 and the corresponding production performance parameters are summarized in Table 15.

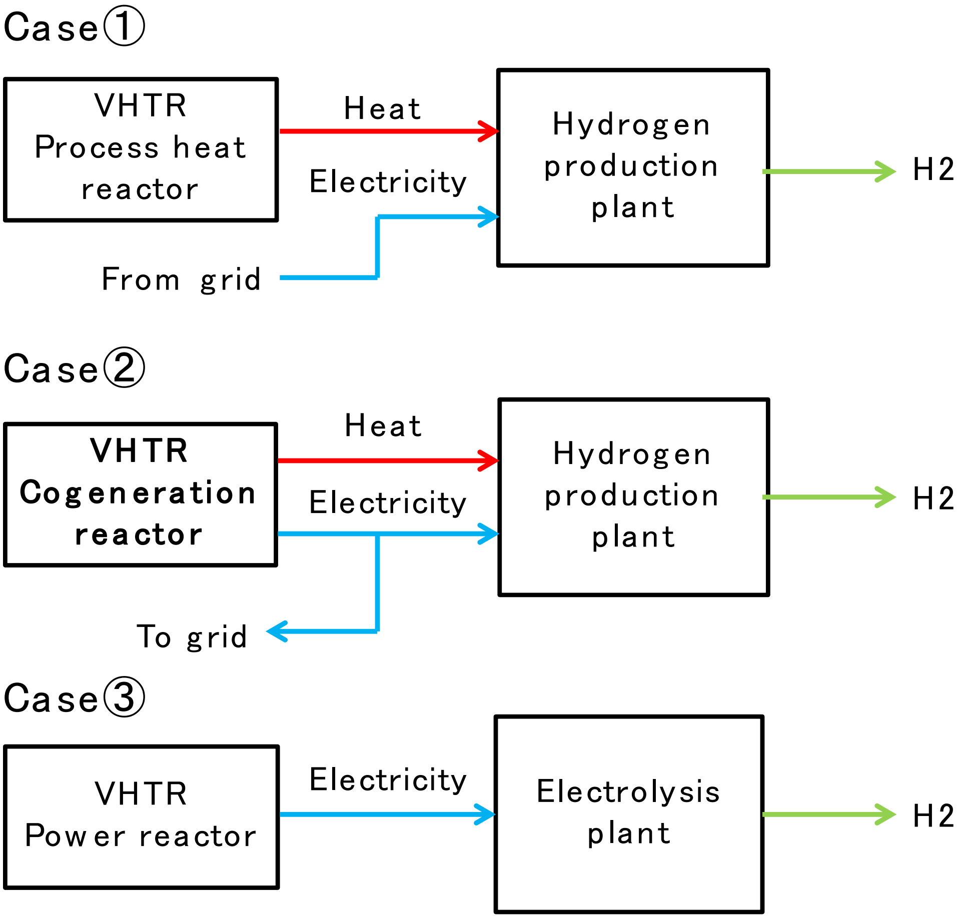


FIG. 8. Case studies of VHTR (GTHTR300C) hydrogen production plant arrangement

Case 1: VHTR acts as process heat reactor to produce and supply the heat to an S–I cycle hydrogen production plant (see Section 2.1.2.4 for a description of the water splitting thermochemical cycle), while the electricity required by the hydrogen plant is imported from the grid at wholesale price for industrial users.

Case 2: VHTR cogenerates both the heat and electricity to supply to the S–I cycle hydrogen production plant with any surplus of the electricity generated by the VHTR to be exported and sold to grid.

Case 3: VHTR produces and supplies only the electricity, all of which is used to power a conventional water electrolysis plant for hydrogen production.

The cost of hydrogen production from each of the three cases is estimated based on the financial assumptions given in Table 16. The nuclear plant parameters including discount rate, interest and property tax are typical values used for cost estimation of utility nuclear power reactors in Japan. An average lifetime of 20 years for the S–I cycle hydrogen plant for Cases 1 and 2 is expected to be achievable. As a result, the cost for one-time replacement of hydrogen plant is considered during the reactor lifetime. For simplicity, the electrolysis plant of Case 3 assumes the same scheme of lifetime and replacement.

TABLE 15. HYDROGEN PRODUCTION PERFORMANCE PARAMETERS

		Case 1	Case 2	Case 3
Reactor thermal power	MW(th)	600	600	600
Reactor outlet temperature	°C	950	950	950
Reactor power generation	MW(e)	-	204	302
Reactor plant power output (to grid)	MW(e)	0	159	0
Hydrogen production rate	t/d	236	67	118
	Nm^3/h	109 525	31 032	55 406
Hydrogen production heat consumption	MW(th)	600	170	-
Hydrogen production electricity consumption	MW(e)	93.9	24.9	266.1
Hydrogen production efficiency	%	47.5	49.3	37.9
Hydrogen product liquefaction electricity consumption	MW(e)	70.8	20.1	35.9
Total electricity consumption (H_2 production + liquefaction)	MW(e)	164.7	45.0	302.0

TABLE 16. FINANCIAL PARAMETERS FOR HYDROGEN PRODUCTION COST ESTIMATION

Plant load factor	90%
Discount rate	3.0%
Interest rate	3.0%
Property tax rate	1.4%
Reactor plant	
Plant lifetime	40 years
Depreciation period	16 years
Residual value	10%
Hydrogen plant	
Plant lifetime	20 years
Depreciation period	8 years
Residual value	10%

TABLE 17. COST OF ELECTRICITY FOR HYDROGEN PRODUCTION

	Case 1a	Case 1b	Case 2	Case 3
Capital	-		1.52	1.52
O&M	-		1.46	1.46
Fuel	-		1.36	1.36
Policy (siting, R&D, etc)	-		1.10	1.10
Wholesale electricity (for industry users)	13.65	18.85	-	-
Total (¥/kW·h)			5.44	5.44

Table 17 lists the cost of electricity consumption for hydrogen production in each case. Case 1 refers to the historical wholesale prices of electricity in a twenty-year period between 1995 and 2014 in Japan. Case 1 is further divided to Case 1a, which refers to the lowest of ¥13.65/kW·h charged to industrial users in 2010, and Case 2, which refers to the highest price of ¥18.85/kW·h recorded in 2014.

Cases 2 and 3 are based on the cost of GTHTR300 power generation estimated jointly by JAEA and domestic nuclear vendors. The cost of electricity is same for Case 2 and Case 3 because of their identical power generation infrastructure design in the nuclear plant.

Similarly, Table 18 summarizes the estimated cost of heat supply for hydrogen production in each case. Case 1 and Case 2 are based on the designs and associated costs evaluated by JAEA together with domestic nuclear vendors. The cost of heat in Case 2 is lower due to the advantage of cogeneration in that most components of the nuclear plant in Case 2 are shared between power generation and heat supply while all components in Case 1 are dedicated to heat supply only. The heat consumption is nil for the electrolysis production of Case 3.

TABLE 18. COST OF HEAT ENERGY FOR HYDROGEN PRODUCTION

	Case 1a & 1b	Case 2	Case 3
Capital	1.14	1.08	-
O&M	0.96	0.92	-
Fuel	0.62	0.62	-
Policy (siting, R&D, etc)	0.50	0.50	-
Total (¥/kW(th))	3.23	3.13	0

The final results of estimated costs of hydrogen are given in Table 19. The hydrogen cost is the lowest with Case 2. The cost advantage is attributed to the ability of Case 2 to cogenerate the energy of electricity and heat required by the hydrogen production at the lowest combined price comparing to the other cases. Such cost advantage is achieved despite the fact that its hydrogen plant costs are the highest due to the penalty of economy of scale of the hydrogen rate.

TABLE 19. HYDROGEN PRODUCTION COST

		Case 1a	Case 1b	Case 2	Case 3
Electricity	¥/Nm^3-H_2	11.70	16.16	4.37	26.13
Heat	¥/Nm^3-H_2	17.67	17.67	17.14	-
Hydrogen plant (capital & O&M)	¥/Nm^3-H_2	7.77	7.77	8.80	7.93
Total (production)	¥/Nm^3-H_2	37.14	41.60	30.31	34.06
	US \$/kg-H_2	3.44	3.86	2.81	3.16
Liquefaction	¥/Nm^3-H_2	14.25	18.02	8.17	8.17
Total (production and liquefaction)	¥/Nm^3-H_2	51.39	59.62	38.48	42.23
	US \$/kg-H_2	4.76	5.53	3.57	3.92

Finally, the estimated production costs of hydrogen are summarized in Fig. 9 and additional details including the cost of liquefaction for hydrogen product are given in Table 19. The hydrogen cost is the lowest for Case 2 of the cogeneration system. The cost advantage is attributed to the ability of Case 2 to cogenerate the energy of electricity and heat required by the hydrogen production and the additional electricity required for liquefaction at the lowest combined price comparing to the other cases. Such cost advantage is achieved despite that its hydrogen plant costs the highest due to the penalty of economy of scale due to Case 2's lowest hydrogen rate. The range of hydrogen production costs in all three cases of VHTR-based hydrogen production appears to be competitive to those reported by METI for non-nuclear energy supplied routes of hydrogen production as shown in Fig. 9. However direct cost comparison with the non-nuclear routes is not possible because of the different costing methods used.

Besides the competitive cost of hydrogen production, the VHTR is a promising GHG-emission-free nuclear energy source due to its advantages of inherent safety, low specific waste volume, high temperature capability to enable high-efficiency power generation and industrial heat supply.

As highlighted in Fig. 10, JAEA envisions that the 40% of the demand of hydrogen in 2050 (Table 8) could be met with production with the VHTR. This would undoubtedly reduce the price uncertainty and supply stability of the existing plan, as stated in Section 1.1.1.1, that relies on import to meet the majority of national demand of hydrogen in 2050. In addition, JAEA calls for the VHTR to provide 30% of the nuclear power generation and 20% of industry heat demand in 2050. Taking all production activities all together, the VHTR could make 15% contribution to Japan's 80% CO_2-emission-reduction goal in 2050 [14].

Realizing this vision through JAEA's current plan of research and development to deploy the VHTR around 2030 would contribute to meet the huge challenge of Japan's future energy landscape. In particular, the VHTR deployment would help meet the expectation of nuclear

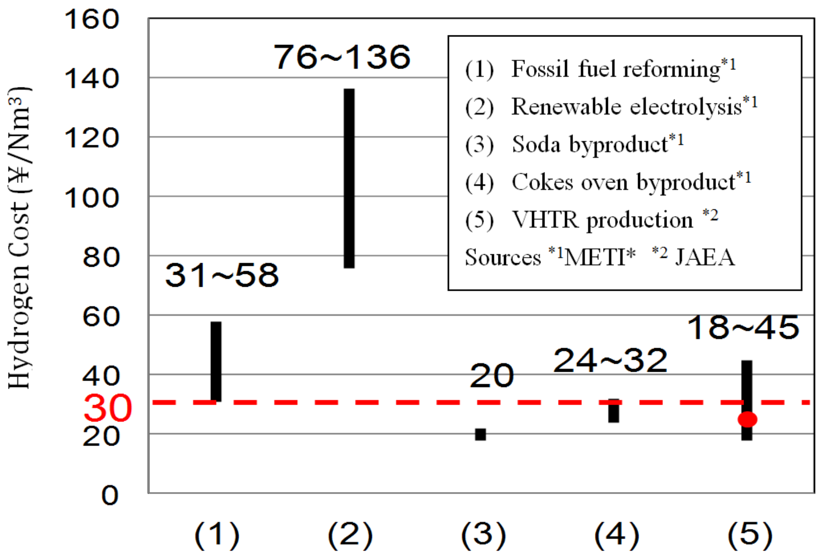
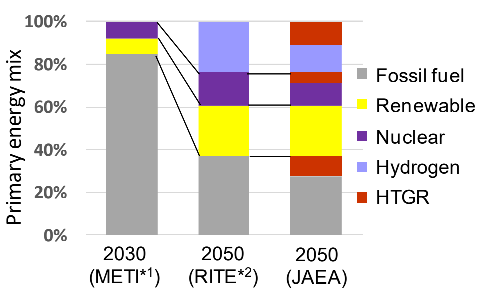


*FIG. 9. Potential of competitive VHTR hydrogen production cost relative to other methods (Note: *1METI, Agency for Natural Resources and Energy, Working Group on Hydrogen and Fuel Cell Strategy Council (Part 5) - Hydrogen Production, Transportation and Storage, April 14, 2014; *2JAEA`s estimation).*

power generation to supply 22% and 42% of national electricity demand in 2030 and 2050, respectively, in spite of the experience of slow progress to restart the existing fleet of LWRs. Similarly, it would reduce the reliance on fossil fuels and environmental performance in the industry heat sector.

Potential of HTGR to meet Japan's primary energy demands

	Share of supply by HTGR
Hydrogen	40%
Nuclear power generation	30%
Industry process heat supply	20%



HTGR contribution to Japan's 80% CO2 reduction in 2050

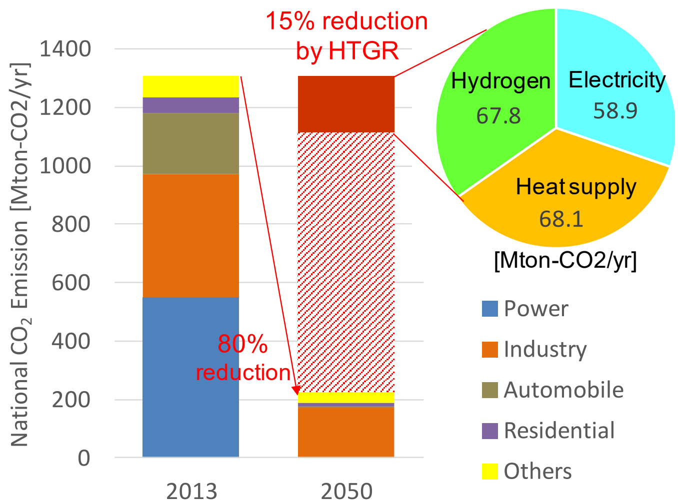


*FIG.10. JAEA's vision of VHTR potential to contribute to Japan's primary energy supply and CO_2 reduction in 2050. (Sources - METI*1:[6];RITE*2:[7])*

1.1.2.2.Evaluation of Germany

Germany carried out a large number of case studies including nuclear, fossil and renewable energy based hydrogen production. The cases are defined in Table 20. The results of evaluation for each case are presented. A comparative analysis is also made.

TABLE 20. CASE STUDIES PERFORMED BY GERMANY

Case	Case I	Case II	Case III	Case IV	Case V	Case VI
Energy plant	HTGR	HTGR	HTGR+ fossil backup	Fossil	Fossil	Solar + Fossil backup
Hydrogen plant	HTSE	S–I	SMR	SMR	SMR + CCS	SMR

1.1.2.2.1. Cases I and II: Nuclear water-splitting

Two of the scenarios examined are reported here. The nuclear concept chosen is the H_2-MHR (see Chapter 2 for the reactor description) that has been designed by General Atomics of the USA and which are applied here as a four-module plant. Case I couples an HTSE plant to the reactor plant. Case II couples a S–I thermochemical cycle to the same reactor. In both cases, four nuclear units of 600 MW(th) each are connected to one hydrogen production system. For both nuclear and hydrogen plants, a load factor of 90% and a 100% availability were fixed.

Table 21 summarize the results of HEEP calculation for the two cases. Since the country report on the CD-ROM explains these results in detail, only a summary is given here.

The combined nuclear HTSE system (cases 1) needs major input of electricity (292 MW(e)) and minor heat (58 MW(th)) from the supply of one nuclear unit. Given the hydrogen product rate of 298 million kg per year, the energy input values put the overall hydrogen conversion efficiency to 54% of conversion efficiency. On the other hand, the combined nuclear S–I system, all thermal energy provided by the nuclear reactor is delivered to the S–I cycle. This power allows for a nominal production of 409 million kg per year. While no electricity is produced in the reactor plant, the power demand (325 MW(e)) for the H_2 plant operation is supplied from the grid and the cost of the supply is included as a part of the H_2 plant O&M.

HEEP is used for cost estimation. Table 22 lists the financial parameters as input to HEEP.

Nuclear hydrogen production applying HTSE at today's cost and state of technology results in a production cost of 1.65 €/kg-H_2, of which 65% is from nuclear plant capital cost. 54% of the final hydrogen cost dominant contribution is from capital costs (64%) with the balance from operating costs. Decommissioning cost contribution is less than 0.5% and neglected from the table.

The cost of nuclear hydrogen through the S–I process is slightly higher but remains in close range to the HTSE hydrogen cost. Unlike the HTSE case, the majority share of the cost is from hydrogen plant (61%). A close examination reveals that the strikingly higher O&M cost as a result of the need to purchase external grid electricity is responsible for the larger cost share of the hydrogen plant. As indicated by the previous section of Japan`s result, reconfiguring the reactor from a dedicated heat reactor to one of cogenerating heat and electricity required by the hydrogen plant, would lead to reduced final cost of hydrogen for the combined S–I cycle.

TABLE 21. RESULTS OF CASE STUDIES FOR NUCLEAR WATER SPLITTING HYDROGEN PRODUCTION COST

Case	Case I	Case II
Thermal power (MW(th))	4 × 600	4 × 600
Electric power (MW(e))	4 × 292	0
Process heat production (MW(th))	4 × 58	4 × 600
NPP capital cost (€)	4 × 287 306 000	4 × 291 099 091
Cost for electricity generating infrastructure (% of CC)	8.68	0
Initial fuel load (kg/unit)	0	0
Annual fuel reload (kg/unit)	24 046	24 046
Fuel cost (€/a)	4 × 15 986 529	4 × 15 986 529
Operational + refurbishment cost (% of CC)	2.5 + 2.5	2.42
Decommission cost (% of CC)	10	10
H_2 production rate (kg/a)	297 699 840	409 021 920
He plant heat consumption (MW(th))	232	2400
He plant power consumption (MW(e))	1168	812
H_2 plant capital cost (€)	936 437 202	868 920 349
Energy consumption cost (€/a)	0	629 937 907
Operational + refurbishment cost (% of CC)	5.78 + 2	5.91 + 2
Decommission cost (% of CC)	10	10
Hydrogen production cost		
NP Capital cost (equity) (€/kg)	0.58	0.43
NP O&M + refurbishment (€/kg)	0.10	0.07
NP Fuel (€/kg)	0.21	0.16
H_2 Capital cost (equity) (€/kg)	0.47	0.32
H_2 O&M + refurbishment (€/kg)	0.28	0.73
total (production) (€/kg)	1.65	1.71

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TABLE 22. HEEP FINANCIAL PARAMETERS USED IN GERMAN EVALUATION

Discount rate (%)	10
Inflation rate (%)	2.1
Finance Equity:Debt ratio (%)	100:0
Borrowing interest (%)	0
Tax rate (%)	23.8
Depreciation period (year)	20
Plant construction period (years)	3
Plant operation period (years)	40

1.1.2.2.2. Case III: Nuclear SMR

The nuclear reactor considered is a 250 MW(th) HTGR with outlet temperature of 800°C, whose nth-of-a kind cost (Table 23) is estimated from the cost models of NGNP [15]. Compatible to the temperature of the nuclear supplied heat the SMR process of the hydrogen plant runs at a maximum temperature of 800 °C. The production rate of the hydrogen production process is normalized to the heat rate of the HTGR unit. The electricity consumption of the plant is purchased from the grid. A natural gas fired heater takes the task of the backup for the average (scheduled and forced) outage of the HTGR so as to ensure year-round continued hydrogen production. Continued production would eliminate the requirement for hydrogen storage in the case of on-site hydrogen production and consumption in a steel mill or refinery. Accordingly, the HTGR supplies 2014.6 GWh of heat, whereas the fossil heater generates 87.7 GWh of heat.

Using an internally-developed cost optimization code, which may be used to optimize system design and operation for the least cost, the hydrogen cost for the above-specified HTGR SMR production arrangement is found to be 2.41 €/kg. The nuclear plant and hydrogen plant appear to contribute equally to the final production cost. Note that the backup fossil heater would add about 1.7% to the total cost, an affordable option to ensure uninterrupted hydrogen product flow.

1.1.2.2.3. Cases IV and V: Conventional SMR

Two cases of conventional SMR are considered. Case 1 represents a reference SMR case. Case 2 takes additionally into account a carbon capture and storage system connected to the SMR plant. Some cost information can be retrieved from CCS projects that are presently in operation or short before starting operation, including also the demonstration of CCS for SMR plants. Cases 1 and 2, although fictitious plants, may represent state of the art as of 2010.

HEEP is used for cost estimation using the same set of financial parameters in Table 22. All essential input data for the cases were basically taken from the US-DOE directed so-called Hydrogen Analysis Project (H2A) [17] and from EU sources. The results of HEEP calculation for the two cases are given in Table 24. Since the country report explains the input and HEEP results in detail, only a summary is given here.

TABLE 23. RESULTS OF CASE STUDY FOR HTGR SMR HYDROGEN PRODUCTION COST

Case	Case III
Hydrogen production rate	12.73 t/h
Number of reactor units	1
Reactor thermal power/unit	250 MW(th)
Reactor outlet temperature	850°C
Reactor availability	92%
Reactor cost	
Capital cost	2,100 €/kW(th)
Maintenance cost/year	5% of capital cost
Insurance cost/year	2% of capital cost
Labour cost/year	27.5 M€
Fuel cost/year	6.76 €/MW(t)h
Decommissioning cost	100% of capital cost
Number of backup fossil heater units	1
Thermal power of fossil heater/unit	250 MW(th)
Fossil heater cost	
Capital cost	80 €/kW(th)
Maintenance cost/year	1% of capital cost
Insurance cost/year	1% of capital cost
Labour cost/year	0
Fuel (natural gas) cost/year	28.7 €/MW(t)h
CO_2 emission cost	10 €//t
Hydrogen production cost (€//kg-H_2)	
Nuclear plant	1.12
Fossil standby heater	0.04
Hydrogen plant	1.20
Grid electricity purchase	0.05
Total hydrogen production cost	2.41

If taking into account a load factor of 90% and a 100% plant availability, the hydrogen production rate of 138 476 255 kg/a or ~15.8 t/h translates into a rate of 170 000 Nm^3/h, thus belonging to the largest SMR plants of today. Assuming a specific electricity demand of 0.569 kWh/kg-H_2, total demand amounts to 78.8 MWh/a or ~9 MW(e). Thermal energy needed in the endothermic steam reforming reaction is provided here basically by burning natural gas and part of the hydrogen produced. Total thermal power demand is 231 MW(th). With the implementation of a CCS system (case 2) capital cost have drastically increased. Power demand has more than doubled to 22.22 MW(e), while thermal energy demand has only marginally changed. For the future scenario (case 3), efficiencies are presumed to remain unchanged meaning that electric and thermal power consumption remains constant.

From the capital costs of the conventional SMR plant assumed, almost three-quarters are direct costs, i.e. investment and installation costs. The remainder is energy consumption cost of 58 701 286 € per year. This includes the cost for electricity purchased from the grid at a price of 98.4 €/MWh and ~100 000 t/a of natural gas for process heat production at a price of 36.4 €/MWh. Other O&M costs including salaries for 20 workers, the feedstock natural gas for the conversion to hydrogen (~400 000 t/a), CO_2 emission certificates (7.39 €/t-CO_2) amount to 110.35% of the capital costs; the "+ 2" in the table refers to refurbishment costs. In case 2, capital costs include now the purchase and installation of the CO_2 treating parts of the plant like pipelines, compressors, dryers. Other O&M costs are almost cut to half due to the substantially reduced costs for CO_2 emissions (assuming a CCS efficiency of 90).

Total hydrogen costs are principally determined by operational costs (80% or greater) in either of the cases as a result of feedstock consumption. The implementation of a CCS system raises the H_2 production costs by 0.20 €/kg. Decommissioning costs are negligible in all cases.

TABLE 24. HEEP COST ANALYSIS RESULTS FOR CONVENTIONAL SMR CASES

Case	Case IV (SMR only)	Case V (SMR + CCS)
H_2 production rate (kg/a)	138 476 255	138 476 255
Capacity factor (%)	90	90
Availability factor (%)	100	100
Heat consumption (MW(th))	230.94	230.55
Power consumption (MW(e))	8.99	22.22
Capital cost (€)	152 665 088	285 375 033
Energy consumption cost (€/a)	58 701 286	68 958 442
Other operational cost (% of CC)	110.35 + 2	57.52 + 2
Decommission cost (% of CC)	10	10
Hydrogen production cost		
Capital cost (€/kg)	0.17	0.31
O&M + refurbishment (€/kg)	1.81	1.87
Total production (€/kg)	1.98	2.18

1.1.2.2.4. Case VI: Solar SMR

In the solar scenario ten solar towers with a thermal power of 200 MW(th) each are necessary to guarantee a continuous heat supply of the SMR process. Consequently, a huge thermal storage with a storage capacity of 41,077 MW(t)h is necessary.

The case considered is a solar receiver plant supplying heat to a SMR plant with system specification found in Table 25. A large number of solar tower units with huge thermal storage is necessary to ensure continued production of hydrogen. Similar to the nuclear SMR, a natural backup heater is used. The backup heater reduces the number of solar towers required for continuous production to 7 from 10 units in addition to reducing the thermal storage capacity by 15%. The capacity of the fossil heater is rated to supply the process heat demand solely. A power turbine plant is built to use the surplus energy occurring especially in summer. Electricity generated is used to recharge the thermal storage. The surplus electricity is sold. The sale of the electricity reduces the net cost of electricity purchase by 67%.

The cost optimization code used in Case III is also used here. The estimated hydrogen cost for the above-specified Solar SMR production arrangement is 2.83€/kg. The cost would be 62% greater for a standalone solar heating plant, i.e. without using the fossil heater as backup to ensure continuous hydrogen production.

1.1.2.2.5. Comparative analysis

The hydrogen generation costs of the technology cases evaluated by Germany are compared in Fig. 11. Note that the costs of Cases I and II are obtained with HEEP while those of all other cases by MILP, the Germany's internal code. As will be discussed in Chapter 4, the hydrogen costs obtained by the two codes are in good agreement. This validates the comparison made in Fig. 11.

By taking advantage of economy of scale, Cases I and II of nuclear production with a hydrogen production range of about 30–50 t/h offer the lowest hydrogen generation costs without carbon dioxide emission. Furthermore, the centralized production arrangement of these plants with multiple reactor modules are shown cost competitive even to smaller production capacity plants of conventional SMR of Cases IV and VI with or without CCS.

At similar scale of hydrogen production, the nuclear production is seen comparable in cost to fossil options. The cost of Case III, the nuclear SMR along with fossil heater back to ensure continued availability of production, is about 30% higher than Case IV of the fossil SMR and only 10% than Case V with CCS.

The solar production appears the highest of the cases evaluated. The chief reason is the low solar load factor, 22.7% or 1996 full load hours per year, which requires 10 solar towers with a total thermal capacity of 2000 MW(th) and a huge thermal or hydrogen storage to ensure continued hydrogen supply at the same rate produced by a 250 MW(th) fossil SMR. Even though a backup fossil heat is employed as is in Case VI, the most economical solar system would still require seven solar towers and a large thermal or hydrogen storage.

TABLE 25. RESULTS OF CASE STUDY FOR SOLAR SMR HYDROGEN PRODUCTION COST

Case	Case VI		
Hydrogen production rate	12.73 t/h	Power turbine plant capacity	101.7 MW(e)
Number of solar towers	7	**Power turbine plant cost performance**	
Thermal power/tower	~190 MW(th)	Capital cost	337 €/KW(e)
Solar heating temperature	850°C	Maintenance cost/year	1% of capital cost
Solar load factor	22.7%	Insurance cost/year	2% of capital cost
Solar plant cost		Labour cost/year	4 M€
Heliostat field	Efficiency	Efficiency	40%
Solar receiver	150 €/kW(th)	Thermal storage capacity	6,121 MW(th)
Direct capital cost/solar tower	2 M€	**Thermal storage cost performance**	
Indirect cost, owner cost, contingency	41% of direct capital cost	Capital cost	30 €/KW(th)
Maintenance cost/year	2% of capital cost	Maintenance cost/year	1% of capital cost
Insurance cost/year	1% of capital cost	Insurance cost/year	1% of capital cost
Operators/1st tower	30	Labour cost/year	0
Operators/nth tower	15	Heat loss rate	0.5%/h
Labour cost per person/year	60 000 €	**Hydrogen production cost (€//kg-H_2)**	
Number of backup fossil heater units	1	Solar plant	1.24
Thermal power of fossil heater/unit	250 MW(th)	Fossil standby heater	0.13
Fossil heater cost		Thermal storage	0.19
Capital cost	80 €/kW(th)	Power turbine plant	0.04
Maintenance cost/year	1% of capital cost	Hydrogen plant	1.20
Insurance cost/year	1% of capital cost	Grid electricity purchase	0.03
Labour cost/year	0	Total hydrogen production cost	2.83
Fuel (natural gas) cost/year	28.7 €/MW(t)h		
CO_2 emission cost	10 €//t		

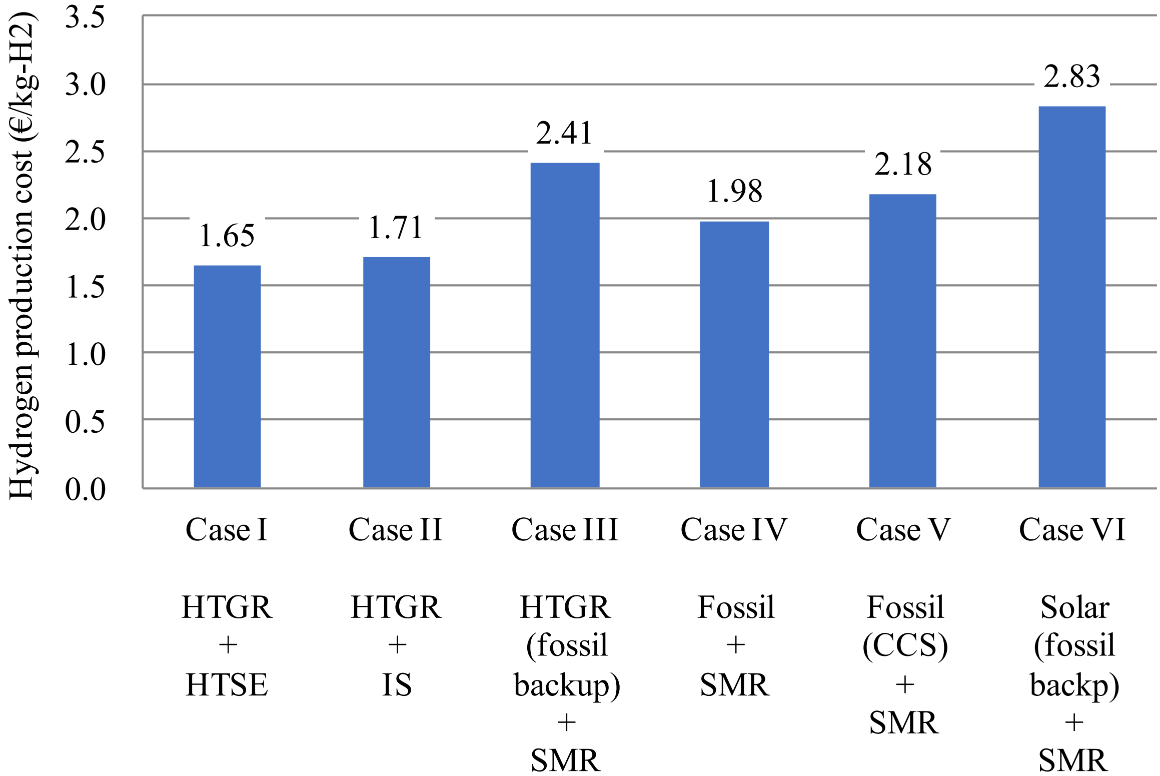


FIG.11. Comparison of hydrogen costs among technologies evaluated by Germany.

1.1.2.3.Cost of hydrogen in Argentina

Table 26 provides hydrogen costs reported from several sources in the country. Currently there are several plants in the country of captive hydrogen production for ammonia, methanol and iron metallurgy industries, but the cost of hydrogen production of such plants is not available to the public. Furthermore, there are two industrial plants dedicated to the supply of high-purity special gases for industries and research laboratories. They produce hydrogen by steam–methane reforming and electrolysis processes, and the levelized cost of such high-purity hydrogen ranges between 3 U$D/kg H_2 at wholesale level and 37 U$D/kg H_2 at retail level.

A research group conducted an evaluation of the hydrogen production costs in Argentina using wind power in areas with capacity factor greater than 35%. The evaluation could determine the annual energy available in each area studied using the information contained in the national wind map, from which an estimate of the threshold cost of wind power generation such that a project does not have negative returns was done, establishing a relationship between the unit cost in US $/MWh and the capacity factor value. From these analysis results, the cost of hydrogen production for each area studied was then evaluated using the H2A software. The levelized cost of hydrogen production by electrolysis process powered by wind energy was estimated in the order of 2.8 to 3.9 US $/kg H_2 (without considering the costs of hydrogen storage and transportation). As expected, the cost of hydrogen production from wind power was predicted to decrease with increasing the capacity factor: for a conventional electrolysis system with an efficiency of 75% (52 kW·h/kg H_2), the lowest cost of hydrogen production was obtained in the provinces of Chubut and Santa Cruz in the south of the country (with a capacity factor of 63%), resulting in 2.8 US $ /kg H_2. Similar evaluations were carried out for hydrogen production using solar energy to generate the electricity needed for the electrolysis process. The levelized cost of hydrogen in the most beneficial regions of solar energy context located in the mountains of the northern of Argentina is predicted to be 3.8 US $ /kg H_2.

TABLE 26. HYDROGEN COSTS REPORTED IN ARGENTINA

Production routes	Levelized cost	Remarks
SMR	unknown	Several plants of captive H_2 production
SMR/Electrolysis	US $37/kg retail	Two industrial plants
	US $3/kg whole sale	
Renewables		
Wind/electrolysis	US $2.8–3.9/kg	Calculated by H2A software
Solar/electrolysis	US $3.8/kg	

1.1.2.4.Estimated cost of hydrogen in Algeria

According to CSI, Ms. Boudries of Division of Renewable Hydrogen Energy, Development Centre for Renewable Energy of Algeria, the cost of renewable energy-electrolysis process production is found to be both site and energy collection/ conversion technology dependent. Moreover, the cost of hydrogen production is dominated by the cost of energy necessary for powering the electrolysis system. Fig. 12 includes some of the evaluation results.

The cost of hydrogen production by PV-electrolysis may depend on:

- PV technology, more particularly on its efficiency;
- Insolation at the site under consideration;
- Meteorological condition at the site and its effects on the PV-system performance;
- Process of solar collection

Only sites with global horizontal irradiance larger than 1000–1500 kW·h/m^2 per year are considered economically viable. The economic viability is additionally affected by the meteorological condition in that the efficiency of the PV module is affected by the site temperature, irradiance and wind speed. The absorbed solar radiation is also affected by the humidity and by the dust accumulation on the PV module.

The cost of hydrogen production by wind electrolysis depends on one hand on the wind potential and on the other hand on the WECS technology and the height at which the wind is converted. Here the cost of production is highly affected by the cost of wind conversion to energy (electricity). For most WECS technologies, wind electricity production is considered economically viable only for wind speed of greater than 2 m/s.

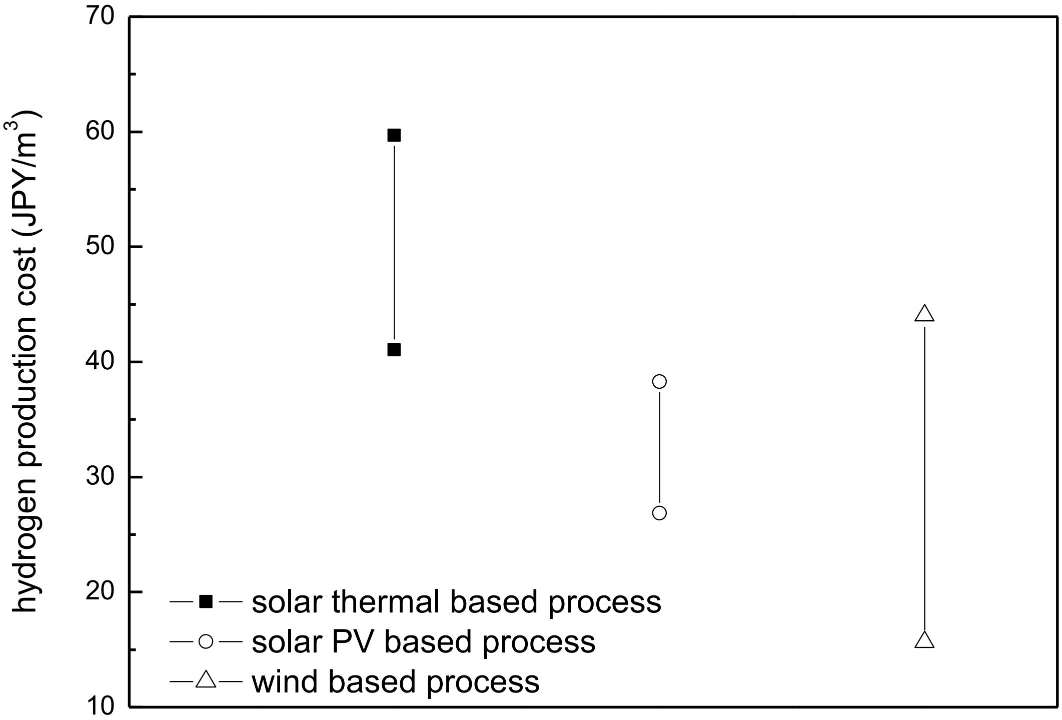


FIG. 12. Cost of hydrogen produced from renewable energy sources

1.2. OBJECTIVES

One of the IAEA's statutory objectives is to "seek to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world". This objective may be achieved through hydrogen production from nuclear energy on a scale comparable to nuclear power generation. Such potential of nuclear hydrogen production has led the IAEA to carry out an active programme on the subject including meetings for information exchange on the present status and future challenges of the development of nuclear hydrogen production and on the techno-economic aspects of the production. So far, the programme has produced two technical reports.

Nuclear Hydrogen Production Using Nuclear Energy (IAEA Nuclear Energy Series No. NP-T-4.2) was published in 2013. The report documents the state of the art of the development of hydrogen production methods through the use of nuclear power in Member States. It includes an introduction to the technology of nuclear process heat reactors as a means of producing hydrogen or other upgraded fuels, with a focus on high temperature reactor technology to achieve simultaneous generation of electricity and high temperature process heat and steam. Special emphasis is placed on the safety aspects of nuclear hydrogen production systems.

The other report is the present publication, which documents the result of an IAEA CRP by the same name. Launched in December 2013, the CRP sought to establish platform for coordinated efforts and information exchange between Member States, assess various hydrogen production options and technologies including transportation and storage, and evaluate technical and economic potential of hydrogen production using nuclear power. The IAEA has previously developed the Hydrogen Economic Evaluation Programme (HEEP) computer software that allows analysing various options for a future hydrogen economy. Being the first-of-a kind, HEEP needs to be validated. The CRP performed benchmarking against various scenarios of hydrogen production and distribution and recommended improvement to and upgrade of the code.

The detailed objectives are to:

1.2.1. Promote Information exchange and coordinated research

- Establish a platform for information exchange between MSs representative of various levels of the technology ranging from advanced to newcomer countries;
- Facilitate research collaboration among CSIs sharing data bases of experiment, design, operation, and cost analysis.
- Presentation by MSs of updated national research and development regarding the techno-economics of hydrogen production.

1.2.2. Assess techno-economics of hydrogen production options

- Review design and cost databases of hydrogen production systems including cogeneration options under consideration in MSs;
- Select reference cases for economic assessment;
- Furnish important data on techno-economics of hydrogen production options using nuclear energy;
- Propose technology improvements that may improve the cost of the hydrogen processes being developed in MSs;
- Identify the challenges and recommend follow-on activities for IAEA to address these challenges.

1.2.3. Validate HEEP through benchmarking exercises

- Improve HEEP through various assessment of integrated system's design and cost performance;
- Perform generic benchmark of HEEP against other open software and internal programmes in MSs;
- Improve Member State's analytical capabilities in the field of economic evaluation of hydrogen production using nuclear energy;
- Suggest enhancement for increased capabilities such as transportation and storage, user interface.

1.2.4. Perform case studies under country-specific conditions

- Identify and design multiple technology-based cases representative of the states-of-the-art;

– Perform techno-economics analysis using HEEP and country financial parameters by all participating CSIs.

– Present the findings of the case studies in CRMs and on the basis of the findings recommend to IAEA for future activities.

1.3. OVERVIEW OF THE SUBJECT

1.3.1. Technology models

One of the key attributes of hydrogen for potentially economy-wide uses is that it can be produced from flexible feedstock options ranging from fossil resources such as natural gas and coal to renewable biomass and water. Similarly, primary energy sources required are flexible, including nuclear, renewable and fossil energy. As a result, hydrogen production follows more processes or pathways than listed below:

- Chemical reforming of fossil fuels and biomass, using nuclear heat;
- Electrolysis of water, using nuclear power;
- Electrolysis of steam, using major nuclear power and minor nuclear heat;
- Thermochemical process, using nuclear heat and often minor nuclear power.

The last three pathways essentially are based nuclear cogeneration of electricity and hydrogen, as shown in Fig. 13. Also seen in the figure is that the two energy carriers are reversible one to the other by the routes of water electrolysis and fuel cell.

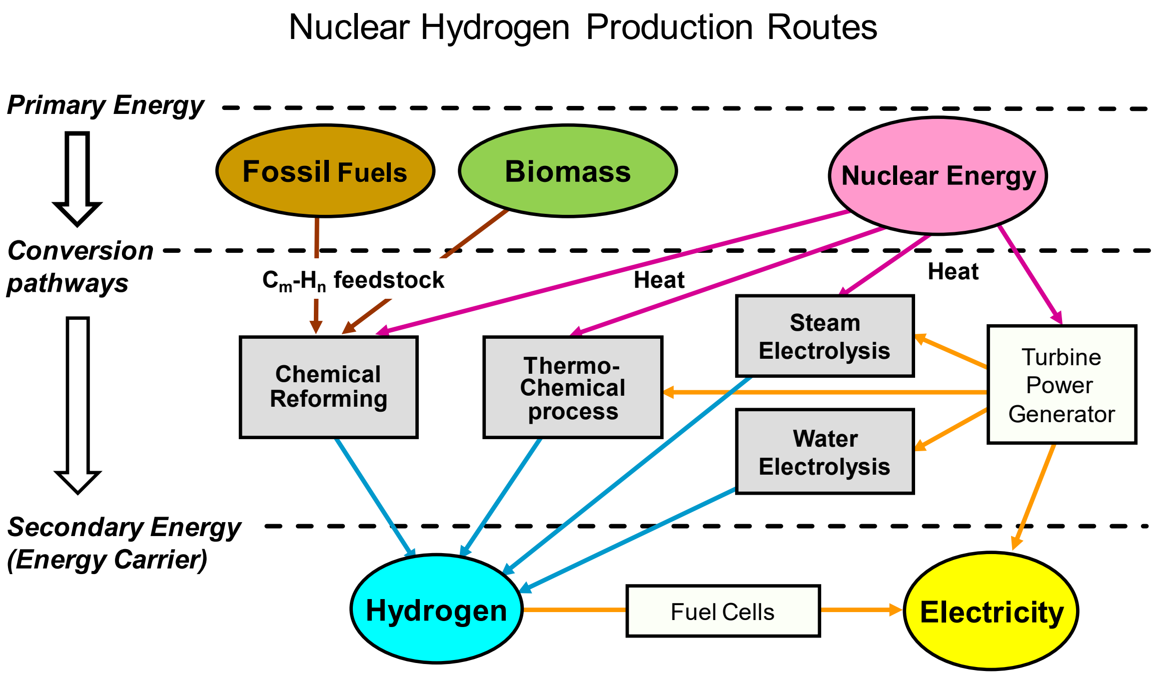


FIG. 13. Potential pathways of hydrogen production from nuclear energy

The chemical reforming relies on net endothermic chemical reactions of carbon or hydrocarbon feedstock with steam, in which nuclear energy meets the heat requirement. Conventional electrolysis splits water molecules into hydrogen and oxygen by consuming nuclear power. Advanced electrolysis raises water to high temperature steam by nuclear heat prior to the electrolysis step, resulting in an improvement of thermal efficiency for hydrogen production. The thermochemical process consists of a series of chemical reactions using water as the only reactant and all other chemicals as reagents. Nuclear energy, in the form of heat and often additional nuclear power, drives a pure or hybrid thermochemical process. All four pathways use renewable sources of water or biomass as feedstock and are consistent with the sustainability goal of nuclear energy.

The choices of nuclear reactors vary with the conversion pathways. The CRP examines the few systems most interesting to participating countries. They include small-medium light water reactors (SMR), large light water reactor (LWR), advanced CANDU supercritical water reactor, high temperature gas reactor (HTGR). The light water reactors are suitable for use in conventional electrolysis due to their working temperature range of 280–325°C. The working temperature ranges of the supercritical water reactors like CANDU are 430–625°C, making them suitable for production of hydrogen using medium-temperature hybrid cycle. The high working temperature range of 750–950°C of high temperature gas reactor using helium as a coolant makes them suitable for generation of hydrogen with high temperature processes including steam reforming, steam electrolysis, and thermochemical cycles.

Matching the nuclear reactors to the pathway processes, IAEA has developed five generic cases of nuclear hydrogen production technology models as described in Table 27. The design and cost data are obtained from the literature. These cases are used for benchmarking including sensitivity analysis of IAEA's HEEP software for hydrogen production cost by each of the CRP participating countries. The results are presented in the country reports available on the CD-ROM attached to this publication.

TABLE 27. GENERIC CASES SELECTED BY IAEA FOR BENCHMARKING HEEP

Case number	Case 1	Case 2	Case 3	Case 4	Case 5
System design	APWR+CE	APWR+CE	APWR+CE	HTGR+HTSE	HTGR+SI
System description	A combination of small-size light water power reactor and conventional electrolysis	A combination of medium-size light water power reactor and conventional electrolysis	A combination of large-size light water power reactor and conventional electrolysis	A combination of large-size light water power reactor and high temperature electrolysis	A combination of large-size light water power reactor and high temperature electrolysis
Hydrogen production rate	4 kg/s	8 kg/s	12.43 kg/s	4 kg/s	4 kg/s

The CRP participants have designed, based on the current state of the art, four technology-based cases of nuclear hydrogen production as described in Table 28. The design and cost data are provided by the participants. These cases are also used for techno-economics analysis of hydrogen production cost using country specific site and project financing conditions. The results are presented in the country reports.

TABLE 28. TECHNOLOGY BASED CASES DESIGNED BY CRP PARTICIPANTS

Case number	Case A	Case B	Case C	Case D
Designed by country	Canada	China	Germany	Japan
System design	CANDU6+CuCl	HTR-PM+SI	HTR-Modul+SRM	GTHTR300C+SI
System description	Involves the use of thermochemical cycle Cu–Cl and the SCWR	Involves the use of thermochemical cycle SI and the HTR-PM	Involves the use of steam–methane reforming and the HTR-Module	Involves the use of thermochemical cycle SI and the GTHTR300C
Hydrogen production rate	4.25 kg/s	1.36 kg/s	3.48 kg/s	0.77 kg/s

1.3.2. Economic models

1.3.2.1.HEEP

The Hydrogen Economic Evaluation Program (HEEP) [16] is a tool made freely available by the IAEA, which can be used, similar in principles to the IAEA software DEEP, for performance and cost evaluation of large scale hydrogen production using nuclear energy. The software can be used to analyse the economics of the four most promising processes for hydrogen production: high and low temperature electrolysis, thermochemical processes including S–I process, conventional electrolysis and steam reforming.

HEEP may be used for comparative studies not only between nuclear and fossil energy sources for hydrogen production, but also between hydrogen production and cogeneration with electricity. The HEEP software models process systems with technical data, and perform financing and cost analysis of discounted or constant value problems, which include essential aspects of the hydrogen economy including production, storage, transport and distribution with options to eliminate or include specific details as required by the users.

The HEEP software may be obtained by download from the IAEA web site [16]. The IAEA maintains and updates the software based on the input from leading international experts in the field and feedback from users. The latest version of the software, which incorporates the improvements recommended by this CRP and the feedback from a users' technical meeting held in conjunction with the CRP, was released on the occasion of the 3rd RCM of the CRP on December 18, 2014.

1.3.2.2.H2A

The H2A code is being developed by the US DOE-funded Hydrogen Analysis (H2A) Project since 2003 [17]. It is designed to perform transparent cost analysis for hydrogen technologies based on a consistent set of financial assumptions and methodology. Although an Excel based program, the program is built functionally similar to HEEP (which is Windows UI based) and thus the analysis processes and results are easily comparable. The H2A analysis begins with model construction of the plant (a central or distributed production system), and then input of standard financial assumptions such as discount and interest rates, debt to equity ratio, tax rate, depreciation period, etc. The analysis includes hydrogen production and product delivery aspects. Sensitivity of each aspect to assumptions is automatically performed. The information including the results of each analysis is summarized in a standard report spreadsheet.

1.3.2.3.G4-ECONS

The G4-ECONS (Generation IV Excel-based Calculation Of Nuclear Systems) code developed by the GIF EMWG (Generation IV International Forum Economic Modelling Working Group) is an Excel based program for the economic evaluation of nuclear systems [18]. G4-ECONS consists of three major modules. The first module of G4-ECONS is the reactor cost module which calculates the LUEC (levelized unit energy cost) for the reactor. The second is the nuclear heat applications module, which calculates the cost of a product from a heat application facility adjacent to the reactor. The third module of G4-ECONS is the G4-ECONS-FCF (fuel cycle facility) module, which calculates levelized costs of fuel cycle products and services. The unit fuel cycle cost calculated from this module is used as an input to the reactor cost module to calculate the levelized unit electricity cost (LUEC).

In summary, G4-ECONS calculates the LUEC from the reactor module and LUHC (Levelized Unit Hydrogen Cost) from the facility module for hydrogen production plant that requires the use of thermal and/or electrical energy from the reactor.

1.3.2.4.ASPEN PLUS

The ASPEN PLUS is the modelling and simulation software [19] for conceptual and engineering design, optimization and performance monitoring of chemical processes widely used by research organizations and chemical industries for the design, operation and optimization of chemical manufacturing facilities. Aspen Process Economic Analyser evaluates and optimizes conceptual process for capital and operating costs.

1.3.2.5.Japan's program

Japan Atomic Energy Agency has developed a cost analysis program following the trial estimation method used by the FEPC to estimate the power generation cost of utility type nuclear plants in Japan [20]. The program calculates the cost components including capital cost, operating cost, fuel cost and decommissioning cost. The costs are obtained as present values at a discount rate. The discount rate used in Japan is typically 3 to 4%.

1.3.2.5.1. Capital cost

The capital cost is the sum of depreciation cost, interest cost, fixed property tax and decommissioning cost. Depreciation cost is determined by using a declining balance method over the operating lifetime of the plant at the discount rate. The residual book value of the plant is assumed to be 5% at the last year of operation. Interest cost is calculated by multiplying the construction cost in initial year or depreciated values in other years by the discount rate. The interest cost includes the interest incurred for funds used during construction. Fixed property tax is calculated by multiplying the construction cost in initial year or depreciated values in other years by a rate of 1.4% prescribed by law.

1.3.2.5.2. O&M cost

The O&M cost considered includes maintenance cost, miscellaneous cost, personnel cost, overhead cost and business tax. The maintenance cost is estimated by multiplying the construction cost by a maintenance cost rate of 1.4%, the same used for a Japanese reference plant of LWR. The miscellaneous cost is estimated by multiplying the construction cost by a miscellaneous cost rate of 1.55%, the same used in a trial estimate for a large-scale fast breeder reactor (FBR) plant. Personnel cost estimated by multiplying the sum of salaries of employees and administrative expenses by the number of employees. They are opened to the public in securities reports of electric power companies. The overhead cost is calculated by multiplying the sum of maintenance cost, miscellaneous cost and personnel cost by a rate of 0.42%, the same used for the large-scale FBR. The business tax is calculated by multiplying the sum of capital cost, maintenance cost, miscellaneous cost, personnel cost and fuel cost by a business tax rate of 1.3% prescribed by tax law.

1.3.2.5.3. Fuel cost

The fuel cost is estimated by a calculation method of uniformly divided nuclear fuel cycle cost as described in the report of the OECD/NEA [21]. The fuel cost includes the front-end costs of uranium purchase, conversion, and fabrication and the back end costs of reprocessing, storage and waste disposal.

1.3.2.5.4. Decommissioning cost

The decommissioning cost includes dismantlement cost of facilities and disposal cost of waste materials. The fund required for dismantling a nuclear power plant is deposited every year over the plant operation life. The decommissioning of the reactor starts after the seven years cooling time after the end of operation.

1.3.2.6.Germany's MILP

As shown in Fig. 14, given a set of boundary conditions as input, the MILP optimizes sizes and operation modes of the energy system by solving an objective function under several technical constraints. The objective function in the present study is maximization of the net present value of the hydrogen production. The technical constraints such as demand and supply balances of energy and materials ensure fidelity and accuracy of the solution output. The model calculates hydrogen generation costs and optimum sizes and operation mode of each of the facilities that comprise the production system and environment. The calculation considers the variation of input parameters over one year. All cash flows arising from this one-year calculation are extrapolated for the observation period, for example of a plant life including decommissioning period using the discounted cash flow method. By this means the net present value of the whole system is determined.

The facilities built in the model library include industrial heat processes such as various hydrogen production processes and power generation processes and the energy production processes such as nuclear reactor, fossil heater, and solar towers. Thermal storage with electrical recharging is modelled. The coupling methods between these facilities are defined and modelled.

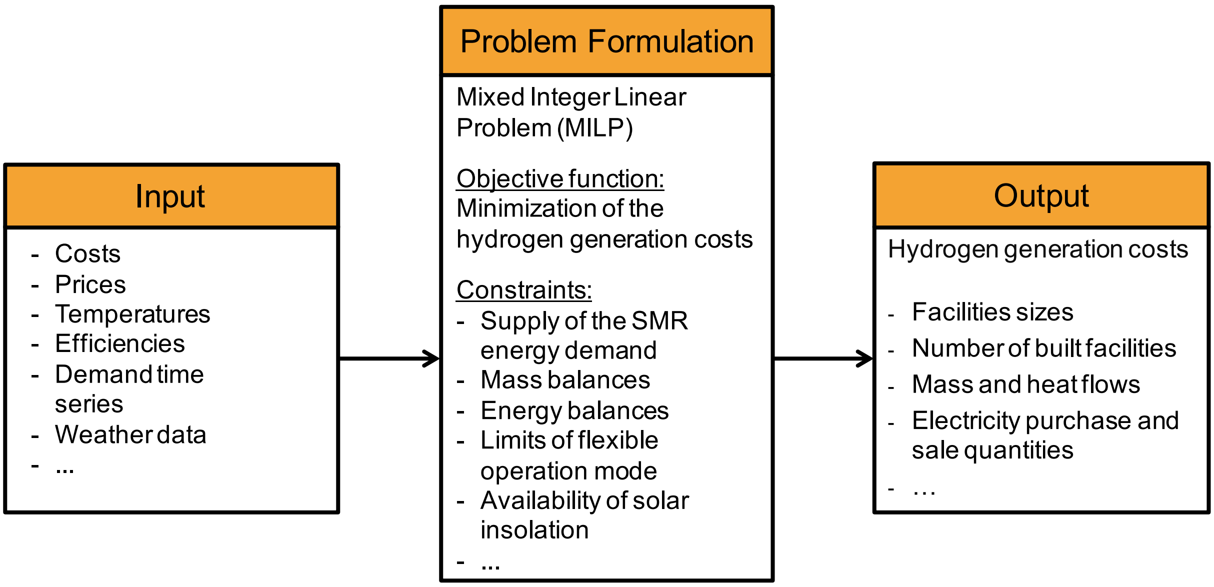


FIG. 14. MILP hydrogen cost optimization model [15]

1.3.3. Financial parameters

Table 29 lists the financial parameters to be considered in the HEEP analysis, which may be varied from the default values, given in the table, to test the sensitivity of the costs.

TABLE 29. FINANCIAL PARAMETERS CONSIDERED IN HEEP

	HEEP default financial parameters
Discount rate (%)	5
Inflation rate (%)	1
Finance Equity:Debt (%)	70:30
Borrowing interest (%)	10
Tax rate (%)	10
Depreciation period (year)	20

Similarly, the H2A model has developed a set of base case financial assumptions, since the results of technology lifecycle costing exercises depend on various financial assumptions.

The financial parameters used in the proprietary programs are varied depending on the plant designs (nuclear, fossil, or solar heated systems) and the details are described in Section 1.1.2.1 for Japan's program and Section 1.1.2.2 for Germany's models.

1.4. CONTRIBUTING MEMBER STATES

This section introduces the present status of nuclear hydrogen production and related development and deployment programs in the participating Member States.

Algeria (R. Boudris) Interest in hydrogen production can be found in research centre such as CDER and at some universities. The interest is more on renewable techniques. Interest in nuclear based techniques is growing. Steps are going to be taken to investigate the possibility of carrying out activities in this field in collaboration with COMENA. Small scale experiments are being carried out. Techno-economic studies have been carried out through extensive modelling and simulation using `homemade` programs. Demonstration and eventually small scale hydrogen production facilities are under consideration.

Argentina (A. Bohe) Even though many types of thermochemical processes were developed, this project continues to be concentrated on chlorine cycles which is one of the leading long-term methods: vanadium–chlorine cycles, rare earth-chlorine cycles and mixed chlorine cycles. A lot of studies have been performed in the past on these methods, but the kinetics and mechanisms of reactions are not completely understood yet, and this project will go on contributing to a better understanding of the critical problems identified for each cycle. Also it will let to obtain the parameters that permits the best results in the production of hydrogen as much as the highest efficiency as the economic advantages.

Canada (I. Dincer) Clean Energy Research Laboratory at the University of Ontario Institute of Technology (UOIT), in Oshawa, Ontario, is one of the hydrogen production research leaders in Canada. In collaboration with Atomic Energy of Canada Limited (AECL) and other universities and institutes, our UOIT-led team is developing the world's first integrated Copper–Chlorine (Cu–Cl) cycle for nuclear hydrogen production. This proposal aimed to contribute to a new version of hydrogen economic evaluation program (HEEP) software based on the Cu–Cl thermochemical cycle. Dr. Ibrahim Dincer's group has actively been working on Cu–Cl cycle for hydrogen as part of a large-scale project on the development and commercialization of this cycle.

China (P. Zhang) As one of sixteen Chinese National Science and Technology Major Projects supported by central government, the HTR-PM project covers the design, the construction and operation of a commercial pebble bed modular high temperature reactor demonstration plant, including the associated development of key components. HTR-PM constitutes the first of a kind test of some components and systems in full scale, including the development of the TRISO fuel fabrication technology, construction of the fuel fabrication plant, research and development of new technology, etc. The manufacturing of components was started in 2008, followed by first concrete pour on site in 2012. Relying on developing and application of domestic research and industrial capabilities, the plant, when completed, is claimed to be 95% indigenously made. The construction schedule of the HTR-PM is reported to aim at an operational date in 2018.

As a precursor to the HTR-PM, China has developed and constructed the pebble bed high temperature gas cooled experimental reactor HTR-10 on the site of INET, Tsinghua University. This test reactor configured initially for power generation by steam turbine achieved full operation in 2003. The plan is also made to replace gas turbine and connect to hydrogen production system.

The INET is one of the leaders in the research on hydrogen production for potential nuclear reactor applications. It is experimentally testing two candidate hydrogen systems of high temperature electrolysis and the Sulfur–Iodine thermochemical cycle (Fig. 15) as advanced applications of the HTR-PM. At the end of the year 2013, INET completed the construction and successful close-cycle test run of the S–I process with the rate of hydrogen production of 60 NL/h. Meanwhile, a lab-scaled facility and 10-cell SOEC stack have been developed to perform 100h electrolysis experiment to test the performance. The future plan calls for the engineering and construction of a pilot hydrogen plant to be coupled to the HTR-10 after 2020.

FIG. 15. Integrated lab-scale S–I process facility (left photo) and the HTSE facility

Germany (K. Verfondern) Germany has gained in the past a broad experience in the development of high temperature reactors which also covered the operation of the test reactor AVR and the prototype commercial reactor THTR-300. The HTGR program also included the development of process heat reactors for non-electricity applications. Current reference design is the Siemens concept of the 200 MW(th) HTR-Modul as electricity producing baseline concept, and a 170 MW(th) variant with higher coolant outlet temperatures for process heat applications such as steam reforming of natural gas or coal gasification. Depending on the reforming conditions and downstream processes, the main product will be synthetic natural gas, synthesis gas, hydrogen or other liquid fuels.

India (A. Antony) Under its high temperature reactor programme, currently India is developing a Compact High Temperature Reactor as a technology demonstrator for associated technologies. In addition, several design options for a 600 MW(th) Innovative High Temperature Reactor for commercial hydrogen production are also being evaluated.

For this reactor various design options as regards fuel configurations, such as prismatic bed and pebble bed were considered for thermal hydraulics and temperature distribution analysis. Coolant options such as molten lead, molten salt and gaseous medium like helium were analysed. Besides these, other criteria such as ease in component handling, irradiation related material and fuel degradation, better fuel utilization and passive options for coolant flow etc. were also considered. Initial studies carried out indicate selection of pebble bed reactor core with either lead or molten salt -based coolant. These would be finalized after carrying out further studies.

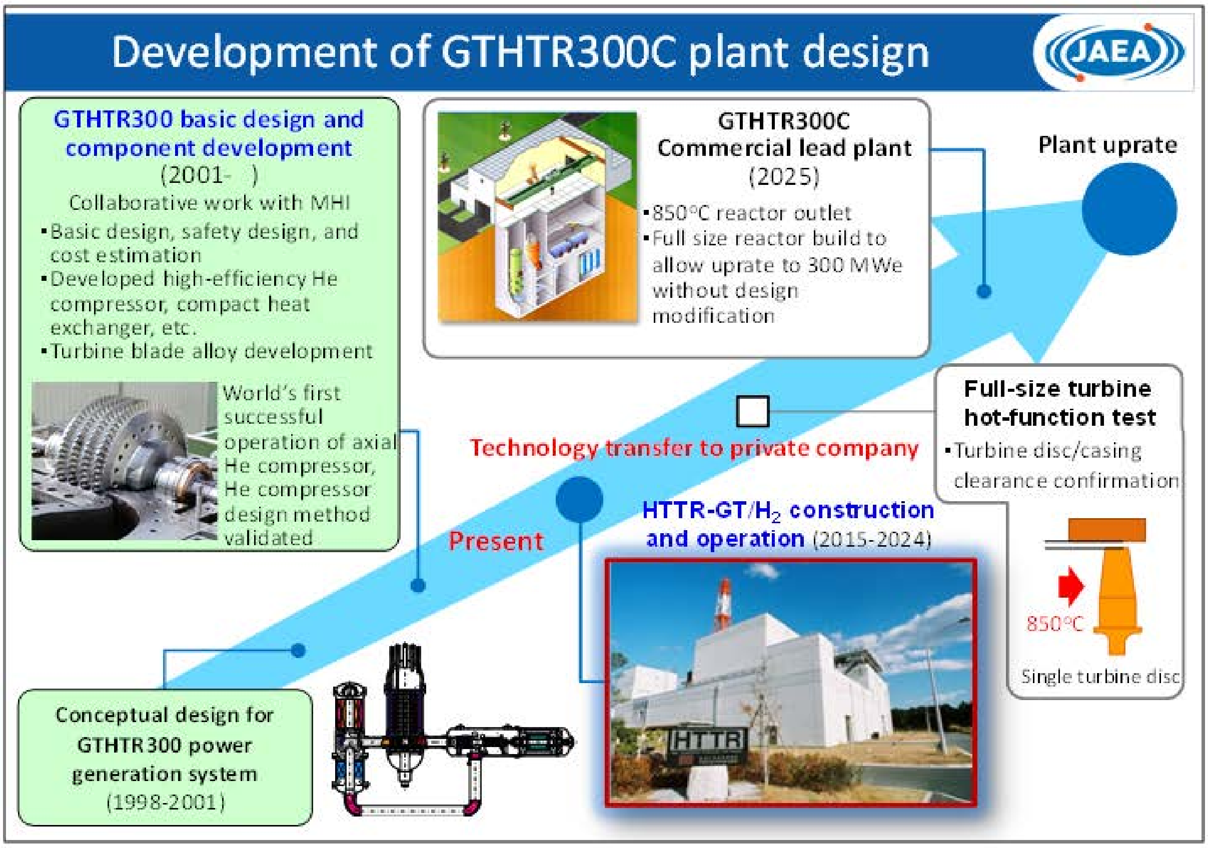
Indonesia (E. Dewita) National Nuclear Energy Agency (BATAN) of Indonesia has recently launched a feasibility design study of the 10 MW(th) HTR experimental power reactor, with international partners and also with expert assistance by IAEA. Hydrogen production activities in Indonesia have focused on two methods, (i) S–I cycle and (ii) Steam–Methane Reforming. Actually, in Indonesia Steam–Methane Reforming Methods has already been commercially implemented in the fertilizer industry. However, for nuclear hydrogen, both methods are still investigated in Laboratory activities. The CSI from BATAN has reported the study of steam–methane reforming based on the HTR technology (refer to the country report on the CD-ROM).

Japan (X. Yan) Japan Atomic Energy Agency has developed and is operating the currently largest high temperature gas cooled reactor in the world. The 30 MW(th) HTTR achieved the initial criticality in 1998 and has since performed various technology demonstration tests including 950°C-coolant, full-power operations. The technologies verified on the HTTR are applied to designing the commercial reactor GTHTR300C for hydrogen cogeneration based on the Sulfur–Iodine thermochemical process. The basic design including cost estimation has been concluded for the GTHTR300C. To prepare for the licensing and to validate the system performance, a model test plant for the GTHTR300C is being developed for operation with the HTTR. This will provide for the first nuclear hydrogen production based on the S–I process. These development efforts are made to pave the way for the lead commercial plant construction around 2025 (Fig. 16).

In parallel, JAEA succeeded in a week-long continuous closed loop operation of the Sulfur–Iodine process for hydrogen production in 2004, at that time the world first successful demonstration of the thermochemical water-splitting method. The next ten years were focused on the research for heat and corrosion resistant materials, equipment designs and acquisition of multi-phase fluid and chemical reaction database required to develop practical systems. These efforts culminated to the construction of a 100 L/h scale test plant using the candidate industrial materials identified for a commercial plant. The test plant, while currently under commissioning, has achieved a closed cycle operation in February 2016.

Republic of Korea (Kim HTR2014 plenary) Nuclear energy contributes as one of the important energy sources to the country. With 24 commercial operating reactors, it meets 10.4% of the country total energy demands, and in 2013 was providing 29% of national electricity generation. To seek to expand the role of nuclear energy, the government is promoting development of hydrogen production based on very high temperature reactor (VHTR).

Korea Atomic Energy Research Institute leads the VHTR R&D program in cooperation with other national research institutes and domestic industries. The program, launched in 2006, aims to demonstrate nuclear hydrogen production by 2030. The VHTR R&D consists of two major projects; the nuclear hydrogen key technologies development project and the nuclear hydrogen development and demonstration (NHDD) project. The former development project focuses on the development and validation of key and challenging technologies required for the realization of the nuclear hydrogen system, including design and analysis tools, high temperature experimental technology, high temperature material database, TRISO fuel fabrication and hydrogen production process. An engineering scale 50 NL/hr integrated S–I process facility was built and operated continuously for eight hours under pressurized condition. Longer period of operation is planned with the facility. On the other hand, the NHDD project is aimed at the design and construction of a nuclear hydrogen demonstration system for demonstration of massive hydrogen production and system safety. In order to promote the NHDD project, a three-year study has been performed since 2011 to develop the VHTR system concepts for nuclear process heat and electricity supply to industrial complexes, for the massive nuclear hydrogen production required to enter a future hydrogen economy, and to establish the demonstration project plan of VHTR systems for subsequent commercialization. A feasibility evaluation on the VHTR demonstration plan is being performed for conclusion in 2016.



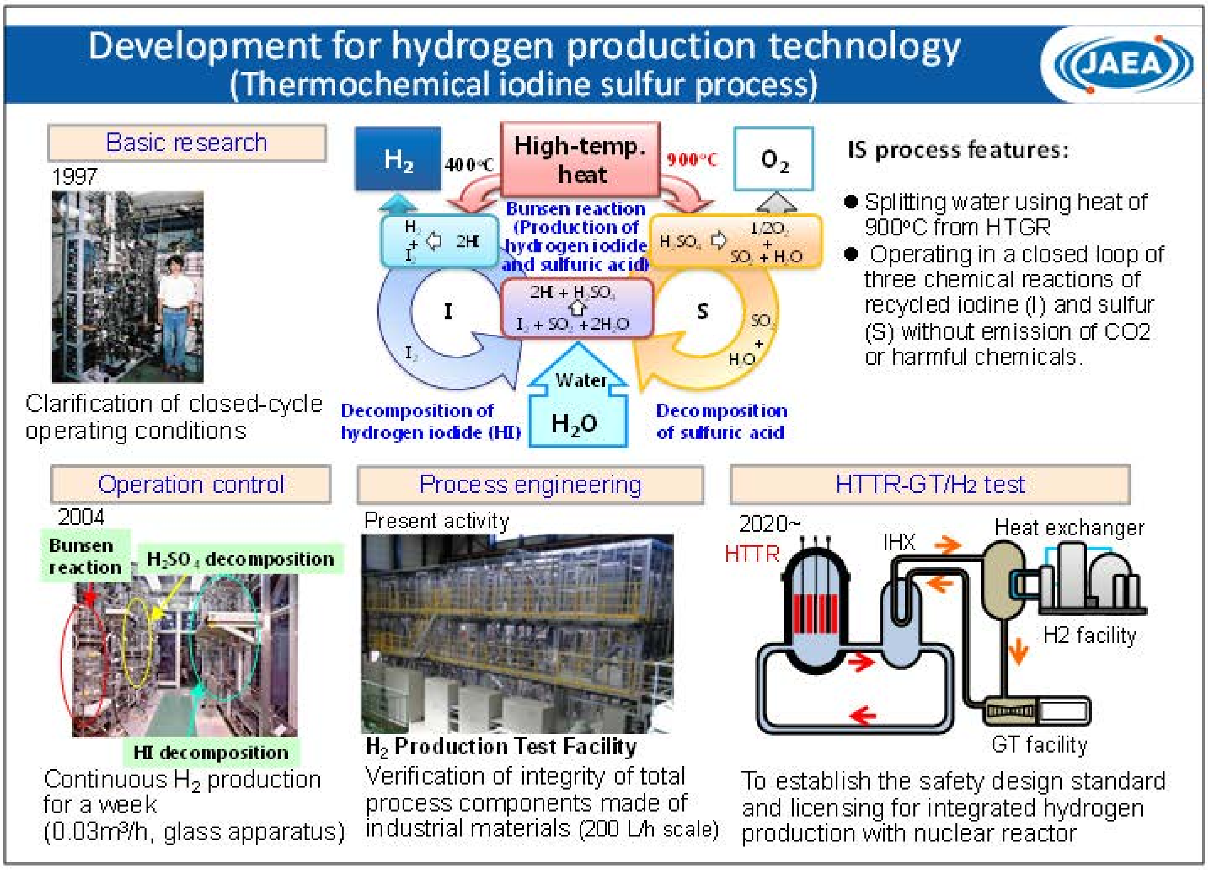


FIG.16. Development of nuclear reactor plant (left) and hydrogen production in Japan

United States of America/Republic of Korea (S. Revankar) Nuclear hydrogen production activities in the USA have focused on three methods, (i) S–I cycle and (ii) HyS cycle based thermochemical water splitting and (iii) high temperature electrolysis using solid oxide electrolyzer. Small scale test facilities have been built and each of these processes are demonstrated through experiment and extensive modelling and simulations at General Atomics, Sandia National Lab, Savannah River National Lab, Idaho national lab and various academic institutions including Purdue University. The S–I cycle is also studied in the Republic of Korea through small scale experiments and simulations at national labs like KAERI, KEIR, RIST and academic institutions including POSTECH. At POSTECH and Purdue University, S–I cycle has been simulated with ASPEN PLUS simulation code where detailed flowsheets have been developed, Bunsen process analysis is performed for optimized operation, and models for coupled S–I plant and PBMR nuclear plant have been studied for various transients.

Pakistan (G. Mustafa) At present, the country is operating two PWRs and a PHWR type nuclear power plants while two PWR type nuclear power plants of 680 MW(e) capacity are under construction.

The country produces around one million tonnes of hydrogen from fossil fuels. Hydrogen is being produced mainly from natural gas using SMR process. Fertilizer sector is the major consumer of hydrogen to produce ammonia based fertilizer. The country's annual demand of hydrogen is projected to exceed 2.5 million tonnes per year by 2030 and 6.0 million tonnes per year by 2050. The production of natural gas in the country is insufficient to meet its growing demand. As a result, natural gas consumers in all sectors; industry, power, household, commercial and transports suffer shortage of supply round the year. Therefore, there is immense need to assess alternative economical processes to meet the hydrogen demand of the country.

2. TECHNO-ECONOMIC ASPECTS OF NUCLEAR HYDROGEN PRODUCTION

Global energy demand tends to increase with increasing population and welfare. In this regard, energy has been a critical element in shaping local and external policies of countries, their economies, environmental policies, sustainable issues, social dimensions, etc. [22]. Fossil fuel based energy systems cannot be considered as sustainable due to their finite nature and environmental effects. A shift to sustainable sources including nuclear and renewable energies has well begun to shape national energy strategies of great many countries in tackling both issues of meeting energy demand and tackling environmental issues such as global warming.

2.1. PRODUCTION TECHNOLOGIES

Sustainable production of any form of energy is based on clean and non-polluting resources. Renewable energy sources can be considered as the most suitable resources for clean energy production. However, cost of the energy produced from most renewable sources can be relatively higher than fossil fuel based energy production methods, since these systems are still not mature enough, and possess higher capital costs [23, 24]. Nuclear energy is already a sustainable, mature and in many cases cost-competitive source of electricity and heat. Many nuclear-supplied hydrogen production technologies and systems have been proposed and some are well developed [25]. Figure 7 summarizes the hydrogen production pathways from the nuclear energy. Detailed discussions follow.

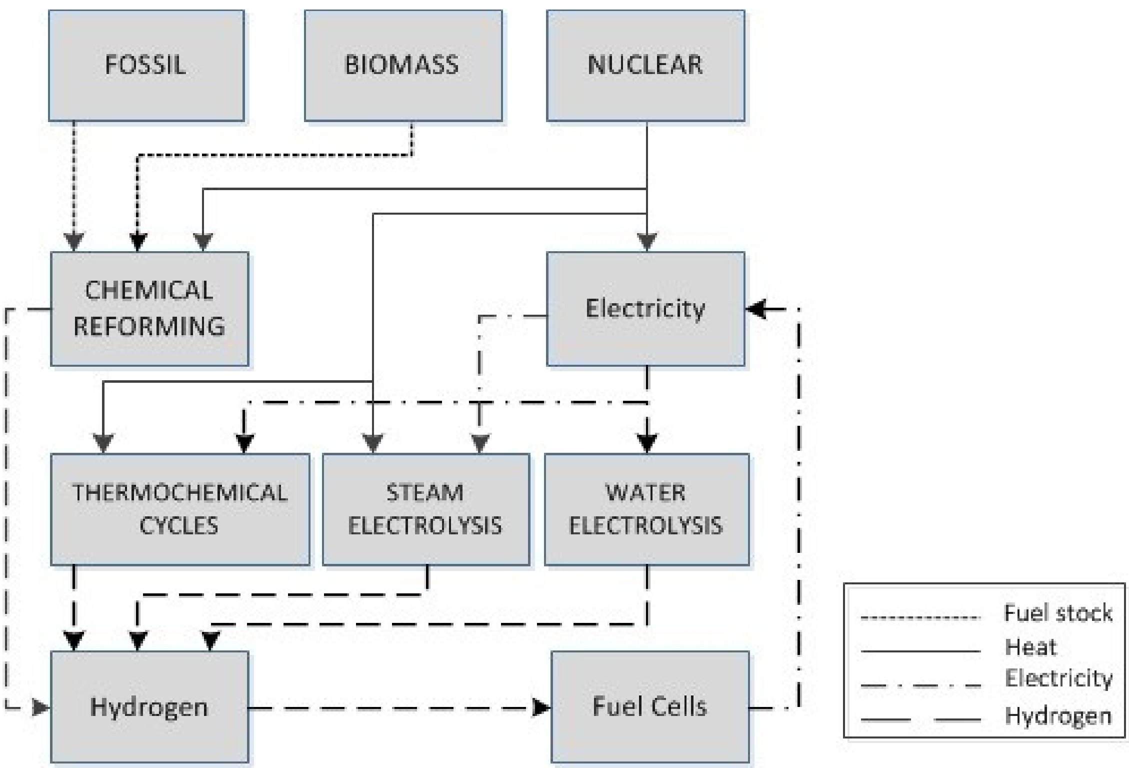


FIG. 17. Potential pathways of hydrogen production from nuclear energy [26]

2.1.1. Nuclear reactor technologies for hydrogen production

Any nuclear reactor can be the basis for hydrogen production. Present commercial nuclear reactor plants can produce hydrogen via conventional electrolysis of water. Several configurations of nuclear plants based on pressurized water reactor technology are studied for this method of hydrogen production. In addition, advanced CANDU reactors are studied for potential hydrogen production from thermochemical decomposition of water.

Future nuclear reactors are expected to be further advanced in terms of safety, performance, proliferation resistance, sustainability. One of the promising nuclear reactor technologies is HTGR including its next generation design of VHTR. The characteristic features are a helium cooled, graphite moderated, passive and inherent safety with a reference thermal power production of 400–600 MW(th). The reactor coolant outlet temperatures of 750–1000 °C can open to each of the pathways shown in Fig. 17 for hydrogen production. Several systems that are proposed or being constructed in Member States are investigated in connection to wider options of hydrogen generation methods. Top candidate methods, considered presently by various countries, are Sulfur–Iodine thermochemical process and high temperature electrolysis of steam (HTSE). Assuming a plant availability of 90% and an overall conversion efficiency of (aimed at) 50%, the system would have a capacity of 27.4 t/d of hydrogen (HHV) per 100 MW of nuclear thermal power.

The technology of the HTGR benefits from the broad experience obtained in the past and current research projects in the past, notably the German Prototype Nuclear Process Heat (PNP) project, the currently operated HTTR in Japan and HTR-10 in China, as well as comprehensive R&D efforts which were initiated in many countries since recently to investigate HTGR systems in connection with nuclear hydrogen production provide valuable knowledge.

The following sections provide a short overview of the nuclear process heat reactor concepts that are part of the study here.

2.1.1.1.Conventional LWR

The light water reactor (LWR) is a conventional type of nuclear fission reactor, and the technology basis for the majority of the world's nearly 500 commercial nuclear power stations operational or under construction to date. As so named, the light water (H_2O) is used as both coolant and neutron moderator in the reactor. In contrast, the heavy water (D2O) is used exclusively or in part in another type of water reactor to be described later.

The LWR produces heat from controlled fission chain reaction in a reactor core. The reactor coolant removes the fission heat from the core to the balance of plant to engage in energy conversion and delivery. The reactor core contains mainly nuclear fuel assemblies and reactivity control rods. A steel pressure vessel supports structurally and encloses the reactor core while withstanding all thermal and seismic loadings and irradiation exposure over the reactor operation lifetime.

A fuel element is generally a cylindrical rod that includes many small fuel pellets inside a metallic tube. The fuel pellet is made typically of low-enriched uranium oxide ceramic. As many as two hundreds of fuel rods may be bundled to form a fuel assembly. Equally many fuel assemblies may be loaded in a large size reactor core. A partial number of these fuel assemblies need to be replaced with fresh ones in normally less than two years of fuel burnup in reactor.

A control rod contains various elements which easily capture neutrons. A number of control rods are arranged for distributed insertion in the core. Inserting the control rods deeper into the core causes more neutrons to be captured and consequently the chain reaction to decrease or stop. Pulling the control rods out of the core results in more neutrons unabsorbed in the core and thus the chain reaction increased. The movement of the control rods is carried out by control rod drive mechanism.

As mentioned, the majority of current commercial reactors worldwide are LWRs with the technology variants of pressurized water reactor (PWR) (seen in Fig. 18) and boiling water reactor (BWR). Generation II and older systems were built prior to 2000. Those currently being constructed or commercially-offered are Generation III advanced systems, collectively referred to APWR or ABWR, that incorporate improvement to fuel, cost-reduction features such as design standardization, and passive safety features. The following are examples of Generation III systems:

– AP1000 – advanced pressurized water reactor by Westinghouse;
– EPR – European pressurized water reactor by AVERA;
– ESBWR – economic simplified boiling water reactor jointly by GE-Hitachi;
– US-APWR – advanced pressurized water reactor by MHI;
– APR-1400 – advanced pressurized water reactor by KEPCO consortium

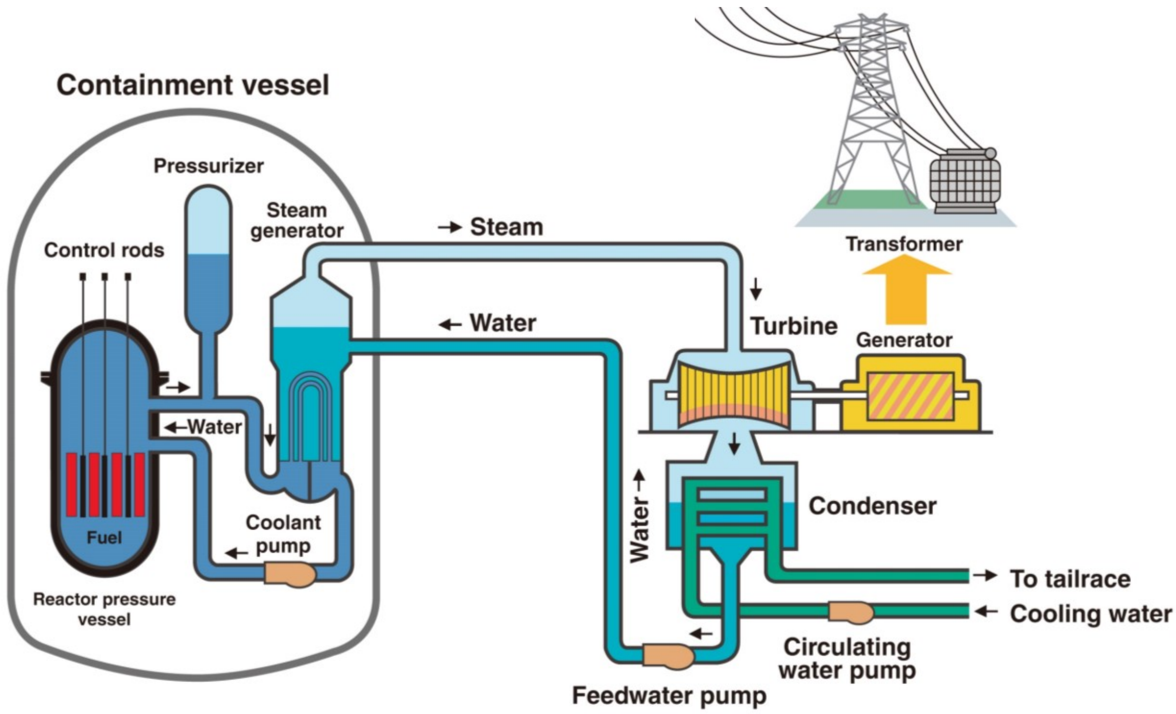


FIG. 18. Schematic of a PWR power plant (Reproduced courtesy of JAERO)[27]

2.1.1.2.GTHTR300C

The JAEA reference concept for commercial nuclear hydrogen production in Japan is based on the GTHTR300C reactor to be connected to an S–I thermochemical water splitting process [28, 29]. The reactor design is of a block type HTGR with a thermal power of 600 MW and a reactor outlet coolant temperature of 950 °C. The direct cycle gas turbine efficiently circulates the reactor coolant and generates electricity. Hydrogen cogeneration is enabled by adding an intermediate heat exchanger (IHX) arranged in series between reactor and gas turbine (Fig. 19).

In the IHX, a part of the thermal power, 168 MW(th), is transferred as 900 °C process heat to the hydrogen generation process. The remaining thermal power is used for electricity generation of 202 MW(e). The secondary loop, which includes safety design measures such as isolation valves, provides for physical and material separation between the nuclear plant and the conventional grade hydrogen plant. The conceptual flowsheet design reports a hydrogen production rate of 31 900 Nm³/h, corresponding to 50.2% net efficiency, and by-product oxygen of 15 950 Nm³/h [30]. The hydrogen rate from one reactor is sufficient to fuel 191 000 fuel cell vehicles (~3.6 Nm³/d hydrogen per vehicle).

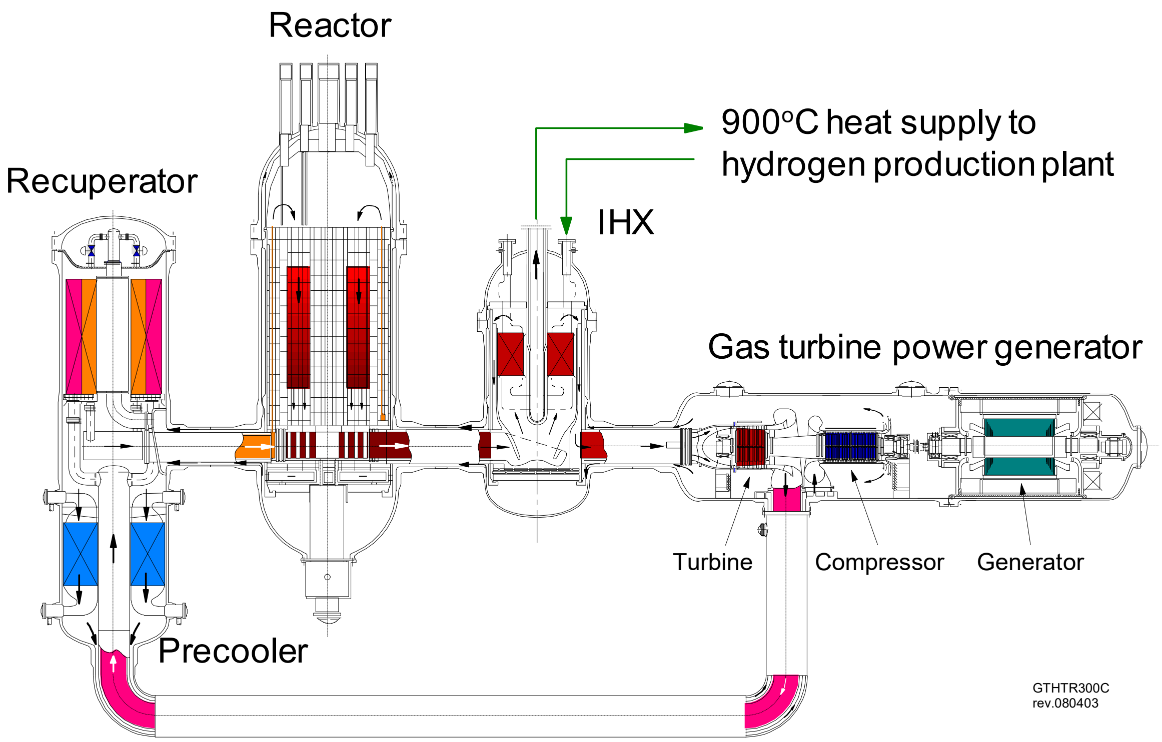


FIG.19. Japan`s commercial cogeneration reactor system GTHTR300C (Reproduced courtesy of JAEA).

2.1.1.3.H$_2$-MHR

The GT-MHR design (Fig. 20) is a General Atomics development characterized by a helium cooled, graphite moderated, thermal neutron spectrum reactor with a prismatic and annular core directly coupled to a Brayton cycle power conversion system and with a filtered confinement [31]. The reactor core having a thermal power of 600 MW(th) is designed for averaged coolant outlet temperatures of 850 °C working with an efficiency of about 48% for electricity production. The design variants for cogeneration of process heat for non-electric applications including steam and hydrogen production have also been studied [32]. The option for hydrogen production is referred to as H_2-MHR. In this process heat variant, the coolant outlet temperatures is raised in order to improve the efficiency and economics of hydrogen production, but still limited to 950 °C to avoid any potential adverse impacts on fuel performance and materials during normal operation.

For the HTSE based H_2-MHR, approximately 68 MW(th) of heat is transferred through the IHX to generate superheated steam and the remaining heat is used to generate electricity. Helium at 924 °C temperature and 7.1 MPa pressure enters the thermochemical plant. For the S–I cycle based H_2-MHR, nearly all of the heat is transferred through the IHX to a secondary helium loop that supplies heat to the S–I process [33].

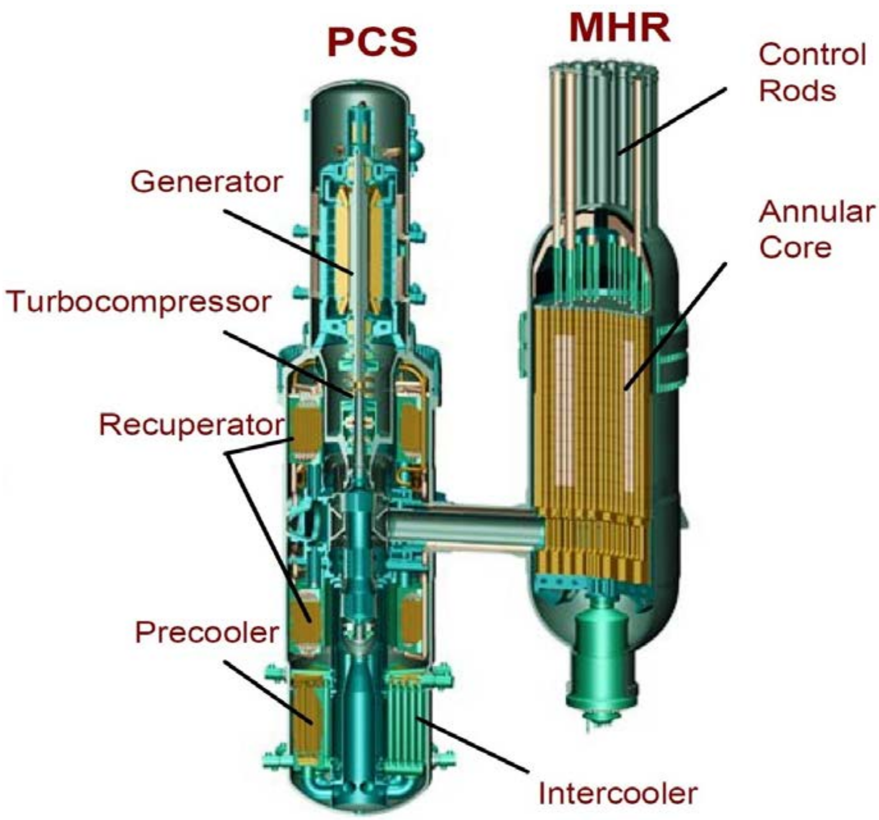


FIG.20. US`s Gas Turbine Modular Helium Reactor GT-MHR (Reproduced courtesy of GA).

2.1.1.4.HTR-Modul

The baseline concept for a German modular HTR is the electricity producing 200 MW(th) HTR-Modul pebble-bed reactor [34]. It is characterized by a tall (9.43 meters) and slim (3.0 diameter) cylindrical core to ensure — in combination with a low power density — that the release of fission products from the core would remain sufficiently low to cause no harm to people or environment even in postulated accidents [35]. Consequently, a process heat variant of the HTR-Modul reactor (Fig. 21) has been developed, for which — in comparison to the electricity generating plant — several modifications were necessary [36, 37].

The principal cornerstones of the process heat version are a thermal power of 170 MW and a helium outlet temperature of 950 °C to deliver process heat for the SMR process. A reduced system pressure of 5 MPa was chosen as compromise between a high pressure desired for its favourable effect on operating and accident conditions of the nuclear reactor and a low pressure desired for chemical process reasons in the secondary and tertiary circuit.

Without employing an IHX (which was deemed feasible and licensable at that time), the hot helium coolant is directly fed to the steam reformer which consumes 71 MW(th), and to the steam generator operated with 99 MW(th). From the total heat transferred into the steam reformer, 85% are used for the reforming process, while 15% are taken to heat up the feed gas. Partial load conditions of the steam reforming process can be regulated by changing the feed gas flow. A requirement, however, is that product gas quality, i.e. composition should remain constant, which can be accomplished by maintaining a constant reforming temperature.

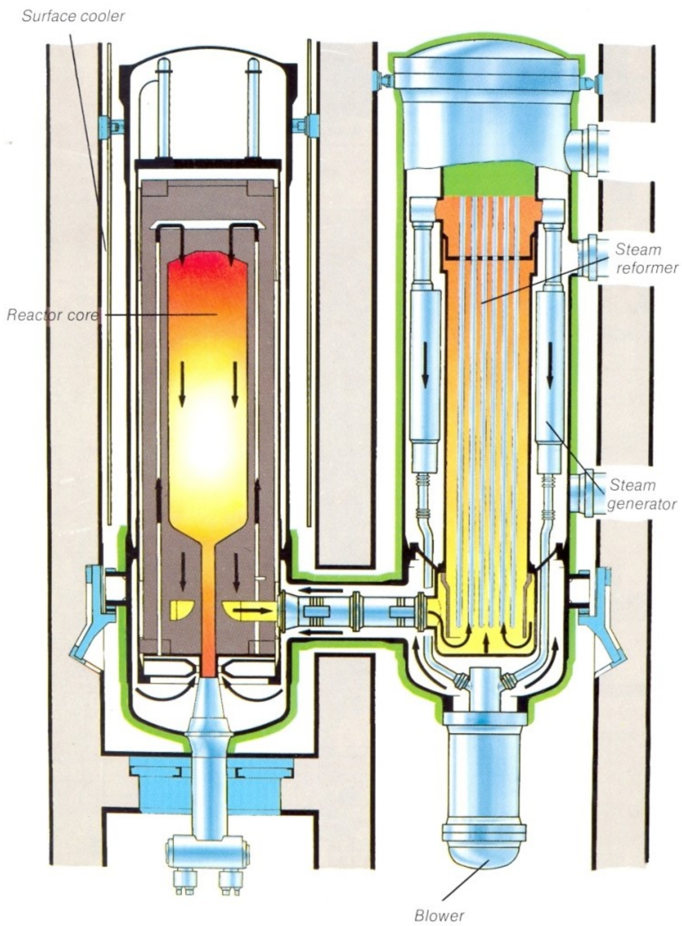


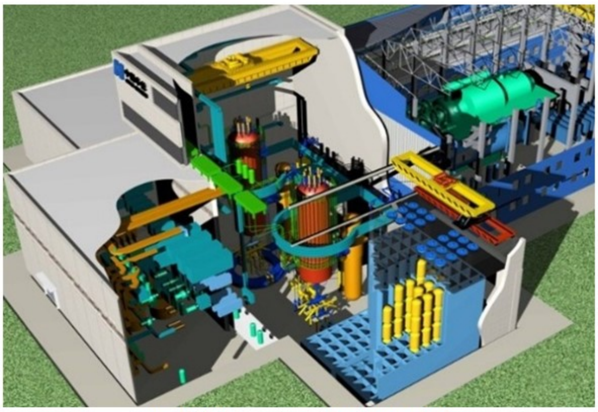
FIG.21. Germany`s HTR-Modul with steam reformer [36].

2.1.1.5.HTR-PM

The HTR-PM is the world`s first modular commercial HTGR, which is being built in Shidao Bay, Northeastern China [38]. The site construction begun with first concrete in December 2012. Currently, the operation and grid connection is planned in 2018. The plant layout, construction site, reactor pressure vessel, and control room simulator are shown in Fig. 22.

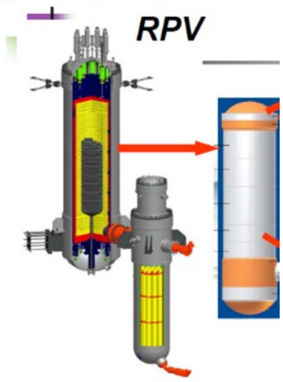
The HTR-PM consists of twin pebble bed reactors of 250 MW(th) each, 210 MW(e). The reactor outlet is 750°C and 7 MPa. Each reactor is connected to its own steam generator with main steam conditions of 567°C and 13.3 MPa. The steam from the steam generators is fed to a common steam turbine to produce a rated power output of 210 MW(e). According to the original concept, the plant is aimed at demonstrating the advantages and key benefits of design standardization that allows factory build and modular site construction. If the market requires, more identical modular reactor units can be constructed in series to form a larger nuclear power plant with appropriate power output, for which the HTR-PM600 design exists that consists of 6 reactors having identical operating conditions (250 MW(th), 250/750, 7.0 MPa each) and connecting to one steam turbine of 650 MW(e) [39].

A precursor to the HTR-PM is the pebble bed high temperature gas cooled experimental reactor HTR-10 developed and built by INET, Tsinghua University. Sited on the outskirts of Beijing, this test reactor configured initially for power generation by steam turbine achieved full operation in 2003. To develop advanced application for the HTR-PM, the future plan for the HTR-10 includes replacement of gas turbine for power generation and connect to an HTSE or S–I cycle system for hydrogen production.



(a) *Diagram of HTR-PM*

(b) *Construction site in Shidaowan,*



(c) *RPV (25 m long weighing 700 t)*

(d) *Control room simulator*

FIG. 22. HTR-PM commercial reactor under construction in China (Reproduced courtesy of INET).

2.1.1.6.Enhanced CANDU6

The next generation CANDU reactor concept pursued in Canada is the so-called Enhanced CANDU6 or EC6 reactor which evolved from the established CANDU6 technology. A schematic is shown in Fig. 23 [40, 41]. The EC6 is a third generation, heavy water cooled and moderated reactor with a design electric power output of 740 MW and a thermal power of 2084 MW. Similar to all CANDU reactors, the EC6 design is based on the use of horizontal fuel channels (here 380) surrounded by a D_2O moderator and arranged in a square pitch. Each fuel channel houses twelve 37-element fuel bundles containing natural uranium fuel and the pressurized D_2O coolant. They are mounted in a calandria vessel containing the heavy water moderator. Individual calandria tubes surround each individual fuel channel. Refuelling can be done online. The fission heat is carried by the reactor coolant to four steam generators provided in the heat transport system producing steam at 260 °C. With 310 °C coolant exit temperature; however, the temperature level is comparatively low and by far not sufficient to assist in hydrogen production.

The fundamental product of the nuclear reactor is steam from the coolant system steam generators. Alternatively, to routing this steam to a turbine, it could also be used as process steam for, e.g. oil sands application. Each oil sands project, however, will have its own specific features regarding steam amount, steam pressure, electricity demand, location, etc., and therefore needs its individual solution in order to optimize CANDU economics as far as possible [42].

2.1.2. Hydrogen production processes

The hydrogen production processes can be divided into thermal processes, electrolysis processes and thermochemical cycles. Today, the process heat required for hydrogen production is basically coming from the combustion of fossil fuels accompanied by the emission of climate affecting gases. CO_2 neutral or even CO_2 emission free alternatives to the fossil derived process heat is the heat that could be supplied by nuclear or renewable (solar) energy sources.

Besides the conventional processes of water electrolysis and hydrocarbon reforming, several advanced processes are introduced which on the one hand allow the absorption of high temperature process heat and on the other hand also have the potential to become commercial in the near future. Further details for the processes introduced here can be found elsewhere [25].

2.1.2.1. Steam methane reforming (SMR)

Steam methane reforming is a method of catalytic decomposition of natural gas (mainly methane) with the reactant of superheated steam and the resulting product of a hydrogen rich gas mixture. The process essentially follows the two reaction steps:

Steam reforming reaction (endothermic): $CH_4 + H_2O \rightarrow CO + 3H_2$, ΔH=206 kJ/mol

Water gas shift reaction (exothermic): $CO + H_2O \rightarrow CO_2 + H_2$, ΔH=−41 kJ/mol

Steam methane reforming remains the most economical and most widely-used process of industrial hydrogen production, accounting for nearly half of the world hydrogen output [43]. Large steam reformer units with production capacity of around 130,000 Nm^3/h are in use. Conventional process emits about 0.9 kg of CO_2 for each normal cubic meter of hydrogen produced. Replacing the heating fuel with nuclear energy reduces the emission by 35% and saves the natural gas feedstock by similar amount.

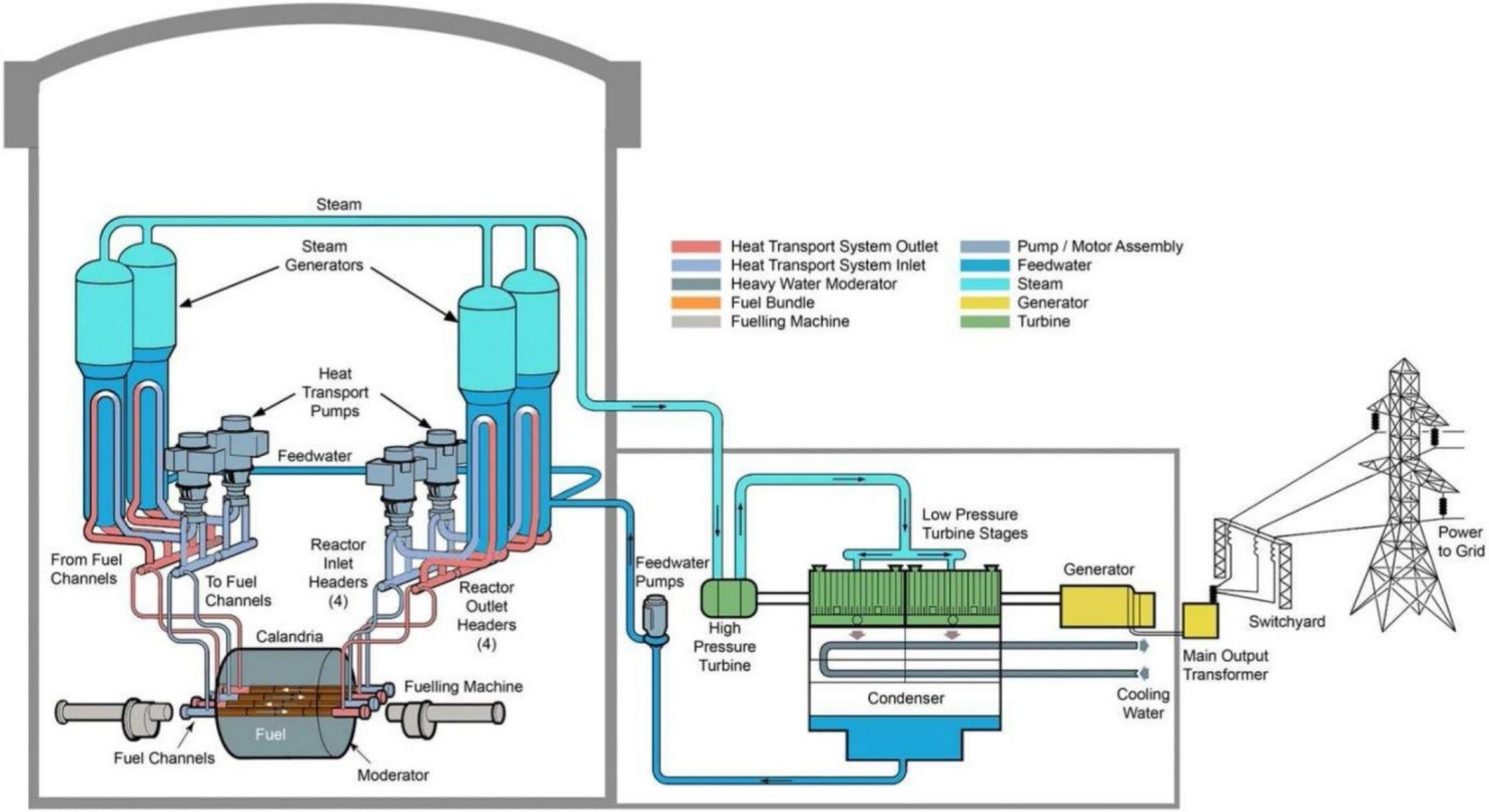


FIG. 23. Flow diagram of the Enhanced CANDU6 or EC6 [41].

A schematic of the process based on HTGR as external heat source is shown in Fig. 24. The process begins by desulfurizing the natural gas/methane feedstock usually employing a cobalt molybdenum catalyst where the sulfur compounds are hydrogenated to H_2S. The purified feed is then mixed in the reformer with superheated steam at pressures of 2.5–5 MPa and temperatures of about 850 °C and catalytically converted to a mixture of hydrogen, carbon monoxide, the products of the first reaction above. The endothermal reaction is supported by heating the reformer with nuclear heat. High temperature but low pressure at steam/methane ratio of greater than 2 leads to high conversion rate of methane. After cooling, the generated synthesis gas (H_2 + CO) can be converted in the water gas shift reaction to a mixture of H_2 and CO_2, the products of the second reaction above, thus further raising the hydrogen output. Finally, the pressure swing adsorption (PSA) removes the remaining amounts of methane and carbon monoxide to eventually result in a hydrogen gas purity of 99.99% as final product. The efficiency of today's large-scale reformer plants is about 74% (based on lower heating value).

2.1.2.2.Conventional electrolysis (CE)

Electrolysis may produce hydrogen and by-product oxygen by directly splitting water molecules using electric energy. The method was commercialized in 1890s and as early as in 1920s and 1930s, large plants in over 10 MW(e) were installed [44]. Industrial research and development continue to improve the performance of the method to the present. The technologies include atmospheric pressure and pressurized AWE (Fig. 25) and membrane electrolysis [45]. Toshiba offers Japan's largest AWE hydrogen production system as commercial product. The system can produce 100 Nm^3/hr of hydrogen [46]. The method can be economical if accessible to a cheap source of electricity. It accounts for about 4% of the world's hydrogen production today.

The AWE process proceeds at 90–120 °C and consumes about 4.7 kWh of electricity to produce 1 Nm^3 of hydrogen. Ions in the electrolyte solution work as transfer agent of electricity. When the electrolyte contains cations, which are reduced more easily than H+ or anions which are oxidized more easily than OH-, water decomposition reaction cannot be progressed. Therefore, strong acid or strong alkali is used so as to decompose only water. Alkaline electrolyte is usually chosen in order to avoid corrosion of cell materials. High concentration KOH solution of 25-30 wt% is often used. Low over potential, large contact area with electrolyte, good detachment of product bubbles is desired for electrodes. Low carbon steel mesh or nickel coated low carbon steel mesh is used as cathode in normal cells. Alkali and oxidation resistant materials like nickel coated low carbon steel or nickel series metal are applied for anode. Electrode catalysts on which reaction occurs more easily such as Pt are sometimes used together. A porous diaphragm works for preventing mixture of products gases and direct contact of electrodes.

The design groups unipolar and bipolar electrolysis cells as shown in Fig. 25. Several pairs of anode and cathode are in one tank of electrolyte. Electrolyte can transfer through porous diaphragms. Total voltage in one electrolyzer is the same as a pair of electrodes because all electrodes are parallel. Instead, electric current is large. Several cells connect with each other in serial in large plants. This type is advantageous in simple structure and low leakage current. However, current density is usually smaller compared with bipolar cell. This type requires space among cells and large plant area is necessary. In a bipolar electrolysis cell, electrolyte circulates through the cell to release the heat made in electrolysis. The electrolyte is fed from the bottom and mixture of the electrolyte and product gas flows out from the top. The gas and the electrolyte are separated in drums at the top. When one side of an electrode is anode, the other side works as cathode. Electrons made by reaction at cathode side in a cell unit compartment transport to anode side of the neighbour unit, and are used in reaction. Electrodes work as also flow separators. The total electrolyzer is equivalent to a serial connection of many cells. Total voltage is large instead of small electric current.

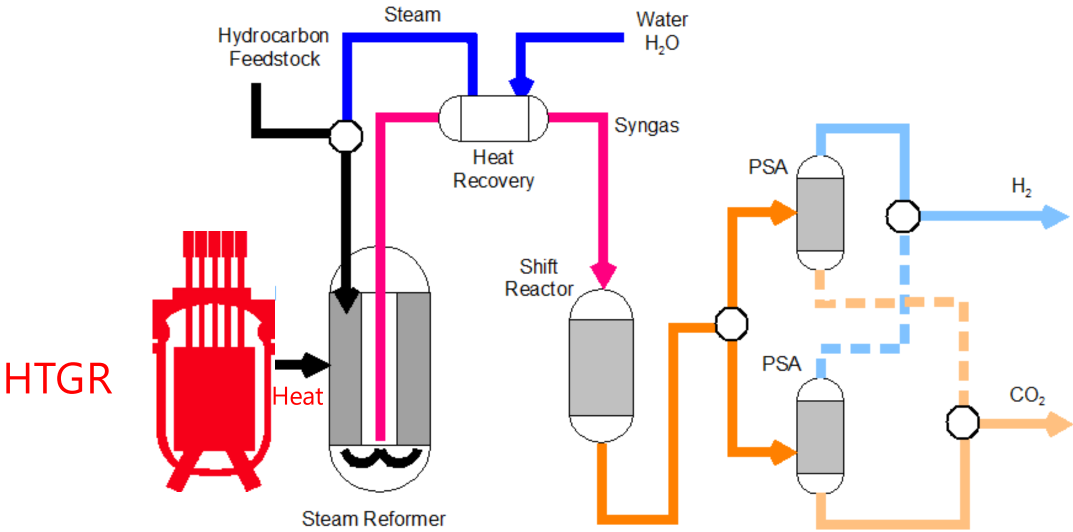
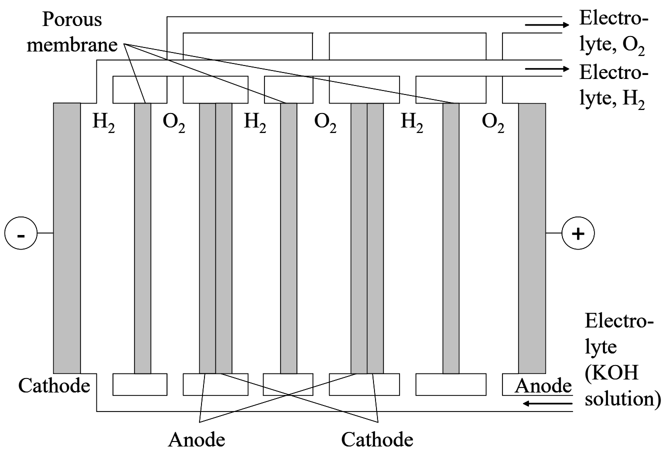
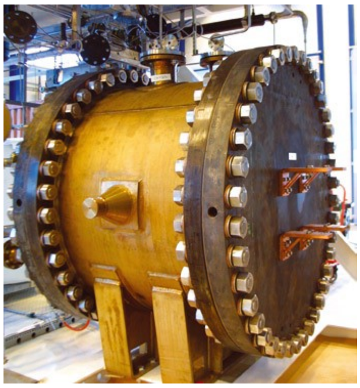


FIG. 24. Schematic of steam–methane reforming process.





Atmospheric 2 MW(e) modular unit Pressurized (1.5-3.0 MPa) 0.5 MW(e) unit

FIG. 25. Conventional atmospheric and pressurized electrolyzers.

Membrane electrolysis is an advanced method still in the development phase. It employs a solid polymer electrolyte membrane (PEM) instead of an alkaline solution as the ion conducting medium. The process operates at higher temperatures of 200–400 °C and higher pressures of ~3 MPa and its electricity consumption is reduced to about 4 kWh per generated Nm^3 of hydrogen. PEM electrolysis is simpler in its design, safer and promises higher power densities, longer lifetimes, and higher efficiencies of ~90%.

2.1.2.3.High temperature steam electrolysis (HTSE)

The high temperature steam electrolysis is an advanced method that promises higher thermal efficiency and potentially lower production cost than the conventional low temperature water electrolysis. Although the overall energy required for the electrolytical water splitting increases with increasing temperature, it is the thermal energy needed that rises steeply with increasing temperature while the consumption of more expensive electric energy decreases. Compared to the low temperature electrolysis, electricity consumption in the HTSE is reduced by about 35% compared to conventional electrolysis in the high temperature range of 800–1000 °C. The method is considered promising for a future large-scale hydrogen production based on nuclear energy as well as renewable energy.

The development of the HTSE has been pursued in China, France, Japan, the USA among others. Within the US-DOE Nuclear Hydrogen Initiative (NHI), an HTSE test facility has been developed, constructed, and operated at the INL[47]. The facility final configuration consists of 720 planar electrolysis cells in three SOEC stack modules with a total power of 15 kW(e). Test operation of hydrogen production of 5000 NL/hr was carried out for 1080 hrs [48]. Japan has carried out long-term development in both public and private sectors [49, 50]. Japan`s Toshiba announced in 2016 that the company with support of Japan's New Energy and Industrial Technology Development Organization has developed a HTSE hydrogen production system with a next generation SOEC technology [46].

As seen in Fig. 26, the HTSE cell essentially consists of a solid oxide electrolyte with conducting electrodes deposited on either side. The electrolyte is an oxygen conducting ceramic material, typically Y_2O_3 stabilized ZrO_2 (YSZ) and MgO. The electrochemical stack can be heated directly by the steam supplied to the hydrogen (cathode) electrode which is then dissociated at 750–950 °C and 2 MPa to hydrogen and oxygen ions. The latter migrate through the solid electrolyte to the anode where they recombine with electrons to oxygen.

Energy consumption per 1 Nm^3 of hydrogen produced is 2.6 kWh of electrical energy, 0.6 kWh of low temperature thermal energy (for preheating) and 0.5 kWh of high temperature thermal energy. A practical electricity to hydrogen efficiency of about 90% appears to be achievable. The overall efficiency expected is about 50%. The main issue that needs further improvement still remains lifetime of the hydrogen electrode which is limited by degradation.

2.1.2.4.Sulfur–Iodine thermochemical cycle (S–I cycle)

The S–I cycle is another water splitting process where in the presence of chemicals the temperature for thermal decomposition of water molecules is reduced to a level, saying 900°C, which makes the cycle technically as well as economically attainable. China, Japan, Republic of Korea lead the world development efforts, as described in the country reports. Japan has developed a 200 NL/hr engineering test facility for continuous closed cycle production of hydrogen [51, 52].

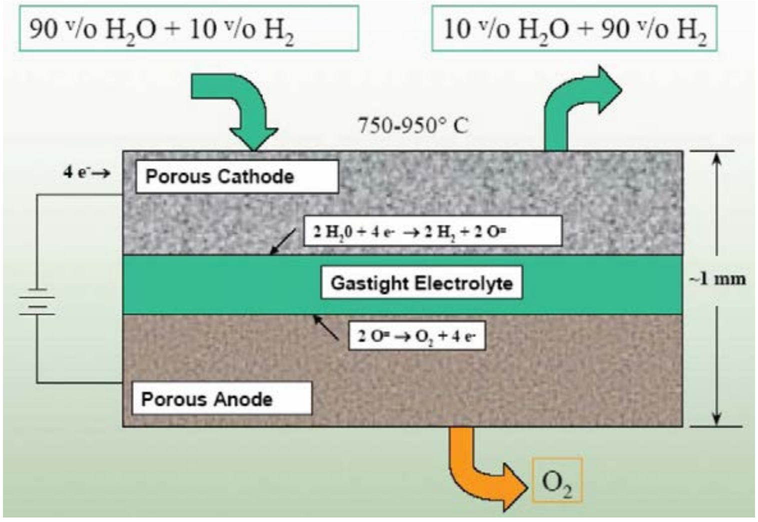


FIG. 26. High temperature steam electrolysis cell.

As depicted in in Fig. 27, the cycle basically consists of three process steps. In the so-called Bunsen reaction (centre part in the figure), I_2 and SO_2 are reacting with steam at about 120 °C to form two immiscible acids, HI and H_2SO_4. The acids are separated, purified, and concentrated. The other two, endothermic process steps describe the decomposition of these two acids. The highest temperature of about 850 °C is required for the decomposition of the sulfuric acid (right hand side in figure) resulting in the generation of O_2 and SO_2 with the latter being recycled to the Bunsen section. The decomposition of HI (left hand side in figure) is conducted at around 400 °C forming H_2 with the left over I_2 being recycled to the Bunsen section. The recent conceptual study by JAEA reported a thermal efficiency of more than 50% for an optimized cycle based on several equipment proposals [30]. Further research and development is required to confirm the equipment performance.

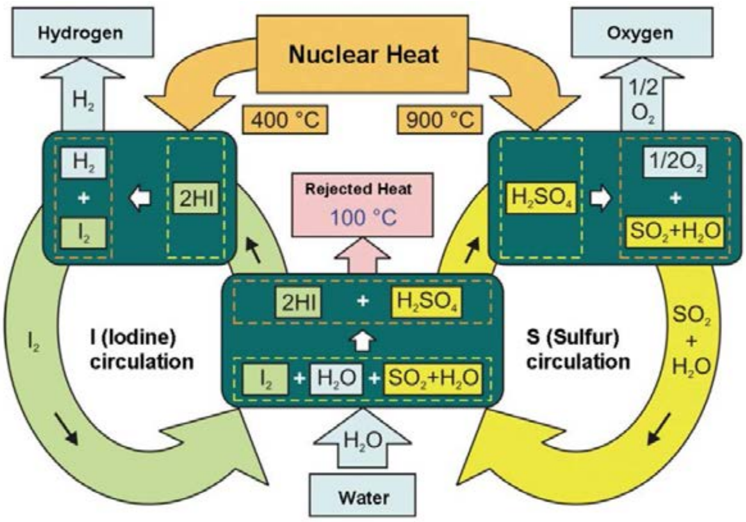


FIG. 27. Sulfur–Iodine thermochemical cycle with nuclear heat source being HTGR.

2.1.2.5.Hybrid sulfur cycle (HyS)

Another process of the sulfur family considered worth of further investigation is the so-called Westinghouse process, a sulfuric acid hybrid (HyS) cycle [53]. By 1978, Westinghouse had demonstrated closed loop operation at 120 NL/hr hydrogen production scale. Referring to Fig. 28, this process consists of only two reaction steps where the low temperature step runs in an electrolysis cell to regenerate the sulfuric acid aqueous phase and the hydrogen product, and the high temperature step is the decomposition of the sulfuric acid. The electrolytic step offers the advantage of requiring not more than 25% of the electricity needed in the low temperature water electrolysis.

While the cycle shares the H2SO4 decomposition reaction step with the S–I cycle, the challenge unique to the HyS cycle is developing the SO2 electrolysis cell. The most recent known development has been made in SRNL [54. 55]. Based on the PEM technology, SRNL completed a 100 h test on a single-cell SO2 depolarized electrolyzer (SDE) and also tested a multi-cell electrolyzer for 72 hrs with a hydrogen output of 86 L/hr [56]. The flowsheet design and process engineering resulted in a projected efficiency for hydrogen production by the HyS hybrid cycle connected to a helium cooled reactor of 51.6% (HHV) [57].

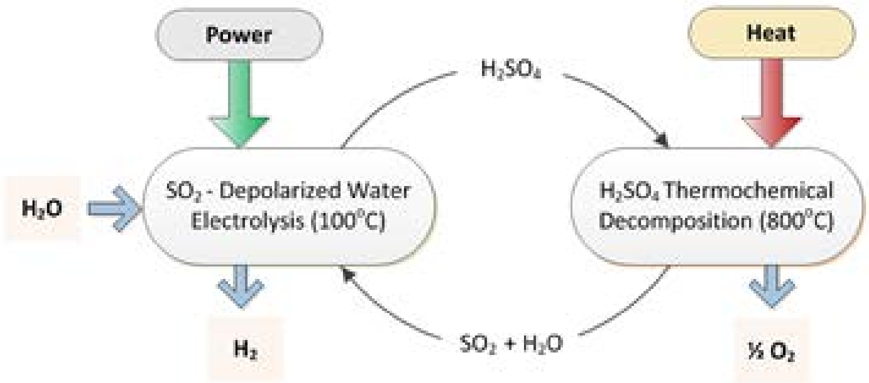


Fig. 28. The hybrid sulfur cycle [58].

2.1.2.6.Copper–Chlorine thermochemical hybrid cycle (Cu–Cl cycle)

The Cu–Cl is another hybrid cycle. Unlike the HyS cycle, the maximum temperature level required from the heat source is about 550 °C needed to drive the oxygen generation reaction. The lower operating temperature should reduce the costs of materials and maintenance, and can effectively use low grade waste heat, thereby improving the cycle and power plant efficiencies. Presently, the Cu-Cl cycle is mainly being investigated at the Canadian Nuclear Laboratories (CNL), formerly Atomic Energy of Canada Limited (AECL) [59, 60]. The incentive is given by the modest maximum temperature requirement for the heat, which could be provided by the CANDU type supercritical water reactor (SCWR), Canada's next generation nuclear concept.

There are several variants of the Cu–Cl cycle, a three, four and five step version, of which the five-step version is shown in Fig. 29. The five-step cycle added a physical step of drying. The feasibility of all reactions and, in particular, the H_2 and O_2 generation, has been demonstrated on bench scale level [61].

HCl heated up to 475°C and solid copper are fed into a reactor. The reaction preferably takes place at temperatures greater than 425°C to obtain the CuCl in liquid form. In the electrochemical reaction, aqueous CuCl enters the electrochemical cell and is electrolyzed, with $CuCl_2$ formed at the anode and Cu particles at the cathode exiting the cell. Drying of the aqueous cupric chloride is an energy intensive step that requires heat at temperatures less than 100°C. The hydrolysis step is an endothermic, non-catalytic, gas–solid reaction taking place in the temperature range 350–400°C. Here, solid $CuCl_2$ particles react with steam to generate copper oxychloride and HCl gas. The endothermic oxygen production reaction requires the highest temperatures. It is the thermal decomposition of solid $CuO \cdot CuCl_2$ which produces liquid copper monochloride and oxygen gas.

Heat requirements for the Cu–Cl cycle amount to 221 kJ/g of H_2 produced. Studies have shown that a large portion could be delivered by low grade waste heat and other heat recovery. Here, the waste heat from the moderator of a CANDU reactor could be used [62]. The electric energy demand is about 39% of the total energy requirement. The efficiency of the cycle is estimated in the range of 40-43% [63, 64].

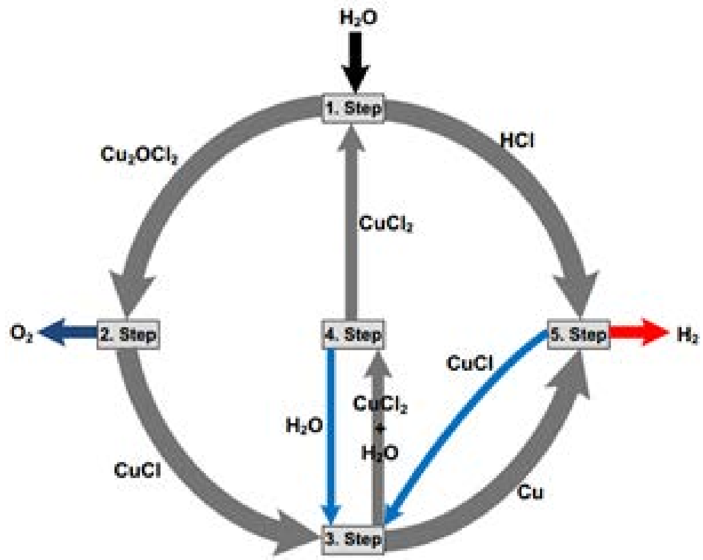


FIG. 29. Copper–Chlorine thermochemical hybrid (5 step) cycle [58].

2.1.3. Nuclear reactor to hydrogen process coupling

The combination of an external heat source with chemical processes will need a device to decouple the heat from its origin to the heat utilization system. In the case of a nuclear plant, it is the intermediate heat exchanger (IHX) that provides a clear separation between nuclear plant and heat application. Under normal operating conditions, the IHX prevents the primary coolant from accessing the process plant and, on the other side, process gases from being routed through the reactor containment, thus limiting or excluding a potential radioactive contamination of the product (e.g. by tritium). Furthermore, the physical separation allows for the heat application facility to be conventionally designed meaning easy maintenance and repair works under non-nuclear conditions. The VHTR will have three heat exchanging levels, from the primary side to an intermediate circuit, then to a heat delivery system of the chemical plant before transferred to various chemical processes.

Different technologies for heat exchanging components designated for nuclear applications have been developed in the past. Two IHX components, one with a helical tube bundle and the other one with U-tubes, designed for a power level representative for large and medium sized plants were constructed by German companies and tested under conditions of nuclear process heat applications in a 10 MW(th) component test loop (KVK) with 950 °C helium on the primary and 900 °C helium on the secondary side [65]. In the Japanese HTTR, a 10 MW(th) helically coiled IHX is presently being operated under the same conditions [66]. Based on this proven design and operation experience on the HTTR, a new helical tube and shell design that doubles life time under the high temperature conditions has been reported [67]. Other new IHX designs currently under investigation for nuclear applications are the so-called Printed Circuit Heat Exchangers, PCHE, are composed of metal plate layers containing alternately coolant channels for the primary and secondary fluid and stacked together to a solid, all metal core. PCHEs are highly compact, robust and thermally efficient.

For both nuclear and solar systems, appropriate material selection will be essential. A qualification program for high temperature metallic materials must demonstrate their good long-term performance. In the nuclear case, candidate materials will be exposed to helium of 1000 °C with impurities such as CO, CO_2, H_2, H_2O, CH_4 and to neutron irradiation. The experience gained so far has disclosed that the technical solution of material problems requires further efforts in future.

2.2. STORAGE AND TRANSPORTATION TECHNOLOGIES

Hydrogen storage and transportation technologies may be evaluated by HEEP. The main options for storing hydrogen are as a compressed gas, as a liquid or combined with a metal hydride. The options for hydrogen transportation are through pipeline and road vehicles.

2.2.1. Storage

2.2.1.1. Liquid storage

Liquefaction is done by cooling the hydrogen to form a liquid. Liquefaction increases the density of hydrogen. The liquefaction is achieved by use of compressors and necessitates the use of cryogenic equipment due to low boiling point of hydrogen. A major concern in liquid hydrogen storage is minimizing hydrogen losses from liquid boil-off. Because liquid hydrogen is stored as a cryogenic liquid that is at its boiling point, any heat transfer to the liquid causes some hydrogen to evaporate. Based on the requirement spherical or cylindrical tanks can be used for storage with appropriate facility to minimize boil-off.

2.2.1.2. Compressed gas storage

Storage as compressed hydrogen is the most common way to store hydrogen and the technique is well proven and gases can be stored in high-pressure cylinders to desired pressures.

2.2.1.3. Metal hydride storage

Hydrogen can be stored either by adsorption, or absorption in materials. Adsorption is when the hydrogen atoms are bound to the surface of a material and absorption is when the hydrogen atoms are absorbed at interstitial locations in the lattice of the host material. There are many metals and alloys capable of reversibly absorbing hydrogen. Hydrogen atoms are stored at interstitial locations in the lattice of the host material. During desorption, hydrogen atoms recombine into molecular hydrogen. There are many metals available for use as an hydrogen absorber such as magnesium Mg, lanthanum La or palladium Pd but also some alloys such as iron-titanium FeTi, zirconium-vanadium ZrV_2 and titanium-vanadium TiV_2. Alloys derived from $LaNi_5$ shows the most promising properties such as fast and reversible sorption at relatively low pressures at room temperature.

2.2.2. Transportation

2.2.2.1. Pipeline transportation

Pipe line transportation is the most energy efficient way of distributing hydrogen. However, initial investment in laying out the piping network will have to be considered. The energy losses in pipe transportation can be met from compressors stationed in the pipe line network. Hydrogen has a tendency to permeate through materials and a hydrogen pipe-line will most likely be subjected to larger losses than a natural gas pipe-line. A hydrogen pipe-line needs to be thicker and use materials less sensitive to hydrogen embrittlement.

2.2.2.2. Vehicular transport

Road transportation may be preferred until a wide spread hydrogen pipe line system is built. Road transportation of gaseous hydrogen is extremely inefficient due to low energy density, though gaseous hydrogen can be transferred using trailers. Liquefied hydrogen has higher energy density than gaseous hydrogen and hence preferred method of vehicular transportation.

2.3. TECHNO-ECONOMIC ANALYSIS

This section discusses a number of key techno-economic aspects underscoring nuclear hydrogen production based on the technologies of the nuclear reactors, hydrogen processes and their coupling methods outlined earlier in the chapter.

2.3.1. Nuclear reactor technology impact

Nuclear reactor technological options ranging from existing and advanced LWRs to next-generation systems such as HTGR can greatly affect the practice and costs of nuclear hydrogen production, storage and transportation including. This may be highlighted through the method of conventional electrolysis coupled to LWR or HTGR for centralized hydrogen production.

As shown in Fig. 30, the GTHTR300 (of HTGR) systems evaluated by Japan using the HEEP and internal codes consistently result in a significant cost advantage over the APWR based systems. A key contributor is the difference in thermal efficiency between the HTGR systems with 50% and the LWR systems with 33%. The cost advantage is about 30% on the 2006 year cost basis and increases to 40% in the 2013 year cost basis. The heightened safety standards put in place after the Fukushima accident (March 2011) in Japan subject the LWR to relatively more expenditure in upgrading the safety performance comparing to the HTGR already designed with inherent safety features.

2.3.2. Nuclear power plant efficiency

Nuclear reactors, especially high temperature reactors, are suited to meet the requirements posed by the hydrogen production processes, for only the process heat, only the electricity or both. The effect of electricity generation efficiency by the nuclear power plant on the cost of hydrogen has been studied using HEEP. Hydrogen production cost is calculated and compared for cases generated by varying the thermal efficiency of electricity generation, assuming that the co-located nuclear power plant is generating electricity to feed hydrogen generation plant along with process heat.

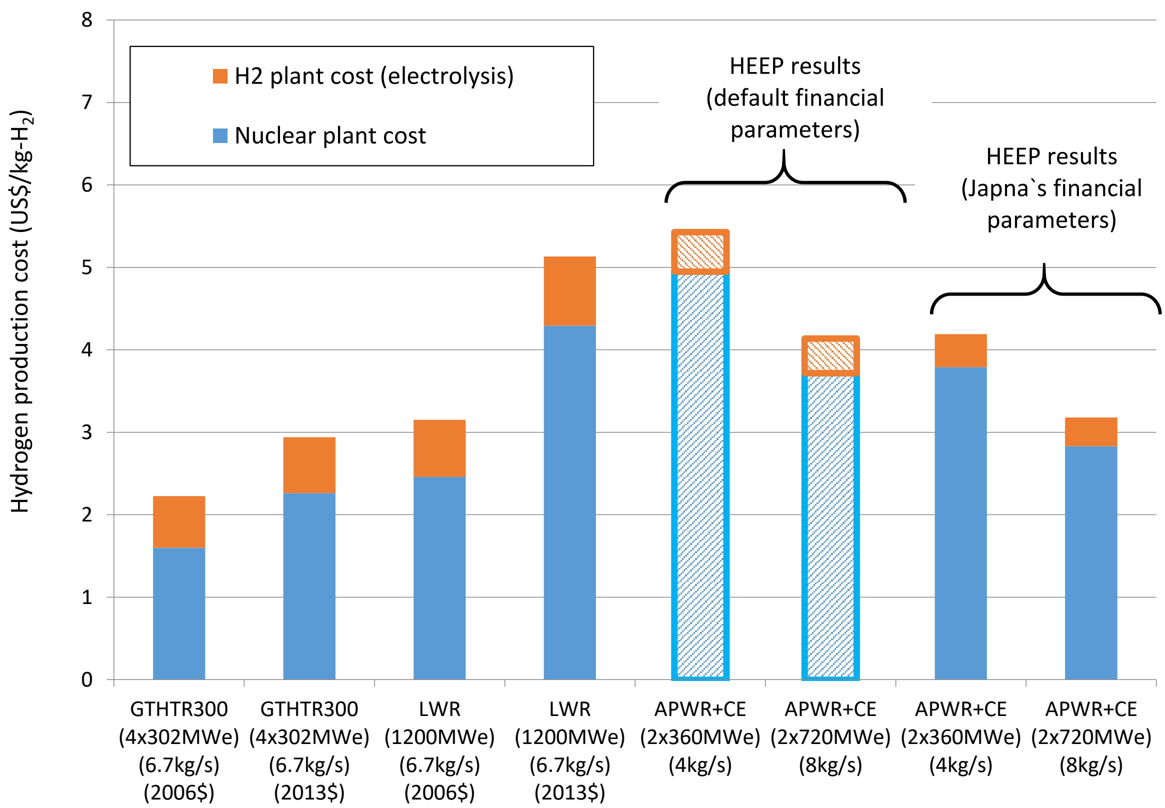


FIG. 30. Impact of nuclear technology options on levelized hydrogen production cost.

2.3.2.1.Description of the reference case

An economic assessment of Sulfur–Iodine (S–I) thermo-chemical based hydrogen generation plant coupled with a high temperature nuclear reactor has been reported, which forms the reference case for the current parametric study [68]. The system configuration of the reference case comprises of 4 modular units of 600 MW(th) HTGR feeding heat energy to an S–I cycle based hydrogen generation plant annually generating 216 000 tonnes of hydrogen. In this configuration, entire thermal energy generated in the HTGR plant is fully utilized as heat input to the S–I based hydrogen plant, without any electricity generation. It is highlighted here that, as reported in [68], the hydrogen plant, even though a thermochemical process plant, also consumes considerable electricity, which needs to be obtained from grid, incurring a large so-called energy usage cost.

2.3.2.2. Description of the cases considered in the parametric study

Electricity would be available to the hydrogen generation plant at production cost, if the hydrogen plant is co-located with nuclear power plant. However, additional number of reactors would need to be constructed, as compared to the reference case, to meet the dual needs for maintaining the same rate of hydrogen production. Thus, electrical generating efficiency of the nuclear power plant is one of the important parameters that can affect the hydrogen production cost in a co-located setup. To study such effect, three cases have been modelled, as shown in Table 30.

TABLE 30. DETAILS OF THE CASES STUDIED

Nuclear Plant	**Reference case**	**Case-1**	**Case-2**	**Case-3**
Number of units	4	10	9	8
Electrical generation efficiency	-	30%	38%	46%
Thermal power rating (MW(th)/unit)	600	600	600	600
Capacity factor (%)	90	90	90	90
Availability factor (%)	100	100	100	100
Process heat for H_2 plant (MW(th)/unit)	600	276.67	297.37	336.96
Electrical power generated (MW(e)/unit)	0	97	115	121
Initial fuel loading(kg/unit)	100 000	100 000	100 000	100 000
Annual fuel reloading (kg/unit)	100 000	100 000	100 000	100 000
Capital cost (M$/unit)	459	579	579	579
Capital cost fraction for electricity producing infrastructure (%)	0	25	25	25
Fuel cost(US $/kg)	250	250	250	250
O&M cost (% of capital cost)	2.3	2.3	2.3	2.3
Decommissioning cost (% of CC)	0	0	0	0
Hydrogen production plant				
Number of units	1	1	1	1
Capacity factor (%)	90	90	90	90
Availability factor (%)	100	100	100	100
H2 generation per unit (kg/year)	2.16E+8	2.16E+8	2.16E+8	2.16E+8
Heat consumption (MW(th)/unit)	2400	2400	2400	2400
Power consumption (MW(e)/unit)	869	869	869	869
Capital cost (M$/unit)	1410	1410	1410	1410
Annual energy usage cost (M$)	457	0	0	0
O & M cost (% of CC)		5.46	5.46	5.46
Decommissioning cost (% of CC)	0	0		

To match a supply of 2400 MW(th) as heat, 869 MW(e) of electricity would be demanded in the hydrogen plant. To produce these rates of energy, 10 nuclear reactors are required for electrical generating efficiency of 30%, 9 nuclear reactors for 38% and 8 for 46% electrical generating efficiency.

It is assumed that the total energy requirement for each of Cases 1 through 3 is divided evenly among the multiple reactors required and that each of the reactors co-generates the same rate of heat and electricity. Relative to the reference case, additional equipment for electricity generation such as turbo-generator, condenser etc. will be required. Further, electrical equipment will also be required. While the additional equipment needed would add the capital cost to the nuclear power plant, there would be a simultaneous reduction in cost arising from a change in heat supply equipment size due to a reduction in the amount of heat supplied to the hydrogen plant from the same reactor. However, any reduction in heat supply equipment cost is ignored here for simplicity.

The contribution to the capital cost from turbo-generator, electrical equipment, etc. is reportedly in the range of 20% to 30% for currently operational reactors [69]. Assuming this is valid for the present HTGR reactor, the cost of each unit of nuclear power plant is increased by 25% from the capital cost of nuclear power plant in the reference case. The O&M cost for electricity generating equipment is assumed to be the same percentage of the capital cost as that used to compute the O&M cost of the reference case.

HEEP is used to calculate Cases 1 through 3 using financial parameters in Table 31.

TABLE 31. FINANCIAL PARAMETERS

Discount rate	5.3%
Inflation rate	0%
Equity to Debt ratio	0:100
Interest on borrowings	5.3%
Tax rate	0%
Depreciation period	20 years
Return period for market borrowing	60 years
Construction period	3 years
Cash flow assumed during construction period	Equally distributed

2.3.2.3. Results and discussion

HEEP can calculate and output intermediate costs such as the levelized cost of energy, be it in the form of heat or electricity, used to produce final product of hydrogen. The levelized cost of electricity calculated by HEEP for Cases 1, 2 and 3 is given in Table 32.

TABLE 32. LEVELIZED COST OF ELECTRICITY FOR THE CASES OF VARYING ELECTRICAL EFFICIENCIES

	Case-1	Case-2	Case-3
Levelized Unit Electricity Cost ($/kWh)	0.055	0.045	0.039

Fig. 31 shows the effect of electrical generation efficiency on the cost of hydrogen. As electrical generation increases, the total number of reactors required for producing the same quantity of hydrogen goes down. Due to this, both the total capital cost and O&M costs are reduced. The relationship between electrical generation of nuclear reactor and cost of hydrogen is not linear. The hydrogen cost reduces from \$4.0/kg-H_2 in Case 1 to \$3.4/kg-H_2 in Case 3.

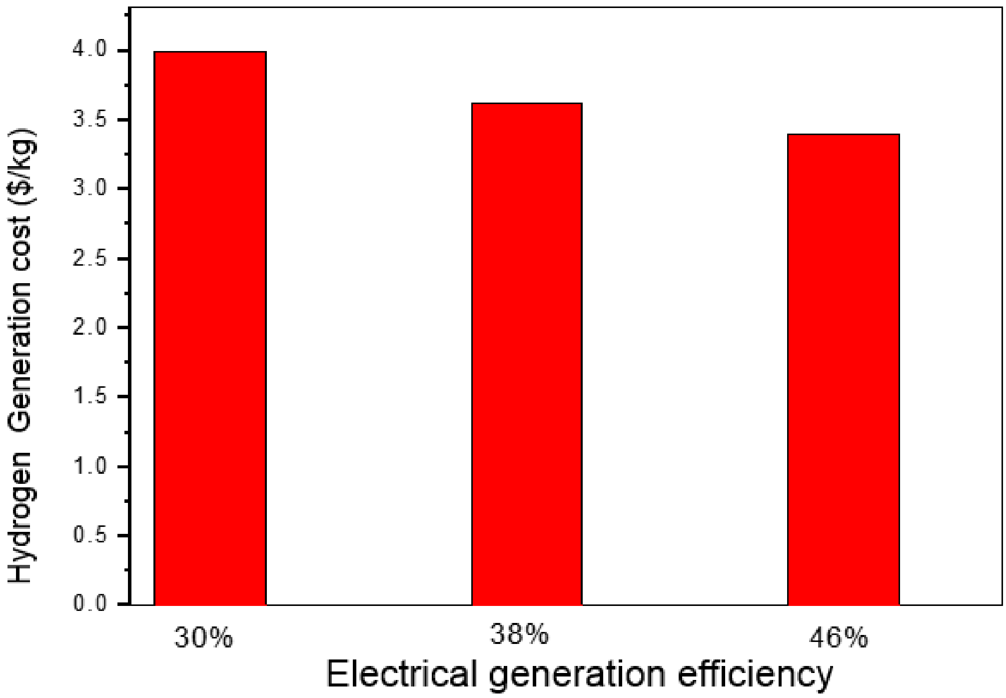


FIG. 31. Comparison of hydrogen cost for varying thermal efficiency

2.3.3. Nuclear plant overnight construction cost

The impact of overnight cost of nuclear power plant was studied by varying it from the reference value between 30% reduction to 30% increase. The generation cost is found to increase from 4.47 to 7.82 $/kg as shown in Fig.32. However, the sensitivity to hydrogen generation cost for the change in overnight cost is less compared to the change in discount rate. Scenarios where the cost of investment is less or the funds can be sourced at lower cost, the economics of hydrogen generation improves. Also since the cost of NPP contributes of the hydrogen generation cost significantly, reduction in construction cost of NPP will also favour the economics of hydrogen generation.

2.3.4. Hydrogen technology impact

For a given nuclear reactor technology, the decision concerning specific design options ranging from power generation, heat supply and cogeneration of both power and heat may affect the costs of nuclear hydrogen productions. This may be highlighted through comparing the levelized costs in Fig. 33, calculated by HEEP and JAEA's internal code, of three system configurations of hydrogen production based on high temperature gas reactor including the following :

- HTGR heat generation to supply the S–I cycle for hydrogen production;
- HTGR cogenerating power and heat to supply the S–I cycle;
- HTGR: HTGR power generation to supply the conventional electrolysis (CE)

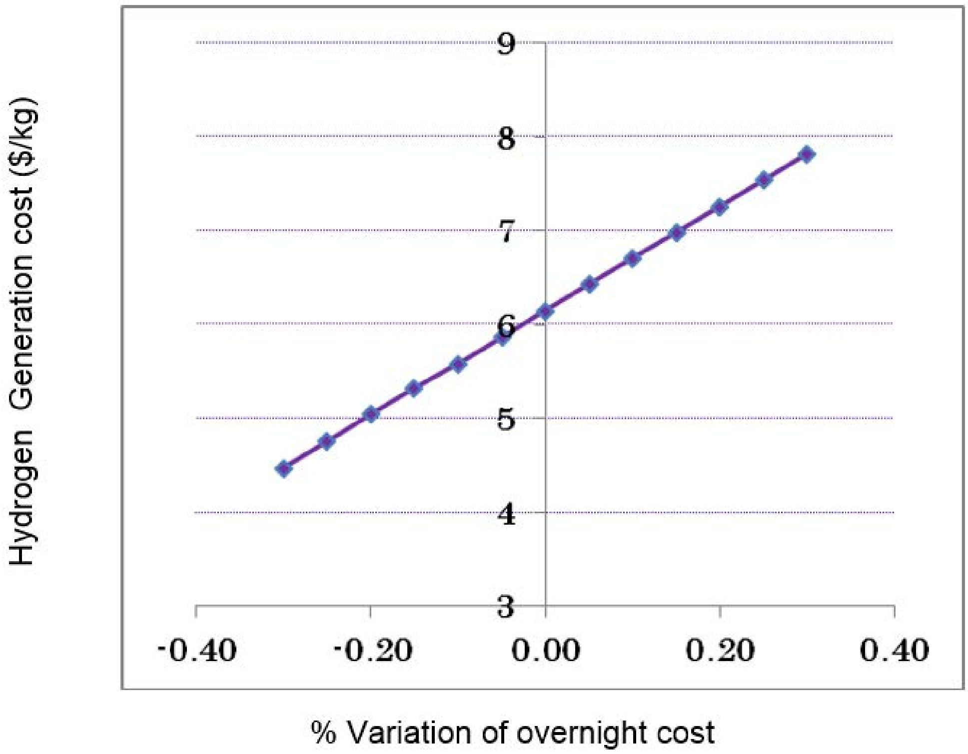


FIG. 32. Variation in overnight cost vs. levelized hydrogen cost

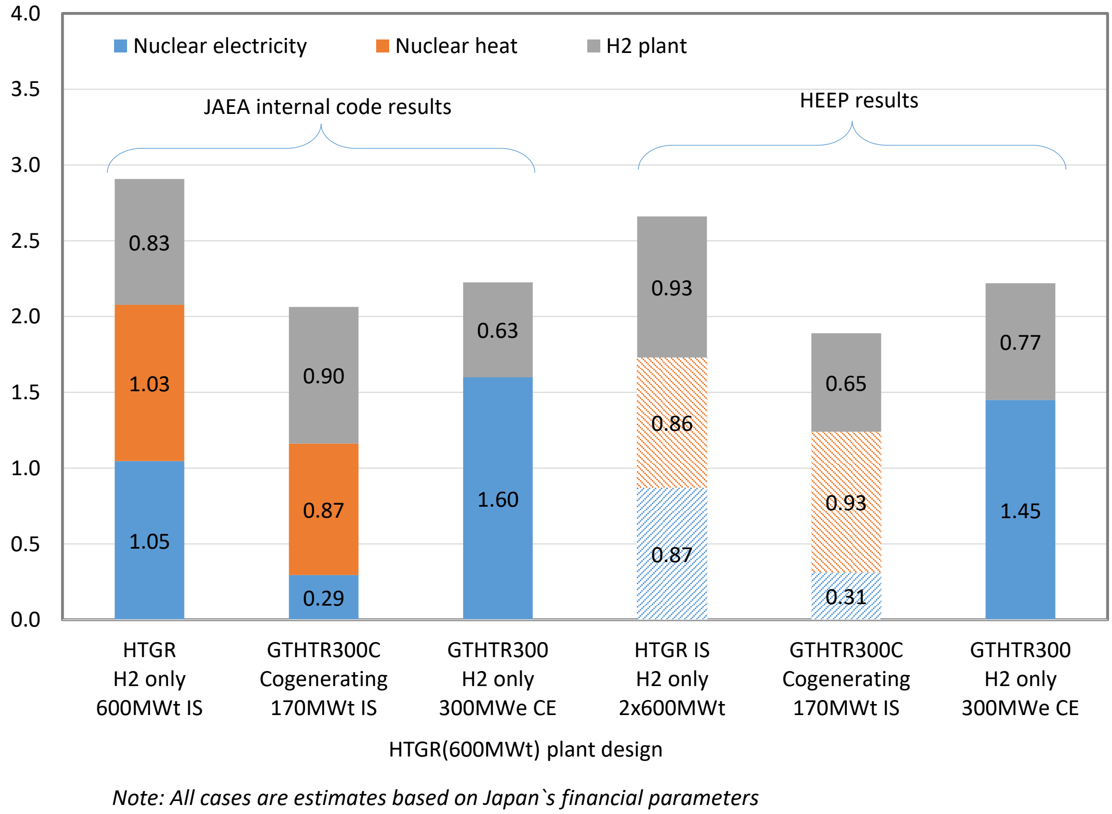


FIG. 33. Impact of system design options on hydrogen production cost.

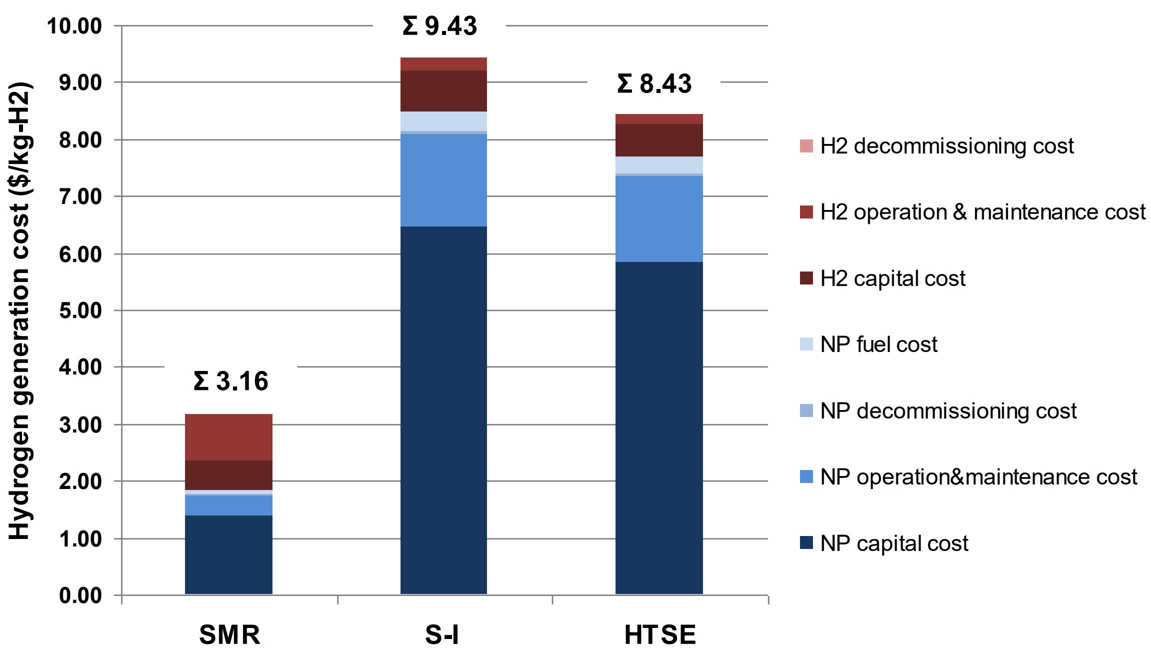


FIG. 34. Comparison of H_2 costs for the HTR-Modul coupled to different H_2 production methods.

Using HEEP, German study calculated the three cases where the HTR-Modul of country specific Case 3 is connected to different hydrogen production technologies including steam–methane reforming (same as Case 3), Sulfur–Iodine cycle and high temperature electrolysis. As seen in Fig. 34, the application of a steam reforming system results by far in the lowest hydrogen production cost. This price, however, includes a fairly large fraction for operation and maintenance cost of the hydrogen plant, mainly due to the cost of natural gas feedstock price (US \$0.56/kg-natural gas) and of the CO_2 emissions (US \$7.01/t-CO_2). On the other hands, the two water splitting options are characterized by high capital costs and high operation and maintenance costs on the nuclear side resulting from their higher specific energy consumption and consequently lower specific H_2 production rates.

Note that the higher costs for the S–I and HTSE are also attributed to the fact that the nuclear reactor HTR-Modul is designed to optimize the application of SMR, instead of the S–I and HTSE. The HTR-PM, a pebble bed reactor similar to HTR-Modul, is designed for application to S–I process by China. The levelized cost of hydrogen from HTR-PM connected to S–I is estimated by HEEP to be \$2.73/kg-H_2 from Chinese financial parameters and \$2.94/kg-H_2 from German financial values.

2.3.5. Hydrogen production efficiency

Hydrogen production economics is also strongly impacted by the progresses of technology advancement. These are concerned both the technology development to improve the cost performance of the reactor system, for example to base on next-generation of reactor designs, and the continued efforts undertaken to improve the efficiency of hydrogen production processes. This may be highlighted through examining the effect in Fig. 35 of overall system thermal efficiency on the levelized cost of hydrogen production system based on high temperature gas reactor:

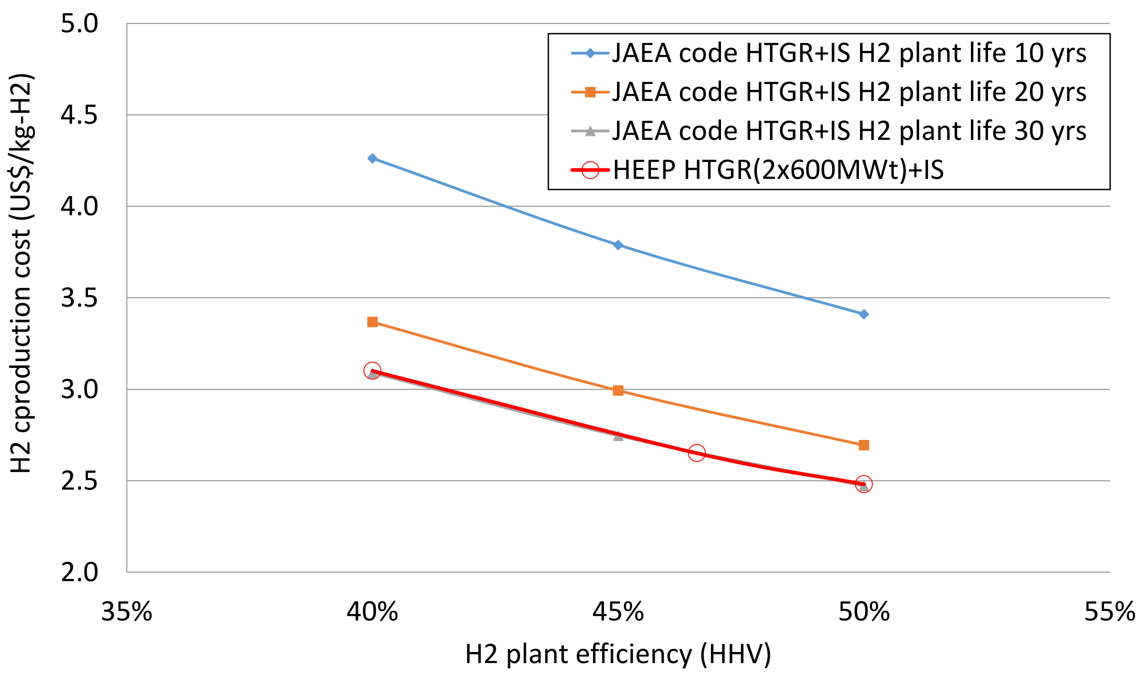


FIG. 35. Hydrogen production sensitivity to the hydrogen plant thermal efficiency

2.3.6. Hydrogen plant operation life cycle

Hydrogen production economics is also strongly impacted by the progresses of technology advancement. These are concerned both the technology development to improve the cost performance of the reactor system, for example to base on latest generations of reactor designs, and the continued efforts undertaken to improve the efficiency of hydrogen production processes. This may be highlighted through examining the effect in Fig. 36 of overall system thermal efficiency on the levelized cost of hydrogen production system based on high temperature gas reactor.

2.3.7. Hydrogen plant technology improvement

Nuclear hydrogen production cost depends strongly on the capital cost of the reactor and that of the coupled hydrogen plant. Though there is relatively limited possibility on reducing the cost of the nuclear reactor plant, the opportunity to decrease the chemical plant capital and operating costs by improving chemical processes is ample. The sensitivity of this is investigated for a nuclear hydrogen production plant design based on two units 268 MW(th) PBMR and one S–I hydrogen plant. In particular, the Bunsen process in the S–I cycle is improved through detail analysis of the Bunsen process using ASPEN PLUS and associated chemical models. Table 33 shows the details on the change of cost associated with improved items of the Bunsen process. The analysis assumes the plant availability at 90% and a conservative value of value of 33% for the S–I process efficiency. Although a modest hydrogen cost reduction of 2.16 % is observed, the reduction in hydrogen cost is achieved through a reduction in capital cost associated with Bunsen process plant, O&M cost and reduction in water cost in the hydrogen plant.

TABLE 33. REDUCED HYDROGEN COST WITH IMPROVEMENT IN THE S–I PROCESS TECHNOLOGY.

Reactor	S–I cycle Base	S–I- Cycle with Improved Bunsen Process	% Change
Capital Recovery Factor	0.105	0.105	
Water Cost ($/cubic meter)	1.57	1.57	
Annual Single Reactor Capital Cost (K$)	16 013	16 013	
Annual Hydrogen Plant Capital Cost (K$)	16 883	16 079	4.76%
Annual Single Reactor O&M Cost (K$)	3686	3686	
Annual Hydrogen Plant O&M Cost (K$)	12 542	11 613	7.41%
Annual Single Reactor Fuel Cycle Costs (K$)	9283	9283	
Annual water cost (K$)	843	675	20.00%
Total Annual Cost of Two Reactors and One IS Plant(K$)	88 232	86 330	2.16%
Total Annual Hydrogen Production (tonne)	12 551	12 551	
Cost ($/kg)	7.0299	6.88	2.16%

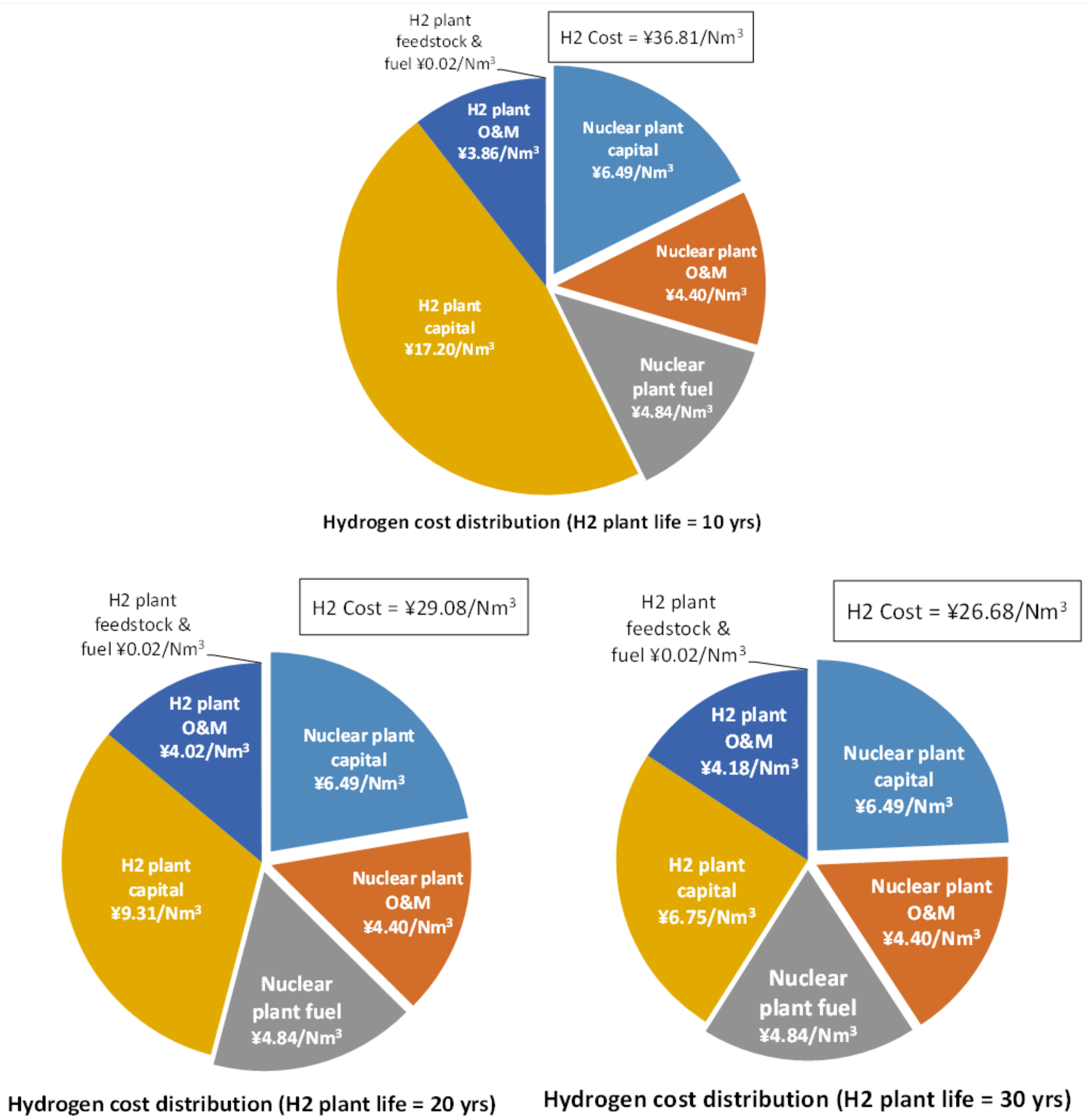


FIG. 36. Impact of improved hydrogen plant life cycle on hydrogen production cost.

In Fig. 37, the hydrogen production cost comparison with improved Bunsen process is shown for the S–I cycle over a range of capital recovery factor. An incremental cost reduction is possible by improving the three cycles in S–I process, the Bunsen process, sulfuric acid decomposition and hydriodic acid decomposition.

2.3.8. Financing parameters

Effect of financial parameters was studied for the Case-1 (Minutes of 1st RCM on CRP Examining the Techno-Economics of Nuclear Hydrogen Production and Benchmark Analysis of the IAEA HEEP Software). The technical and financial parameters of the case are listed in Tables 34 and 35.

TABLE 34. DETAILS OF CASES FOR STUDIED

Nuclear Plant	APWR
Number of units	2
Electrical generation efficiency	33%
Thermal power rating(MW(th)/unit)	1089
Capacity factor (%)	93
Availability factor (%)	100
Process heat for H_2 plant(MW(th)/unit)	0
Electrical power (MW(e)/unit)	359.37
Initial fuel loading(kg/unit)	27 000
Annual fuel reloading (kg/unit)	27 000
Capital cost (M$/unit)	3160
Capital cost fraction for electricity producing Infrastructure (%)	10
Fuel cost(US $/kg)	1850
O&M cost (% of capital cost)	1.66
Decommissioning cost (% of capital cost)	2.6
Hydrogen production plant	
Number of units	1
Capacity factor (%)	93
Availability factor (%)	100
H2 generation per unit (kg/year)	1.26E+08
Heat consumption (MW(th)/unit)	0
Power consumption (MW(e)/unit)	718.74
Capital cost (M$/unit)	423
Energy usage cost (M$)	0
O & M cost (% of CC)	4
Decommissioning cost (% of CC)	10

TABLE 35. FINANCIAL PARAMETERS

Nominal discount rate	5%
Inflation rate	1%
Equity to Debt ratio	70:30
Interest on borrowings	10%
Tax rate	10%
Depreciation period	20 years
Return period for market borrowing	40 years
Cash flow during construction period	Equally distributed
Important time periods	
Operating life	40 years
Cooling before decommissioning	2 years
Decommissioning period	10 years

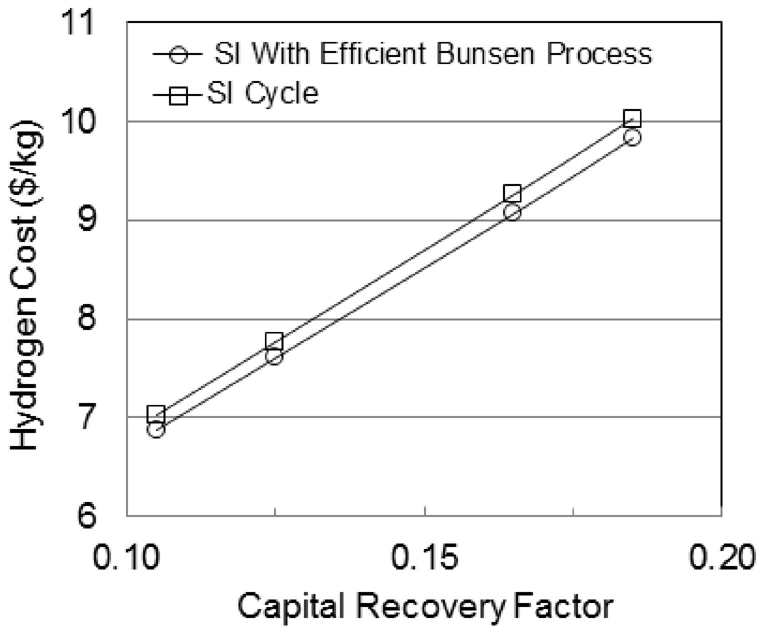


FIG. 37. Comparison of hydrogen cost with the improved Bunsen process of the S–I cycle

Several parameters affect the economics of hydrogen generation. Some of them are; discount rate, interest rate, capital cost of NPP & HGP, construction time, cash flow profile, debt to equity ratio. Out of these, four parameters are selected, which is expected to affect the cost of hydrogen to a considerable extent. Discount rate, interest rate, capital cost of NPP and HGP are taken for the study. These parameter values were varied from -30% to +30% of its reference value one by one while keeping all other parameters fixed at its reference value

Based on the technical parameters and the financial parameters listed in Tables 34 and 35 the cost of hydrogen is estimated to be 5.46 $/kg for the reference case (Fig. 38). The sensitivity results are plotted in Figure-1. Hydrogen cost varies between 4.04 to 6.88 $/kg for variation in capital cost of NPP between 30% reduction to 30% increase from its reference value while the hydrogen cost varies from 4.92 to 6.12 $/kg for absolute value of discount rate changes from 3.5 % to 6.5%. Hydrogen cost found to increase from 4.96 to 6 and 5.33 to 5.59 $/kg respectively for variation in interest rate and capital cost of HGP from -30% to +30%. It can be seen from the Figure-1 that variation in capital cost of NPP has maximum impact to the hydrogen cost, followed by discount rate, interest rate and capital cost of HGP. It is obvious since the NPP are capital intensive entity and any reduction in its capital cost will contribute to the reduction in hydrogen cost. Therefore it is favorable to build large NPPs, to produce hydrogen in larger scale, which will lead to reduction in hydrogen cost due to reduction in specific capital cost of NPP, realized by economy of scale.

Discount rate also has significant impact on the hydrogen cost. This implies that cost of investment has a bearing on the hydrogen generation cost and as the cost of investment decreases the hydrogen generation cost also decrease and vice versa. Scenarios where the cost of investment is less or the funds can be sourced at lower cost, the economics of hydrogen generation improves. If the required investment can be borrowed at a lower interest rate from the market then also economy of hydrogen improves.

To demonstrate the significant influence of the discount rate, Fig. 39 shows for the example of the HTR-Modul with steam methane reforming. The H_2 generation cost increases with increasing discount rate, where the difference between the discount rates 10% (Germany) and 5% (Japan, China) is as much as 0.89 $/kg-$H_2$.

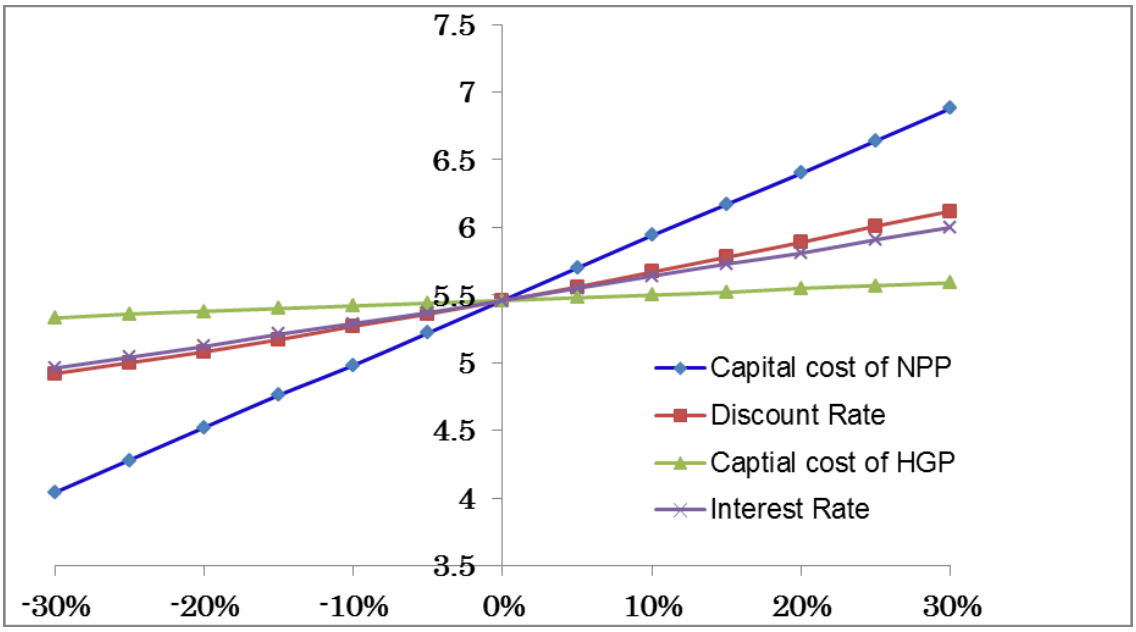


FIG. 38. Sensitivity to levelized cost of hydrogen to financial variables

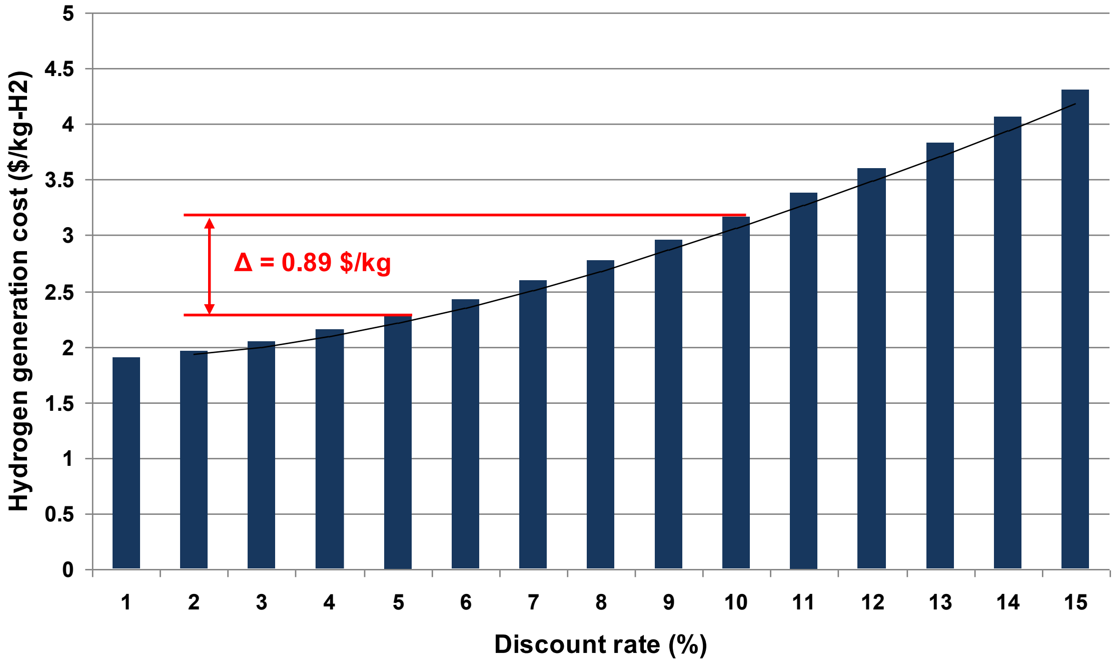


FIG. 39. Influence of discount rate on hydrogen generation cost for HTR-Module SMR..

3. HYDROGEN ECONOMIC EVALUATION PROGRAMME (HEEP): MODELS DESCRIPTION

HEEP is Window-based software developed by IAEA to allow techno-economic assessment of various options for hydrogen economy [70]. It is easy to use within a graphic user interface. It provides modelling for production, storage and delivery, variable and expandable systems and design database, and meets user needs for composite as well as parametric studies including sensitivity analysis to financial parameters.

3.1. OVERVIEW

Levelized cost of intermediate nuclear energy or final hydrogen product is computed in HEEP by using the discounted algorithm at a prescribed discount rate. The code considers separately money inflation to distinguish nominal and real values of the cost. The source of financing can be modelled using a mix of equity and debt simulating a realistic financing scenario. Additional financial parameters considered include borrowing interest, taxation, and so on.

All associated cost elements in the hydrogen production infrastructure including the nuclear plants and hydrogen facilities are modelled. The code has the flexibility for simulation of a hydrogen generation facility either located nearby to the energy source or away from it. Further, it can model the Nuclear Power Plant which supplies energy inputs to the hydrogen generation plant in detail and the unit energy cost of both thermal energy and electrical energy from the dual purpose NPP are computed and displayed in the code along with their components.

The remainder of the chapter describes these features and the models used in the software to estimate the cost of hydrogen production, storage and transportation. The description refers to the latest version of the software released on December 18, 2014 by IAEA. Further, a comparison of the features and models to those in other similar software tools of H2A, GEN4, ASPEN-Plus is also provided.

3.2. MAJOR FEATURES OF HEEP

3.2.1. Modules of HEEP

HEEP is a `Single` window based tool for data input, analysis and display of results comprising of three modules viz.

1) A pre-processing module for providing inputs to calculate the hydrogen cost;
2) An executing module that calculates hydrogen cost based on the inputs transmitted by pre-processing module, and
3) A Post processing module which displays output of the executing module.

The pre- and post- processing modules have been designed to provide a Graphical User Interface (GUI). The pre-processing module provides an interactive, user-friendly interface to enter technical details, chronological inputs and cost components for each utility including (a) nuclear power plant (NPP), (b) hydrogen generation plant (HGP), (c) hydrogen storage (HS) and (d) hydrogen transportation (HT) as depicted in Fig. 40.

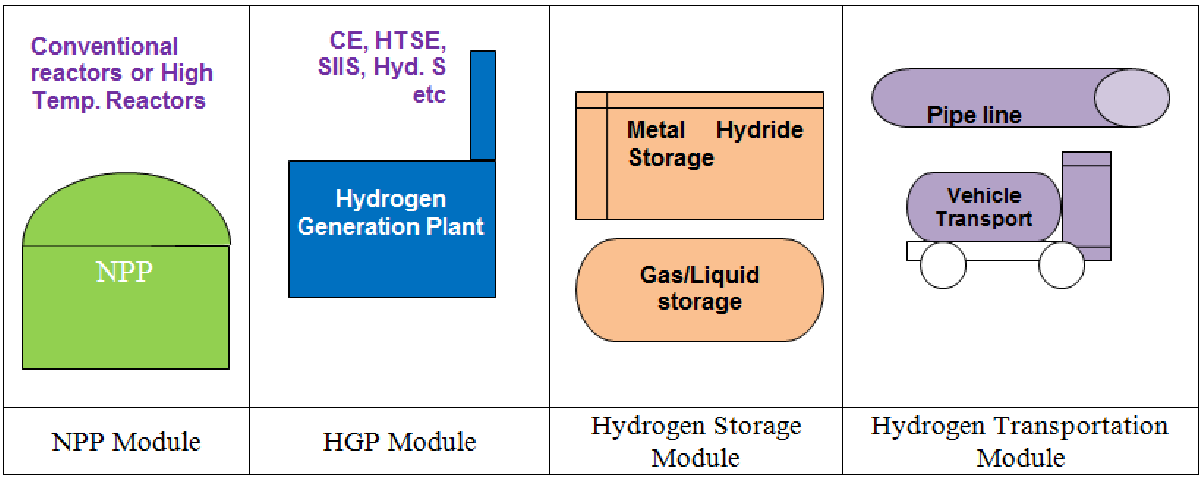


FIG. 40. Modules of NPP, HGP, HS & HT

3.2.2. Comprehensive assessment ability

The assessment of cost of hydrogen production must consider all aspects of the components of hydrogen economy, right from its production and till its dispensation to the end-user. The software tool HEEP has been designed to account for cost elements of all plants and facilities involved in hydrogen production, viz. source of energy required by the process generating hydrogen, production and storage of hydrogen, and its transportation to distribute hydrogen to the end-user. However, the design of the software is also flexible which means that the analyst has an option available to estimate the hydrogen cost with and without considering nuclear power plant as a source of energy, as well as other auxiliary facilities for storage and transportation.

3.2.3. Expandable database

Steam–methane reforming technology for hydrogen production have been developed and deployed on industrial scale for industrial uses. On this scale, no 'nuclear' hydrogen has ever been produced nor are there any existing reactors that produce only high temperature process heat as primary output. Thus, we are considering economics of a system which itself is evolving. This is exemplified when we observe that high temperature reactor technology, thermochemical based processes, storage of hydrogen in metal hydride form etc. are some examples of technologies and processes still undergoing R&D. The amount of information available for economic assessment of hydrogen production would naturally depend on the scale of development of various associated processes and technologies.

The information on economic parameters for these technologies would also evolve, as and when the maturity level of these technologies will be increased through rigorous R&D.

This aspect places a demand for the HEEP database to be technology independent and expandable. Typically, a database would consist of library of files containing techno-economic details of plant supply energy, hydrogen plant including storage facility and transportation infrastructure. Considering this aspect, features to generate new database and append to the existing database for plants operating on such processes and technologies has been incorporated in the HEEP.

3.2.4. Multiple options to build the case for assessment using expandable database

A number of combinations among sources of heat, various hydrogen generating processes and different methods to store and distribute hydrogen are available for modelling.

Many reactor concepts can provide process heat in different temperature range and/or electricity to hydrogen generating process. Reactor technologies of present generation such as PWR and PHWR can provide process heat in lower temperature range. In future, technologies such as fast reactors, molten-salt cooled reactors and very high temperature reactors would be able to supply heat at medium to high temperature range.

Multiple hydrogen production processes operate in a same temperature range. High temperature steam electrolysis and thermo-chemical processes such as sulfur–Iodine or hybrid sulfur require high temperature. Some of the thermochemical processes using metal chlorides as well as hybrid processes operate in medium temperature zone. The conventional electrolysis and steam reforming, etc. operate at lower temperatures.

Further, hydrogen can be stored and transported to end-user using different methods. User may choose any one of the option provided in the software tool to model the case for assessment. These options use the expandable database described earlier.

It is possible for the user to develop economic models for a wide range of combinations of source of energy, hydrogen production process, its storage and transportation using one or more features provided in the software tool. The GUI based pre-processing module has facilitated the following features for building a case/s.

- Provide fresh inputs for assessment and generate a new library file;
- Build new cases by creating new combinations from using previously generated library files;
- Save a case for future use;
- Read and analyse previously evaluated and stored cases.

3.2.5. Ability to address requirements of different types of users

As mentioned earlier, users would have different objectives while performing economic assessment of production of hydrogen using nuclear energy. While some users may be interested in generating ballpark numbers for economic optimization of the process, others may be interested in carrying out detailed assessment to study the effect of variation of a specific parameter of interest. For example, studying effect of variation in enrichment of nuclear fuel or comparing a case with constant O&M cost distributed over operating period with O&M cost gradually increasing with number of operating years etc.

To meet the requirement of different users, HEEP is provided with features that facilitate quick estimates of hydrogen cost by providing a few mandatory techno-economic inputs to the programme. A few examples of mandatory parameters are plant capacities, total capital costs, O&M as well as decommissioning cost as percentage of total capital cost, initial as well as annual fuel load and its cost etc. For non-mandatory input parameters, default values are considered for this type of analysis. A few examples of these non-mandatory parameters are variation in cost of one of the processes of front end (fuel production) or back end (reprocessing and waste management) of fuel cycle, availability and capacity factors of plants, various time periods during the lifetime such as hydrogen storage period, decommissioning period, spent duel cooling period etc., variation of O&M cost, cost of consumables and decommissioning cost with time, number of refurbishments and its period, cost of electricity if obtained from national distribution system etc.

The HEEP input interface developed in Visual Basic uses multiple document interface feature of this programming language. This structure consist multiple window pages in a single main window of the programme. The information among these pages can be seamlessly exchanged. Such type of feature has facilitated grouping input parameters and display on a dedicated window page as per the category of information to be provided. All mandatory parameters are grouped together which is can be entered or viewed or modified in the first layer of input window. For carrying out detailed study user may like to modify non-mandatory which otherwise use default values for quick estimates. Viewing and/or editing non-mandatory parameters is possible in subsequent layers depending on its category.

3.2.6. Input parameters

Data to be provided for estimation of hydrogen cost using HEEP can be broadly classified in two categories, namely (a) parameters common to all plants and facilities; (b) facility dependent parameters. While fiscal parameters and details associated with time period are common to all facilities, details pertaining to technical features and cost components are facility dependent parameters.

3.2.7. Parameters common to all plants and facilities

Fiscal parameters and details associated with time period are common to all facilities.

3.2.7.1.Financial parameters:

The HEEP code uses a discounted cash flow method, for which discount rate is essential. The funding for capital investment can be raised either through equities or market borrowings or combination of both. Equity to debt ratio, borrowing interest rate and its return period are essential for modelling these funding. These parameters also affect interest during construction and thus the capital investment required. The tax rate also significantly affects the hydrogen cost. Depreciation and depreciation period are important when tax on income is to be considered. Inflation rate is considered when nominal rates are entered by the user.

3.2.7.2.Chronological details:

All chronological parameters such as time periods for construction, operation, decommissioning, cooling before decommissioning etc. are essential as levelized cost of hydrogen generation is estimated by discounting the expenditure incurred or revenue generated over entire lifespan to their present value with respect the year of start of plant operation (refer to Section 3.3.1). The construction period is important as it significantly affects interest during construction. For any output producing plant, higher the operating period, lower production cost would be expected. The de-commissioning period may be effective when the fraction of de-commissioning cost is very high.

3.2.8. Facility dependent parameters

Technical parameters and cost elements depend on the plant / facility.

3.2.8.1.Technical parameters:

Capacity of the plant or facility to produce and deliver the specific product is essential as it is going to result in revenue generation. This also depends on capacity and availability factors. The nuclear power plant may be generating heat energy or electricity or both. HEEP can consider any of these cases.

Additional parameter pertaining to nuclear power plant that user must provide for HEEP calculations are thermal power available for hydrogen generation. The location of plant / facility for hydrogen generation, storage and transportation with respect to nuclear power plant can also affect the cost of hydrogen generation. The Heat and electricity required by these plants/ facilities are also considered by HEEP. The process used for production, storage and transportation not only affects these parameters but also influence some of the cost elements.

3.2.8.2.Cost elements:

Cost components considered in HEEP can be classified into three groups viz. Capital cost, Operating cost and Decommissioning cost.

The HEEP programming has considered many aspects of capital investments which could eventually affect the cost of hydrogen. Some of them have already been described earlier in the section dealing with fiscal parameters. The cash flow during construction is another important parameter, which affects the interest during construction. This is particularly prominent when a high capital investment with longer construction period is required.

The operating cost comprises of operational expenditures like wages, salaries, rents to be paid etc., routine maintenance as well as refurbishment expenditures, cost of consumables. The routine operation cost can also comprise of charges for energy/electricity consumed while operating various systems of plants and facilities. In case of nuclear power plant, the costs of front and back end of fuel cycle are also treated as component of operation and maintenance cost.

The decommissioning cost of the nuclear power plant may have significant contribution towards the cost of hydrogen production compared to decommissioning cost of hydrogen generation, storage and transport facility.

3.2.9. Built-in formulas for processing the inputs provided by users:

For quick estimates, using built-in algorithm, the programme calculates certain parameters such as thermal efficiency for electricity generation, parameters associated with storage and transportation such as compressor capacity, power requirement, capital cost of equipment used for storage and transportation, energy usage cost for hydrogen generation, storage and transportation as a part of O&M cost, cooling water cost etc. Formulas used for quick estimation of techno-economic parameters of storage and transportation facility are taken from [71].

3.2.10. Ability to assess effect of location of hydrogen and nuclear plant

HEEP has been mainly developed to estimate the cost of hydrogen generated by usage of energy from nuclear power plants. However, it is also possible to model a hydrogen plant, which works independently of nuclear power plant by drawing required energy from other commercially available sources. This has facilitated modelling the hydrogen generation plant co-located with nuclear power plant as well as modelling hydrogen generation plant isolated from nuclear power plant, which receives energy from a commercial network of energy supply. Models used for both these scenarios viz. co-located and isolated facilities are described in Section 3.3.

3.2.11. Ability to model nuclear power plant meeting energy needs other than hydrogen production:

When part of thermal energy generated by nuclear power plant is diverted for production of electricity, cost of thermal energy as well as cost of electricity generation is estimated using `Power Credit Method`. The model used for power credit method is described Section 3.3.6 of this publication. This feature helps in studying the effect of location of hydrogen and nuclear plant.

3.2.12. Ability to model plant or facility with more than one unit

Hydrogen generation units operating on high temperature thermo-chemical process may have higher efficiency, but the systems are subjected to very aggressive environment. This may lead to more outage on account of repair and maintenance resulting into lower availability factor. The hydrogen production rate can be maintained by installing redundant units and creating hydrogen generation 'parks'.

For a case of nuclear reactor units meeting total energy i.e. thermal energy as well as electrical energy requirement of hydrogen generating plant, total number of nuclear reactor units required will depend on the thermal efficiency of electricity generation.

In order to model such cases, user can provide number of units as one of the input and the required techno-economic data for each unit. This feature facilitates modelling some interesting cases of parametric studies to assess the effect of variation in plant availability factor, process or cycle efficiency, nuclear power plant meeting energy need other than hydrogen production etc.

3.3. DESCRIPTION OF MODELS USED IN HEEP

3.3.1. Model for estimation of hydrogen generation cost

The mathematical modelling used in HEEP is based on the Discounted Cash Flow (DCF) methodology to obtain a Levelized cost for hydrogen at prescribed discount rate. Levelized cost is the uniform constant price at which hydrogen is to be sold over the lifetime of the plant to recover all the expenses incurred without any loss or profit at the prescribed discount rate. The fundamental principle of this approach is that the money received or spent as on today is worth more than the same amount of money received or spent in future. For example, at a discount rate or interest rate of 10%, $ 100/- of today will be equivalent to $ 110/- after one year or an amount of $ 110/- after one-year worth only $ 100/- of today.

In any project, the cash flow consisting of both costs and benefits takes place at different magnitude at different point of time, and hence for the purpose of cash flow analysis, the concept of 'value of money' is to be taken into consideration by the process of discounting as described below.

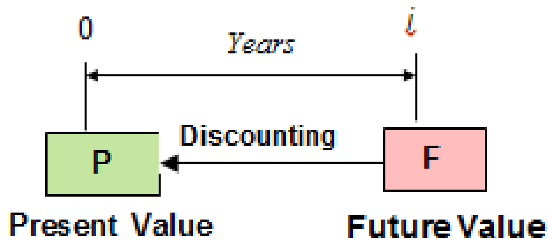


FIG. 41: Discounting process

The process of discounting is depicted in Fig. 41. The present value, P, of future payment, F, incurred '*i*' years from now is given by

$$P = \frac{F}{(1+d)^i} \tag{1}$$

Where,'*d*' is the discount rate. Discount rate represents the cost of the capital employed. It also represents the minimum cut-off return below which investors may not be interested in investing in the project.

A typical life cycle cost for a nuclear power plant is shown in the Fig. 42. During construction of the reactor, capital cost is incurred all throughout the construction period for construction various facilities. Once the reactor become operational, additional expenditures are incurred in the form of fuel cycle costs; both front end and back end, Operation and maintenance charges, refurbishment costs for major replacements, costs for consumables such as demineralized water for electrolysis or heavy water in case of heavy water type reactors etc.

Costs are incurred for the initial core fuel charge inventory also. During operation of the reactor the spent fuel is reprocessed (if reprocessing option is considered for back end) and wastes are disposed off. The useful materials (Plutonium, reprocessed uranium or thorium) recovered will have credits since they can be used for making new fuel.

Finally, the decommissioning costs are incurred for decommissioning of the nuclear power plant. During the operation the product is sold out to earn revenue. The expenditure is indicated by blue lined boxes and revenue generated in green coloured boxes in the Fig 3. Similar cash flow is also considered for hydrogen generation plant.

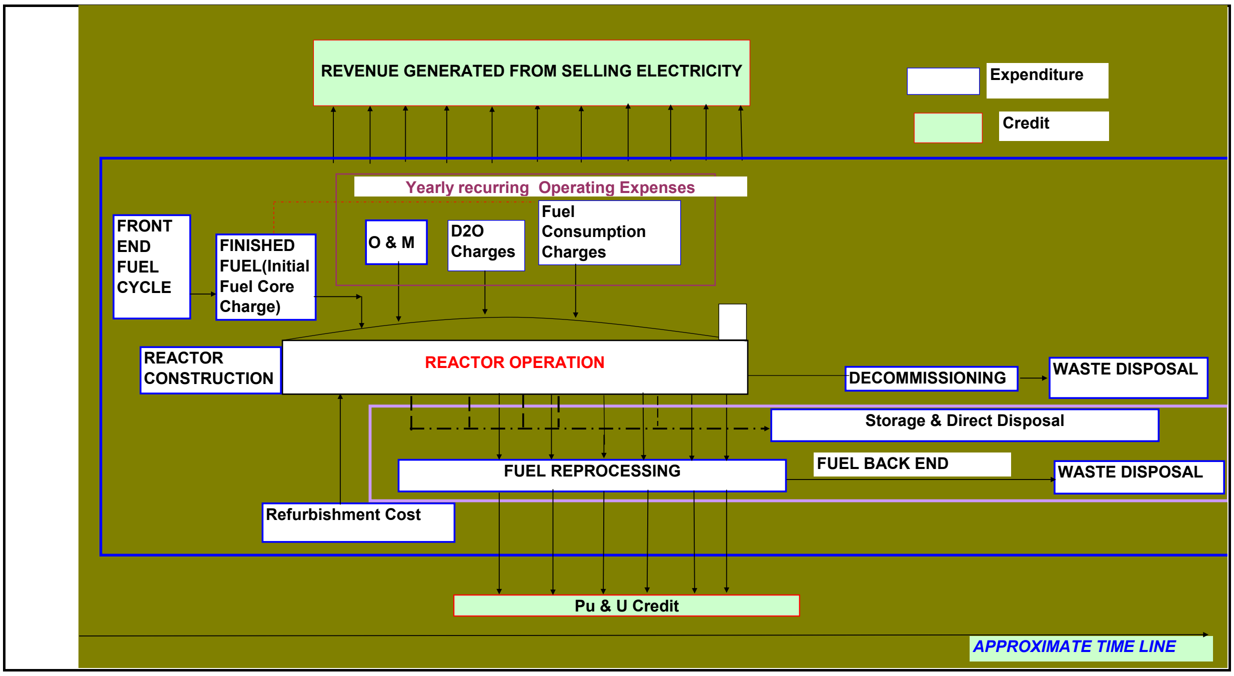


FIG. 42. Life cycle cost elements in a typical nuclear reactor

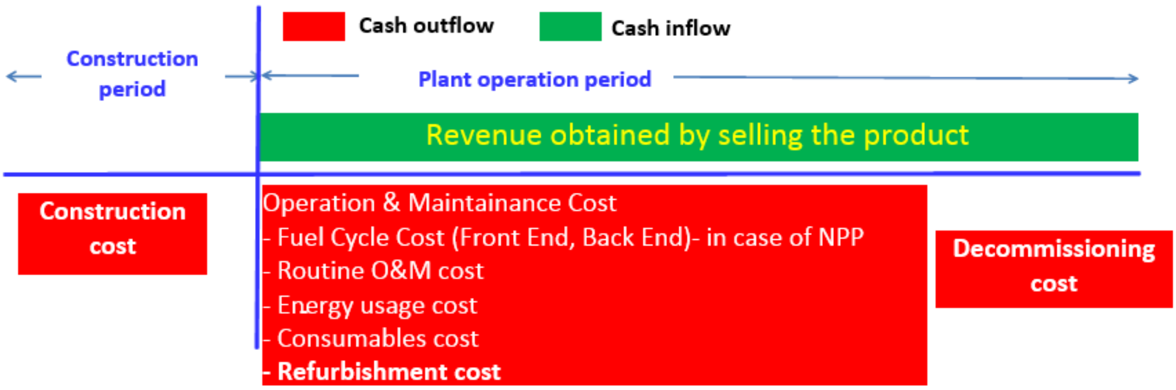


FIG. 43 Block diagram of Cash inflow & out flow entities

Cash flows are made up of costs and revenues in Fig. 43. All the costs and revenues are brought to the present value at the specified discount rate. The costs are entered at constant price level. Costs include capital expenditures, operating and maintenance costs, fuel costs, decommissioning costs and any taxes, if applicable. Generally values entered by the user are nominal values. Real and nominal rates are correlated as follows:

$$Nominal\_value = [(1+real\_value)*(1+inflation)]-1 \tag{2}$$

The Discounted Cash Flow method discounts the series of expenditures and revenue generated over the lifespan to their present value with respect to a specified reference year by applying a discount rate.

The present value (PV) of any cash flow (CF_i) during the year 'i' in the reference year 'i_o' at discount rate 'd' is calculated as:

$$PV[CF_i] = \sum_{i=t_{start}}^{i=t_{end}} \frac{CF_i}{(1+d)^{i-i_o}} \tag{3}$$

Where, t_{start} and t_{end} are the start and end time of the cash flows.

Present value of expenditures is calculated by summation of present value of all expenditures associated with capital cost, O&M cost, decommissioning cost etc.

$$PV[Expenditure] = PV[CF_i] \tag{4}$$

The revenue is generated by sale of the product at given cost. Present value of revenue generated by sale of hydrogen at Levelized Cost (LC) can be given by:

$$PV[\mathrm{Re}\,venue] = \sum_{i=t_{start}}^{i=t_{end}} \frac{LC * H_2\,\mathrm{Pr}\,od}{(1+d)^{i-i_o}} = LC * \sum_{i=t_{start}}^{i=t_{end}} \frac{H_2\,\mathrm{Pr}\,od}{(1+d)^{i-i_o}} = LC * PV[H_2\,\mathrm{Pr}\,od] \tag{5}$$

Here (H_2 Prod) is the annual hydrogen produced by the plant.

For net cash flow to be zero, present value of expenditures should be equal to present value of revenue. Thus,

$$PV[Expenditure] = PV[\mathrm{Re}\,venue] \tag{6}$$

$$LC = \frac{PV[CF_i]}{PV[H2\,\mathrm{Pr}\,od]} \tag{7}$$

Model for calculations associated with the capital cost

$$PV[CF_i] = LC * PV[H2\,\mathrm{Pr}\,od] \tag{8}$$

As an input, user has to provide overnight capital cost, Debt to Equity ratio, interest on borrowings and cash flow during construction period in terms of fraction of total overnight capital cost. The overnight capital cost comprises of sum of all expenditures incurred in design, licensing, manufacturing and erection, construction and commissioning of the plant.

When the construction cost is fully equity funded then debt portion become zero. If the equity portion is zero, then the entire construction cost is sourced from market borrowing. Debt portion of overnight capital cost is calculated by simply applying Debt to Equity Ratio. Based on fraction of cash flow specified during the year, the Debt portion during that year is calculated by multiplying this fraction with the Debt portion. As a first step, the total construction cost including interest during construction (IDC) is estimated. The compound interest on the Debt part during the specific year is calculated up to start of construction. Total interest during construction is sum of compound interest for Debt part calculated for each year during the construction period. The total capital cost is sum of interest during construction and the overnight capital cost. In HEEP, interest during construction is treated as part of total borrowings. Total amount of borrowings is the sum of Debt portion of overnight capital cost and interest during construction.

The debt part including interest during construction is paid back at interest rate for debt repayment period. The total debt part paid during the repayment period is split into principal payment and interest payment for taxation purpose. Thus the debt portion of total capital cost is assumed to be recovered in the form of payment for total debt for the duration of debt repayment period.

3.3.2. Model for calculation of total fuel cost

As a part of mandatory inputs, user can directly provide finished fuel cost for initial fuel load as well as for annual feed. However, provision to arrive at the finished fuel cost starting from purchase of raw material is also available. User can provide following relevant data pertaining to one or more processes which include procurement of raw material, conversion to suitable chemical form, enrichment and fabrication (Fig. 44).

- Rate of purchase (*Pr*) of raw material, say uranium ore;
- Rate of conversion (Cr) of uranium ore in suitable chemical form;
- Rate of enrichment (Er);
- Rate of fuel fabrication (Fr)
- Loss in each of the above activity i.e. conversion (lc), enrichment (le) & fabrication (lf);
- Advance periods (lead time) for each of the above activity i.e. procurement of raw material (tp), conversion (tc), enrichment (te) and fabrication (tf).

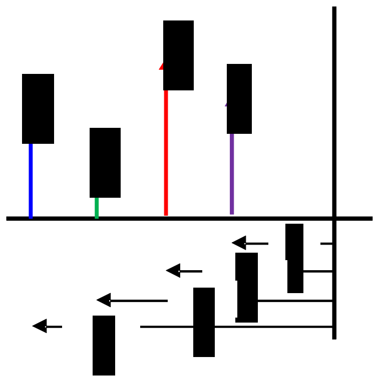


FIG. 44. Lead time for various activities of Front End of Fuel Cycle

Based on these inputs, the cost for each process viz. purchase (F_p), conversion (F_c), enrichment (F_e) and fabrication (F_f) per unit mass of finished fuel is calculated using:

$$F_p = \frac{\dfrac{\Pr * RR}{(1-l_f)*(1-l_c)*(1-l_e)}}{(1+d)^{-tp}}; \quad F_c = \frac{\dfrac{Cr * RR}{(1-l_f)*(1-l_e)}}{(1+d)^{-tc}}; \quad F_e = \frac{\dfrac{S * Er}{(1-l_f)}}{(1+d)^{-te}}; \quad F_f = \frac{Fr}{(1+d)^{-tf}}$$

Where, *RR* is enrichment ratio calculated based on fraction of feed (x_f), Product (x_p), and tail (x_t) provided by user.

$$RR = \frac{x_p - x_t}{x_f - x_t} \qquad (9)$$

$$S = V(x_p) - V(x_t) - RR * (V(x_f) - V(x_t)) \quad (10)$$

$$\text{Where, } V(x) = (2x-1) * \ln(\frac{x}{1-x}) \quad (11)$$

HEEP models both front-end cost and back end cost of the fuel cycle. The back end cost depends on open cycle or closed cycle, i.e., direct disposal or reprocessing route as given in Figs. 45 and 46.

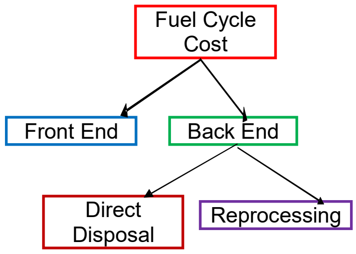


FIG. 45. Fuel Cycle Components

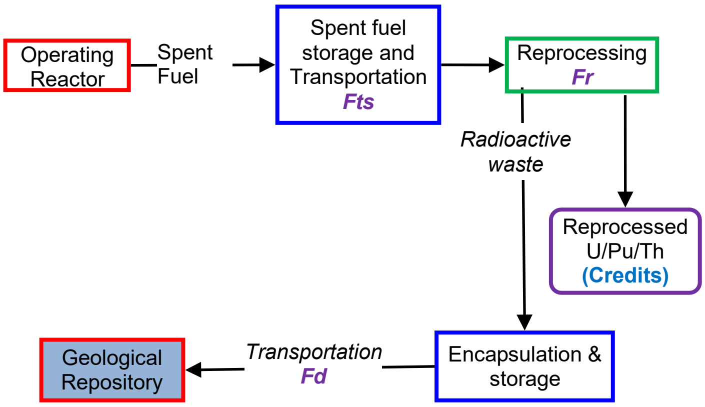


FIG. 46. Fuel cycle cost elements of back end (reprocessing)

Total fuel cycle cost at a given time '*i*' is given by the expression

$$F_i = F_p + F_c + F_e + F_f + F_{ts} + F_r + F_d - C_{pu} - C_{ru} - C_{rTh} \quad (12)$$

Back End cost

- Storage and transportation, $F_{ts;}$
- Reprocessing, $F_{r;}$
- Waste disposal, F_d

Credits

- Cost of recovered Plutonium, $C_{pu;}$
- Cost of recovered Uranium, $C_{ru;}$
- Cost of recovered Thorium, C_{rTh}

Analogous to the lead time considered for different processes of front end of fuel cycle, the lag time is also considered for different stages of back end of the fuel cycle.

3.3.3. Depreciation model

Linear depreciation has been assumed in HEEP. Salvage value of 10% is assumed at the end of specified depreciation period. Depreciation is applied on the capital cost inclusive of interest during construction. Depreciation is also applied on refurbishment cost component.

3.3.4. Model for calculation of refurbishment cost

The software tool considers refurbishment cost in addition to routine maintenance cost. Even though, both these components are elements of O&M cost, the main difference between these elements is that the refurbishment cost is applied only during the refurbishment year specified by the user. Also, during refurbishment year, power generation and/or hydrogen production is nil. The refurbishment cost is depreciable while routine maintenance cost is not depreciable. Linear depreciation model with salvage value of 10% has been incorporated in the programme.

3.3.5. Model for inclusion of Tax

HEEP considers the tax on the net income. Based on the basic principle of economics and accounting, the net present value of `After Tax Cash Flow` shall be zero at real discount rate for computation of the levelized cost.

After tax cash flow *(ATCF)* is computed from Before tax cash flow *(BTCF)* minus taxes paid. Taxes paid *(T)* are computed on the net income after depreciation *(D)* at a tax rate of *t*. Net income is computed by the difference between revenue generated *(R)* by sale of product (hydrogen or energy either in the form of electricity or heat) and operating expenses *(OPE)*. *BTCF* is defined as difference between the net income and capital expenditure *(CC)*. Based on these the following expressions can be derived. Fig. 47 shows the cash flow accounting details.

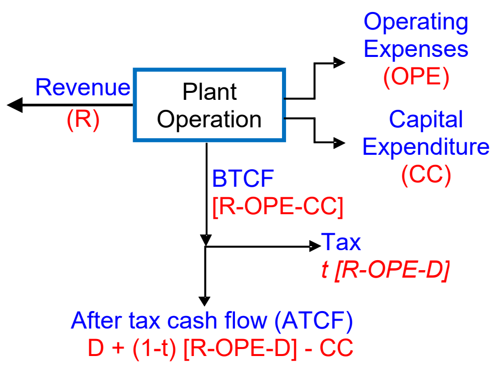


FIG. 47. Cash flow accounting details

$$PV(ATCF) = PV(BTCF - T) = 0 \tag{13}$$

$$where, T = t(R - OPE - D), BTCF = R - OPE - CC \tag{14}$$

$$PV[(1-t)*(R - OPE - D) + D - CC] = 0 \tag{15}$$

$$PV[CC] = PV[(1-t)*(R-OPE-D)+D] \quad (16)$$

$$PV[R] = PV\left[\frac{CC-D*t}{1-t} + OPE\right] \quad (17)$$

$$LC = \frac{PV\left[\frac{CC-D*t}{1-t} + OPE\right]}{PVof(H2prod)} \quad (18)$$

The operating expenses include O&M cost, decommissioning component and interest paid on borrowing. Annual fuel charges, consumable charges, operating charges, routine maintenance expenses are included in the O&M cost. The capital cost expenditure includes equity component of capital cost, refurbishment cost, and principal part of debt component paid back.

3.3.6. Model for dual purpose plants

When the nuclear power plant produces both electricity and heat energy, the power credit methodology [72], also used by G4-ECONS, has been applied to arrive at the cost of electricity produced. As per this methodology, the amount of net energy generated by the reference single-purpose plant (E_{th}) and total expenses incurred (C_{th}) are calculated first, from which the cost per saleable kW_{th} (C_{kWth}) is derived ($C_{kWth} = C_{th} / E_{th}$). Then the amounts of both the electricity (W_e) and the (lesser) net saleable thermal power (E_2) produced by the dual-purpose plant, as well as its total expenses (C_2), are calculated. E_2 is lower than E_{th} because of the energy needed for electricity in the dual-purpose plant, and C_2 is higher than C_{th} because of the extra electricity production expenses. The electricity is then charged by these expenses and afterwards credited by the net saleable power costs *(C_2 - $E_2(C_{kWth})$)*. Figs. 48 and 49 describes the details of this methodology.

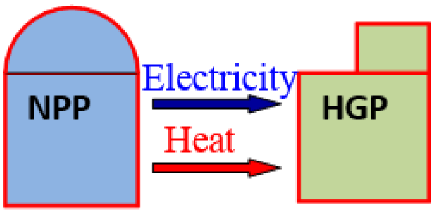


FIG. 48: Dual purpose NPP

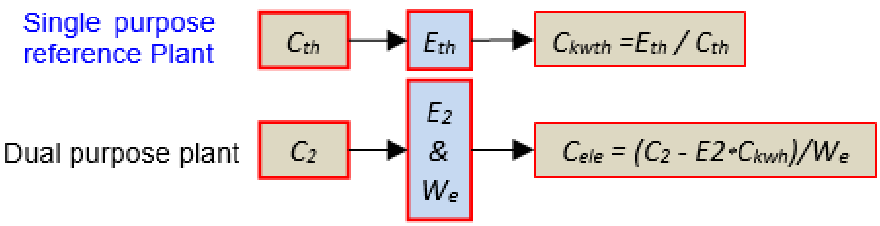


FIG. 49. Modelling of power credit method

The cost of the electricity (C_{ele}) is then calculated as

$$C_{ele} = \frac{C_2 - E_2(C_{kWth})}{W_e} \tag{19}$$

In the above formulas it shall be noted that the costs are the levelized cost which includes, capital, O&M and fuel cycle cost. It is assumed that the fuel cycle costs for dual purpose and reference plant are the same. In HEEP from the costs elements of dual purpose plant which produces both electricity and heat, the cost of reference plant which produces thermal energy alone is derived by subtracting the cost elements infrastructure required for electrical generation.

HEEP can simulate the cases of co-located NPP and HGP. In such case input energy is supplied by the co-located NPP and the cost of energy input to the hydrogen generation, storage and transportation facility depends on the amount of electricity and thermal energy derived from the nuclear power plant.

The programme first computes Levelized Cost of Unit Energy (either thermal and/or electricity). Depending on quantity of energy consumed by hydrogen production plant (including storage and transportation facilities, if applicable), cost of energy usage is considered by the programme as a product of Levelized Cost of Unit Energy and energy consumed. When the co-located nuclear power plant is generating enough energy required by hydrogen generation plant (including storage and transportation facilities, if applicable) user is not supposed to provide energy usage cost separately, as an element of O&M cost. However, if the energy from nuclear power plant is insufficient, the programme has a provision to consider energy needed for hydrogen generation plant, storage facility, and transportation from offsite power sources. User has to provide information in the form of energy usage cost in such cases.

3.3.7. Models for co-located facilities

HEEP simulates the economics of a hydrogen generation plant which receives energy inputs from an NPP. Depending on the process of hydrogen production like conventional electrolysis, S–I cycle, Hybrid Sulfur cycle, or High Temperature electrolysis either electricity or heat or combination of both can be derived from the NPP as input to the hydrogen generation plant operation. Based on the user inputted technical and cost & financial parameters NPP module calculates the levelized electricity and thermal costs (LUEC-e and LUEC-t) and these values will be given to the hydrogen generation module for calculating energy input costs required for running the hydrogen generation plant (see Fig. 50). Based on the technical and cost and financial parameters entered by the user for the hydrogen generation plant, the hydrogen generation plant module evaluates the levelized hydrogen generation cost (LHGC). HEEP models the hydrogen storage and transportation also and compute these components based on the user given inputs. Hydrogen storage module considers storage as gas, liquid or in metal hydrides. Transportation module simulates economics of transportation via pipe line or truck.

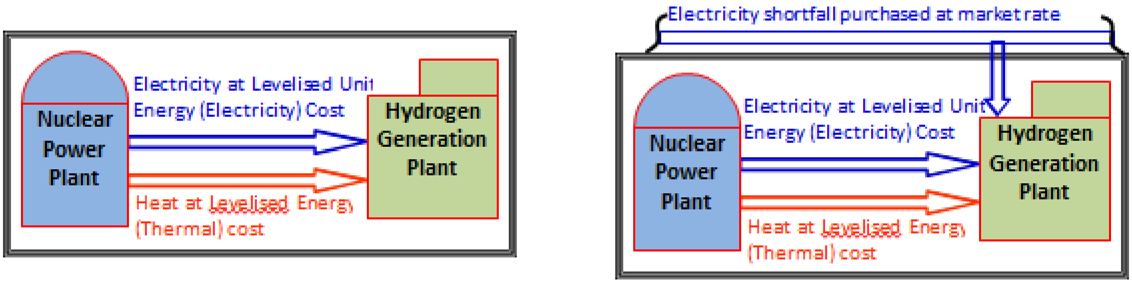


FIG. 50. HEEP module for co-located plants

3.3.8. Models for isolated facilities

If the hydrogen generation plant is drawing energy from commercially available offsite power sources, user has to provide the cost of this energy as energy usage cost. This cost is considered as part of O&M cost component.

3.4. COMPARISON WITH OTHER CODES

3.4.1. H2A

3.4.1.1. Description of H2A code

H2A, which stands for Hydrogen Analysis, was first initiated in February 2003 by U.S. Department of Energy (DOE) under the Hydrogen and Fuel Cells Program for bettering capabilities of analysts working on hydrogen systems, and to establish a set of financial parameters and methodology for analyses [17]. The first task the H2A effort has chosen to tackle is to develop a standardized approach and set of assumptions for estimating the lifecycle costs of hydrogen production and delivery technologies and the resulting cost of hydrogen. Applying the same methodology to each technology and choosing appropriate assumptions will lead to an equitable comparison across technologies. A Core H2A Group was formed to complete this task. A set of hydrogen production and delivery technologies chosen for analysis. These are technologies for which considerable information already exists and that are currently considered prospects for future commercialization. The analyses include various options for central production of hydrogen in large plants and for forecourt production in distributed production facilities which also dispense hydrogen to vehicles in a manner similar to that at gasoline stations.

H2A methodology uses a spreadsheet tool based on the discounted cash flow methodology to estimate the levelized cost of hydrogen. Basic process information (feedstock and energy inputs, size of plant, co-products produced, etc.), technology (e.g., process efficiency and hydrogen product conditions) and economic assumptions (after tax internal rate of return, depreciation schedule, plant lifetime, income tax rate, capacity factor, etc.) are considered in the tool. These models do a discounted cash flow analysis over the analysis time period based on the specified economic assumptions to calculate the cost of hydrogen produced over the analysis time with the after tax internal rate of return on capital investment. Version 2.1 of the central and distributed H2A models was released in September 2008, Version 3.0 of the models was released in 2012 and Version 3.1 of the models was released in 2015.

The following set of key economic parameters was selected by the H2A analysts to utilize within their analyses. These were discussed with the Industry Collaborators who participated in the H2A effort. The user of the H2A analysis model tools is free to change these parameters to any value they chose for their own purposes.

Reference year dollars: 2005
Debt versus equity financing: 100% equity
After tax internal rate of return: 10% real
Inflation rate: 1.9%
Effective total tax rate: 38.9%
Depreciation period and schedule: MACRS
Central plant production: 20 years.
Forecourt production: 7 years.
Delivery components: typically 5 years with a few exceptions
Economic analysis period:
    Central plant production — 40 years.
    Forecourt production — 20 years.
    Delivery Components Model — 20 years.
Decommissioning costs are assumed equal to salvage value

3.4.1.2.Comparison of model features

Both HEEP and H2A use discounted cash flow method to estimate the levelized cost of hydrogen. However, some of the features of HEEP and H2A differ. While comparison between results obtained using HEEP and H2A is given in Chapter-4, some of the distinctive features of HEEP and H2A are compared as follows.

3.4.1.2.1. Methodology

Input interfaces of HEEP and H2A are different. While H2A has Microsoft Excel spreadsheet based interface for modelling the hydrogen generation plant, HEEP is an independent executable application developed using Microsoft Visual Studio programming language. The computational module of HEEP is developed in FORTRAN.

3.4.1.2.2. Detailing

Both HEEP and H2A gives contribution of each cost component viz. capital cost, running cost and decommissioning cost, but H2A is unable to provide share of each of the facility associated with hydrogen generation and distribution. This is mainly because in HEEP all details have to be provided as a separate entity of each plant or facility (source of heat/electricity, storage and transportation) associated with hydrogen production. As an output, programme gives contribution of each facility in the total hydrogen cost. However, H2A considers the cost components of all facilities on lump sum basis and do not have any separate module for consideration of cost inputs from NPPs.

3.4.1.2.3. Construction period

Another difference between HEEP and H2A is the construction period. The version of H2A used for comparison considers construction period not exceeding 4 years. While in HEEP there is no limit on construction period.

3.4.1.2.4. Debt repayment

In H2A, debt portion (market borrowing) of the capital cost is incurred in the first year of the construction period itself. Repayment of debt component starts from the first year of construction period. In HEEP, debt part incurred in each year of the construction period is based on the fraction of cash flow during that year and debt-equity ratio. Repayment of debt part borrowed in each year starts from the respective year of incurring.

3.4.2. G4-ECONS

3.4.2.1.Description of G4-ECONS

G4-ECONS (Generation 4 Excel-based Calculation Of Nuclear Systems) developed by the GIF EMWG (Economic Modelling Working Group) is an excel based program used for the economic evaluation of nuclear systems [73, 74]. G4-ECONS consists of three major modules. The first module of G4-ECONS is the reactor cost module which calculates the LUEC (Levelized Unit Energy Cost) for the reactor. The "energy" cost is typically the unit cost of electricity. The unit cost of the thermal energy available from the reactor can be calculated by dividing unit electricity cost into the thermodynamic efficiency of the nuclear plant.

The second is the nuclear heat applications module which calculates the cost of a product from a heat application facility adjacent to the reactor. The heat application facility makes use of the electrical or heat energy generated from the reactor. The unit cost of energy from the reactor is a major input to this module along with unit amount of energy needed to produce a unit of product. The product from heat application facility could be either desalinated water or hydrogen. The cost data for the "adjunct facility", such as the hydrogen plant or desalination plant should be organized in a form similar to that for the reactor, i.e. with a code-of-accounts structure. The major cost categories are capital, recurring O&M, and D&D costs. Note that there is no fuel cycle cost here. Any fuel consumables, such as gas or petroleum, are considered part of the O&M cost. Annualisation and levelisation algorithms needed to calculate the "levelized unit product cost" (LUPC) are basically the same algorithms used to calculate the LUEC for the reactor. Again, the LUEC from the reactor model becomes input to this module.

The fuel cycle part of the reactor cost module requires unit fuel cycle costs as an input. For some fuel cycle steps, such as ore purchase, conversion, and U-enrichment, price or cost data is easy to find. For special fuels or fuel recycle, however, unit cost data may not be readily available and must be developed from separate fuel cycle facility cost estimates. These estimates are typically developed in the same code-of-accounts format and with the same major cost categories (capital, recurring O&M, and D&D) as the reactor estimate.

The third module of G4-ECONS is G4-ECONS-FCF (Fuel Cycle Facility) module which calculates levelized costs of fuel cycle products and services. The unit fuel cycle cost calculated from this module is used as an input to the reactor cost module to calculate LUEC. The levelisation and annualisation algorithms used are basically the same as those used in the reactor model. The resulting unit fuel cycle cost from this model is entered by hand into the fuel cycle portion of the overall reactor model.

In summary, G4-ECONS calculate the LUEC (Levelized Unit Electricity Cost) from the reactor module and LUHC (Levelized Unit Hydrogen Cost) from the facility module for hydrogen production plant that requires the use of thermal and/or electrical energy from the reactor. The main characteristics of the G4-ECONS are transparency, simplicity and university.

The concept of annualisation and levelisation are used, because they can eliminate the complexity of having to develop year-by-year cash flow data which requires schedule and cash flow data that may not be available early in the development phase. Because of the international nature of the Gen IV Program it was decided not to use financing models typical of one nation, such as the USA.

3.4.2.2.Comparison of model features

In HEEP, all the financial parameters such as tax rate, inflation rate, equity to debt ratio and interest rate are listed separately as an input to HEEP.

On the other hand, all the financial parameters are all incorporated into the real discount rate which is supposed to represent financial situation of the individual country. This provides a simple means for adjustment of G4-ECONS in both developed and developing countries, even though tax structures, discount rates and financing methods are different in different countries and regions.

The same real (inflation-free) discount rate is used for construction financing, capital amortization, and decontamination and decommissioning (D&D) escrow fund accumulation. Judicious selection of the real discount rate can be used to account for the effects of socioeconomic factors or policies such as taxation, financing risk, market risk, “merchant” plant financing, government vs private ownership and national investment policy.

This is one of the inherent reasons why the output results of G4-ECONS and HEEP can’t exactly match each other.

The total amount of heat and/or electricity that hydrogen production plant needed is calculated by multiplying specific thermal consumption with hydrogen production rate. The “specific thermal consumption” and/or “specific electricity consumption” should be provided as an input data to G4-ECONS while and provided as and, while “thermal rating “and “heat for H2 plant” should be provided as input to the nuclear power plant in HEEP.

In HEEP, If the energy for hydrogen production exceeds the reactor capacity, extra energy should be imported from the outside. This energy cost imported from outside is entered into “Energy Usage Cost”. On the other hand, in G4-ECONS, the energy requirements for the non-electricity application (i.e., hydrogen or desalinated water) must not exceed what the reactor can produce. The user can adjust the production capacity of the application to provide a correct match. The energy cost for the hydrogen production is calculated based on the electricity cost(or thermal energy cost) produced from the reactor plant.

In other words, G4-ECONS is reliable in calculating energy cost as long as the energy required from the hydrogen plant is within the reactor capacity. Therefore, the energy cost is not input data, and is calculated from the reactor module. On the other hand, in case of HEEP if the energy required from the hydrogen plant is within the reactor capacity, the energy usage cost is "zero". If the energy required from hydrogen plant exceeds the reactor capacity, the corresponding difference between the two will be input value to "energy usage cost".

3.4.3. ASPEN PLUS

3.4.3.1.Description of ASPEN PLUS

There are two ways one can study chemical processes. One is to actually conduct experiments or build facilities that will carry out the chemical process. Another way is to mathematically simulate the process. The latter is the objective of ASPEN PLUS, which is a computer-aided process simulation tool for conceptual design, optimization, and performance monitoring for chemical processes [75].

Simulation of large processes in chemical engineering require underlying physical and chemical relationships: Mass balances, Energy balances, Thermodynamic properties, Mass and energy balance, Equilibrium relationships Rate correlations (reaction kinetics and mass/heat transfer). In addition, one may require certain models or empirical relations to define some sub-processes. A process model can be defined as an engineering system's "blue print." The process model is a complete layout of the engineering system including the following:

a) ***Flowsheet:*** The process model flowsheet maps out the entire system. The flowsheet shows one or more inlet streams entering into the system's first unit operation (i.e., heat exchanger, compressor, reactor, distillation column, etc.) and continues through the process, illustrating all intermediate unit operations and the interconnecting streams. The flowsheet also indicates all product streams. Each stream and unit operation is labelled and identified.

b) **Chemical Components**: The process model specifies all chemical components of the system from the necessary reactants and products, to steam and cooling water.

c) **Operating Conditions**: All unit operations in the process model are kept under particular operating conditions (i.e., temperature, pressure, size). These are usually at the discretion of the engineer, for it is the operating conditions of the process that affect the outcome of the system.

ASPEN PLUS allows one to create process model, starting with the flowsheet, then specifying the chemical components and operating conditions. ASPEN PLUS will take all of specifications and simulates the model. The process simulation is the action that executes all necessary calculations needed to solve the outcome of the system, hence predicting its behaviour. When the calculations are complete, ASPEN PLUS lists the results, stream by stream and unit by unit, stream flowrates, compositions and properties and operating conditions, equipment sizes, so one can observe what happened to the chemical species of process model. Aspen can be a very powerful tool for a Chemical Engineer in a variety of fields, oil and gas production, refining, chemical processing, environmental studies and power generation. With reliable physical properties, thermodynamic data, realistic operating conditions, and rigorous equipment models, one can simulate actual plant behaviour. Applications of ASPEN PLUS include: improving engineering productivity and reducing costs, reducing energy consumption and greenhouse gas emissions, improving product yields and quality, minimizing capital and operating costs, optimizing designs for large-scale integrated chemical plants, and optimizing plant operations.

There are numbers add-on optional applications suits associated with ASPEN PLUS. Among them, Aspen Economic Evaluation product family (the ICARUS family) enables process engineers to rapidly estimate the relative capital and operating costs in their process modelling studies.

3.4.3.2.Comparison of model features

The most important difference between HEEP and ASPEN is that the cost of the chemical process equipment is input by the user in HEEP whereas it is estimated by ASPEN by taking into account of physical equipment design and labour costs. The ASPEN economic model features are detailed in the following.

3.4.3.2.1. Aspen economic evaluation suite

This suite contains the following simulation tools:

1) Aspen Process Economic Analyser (APEA) (formerly known as Icarus Process Evaluator): Project scoping tool that enables front-end consideration of lifecycle costs;
2) Aspen Capital Cost Estimator (ACCE): Generates both conceptual and detailed estimates using a highly scalable and comprehensive solution;
3) Aspen In-Plant Cost Estimator: Economic project management tool for in-plant capital and maintenance projects.

The new costing module evaluates economics based on Icarus technology. The approach used in the technology doesn't rely on capacity-factored curves for equipment sizing, nor does it rely on factors to estimate installation quantities and installed cost from bare equipment cost. Instead, it follows industry-standard design codes and procedures to represent equipment with associated plant bulks, and cost modelling and scheduling methods to estimate the cost of project.

The Aspen Economic Evaluation Suite and the Project Lifecycle analysis methodology is shown in Fig. 51.

The main steps in the integrated economic evaluation are as follows:

- Activating the costing engine;
- Mapping unit operations to equipment;
- Sizing equipment;
- Economic evaluation and reviewing results.

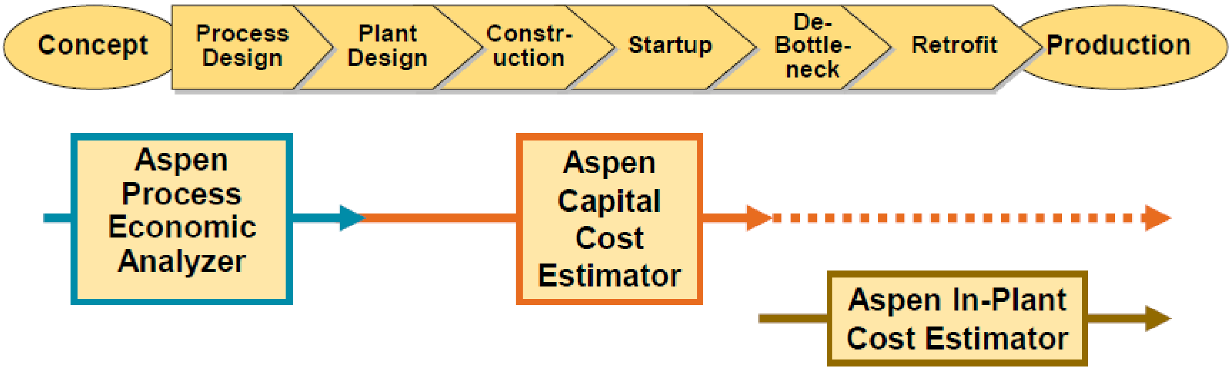


FIG. 51. Aspen Economic Evaluation Suite and the Project Lifecycle analysis methodology

The Mapping and Sizing steps can be individually performed or can be skipped in favour of an "Auto Evaluation" based on default-assigned mappings and sizing algorithms.

Activating the costing engine

The costing engine is Aspen Process Economic Analyser [76]. By activating the economic module, the Aspen simulation results automatically transfer to APEA. The module develops estimates based on a `standard basis file` which includes company-standardized, project-standardized, and the geographic cost basis (US Gulf Coast, Europe, Middle East, UK, and Japan) information.

Mapping unit operations to equipment

A key step in economic evaluation with the new integrated evaluation feature is the mapping of each simulator model (unit operation) to one or more process equipment. For example, a distillation column in Aspen HYSYS [77] might be mapped into several items such as a trayed tower, a kettle-type reboiler, an overhead condenser, a reflux pump, and a horizontal drum (Fig. 52). The new workflow has both the ability to automatically establish `default` mappings as well as the capability to over-ride these mappings and substitute the user's own mappings. The user can change, remove and add equipment during the mapping process.

Sizing Equipment

Sizing of the equipment is performed using the available simulation data and the default sizing procedure; missing data is estimated by the system. The default material of construction for all equipment is carbon steel. Users can review the sizing and materials of construction and override estimated sizes, revise material of construction and enter values for unsized equipment.

Economic evaluation

The Economic Evaluation module develops both capital cost and utility cost. The following costs have been considered for the calculation of the project capital cost:

Direct Costs which refers to material costs and labour costs for:

- Equipment and Setting;
- Piping;

- Civil;
- Structural Steel;
- Instrumentation and controls;
- Electrical equipment and materials;
- Insulation;
- Paint.

Indirect Field Costs

- Engineering and supervision, Start-up and commissioning;
- Construction expenses: Fringe benefits, Burdens, Insurance, Scaffolding, Equipment Rental, Field services, temporary constructions.

Indirect Non-Field Costs

- Freight;
- Taxes and permits;
- Engineering - Basic engineering, Detailed engineering and Material procurement;
- Contingency - allowances for unpredictable events;
- Other project costs - General and Administrative expenses, Contract fees, Home office expenses.

The utility cost of a project is determined by the Economic module based on the appropriate process utility fluids selected either by the user or by the Sizing Expert from the list of 21 default utility streams already present in the system. Once the utility resources are selected, the utility cost for every utility resource used in the project is determined during the operating cost evaluation.

The results of the economic evaluation and the equipment summaries can be created in Excel format as a complete project economic report. The summary and detailed results can be reviewed in order to study the feasibility of the design and to compare process alternatives.

Contingency (defined based on specified process description, process complexity, and project type), process control, location, engineering start date, soil conditions, vessel design code and level of instrumentation are the general specifications affecting capital and operating costs. The costing scenario created by Aspen can be opened directly by Aspen Process Economic Analyser (APEA) or by Aspen Capital Cost Estimator (ACCE) for further development, define a custom model for sizing equipment or tuning of the cost estimate.

3.4.3.2.2. Aspen Capital Cost Estimator (ACCE)

ACCE is a model based, E-P-C cost estimating tool for process project work. It allows for minimum scope definition in conceptual phases of project. For preliminary/conceptual estimates, volumetric models estimate bulk and infrastructure requirements (based upon sized equipment list). ACCE accommodates thorough definition of scope and execution plan as project definition increases

- Process equipment (vessels, heat exchangers, etc.)
- Bulks (pipe rack, utility piping, etc.)
- Process control and power distribution
- Areas (process structures, modules, etc.)
- Contractors and workforces.

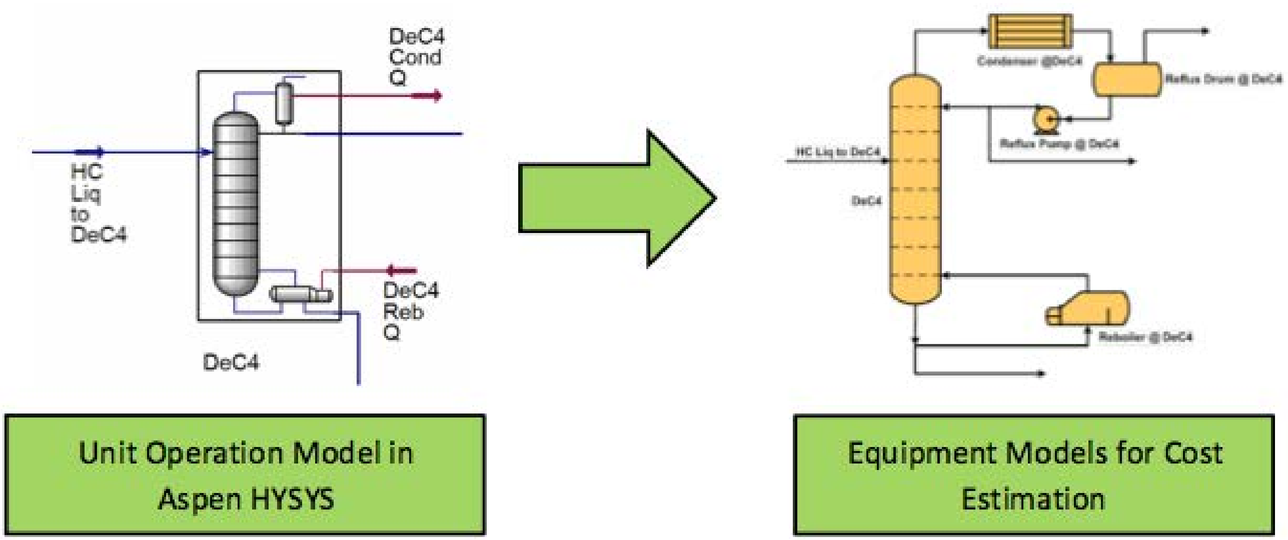


FIG. 52. Mapping a distillation column in Aspen to equipment models for cost estimation

ACCE uses built-in, industry-standard mechanical and construction design and cost models to prepare detailed lists of:

- Quantities, costs, man-hours, drawings, construction equipment
- Mechanical designs of engineered equipment and bulks
- Costs of process equipment and bulk materials
- Construction equipment rental requirements
- All phases of contractor engineering and field supervision.

3.4.3.2.3. Cost basis

The cost basis are updated annually by Aspen Tech and has five base locations, US Gulf Coast, Middle East, EU, UK, Japan and Chinese design basis was introduced in 2012. The base locations reflect typical commodity pricing, labour rates and design code rules. Material and labour specifications can be adjusted to represent site-specific conditions

4. HEEP BENCHMARKING

The HEEP is a previously developed software by IAEA to allow analysing various options of hydrogen production and delivery for future hydrogen economy. Unlike the H2A and ASPEN Plus, which are designed to meet broad user expectation of energy systems and application processes, the HEEP is focused on the aspects of nuclear hydrogen production although it may be tailored, albeit in limited scope, to model production with the alternative energy sources as has been described elsewhere in this report. Moreover, the HEEP is developed on a Windows' platform. Coming with graphic user interface for input and output, it is extremely easy to operate. On the other hand, the design of the software remains in a black box, without the kind of transparency that comes with the spreadsheet programs like the H2A and G4-ECONS. Therefore, being the first-of-a-kind and distributed freely for Member States, the HEEP needs to be validated, and improved when necessary, as a reliable and more useful tool for the intended purpose.

In the course of the CRP, cross-cutting benchmark exercises have been performed by all participating countries under various scenarios of hydrogen production and against other codes. As a result of these robust efforts, the recommended improvements and additions have been made to the code, which enabled the IAEA to update and release the newest version of the software in December 2014. This version caters to the requirements arising from the status of development of various processes and technologies associated with hydrogen production using nuclear energy by this time. Further, the version incorporates features and models that can cater to a wide variety of analysis demands because different users could have different objectives while performing an economic assessment of production of hydrogen using nuclear energy. Some of these features and models are interlinked with each other.

The benchmark process and results discussed in this chapter refers to the December 18, 2014 released version of HEEP.

4.1. METHODOLOGY

International Atomic Energy Agency provided five cases for generic and code-to-code benchmark. These cases have been formulated, based on designs and technical data obtained in the literature, to be generic as being representative of the system technologies of their kinds. Benchmarking of HEEP against these generic cases is thus expected to validate the reliability of the code in terms of quality and sensitivity criteria to predict major cost contributions to nuclear hydrogen production as they are generally understood.

To perform generic benchmark, all country participants of the CRP performed their own exercises of various kinds for these cases against one or more of the following benchmark criteria:

a) Levelized cost of hydrogen and cost components;
b) Sensitivity to scale of production;
c) Sensitivity to choices of reactor and process technologies;
d) Sensitivity to financial parameters;
e) Sensitivity to country specific site conditions

While only a summary of the country results is presented in this chapter, the detailed country specific results are included in their country reports on the CD-ROM.

The code-to-code benchmark exercises have been carried out between HEEP and other open codes. The hydrogen costs obtained for the five generic cases were compared to the results obtained by H2A and G4-ECONS. Two new cases were developed based on commercial nuclear plant designs, one of which is under construction in China. These cases were analysed by ASPEN PLUS and the results of hydrogen costs were compared by the estimates of the HEEP.

Finally, the HEEP was benchmarked against proprietary codes. Japan performed two case studies, one for a conventional electrolysis plant under the assumption that it is collocated with a utility PWR for large-scale centralized hydrogen production, the other for a thermochemical process coupled to the HTGR. The costs and cost breakdowns of hydrogen production obtained with the internal costing code are compared with those of the HEEP in similar cases. Germany performed a design and cost optimization study for an HTGR-based SMR system using its optimization code MILP. It then estimated the cost of the optimized system with the HEEP for code-to-code benchmark against the MILP.

4.2. GENERIC BENCHMARKING

4.2.1. Description of the cases

The generic case studies assume the co-locating of nuclear plant and hydrogen production in proximity. Accordingly, no costs of transportation and distribution of hydrogen are considered. The levelized cost of hydrogen shown in this chapter is thus cost of the hydrogen at the plant gate.

Figure 53 illustrates the process configurations of the generic cases studied. The first three of the generic cases, identified in the following as Case-1, Case-2 and Case-3, respectively, correspond to the coupling of twin units of advanced pressurized light water reactor (APWR) to a hydrogen generation facility that uses conventional (low-temperature) electrolysis (CE) of water for producing hydrogen. The size of both nuclear reactors and hydrogen generation plant increases from Case-1 to Case-3 such that a comparative analysis of these three generic cases to be presented later in this chapter will demonstrate the influence of the economy of scale on the cost of nuclear hydrogen production.

The remaining two of the generic cases, identified as Case-4 and Case-5 respectively, correspond to the coupling of twin units of high temperature gas reactor (HTGR) to a hydrogen generation facility that is based on high temperature steam electrolysis (HTSE) in Case-4 and Sulfur–Iodine thermochemical process (S–I process) in Case-5. While the hydrogen generation rate is the same for the two cases, i.e. 4 kg/sec of hydrogen, the energy requirement for the hydrogen facilities are different: in Case-4, the HTSE facility consumes 1020 MW(th) heat provided by the reactors but no electricity (this obviously mistakes very nature of the electrolysis. A correction is to be made later) while in Case-5, the SI-process facility consumes 1261.4 MW(th) heat provided by nuclear energy and additional 42.8 MW(e) non-process electricity (presumably to power process utility equipment such as pumps, gas circulators, etc.) provided by external electrical grid. The base cost of the grid electricity is assumed to be 7.2 US¢/kW·h. However, the sensitivity of hydrogen cost to electrical price is also investigated. Accordingly, a comparative analysis of Cases 4 and 5 of the same hydrogen production rate is suitable for evaluating the influence of the hydrogen generation process technology on the hydrogen cost whereas a comparative analysis of Cases 1, 4 and 5 of the same hydrogen production rate is suitable for evaluating the influence of the overall nuclear hydrogen processes have various combinations of nuclear reactors and hydrogen generation technologies.

As pointed earlier, Case-4, HTGR coupled to HTSE, is apparently ill defined as the electrolytic process is shown to consume no electricity from either nuclear reactor or external grid. As a matter of fact, approximately 85% of the effective energy input to the HTSE is in the form of electricity while the balance is heat.

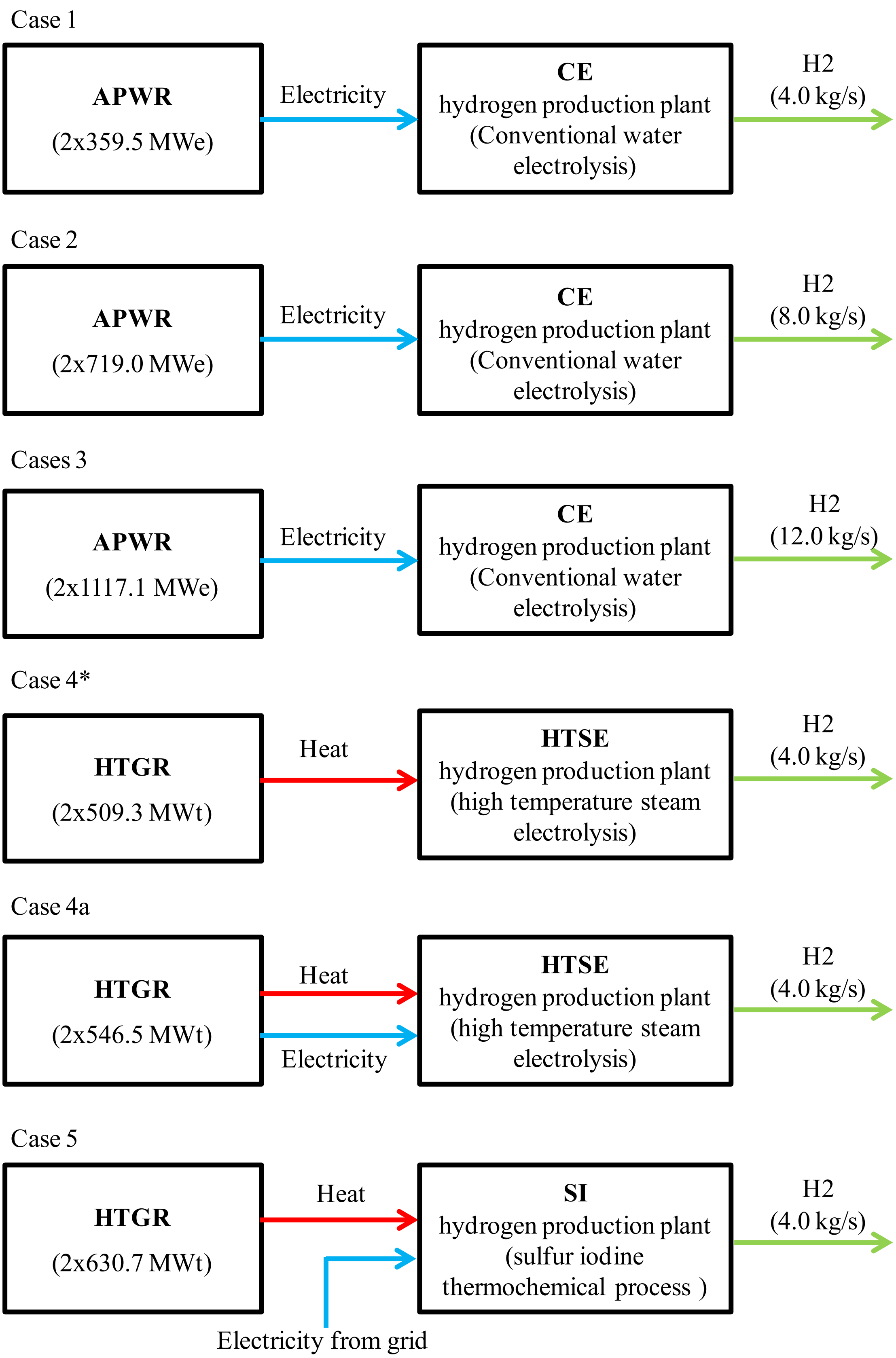
To correct Case-4, a new case is created and identified as Case-4a in Table 36. Case-4a is designed as a cogeneration plant to produce heat and electricity to supply the hydrogen plant. The thermal power of the twin units of the HTGR were determined to produce hydrogen rate of 4.0 kg/s. The rates of heat and electricity consumed in Case-4a are scaled from a reference case of highly-efficient HTSE given in literature [25]. Table 1 compares the process parameters including heat and electricity consumptions between Case-4a and the reference case.

TABLE 36. THERMAL SCALING OF CASE 4A FROM THE REFERENCE CASE [25]

	Reference case*	Case 4a
Hydrogen generation rate (kg/s)	0.15	4.0
Heat consumption (MW(th))	5.59	95.7
Electricity consumption (MW(e))	18.7	498.7
Electricity generating efficiency (%)	50.0	50.0
Effective thermal (heat+electricity) consumption (MW(th))	41.0	1093.1
Hydrogen HHV (MJ/kg)	142.18	142.18
Hydrogen energy HHV (MW(th))	21.3	568.7
Hydrogen generation efficiency (%)	52%	52%
Cost of electricity consumed (US¢/kW·h, HEEP default)	7.2	7.2
Annual cost of electricity ($M)	11.8	314.5

The new Case-4a is used for analysis in this chapter.

Table 37 includes all relevant input parameters as required to run HEEP for the corresponding cases. Table 38 lists the country specific financial parameters to be used for benchmark calculations.



* Incorrect case condition because of lacking an electricity source required by H2 plant.

FIG. 53. Five generic cases of hydrogen production configurations for benchmarking

TABLE 37. HEEP INPUT CONDITIONS FOR GENERIC CASES

	Case 1	Case 2	Case 3	Case 4	Case 4a	Case 5
	APWR+CE H2 rate: 4 kg/s	APWR+CE H2 rate: 8 kg/s	APWR+CE H2 rate: 12.43 kg/s	HTGR+HTSE H2 rate: 4 kg/s	HTGR+HTSE H2 rate: 4 kg/s	HTGR+SI H2 rate: 4 kg/s
Nuclear plant project	2×359.5 MW(e) APWR	2×719.0 MW(e) APWR	2×1117.1 MW(e) APWR	2×509.3 MW(th) HTGR	2×546.5 MW(th) HTGR	2×630.7 MW(th) HTGR
Construction period (year)	5	5	5	3	3	3
Operation period (year)	40	40	40	40	40	40
Cooling before decommissioning (year)	2	2	2	2	2	2
Decommissioning (year)	10	10	10	10	10	10
Refurbishment (year)	1	1	1	1	1	1
Spent fuel cooling (year)	2	2	2	2	2	2
Waste cooling (year)	10	10	10	10	10	10
Nuclear plant design						
Number of units	2	2	2	2	2	2
Capacity factor (%)	93	93	93	90	90	90
Availability factor (%)	100	100	100	100	100	100
Thermal rating (MW(th)/unit)	1089	2178	3385	510	546.5	630.7
Heat for H_2 plant (MW(th)/unit)	0	0	0	510	47.9	630.7
Electricity rating (MW(e)/unit)	359.5	719.0	1117.1	0	249.3	0
Initial fuel load (kg/unit)	27 000	540 00	75 000	14 000	15 001	18 000
Annual fuel feed (kg/unit)	9000	18 000	25 000	5000	5357	6000
Capital cost (US $/unit)	3.16E+9	4.66E+9	5.96E+9	4.02E+8	5.21E+8	6.05E+8
Capital cost fraction for electricity generating infrastructure (%)	10	10	10	0	21	0
Fuel cost (US $/kg)	1850	1365	1260	3660	3660	5535
O&M cost (% of capital cost)	1.66	1.67	1.7	5.8	5.8	5.75
Decommissioning cost (% of capital cost)	2.8	2.8	2.8	11.7	11.7	8.35
Hydrogen plant design						
Process method	Water electrolysis	Water electrolysis	Water electrolysis	HT steam electrolysis	HT steam electrolysis	thermochemical SI process
Number of units	1	1	1	1	1	1
Capacity factor (%)	93	93	93	90	90	90
Availability factor (%)	100	100	100	100	100	100
H_2 generation rate (kg/year/unit)	1.26E+08	2.53E+8	3.92E+8	1.26E+8	1.26E+8	1.26E+8
Heat consumption (MW(th)/unit)	0	0	0	1020	95.8	1261.4
Electricity consumption (MW(e)/unit)	719	1438	2234	0	498.6	0
Non-process Electricity consumption (MW(e)/unit)	0	0	0	0	0	42.8
Capital cost (US $/unit)	4.28E+8	8.45E+8	1.31E+9	4.59E+8	4.59E+8	6.66E+8
Annual energy usage cost (US $)	0	0	0	0	0	2.7E+7
O&M cost (% of capital cost)	4	4	4	17.23	17.23	6.68
Decommissioning cost (% of capital cost)	10	10	10	10	10	10

TABLE 38. FINANCIAL PARAMETER VALUES USED FOR THE BENCHMARKING OF GENERIC CASES

	(HEEP default)	Algeria	Argentina	Canada	China	Germany	India	Japan	Republic of Korea	Pakistan
Discount rate (%)	5	6	5	2	12	10	12	3	4	8
Inflation rate (%)	1	1	9.5	2	2	1.66	5.65	0	2	5
Finance Equity:Debt (%)	70:30	70:30	70:30	50:50	30:70	50:50	30:70	0:100	50:50	20:80
Borrowing interest (%)	10	6	30	7	5	5.5	10.5	3	10	8
Tax rate (%)	10	1.5	10	30	15	28.2	30	1.4	10	0
Depreciation period (year)	20	20	20	30	20	20	20	20	20	20

4.2.2. Benchmark results

Results of the benchmark calculations of levelized hydrogen production costs for the generic cases are shown in Fig. 54. The cost components are detailed in Table 39.

The highest hydrogen generation costs have been calculated for the small APWR plus conventional electrolysis with 5.44 \$/kg-H_2. These specific costs are decreasing with increasing nuclear plant size as would be expected from the economy of scale principle. For all three APWR cases, the lion's share in the H_2 generation costs is from the capital costs of the nuclear plant which amounts to 79%, 77%, and 75%, respectively, of the total costs. The contribution from the hydrogen production plant to the overall H_2 costs is with 0.66 \$/kg virtually constant for the three different production sizes (as there is, different from the nuclear plant, no economy of scale assumed for the hydrogen plant) representing more or less 10% of the total costs. There is negligible contribution from decommissioning of both nuclear and hydrogen plant. It should be noted here that nuclear fuel disposal is not part of the decommissioning cost, but rather included in the fuel cost.

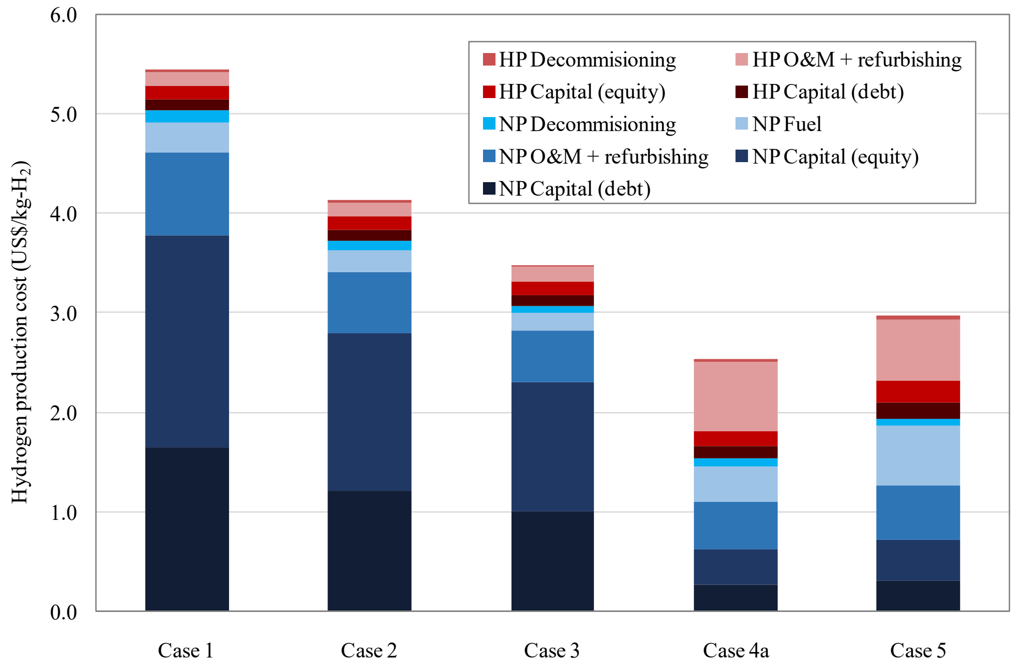


FIG. 54. Levelized hydrogen generation cost for the generic cases (HEEP default financial values)

TABLE 39. LEVELIZED HYDROGEN PRODUCTION COST

Unit (US $/kg-$H_2$)

	Case 1: APWR+CE	Case 2: APWR+CE	Case 3: APWR+CE	Case 4a: HTGR+HTSE	Case 5: HTGR+SI
Nuclear plant					
Capital Debt	1.64	1.21	1.00	0.27	0.31
Capital Equity	2.14	1.58	1.30	0.35	0.40
O&M	0.83	0.62	0.52	0.48	0.55
Fuel	0.30	0.22	0.18	0.35	0.60
Decommission	0.12	0.09	0.07	0.09	0.07
Total	5.03	3.72	3.07	1.54	1.93
Hydrogen plant	(4 kg/s)	(8 kg/s)	(12.43 kg/s)	(4 kg/s)	(4 kg/s)
Capital Debt	0.11	0.11	0.11	0.12	0.17
Capital Equity	0.14	0.14	0.14	0.15	0.22
O&M	0.14	0.14	0.14	0.70	0.61
Decommission	0.02	0.02	0.02	0.03	0.04
Total	0.41	0.41	0.41	1.00	1.04
Levelized cost of hydrogen ($/kg-H2)	5.44	4.13	3.48	2.54	2.97

The results for the two HTGR cases, at first sight, surprise with their very low nuclear contribution to the total costs, at least if compared with the APWR cases. It is only the HTGR fuel that is more expensive than the PWR fuel presumably. The reason lies with improved economic performance potential of the next-generation reactor technology HTGR over the existing LWR. There are two major factors for this result. First, the specific energy production cost (dollar per thermal kilowatt produced by reactor) for HTGR is significantly less than the LWR, as seen earlier from input parameters in Table 37. Second, the HTGR with capability of high temperature heat supply to drive the thermochemical cycle S–I and hybrid cycle HTSE for hydrogen production yields much greater overall production thermal efficiency than the LWR electrolysis production. Table 40 compares the efficiencies of the cases. The efficiency is defined as follows:

$$Hydrogen\ production\ thermal\ efficiency = \frac{H2\ production\ rate\ x\ HHV(H2)}{net\ heat\ consumed + \dfrac{net\ electricity\ consumed}{power\ generation\ efficiency}} \tag{17}$$

TABLE 40. HYDROGEN GENERATION THERMAL EFFICIENCY

Unit (US \$/kg-H_2)

	Case 1 APWR+CE	Case 2 APWR+CE	Case 3 APWR+CE	Case 4a HTGR+HTSE	Case 5 HTGR+SI
H2 production rate (kg/s)	4	8	12.43	4	4
Nuclear heat consumed (MW(th))	0	0	0	95.8	1261.4
Process electricity consumed (MW(e))	719	1438	2234	498.6	0
Non-process Electricity consumed (MW(e))	0	0	0	0	42.8
Nuclear power generating efficiency (%)	33.0%	33.0%	33.0%	50.0%	50.0%
Hydrogen production thermal efficiency (%)	26.1%	26.1%	26.1%	52.0%	42.2%

Comparing the two HTGR cases, it can be seen that in case 5 the H_2 generation costs are somewhat higher (3.62 \$/kg) than in case 4 (2.95 \$/kg). While the contributions from the H_2 plant to the LHGC are not significantly different, with the S–I plant contribution slightly higher (1.41 \$/kg) than the HTSE plant in case 4 (1.28 \$/kg), the major price difference comes from the smaller and cheaper nuclear plant of case 4, but assuming the same hydrogen output for both cases 4 and 5.

As already mentioned earlier, the non-process electricity demand was incorrectly assumed in case 5 to be 428 MW(e), instead of 42.8 MW(e). Since the value was provided initially to the CRP participants, some of case studies reported in the country reports were performed with this input error. Unfortunately, the effect is not negligible. The assumption of a factor 10 higher value would raise the O&M costs of the S–I plant from 0.67 $/kg to 2.80 $/kg due to the external purchase of 3.4×10^6 MWh(e) per year, resulting in a total LHGC value of 5.75 $/kg. In case 4, no non-process electricity demand was taken into account. As a rough estimation, the process related energy required in high temperature steam electrolysis is ~75% electric and 25% thermal, if the process is operated at 800 °C. If now in case 4, the total nuclear thermal power of 1020 MW(th) is consumed in the HTSE process, it would need, in addition, 3060 MW(e) which translates into an annually required electricity of 24.1 million MWh(e) and — at a price of 72 $/MWh — electricity costs of 1737 M$ per year, respectively.

4.2.3. Sensitivity analysis

4.2.3.1.Economy of scale

The first three generic cases, Case-1, Case-2 and Case-3, correspond to the coupling of the nuclear plant comprising two advanced pressurized light water reactors with a co-located hydrogen generation facility that uses conventional electrolysis (CE) for the production of hydrogen from demineralized water. Both the nuclear plant and hydrogen generation plant increase in size from Case-1 to Case-3: in Case-1, the two reactors are each rated at a thermal rating of 1089 MW(th) per unit and a net electrical power of 359.5 MW(e) per unit, yielding the next electrical generating efficiency of 33.0%, while the single CE facility is designed to produce 4 kg/s hydrogen; in Case-2, the rating of the reactors is each doubled to generate a net electrical power of 719 MW(e) per unit at the same thermal generating efficiency and similarly the CE facility produces twice as much the hydrogen rate as does the facility in Case 1; and Case-3 further uprates the reactors and the hydrogen plant to approximately triple the ratings of Case-1. In fact, it refers to the coupling of two AP1000 reactors with a thermal rating of 3385 MW(th) per reactor. Each reactor generates a net electrical power of 1117 MW(e). All electricity generated is consumed in the CE facility designed to produce 12.43 kg H2/s.

The comparative analysis of Cases 1, 2 and 3 showed that the HEEP program was able to predict the expected economy of scale in hydrogen production. As shown in Fig. 55, the total of hydrogen production cost decreases with increasing the rate of hydrogen produced from Case 1 through Case 3. In fact, when the hydrogen production rate is increased by a factor of about 3, from 4 kg/s in Case-1 to 12.43 kg/s in Case-3, the levelized cost of hydrogen production decreases by a factor of about 1.6, from US \$5.44/kg-H_2 to US \$3.48/kg-H_2. Furthermore, the specific cost component of the hydrogen facility remains constant in all cases at US \$0.41/kg-H_2 due to the typical approach of modular construction to electrolysis plant as introduced in Chapter 2. As such, the effect economy of scale is entirely associated with the nuclear reactor plants or with the changing cost of power generation with the capacity of the nuclear plants.

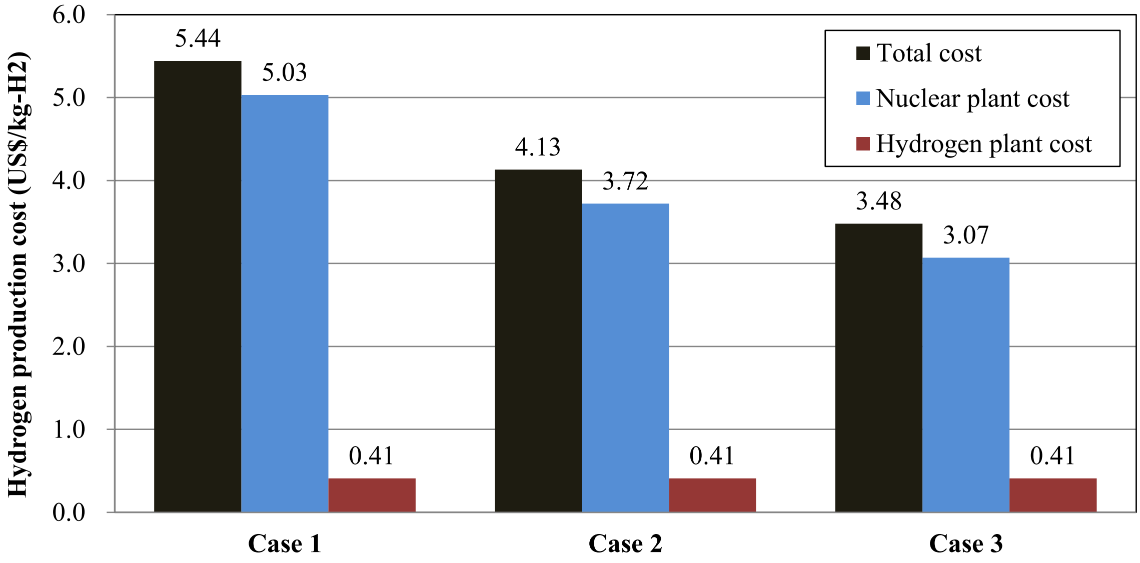


FIG. 55. Economy of scale for APWR based conventional electrolysis plants.

As seen in Table 41, when the capacity of the nuclear plants is increased by a factor of about 3 from Case 1 to Case 3, the corresponding levelized cost of electricity calculated with HEEP and used in the above hydrogen cost estimation, decreases by a factor of 1.66 from US $10.1/kW·h to US $6.1/kW·h, approximating the pace of reduction in the hydrogen cost above. This reduction seems to be attributable to the `economy of scale` expected to be achieved in the practice of power plant construction and operation. As such, both capital cost and O&M cost respond sensitively to the change of capacity among three generic cases considered here..

Table 41 includes another case of LWR cost estimate that was reportedly the reference cost of the utility operational reactors in Japan in 2004. The cost components in Japan's case are rather different from the HEEP cases. While about 75% of the power generation cost is attributed to the capital component in the HEEP cases, this share is reduce to 39% in Japan's practice. The overall power generation cost of Case 3, whose unit reactor capacity is closest to Japan's reference case, is 38% higher than Japan's case. Under the cost conditions in Japan's case, the hydrogen production cost would be US $2.63/kg-$H_2$.

TABLE 41. POWER GENERATION COSTS

	Case 1 APWR 2×359.5 MW(e)	Case 2 APWR 2×719 MW(e)	Case 3 APWR 2×1117.1 MW(e)	Japan reference LWR 1300 MW(e)
Capital cost	7.6	5.6	4.6	1.72
Fuel	0.6	0.4	0.4	1.23
O&M	1.7	1.2	1.0	1.42
Decommission	0.2	0.2	0.1	0.05
Total (US¢/kW·h)	10.1	7.4	6.1	4.42

4.2.3.2.Choice of hydrogen production technology

Note that Cases 1, 4a and 5 provide various combinations of nuclear reactors and hydrogen generation technologies while producing the same rate of hydrogen production. These cases are therefore used here to assess the ability of HEEP to analyse the influence of the overall nuclear hydrogen processes.

The HEEP results in Fig. 56, calculated based on the HEEP default financial parameters, show that the cost of nuclear hydrogen production depends strongly on the specific processes used for hydrogen generation with similar hydrogen production rate. Case 1 of coupling APWRs to the conventional electrolysis process appears to be the most expensive method for hydrogen generation comparing to the HTGR-based Case 4a and Case 5.

The cost of hydrogen in Case 1 is 83% greater than in Case 5. There are two major factors for the significant cost disadvantage for Case 1. APWR is relatively capital cost intensive due to relative design complexity to the HTGR. This is exasperated by the small-size of the APWR unit in this particular case. The overnight construction cost as input to the calculation is about 5 times the cost of Case 5. The second major factor is that the lower overall hydrogen production efficiency of 26.1% in Case 1 comparing to 42.2% in Case 5. To produce the same rate of hydrogen, a larger specific thermal rating is required for the APWR in Case 1.

The results are the opposite for comparison of the hydrogen plants. The specific cost of the CE facility in Case 1 due to the relative design simplicity is 60% less than the cost of thermochemical S–I process of Case 5.

On the other hand, the comparative analysis of Case 4a and Case 5 shows a similar range of hydrogen production costs. The 15% cost advantage of Case 4a comes mainly from the fact that the thermal efficiency of the HTSE hydrogen production process used in Case 4a is 52.0% relative to 42.2% in Case 5. The higher thermal efficiency in Case 4a reduces the unit thermal capacity of the reactor required and thus lowers the capital cost of the both nuclear reactor plant and hydrogen plant. The second, less significantly, factor is that the electricity required in Case 4a is co-generated in the nuclear plant at the HEEP calculated cost of US¢4.1/kW·h while the non-process electricity consumed in Case 5 is assumed to be imported from grid at a cost of US¢7.2/kW·h as input to the HEEP calculation.

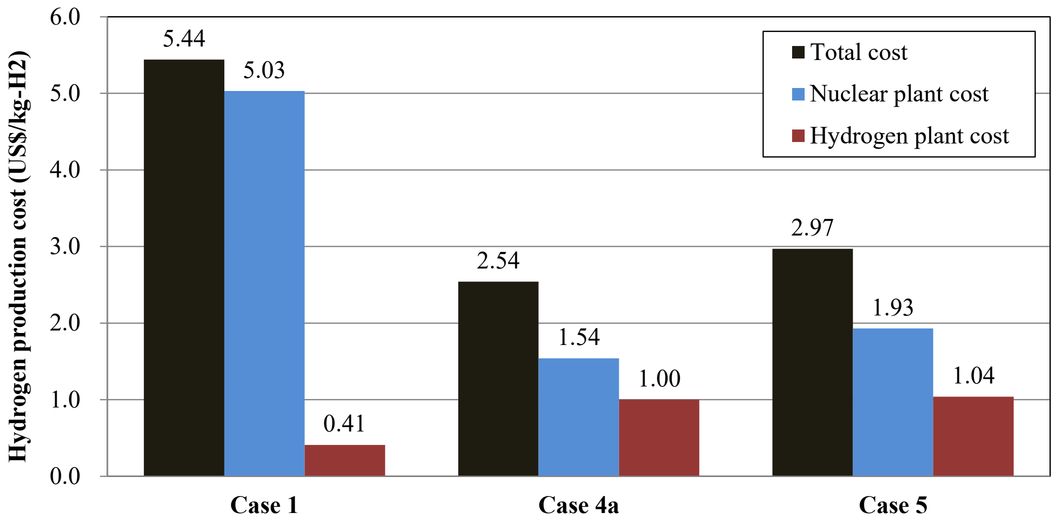


FIG. 56. Impact of technology on hydrogen production costs

4.2.3.3. Sensitivity to financial parameters

The hydrogen cost appears sensitive to the values of financial parameters assumed. Fig. 57 compares the nominal costs of hydrogen production using the two sets of the financial parameter values given in Table 38. It is seen that the APWR-based plants, because of their larger contribution of nuclear plant relative to hydrogen plant to the final hydrogen product cost, appear more sensitive to the assumed values of financial parameters than the HTGR-based plants. In the case of 2×360 MW(e) APWR, the difference in final hydrogen nominal cost is 31% between the HEEP default values and Japan's financial parameter values. In the case of 2×631 MW(th) HTGR-SI, this difference is narrowed to about 12%.

The most significant parameter affecting the final hydrogen production cost is the equity to debt ratio to finance the nuclear plant construction as detailed in Table 42. The other important parameters appear to be interest rate and discount rate. On the other hand, the tax rate and depreciation period appear to have relatively small effects on the hydrogen product cost. Seen from the tabulated values, the more capital intensive APWR+CE appears significantly more sensitive to financial parameters than does the less capital intensive HTGR+SI.

The analysis here focuses on the sensitivity of hydrogen production cost to the difference of financial parameters between the HEEP default values and the Japanese set of values. Some of the conclusions to be drawn from other sets of country-specific financial values might differ considerably as analysed in the following section.

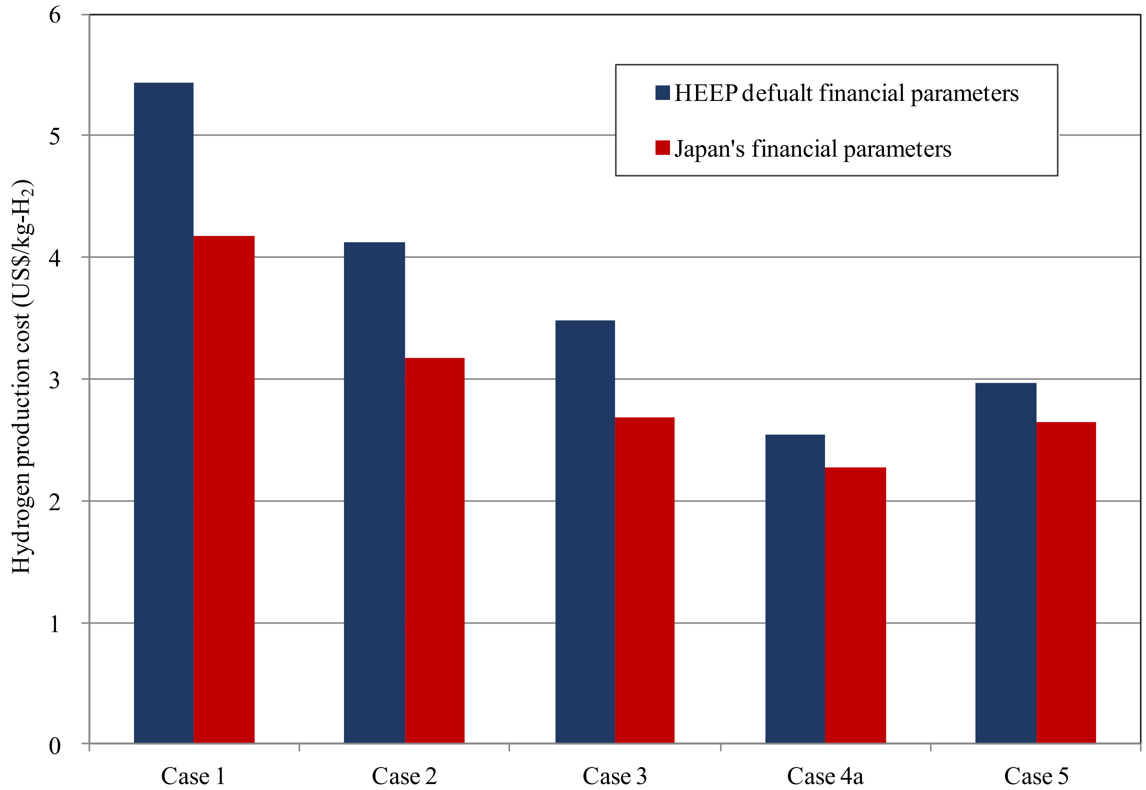


FIG. 57. Sensitivity of hydrogen nominal costs to financial parameters for the generic cases

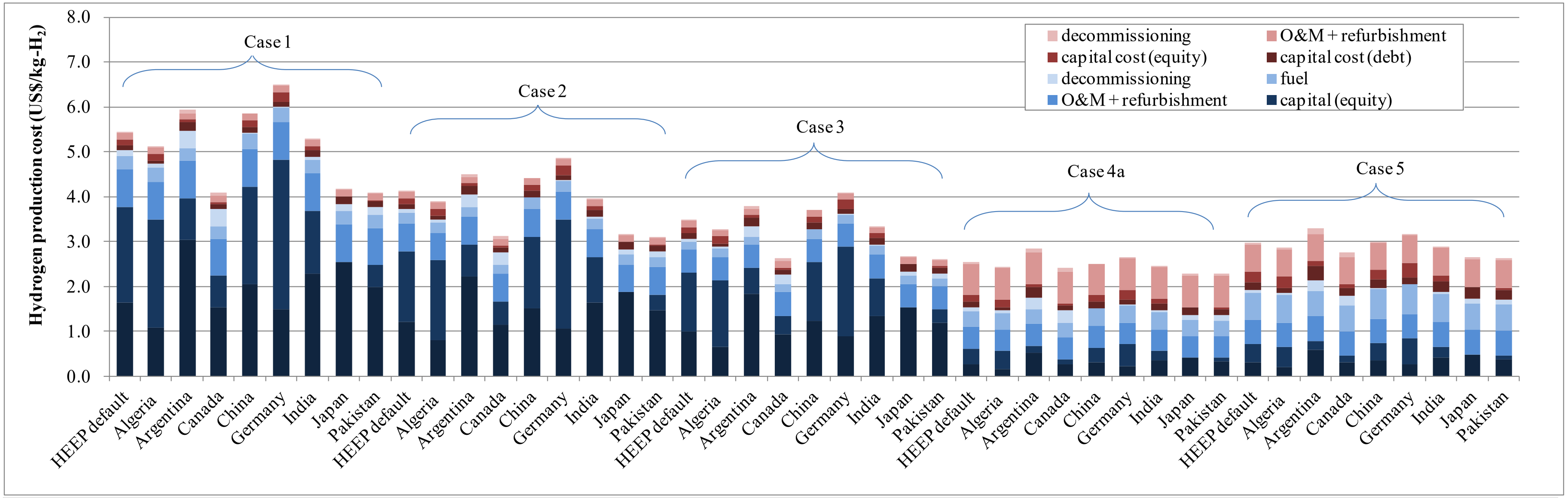
TABLE 42. SENSITIVITY OF HYDROGEN PRODUCTION COST TO FINANCIAL PARAMETERS

	HEEP default financial parameters	Japan's financial parameters	Cost difference due to changing from HEEP default to Japan's financial parameters			
			Nominal cost		Real cost	
			Case 1	Case 5	Case 1	Case 5
Discount rate (%)	5	3	-12.8%	-4.4%	-13.6%	-5.7%
Inflation rate (%)	1	0	+12.1%	+5.4%	0	0
Finance Equity:Debt (%)	70:30	0:100	+33.2%	+16.8%	+31.4%	+16.9%
Borrowing interest (%)	10	3	-19.4%	-9.7%	-18.8%	-10.2%
Tax rate (%)	10	1.4	-0.9%	-0.3%	-1.3%	-0.6%
Depreciation period (year)	20	20	-	-	-	-

4.2.3.4. Effect of country specific financing conditions

The financial parameters among the Member States vary considerably without any countries sharing the same set of financial values. The extent of their impact of the varying financing conditions on final hydrogen cost is found dependent on the technologies considered. This is illustrated in Fig 58. The largest impact is seen on Case 1 where the maximum difference is US $2.38/kg-H2 between Germany's upper end of US $6.48/kg-H2 and Pakistan's lower end of US $4.10/kg-H2. On the other hand, the impact of country-specific financing values is reduced to US $0.53/kg-H2 or less on the HTGR-based Case 4a and Case 5.

It is interesting to note that the ranking of final hydrogen cost between country remains to be same despite the large disparity of financing conditions of Member countries. Figure 59 compares the ranking of three selected countries, Germany, Algeria and Pakistan that represent the highest, medium and lowest ranges of hydrogen production costs. In the case of Algeria, the order of the technologies ranking from the highest to the lowest cost of hydrogen production is Case 1, Case 2, Case 3, Case 5 and Case 4a. This ranking remains unchanged for Germany and Pakistan, and is representative of all countries considered here. This confirms that HEEP provides a useful tool for technology decision makers in the selection of technologies for deployment in a country.



Cases ->	Case 1 (2x359.5 MWe APWR+CE, H2 rate 4.0 kg/s)								
Financial parameters ->	HEEP default	Algeria	Argentina	Canada	China	Germany	India	Japan	Pakistan
Nuclear plant cost									
capital (debt)	1.64	1.08	3.03	1.54	2.06	1.49	2.28	2.55	1.99
capital (equity)	2.14	2.42	0.94	0.70	2.17	3.33	1.41	0.00	0.48
O&M + refurbishment	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83	0.83
decommissioning	0.12	0.09	0.38	0.38	0.02	0.03	0.06	0.16	0.17
fuel	0.30	0.31	0.28	0.28	0.34	0.33	0.31	0.30	0.30
Total ($/kg-$H_2$)	5.03	4.73	5.46	3.73	5.42	6.01	4.89	3.84	3.77
Hydrogen plant cost									
capital cost (debt)	0.11	0.07	0.20	0.10	0.14	0.10	0.15	0.17	0.13
capital cost (equity)	0.14	0.16	0.06	0.05	0.15	0.22	0.09	0.00	0.03
O&M + refurbishment	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
decommissioning	0.02	0.02	0.07	0.07	0.00	0.01	0.01	0.03	0.03
Total ($/kg-$H_2$)	0.41	0.39	0.47	0.36	0.43	0.47	0.39	0.34	0.33
Total H2 production cost($/kg-$H_2$)	5.44	5.12	5.93	4.09	5.85	6.48	5.28	4.18	4.10

Cases ->	Case 2 (2x719.0 MWe APWR+CE, H2 rate 8.0 kg/s)								
Financial parameters ->	HEEP default	Algeria	Argentina	Canada	China	Germany	India	Japan	Pakistan
Nuclear plant cost									
capital (debt)	1.21	0.80	2.23	1.14	1.51	1.07	1.64	1.87	1.46
capital (equity)	1.58	1.78	0.70	0.52	1.60	2.43	1.02	0.00	0.36
O&M + refurbishment	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
decommissioning	0.09	0.07	0.28	0.28	0.01	0.02	0.05	0.12	0.12
fuel	0.22	0.23	0.21	0.21	0.25	0.24	0.23	0.22	0.22
Total ($/kg-$H_2$)	3.72	3.50	4.04	2.77	3.99	4.38	3.56	2.83	2.78
Hydrogen plant cost									
capital cost (debt)	0.11	0.07	0.20	0.10	0.14	0.10	0.15	0.17	0.13
capital cost (equity)	0.14	0.16	0.06	0.05	0.14	0.22	0.09	0.00	0.03
O&M + refurbishment	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
decommissioning	0.02	0.02	0.07	0.07	0.00	0.01	0.01	0.03	0.03
Total ($/kg-$H_2$)	0.41	0.39	0.47	0.36	0.42	0.47	0.39	0.34	0.33
Total H2 production cost($/kg-$H_2$)	4.13	3.89	4.51	3.13	4.41	4.85	3.95	3.17	3.11

Cases ->	Case 3 (2x1117.1 MWe APWR+CE, H2 rate 12.43 kg/s)								
Financial parameters ->	HEEP default	Algeria	Argentina	Canada	China	Germany	India	Japan	Pakistan
Nuclear plant cost									
capital (debt)	1.00	0.66	1.84	0.93	1.24	0.88	1.35	1.54	1.20
capital (equity)	1.30	1.47	0.57	0.42	1.31	2.00	0.84	0.00	0.29
O&M + refurbishment	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
decommissioning	0.07	0.05	0.23	0.23	0.01	0.02	0.04	0.10	0.10
fuel	0.18	0.19	0.17	0.17	0.20	0.20	0.19	0.18	0.18
Total ($/kg-$H_2$)	3.07	2.89	3.33	2.27	3.28	3.62	2.94	2.34	2.29
Hydrogen plant cost									
capital cost (debt)	0.11	0.07	0.20	0.10	0.14	0.10	0.15	0.17	0.13
capital cost (equity)	0.14	0.16	0.06	0.05	0.14	0.22	0.09	0.00	0.03
O&M + refurbishment	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
decommissioning	0.02	0.02	0.07	0.07	0.00	0.01	0.01	0.03	0.03
Total ($/kg-$H_2$)	0.41	0.39	0.47	0.36	0.42	0.47	0.39	0.34	0.33
Total H2 production cost($/kg-$H_2$)	3.48	3.28	3.80	2.63	3.70	4.09	3.33	2.68	2.62

Cases ->	Case 4a (2x509.3 MWt HTGR+HTSE, H2 rate 4.0 kg/s)								
Financial parameters ->	HEEP default	Algeria	Argentina	Canada	China	Germany	India	Japan	Pakistan
Nuclear plant cost									
capital (debt)	0.27	0.17	0.52	0.26	0.31	0.22	0.35	0.42	0.33
capital (equity)	0.35	0.39	0.16	0.12	0.33	0.50	0.22	0.00	0.08
O&M + refurbishment	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
decommissioning	0.09	0.06	0.27	0.27	0.01	0.02	0.05	0.11	0.12
fuel	0.35	0.36	0.33	0.33	0.39	0.38	0.37	0.35	0.35
Total ($/kg-$H_2$)	1.54	1.46	1.76	1.46	1.52	1.60	1.47	1.36	1.36
Hydrogen plant cost									
capital cost (debt)	0.12	0.08	0.23	0.12	0.14	0.10	0.16	0.18	0.14
capital cost (equity)	0.15	0.17	0.07	0.05	0.15	0.23	0.10	0.00	0.04
O&M + refurbishment	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
decommissioning	0.03	0.02	0.08	0.08	0.00	0.01	0.01	0.04	0.04
Total ($/kg-$H_2$)	1.00	0.97	1.08	0.95	0.99	1.04	0.97	0.92	0.92
Total H2 production cost($/kg-$H_2$)	2.54	2.43	2.84	2.41	2.51	2.64	2.44	2.28	2.28

Cases ->	Case 5 (2x630.7 MWt HTGR+SI, H2 rate 4.0 kg/s)								
Financial parameters ->	HEEP default	Algeria	Argentina	Canada	China	Germany	India	Japan	Pakistan
Nuclear plant cost									
capital (debt)	0.31	0.20	0.60	0.31	0.35	0.26	0.41	0.48	0.38
capital (equity)	0.40	0.45	0.19	0.14	0.38	0.58	0.25	0.00	0.09
O&M + refurbishment	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
decommissioning	0.07	0.05	0.22	0.22	0.01	0.02	0.04	0.10	0.10
fuel	0.60	0.61	0.57	0.57	0.67	0.65	0.63	0.59	0.59
Total ($/kg-$H_2$)	1.93	1.86	2.13	1.79	1.96	2.06	1.88	1.72	1.71
Hydrogen plant cost									
capital cost (debt)	0.17	0.11	0.33	0.17	0.20	0.14	0.23	0.27	0.21
capital cost (equity)	0.22	0.25	0.10	0.08	0.21	0.33	0.14	0.00	0.05
O&M + refurbishment	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61
decommissioning	0.04	0.03	0.12	0.12	0.01	0.01	0.02	0.05	0.05
Total ($/kg-$H_2$)	1.04	1.00	1.16	0.98	1.03	1.09	1.00	0.93	0.92
Total H2 production cost($/kg-$H_2$)	2.97	2.86	3.29	2.77	2.99	3.15	2.88	2.65	2.63

FIG. 58. Sensitivity of hydrogen production costs to country specific financing conditions

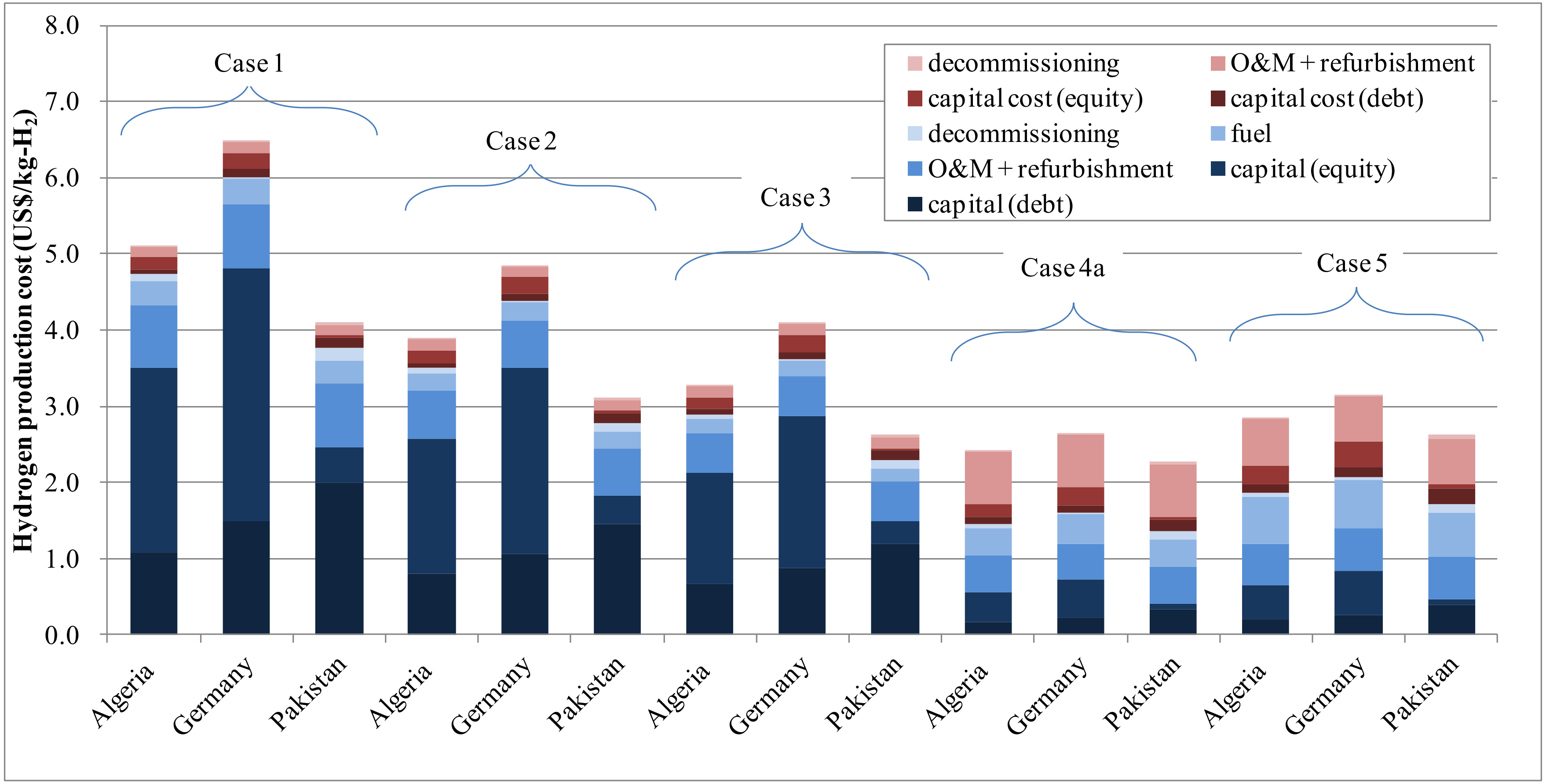


FIG. 59. Hydrogen production costs estimated using country specific financing parameters

4.3. BENCHMARK WITH H2A CODE

The H2A is a spreadsheet code developed in the U.S. Department of Energy (DOE) under the Hydrogen and Fuel Cells Program. A description of the code can be found in Chapter 3.

4.3.1. Benchmark cases

During first RCM of the CRP "Examining the Techno-Economics of Nuclear Hydrogen Production and Benchmark Analysis of the IAEA HEEP Software", five combinations of nuclear power plant and hydrogen generating processes were identified for benchmarking of the IAEA software tool HEEP (Minutes of 1st RCM on CRP Examining the Techno-Economics of Nuclear Hydrogen Production and Benchmark Analysis of the IAEA HEEP Software). During this meeting, it was agreed to use following information on technical features, construction time and cost components provided in Table 43 for estimation of hydrogen cost.

TABLE 43. DETAILS OF CASES IDENTIFIED FOR BENCHMARKING EXERCISE

	Case-1	Case-2	Case-3	Case-4	Case-5
Common parameters for both nuclear power plant & hydrogen production plant					
Capacity factor	93%	93%	93%	90%	90%
Construction period	5 years	5 years	5 years	3 years	3 years
Nuclear power plant details					
Reactor type	APWR	APWR	APWR (AP1000)	HTGR	HTGR
Capacity	359.5 MW(e)	719 MW(e)	1117 MW(e)	509.3 MW(th)	630.7 MW(th)
Number of units	2	2	2	2	2
Capital investment	$6310 M	$9313 M	$11 928 M	$804.6 M	$1210 M
Annual O&M	$104.9 M (1.66%)	$154.8 M (1.66%)	$198.28 M (1.66%)	$46.96 M (5.83%)	$21.97 M (1.82%)
Annual fuel cost	$34.96 M	$51.6 M	$66.09 M	$38.24 M	$69.73 M
Decommissioning cost	2.8% of Capital cost	2.8% of Capital cost	2.8% of Capital cost	$94.04 M	$101 M
Hydrogen production plant details					
Process type	Electrolysis	Electrolysis	Electrolysis	HTSE	S–I
Hydrogen generation	4 kg/s	8 kg/s	12 kg/s	4 kg/s	4 kg/s
Capital cost	$422.6 M	$846.2 M	$ 1313 M	$458.5 M	$666.2 M
Non-process electricity requirement					42.8 MW(e)
Annual O&M expenses	$16.9 M (4%)	$33.81 M (4%)	$52.52 M (4%)	$79.04 M (17.24%)	$44.52 M (6.68%)
Demineralized water consumption	1.136×10^9 L/year	2.272×10^9 L/year	3.530×10^9 L/year	1.136×10^9 L/year	
Decommissioning cost	10% of capital cost	10% of capital cost	10% of capital cost	10% of capital cost	10% of capital cost

As per the information compiled during first RCM, the cost for disposal of nuclear fuel is considered to be included in the annual fuel cost. Further, the thermal efficiency of nuclear power plants in Cases 1 to 3 is considered as 33% and efficiency of electrolyser to generate hydrogen is considered as 79% w.r.t. electrical energy. In the absence of relevant information, default values for techno-economic parameters given in Table 44 are considered for the assessment using HEEP.

TABLE 44. DETAILS OF DEFAULT VALUES OF PARAMETERS

Fiscal parameters		
1.	Nominal discount rate	5%
2.	Inflation rate	1%
3.	Equity to Debt ratio	70:30
4.	Interest on borrowings	10%
5.	Tax rate	10%
6.	Depreciation period	20 years
7.	Return period for market borrowing	40 years
8.	Cash flow during construction period	Equally distributed
Important time periods		
9.	Operating life	40 years
10.	Cooling before decommissioning	2 years
11.	Decommissioning period	10 years

During the first RCM, a lump sum of annual fuel cost for the nuclear power plant was provided. However, HEEP models the fuel cost through the cost of fuel per unit weight. Thus, based on the anticipated initial fuel load as well as annual fuel consumption, the fuel cost per kg was derived from the annual fuel cost given in Table 45. The values of initial fuel load and annual fuel consumption considered for all five cases are given in Table 45. For batch type annual loading, it is further assumed that one-third core is replaced during each re-loading, as done for many operating PWRs.

TABLE 45. DETAILS OF FUEL COST PARAMETERS

	Case-1	Case-2	Case-3	Case-4	Case-5
Initial fuel load per unit	27 000 kg	54 000 kg	75 000 kg	14 000 kg	18 000 kg
Annual fuel consumption per unit	9000 kg	18 000 kg	25 000 kg	5000 kg	6000 kg
Rate of fuel $/kg	1850	1365	1260	3660	5535

Hydrogen generation in three cases, viz. Case-1 to Case-3, employs the conventional electrolysis process. This process requires energy in the form of electricity only. The nuclear power plant co-located with hydrogen generation plant is considered to produce only electricity for these three cases.

Case-4 deals with a combination of nuclear power plant and hydrogen plant which operates on high temperature steam electrolysis process. The process requires electricity. However, no information on electricity required by the process was available. In absence of this information, supply of heat energy alone from nuclear power plant is considered in HEEP. In such circumstance, user has to provide energy usage cost to meet the electricity demand to operate hydrogen plant. However, it is further assumed that the cost of electricity purchase from grid is included in the total O&M cost. This is assumed as the O&M cost per unit of hydrogen produced for hydrogen plant based on high temperature steam electrolysis was found to be 5 time higher than plants operating on conventional electrolysis process. Hence, the energy usage cost, which covers the cost of external electricity usage at market rate, has not been considered separately, but considered to be included in the annual O&M cost. It should be noted here that this cost is expected to be substantial contributor to the final cost of hydrogen.

Hydrogen generation in Case-5 uses the high temperature S–I process. As per the information compiled, the hydrogen generation plant consumes electric power of 42.8 MW(e). It is assumed that the electricity is obtained from the grid at \$0.072 /kW·h, in both H2A and HEEP.

4.3.2. Benchmark results

With the same inputs, hydrogen cost is estimated using another software tool H2A. This tool was downloaded from the internet. Table 46 gives comparison between results generated by HEEP and H2A.

TABLE 46. COMPARISON OF HYDROGEN COST ESTIMATED BY HEEP AND H2A

	Case-1	Case-2	Case-3	Case-4	Case-5
HEEP results	\$5.44	\$4.13	\$3.48	\$2.54	\$2.97
H2A results	\$5.32	\$4.03	\$3.39	\$2.21	\$2.53

The levelized hydrogen cost estimated by HEEP closely matches with that estimated by H2A. The range of variation is from \$0.14 to \$0.03 per kg of hydrogen.

In Cases 1 to 3, the construction period specified is 5 years. H2A cannot account for construction period more than 4 years. Hence, the cost estimated by H2A model is with an assumption of 4 years construction period while that from HEEP is with 5 year construction period. For Cases 4 and 5, where construction period considered is same for both HEEP and H2A estimations, the match between the results obtained from H2A and HEEP are in excellent agreement being within 16%.

When the construction period for Case 1 to 3 is reduced to 4 years in HEEP, it was observed that the match improves. The variation reduces from \$0.14 to \$0.05. The comparison is given in Table 47.

TABLE 47. COMPARISON OF HYDROGEN COST ESTIMATED BY HEEP AND H2A

	Case-1	Case-2	Case-3
HEEP results	\$5.37	\$4.08	\$3.44
H2A results	\$5.32	\$4.03	\$3.39

These results indicate that the underlying mathematical models and the programming of HEEP are accurate, and flexible enough, to analyse any nuclear hydrogen generation scenario.

4.4. BENCHMARK WITH G4-ECONS CODE

G4-ECONS is a spreadsheet program developed by the Economic Modelling Working Group of the Generation IV International Forum. A description of this code can be found in Chapter 3.

4.4.1. Benchmark cases

For benchmarking HEEP program, with G4-ECONS program the 5 generic cases were run.

4.4.2. Benchmark results

4.4.2.1.Generic Case 1

Generic case 1 is a small scale nuclear hydrogen production plant by CE (Conventional Electrolysis) combined with APWR(Advanced Pressurized Water Reactor) of which reactor capacity is 2×359.5 MW(e) and hydrogen production rate is 4 kg/sec, respectively.

The input data for generic case 1 with HEEP is displayed in Table 48. LUHC for case 1 with HEEP calculation is \$5.6/kg.

As previously explained, the “energy usage cost” is an input data for HPP in HEEP. Only if the energy needed in HPP exceeds the thermal and/or electrical output of the reactor, the “energy usage cost” will be entered. This is the reason we have input data for “energy usage cost” is \`zero\`in this case.

On the other hand, G4-ECONS Input Data for Generic Case 1 are shown in Table 49.

In G4-ECONS, SEPC (Specific Electric Power Consumption) for HPP is needed as an input data. This value expresses the electrical energy required per unit of hydrogen produced. Technical analysis of the process or experimental data is needed to determine this value. This value is calculated from the given information to be 4.81 kW(e)h/m^3 H2. Using above input data, energy consumption in HPP is 5.86E+09 kW(e)h/year. Using above input data, LUEC and LUHC for generic case 1 with G4-ECONS is 40 mills/kW(e)h and \$5.41/kg H2, respectively.

TABLE 48. HEEP INPUT DATA AND OUTPUT RESULT FOR GENERIC CASE 1

APWR		Conventional Electrolysis	
Thermal Rating (MW(th)/unit	1089.4	Hydrogen Production Rate(kg/year)	1.26×10^8
Heat for H2 Plant (MW(th)/unit	0	Heat Consumption (MW(th)/unit)	0
Electricity Rating (MW(e)/unit	360	Electricity Required (MW(e)/unit)	719
Number of Units	2	Number of Units	1
Initial Fuel Load (kg/unit)	27 000	Capital Cost ($/unit)	4.23×10^8
Annual Fuel feed (kg/unit)	9 000	Energy Usage Cost ($)	0
Capital Cost ($/unit)	3.16×10^9	O&M Cost (% of capital cost)	4
Capital cost fraction for electricity generation infrastructure	10	Decommissioning cost (% of capital cost)	10
Fuel Cost ($/kg)	1 850		
O&M Cost (% of capital cost)	1.66		
Decommissioning cost (% of capital cost)	2.8		

TABLE 49. G4-ECONS INPUT DATA FOR GENERIC CASE 1

APWR		Conventional Electrolysis	
Reactor Capacity(MW(e))	2×359.5	Hydrogen Production Rate(kg/sec)	4
Capital Cost ($M)	6320	Capital Cost ($M)	845
Annual O&M Cost (M$/year)	104.9	Annual O&M Cost (M$/year)	33.8
Annual Fuel Cost (M$/year)	33.3	D&D Cost($ M)	84.5
D&D Cost($ M)	17.70	SEPC(Specific Electric Power Consumption) for Hydrogen Plant(KW(e)h/m^3 H_2)	4.81
Initial Fuel Load (kg)	54 000	STPC(Specific Thermal Power Consumption) for Hydrogen Plant(KW(th)h/m^3 H_2)	-
Annual Fuel Consumption (kg/y)	18 000		
Rate of finished fuel($/kg)	1850		

4.4.2.2.Generic Case 2

Generic case 2 is a small scale nuclear hydrogen production plant by CE combined with APWR of which reactor capacity is 2×719.0 MW(e) and hydrogen production rate is 8 kg/sec, respectively. The input data for generic case 2 with HEEP is shown in Table 50. LUHC for case 2 with HEEP calculation is $4.25/kg.

TABLE 50. HEEP INPUT DATA AND OUTPUT RESULT FOR GENERIC CASE 2

APWR		Conventional Electrolysis	
Thermal Rating (MW(th)/unit	2178.8	Hydrogen Production Rate(kg/year)	2.52×10^8
Heat for H2 Plant (MW(th)/unit	0	Heat Consumption (MW(th)/unit)	0
Electricity Rating (MW(e)/unit	719	Electricity Required (MW(e)/unit)	1 438
Number of Units	2	Number of Units	1
Initial Fuel Load (kg/unit)	54 000	Capital Cost ($/unit)	8.45×10^8
Annual Fuel feed (kg/unit)	18 000	Energy Usage Cost ($)	0
Capital Cost ($/unit)	4.66×10^9	O&M Cost (%)	4
Capital cost fraction for electricity generation infrastructure	10	Decommissioning cost (% of capital cost)	10
Fuel Cost ($/kg)	1 365		
O&M Cost (% of capital cost)	1.66		
Decommissioning cost (% of capital cost)	2.8		

On the other hand, G4-ECONS Input Data for Generic Case 2 are displayed in Table 51.

Initial Fuel Cost = 108 000 × 1365 =147.42 M$
Annual Fuel Cost = 36 000 ×1365=49.14 M$

In generic case 2, SEPC for HPP is calculated to be 4.81 kW(e)h/m^3 H2 from the given information. Using above input data, the results for generic case 2 with G4-ECONS are:

Energy Consumption in Hydrogen Plant = SEPC * HPR * capacity factor = 1.17E+10 kW(e)h/year

Unit Energy Cost from Reactor: 66.87 mills/kW(e)h.
Annual Energy Cost :783.34 $M/year
LUHC from G4-ECONS : $4.17/kg H_2 (Electricity supplied at cost of 66.87$/MWh)

TABLE 51. G4-ECONS INPUT DATA FOR GENERIC CASE 2

APWR		Conventional Electrolysis	
Reactor Capacity(MW(e))	2×719	Hydrogen Production Rate (kg/sec)	8
Capital Cost ($M)	9 320	Capital Cost ($M)	845.2
Annual O&M Cost (M$/year)	154.7	Annual O&M Cost (M$/year)	33.8
Annual Fuel Cost (M$/year)	49.14	D&D Cost($ M)	84.5
D&D Cost($ M)	260.9	SEPC (Specific Electric Power Consumption) for Hydrogen Plant(KW(e)h/m^3 H_2)	4.81
Initial Fuel Load (kg)	108 000	STPC(Specific Thermal Power Consumption) for Hydrogen Plant	-
Annual Fuel Consumption (kg/y)	36 000		
Rate of finished fuel($/kg)	1365		

4.4.2.3.Generic Case 3

Generic case 3 is a small scale nuclear hydrogen production plant by CE combined with APWR of which reactor capacity is 2 × 1117 MW(e) and hydrogen production rate is 12 kg/sec, respectively. It is assumed that all the electricity produced by the reactor is used to produce hydrogen by electrolysis with 93% capacity factor. The input data for generic case 3 with HEEP is as in Table 52. LUHC for case 3 with HEEP calculation is \$3.70/kg.

TABLE 52. HEEP INPUT DATA AND OUTPUT RESULT FOR GENERIC CASE 3

APWR		Conventional Electrolysis	
Thermal Rating (MW(th)/unit	3 384.8	Hydrogen Production Rate(kg/year)	3.78×10^8
Heat for H_2 Plant (MW(th)/unit	0	Heat Consumption (MW(th)/unit)	0
Electricity Rating (MW(e)/unit	1 117	Electricity Required (MW(e)/unit)	2 234
Number of Units	2	Number of Units	1
Initial Fuel Load (kg/unit)	75 000	Capital Cost (\$/unit)	1.31×10^9
Annual Fuel feed (kg/unit)	25 000	Energy Usage Cost (\$)	1.66×10^4
Capital Cost (\$/unit)	5.96×10^9	O&M Cost (% of capital cost)	4
Capital cost fraction for electricity generation infrastructure	10	Decommissioning cost (% of capital cost)	10
Fuel Cost (\$/kg)	1 260		
O&M Cost (% of capital cost)	1.66		
Decommissioning cost (% of capital cost)	2.8		

On the other hand, G4-ECONS Input Data for Generic Case 3 are displayed in Table 53.

TABLE 53. G4-ECONS INPUT DATA FOR GENERIC CASE 3

APWR		Conventional Electrolysis	
Reactor Capacity(MW(e))	2 × 1117	Hydrogen Production rate (kg/sec)	12
Capital Cost (\$M)	11 920	Capital Cost (\$M)	1 310
Annual O&M Cost (M\$/year)	197.8	Annual O&M Cost (M\$/year)	52.4
Annual Fuel Cost (M\$/year)	63.0	D&D Cost(\$ M)	131
D&D Cost(\$ M)	333.8	SEPC (Specific Electric Power Consumption) for Hydrogen Plant(KW(e)h/m^3 H_2)	4.79
Initial Fuel Load (kg)	150 000	STPC (Specific Thermal Power Consumption) for Hydrogen Plant(KW(th)h/m^3 H_2)	-
Annual Fuel Consumption (kg/y)	50 000		
Rate of finished fuel(\$/kg)	1260		

Initial Fuel Cost = 150 000 × 1260 =189 M$

Annual Fuel Cost = 50 000 × 1260 = 63 M$

In generic case 3, SEPC for HPP is calculated to be 4.79 kW(e)h/m^3 H_2 from the given information. Using above input data, the results for generic case 3 with G4-ECONS are:

Energy Consumption in Hydrogen Plant = SEPC * HPR *CF = 1.82E+10 kW(e)h/year

Unit Energy Cost from Reactor: 57.81 mills/kW (e)h

Annual Energy Cost: 1052.17 $M/year

LUHC from G4-ECONS: $3.39/kg H_2 (Electricity supplied at cost of $57.81/MWh)

4.4.2.4.Generic Case 4

Generic case 4 is a small scale nuclear hydrogen production plant by HTSE (High Temperature Steam Electrolysis combined with HTGR (High Temperature Gas Reactor) of which reactor capacity is 2×509.3 MW(th) and hydrogen production rate is 4 kg/sec, respectively.

The input data for generic case 4 with HEEP is displayed in Table 54. LUHC for case 4 with HEEP calculation is $2.34/kg.

TABLE 54. HEEP INPUT DATA AND OUTPUT RESULT FOR GENERIC CASE 4

HTGR		HTSE	
Thermal Rating (MW(th)/unit	510	Hydrogen Production Rate(kg/year)	1.14×10^8
Heat for H_2 Plant (MW(th)/unit	510	Heat Consumption (MW(th)/unit)	1020
Electricity Rating (MW(e)/unit	0	Electricity Required (MW(e)/unit)	0
Number of Units	2	Number of Units	1
Initial Fuel Load (kg/unit)	14 000	Capital Cost ($/unit)	4.59×10^8
Annual Fuel feed (kg/unit)	5 000	Energy Usage Cost ($)	0
Capital Cost ($/unit)	4.02×10^8	O&M Cost (% of capital cost)	17.24
Capital cost fraction for electricity generation infrastructure	10	Decommissioning cost (% of capital cost)	10
Fuel Cost ($/kg)	3 660		
O&M Cost (% of capital cost)	5.84		
Decommissioning cost (% of capital cost)	10		

On the other hand, G4-ECONS Input Data for Generic Case 4 are displayed in Table 55.

TABLE 55. G4-ECONS INPUT DATA FOR GENERIC CASE 4

HTGR		HTSE	
Reactor Capacity(MW(th))	2 × 509.3	Hydrogen Production Rate (kg/sec)	4
Capital Cost ($M)	804.6	Capital Cost ($M)	458.5
Annual O&M Cost (M$/year)	5.84% of Capital Cost (=47.0)	Annual O&M Cost (M$/year)	79.13
Annual Fuel Cost (M$/year)	36.6	D&D Cost ($ M)	79.04
D&D Cost ($ M)	10 % of Capital Cost (= 80.5)	SEPC (Specific Electric Power Consumption) for Hydrogen Plant(KW(e)h/m^3 H_2)	2.90
Initial Fuel Load (kg)	28 000	STPC (Specific Thermal Power Consumption) for Hydrogen Plant(KW(th)h/m^3 H_2)	0.45
Annual Fuel Consumption (kg/y)	10 000		
Rate of finished fuel($/kg)	3660		

Initial Fuel Cost = 28 000 × 3660 =189 M$

Annual Fuel Cost = 10 000 × 3660 = 36.6 M$/year

In G4-ECONS, SEPC and STPC for HPP are needed as input data. The SEPC is calculated from the given information to be 2.90 kW(e)h/m^3 H_2 and STPC is calculated to be 0.60 kW(th)h/m^3 H_2.

Using above input data, the results with G4-ECONS are:

Energy Consumption in Hydrogen Plant = (SEPC + STPC) * HPR *CF = 4.13E+09 kW(e)h/year

Unit Energy Cost from Reactor: 38.08 mills/kW(e)h

Unit Thermal Energy Cost from reactor: 18.28 mills/kW(th)h

Annual Energy Cost: 134 $M/year

LUHC from G4-ECONS: $2.58/kg H_2 (Electricity supplied at cost of $38.08/MWh)

4.4.2.5.Generic Case 5

Generic case 5 is a small scale nuclear hydrogen production plant by S–I (Sulfur–Iodine) is combined with HTGR of which reactor capacity is 2×630.7 MW(th) and hydrogen production rate is 4 kg/sec, respectively. The input data and output result for generic case 5 with HEEP are shown in Table 56. LUHC for case 5 with HEEP calculation is $5.08/kg.

In generic case 5, it is assumed that electricity of 428 MW(e) is supplied to HPP from outside at cost of \$72/MWh. Hence, "Energy Usage Cost" in HEEP 72\$/MW(e)h X 428 MW(e) × 8760 hrs/year = 269.95 M\$/year

On the other hand, G4-ECONS Input Data for Generic Case 5 are shown in Table 57.

Initial Fuel Cost = 36 000 × 5535 =199.26 M\$

Annual fuel cost: 12 000 × 5535= 66.42 M\$

In the generic case5, SEPC is calculated from the given information to be 3.80 kW(e)h/m^3 H_2.

Using above input data, the results with G4-ECONS are:

Energy Consumption in Hydrogen Plant = SEPC * HPR *CF = 4.48E+09 kW(e)h/year

Unit Electric Energy Cost from reactor: 35.66 mills/kW(e)h

Unit Thermal Energy Cost from reactor: 17.12 mills/kW(th)h

Energy Cost (Thermal Energy Cost + Electrical Energy Cost)= 81.73 \$M/year + 269.95 M\$/year

= 351.68 \$M/year

LUHC from G4-ECONS: \$4.77/kg H_2 (Electricity supplied at cost of \$37.96/MWh)

LUHC from G4-ECONS: \$4.77/kg H_2 based on the assumption that HPP is provided with electrical energy equal to the amount of 243 \$M/year from outside. If we assume no electrical supply from outside, the LUHC estimated from G4-ECONS and HEEP will drop to \$2.21/kg H_2 and \$2.71/kg H_2, respectively.

TABLE 56. HEEP INPUT DATA AND OUTPUT RESULT FOR GENERIC CASE 5

HTGR		S–I	
Thermal Rating (MW(th)/unit	630.7	Hydrogen Production Rate(kg/year)	1.14×10^8
Heat for H_2 Plant (MW(th)/unit	630.7	Heat Consumption (MW(th)/unit)	1 261.4
Electricity Rating (MW(e)/unit	0	Electricity Required (MW(e)/unit)	428
Number of Units	2	Number of Units	1
Initial Fuel Load (kg/unit)	18 000	Capital Cost (\$/unit)	6.66×10^8
Annual Fuel feed (kg/unit)	6 000	Energy Usage Cost (\$)	2.7×10^8
Capital Cost (\$/unit)	6.05×10^8	O&M Cost (% of capital cost)	6.68
Capital cost fraction for electricity generation infrastructure	0	Decommissioning cost (% of capital cost)	10
Fuel Cost (\$/kg)	5 535		
O&M Cost (% of capital cost)	1.82		
Decommissioning cost (% of capital cost)	10		

TABLE 57. G4-ECONS INPUT DATA FOR GENERIC CASE 5

HTGR		S–I	
Reactor Capacity(MW(th))	2 × 630.7	Hydrogen Production Rate (kg/sec)	4
Capital Cost ($M)	1210.0	Capital Cost ($M)	666.0
Annual O&M Cost (M$/year)	22.02	Annual O&M Cost (M$/year)	44.49
Annual Fuel Cost (M$/year)	66.42	D&D Cost ($ M)	66.6
D&D Cost ($ M) 10 % of Capital Cost	121.0	SEPC (Specific Electric Power Consumption) for Hydrogen Plant(KW(e)h/m³ H_2)	3.80
Initial Fuel Load (kg)	36 000	STPC (Specific Thermal Power Consumption) for Hydrogen Plant (KW(th)h/m³ H_2)	-
Annual Fuel Consumption (kg/y)	12 000		
Rate of finished fuel($/kg)	5535		

4.4.2.6.Detailed discussion

HEEP is very simple and easy program to deal with. It is understood that the nature and accuracy of input data is very important in evaluating economy using HEEP. For example, it is assumed that electricity of 428 MW(e) is supplied to HPP from outside at cost of $72/MWh in generic case 5 (HTGR+SI). Due to this electrical energy cost the LUHC in generic case 5 rises up to 5.08$/kg H_2, which is much higher than 2.34 $/kg H_2 of generic case 4 (HTGR+HTSE). Based on the assumption we used, it is possible to mislead you to conclude that HTSE is much more economical than S–I in hydrogen production. The erratic electricity consumption of Case 5 has been identified by the CRP and corrected to 42.8 MW(e), with which the LUHC predicted by HEEP and G4-ECONS are corrected to 2.95 $/kg H_2 and 2.47 $/kg H_2, respectively. Benchmark results of HEEP with G4-ECONS for 5 generic cases are summarized in Table 58 and Fig. 60.

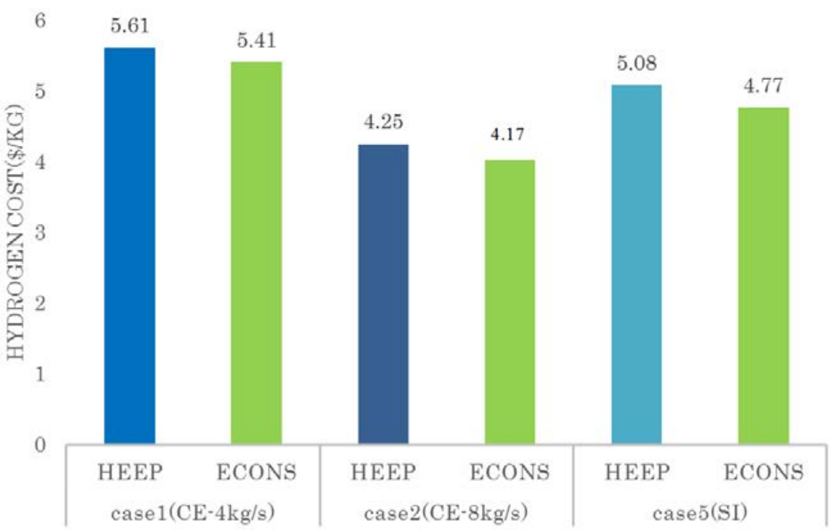


FIG. 60. Benchmark Results of HEEP with G4-ECONS for 5 Generic Cases

As shown in the Table 58, the LUHC calculated from G4-ECONS is 1.9% ~8.4% lower than those from HEEP for all generic cases except for generic case4 where LUHC from G4-ECONS is 5% higher than that from HEEP.

HTSE uses both energy and heat to produce hydrogen. With G4-ECONS calculation, the thermal energy used in HTSE is 7.08E+08 kW(th)h which is equal to 3.40E+08 kW(e)h. However, this thermal energy cost is not counted in HEEP as input for "Energy Usage Cost" and as a result we have lower LUHC in HEEP than in G4-ECONS for generic case 4. For cases 1~3, where nuclear hydrogen production is done by conventional electrolysis, the results by HEEP and G4-ECONS are presented in Fig. 61 and Fig. 62, respectively. The result shows that LUHC calculated by HEEP and G4-ECONS are pretty close to each other for cases 1~3.

TABLE 58. BENCHMARK RESULTS OF HEEP WITH G4-ECONS FOR 5 GENERIC CASES

		Generic Case 1	Generic Case 2	Generic Case 3	Generic Case 4	Generic Case 5
G4-ECONS	LUEC	\$90.40 /MWh	\$66.87 /MWh	\$57.81/MWh	\$35.66/MWh	\$37.96 MW h
	LUHC	\$5.41 /kg	\$4.17 /kg	\$3.39 /kg	\$2.58 /kg	\$2.47 /kg
HEEP	NPP	\$5.17 /kg	\$3.81 /kg	\$3.25 /kg	\$1.26 /kg	\$1.78 /kg
	HPP	\$0.44 /kg	\$0.44 /kg	\$0.495 /kg	\$1.12 /kg	\$1.17 /kg
	LUHC	\$5.61 /kg	\$4.25 /kg	\$3.70 /kg	\$2.34/kg	\$2.95/kg
Remarks		APWR + CE H_2 : 4 kg/s	APWR + CE H_2 : 8 kg/s	APWR + CE H_2 : 12 kg/s	HTGR+HTSE H_2 : 4 kg/s	HTGR+SI H_2 : 4 kg/s

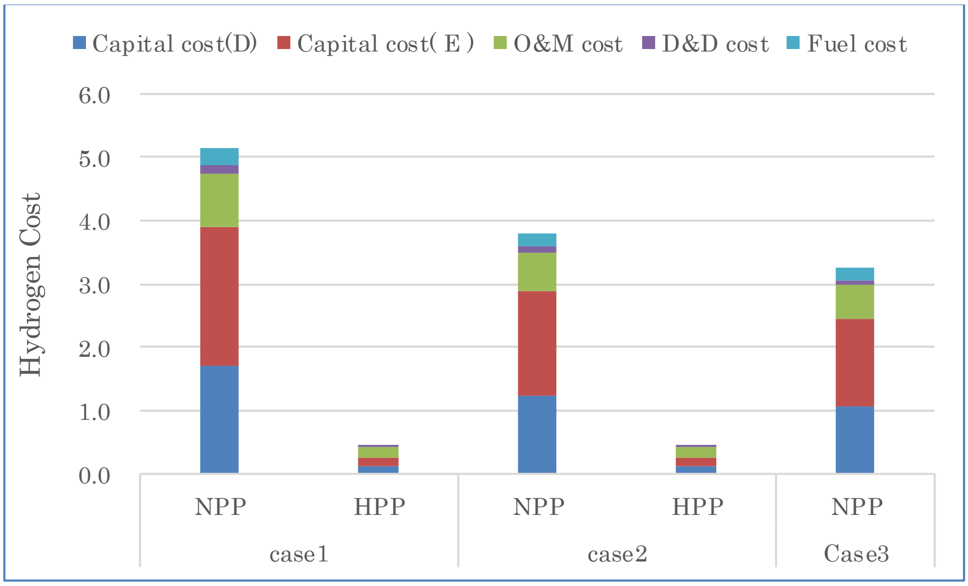


FIG. 61. Contribution of Various Cost Factors to Hydrogen Cost in Cases 1~3 with HEEP Calculation

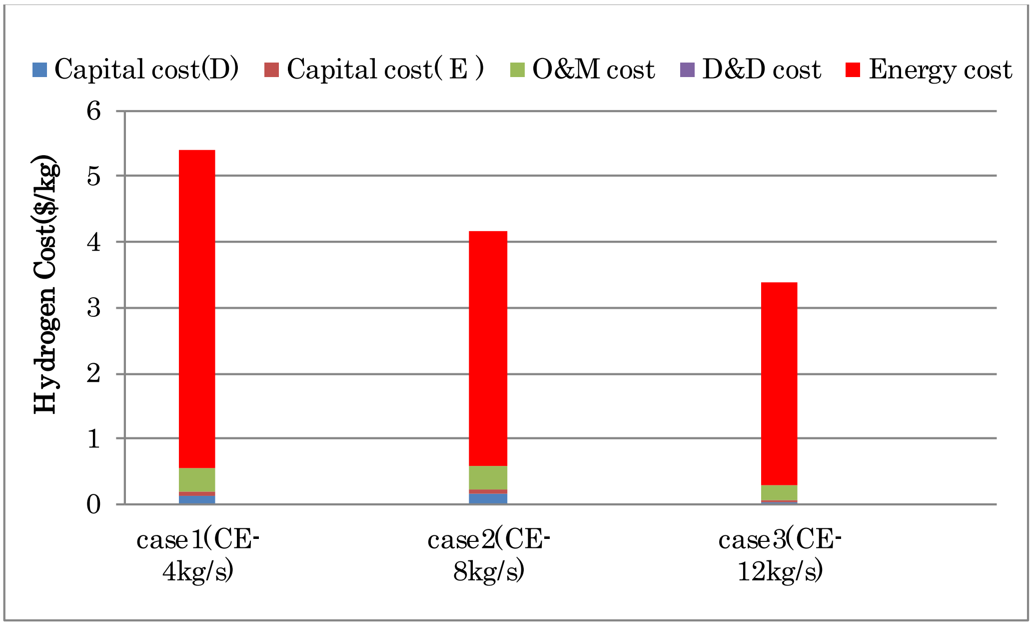


FIG. 62. Contribution of Various Cost Factors to Hydrogen Cost in Cases 1~3 with G4-ECONS Calculation

The figures show the hydrogen production cost change in accordance of hydrogen production rate. The hydrogen production cost decreases as the hydrogen production rate increases, which can be predicted as a scale effect. The contribution of HPP to hydrogen cost is much smaller than that of NPP for cases 1~3.

The degree of contribution of each cost factor to hydrogen cost is almost the same regardless of hydrogen production rate. Fig. 61 shows that contribution of cost factors to the nuclear hydrogen cost. The capital cost is the biggest contributor, followed by O&M cost, Fuel cost and D&D cost with HEEP calculation result. As seen, the energy cost is the biggest contributor, followed by O&M cost, capital cost for HPP with G4-ECONS calculation result.

Unlike HEEP, G4-ECONS can calculate LUEC and LUHC. LUEC is calculated from the input data of NPP. LUEC is then incorporated into HPP to calculate "energy cost for HPP" in G4-ECONS by multiplying energy amount needed in HPP with LUEC calculated from NPP. This is the reason that energy cost is the biggest contributor in G4-ECONS calculation as shown in Fig. 62. In a sense, the energy cost seems to be almost equal to the contribution of NPP with HEEP calculation. For cases 4~5 where nuclear hydrogen production is done by HTSE and S–I, respectively, the results by HEEP and G4-ECONS are presented in Fig. 63 and Fig. 64, respectively. The result shows that LUHC calculated by HEEP and G4-ECONS are pretty close to each other for cases 4~5.

For cases 1, 4 and 5 where nuclear hydrogen production is done by CE, HTSE and S–I, respectively.

The results for LUHC by HEEP and G4-ECONS are presented in Fig. 65 and Fig. 66.

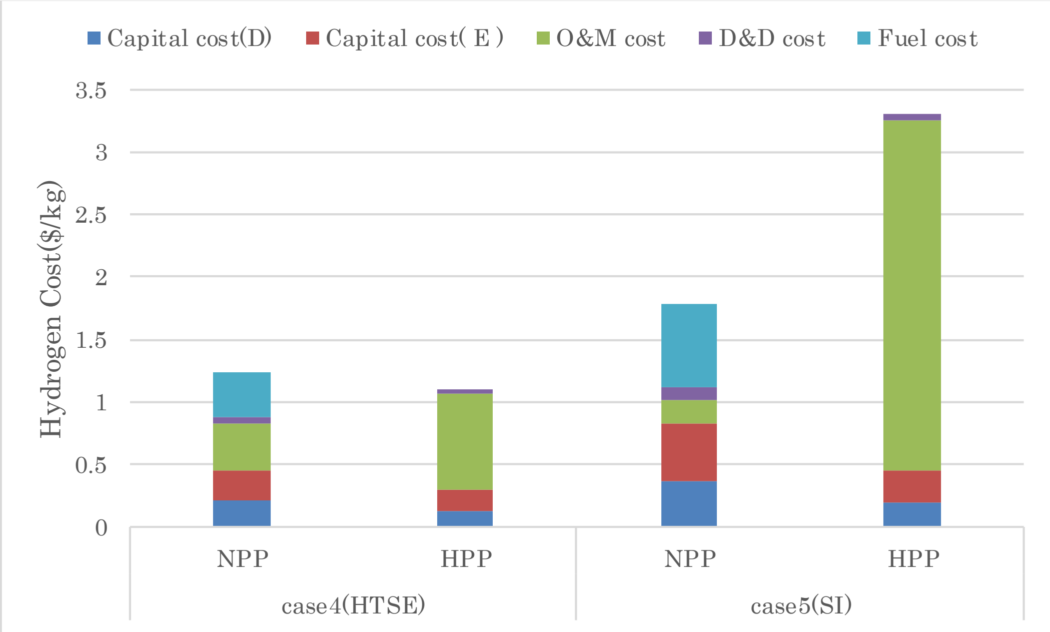


FIG. 63. Contribution of Various Cost Factors to Hydrogen Cost in Cases 4~5 with HEEP Calculation

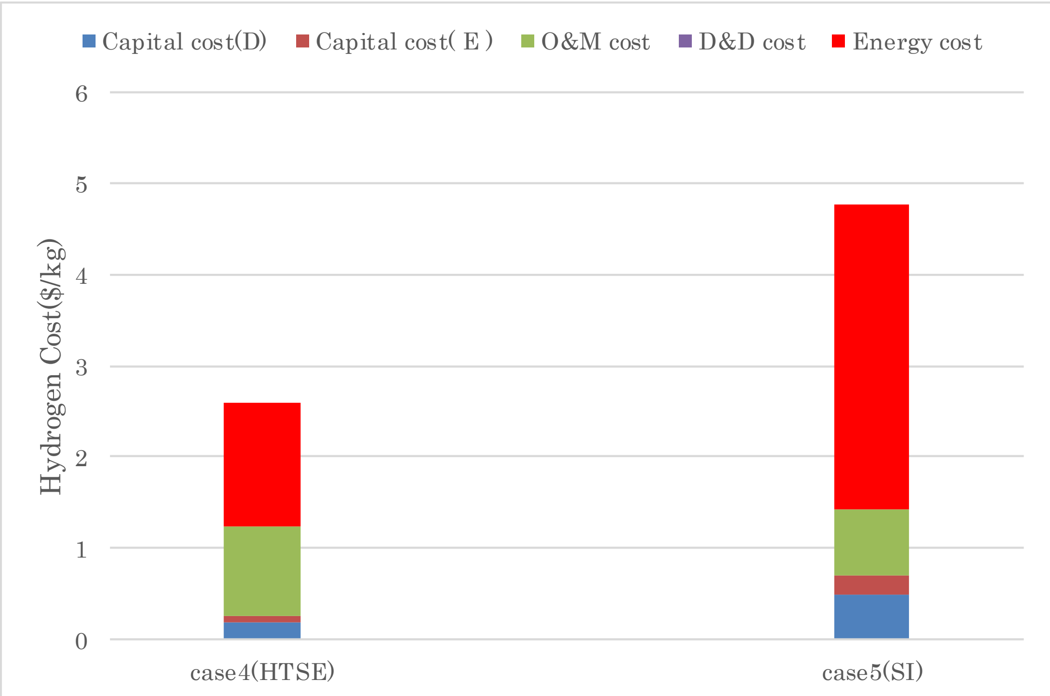


FIG. 64. Contribution of Various Cost Factors to Hydrogen Cost in Cases 4~5 with G4-ECONS Calculation

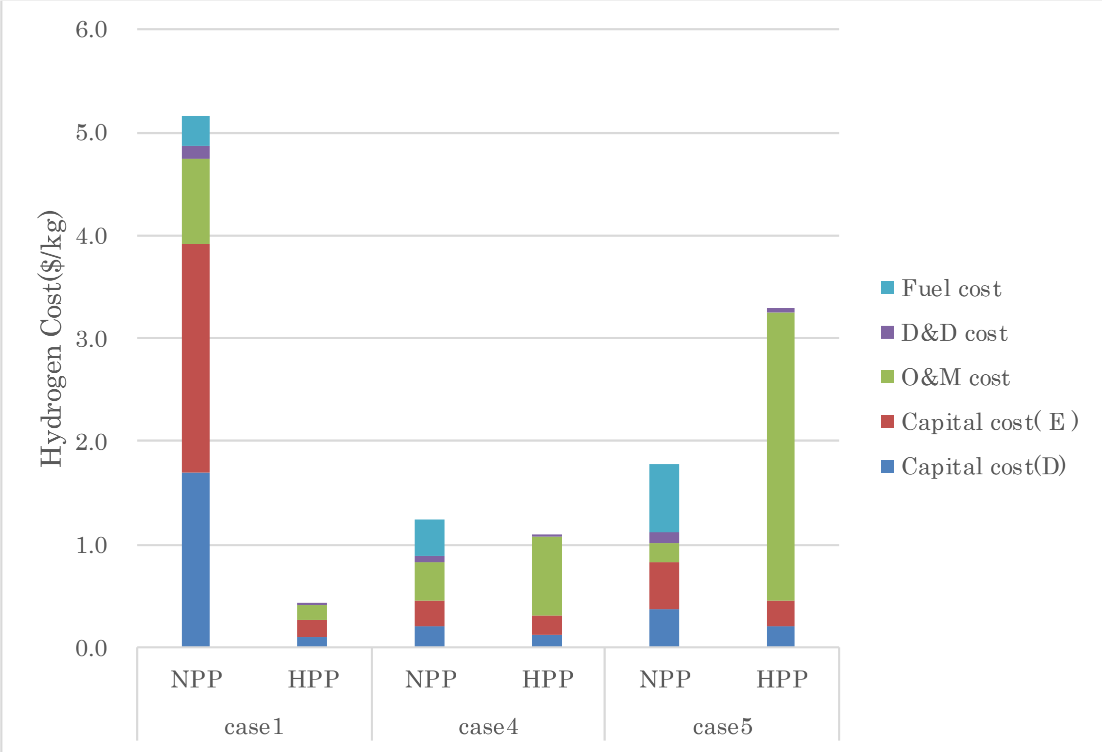


FIG. 65. Contribution of Various Cost Factors to Hydrogen Cost in Cases 1, 4~5 with HEEP Calculation

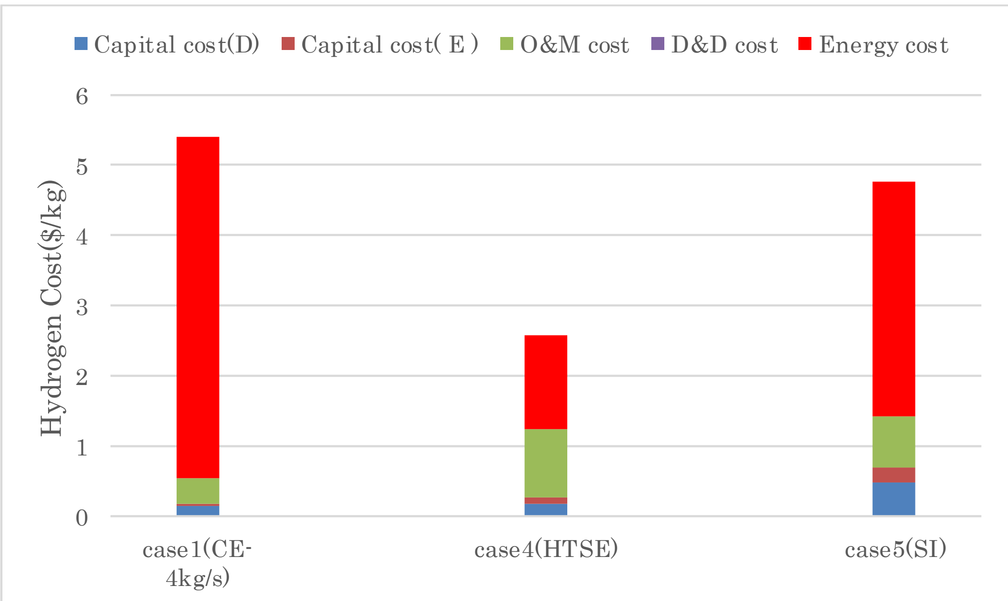


FIG. 66 Contribution of Various Cost Factors to Hydrogen Cost in Cases 1,4~5 with G4-ECONS Calculation

It can be concluded from the LUHC calculation in this figures that the HTSE is relatively more efficient than S–I and CE. Benchmark of HEEP with G4-ECONS shows the results from two programs are within tolerable error bound. The LUHC calculated from G4-ECONS is 1.9% ~8.4% lower than those from HEEP for all generic cases except for generic case 4. The LUHC from G4-ECONS is 5% higher than that of HEEP in case4. Therefore, it can be concluded that benchmarking of HEEP with G4-ECONS results in confirming the reliability of HEEP.

4.5. BENCHMARK WITH ASPEN PLUS CODE

ASPEN PLUS is a computer-aided process simulation tool for conceptual design, optimization, and performance monitoring for chemical processes. A description of this commercial code can be found in Chapter 3.

4.5.1. Benchmark cases

The ASPEN economic evaluation package gives detailed process design and the cost of front end capital costs for process equipment, in-plant cost and O&M costs with present economic realities. A design of hydrogen production system consisting of two units of 268 MW(th) PBMR plants and a single S–I process plant for hydrogen generation provided cost distribution for the hydrogen as shown in Table 59. The plant availability is assumed at 90% and the hydrogen production efficiency is considered at conservative value of at 33%. Both the nuclear reactor and chemical plant are capital intensive so the hydrogen cost is a strong function of interest rates. The table presents results for 10.5%, 12.5% and 16.5% capital recovery factors.

TABLE 59. COST OF HYDROGEN WITH 2×268 MW(th) PBMR+SI PROCESS PLANT

Capital Recovery Factor	0.105	0.125	0.165
Water Cost ($/cubic meter)	1.57	1.57	1.57
Annual Single Reactor Capital Cost (K$)	16 013	19 063	25 163
Annual Chemical Plant Capital Cost (K$)	16 079	19 142	25 267
Annual Single Reactor O&M Cost (K$)	3686	3686	3686
Annual Chemical plant O&M Cost (K$)	11 613	11 613	11 613
Annual Single Reactor Fuel Cycle Costs (K$)	9283	9283	9283
Annual water cost (K$)	675	675	675
Total Annual Cost of Two Reactors and One S–I Plant(K$)	86 330	95 493	113 819
Total Annual Hydrogen Production (tonnes)	12 551	12 551	12 551
Cost ($/kg- H_2)	**6.88**	**7.61**	**9.07**

In order to compare the cost of hydrogen from a similar PBMR reactor and S–I process based hydrogen production, the case of China HTR-PM+SI is chosen as it has two reactors with 250 MW(th) and S–I cycle for hydrogen production. Since the capital recovery used in the original HTR-PM+SI case is 5% it was changed to 10.5% so that direct cost of hydrogen production can be compared with present ASPEN based case, the case with two 268 MW(th) PBMR and Sulfur–Iodine Process Plant (PBMR+SI).

4.5.2. Benchmark results

HEEP Inputs were prepared for the HTR-PM+SI with 10.5% and remaining parameters were kept without changes. Similarly, HEEP inputs were prepared for the PBMR-SI case using the capital costs and O&M cost based on the ASPEN economic analysis. In Table 60, the comparison between the two is shown for 10.5% capital recovery factor with cost contributions from nuclear power plant (NPP) and hydrogen generation plant (HGP). The cost of hydrogen values from HEEP calculations show $4.05 and $4.92 for PBMR+SI and HTR-PM+SI cases respectively. However, when the ASPEN based calculations are done the cost of hydrogen is $6.88 for PBMR+SI. This shows that HEEP calculations under predict than the ASPEN calculations. The reason seems that the HEEP calculations assumes simple formulas to calculate the capital costs and for NPP and HGP and the operating and maintenance costs are not properly accounted. In ASPEN the detailed equipment cost account for most updated values and the operating and maintenance costs are accounted in detail and reflect most realistic values.

The US Department Energy and EPRI based nuclear hydrogen generation cost estimation methodology were reviewed. These cost estimates utilized the existing technology for reactor cost and the hydrogen generation. An economic analysis was performed for hydrogen production with a S–I cycle plant coupled to two units of the PBMR 268 MW standard reactor. The analysis indicated that two 268 MW(e) PBMR reactors are needed to generate 670 mole/s hydrogen that require heat and the process equipment electricity. The hydrogen cost estimated is $6.88 per kg for 10.5% capital recovery. The cost of hydrogen is high compared to HEEP based calculations which are in the range of $2-$5 per kg. It is clear from these analysis is that the capital cost for chemical plant and nuclear plant are higher and also the O&M cost for hydrogen plant than HEEP results. Two major factors contribute to the difference. First, the cost of the chemical process equipment estimated by ASPEN economic analysis takes into account detailed equipment and labour costs. HEEP, on the other hand, does not provide detailed equipment cost. Second, the conservative assumption of 33% hydrogen production efficiency with ASPEN produces more conservative cost. If the efficiency of the hydrogen production were 45% as shown by the JAEA design, the cost of hydrogen would reduce by 30%

TABLE 60. COMPARISON OF THE HEEP COST FOR HTR-PM-SI WITH PBMR-SI AND PBMR-SI ASPEN

Case	Plant	$/kg
2×268 MW(th) PBMR+SI HEEP	NPP	2.74
	HGP	1.31
	Total	**4.05**
2×250 MW(th) HTR-PM+SI HEEP	NPP	3.81
	HGP	1.11
	Total	**4.92**
2×268 MW(th) PBMR+SI ASPEN	NPP	4.62
	HGP	2.26
	Total	**6.88**

4.6. BENCHMARK WITH PROPRIETARY CODES

4.6.1. Benchmark study by Japan

JAEA has estimated the nuclear hydrogen production costs of two plant designs using the internal program, as detailed in Section 1.3.2.5, and basing on industrial and actual plant design and operation databases. These systems are compared with selected generic cases of similar technologies. The results are summarized in Table 61. These data are used to plot Fig. 67.

TABLE 61. LEVELIZED HYDROGEN GENERATION COST

Unit (US $/kg-$H_2$)

	Case 1: APWR+CE 4 kg/s	Case 2: APWR+CE 8 kg/s	Case 3: APWR+CE 12.43 kg/s	Case 5: HTGR+SI 4 kg/s	Japan LWR+CE 6.1 kg/s	Japan HTGR+SI 4.4 kg/s
Reactor rating	2×359.5 MW(e)	2×719.0 MW(e)	2×1116.1 MW(e)	2×650.7 MW(th)	1×1200 MW(e)	2×600 MW(th)
Hydrogen rate	4 kg/s	8 kg/s	12.43 kg/s	4 kg/s	6.1 kg/s	4.4 kg/s
Nuclear plant						
Capital Debt	2.55	1.87	1.54	0.48	0.94	0.60
Capital Equity	0	0	0	0	0	0
O&M	0.83	0.62	0.52	0.55	0.90	0.43
Fuel	0.30	0.22	0.18	0.59	0.64	0.41
Decommission	0.16	0.12	0.10	0.10	0.04	0.05
Total	3.84	2.83	2.34	1.72	2.52	1.49
Hydrogen plant						
Capital Debt	0.17	0.17	0.17	0.27	0.37	0.43
Capital Equity	0.00	0.00	0.00	0.00	0.00	0.00
O&M	0.14	0.14	0.14	0.61	0.33	1.10
Decommission	0.03	0.03	0.03	0.05	0.02	0.02
Total	0.34	0.34	0.34	0.93	0.72	1.55
Levelized cost of hydrogen ($/kg- H_2)	4.18	3.17	2.68	2.65	3.24	3.04

By taking into account of strong effect of economy of scale (i.e., hydrogen production rate) found for LWR conventional electrolysis cases (Section 4.2.2.2), the levelized costs of hydrogen estimated by HEEP for Case 1 and Case 2 agree well with the case of Japan's LWR+CE estimated for a PWR nuclear power plant operated in the country.

Japan's 2nd case and Case 5 are based the same technology arrangement of HTGR coupled to S–I hydrogen plant with similar hydrogen production rates. The S–I hydrogen plant for Japan's HTGR+SI case is 20% more efficient that Case 5. This results in a lower specific cost of the reactor contribution to the final hydrogen cost. On the other hand, the higher capital cost and higher O&M cost of the hydrogen plant in Japan's case significantly expand the share of hydrogen plant to the final hydrogen cost, relative to Case 5. The difference in levelized cost of hydrogen estimated by HEEP for Case 5 and by the internal program for Japan's case is within 15%.

4.6.2. Benchmark study by Germany

A case study of HTGR based hydrogen cogeneration is performed and used to benchmark between the HEEP and Germany's internal code MILP. A brief description of the MILP code can be found in Section 1.3.2.6. The case design parameters are provided in Table 62. Note that two HTGR reactor units of 250 MW(th) each are used to ensure a heat supply to the hydrogen production process at any time the process is not in maintenance. One HTGR unit is not enough because the availability factor of the HTGR is lower than the SMR process. Therefore, one backup HTGR unit is necessary. The back unit is used for electricity generation in those times it is not required for heat supply. The electricity generated is sold to the market.

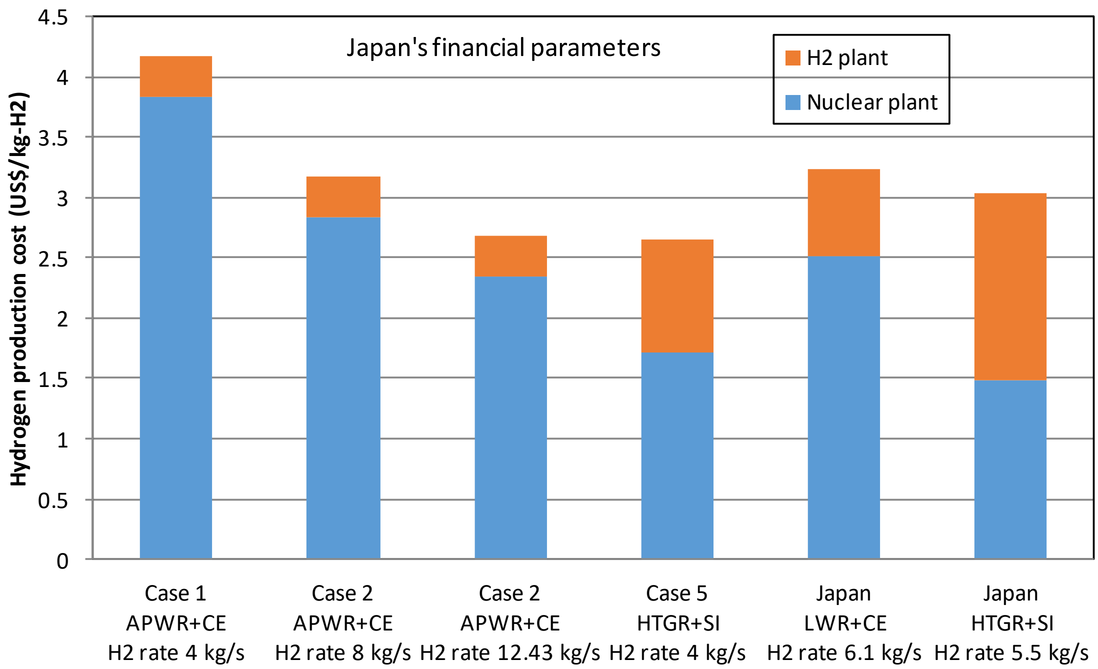


FIG.67. Benchmark results between HEEP and Japan's internal code.

TABLE 62. GERMANY'S BENCHMARK CASE OF HTGR HYDROGEN COGENERATION

Case	Case III
Hydrogen production rate	12.73 t/h
Number of reactor units	2
Reactor thermal power/unit	250 MW(th)
Reactor outlet temperature	850°C
Reactor availability factor/unit	92%
Nuclear plant heat supply to hydrogen plant	250 MW(th)
Nuclear plant power generation	100 MW(e)
Reactor plant cost	
Capital cost	2100 €/kW(th)
Maintenance cost/year	5% of capital cost
Insurance cost/year	2% of capital cost
Labour cost/year	32.5 M€
Fuel cost/year	6.76 €/MW(t)h
Decommissioning cost	100% of capital cost
Hydrogen plant (SMR) availability factor	96%
Hydrogen plant heat consumption	19.63 MW(t)h/t-H_2
Hydrogen plant power consumption	0.64 MW(e)h/t-H_2
Hydrogen plant cost	
Capital	26.5 M€/(t/h)
O&M/year	3% of capital cost
Insurance/year	3% of capital cost
Labour/year	2.4 M€
Fuel (natural gas)	766 €/t
Hydrogen production cost (€//kg-H_2)	
Nuclear plant	1.12
Fossil standby heater	0.04
Hydrogen plant	1.20
Grid electricity purchase	0.05
Total hydrogen production cost	2.41

The financial assumptions for the benchmark are shown in Table 63. The benchmark results including component and final costs of hydrogen are given in Table 64. The hydrogen generation costs calculated with both tools agree quite well. The HEEP obtains a hydrogen production cost of 2.91 €/kg comparing to the MILP result of 2.94 €/kg. Nevertheless, the cost components differ, in part because the two codes allocate the individual costs differently. For example, while the MILP considers the electricity sold to the market as a product credit of 0.33 €/kg, this revenue is already factored in the HEEP cost components.

TABLE 63. FINANCIAL PARAMETERS USED FOR BENCHMARK

Discount rate (%)	10
Inflation rate (%)	1.66
Finance Equity:Debt ratio (%)	20:80
Equity interest (%)	10
Debt interest (%)	8
Tax rate (%)	28
Depreciation period (year)	20
Construction period (year)	6
Operation lifetime (year)	60
Decommissioning (year)	6

TABLE 64. BENCHMARK RESULT BETWEEN HEEP AND MILP CODES

Unit (€/kg-H_2)

	Germany's code MILP	IAEA's HEEP
Nuclear plant		
Capital Debt	1.01	0.67
O&M	0.75	0.69
Fuel	0.19	0.13
Decommission	0.12	0.00
Electricity sale	(-0.33)	-
NP Total	1.74	1.49
Hydrogen plant		
Capital Debt	0.25	0.36
O&M (methane)	0.95	1.06
Decommission	0.00	0.00
HP Total	1.20	1.42
Levelized cost of hydrogen	2.94	2.91

5. TECHNOLOGY-BASED CASE STUDIES USING HEEP

Techno-economics of nuclear hydrogen production have been studied in depth for four technology-based cases. The respective concepts and corresponding input data required for HEEP calculation were provided by four countries. The four nuclear hydrogen concepts are:

Case A: EC6 coupled with Copper–Chlorine (Cu–Cl) hybrid cycle, designed by Canada

Case B: HTR-PM with Sulfur–Iodine (S–I) thermochemical cycle, designed by China

Case C: HTR-Module with steam methane reforming (SMR), designed by Germany

Case D: GTHTR300C with Sulfur–Iodine (S–I) thermochemical cycle, designed by Japan

All cases differ significantly in technical aspects as illustrated in Fig. 68 and will be explained in more detail in the following sections. The Canadian case was composed of four subcases referring to the same nuclear system to be connected to four different hydrogen production technologies. For the comparative study here, it was agreed upon to consider the subcase with the 5-step Cu–Cl cycle.

The idea of this study is to have each participating country conduct HEEP calculations for the above four technology cases applying the same technical data for both the nuclear and the hydrogen plant, but choosing the respective country's set of financial parameters to determine the hydrogen generation costs.

5.1. DESCRIPTION OF CASES

5.1.1. Case A by Canada

The next generation CANDU reactor concept pursued in Canada is the so-called Enhanced CANDU6 or EC6 reactor which evolved from the established CANDU6 technology [40, 41, 78]. The EC6 is a third generation, heavy water cooled and moderated reactor mainly designed for electricity production with an electric power output of 740 MW(e) and a thermal power of 2084 MW(th). In general, CANDU6 is considered the only commercialized reactor with adaptability and flexibility in the fuelling arrangements. Fuel alternatives starts from recovered or reprocessed uranium fuel to advanced fuel like thorium and actinides. Similar to all CANDU reactors, the EC6 design is based on the use of horizontal fuel channels (here 380) arranged in a square pitch. Each fuel channel houses twelve 37-element fuel bundles containing natural uranium fuel and the pressurized D_2O coolant. They are mounted in a calandria vessel containing the low-temperature, low-pressure D_2O moderator. The fission heat is carried by the reactor coolant to four steam generators provided in the heat transport system producing steam at 260 °C. Major design parameters of the EC6 plant are in Table 65.

Current CANDU reactors (CANDU6 and EC6) produce nuclear heat at ~300 °C. Heat upgrading has to be performed to increase the temperature to the range of operating temperature of current thermochemical cycles. Integration of heat pump with the system to upgrade the nuclear heat is proposed and studied by several researchers. There is potential of internal heat recovery from thermochemical cycles integrated with nuclear power plant [62, 63]. In these studies, the feasibility of a new high temperature heat pump is analysed, which is integrated into a Copper–Chlorine (Cu–Cl) thermochemical water splitting cycle for internal heat recovery, temperature upgrades and hydrogen production. (See Canada country report on the CD-ROM for more details).

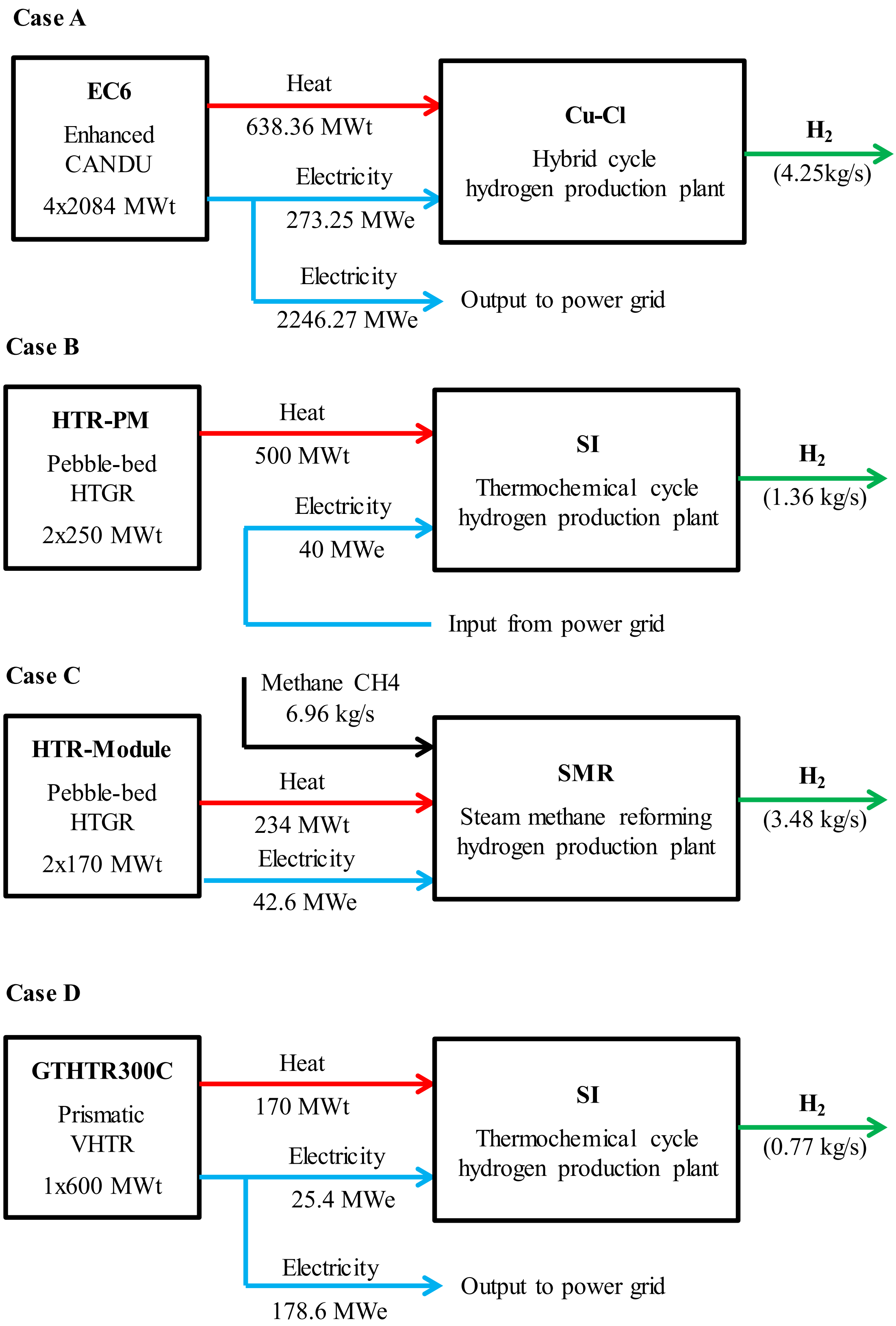


FIG. 68. Four technology-based cases of nuclear hydrogen production studied

TABLE 65. MAJOR CORE DESIGN PARAMETERS OF THE EC6

Reactor type	Horizontal pressure tube
Thermal power	2084 MW(th)
Core power density	11.3 MW(th)/m^3
Primary coolant	Heavy water
Coolant inlet / outlet temperature	266.3 / 310.0 °C
Coolant pressure	10.1 MPa
Coolant mass flow rate	9200 kg/s
Electric power gross / net	740 / 690 MW(e)
Moderator	Heavy water
Moderator temperature	69 °C
Number of fuel channels	380
Number of fuel bundles per channel	12
Channel length	5.94 m
Pressure tube inside diameter	103.4 mm
Number of fuel elements per bundle	37
Length of fuel element/bundle	~0.5 m
Fuel	$U_{nat}O_2$
Average fuel burnup	7.5 GWd/t-HM
Calandria inside diameter	7595 mm
Calandria wall thickness	28.6 mm
Number of steam generators	4
Steam temperature	260 °C
Steam pressure	4.7 MPa
Steam mass flow rate	1043 kg/s
Design lifetime	60 a

The hydrogen production method considered in Canada is the Copper–Chlorine (Cu–Cl) hybrid cycle which was first developed in 1970s. It is a medium temperature cycle operating around 550°C in three to five steps of thermochemical and electrochemical steps in different configurations. The efficiency of this cycle is calculated at about 40% [61]. Selected for the HEEP study here is only the 5-step Cu–Cl cycle [64].

5.1.2. Case B by China

China's case is based on the on-going HTR-PM project and research results of the Sulfur–Iodine process investigated at the Institute of Nuclear and New Energy Technology (INET), Tsinghua University in Beijing. The HTR-PM is designed for generating an electric power of 210 MW(e) by utilizing two identical reactor units of 250 MW(th) each serving one steam turbine. It is the first commercial pebble-bed modular HTGR in China currently under construction and anticipated to be completed by the end of 2017. The plant concept is such that a high degree of standardization and modularization will be achieved. In this dedicated electricity generating plant, the helium coolant temperature at the exit is 750 °C. In the steam generator, a genuine Chinese development, heat is transferred to the steam cycle. Major design parameters of the HTR-PM are listed in Table 66.

Since the HTGR is the most suitable reactor type for nuclear-assisted hydrogen production, comprehensive investigation on nuclear hydrogen production has been initiated at the INET as part of the R&D objectives of the HTR-PM project. The Sulfur–Iodine (S–I) thermo-chemical cycle for splitting water and the high temperature steam electrolysis (HTSE) process were selected as the most promising processes of nuclear hydrogen production. Since 2005, INET has conducted preliminary studies on the S–I and HTSE processes. A Laboratory with the necessary facilities has been established for process studies of nuclear hydrogen. At the same time, the test reactor HTR-10 located at INET will provide a suitable nuclear facility for future R&D of nuclear hydrogen production technologies.

TABLE 66. MAJOR CORE DESIGN PARAMETERS OF THE BASELINE HTR-PM

Thermal power (two units)	2×250 MW(th)
Average thermal power density	3.2 MW(th)/m^3
Primary coolant	Helium
Coolant inlet / outlet temperature	250 / 750 °C
Coolant pressure	7.0 MPa
Coolant mass flow rate (per unit)	96 kg/s
Electric power production	210 MW(e)
Active reactor core diameter / height	3.0 / 11.0 m
Number of spherical fuel elements (per unit)	420 000
Average / maximum fuel burnup	90 / 100 GWd/t
RPV inner diameter/height	5.7/24.9 m
Power conversion efficiency	42 %
Steam temperature at turbine inlet	566°C
Steam pressure at turbine inlet/outlet	13.2 MPa / 4.5 kPa
Flow rate of superheated steam per unit	96 kg/s

5.1.3. Case C by Germany

The baseline concept for a German small modular HTGR is the electricity producing 200 MW(th) HTR-Modul pebble bed reactor designed by the former German company

SIEMENISNTERATOM [34]. It is characterized by a tall and slim core which ensures — in combination with a low power density — that even in hypothetical accidents, the release of fission products from the core will remain sufficiently low to cause no harm to people or environment. Consequently, a process heat variant of the HTR-Modul reactor [36] has been developed, for which — in comparison to the electricity generating plant — several modifications were necessary. The principal cornerstones of the process heat version are a thermal power of 170 MW and a helium outlet temperature of 950 °C to deliver process heat for the SMR process. A reduced system pressure of 5 MPa was chosen as compromise between a high pressure desired for its favourable effect on operating and accident conditions of the nuclear reactor and a low pressure desired for chemical process reasons in the secondary and tertiary circuit to enhance the conversion rate for maximal hydrogen production. Major design parameters of the HTR-Modul are listed in Table 67.

TABLE 67. MAJOR CORE DESIGN PARAMETERS OF THE PROCESS HEAT HTR-MODUL

Thermal power	170 MW(th)
Thermal power density	2.55 MW(th)/m^3
Primary coolant	Helium
Coolant inlet / outlet temperature	300 / 950 °C
Coolant pressure	5.0 MPa
Coolant mass flow rate	50.3 kg/s
Active core diameter / height	3000 / 9430 mm
Number of spherical fuel elements	360 000
Average fuel burnup	80 GWd/t-HM
Coolant temperature at SR outlet	680 °C
Coolant temperature at SG outlet	293 °C
Process gas temperature	810 °C
Process gas pressure	5.2 MPa
Steam temperature	540 °C
Steam pressure	11.5 MPa
Steam mass flow rate	37.6 kg/s
H_2 + CO production rate	25.6 m^3/s

The steam reformer uses the temperature of the helium between 950 and 700 °C, while the steam generator is using that part of heat between 700 and 250°C. The feed gas mixture with an H_2O/CH_4 ratio of ~ 3 is preheated up to around 500°C and reformed at a maximum process temperature of 800 °C. A fraction of 85 % of the methane is then converted in this first step. Utilization of the heat of the reformer gas for preheating the feed gas, shift conversion, and methanation are the steps following the reformer to finally get the product hydrogen. The steam generator supplies the steam needed for the reforming process and power generation. The overall energy balance delivers roughly the following numbers:

$$170\ \text{MW(th)} + 2.5\times10^4\ \text{Nm}^3\ CH_4 / \text{h} \rightarrow \sim10^5\ \text{Nm}^3\ H_2 / \text{h}$$

CH_4 as raw material is completely converted to hydrogen; the total efficiency including the nuclear heat is around 65%. A complete life cycle analysis has even revealed that depending on operating conditions, about 40% savings of natural gas feedstock could be achieved, if nuclear is selected the primary energy source [79].

Without employing an IHX (which was deemed feasible and licensable at that time), the hot helium coolant is directly fed to the steam reformer as a new nuclear component which is a bundle consisting of straight splitting tubes with a length of 14 m. The reformer consumes 71 MW(th), while the steam generator is operated with 99 MW(th). From the total heat transferred into the steam reformer, 85% are used for the reforming process, with the remaining 15% being taken to heat up the feed gas.

5.1.4. Case D by Japan

The JAEA reference concept for commercial nuclear hydrogen production in Japan is based on the GTHTR300C (C = cogeneration) reactor [28, 80] to be connected to an Sulfur–Iodine thermochemical water splitting process.

The GTHTR300C design is based on a prismatic VHTR. The reactor is rated at 600 MW(th) thermal power and 950 °C coolant outlet temperature. Coolant pressure is 5.1 MPa, a reduced value compared to the electricity-only variant. The intermediate heat exchanger (IHX) used to deliver 900 °C helium as nuclear heat source to the hydrogen process is designed based the helical He-to-He counter-flow tube and shell heat exchanger, the same type operated in the HTTR. The heat capacity of the IHX is 170 MW(th). The gas turbine is designed to produce 300 MW(e) maximum in standalone power generation and 204 MW(e) when hydrogen is being cogenerated. Major design parameters of the GTHTR300C are listed in Table 68.

TABLE 68. MAJOR CORE DESIGN PARAMETERS OF THE GTHTR300C FOR HYDROGEN PRODUCTION

Thermal power	600 MW(th)
Average thermal power density	5.8 MW(th)/m^3
Primary coolant	Helium
Coolant inlet / outlet temperature	594 / 950 °C
Coolant pressure	5.1 MPa
Coolant mass flow rate	322 kg/s
Electric power production	204 MW(e)
Reactor core equivalent inner–outer radius / height	3600–5500 / 8000 mm
Number of fuel blocks	720 (in 90 columns)
Average fuel burnup	120 GWd/t-HM
Helium temperatures at IHX inlet / outlet	950 / 556 °C
Secondary helium IHX inlet / outlet temperature	900 / 850 °C
Hydrogen conversion process	S–I thermochemical cycle
Efficient thermal power input to H_2 production	219 MW(th)
Hydrogen production rate	1.9–2.4 t/h

The process heat required for the S–I process is provided in form of hot helium gas from the high temperature nuclear reactor and used in various steps of the process stream concentration and decomposition. The electricity is generated in-house by the same nuclear reactor and used to power the process electrolysers for stream concentration, gas circulators including the ones used in the helium gas loop to transport the heat from the nuclear reactor to the hydrogen process plant, the process fluid pumps and other utilities.

According to the energy and material balance of the S–I process, the gross thermal input is 175 MW(th), of which 5 MW(th) is input from the helium circulator gas compression heating of the heat transport loop that connects the reactor to the hydrogen plant. The net thermal input to the process is 168.9 MW(th). The net electricity consumption is 25.4 MW(e) accounting for all major usages of electricity including process electric utility (pumps and electrolyzer), and the helium gas circulation power consumption of the helium heat transport loop. Assuming a conversion efficiency of 48.8%, the hydrogen production rate is 30 655 Nm^3/h (or 66.1 t/d). By-product is oxygen produced at a rate of 15 328 Nm^3/h.

5.2. BOUNDARY CONDITIONS

5.2.1. Nuclear plant

The main operating and cost parameters of the nuclear power plants considered for the four technology cases are listed in Table 69. The electricity rating provided in the table is adjusted based on the thermal power required for hydrogen production and the thermal efficiency of the reactor.

5.2.2. Hydrogen production plant

The main operating and cost parameters of the integrated hydrogen generation plants for the four technology cases are listed in Table 70.

5.2.3. Economic parameters

Based on the above HEEP input data for the nuclear and the hydrogen production plant, each participating country was to provide country-specific financial parameters to run the four technology-based cases. Table 71 contains the economic parameters for each participating country, including also the HEEP default data set for comparison purposes. For Indonesia and USA, no financial parameter sets were provided, therefore they could not be considered in the comparative analysis.

As there is no separate set of data for the hydrogen plant in HEEP, the economic parameters apply to the nuclear plant.

TABLE 69. HEEP PARAMETERS FOR THE NUCLEAR PROCESS HEAT PLANTS

Cases	Case A	Case B	Case C	Case D
	Canada	China	Germany	Japan
Nuclear plant	EC6	HTR-PM	HTR-Modul	GTHTR300C
Number of units	4	2	2	1
Thermal power (MW(th)/unit)	2084	250	170	600
Capacity factor (%)	90	90	90	90
Availability factor (%)	100	100	100	100
Thermal power for H_2 plant (MW(th)/unit)	159.58 (heat pump)	250	117	170
Electrical power (MW(e)/unit)	629.88	0	21.3	204
Initial fuel loading (kg/unit)	87 552	2940	2396	7090
Annual fuel reloading (kg/unit)	126 000	1014	767	1773
Capital cost (M $/unit)	2243.77	250	599	547
Capital cost for electricity producing infrastructure (% of CC)	12.2	0	10	21
Fuel cost ($/kg)	137.2	4800	11 000	12 962
O&M cost (% of CC)	4.21	3.81	4.0	3.98
Decommissioning cost (% of CC)	14.75	4	10	0.52
Construction period (a)	6	3	3	4
Operation period (a)	30	40	40	40
Cooling before decommissioning (a)	0	2	2	2
Decommissioning period (a)	50	10	10	10
Refurbishment (a)	0	?	1	1
Spent fuel cooling (a)	7	2	2	2
Waste cooling (a)	0	10	10	10

TABLE 70. HEEP PARAMETERS FOR THE HYDROGEN PRODUCTION PLANTS

Cases	Case A	Case B	Case C	Case D
	Canada	China	Germany	Japan
Hydrogen production plant	Cu–Cl (5-step)	S–I	SMR	S–I
Number of units	1	2	2	1
Capacity factor (%)	90	90	90	90
Availability factor (%)	100	100	100	100
Production rate (kg-H_2/s(per unit))	4.25	0.68	1.74	0.77
Thermal power consumption (MW(th)/unit)	638.36	250	117	170
Electrical power consumption (MW(e)/unit)	273.25	20	21.3	25.4
Capital cost (M $/unit)	400.23	100	203	143
Energy consumption cost (M $)	0	10.5	0	0
O&M cost (% of CC)	7.0	5.46	5.0 + 22 (CH_4)	4.26
Decommissioning cost (% of CC)	10	5	10	0

TABLE 71. ECONOMIC INPUT PARAMETERS FOR HEEP SIMULATIONS

Economic parameter	HEEP default	Algeria	Argentina	Canada	China	Germany	India	Indonesia	Japan	Pakistan	Republic of Korea	USA
Real discount rate (%)	5	6	5	2	12	10	12	No data provided	3	8	4	No data provided
Inflation rate (%)	1	2	9.5	2	1	1.66	5.65		0	5	2	
Equity ratio (%)	70	70	70	50	70	50	30		0	20	50	
Borrowed capital ratio (%)	30	30	30	50	30	50	70		100	80	50	
Capital market interest rate (%)	10	6	30	7	10	5.5	10.5		3	8	10	
Tax rate (%)	10	1.5	10	30	10	28.2	30		1.4	0	10	
Depreciation period (a)	20	20	20	30	20	20	20		20	20	20	

5.2.4. Explanation of input parameters

A. CANADA

Four nuclear units of the Canadian EC6 type are being considered each producing a thermal power of 2084 MW(th). Assuming an electricity conversion efficiency of 32.2%, the net power generated is calculated as 629.88 MW for each unit. As the D_2O coolant exit temperature is too low for use in the hydrogen production process, heat upgrading needs to be performed. Therefore, each nuclear unit is combined with a chemical heat pump which produces 159.58 MW(th) of upgraded heat at temperatures of 800 to 1000 °C, this heat being the process heat for the hydrogen plant. Capital costs for the nuclear system comprise both the cost of the EC6 (2000 M$/unit) and the cost for the heat pumps (243.77 M$/unit) totalling to 2243.77 M$/unit. Heat pump costs represent 12.2% of the total capital cost of the nuclear reactor. Nuclear fuel loading and reloading are high due to the power size, but specific fuel costs are low compared to the respective figures for HTGR fuel in the other cases.

The four EC6 units are connected to one hydrogen production plant that is expected to generate hydrogen at a rate of 4.25 kg/s, if the 5-step Copper–Chlorine cycle is applied. Thermal power input to the H_2 plant is from the four chemical heat pumps, a total of 638.36 MW(th). Of the total nuclear power output of 2519.52 MW(e), only a small fraction, 273.25 MW(e), is consumed in the hydrogen production process, while the remaining ~90% of the electricity is directed to the grid. The capital costs for the hydrogen plant based on the given thermochemical cycle and production rate are estimated to be 400.23 M$.

B. CHINA

In the China case, the nuclear plant of choice is the HTR-PM. As the electricity generating reference variant is currently under construction in China, respective input data for the HEEP calculation could be derived from the report. Capital costs for the nuclear twin plant are estimated to be 500 M$ or 250 M$ per unit. The nuclear system here does not produce any electricity, all of the thermal power produced is directed to the H_2 production system.

The hydrogen production system considered here is composed of two units based on the S–I cycle. Capital costs per unit are 100 M$. While the nuclear thermal power generated is completely consumed in the H_2 plants. For the given hydrogen production rate, it includes already the fraction needed to generate the required electric power of 20 MW(e) per unit.

C. GERMANY

In the process heat HTR-Modul, the helium coolant is heated up to an average maximum temperature of 950°C and then passed through the steam reformer component where the high temperature heat is utilized to exchange heat with the process gas (methane plus steam). While the process gas mixture is heated up to reaction temperature, the primary helium is cooled to ~680°C. This heat exchange thus consumes about 65 MW(th). The helium is then routed to the steam generator where part of the steam is diverted to the steam reformer as feedstock for the reforming process, while the remainder is used for generating 21.3 MW(e) of electricity. Assuming an electric efficiency of 40%, a total of 117 MW(th) is consumed in the SMR hydrogen production system. In the 2-module plant, each nuclear unit has its own integrated steam reformer for hydrogen generation.

Capacity and availability factors of both nuclear and hydrogen plant are fixed at 90% and 100%, respectively. Nuclear fuel needed is 2396 kg as initial loading as well as 767 kg as annual reloadings. Specific fuel costs are assumed to be 11 000 $/kg. This value was derived from a specific fuel price of 6.37 $/MWh considering an annual heat production in the HTR-Modul of 170 MW × 8760 h/a × 0.9 = 1 340 280 MWh/a and an annual fuel demand of 767 kg/a.

Based on the assumption of 1.3 billion Euro for the two-module plant including two steam reforming plants, the per-unit price is 802 M US $ based on an exchange rate between Euro and US $ (1.23 US $ = 1 Euro). A partition of the total capital costs between nuclear heat production system and hydrogen production system was made as 75:25. This yields capital costs of 599 US $ per nuclear unit and 203 US $ per hydrogen unit. An estimated 10% of the nuclear capital costs are spent for the electricity generating infrastructure. Operation and maintenance of the nuclear plant are assumed to cost annually 4% of the capital cost. After the final shutdown, 10% of the capital costs are assumed to be spent on decommissioning.

Costs for the methane feed will be again attributed to the O&M costs of the steam reforming plant. A hydrogen production rate of 1.74 kg/s per steam reforming unit translates into a net annual production of 4.94×10^7 kg of hydrogen of the unit. Doubling this mass, 9.88×10^7 kg, is needed as annual methane feedstock to each steam reforming unit according to the following reaction of steam–methane reforming:

$$CH_4 + 2H_2O = 4H_2 + CO_2$$

With a net heat value of combustion of methane to be 50.0 MJ/kg, the above methane mass corresponds to an equivalent energy demand of 4.94×10^9 MJ per year or 1.37×10^6 MWh per year per steam reforming unit. Assuming a natural gas / methane price of 26.50 Euro/MWh or 32.60 US $/MWh, the total annual methane feedstock costs amount to 44.7 M US $ or about 22% of the capital costs of per unit of the hydrogen plant. Together with 5% of the capital costs for other (overhead) O&M, the overall O&M costs are 27% of the capital costs. The cost of CO_2 certificates has been neglected here.

D. JAPAN

In the Japan case, the nuclear reference plant for cogeneration of heat and electricity is the GTHTR300C to be connected to a hydrogen production plant based on the S–I cycle. The GTHTR300C is designed for a thermal power of 600 MW(th), of which 170 MW(th) are decoupled via the IHX to the H_2 production system, while the remaining thermal power is used to run a gas turbine for the generation of 204 MW(e) of electricity. Estimated capital costs for the nuclear plant are 547 M$.

The GTHTR300C is connected to one hydrogen plant with estimated capital costs of 547 M$. Besides the 170 MW(th) of thermal power, the H_2 plant also receives from the nuclear plant an electric power of 25.4 MW(e) to run the system. The remaining power of 178.6 MW(e) is given to the grid.

5.3. COUNTRY SPECIFIC CALCULATION RESULTS

5.3.1. Global results

Global results are given in Table 72.

TABLE 72. LEVELIZED HYDROGEN GENERATION COSTS FOR TECHNOLOGY BASED CASES (OVERALL RESULTS FOR PRODUCTION)

Unit: US $/kg-$H_2$

Cases Nuclear plant	Case A	Case B	Case C	Case D
	Canada	China	Germany	Japan
	EC6	HTR-PM	HTR-Modul	GTHTR300C
ALGERIA	2.60	2.44	2.41	2.04
ARGENTINA	5.83	2.74	3.29	2.06
CANADA	5.33	2.16	2.78	1.58
CHINA	2.08	2.73	1.98	2.40
GERMANY	2.69	2.88	2.83	2.45
INDIA	2.96	2.62	3.33	2.36
JAPAN	2.93	2.15	2.64	1.70
PAKISTAN	2.97	1.06	2.62	1.65
REPUBLIC OF KOREA	3.66	2.45	2.94	1.88
HEEP DEFAULT	2.86	2.83	2.83	2.37

The per-kg prices of nuclear-produced hydrogen calculated with HEEP by the different countries for the four technology-based cases are ranging between 1.06 and 5.83 $/kg-$H_2$. These extreme values, together with the second largest value, however, were derived based on unusual boundary conditions as will be explained below. Ignoring those data, the range of results is now significantly narrowed down from 1.58 to 3.66 $/kg. Considering the cases individually, it can be observed that in general prices tend to be lowest for the Japan case and highest for the Canada case.

The detailed results for each country are given in the following subchapters.

5.3.1.1. Algeria

The results from Algeria are given in Table 73. The nuclear to hydrogen plant cost ratio is shown in Fig. 69.

TABLE 73. ALGERIA LHGC FOR TECHNOLOGY BASED CASES (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.72	0.65	0.60	0.36
NP Capital cost (debt) ($/kg)	0.34	0.29	0.27	0.18
NP O&M + refurbishment ($/kg)	0.48	0.45	0.44	0.29
NP Decommissioning ($/kg)	0.39	0.02	0.05	0.00
NP Fuel ($/kg)	0.08	0.26	0.18	0.44
Total (nuclear plant) ($/kg)	2.01	1.67	1.54	1.27
H_2 Capital cost (equity) ($/kg)	0.20	0.26	0.20	0.34
H_2 Capital cost (debt) ($/kg)	0.09	0.12	0.09	0.15
H_2 O&M + refurbishment ($/kg)	0.23	0.39	0.55	0.28
H_2 Decommissioning ($/kg)	0.07	0.01	0.01	0.00
Total (hydrogen plant) ($/kg)	0.59	0.77	0.87	0.76
Total LHGC from production ($/kg)	2.60	2.44	2.41	2.04

Algeria results of hydrogen generation costs for the four cases are lying in a narrow price range between 2.04 \$/kg-H_2 for Japan and 2.60 \$/kg-H_2 for Canada. All results are well within the range of prices calculated by the other countries.

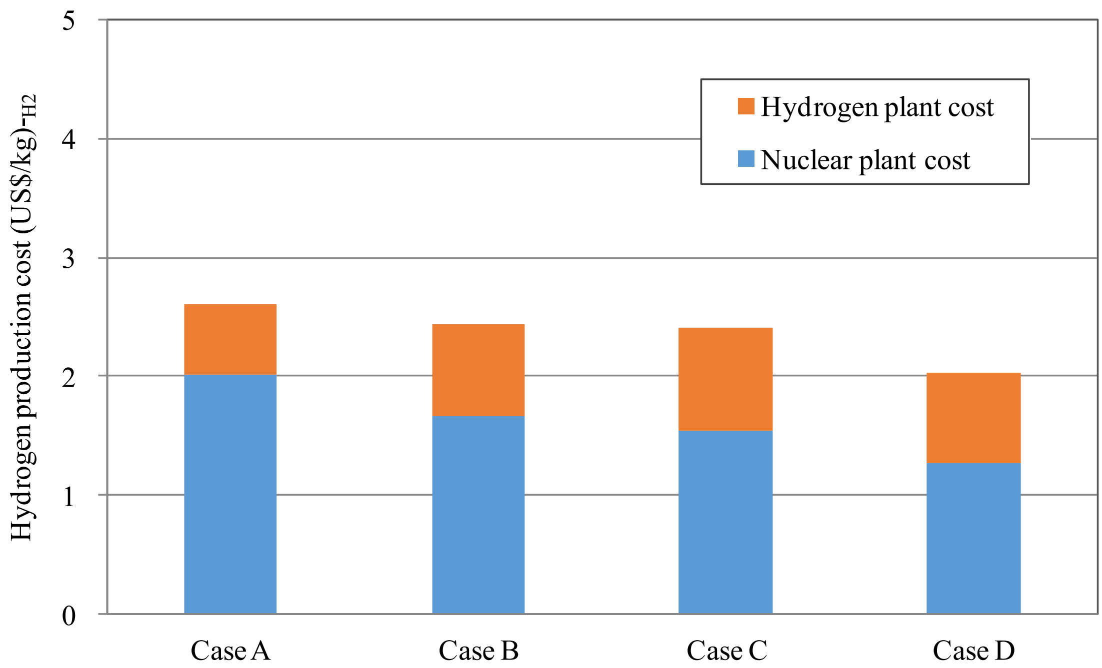


FIG. 69. The result of case studies by Algeria

5.3.1.2. Argentina

The results from Argentina are given in Table 74. The nuclear to hydrogen plant cost ratio is shown in Fig. 70.

TABLE 74. ARGENTINA LHGC FOR TECHNOLOGY BASED CASES (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.28	0.23	0.21	0.12
NP Capital cost (debt) ($/kg)	0.71	0.73	0.68	0.46
NP O&M + refurbishment ($/kg)	0.47	0.45	0.44	0.31
NP Decommissioning ($/kg)	3.23	0.13	0.30	0.01
NP Fuel ($/kg)	0.09	0.24	0.17	0.39
Total (nuclear plant) ($/kg)	4.78	1.78	1.80	1.29
H_2 Capital cost (equity) ($/kg)	0.08	0.09	0.07	0.12
H_2 Capital cost (debt) ($/kg)	0.09	0.29	0.23	0.37
H_2 O&M + refurbishment ($/kg)	0.23	0.53	1.11	0.28
H_2 Decommissioning ($/kg)	0.55	0.05	0.08	0.00
Total (hydrogen plant) ($/kg)	1.05	0.96	1.49	0.77
Total LHGC from production ($/kg)	5.83	2.74	3.29	2.06

Lowest specific costs for hydrogen production are being achieved for the Japan case (2.06 $/kg-$H_2$), followed by the China, Germany and Canada cases. The very high production costs in the latter case are due to an unusually high contribution from decommissioning costs (~65% of total costs), which again is the result of the (unintentional) assumption of a zero % discount rate. The LHGC for the other cases are comparable with the other countries' results.

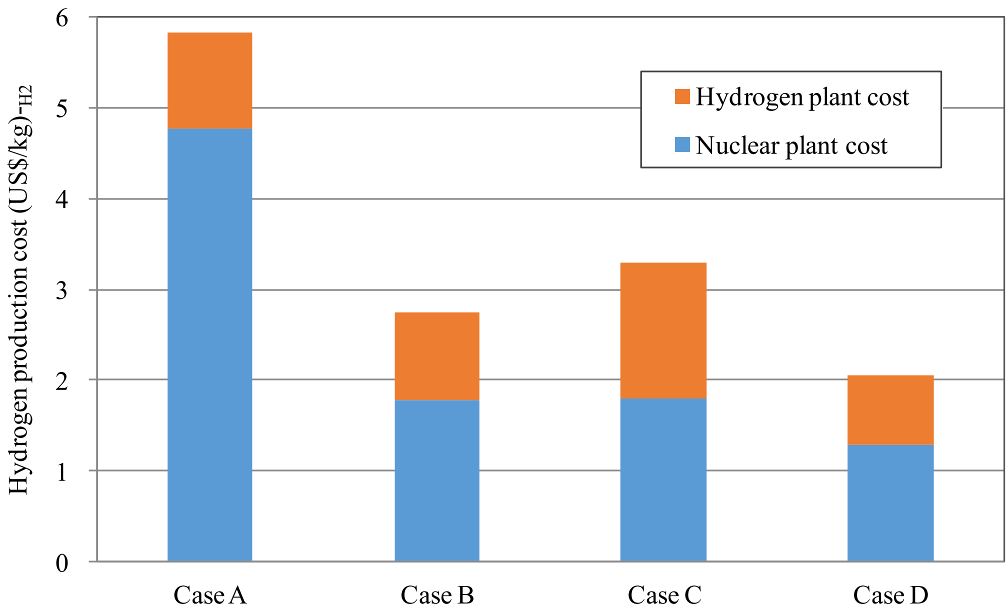


FIG. 70. The result of case studies by Argentina

5.3.1.3. Canada

The results from Canada are given in Table 75. The nuclear to hydrogen plant cost ratio is shown in Fig. 71.

TABLE 75. CANADA LHGC FOR TECHNOLOGY BASED CASES (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.20	0.17	0.16	0.08
NP Capital cost (debt) ($/kg)	0.39	0.37	0.35	0.23
NP O&M + refurbishment ($/kg)	0.47	0.45	0.44	0.31
NP Decommissioning ($/kg)	3.23	0.13	0.30	0.01
NP Fuel ($/kg)	0.09	0.24	0.17	0.39
Total (nuclear plant) ($/kg)	4.38	1.36	1.42	1.02
H_2 Capital cost (equity) ($/kg)	0.06	0.07	0.05	0.09
H_2 Capital cost (debt) ($/kg)	0.11	0.15	0.12	0.19
H_2 O&M + refurbishment ($/kg)	0.23	0.53	1.11	0.28
H_2 Decommissioning ($/kg)	0.55	0.05	0.08	0.00
Total (hydrogen plant) ($/kg)	0.95	0.80	1.36	0.56
Total LHGC from production ($/kg)	5.33	2.16	2.78	1.58

Calculations with the Canada financial parameters yielded lowest hydrogen generation costs for the Japan case (1.58 $/kg-H$_2$), which is also lowest among all countries, and highest for the Canada case (5.33 $/kg-H$_2$). In the Canada case, it is the extremely high share of decommissioning cost contributing to the hydrogen price. Also, in all four cases, the Canada predicted contribution from capital cost is lowest among all countries, with only one exception (Pakistan for the China case), but this for another reason.

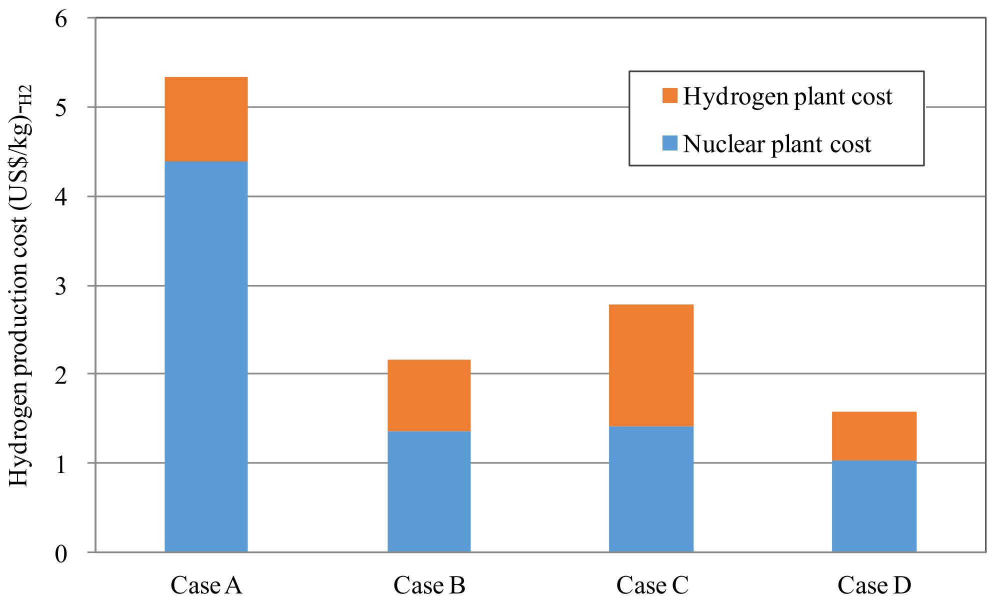


FIG. 71. The result of case studies by Canada

5.3.1.4. China

Results from China are given in Table 76. The nuclear to hydrogen plant cost ratio is shown in Fig. 72.

TABLE 76. CHINA LHGC FOR TECHNOLOGY BASED CASES (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.52	0.50	0.41	0.16
NP Capital cost (debt) ($/kg)	0.57	0.48	0.39	0.20
NP O&M + refurbishment ($/kg)	0.42	0.48	0.41	0.31
NP Decommissioning ($/kg)	0.09	0.01	0.02	0.01
NP Fuel ($/kg)	0.09	0.31	0.18	0.28
Total (nuclear plant) ($/kg)	1.69	1.77	1.4	0.97
H_2 Capital cost (equity) ($/kg)	0.11	0.19	0.14	0.39
H_2 Capital cost (debt) ($/kg)	0.10	0.20	0.13	0.41
H_2 O&M + refurbishment ($/kg)	0.16	0.57	0.30	0.62
H_2 Decommissioning ($/kg)	0.01	0.00	0.01	0.01
Total (hydrogen plant) ($/kg)	0.39	0.96	0.57	1.43
Total LHGC from production ($/kg)	2.08	2.73	1.98	2.40

Different from most other countries, China's predicted hydrogen generation costs are lowest for the Germany case (1.98 $/kg); the comparison shows the contribution from hydrogen plant O&M costs to be lowest for all countries. Highest hydrogen price is predicted for the China case (2.73 $/kg). With an estimated price of 2.08 $/kg- H_2 for the Canada case, China's price is lowest among all countries due to a small decommissioning costs contribution as a result of a high discount rate assumed.

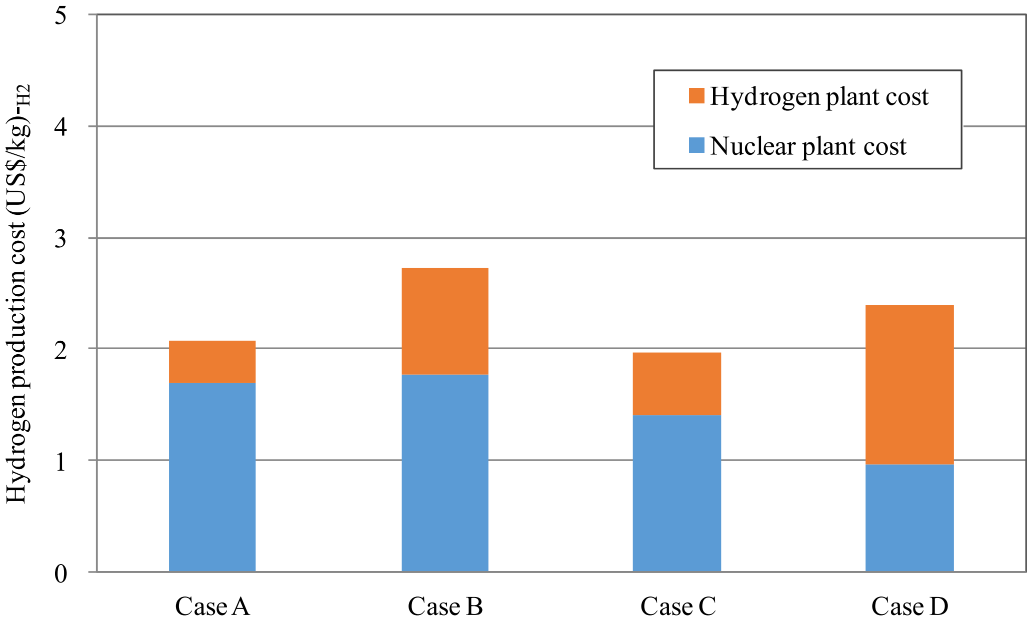


FIG. 72. The result of case studies by China

5.3.1.5. Germany

Results from Germany are given in Table 77. The nuclear to hydrogen plant cost ratio is shown in Fig. 73.

TABLE 77. GERMANY LHGC FOR TECHNOLOGY BASED CASES (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.85	0.81	0.76	0.44
NP Capital cost (debt) ($/kg)	0.46	0.36	0.34	0.23
NP O&M + refurbishment ($/kg)	0.47	0.49	0.49	0.34
NP Decommissioning ($/kg)	0.20	0.01	0.03	0.00
NP Fuel ($/kg)	0.10	0.31	0.21	0.51
Total (nuclear plant) ($/kg)	2.08	1.98	1.83	1.52
H_2 Capital cost (equity) ($/kg)	0.23	0.32	0.26	0.43
H_2 Capital cost (debt) ($/kg)	0.12	0.14	0.11	0.19
H_2 O&M + refurbishment ($/kg)	0.23	0.43	0.62	0.31
H_2 Decommissioning ($/kg)	0.03	0.01	0.01	0.00
Total (hydrogen plant) ($/kg)	0.61	0.90	1.00	0.93
Total LHGC from production ($/kg)	2.69	2.88	2.83	2.45

For all four cases, Germany results are very close to those provided with the HEEP default financial parameters. For the China case, Germany assesses with 2.88 $/kg the highest hydrogen price for all cases and also the highest price among all countries, the latter due a large contribution from capital costs. Lowest hydrogen price is like most other countries being assessed for the Japan case.

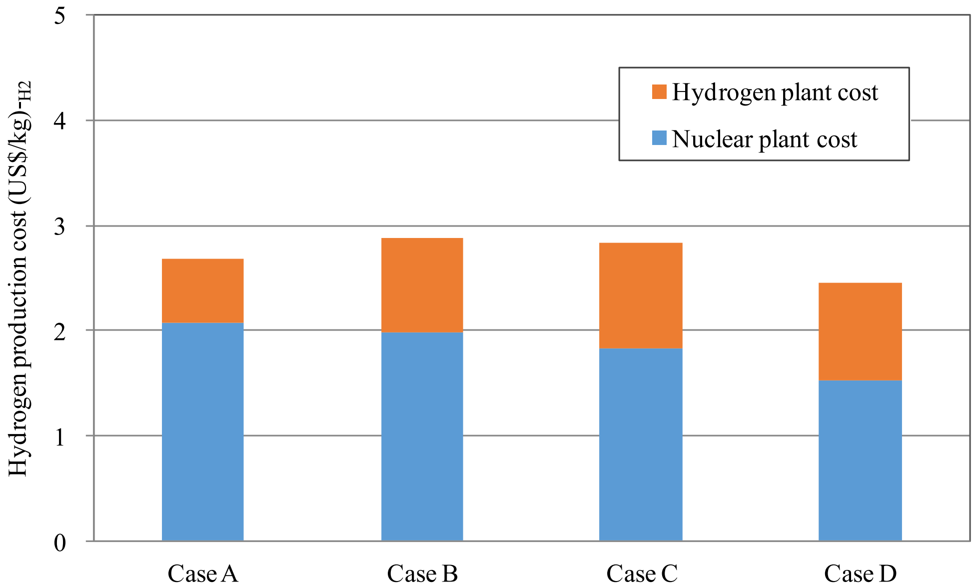


FIG. 73. The result of case studies by Germany

5.3.1.6. India

Results from India are given in Table 78. The nuclear to hydrogen plant cost ratio is shown in Fig. 74.

TABLE 78. INDIA LHGC FOR TECHNOLOGY BASED CASES (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.40	0.32	0.33	0.19
NP Capital cost (debt) ($/kg)	0.84	0.64	0.67	0.45
NP O&M + refurbishment ($/kg)	0.52	0.45	0.49	0.35
NP Decommissioning ($/kg)	0.43	0.02	0.06	0.00
NP Fuel ($/kg)	0.11	0.27	0.20	0.49
Total (nuclear plant) ($/kg)	2.30	1.69	1.74	1.49
H_2 Capital cost (equity) ($/kg)	0.11	0.13	0.11	0.19
H_2 Capital cost (debt) ($/kg)	0.22	0.26	0.23	0.37
H_2 O&M + refurbishment ($/kg)	0.26	0.53	1.23	0.31
H_2 Decommissioning ($/kg)	0.07	0.01	0.02	0.00
Total (hydrogen plant) ($/kg)	0.66	0.92	1.59	0.87
Total LHGC from production ($/kg)	2.96	2.62	3.33	2.36

India's predicted hydrogen price is lowest for the Japan case (2.36 $/kg) and highest for the Germany case (3.33 $/kg). The price in the Germany case is also highest among all countries due to large contributions from both capital costs and O&M costs.

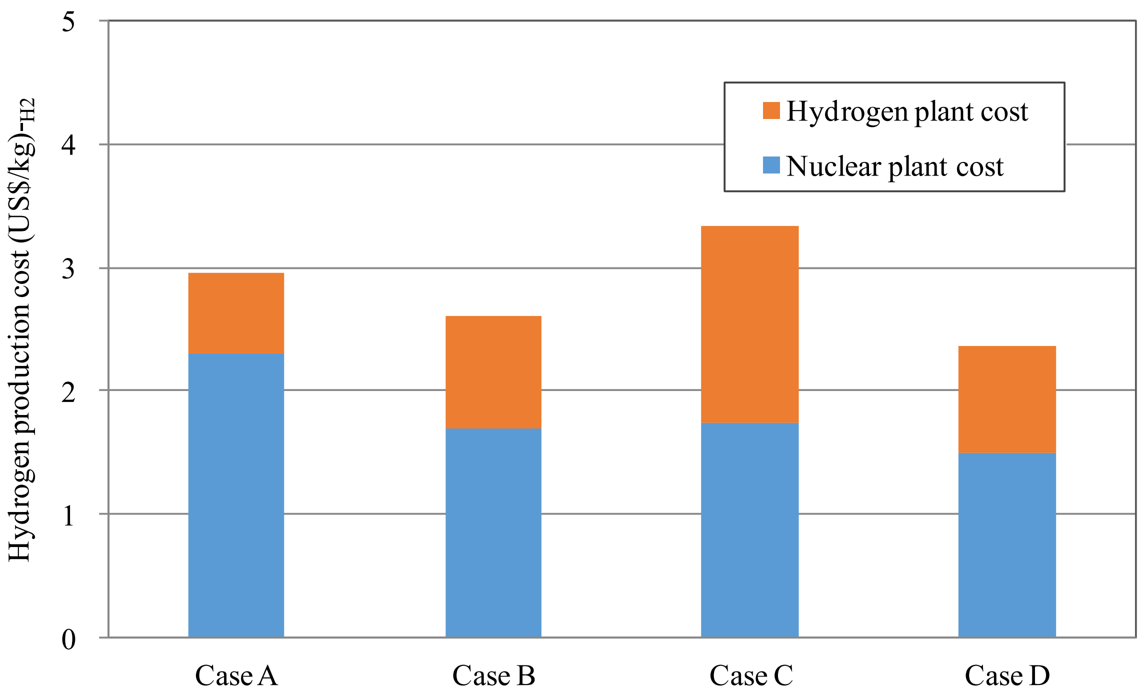


FIG. 74. The result of case studies by India

5.3.1.7. Japan

Results from Japan are given in Table 79. The nuclear to hydrogen plant cost ratio is shown in Fig. 75.

TABLE 79. JAPAN LHGC FOR TECHNOLOGY BASED CASES (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.	0.	0.	0.
NP Capital cost (debt) ($/kg)	0.72	0.59	0.56	0.38
NP O&M + refurbishment ($/kg)	0.47	0.45	0.44	0.31
NP Decommissioning ($/kg)	1.05	0.06	0.13	0.01
NP Fuel ($/kg)	0.09	0.26	0.17	0.41
Total (nuclear plant) ($/kg)	2.33	1.36	1.30	1.11
H_2 Capital cost (equity) ($/kg)	0.	0.	0.	0.
H_2 Capital cost (debt) ($/kg)	0.19	0.24	0.19	0.31
H_2 O&M + refurbishment ($/kg)	0.23	0.53	1.11	0.28
H_2 Decommissioning ($/kg)	0.18	0.02	0.04	0.00
Total (hydrogen plant) ($/kg)	0.60	0.79	1.34	0.59
Total LHGC from production ($/kg)	2.93	2.15	2.64	1.70

Japan predicts lowest hydrogen price for the Japan case (1.70 $/kg). Highest price is being calculated with 2.93 $/kg for the Canada case. Compared to other countries, Japan has generally a small contribution from capital cost which is exclusively based on borrowed capital in connection with a – typical for Japan – low interest rate.

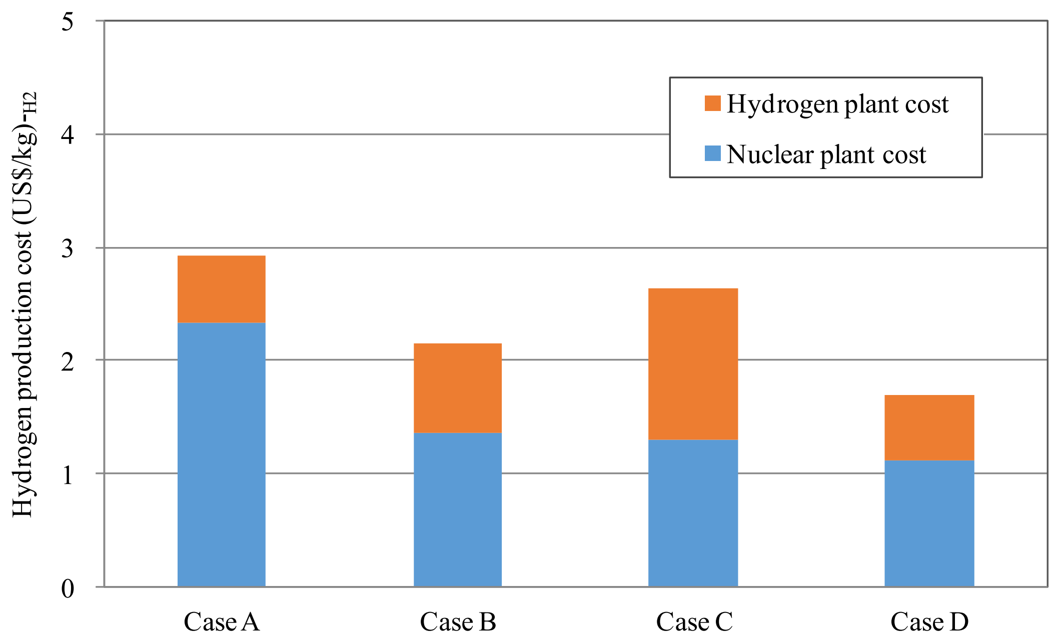


FIG. 75. The result of case studies by China

5.3.1.8. Pakistan

The results from Pakistan are given in Table 80. The nuclear to hydrogen plant cost ratio is shown in Fig. 76.

TABLE 80. PAKISTAN LHGC FOR TECHNOLOGY BASED CASES (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.56	0.23	0.43	0.30
NP Capital cost (debt) ($/kg)	0.13	0.06	0.11	0.06
NP O&M + refurbishment ($/kg)	0.48	0.22	0.44	0.29
NP Decommissioning ($/kg)	1.10	0.03	0.13	0.01
NP Fuel ($/kg)	0.09	0.13	0.17	0.41
Total (nuclear plant) ($/kg)	2.36	0.67	1.28	1.07
H_2 Capital cost (equity) ($/kg)	0.15	0.09	0.15	0.24
H_2 Capital cost (debt) ($/kg)	0.04	0.02	0.04	0.06
H_2 O&M + refurbishment ($/kg)	0.23	0.26	1.11	0.28
H_2 Decommissioning ($/kg)	0.19	0.01	0.04	0.00
Total (hydrogen plant) ($/kg)	0.61	0.39	1.34	0.58
Total LHGC from production ($/kg)	2.97	1.06	2.62	1.65

Pakistan's predicted hydrogen price is lowest for Case B (1.06 $/kg) and highest for Case A (2.97 $/kg). The extremely low LHGC value in Case B is mainly due to the assumed zero refurbishment for the hydrogen plant. In Case C with steam reforming, Pakistan conducted an additional sensitivity calculation with regard to the gas price; for the more realistic domestic natural gas price of 6 US $ per million BTU, the H_2 O&M costs would be reduced to 0.86 $ resulting in a total LHGC of 2.39 $.

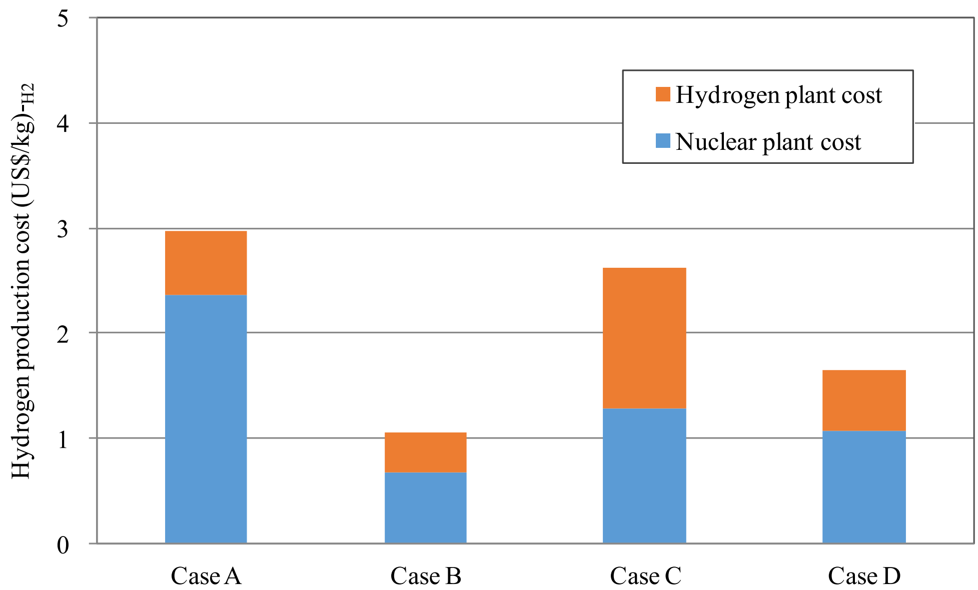


FIG. 76. The result of case studies by Pakistan

5.3.1.9. Republic of Korea

The results from the Republic of Korea are given in Table 81. The nuclear to hydrogen plant cost ratio is shown in Fig. 77.

TABLE 81. REPUBLIC OF KOREA LHGC FOR TECHNOLOGY BASED CASES (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.28	0.24	0.23	0.13
NP Capital cost (debt) ($/kg)	0.58	0.55	0.51	0.34
NP O&M + refurbishment ($/kg)	0.47	0.45	0.44	0.31
NP Decommissioning ($/kg)	1.52	0.08	0.18	0.01
NP Fuel ($/kg)	0.09	0.25	0.17	0.41
Total (nuclear plant) ($/kg)	2.94	1.57	1.53	1.20
H_2 Capital cost (equity) ($/kg)	0.08	0.10	0.08	0.12
H_2 Capital cost (debt) ($/kg)	0.15	0.22	0.17	0.28
H_2 O&M + refurbishment ($/kg)	0.23	0.53	1.11	0.28
H_2 Decommissioning ($/kg)	0.26	0.03	0.05	0.00
Total (hydrogen plant) ($/kg)	0.72	0.88	1.41	0.68
Total LHGC from production ($/kg)	3.66	2.45	2.94	1.88

The hydrogen price predicted by the Republic of Korea is lowest for the Japan case (1.88 $/kg) and highest for the Canada case (3.66 $/kg).

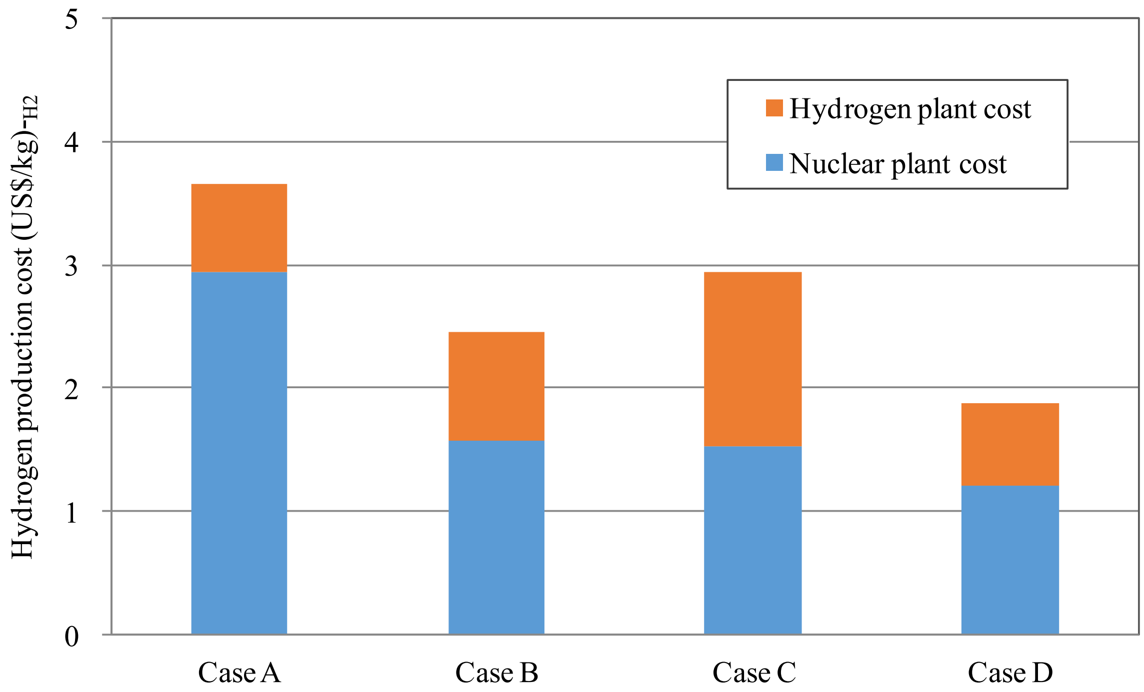


FIG. 77. The result of case studies by Republic of Korea

5.3.1.10. *HEEP default financial parameters*

The results applying the HEEP default financial parameter set are given in Table 82. The nuclear to hydrogen plant cost ratio is shown in Fig. 78.

TABLE 82. LHGC FOR TECHNOLOGY BASED CASES WITH HEEP DEFAULT DATA (DETAILED RESULTS)

Cases	Case A	Case B	Case C	Case D
NP Capital cost (equity) ($/kg)	0.67	0.65	0.61	0.35
NP Capital cost (debt) ($/kg)	0.47	0.48	0.45	0.30
NP O&M + refurbishment ($/kg)	0.47	0.49	0.49	0.34
NP Decommissioning ($/kg)	0.53	0.03	0.08	0.00
NP Fuel ($/kg)	0.10	0.29	0.20	0.48
Total (nuclear plant) ($/kg)	2.24	1.94	1.83	1.47
H_2 Capital cost (equity) ($/kg)	0.18	0.26	0.21	0.34
H_2 Capital cost (debt) ($/kg)	0.12	0.19	0.15	0.25
H_2 O&M + refurbishment ($/kg)	0.23	0.43	0.62	0.31
H_2 Decommissioning ($/kg)	0.09	0.01	0.02	0.00
Total (hydrogen plant) ($/kg)	0.62	0.89	1.00	0.90
Total LHGC from production ($/kg)	2.86	2.83	2.83	2.37

HEEP calculations with default financial parameters lead to LHGC values which in none of the four cases are the lowest or highest prices, but are typically located in the upper price range. Like for the majority of all countries, the lowest hydrogen production price is yielded for the Japan case (2.37 $/kg) and the highest price for the Canada case (2.86 $/kg).

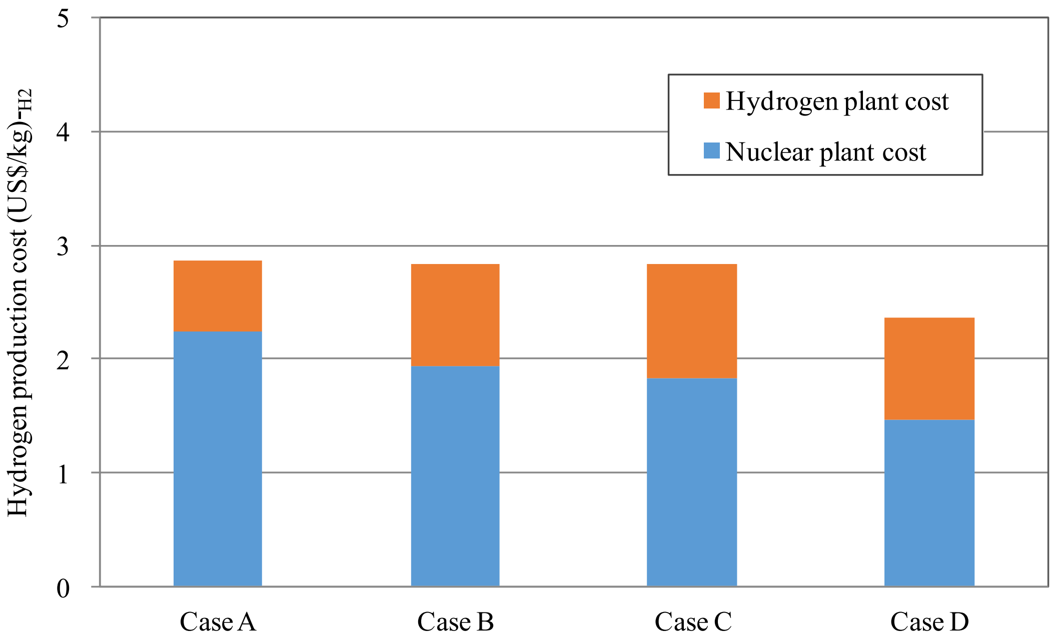


FIG. 78. The result of case studies with HEEP default financial parameters

5.3.2. Analysis of country specific results

The results of the HEEP calculations obtained by the various countries are displayed in the following Figures 12 through 15 comparing case by case.

5.3.2.1.Case A

Figure 79 contains the comparison of HEEP results for the EC6 case provided by Canada based on the Enhanced CANDU6 reactor connected to the 5-step Cu–Cl hybrid cycle and employing country specific financial parameters. While for most countries their calculated LHGC is between 2.08 and 3.66 \$/kg-H_2, two countries have achieved strikingly higher values above 5 \$/kg characterized by a significant contribution from decommissioning. In the case of the Canada calculation, this is due to the assumed high decommissioning cost of 14.75% of CC and the long decommissioning time of 50 years in combination with a low real discount rate of 2%. It similarly applies to the Argentina calculation also, however, obviously unintentionally, as the discount rate originally fixed at 8% was set to 0% by the HEEP program (because of the unwise assumption of an inflation rate higher than the discount rate). Higher discount rates lead to a reduction of the decommissioning portion as can be seen from the other countries' results. Another observation in Fig. 79 is the large contribution from the nuclear plant to the hydrogen price, which is due to the capital costs of four big nuclear units producing an enormous excess amount of electricity that is not required in the hydrogen production and not reflected in (a reduction of) the LHGC.

5.3.2.2.Case B

Figure 80 contains the comparison of HEEP results for the HTR-PM case provided by China based on the HTR-PM reactor connected to the S–I cycle and employing country specific financial parameters. For all countries except Pakistan, LHGC values are in the range between 2.15 and 2.88 \$/kg-H_2. The exceptionally low LHGC value provided by Pakistan for the China case is due to the assumption of zero refurbishment cost. The nuclear share is slightly more than half of the overall hydrogen cost. As the electricity required is assumed to be obtained from grid, the contribution from O&M costs of the H_2 plant is comparatively large.

5.3.2.3.Case C

Figure 81 contains the comparison of HEEP results for the HTR-Modul case provided by Germany based on the process heat variant of the HTR-Modul reactor connected to steam reforming of natural gas and employing country specific financial parameters. For all countries except Pakistan, LHGC values are in the range between 1.98 and 3.33 \$/kg-H_2. The lowest LHGC provided by China is characterized by a comparatively low-cost contribution from the steam reforming plant. The large contribution from hydrogen plant O&M cost is clearly visible. This is due to the methane feedstock required and the natural gas price, respectively. The German gas price assumed here is not necessarily representative for other countries and will certainly have a major influence on the SMR-based LHGC in countries with cheap gas prices.

5.3.2.4.Case D

Figure 82 contains the comparison of HEEP results for the GTHTR300C case provided by Japan based on the cogeneration variant of the GTHTR300 reactor connected to the S–I cycle and employing country specific financial parameters. For this case, all LHGC values calculated are within a narrow price range of 1.58 to 2.40 \$/kg-H_2, representing at the same time the lowest average specific hydrogen production costs. The nuclear costs are covering roughly two thirds of the overall hydrogen price, with the exception of the China calculation where the nuclear share is even less than half of the total value.

5.3.2.5.Comparison of the cases

HEEP results provided by the participating countries for the four technology cases are in a relatively narrow range, i.e. comparing well with each other. The exception is the Canada case where two countries predict an almost double as high LHGC as the others.

Lowest costs of hydrogen were found for the Japan case (GTHTR300C plus S–I), for which the results from all countries remained below 2.50 US \$/kg-H_2. Ranking second is the China case (HTR-PM plus S–I) with all results being below 3.00 US \$/kg-H_2. This holds true also for most results for the Canada case (EC6 plus Cu–Cl), but again here are also some results with exceedingly higher prices. For the Germany case (HTR-Modul plus SMR), HEEP results are ranging from ~2 to ~3.3 US \$/kg-H_2.

Different from the generic case study (where assumed financial parameters were essentially the same), countries with low-cost predictions compared to the other countries for the one case may predict higher cost in the other cases.

HEEP results with default financial parameters are typically well within the range of the other countries' results, meaning that the default set represents a good average basis for cost assessments.

The ratio of nuclear vs. hydrogen cost in the LHGC is strongly biased towards nuclear in the Canada case, while the share of hydrogen is larger for the other three, HTGR-based technology cases.

Differences in the cost contributions from capital cost are basically arising from the different assumptions for real discount rate and the borrowed capital ratio. In relation, tax rate and depreciation period appear to be of minor importance.

With increasing interest rates (mix of capital market and borrowing capital interest rates) investment costs are gaining more importance (since they have to be paid today) versus decommissioning costs (which have to be paid later).

Decommissioning cost data vary from 0.52% of CC in Japan to 14.75% of CC in Canada whereas decommissioning periods vary from 10 years to 50 years. As a result, the share of levelized decommissioning cost in total cost of hydrogen production also varies significantly among the technology cases. The above mentioned strong deviation of the two countries' results from the others in the Canada case is due to extremely large contributions from the nuclear (also the H_2 plant) decommissioning costs. This is due to the assumed high decommissioning cost and long decommissioning time in combination with a low real discount rate.

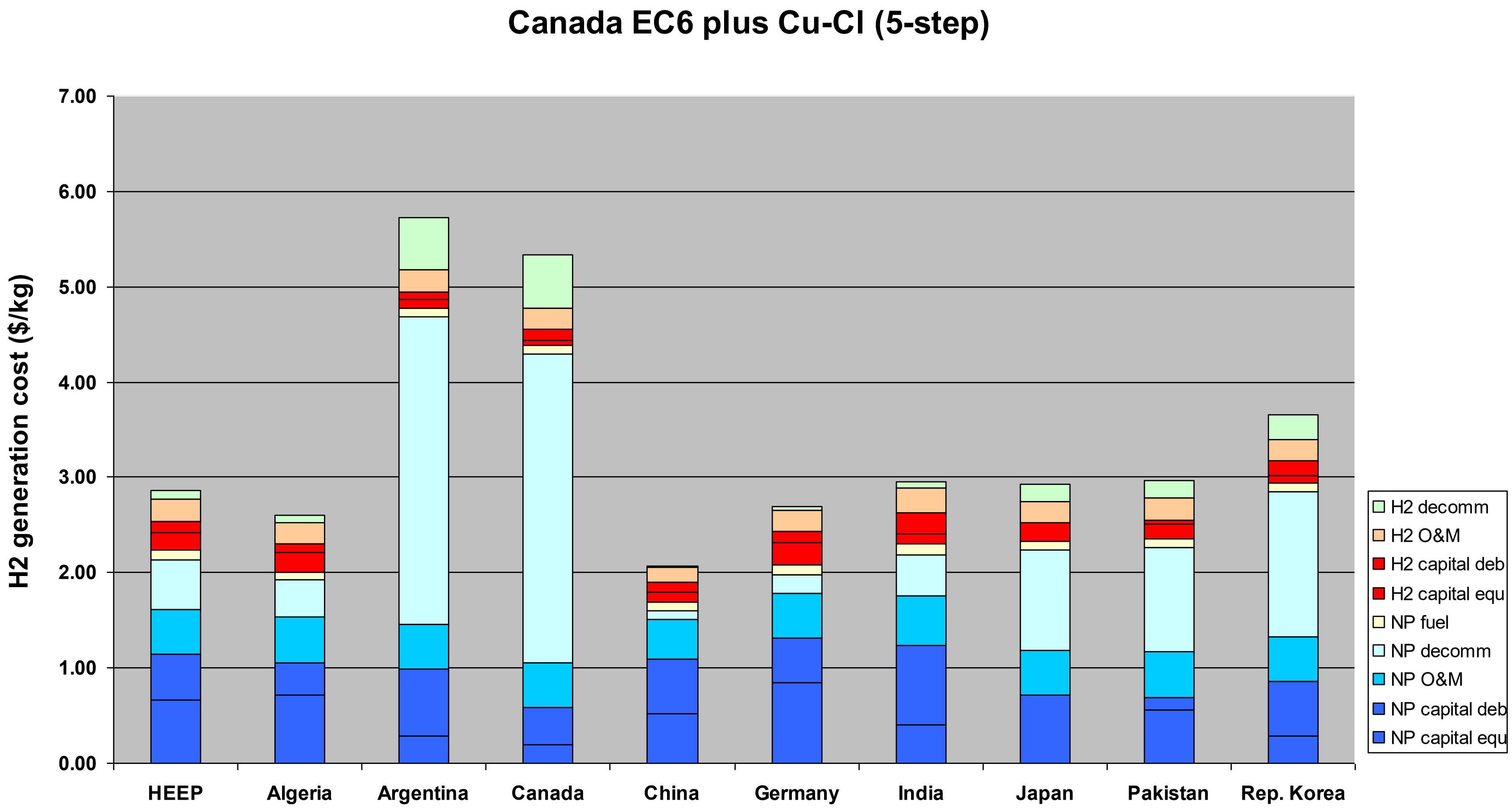


FIG. 79. Comparison of the countries' results of LHGC for Case A.

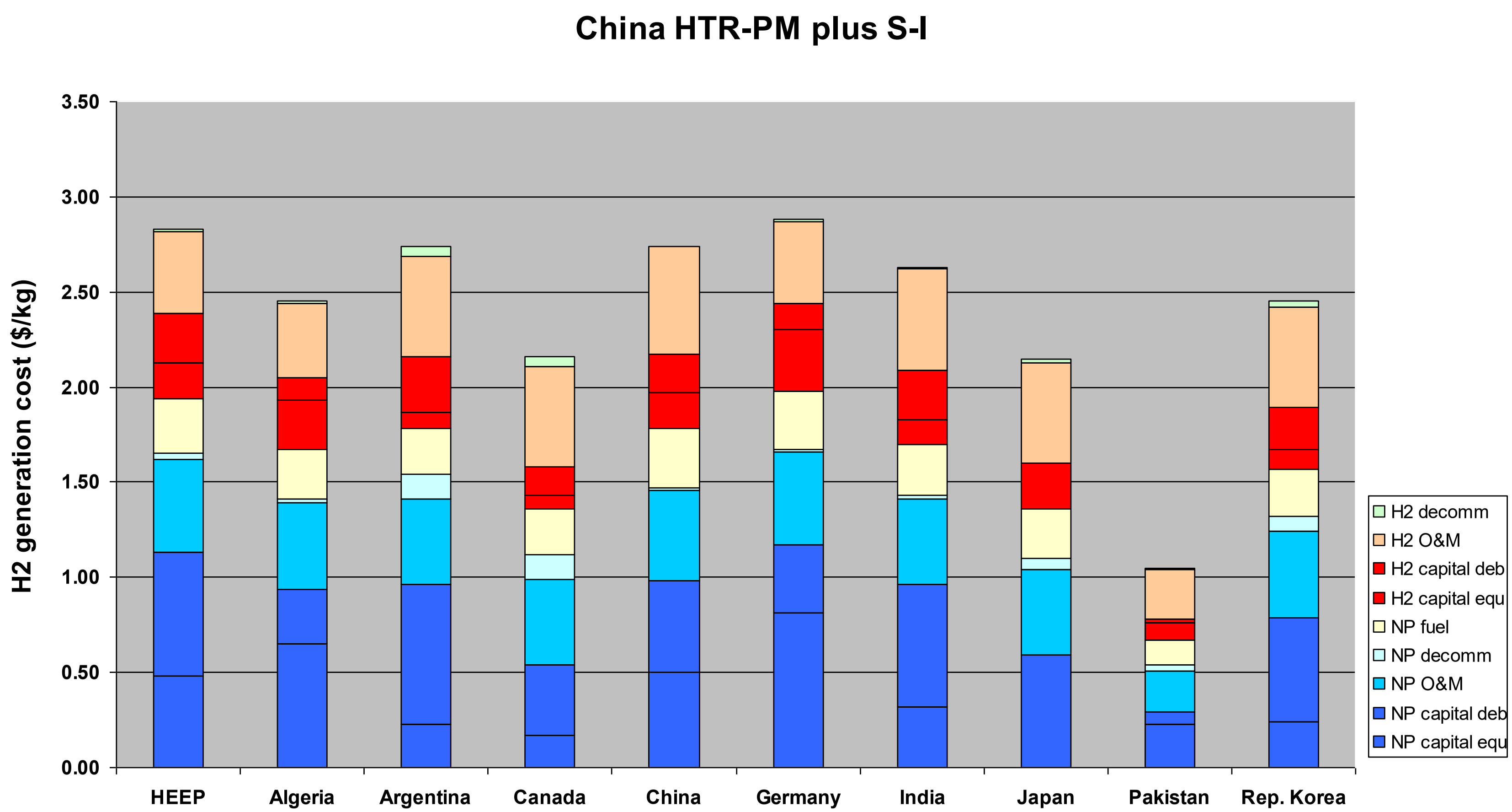


FIG. 80. Comparison of the countries' results of LHGC for Case B.

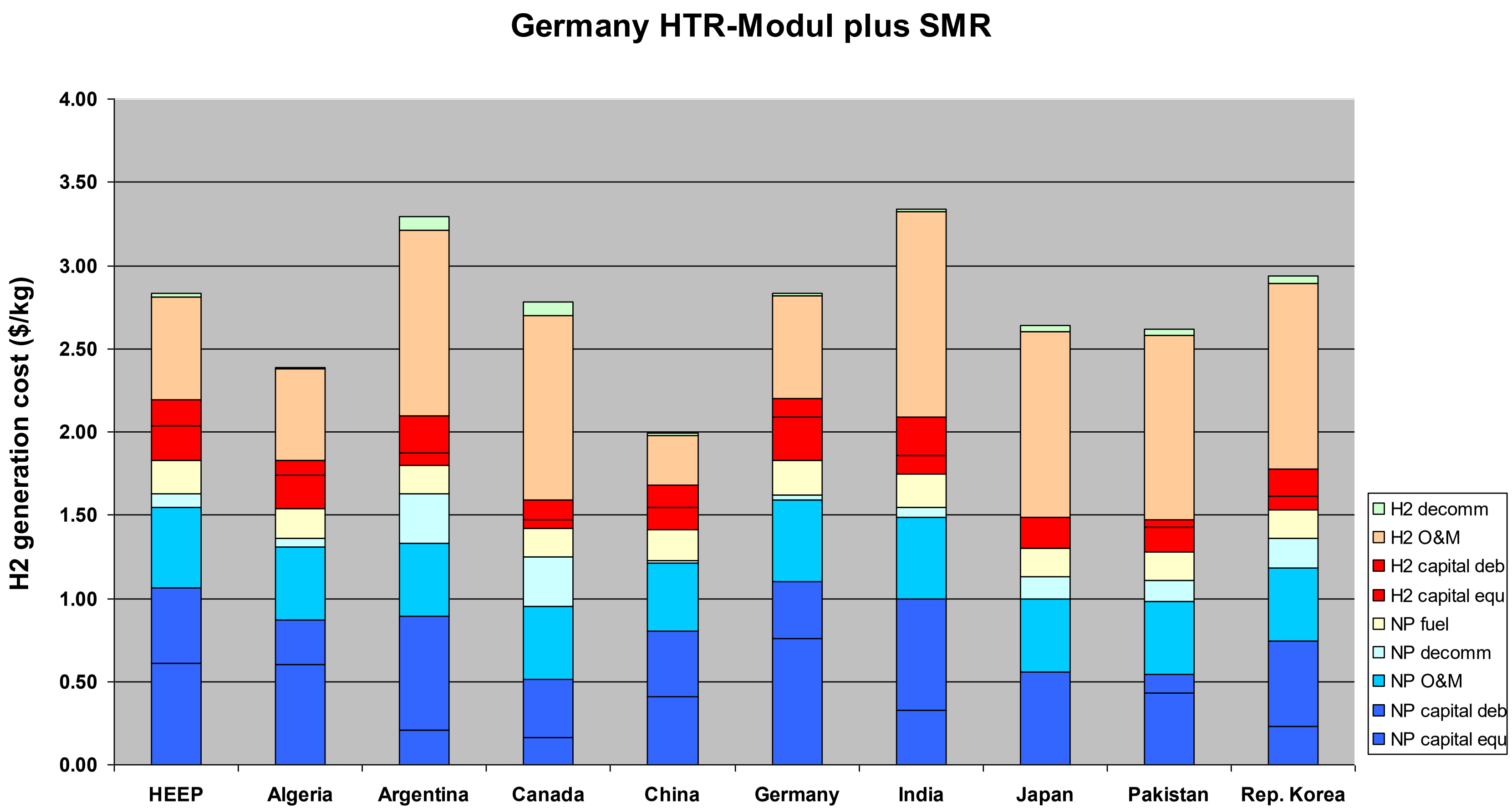


FIG. 81. Comparison of the countries' results of LHGC for Case C

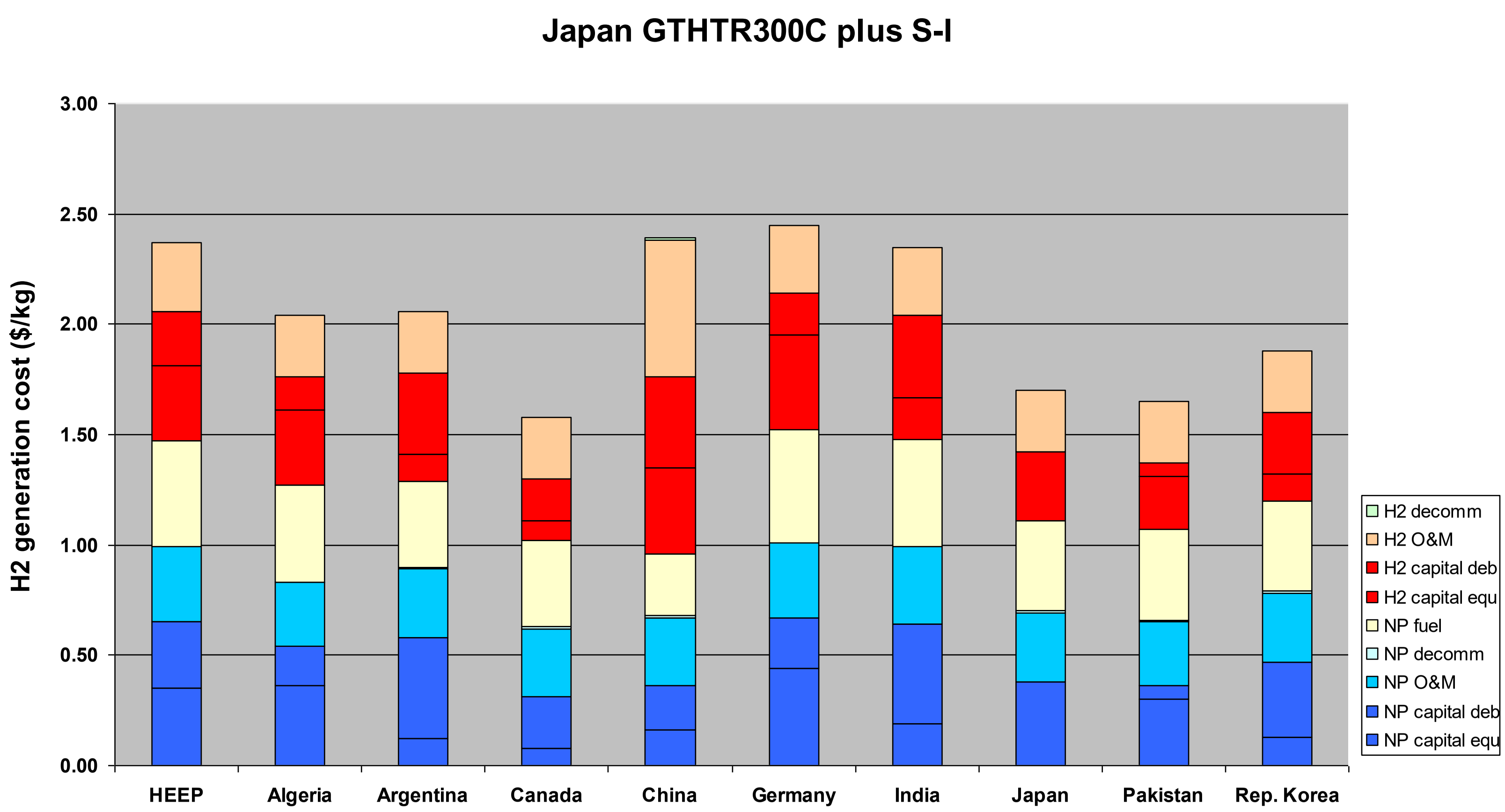


FIG. 82. Comparison of the countries' results of LHGC for Case D.

5.4. ADDITIONAL COUNTRY-SPECIFIC CASE STUDIES

The following subsections provide a few highlights taken from the country reports that provide interesting information from additional sensitivity or case studies.

5.4.1. Argentina

Argentina conducted a specific case study to assess the LHGC for the CANDU 6 reactor, located at Embalse Río Tercero, Córdoba and in commercial operation since 1984, assumed to be coupled to a co-located H_2 generation plant based on low-temperature electrolysis. The nuclear plant has a thermal power capacity of 2160 MW(th) producing an electricity output of 640 MW(e). The capital costs (CC) assumed are 2000 million US \$, while O&M costs amount to 4.48% of CC and decommissioning costs 14.75% of CC. With the total electric power generated being consumed in the electrolysis process, the hydrogen plant can operate with a production capacity of (gross) 3.4 kg H_2/s. The H_2 plant has capital costs of 400 million US \$, furthermore assuming 4% of cc for O&M costs and 10% for decommissioning costs. It was noted that the NNP input data regarding costs are dated from the 1980s, whereas financial parameters correspond to the present conditions of the Argentina economy.

The LHGC through this combination of CANDU reactor plant and low-temperature electrolysis plant and ignoring transportation and storage cost has been estimated to be 4.03 U\$D/kg-H_2, of which ~85% is the contribution from the nuclear plant. These costs fall in the same range as those from other alternatives and also those obtained by other cost models.

5.4.2. Canada

Apart from the above described Canada technology case (EC6 plus 5-step Cu–Cl cycle), three more options of thermochemical cycles for H_2 production have been investigated, the 3-step Cu–Cl cycle as well as from the sulfur family the S–I and the HyS processes. The nuclear energy source remained the same, i.e. an EC6 plant composed of four units with 629.88 MW(e) electric power output and each unit being connected to a chemical heat pump producing 159.58 MW(th) for heat upgrading. The essential HEEP input data for the four cases are listed in Table 83. The required power for H_2 production is taken from the nuclear system, while the left-over electricity is directed to the grid.

TABLE 83. INPUT PARAMETERS FOR THE CANADIAN EC6/CANDU6 NUCLEAR PLANT COUPLED TO FOUR DIFFERENT HYDROGEN PRODUCTION METHODS

Hydrogen production plant	S–I	HyS	Cu–Cl (3-step)	Cu–Cl (5-step)
Number of units	1	1	1	1
Heat consumption (MW(th)/unit)	638.36	638.36	638.36	638.36
Power consumption (MW(e)/unit)	0	181.44	266.89	273.35
Production rate (M kg/(unit·a))	75	124	131	134
Capital cost (M \$/unit)	189.75	326.88	395.07	400.23
O&M cost (% of CC)	7.0	6.8	7.0	7.0
Decommissioning cost (% of CC)	10	10	10	10

HEEP results show that the two Cu–Cl cycles yield a similar price for 1 kg of hydrogen produced, 5.34 US $ and 5.39 US $ for the 5-step and 3-step cycle, respectively. In contrast, costs of hydrogen generated in the sulfur cycles are somewhat lower with 4.10 US $/kg and 4.74 US $/kg for the S–I cycle and the hybrid cycle, respectively. The nuclear share of the price is for all four cases about the same being ~82%. But it should be noted here again that no credit is taken from the large amount of excess electricity produced from the NPP.

5.4.3. China

Following successful start-up operations of the HTR-PM demonstration NPP in China, the next project will be a modular commercial plant, HTRPM600, which will consist of three of the currently being constructed HTR-PM systems, i.e. six 250 MW(th) modules to generate a total of 1500 MW(th) or 600 MW(e).

Based on the Chinese HTR-PM project, the economic potentials of modular reactor nuclear power plant have been analysed by INET. The estimated budget excluding R&D and infrastructure cost for the first HTR-PM demonstration plant is to be $2000/kWe. The economic impact of the main equipment, such as RPV, reactor internals, NSSS, etc., along with the other capital estimates including capital cost, operation cost, fuel cost and power generation cost were analysed and compared with the established PWR technology. Assuming a hydrogen conversion efficiency of 40%, the H_2 production rate achievable is 4.5 kg/s. As there are presently no reliable cost data of H_2 production via the S–I cycle available, respective data from JAEA cost estimation were adjusted to the Chinese new case.

Running the HEEP software, the LHGC were estimated to be 2.52 US $/kg- H_2, not significantly but at least somewhat lower than the value obtained for the above described original HTR-PM case of 2.73 US $/kg. This comparison in more detail reveals most reduction in the capital cost related contribution, whereas contributions from O&M for both nuclear and hydrogen plants remained the same.

5.4.4. Germany

A sensitivity study was made where different nuclear process heat source concepts — the Chinese HTR-PM, the German HTR-Modul and the Japanese GTHTR300C — are connected to the Sulfur–Iodine thermochemical cycle for hydrogen production. For the German HTR-Modul, data concerning the S–I process of INET were adopted. HEEP calculation results are shown in Fig. 83.

It should be noted first that the comparison as made above is not really legitimate due to the different economic parameters characteristic for the three countries. For the GTHTR300C case, lowest H_2 generation costs of 2.96 $/kg can be found compared to the other two nuclear reactors with 4.96 $/kg and 9.43 $/kg, respectively. This is mainly due to the surprisingly small portion from the capital cost of the nuclear plant, whereas the largest contribution is from the capital cost of the hydrogen plant. In the other two cases, capital cost of the nuclear plants is contributing most — as would be expected — by 60% and 70%, respectively, to the overall H_2 cost. One reason for the small influence of the investment cost of the HTGR in the Japanese case are the relatively low investment costs of 911.70 $/kW(th) compared the HTR-Modul or the HTR-PM. Another important issue is the high capital cost fraction for electricity generation infrastructure of 66% in the Japanese case.

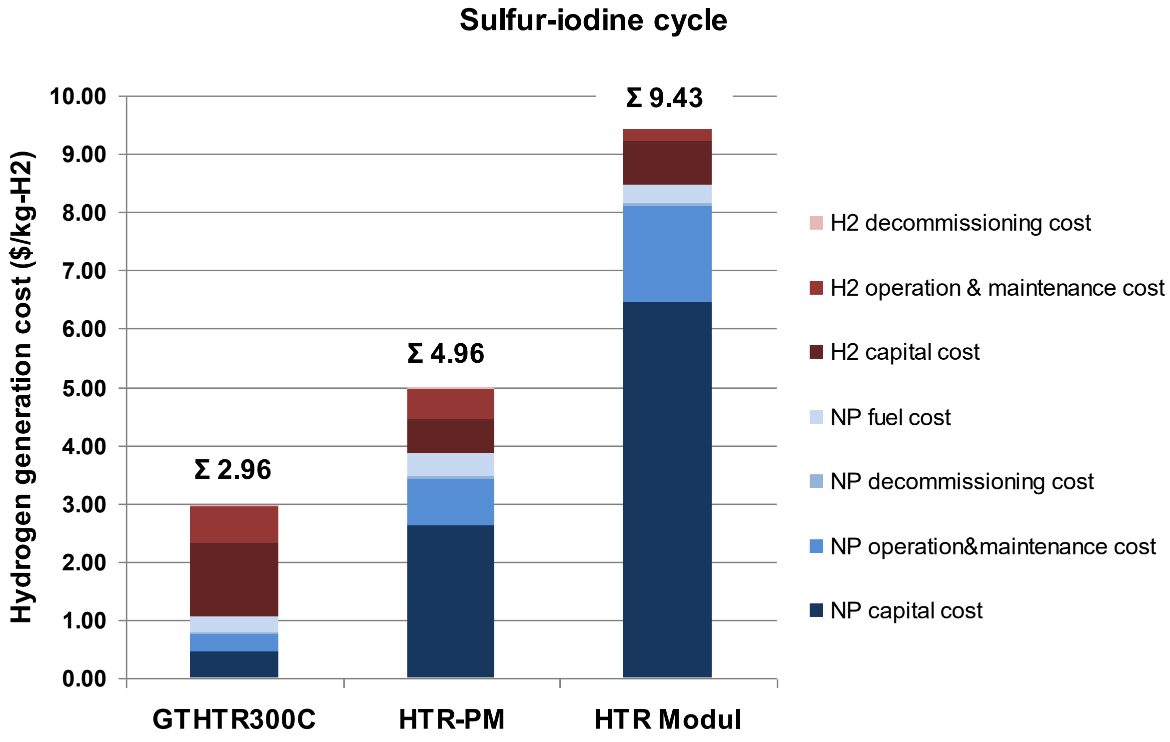


FIG. 83. Comparison of H_2 costs for different nuclear reactor concepts coupled to the Sulfur–Iodine cycle for H_2 production.

Generally, the estimation of the Levelized hydrogen generation costs only considers those costs, which directly arise for hydrogen production. The GTHTR300C generates 202 MW(el) electricity, whereas only 23 MW(el) are needed for the S–I process. That is why just this fraction (11.39%) is considered in the hydrogen cost estimation. Consequently, 58.49% ((100%–11.39%)×66%) of capital cost are neglected, as they don't occur for hydrogen production. Also operation and maintenance costs are higher in the Chinese and German plants in comparison to the Japanese case.

A similar sensitivity study was conducted, now with the HTR-Modul being connected to different hydrogen production technologies — steam–methane reforming, Sulfur–Iodine cycle and high temperature electrolysis. HEEP results for the three cases are shown in Fig. 84.

The application of a steam reforming system results by far in the lowest hydrogen production costs which are 3.16 $/kg-$H_2$. This price, however, includes a fairly large fraction for operation and maintenance cost of the hydrogen plant, mainly due to the natural gas feedstock price and the CO_2 emissions. The two water splitting plants are characterized by high capital costs and high operation and maintenance costs on the nuclear side resulting from their higher specific energy consumption and consequently lower specific H_2 production rates. Both methods show about the same generation cost for hydrogen.

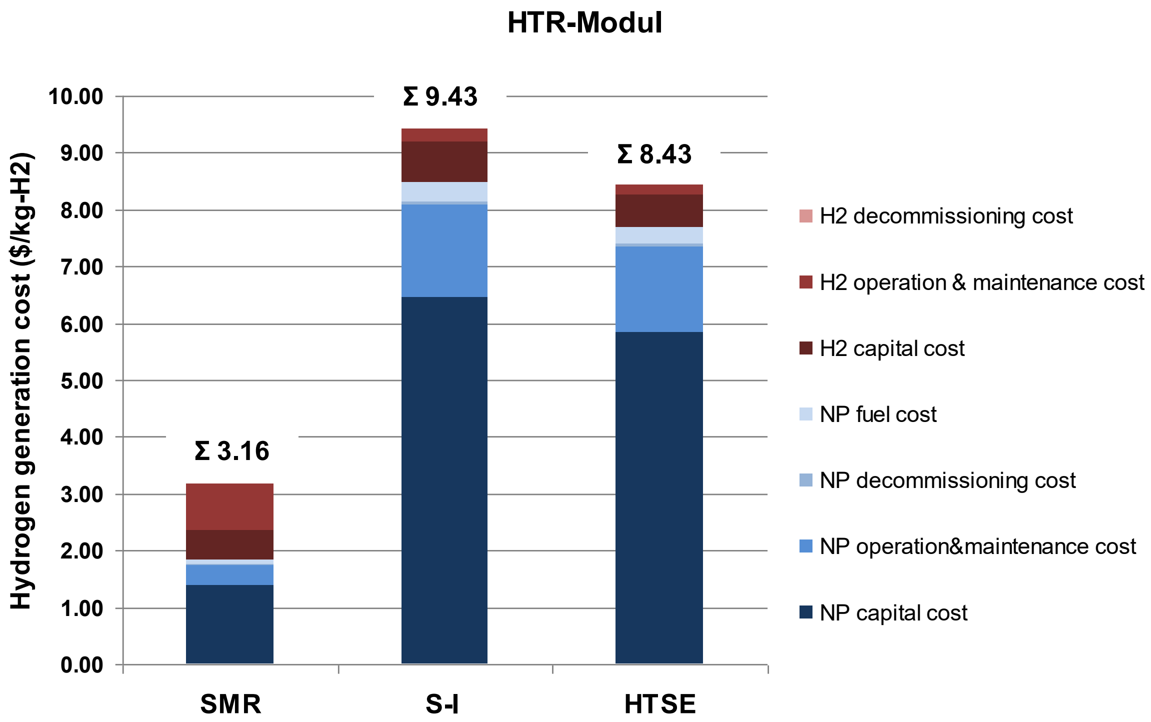


FIG. 84. Comparison of H_2 costs for HTR-Modul coupled to different H_2 production methods.

Striking is the large difference in the contribution from the nuclear plant to the specific hydrogen cost which is much larger for S–I and HTSE compared to SMR, although all are based on the same HTR-Modul. This is due to the correspondingly large difference in the H_2 production rate which is in the cases of the water splitting processes by more than a factor of 4 lower due to their higher energy intensity than in the case of SMR. Decommissioning cost for both the nuclear plant and the H_2 plant have both only a negligible contribution to the overall hydrogen production cost.

An interesting question remaining unanswered is what the effect on the H_2 price would be if the comparatively small share of electrical power production of the HTR-Modul were replaced with purchase of external electricity and then design the HTR-Modul as a dedicated process heat source which would simplify the nuclear plant with no need for the electricity generating components.

5.4.5. Japan

Fig. 85 compares the nominal costs of the hydrogen production for the CRP's four technology-based cases using HEEP default financial parameters, Japan's financial parameters and national finance parameters. The large difference in the costs in Case A (CANDU6+CuCI) is mainly due to the significant difference in Canada`s financial parameters assumed, in particular the discount rate and nuclear reactor decommissioning period and cost ratio, from the HEEP default and Japan`s parameters used (refer to Section 5.2).

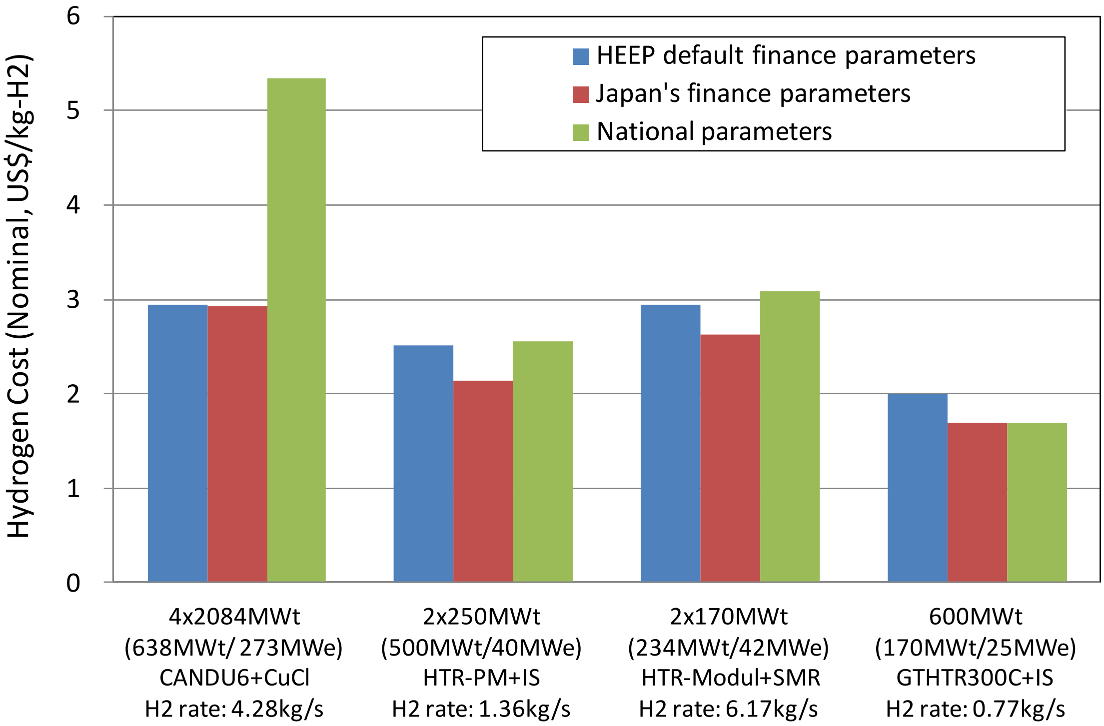


FIG. 85. CRP benchmark cases of nominal cost.

A JAEA-based cost analysis of nuclear hydrogen production was conducted using a JAEA-own methodology. Considering the same system (GTHTR300C+SI), differences to the original Japan technology case are given in the degree of detail of calculation. The capital cost of the hydrogen plant covers equipment cost, site construction cost and indirect cost. The utilities include the S–I process pumps, the helium circulator of the heat transport loop, feed water to the S–I process, electricity, as well as catalysts and chemicals used in the cycle. The required electricity is supplied in-house by the NPP at a cost of 3.2 US₵/kW·h at a discount rate of 3%. The S–I process is assumed to be 100% equity funded, for which the return of investment (ROI) is 8%.

The LHGC costs resulting from the detailed JAEA calculation amount to 2.17 US $, with a 64% contribution from the nuclear plant. This value could be further reduced to 1.89 if revenues from the sale of the by-product oxygen were taken into account. An estimation was also made with regard to the non-negligible cost for H_2 storage and transportation.

The 2.17 US $/kg-$H_2$ are well comparable with the 1.70 US $/kg-$H_2$ from the original HEEP calculation.

5.4.6. Pakistan

A study was conducted to assess the LHGC for three different H_2 production methods and assuming the same NPP but operated at different coolant outlet temperatures. Baseline NPP concept is the Chinese HTR-PM, a 2×250 MW(th) pebble bed modular reactor with a core outlet temperature of 750°C. As hydrogen conversion efficiencies typically increase with temperatures, respective coolant oulet temperatures were chosen adjusted to the considered processes of HTSE (T_{out} = 850°C), steam reforming of methane (T_{out} = 900°C), and S–I cycle (T_{out} = 950°C) and assuming a 50°C loss in temperature in the intermediate heat exchanger.

The natural gas price has been assumed as US $6/MBtu that includes all taxes, levies, royalties, and charges. At 750°C process temperature, natural gas consumption of SMR (coupled with nuclear reactor) is around 2.89 kilogram per kilogram hydrogen production where process efficiency is 80.9%. Natural gas consumption decreases as the core outlet temperature increases, resulting in saving natural gas of up to 30.9% compared to the conventional process.

Table 84 gives the estimates of capital costs of the reference 2×250 MW(th) HTR-PM plants and adjusted capital cost for different core outlet temperatures

HEEP results based on the above input data show that the cost of hydrogen production using nuclear coupled SMR plant is with 1.25 US $/kg-$H_2$ lowest in comparison to 2.10 US $/kg for the S–I cycle, and 2.36 US $/kg for HTSE.

TABLE 84. HEEP PARAMETERS ASSUMED IN THE PAKISTAN STUDY

Parameter	HTR-PM (2 × 250 MW(th) pebble-bed HTGR		
	T_{out} = 850°C	T_{out} = 900°C	T_{out} = 950°C
connected to	HTSE	Steam reforming	S–I cycle
Nuclear plant			
Thermal power [MW(th)]	2 × 250	2 × 250	2 × 250
Capital cost (M US $)	762	788	814
Intermediate loop cost (9% of cc)	69	71	73
Capacity factor	0.85	0.85	0.85
Thermal power for H_2 plant [MW(th)]	39	297	500
Electric power for H_2 plant [MW(th)]	179	78	0
Electricity generating infrastructure (% of cc)	12	12	0
O&M (% of cc)	3.1	3.1	3.1
Decommissioning (% of cc)	6.3	6.3	6.3
Hydrogen production plant			
H_2 production capacity (10^3 t/a)	46	201	68
Thermal power for H_2 plant [MW(th)]	39	297	500
Electric power for H_2 plant [MW(th)]	179	11.4	16.5
Capital cost (M US $)	156	681	340
O&M (% of cc)	9.15	4.2	7.5
Decommissioning (% of cc)	10	10	10

6. RESULTS AND DISCUSSIONS

This chapter presents the results achieved in each of the CRP activities conducted and discusses the findings regarding the techno-economics of nuclear hydrogen production. While only major results and discussions are possible to be presented here, more details and additional studies are included in the country reports available on the attached CD-ROM.

6.1. MAJOR RESULTS

6.1.1. Outcome of CRP

The CRP held research coordinated meetings annually during the four years of the project duration, where the Chief Scientific Investigators, in rare cases their representatives, of the participating Member States exchanged up-to-date information on national activities and status of research and development on nuclear hydrogen production in general and economics assessment in particular.

The period of the CRP also saw some of the most significant progresses being made. China was building the prototype reactor plant HTR-PM with an operation date in 2018 and shared the practical design and cost input. Japan built an engineering test loop for autonomous high temperature thermochemical production of hydrogen, designed the hydrogen cogeneration facility for coupling to the existing HTTR test reactor in JAEA, exchanged the knowledge gained including the design and cost projection of commercial systems.

Germany having conducted the PNP project including development of nuclear steam reforming of methane in the 1980s and 1990s and the USA through the NHI studied a range of thermochemical, electrolytic and hybrid options in the 2000s were the forerunners of national programs for nuclear hydrogen production. The information developed and lessons learned in these past programs proved extremely useful. In fact, relevant design data have been provided to some of the case studies performed by all participants.

Detailed activities and outcome throughout the implementation of the CRP can be found in the country reports available on the attached CD-ROM.

6.1.2. Techno-economics of nuclear hydrogen productions

Cost of nuclear hydrogen production was found to be sensitive to the technologies employed. The key technical parameters include the types of nuclear reactors, source of energy input to hydrogen production, i.e. partially supplied or fully cogenerated in house, thermal efficiency of the processes and operation life cycle of the reactors or processes.

Moreover, the hydrogen cost appears sensitive to the specific financial parameters typically used in developing nuclear projects in Member States. The discount rate, borrowing interest, equity to debt ratio, inflation rate, and plant operating years are found to wield more heavily on final hydrogen cost than the depreciation period, tax rate and others.

The APWR-based conventional electrolysis plants where the nuclear plant cost has a greater share in the final hydrogen cost appear more sensitive to the financing conditions than the HTGR-based plants where reactor and hydrogen plants tend to have similar shares in the final hydrogen cost. For example, the difference in final hydrogen nominal cost is 31% for one of the APWR-based cases between the HEEP default values and Japan's financial parameter values, while this difference is narrowed to about 12% for one of the HTGR-based cases.

Nuclear hydrogen production is found to be potentially cost competitive to conventional steam reforming, coal gasification or water electrolysis using renewable energy sources, but to the extend depending on the financial assumptions. More details are discussed in Section 6.2.5.

6.1.3. Benchmark of HEEP

6.1.3.1.Generic benchmark

The CSIs performed the benchmark analysis of the five generic cases provided by IAEA using each country`s specific financing conditions. Table 85 outlines these cases covering various combinations of reactor designs and hydrogen processes. The benchmark results obtained have demonstrated the reliability of the HEEP software for predicting the hydrogen cost. The quality of the prediction is seen here in the comparison of the HEEP calculated costs among these cases while further accuracy of the prediction is seen in the results of the code-to-code benchmark as discussed in the following sections.

TABLE 85. FIVE GENERIC CASES USED FOR THE BENCHMARKING OF HEEP

	Case 1	Case 2	Case 3	Case 4a	Case 5
Nuclear plant	APWR	APWR	APWR	HTGR	HTGR
Number of reactors	2	2	2	2	2
Rating per reactor	359.5 MW(e)	719 MW(e)	1117.1 MW(e)	546.5 MW(th)	630.7 MW(th)
Hydrogen plant	APWR	APWR	APWR	HTGR	HTGR
Number of units	1	1	1	1	1
Hydrogen rate	4 kg/s	8 kg/s	12.43 kg/s	4 kg/s	4 kg/s

Figure 86 compares the hydrogen costs of the generic cases calculated by HEEP using the default financial parameters. For Cases 1 to 3, whose designs are the same combining a Generation III APWR with conventional low-temperature water electrolysis (CE) except at increasing production rate, about 90% of the final hydrogen production cost comes from the nuclear plant cost. The HEEP can correctly predict the economy of scale as expected from increasing the production capacity, for which the HEEP correctly predicts. Using the HEEP default financial parameters the levelized cost of hydrogen is US \$5.46/kg- H_2 for Case 1 and reduces to US \$3.49/kg- H_2 in Case 3.

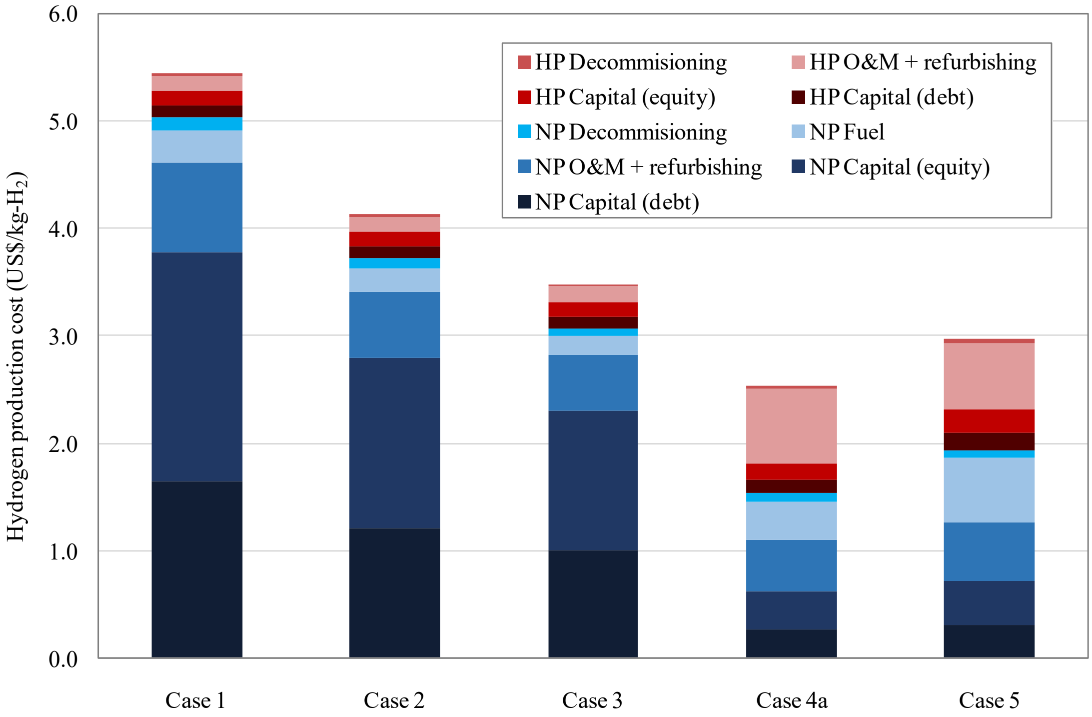


FIG. 86. Levelized hydrogen generation cost for the generic cases (HEEP default financial values)

For Cases 4 and 5, whose designs are based on Generation IV HTGR and advanced hydrogen production processes of HTSE and S–I, HEEP projects the lower costs of hydrogen comparing to the APWR based cases. An important contribution to the lower costs of the HTGR-based production is the higher thermal efficiency, as one would expect, of the combination of the advanced reactor with the high temperature hydrogen production processes. The efficiency is about 52% for HTGR-HTSE and 46% for HTGR-SI, comparing to about 26% for APWR-CE.

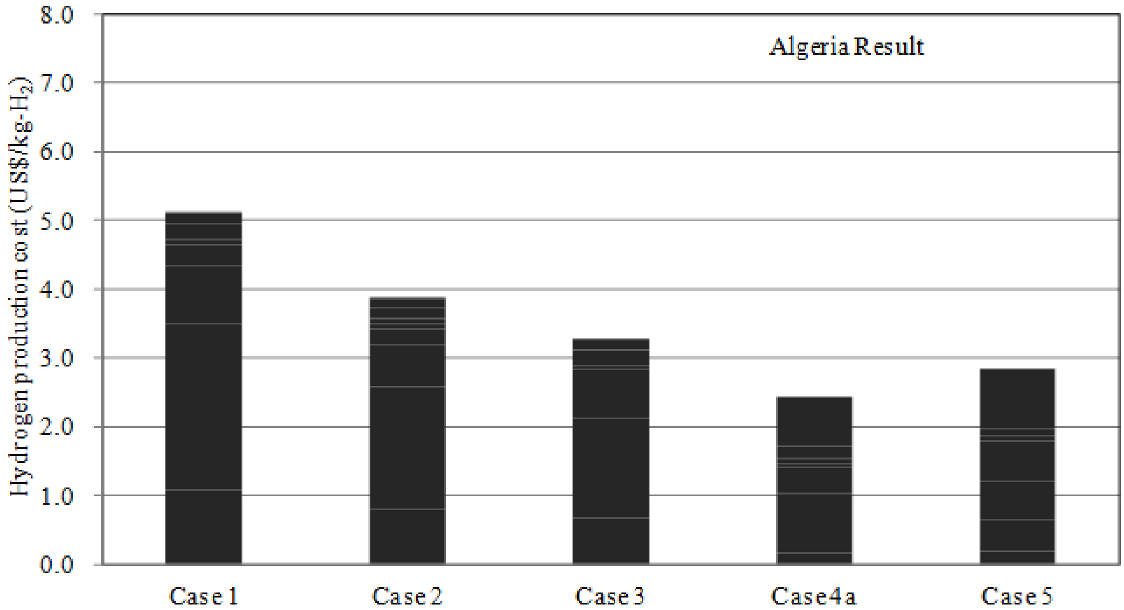
It is interesting to note that the cost ranking of the five generic cases found by all participating countries is rather consistent despite the obvious disparity of the country specific financial values used. For example, Figure 87 show the calculation results of these generic cases obtained with the financial parameters of Algeria and Germany. All other countries reported similar cost rankings. Further study would be required to confirm whether this results simply from input data and code methodologies compensating each other or from an additional capability of HEEP to assess comparative economics of hydrogen production systems independent of the country-specific set of financial assumptions.

6.1.3.2.Code-to-code benchmark

6.1.3.2.1. Comparison with G4-ECONS

HEEP is designed to be simple and easy to use, for which the fidelity of input data becomes essential to reliability of the final results from the code. The original design of Case 4 sets zero for input of electricity consumption, which is obviously wrong for this hybrid cycle. The error has been corrected as Case 4a. Similarly, the overcharging of electricity input to Case 5 of the thermochemical process has also been corrected. With the improved input data, the

HEEP results come in good agreement with G4-ECONS for all five generic cases, as shown in Fig. 89, with the largest discrepancy in all cases being less than 20%.



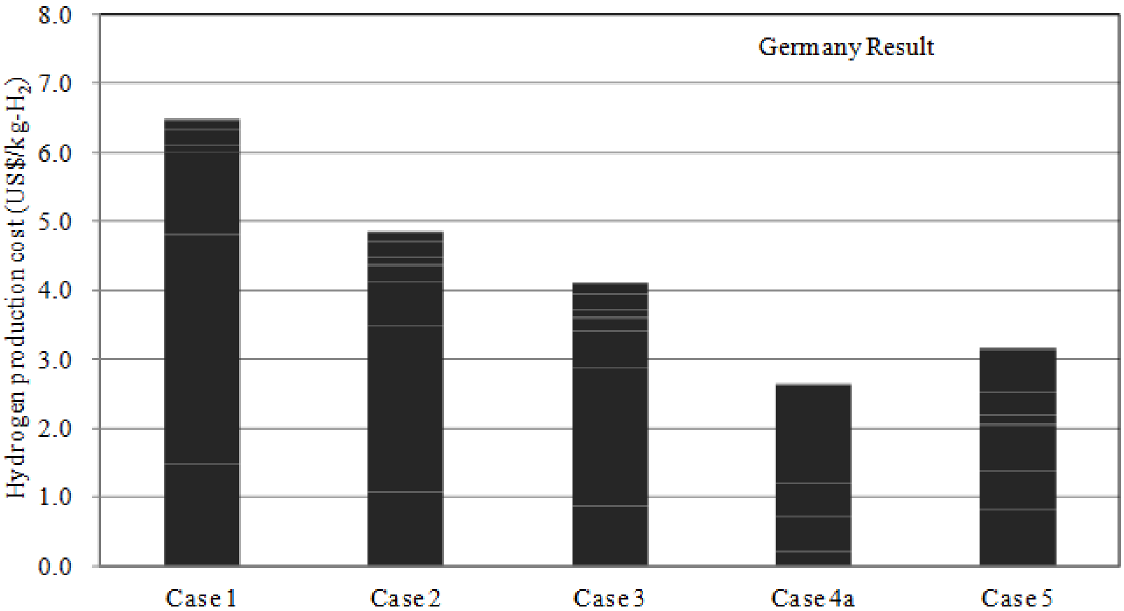


FIG. 87. Calculated hydrogen cost of generic cases using Algeria and Germany financial parameters

6.1.3.2.2. Comparison with H2A

The estimated costs of hydrogen by HEEP closely are found to match those estimated by H2A as shown in Fig. 88. The difference is found within 10%. Note that HEEP calculates Cases 1 to 3 with the construction period of 5 years as these cases are originally designed. On the other hand, a period of 4 years is used by H2A since it does not allow construction period longer than 4 years. If the construction period for these cases were also reduced to 4 years in the calculation by HEEP, the agreement improves further.

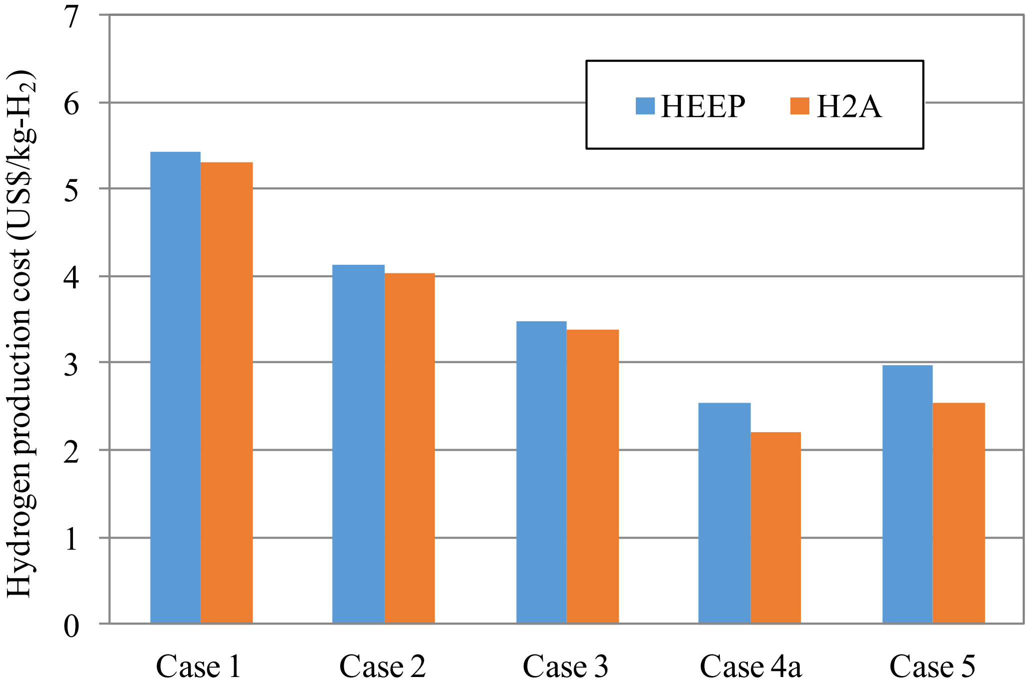


FIG. 88. Benchmark results between HEEP and H2A

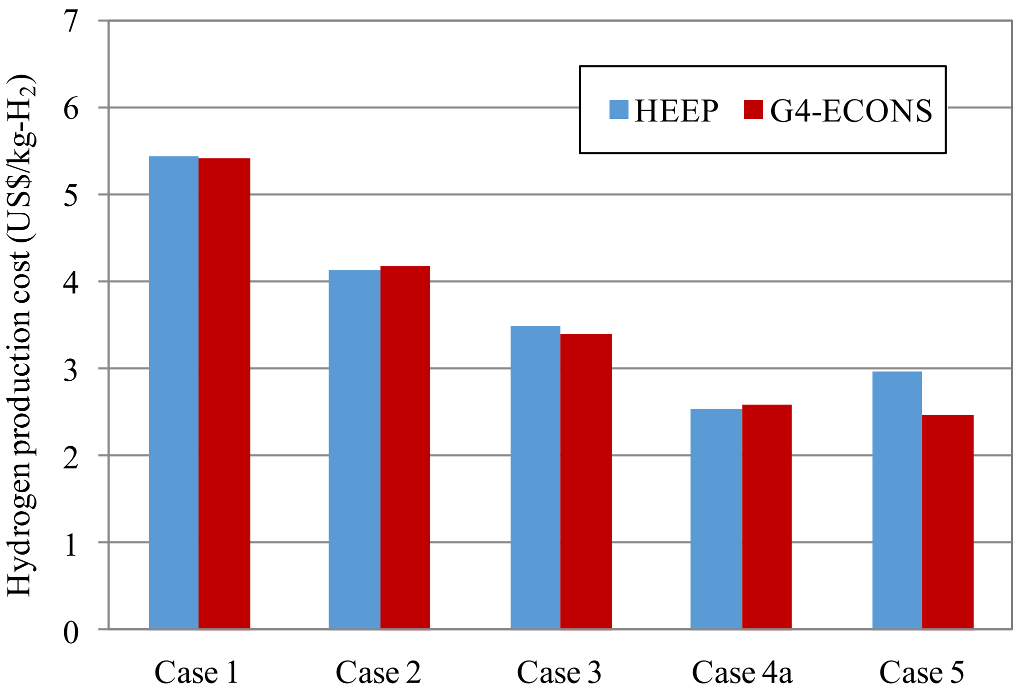


FIG. 89. Benchmark results between HEEP and G4-ECONS

6.1.3.2.3. Comparison with ASPEN PLUS

The cost of hydrogen estimated with ASPEN PLUS is high compared to HEEP based calculations in terms of calculated capital cost for nuclear and process plants and O&M cost for hydrogen plant. Two major factors contribute to the difference. First, ASPEN PLUS takes into account the details of equipment and labour costs while HEEP does not provide detailed accounts of equipment and labour. Second, hydrogen production efficiency assumed is lower in ASPEN PLUS than in HEEP.

When the design parameters of the physical plants and the thermal efficiencies of the plants are adjusted to be equivalent in the two codes, the HEEP code results agree reasonably well with the ones calculated by ASPEN PLUS, as reported in Chapter 4.

6.1.3.3.Additional benchmark studies

6.1.3.3.1. Benchmark by Japan

Using an internal program and industrial database, Japan Atomic Energy Agency calculated hydrogen production costs of two systems including a PWR and an HTGR based plants. The basic production parameters are given in Table 86. The JAEA results are compared with the HEEP calculated costs of the selected cases in Fig. 90.

TABLE 86. CASE STUDIES BY JAEA USING ITS INTERNAL CODE

Nuclear plant	PWR	HTGR
Reactor rating	1×1200 MW(e)	2×600 MW(th)
Hydrogen plant	CE	S–I
Hydrogen rate	6.1 kg/s	4.4 kg/s

JAEA`s PWR+CE case is similar in design to Cases 1 and 3, which are based on APWR+CE. The JAEA result is lower than Case 1 but higher than Case 2 of the HEEP costs. This is consistent the hydrogen rates of the cases and thus reflects the economy of scale. Although the final cost of hydrogen agrees reasonably well, Japan's result shows a higher contribution ratio of electrolysis plant to the final cost.

Japan's HTGR+SI case is similar in design to Case 5, both being based the arrangement of HTGR coupled to S–I hydrogen plant with similar hydrogen production rates. The difference in the levelized cost of hydrogen estimated by HEEP for Case 5 and by the internal program for Japan's case is within 15%. For a closer look, JAEA case having a higher capital cost and higher O&M cost of the hydrogen plant significantly increases the specific cost of hydrogen plant and its share to the final hydrogen cost, relative to Case 5.

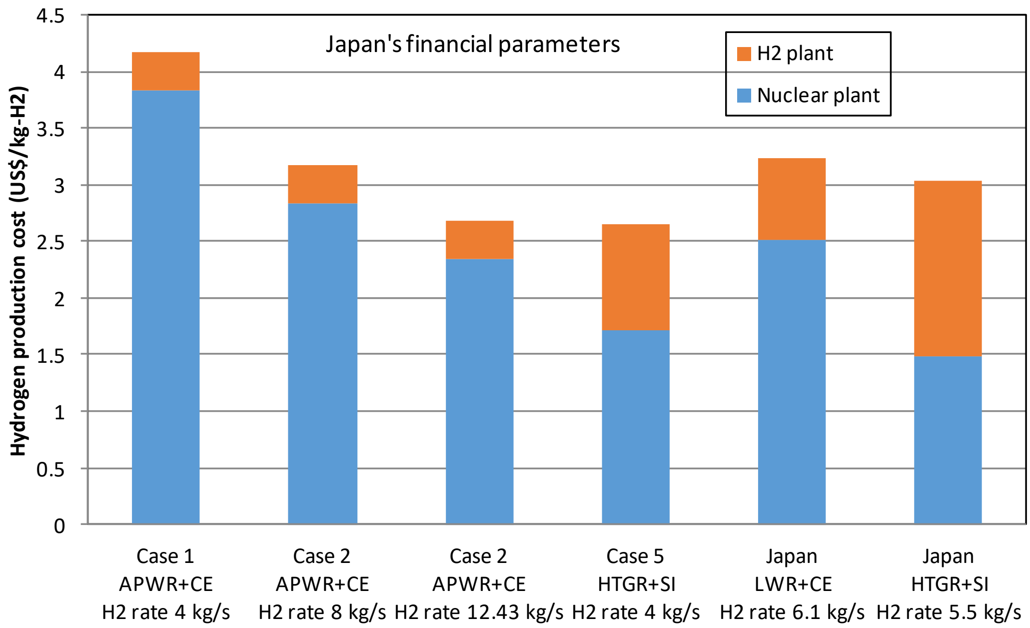


FIG. 90. Benchmark results between HEEP and Japan's internal code.

6.1.3.3.2. Benchmark by Germany

Germany's internal code MILP and the HEEP code are both used to calculate the hydrogen cost of an HTGR-based SMR hydrogen cogeneration system as designed by Germany. The design parameters of the case are given in Table 87.

TABLE 87. GERMANY'S BENCHMARK CASE OF HTGR HYDROGEN COGENERATION

Nuclear plant technology	HTGR
Number of reactor units	2
Reactor thermal power/unit	250 MW(th)
Nuclear plant heat supply to hydrogen plant	250 MW(th)
Nuclear plant power generation	100 MW(e)
Hydrogen plant technology	SMR
Hydrogen plant heat consumption	19.63 MW(t)h/t-H_2
Hydrogen plant power consumption	0.64 MW(e)h/t-H_2
Hydrogen production rate	12.73 t/h

The hydrogen costs obtained from both codes are extremely close shown in Fig. 91. The HEEP obtains a hydrogen production cost of 2.91 €/kg comparing to the MILP result of 2.94 €/kg. Nevertheless, the cost components differ, in part because the two codes allocate the individual costs differently. For example, while the MILP considers the electricity sold to the market as a product credit of 0.33 €/kg, this revenue is already factored in the HEEP cost components.

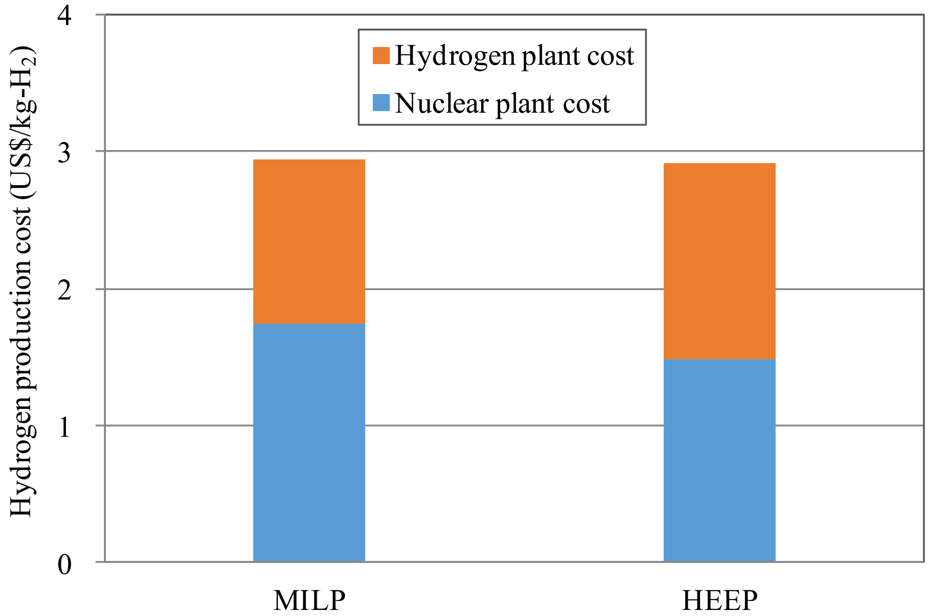


FIG. 91. Benchmark results between HEEP and Germany's MILP.

6.1.4. Technology-based case studies

The four technology-based cases that have been designed and provided by Canada, China, Germany and Japan are summarized in Table 88. The 9 participating countries have reported the hydrogen costs of these cases calculated by HEEP under the financial parameters of each country. These costs are shown in Fig. 92.

TABLE 88. TECHNOLOGY-BASED CASE STUDIES PERFORMED

	Case A	Case B	Case C	Case D
Plant design	EC6 (Canada)	HTR-PM (China)	HTR-Module (Germany)	GTHTR300C (Japan)
Nuclear plant	APWR	HTGR	HTGR	VHTR
Number of units	4	2	2	1
Thermal rating/unit (MW(th))	2084	250	170	600
Heat output/unit (MW(th))	159.58	250	117	170
Electricity output/unit (MW(e))	629.88	0	21.3	204
Hydrogen plant	Cu–Cl	S–I	SMR	S–I
Number of units	1	2	2	1
Heat input/unit (MW(th))	638.36	250	117	170
Electricity input/unit (MW(e))	273.25	20.0	21.3	25.4
Hydrogen rate/unit (kg/s)	4.25	0.68	1.74	0.77

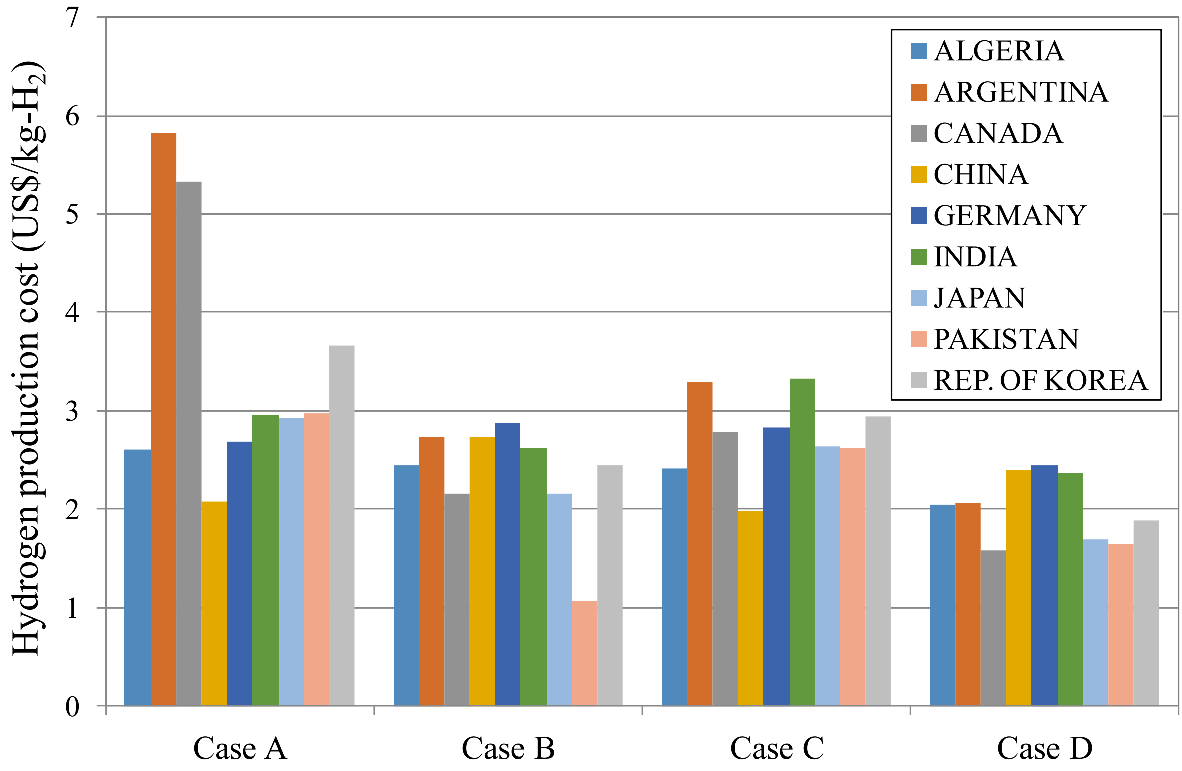


FIG. 92. Levelized cost of hydrogen estimated with country specific financial parameters

The results mostly remain below 3.00 US \$/kg-H_2 for Case A, but here are also some results with significantly higher prices. Canada and Argentina have reported unusual higher values. The Canada calculation assumed unusually high decommissioning cost and long decommissioning time of 50 years. The result is aggregated by a low discount rate used. While similar decommissioning assumptions are made in the Argentina calculation, the discount rate has been reset to 0% by the HEEP code because of a discount rate that has been input advertently being less than the inflation rate.

The results for Case B are below 3.00 US \$/kg-H_2. The exceptionally low value reported by Pakistan is due to the assumption of zero refurbishment cost. For Case C, the results range from about 2 to 3.3 US \$/kg-H_2.

With only the few exceptions, the reported costs of hydrogen are lowest for Case D and within a narrow range of 1.58 to 2.40 \$/kg-H_2. This demonstrates that the cost is generally dependent more on technical design and cost input but less on any particular set of financial assumptions. The design of Case D features in-plant cogeneration of all required energy (heat and electricity) for hydrogen plant, which lowers the share of energy cost to final hydrogen cost (see the analysis of cogeneration impact on hydrogen cost in Section 1.1.2.1). Another reason is the relatively high hydrogen conversion efficiency achieved in Case D as a result of the high temperature (950^{o}C) heat supply of the reactor and an efficient S–I-process flowsheet design.

The overall hydrogen conversion efficiencies given in Table 89 for the technology-based cases are derived from the hydrogen production rates and the thermal and electrical energy consumption data given in Table 88. Here, the electrical energy input is first translated into a thermal energy based on the electric conversion efficiencies for the respective electricity generation technologies applied. The conversion efficiencies for the four cases are in a range between 38 and 50%.

TABLE 89. SPECIFIC ENERGY CONSUMPTION AND H_2 CONVERSION EFFICIENCIES

	Case A	Case B	Case C	Case D
	Copper–Chlorine cycle (5-step)	Sulfur–Iodine cycle	Steam–methane reforming	Sulfur–Iodine cycle
Specific heat consumption (kWh/kg)	41.72	102.12	46.39	61.33
Specific electricity consumption (kWh/kg)	17.86	8.17 (included in heat consumption)	3.40	9.16
Electric conversion efficiency (%)	32.2	-	40	47
Methane feedstock energy (HHV) (kWh)	–	–	30.83	–
Overall specific heat consumption (kWh/kg)	97.19	102.12	80.17	80.82
H_2 conversion efficiency (%)	40.5	38.6	49.2	48.8

6.2. DISCUSSION ON TECHNO-ECONOMICS

6.2.1. Economy of scale with conventional nuclear reactors

In the generic cases of APWR conventional electrolysis (CE), about 90% of the final hydrogen production cost comes from the nuclear plant cost as detailed in Fig. 93. As a result, the hydrogen production cost can be expected, as the HEEP correctly predicts, to be strongly affected by the economy of scale widely-practiced in the current fleet of reactor technologies. The hydrogen cost estimated using HEEP default financial parameters is US \$5.46/kg-H_2 for the 2×360 MW(e) APWR+CE with a production rate of 4 kg/s hydrogen while that from 2×1117 MW(e) APWR+CE with a rate of 12 kg/s hydrogen reduces to US \$3.49/kg-H_2.

6.2.2. Potential cost advantage with advanced systems

All of reported specific costs from the CRP participating countries for the HTGR-based systems of both generic and technology cases are below US \$3.5/kg-H_2 comparing to the range of \$4.0-6.5/kg-H_2 for the APWR based case (generic Case 1) of comparable hydrogen production rate. As the hydrogen rate increases, however, the APWR based cases could also achieve cost below US \$4.0/kg-H_2.

An important contribution to the lower costs of the HTGR-based production cases is the higher thermal efficiency of hydrogen production achieved through the high temperature reactor and the processes of the HTSE and S–I cycles. The efficiency is in the range of 42% to 52% for the HTGR-based generic cases while it is 26.1% for the APWR based generic cases. The high efficiency reduces the specific capital cost of the reactors, which appears more than offsetting the high cost of the high-temperature hydrogen production processes, for which the advanced reactors require.

6.2.3. Nuclear to process plant cost ratio

The advanced nuclear hydrogen production has the potential to improve thermal efficiency and as such reduces the specific cost of investment intensive nuclear reactor. From the results of the generic cases calculated with the HEEP default finance values shown in Fig. 93, the share of nuclear reactor cost in the final hydrogen cost is 60-65% for the cases of HTGR coupled to HTSE and S–I cycles, comparing about 90% for the APWR based cases. For the technology cases in Fig. 94, the ratio of nuclear vs. hydrogen plant cost is strongly biased towards nuclear in Case A, while the share of hydrogen plant is larger for the other three, HTGR-based technology cases.

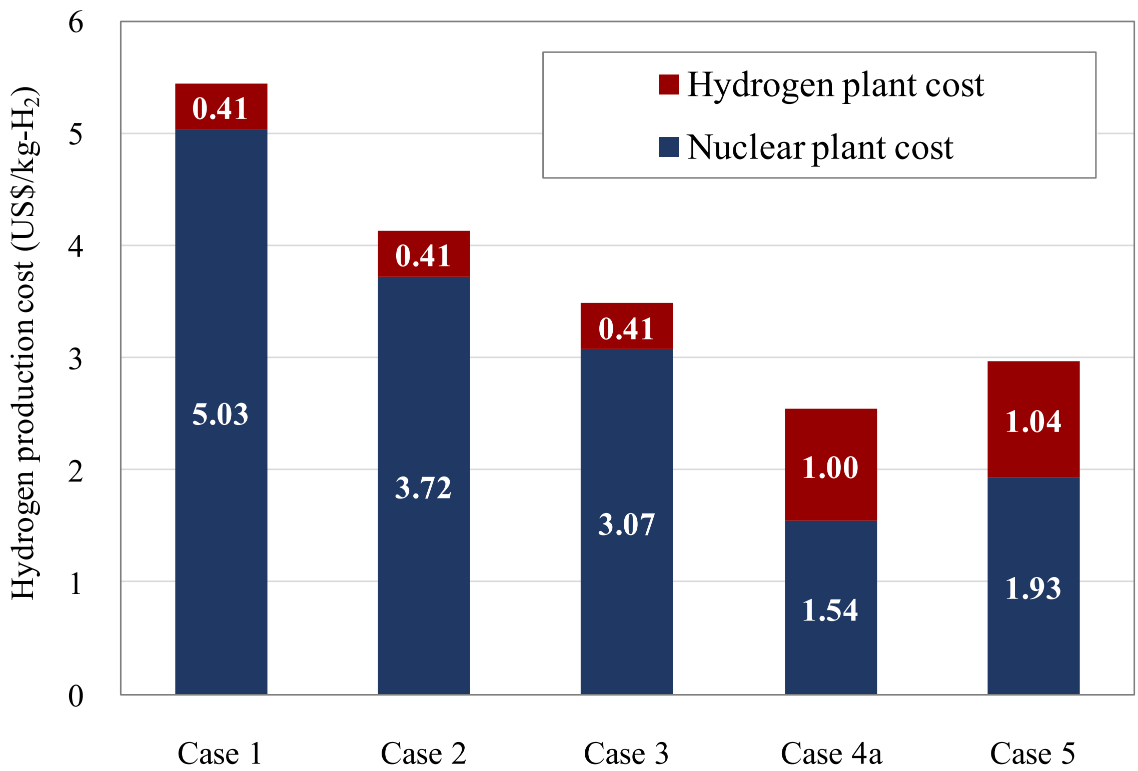


FIG. 93. Reactor to hydrogen plant cost share for the generic cases (HEEP default finance parameters)

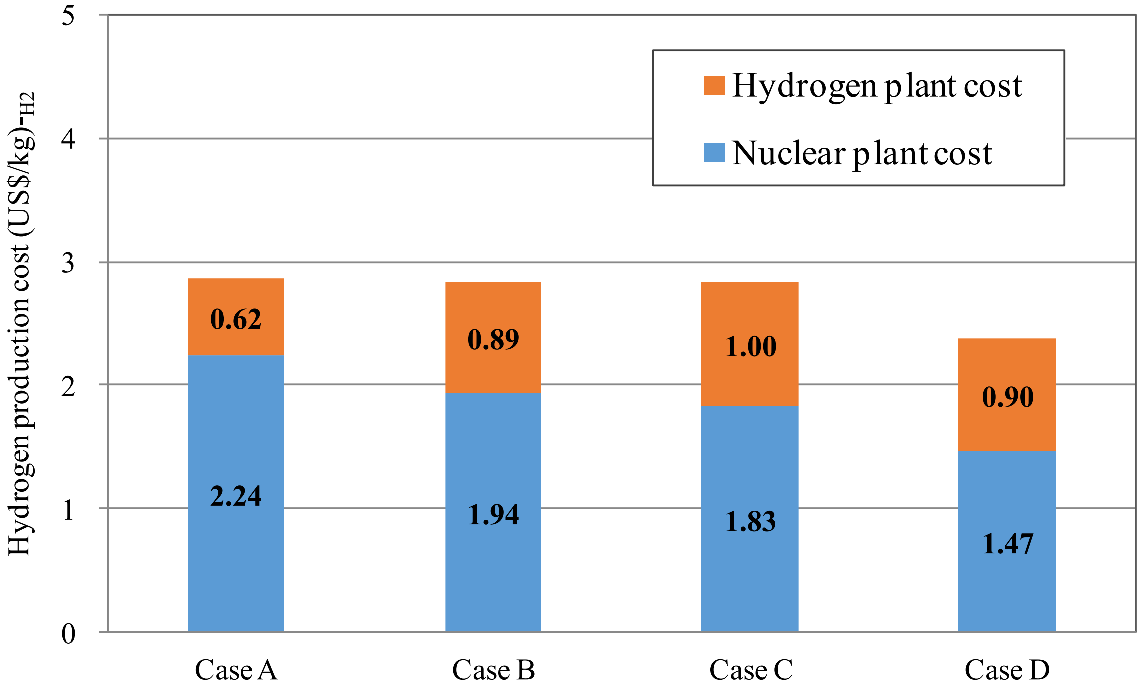


FIG. 94. Reactor to hydrogen plant cost share for the technology cases (HEEP default finance parameters)

6.2.4. Sensitivity to country specific financing

Table 90 shows the financial values typically assumed in the Member States. Figure 95 shows the resulting variation band of hydrogen costs of the generic cases resulting from the range of the country specific financial values. The hydrogen cost appears sensitive to the assumed values of financial parameters as no countries share a similar set of financial values. The extent of the impact of the varying financing conditions on the final hydrogen cost is also depending on the considered technology in the respective generic case.

TABLE 90. COUNTRY SPECIFIC FINANCIAL PARAMETERS

	(HEEP default)	Algeria	Argentina	Canada	China	Germany	India	Japan	Republic of Korea	Pakistan
Discount rate (%)	5	6	5	2	12	10	12	3	4	8
Inflation rate (%)	1	1	9.5	2	2	1.66	5.65	0	2	5
Finance Equity:Debt (%)	70:30	70:30	70:30	50:50	30:70	50:50	30:70	0:100	50:50	20:80
Borrowing interest (%)	10	6	30	7	5	5.5	10.5	3	10	8
Tax rate (%)	10	1.5	10	30	15	28.2	30	1.4	10	0
Depreciation period (year)	20	20	20* (*not known)	30	20	20	20	20	20	20

The largest impact is seen on Case 1 where the maximum difference is US \$2.38/kg-H_2 between Germany's upper end of US \$6.48/kg-H_2 and Parkistan's lower end of US \$4.10/kg-H_2. On the other hand, the impact of country-specific financing values is reduced to US \$0.53/kg-H_2 or less in the HTGR-based Case 4a and Case 5. The results with the HEEP default financial parameters are seen to be close to the mean of the band in each case, meaning that the default set represents an average basis for cost assessments.

Table 91 compares the results calculated with the HEEP default and Japan`s set of financial parameters and highlights the impact of individual financial parameter. Although only Case 1 and Case 5 are shown for simplicity, the results are similar in the other cases. Starting from the HEEP default values as the base, individual financial parameter is varied from HEEP default value to Japan's value. As can be seen, the most significant parameter affecting the final hydrogen production cost appears to be the equity to debt ratio to finance the nuclear plant construction and associated borrowing interest rate. The next important parameters are discount rate and inflation rate. On the other hand, despite the large difference, the tax rate appears to have relatively a small effect on the hydrogen product cost. The effect of the depreciation period was also found to be small, although this was not calculated because the same value is used in HEEP and Japan's set of parameters.

From the four technology based cases considered, the hydrogen costs reported by the CRP participating countries are in a relatively narrow range as shown in Fig. 96. The results obtained with the HEEP default financial parameters are all within the range of the other countries' results and seen to yield more conservative results for cost assessments.

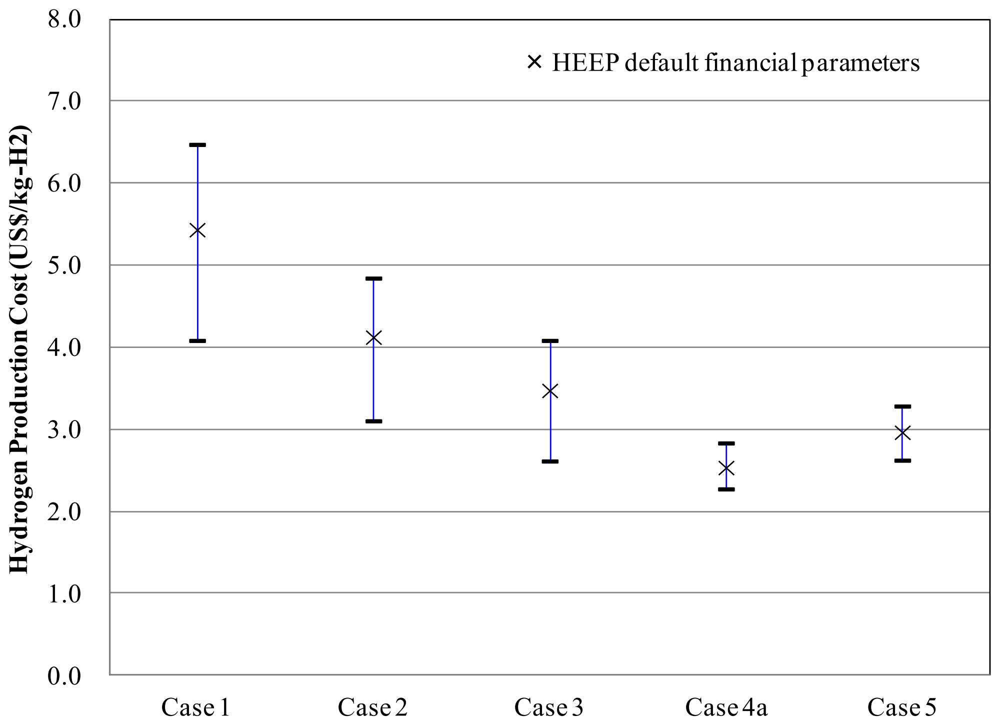


Fig. 95. Hydrogen cost band of generic cases estimated by HEEP within the range of financial parameters used in Member States.

TABLE 91. SENSITIVITY OF HYDROGEN COST TO INDIVIDUAL FINANCIAL PARAMETER

	HEEP default financial parameters	Japan's financial parameters	Cost change due to changing from HEEP to Japan's financial parameters	
			Case 1	Case 5
Discount rate (%)	5	3	-12.8%	-4.4%
Inflation rate (%)	1	0	+12.1%	+5.4%
Finance equity to debt ratio	70:30	0:100	+33.2%	+16.8%
Borrowing interest (%)	10	3	-19.4%	-9.7%
Tax rate (%)	10	1.4	-0.9%	-0.3%
Depreciation period (year)	20	20	-	-

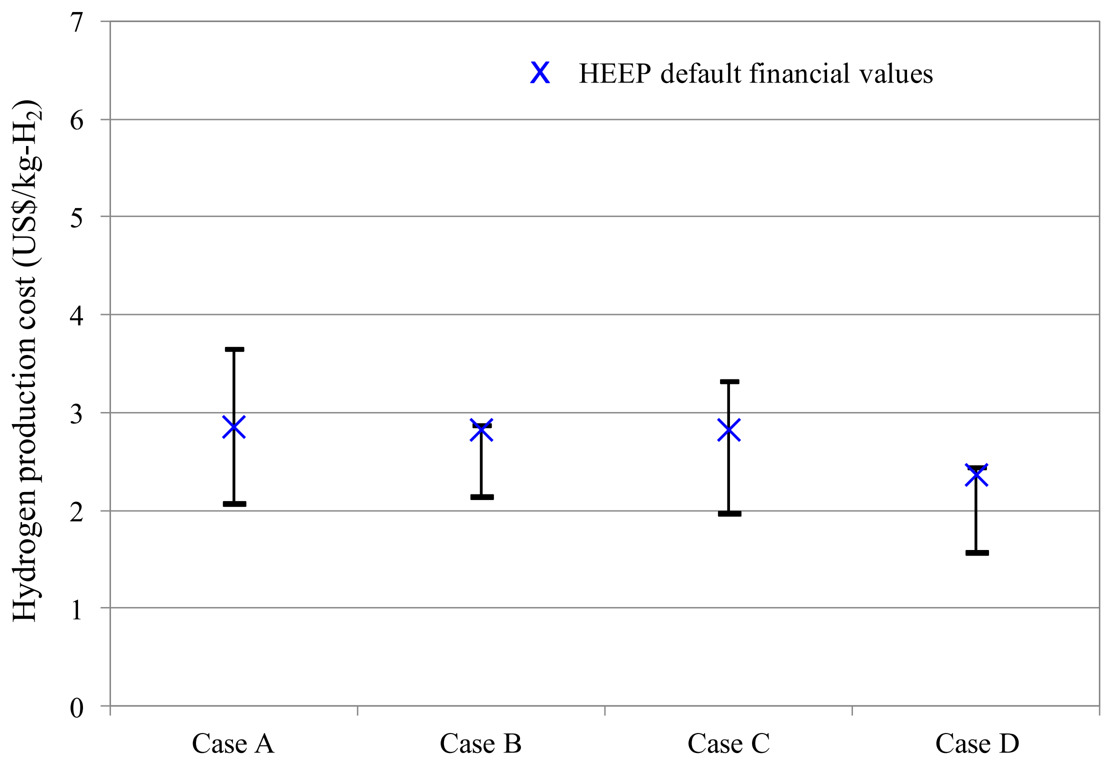


FIG. 96. Hydrogen cost band of technology-based cases estimated by HEEP within the range of financial parameters used in Member States.

6.2.5. Competitiveness of nuclear hydrogen production

The results of hydrogen cost estimates for the generic and technology cases suggest that nuclear hydrogen production is potentially cost competitive vs. conventional steam reforming, coal gasification or water electrolysis using renewable energy sources, but to the extend depending on the financial assumptions.

The costs are in the range of US \$2.6-6.5/kg-H_2 for the APWR based conventional electrolysis systems, depending on the hydrogen production rate, and of US \$1.6-3.8 for the advanced methods based on HTGR and EC6.

Regarding the country specific results, the costs of nuclear hydrogen estimated based on Japan's financial parameters, for example, are in the range of US \$2.3~4.2/kg-H_2 for the generic cases and US1.7-2.9/kg-H_2 for the technology cases. These compare to the range in the country of US \$3.5~6.5/kg-H_2 from reforming of fossil fuels including natural gas, city gas, LPG, naphtha, crude oil, US \$2.7~3.6/kg-H_2 from by-product of coke oven gas, and US \$3.5~6.5/kg-H_2 for conventional water electrolysis using renewable energy sources including solar and wind.

The country specific results of hydrogen generation cost are within a narrow range of 1.6 to 2.4 \$/kg-H_2 for Case D, which is the commercial HTGR based hydrogen cogeneration plant design being developed in Japan. The cost of US \$2.8/kg-H_2 has been stated as the future market target for hydrogen production in Japan.

The case studies performed by Germany reported the range of hydrogen production cost to be \$1.6-2.4/kg-H_2 for the HTGR-based systems coupled to various options of hydrogen cycles including SMR, HTSE and IS processes. These results are comparable to US \$2.2/kg-H_2 by conventional SMR with CCS and competitive to US \$2.8/kg-H_2 by solar heated SMR.

7. CONCLUSIONS AND RECOMMENDATIONS

One of the IAEA's statutory objectives is to "seek to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world". This objective may be achieved, among other methods, through actively engaging Member States in the development and deployment of hydrogen production from nuclear energy on a scale potentially comparable to the present-day nuclear power generation worldwide. Successful conclusion of this CRP completes a milestone of the IAEA programme on the subject.

From September 2012 through December 2015, the participants of the CRP reviewed the current state of research and development on nuclear hydrogen production and assessed the techno-economic aspects of the technology as well as challenges for nuclear hydrogen compared to the alternatives using steam reforming or even solar energy. They also conducted the benchmark analysis for the HEEP including generic and sensitivity studies for hydrogen production using various scenarios and performed the technology-based case studies of hydrogen production for four promising systems selected by the participants. On basis of the outcome of the CRP, they recommended the follow-up activities to address such other critical issues as road-mapping and socio-economics of nuclear hydrogen deployment and application. The conclusions and recommendations of the CRP are presented in this chapter.

7.1. CONCLUSIONS

7.1.1. Information exchange and international collaboration

The CRP has addressed several key development issues keen to Member States: It has created an international platform for coordinated research and information exchange for a network of eleven Member States represented. The platform hoists all levels of development know-how ranging from the newcomer to the most advanced on the subject, thereby maximizing the mutual benefits of research collaboration and information dissemination for the participants. Status of nuclear hydrogen development, economic potential of hydrogen production using nuclear power, identification of the challenges and the requirements to address them are the focus of the group interaction.

7.1.2. Techno-economics of nuclear hydrogen production

The CRP assessed various technological and economical aspects of potential nuclear hydrogen production options including promising cogeneration option. The reactor technologies assessed include the large light and heavy water reactors, small modular reactors, next generation high temperature gas cooled reactors. The technological options examined for hydrogen production processes include conventional water electrolysis, high temperature steam electrolysis, steam reforming, thermochemical cycle and hybrid cycle.

Cost of nuclear hydrogen production is found to be sensitive to not only the base technologies and processes employed but also the methods of integrating these technologies and processes. The technical parameters such as the source of energy, i.e. partially supplied or fully cogenerated in house, thermal efficiency of the processes and operation life cycle of reactor or process are investigated in detail. Moreover, the financial parameters typically used to fund a nuclear project are shown to be country specific and varying in considerable ranges. The financing equity to debt ratio, associated borrowing interest, discount rate, inflation rate, and plant operating years are found to wield more heavily on final hydrogen cost than the depreciation period and tax rate.

The results of the case studies performed in the course of the CRP suggest that nuclear hydrogen production is potentially cost competitive vs. conventional steam reforming, coal gasification or water electrolysis using renewable energy sources, but certainly depending on the financial boundary conditions in which a nuclear project is developed and operated in a country.

7.1.3. Benchmark analysis of HEEP

The benchmark results found HEEP to be comprehensive, expandable and reliable a tool to assess the economics and make comparative analysis of various nuclear hydrogen production options. Its Windows-based user interface is intuitive and easy to operate.

The HEEP modelling capability covers most of the contemporary interest in reactors and processes associated with nuclear hydrogen production. The latest version of HEEP released in December 2014, as an output of the CRP benchmark exercise, incorporates additional features and models that can cater to a wider variety of analysis demands.

The generic benchmark studies performed found that HEEP is capable of appreciating major cost contributors and their relative significance to final hydrogen cost. The code is shown able to assess the impact of varying combinations of the reactors and the hydrogen processes on the levelized cost of hydrogen product. In particular, the results of the benchmark against the cases of varying production rates found that the HEEP is clearly able to predict the influence of the economy of scale of hydrogen production.

The HEEP results obtained with the default set of financial parameters are representative of the average of all country specific results. Furthermore, despite of the obvious disparity of country specific financial values assumed the cost ranking of the five generic cases studied remain consistent among all countries.

The code-to-code benchmark studies found good agreement (less than 20%) with the results of H2A and G4-CONS. The agreement is more difficult to obtain against ASPEN PLUS because of the difference in model treatment. ASPEN PLUS computes costs on equipment levels from built-in database whereas HEEP relies on user inputs for them. When the design parameters are adjusted to be equivalent in the two codes, the reasonable agreement is seen with ASPEN PLUS.

Similar benchmark conclusion was also drawn in the additional benchmark studies carried out by Japan and Germany. Using the respective proprietary codes of the countries, Japan found that the HEEP results were found within 15% of its own code's results, whereas Germany reported nearly identical calculation results of hydrogen production cost between HEEP and its code for an HTGR SMR system.

7.1.4. Technology-based case studies

Canada, China, Germany, and Japan designed four technology concepts completed with the required input of technical and economic design. Each participating country conducted HEEP calculations for the technology based cases applying the same design data but choosing the respective country's set of financial parameters to determine the hydrogen generation costs.

The HEEP results reported by the participating countries for the four technology cases compare well with each other. The exception is for the Canada case where the results estimated by two countries are almost double as the others and the causes were identified.

The HEEP results obtained with the default set of financial parameters are within the range of the other countries' results and tend to yield costs above the average of the countries for cost assessments. The cost ranking is found rather consistent of the technology-based cases among the countries, but unlike the finding for the generic cases, exceptions do exist in some country-specific results.

The results of these case studies suggest that nuclear hydrogen production is potentially cost competitive to conventional steam reforming of fossil fuels, by-production such as of coke oven gas, and conventional water electrolysis using renewable energy sources including solar and wind, but certainly depending on the financial boundary conditions.

7.2. RECOMMENDATIONS

7.2.1. Recommended improvement to HEEP

To perform optimization case studies of nuclear hydrogen production, using HEEP and other codes

To provide users of HEEP with the ability to optimize system and cost of nuclear hydrogen production based on a simple set of boundary conditions that may include one or more choices of reactor types, hydrogen technologies, production scale, site condition, deployment time frame, to match, for example, country-specific requirements including production, storage and transportation. If necessary, appropriate toolkits may be developed as modules and integrated with HEEP at runtime.

Greatly expand the manuals of HEEP with details on all major equations used and to provide detailed explanation of inputs and how the inputs are used for HEEP calculation

As the user manual of HEEP stands now, it contains only 6 pages of a "brief description of the formulation used in HEEP", 1 page of "Entering details of nuclear power plant", and 1 page of "Entering details of hydrogen generation plant". The benchmarking exercise in this CRP has proved amply that these limited manual pages could provide little understanding and confidence in the results produced and demand the multi-rounds of trial and error, even the need of direct consultation with the HEEP programmers (Mr. Malshe and Mr. Antony), before correct inputs could be established in the HEEP. To increase acceptability and user-friendliness of the HEEP, all major equations used should be given with sources of references and explained with examples of simple calculation cases, and that much more detailed instruction of how to make input must be given in the manual.

To cover efficiency and environmental impact as well as sustainability assessments

Calculate efficiency and clarify efficiency calculations for energy plant (NPP) and hydrogen plant and overall system. And implement carbon credits and GHG emission taxes in HEEP.

Enhanced cost evaluation of NPPs for hydrogen production through various potential methods is increasingly important, especially with the fact that efficiency, environmental impact and sustainability assessments are three critical elements and considered essential in system selection and implementation. Including efficiency, environmental impact and sustainability assessments in such a program (e.g., HEEP) will offer a unique opportunity to bring up a more potential tool in a more holistic manner.

To develop detailed model for hydrogen distribution

To expand models and build reference cases for transportation and distribution as well as storage, and study these aspects on country specific bases, considering for example storage for demand fluctuation and sea transportation. However, this is deferred to longer term tasks.

To add renewable and other energy sources for performing competitive assessment as well as for system integration

As future and desirable sources of large scale energy, renewable energy and nuclear energy can complement each other. Though base load may be supplied by the nuclear energy, renewable can furnish more distributed energy and reduces carbon footprint. The hydrogen generated via nuclear hydrogen system serves as storage of large scale energy. Moreover among carbon free energy sources, renewable and nuclear will enable large scale hydrogen generation and eliminate intermittency of the renewables. Hence studies are required on renewable and other energy sources for performing competitive assessment as well as for system integration. Accordingly, the NPP module of the HEEP may be extended to enable such combined energy source as nuclear-renewables.

To add an option and models for small modular reactor (SMR) systems as heat/energy source

Several small modular reactor (SMR) systems are being developed and this provides another option on the type of reactors in the HEEP. The SMR can be light water PWR, high temperature gas cooled, gas cooled fast reactors and have various heat and temperature levels, These options enhance the HEEP capability for integrating next generation of reactors into nuclear hydrogen system. The current library cases that fall in the SMR range should be renamed with minor modification in library files.

To enhance the portfolio of HEEP by including other types of reactors (SCWR and others), hydrogen production methods and cycles

HEEP appears to be a reasonable tool for cost evaluation of hydrogen production, storage and distribution option for a limited number of NPPs. It has become necessary to expand the reactor types considered (including SMR as said above, SCWR, etc.) for hydrogen production in an enhanced manner with various more options for production, storage and transportation and distribution.

To have access to the source files of HEEP (as open source), and the possibility of having different programmers update/initiate the software in a more friendly form

The HEEP program is like a black box, because there is no way for the users to identify situations where inconsistent input data might have been entered or where physically impossible results have been produced. It is suggested that some devices be considered for the HEEP to show the users step by step intermediate calculation procedures so that the users can identify the on-going mistakes through incremental iteration or local debugging. It is also suggested that more detailed and exact definition of the input data are needed to avoid possible misunderstanding among users. IAEA would consider to open HEEP sources based on request.

To include cost estimation credit for by-products such as: oxygen, electricity, and/or heat

Add economic assessment for possible by-product, being it to be electricity cogenerated in nuclear plant or oxygen in hydrogen plant, affecting the final cost of hydrogen production.

To improve the calculations by applying capacity specific cost correlation separately for the different processes

Consider economy of scale for hydrogen production by adding, for example, scaling factors of default values 0.6 for NPP and 0.7 for process plant, or providing options for users to choose these values.

To make the results report accessible in Excel spreadsheet format

Add an option to generate CSV files.

To make HEEP compatible with different operating system compatibility as it does not operate on Windows 8 for example

Several CSIs have complained that they could not run HEEP on their PCs with Windows 8 OS. It would be problematic if IAEA shall be burdened with having to make a new release of HEEP for each routine update of computer operating systems in the future. This problem can be avoided if HEEP be programmed and its executable file be built with immunity to frequent update of OS and also compatibility with multiple (Windows, Apple, Linux) platforms. Add a note with instructions to other operating system users as a Word/txt file added to the downloaded folder.

Display input parameters in graphical form using schematic line diagramme for clear understanding of energy balance

IAEA will develop and incorporate this in HEEP as similarly done and proven helpful in DEEP.

7.2.2. Recommendations to IAEA for future activities

To provide milestone recommendations to the MSs considering development and deployment of nuclear hydrogen production

Hydrogen produced from using nuclear power is potentially one of the most cost-effective as well as carbon-free sources of energy to fuel the hydrogen economy that has become a fast-growing reality in several countries. However, more countries have pursued development and deployment of the nuclear hydrogen production option with mixing results. Therefore, IAEA is strongly urged by MSs to organize a programme such as CRP that would task experienced experts and stakeholders with making milestones recommendations or guidelines for the MSs considering nuclear hydrogen for their future energy mix. The programme would develop a detailed roadmap of development and deployment activities ranging from national planning, research, development, licensing, public acceptance, and commercial demonstration.

To increase the consultation with users and regulators of nuclear hydrogen

IAEA has developed two TECDOCs on the topic with one reviewing the nuclear hydrogen production technologies and the other (this volume) assessing the techno-economics of nuclear hydrogen production. Moving forward, IAEA shall plan activity to address in-depth the other outstanding feasibility issues including user requirements, application selection, demand modelling, safety and utilities regulations by seeking input (through such forum as CRP, consultancy, symposium, etc.) of users and regulators of both production side (manufacturing) and application side (car makers, oil refiners, steel makers).

To study carbon offsetting options with NPPs and HPPs and the effect of cost credit associated with carbon dioxide reduction

The 2015 Paris Conference on Climate Change has made it crystal clear that offsetting the amounts of CO_2 emissions globally is critical. When we look at the potential options to achieve this target, especially in the absence of fossil fuels, the solutions are rather limited. Nuclear power production and cogeneration of hydrogen through HPPs appear to be one of the most attractive options providing multiple benefits, such as that the power generation will be carbon free along with hydrogen as fuel. There are other opportunities to further enhance the benefits of NPPs with HPPs by serving almost all economic sectors, ranging from industrial to residential.

To re-address the safety issue of nuclear hydrogen production, including the coupling, tritium permeation, impact of hydrogen plant accident on NPP and vice versa, and location of the hydrogen plant

The safety and related designs impact the cost of the nuclear hydrogen plant. The coupling methodology of the nuclear heat\electricity to a hydrogen generation plant is dependent on the type of hydrogen generation plant (steam reforming, high temperature electrolysis or thermochemical water splitting). The accident sequence analysis and consequences including tritium permeation for the coupled system (nuclear to hydrogen plant) is required for safe design parameters. These various factors should be studied for the cost of the hydrogen generation.

To study socio-economic, public acceptance and environmental aspects of nuclear hydrogen production

The nuclear hydrogen generation system will involve various infrastructures. The materials and equipment used in the processes may generate some waste products. The end of the life cycle analysis of the coupled system provides the environmental impact and economic viability of the system. In addition, the social acceptance of the nuclear and hydrogen system will also impact its economic viability. The study of socio-economic, public acceptance and environmental aspects of nuclear hydrogen production are required for technology to be reality.

To consider adaptation of low temperature reactors for hydrogen production integration using innovative ideas like chemical heat pumps for heat upgrade

Using potential high-upgrade options for low-temperature reactors will provide a better opportunity for NPPs to be used for hydrogen production. The systems required for this kind of heat upgrade are chemical heat pumps and mechanical heat pumps with special and suitable working fluids. This will make NPPs more efficient, cost effective and environmentally benign and hence more attractive.

To discuss challenges facing large scale nuclear hydrogen productions

Given the significant development and deployment progresses made since the last review report of the subject published by IAEA in 2013, for example, the HTR-PM commercial demonstration construction in China and continuous hydrogen process operation in Japan and the Republic of Korea, the experts should be called upon to assist IAEA in updating the knowledge bases and make the information accessible timely to Member States.

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LIST OF ABBREVIATIONS

ABWR	Advanced boiling water reactor
AC	Alternate current
ACCE	Aspen Capital Cost Estimator
AECL	Atomic Energy of Canada Limited
ALWR	Advanced light water reactor
AP	Acidification potential
APEA	Aspen Process Economic Analyser
APWR	Advanced pressurized water reactor
ANF	Annuity factor
ANL	Argonne National Laboratory
ASPEN	Advanced System for Process Engineering (Brand name for a general process simulator)
ASTM	The American Society for Testing and Materials
ATCF	After tax cash flow
ATR	Autothermal reforming
AVR	Arbeitsgemeinschaft Versuchsreaktor (a nuclear test reactor, Germany)
AWE	Alkaline water electrolysis
BARC	Bhabha Atomic Research Centre
BATAN	National Nuclear Energy Agency of Indonesia
BCR	Benefit cost ratio
BTCF	Before tax cash flow
BTU	British thermal unit
BUN	BUNsen reaction system
BWR	Boiling water reactor
CAN	Calcium ammonium nitrate
CANDU	CANada Deuterium Uranium
CCGT	Combined cycle gas turbine
CC	Capital cost
CCS	Carbon capture and sequestration
CE	Conventional water electrolysis
CEA	Commissariat à l’Energie Atomique
CEPCI	Chemical Engineering Plant Cost Index
CERL	Clean Energy Research Laboratory
CF	Cash flow

CHP	Combined heat and power
CNEA	Comisión Nacional de Energía Atómica of Argentina
CNG	Compressed natural gas
CNL	Canadian Nuclear Laboratories
COP	Coefficient of performance
COMENA	Commissariat à l'Energie Atomique (Algeria Atomic Energy Commission)
CPV	Concentrated photovoltaics (generating electricity through solar cells)
CRP	Coordinated Research Project (of IAEA)
CRS	Central receiver systems
CSI	Chief Scientific Investigator (of the CRP)
CSP	Concentrated solar power (usually solar heated steam turbine generation)
CSTR	Continuous Stirred Tank Reactor
D&D	Decontamination and decommissioning
DANE	Division of Advanced Nuclear Engineering
DAP	Di-ammonium phosphate
DC	Direct current
DCF	Discounted Cash Flow
DEEP	Desalination Economic Evaluation Programme (software by IAEA)
DNI	Direct normal irradiance
DOE	Department of Energy (of the United States of America)
EED	Electro–electro dialysis
EIA	U.S. Energy Information Administration
EMWG	Economic Modelling Working Group
EP	Eutrophication potential
EPRI	Electric Power Research Institute
FA	Fuel assemblies
FBR	Fast breeder reactor
FC	Fuel cell
FCR	Fixed charge rate
FCV	Fuel cell vehicle
FEPC	Federation of Electric Power Companies, Japan
FUS	Feed purification
FZJ	Forschungszentrum Jülich, Germany

GA	General Atomics (of the United States of America)
GC	Gas Cromatograph
GDP	Gross domestic product
GHG	Greenhouse gas
GIF	Generation IV International Forum
GTHTR300C	Gas turbine high temperature reactor of 300 MW(e) for cogeneration
GT-MHR	Gas Turbine Modular Helium Reactor
GUI	Graphical User Interface
GWP	Global warming potential
HAD	HI decomposition systems
HEEP	Hydrogen economic evaluation programme (software by IAEA)
HFCV	Hydrogen fuel cell vehicles
HGP	Hydrogen generation plant
HHV	Higher heating value
HI	Hydrogen iodide
HP	Hydrogen plant
HPP	Hydrogen production plant
HPR	Hydrogen production rate
HS	Hydrogen storage
HT	Hydrogen transportation
HTGR	High temperature gas-cooled reactor
HTR	High Temperature Reactor
HTR-Modul	High temperature reactor module
HTR-PM	High temperature reactor power module
HTS	High Temperature Shift
HTSE	High temperature steam electrolysis
HTTR	High temperature engineering test reactor
HyS	Hybrid sulfur
HYSYS	Aspen HYSYS, an oil & gas process optimization software
IAEA	International Atomic Energy Agency
IAHE	International Association for Hydrogen Energy
ICARUS	Aspen Economic Evaluation product family
IDC	Interest during construction
IEA	International Energy Agency
IHX	Intermediate heat exchanger

INDCs	Intended nationally determined contributions (national post-2020 climate action commitments at 2015 United Nations Climate Change Conference in Paris, France in December 2015.
ILS	Integrated Laboratory scale
INET	Institute for Nuclear and New Energy Technology
INL	Idaho National Laboratory
INPRO	The International Project on Innovative Nuclear Reactors and Fuel Cycles, IAEA
IRR	Internal rate of return
IS	Iodine sulfur
JAEA	Japan Atomic Energy Agency
KAERI	Korea Atomic Energy Research Institute
KEPCO	Korea Electric Power Company
KIER	Korea Institute of Energy Research
KIST	Korea Institute of Science and Technology
KVK	Komponenten-Versuchskreislauf (component test loop)
LC	Levelized Cost
LDV	Light duty vehicles
LHGC	Levelized hydrogen generation cost
LHV	Lower heating value
LNG	Liquefied natural gas
LOHS	Loss-of-heat sink
LTS	Low Temperature Shift
LUEC	Levelized unit electricity cost (e.g. $/kW·h)
LUHC	Levelized unit hydrogen cost (e.g. $/kg-$H_2$)
LUPC	Levelized unit product cost
LWR	Light Water Reactor
METI	Ministry of Economy, Trade and Industry of Japan
MILP	Mixed integer linear problem for an objective function cost analysis code
MSR	Molten salt cooled reactors
MT	Million tonne
MW	Megawatt, MW(e) – megawatt electric; MW(th) – megawatt thermal
NEDO	New Energy and Industrial Technology Development
NETL	National Energy Technology Laboratory
NG	Natural gas

NGNP	Next generation nuclear plant, an HTGR in development in the US
NHDD	Nuclear hydrogen development and demonstration
NHI	Nuclear hydrogen initiative
NHSS	Nuclear heat supply system
NIPA	National Income and Product Accounts
NPP	Nuclear power plant
NPV	Net present value
NREL	National Renewable Energy Laboratory
NRTL	Non-Random, Two Liquids
NSSS	Nuclear steam supply system
O&M	Operation and maintenance
ODP	Ozone depletion potential
OECD	Organization for Economic Cooperation and Development
OPE	Operating expenses
ORNL	Oak Ridge National Laboratory
OS	Operating system
PAEC	Pakistan Atomic Energy Commission
PARCS	Purdue Advanced Reactor Core Simulator
PBMR	Pebble bed modular reactor
PCHE	Printed Circuit Heat Exchangers
PCS	Power conversion system
PCU	Power conversion unit
PEM	Polymer electrolyte membrane
PHX	Process heat exchanger
PHWR	Pressurized heavy water reactor
PN	Nominal power
PNP	Prototype nuclear process heat project
PPU	Product purification
PKE	Point kinetic code (for nuclear reactor neutroics)
POSTECH	Pohang University of Science And Technology (Republic of Korea)
POX	Partial oxidation
PSA	Pressure swing adsorption
PTFE	Polytetrafluoroethylene
PV	Present value
PWR	Pressurized water reactor

RCM	Research coordinated meeting
RCSTR	Rigorous Continuous Stirred Tank Reactor
RepU	Reprocessed uranium
RITE	Research Institute of Innovative Technology for the Earth, Japan
ROI	Return of investment
RPV	Reactor pressure vessel
RR	Enrichment ratio
RWTH	RWTH Aachen University, Germany
SAD	Sulfuric acid decomposition
SCRAM	Sudden shutting down of a nuclear reactor
SCWR	Supercritical water reactor
SEM	Scanning Electronic Microscopy
SEPC	Specific Electric Power Consumption
SG	Steam generator
SHD	Secondary Helium Duct
SI	Sulfur iodine
S–I	Sulfur iodine
SiC	Silicon carbide
SFR	Sodium-cooled fast reactor
SMR	Steam methane reforming
SNL	Sandia National Laboratories
SOEC	Solid oxide electrolysis cell
SOFC	Solid oxide fuel cell
STPC	Specific thermal power consumption
SWU	Separative work unit
TCE	Tonne-coal equivalent
TECDOC	Technical document (IAEA)
TERMIX	Thermal hydraulic computer code (for nuclear reactor analysis)
TNT	Trinitrotoluene (explosive)
TOE	Tonne of oil equivalent
TRISO	Tri-structural-isotropic (fuel particles)
UI	User interface
UN	United Nations
UNFCC	UN Framework on Climate Change
UOIT	University of Ontario Institute of Technology

UOX	Uranium dioxide
USNRC	U.S. Nuclear Regulatory Commission
VHTR	Very high temperature reactor
WECS	Wind energy conversion system
XRD	X-Ray Diffractometer

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