Use of hydrogen in buildings

BatHyBuild study

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Preface

Hydrogen is more and more considered as an important clean energy solution with large potential for making (heavy duty) transport and industry carbon neutral. It can be used as a feedstock or an energy carrier. In general, it is predominantly seen as a solution in those sectors where direct electrification is either very expensive, difficult or even impossible.

The question whether hydrogen will also be applied in buildings, for power and heating appliances, is often subject of debate. Other technologies such as heat pumps or district heating networks supplied with waste heat might be more efficient and cheaper solutions. In new-build neighbourhoods with highly insulated houses (low heat demand) all-electric solutions seem to be the most logical solution. However the question is whether a 100% electrified system is feasible given the intermittence of most renewable energy sources in combination with large scale electric heating and electric mobility; storage and flexibility will have to be incorporated in the system and also there hydrogen might play a role. For older houses and historic city centres, especially where no waste heat sources are available to feed a heating network, a climate neutral gas such as hydrogen might be a good solution.

To shed more light on the possible application of hydrogen in buildings, the "BatHyBuild" study[1] has been set up as an initiative from the Waterstof Industrie Cluster (WIC). Within the industry cluster, various companies develop technology for hydrogen to be applied in buildings, *i.e.* hydrogen boilers, CHP operating on hydrogen, residential energy storage systems and hydrogen panels. There is a need for more understanding on the specific conditions in which these solutions can be optimally applied in the future. These insights are necessary to advise policy makers on how to design future residential energy systems.

Taking the Flemish context as a starting point, the BatHyBuild model follows a bottom-up approach. Within the BatHyBuild study, a model has been built that calculates the energy costs for the residents and for society (local system costs incl. infrastructure in the ground) for buildings that use hydrogen, in various use cases and using different technological solutions. These hydrogen based scenarios are compared with all-electric solutions (heat pumps).

This study has been carried out by KU Leuven (COK-KAT) and WaterstofNet, in collaboration with the Flemish DSO Fluvius and the engineering company Ingenium. An extensive sounding board group has been set up, composed by a number of technology suppliers, possible end-users, societal and governmental organisations, to support and feed the study.

With this study, the final word about the application of hydrogen in buildings has not been said. Rather, this first assessment is a starting point for future analysis and debate. As a follow-up of this study, it is investigated whether interesting test cases and pilot projects can be identified and realised in Flanders.

[1] Bottom-up Analysis of hydrogen Technologies for buildings.

1 Key messages

1. Hydrogen is a valid choice for heating of buildings

This is the main message of this study. Our findings show that cost differences between all-electric and hydrogen solutions will typically be small as of 2030-2040, based on the expected technology developments and future scenarios regarding infrastructure and hydrogen availability. All-electric and hydrogen solutions can co-exist in the future. Both have their specific benefits and drawbacks.

The results of this study are by far insufficient to conclude that hydrogen should in any case be used. However, the results convincingly show that the use of hydrogen should not be discarded without first understanding its potential.

2. Renewable gas will play a role in heating buildings

Buildings equipped with heat pumps will use 2-4 times more electricity in winter, when solar electricity supply is limited. Various studies estimate that between 17-44% of future electricity demand would be produced in gas turbines. Thus, even in an 'all-electric' heating scenario, a large part of the energy used for heating is provided by renewable gas. Furthermore, these studies estimate that at least 30% of final energy demand of the residential sector will be direct use of gas for heating. (Section 4.5)

3. Heat pumps are the most efficient technology

There is no doubt that the maximal efficiency of heat production is achieved by using a heat pump. The high COP of heat pumps cannot be beaten by any other technology. As a result, the primary energy consumption is lower when a heat pump is used for heating. (Figure 39)

4. The use of hydrogen results in a lower electricity demand

Hydrogen boilers consume no electricity for heating. As a result, the electricity demand is lower especially in winter. CHP units produce electricity while heating, and achieve near-zero or even negative electricity demand. Hydrogen-based solutions will induce less pressure on the electrical infrastructure and may reduce the need for domestic renewable electricity production. Instead, they utilize a gas grid infrastructure and rely on import or seasonal storage of green hydrogen. (Figure 6; Section 7.4.4)

5. Hydrogen enables decentralized renewable energy production

The capacity of the electrical infrastructure to absorb solar electricity is limited. However, the capacity of the gas grid is much larger. Decentralized production of renewable energy may be maximized by producing hydrogen (via electrolysis or hydrogen panels). This does not exclude, but complements solar electricity production by photovoltaics. As a result, houses with local hydrogen production may achieve the lowest primary energy demand. Even houses with all-electric heating solutions may become a hydrogen producer and thus reduce their net primary energy demand. (Sections 7.2.5 & 7.4.4)

6. In many existing buildings, hydrogen-based heating is the least-cost option

From 2030 onwards, hydrogen-based heating solutions may become competitive. In many existing buildings, renovation is not straightforward and true low-temperature heating systems are not available. Our results indicate that there is only a very small difference between hydrogen heating and all-electric heating. If one accounts for the extra costs to provide a low-temperature heating system, hydrogen heating clearly leads to the lowest costs. (Sections 7.2.1 & 7.4.2)

7. If low-temperature heating is available, all-electric heating is the least-cost option

If a low-temperature heating system is available at no extra cost, all-electric heating leads to the lowest annual energy costs (from a local point of view, excluding the impact on the energy system). Even more so for new districts, where it seems to make little sense to invest in new gas grids. (Section 7.5)

8. Hybrid heating may become the most common method of heating

Heat pump technology is not in contradiction with hydrogen-based heating. On the contrary, they are ideal partners. In most of the existing building stock, heating at moderate temperatures will be possible. In that case, the combination of a heat pump and a boiler leads to the lowest cost. This 'hybrid heat pump' is also a very flexible and futureproof method of heating. (Section 7.2.1)

The combination of CHP units and heat pumps is cost effective in some cases, such as new-build neighborhoods with district heating networks. This hybrid leads to a nearly zero net electricity demand throughout the year, since the CHP unit provides the electricity that is consumed by the heat pump. In general, houses with low heat demand benefit from a small CHP unit with a larger heat pump, while houses with a higher heat demand benefit from a large boiler with a small heat pump. (Section 7.2.3)

9. Combined heat and power (CHP) units provide green electricity to the grid in winter

CHP units co-produce heat and electricity, at near 100% conversion efficiency. While all-electric heating consumes a lot of electricity at times of high heat demand (in winter), CHP units will produce more electricity in those moments. A house equipped with a CHP unit will become a net producer of electricity during winter. If the CHP unit is fed with renewable hydrogen, it is essentially injecting green electricity into the grid at a time when electricity supply is limited. The presence of CHP units in households may limit the need for gas-fired power plants. (Section 7.4.4)

10. Off-grid installations are expensive and ecologically suboptimal

A building may disconnect from the grid and become self-sufficient. This is technically feasible, and facilitated by using hydrogen. However, not connecting to the grid infrastructure results in much higher costs. In addition, off-grid installations lead to a large amount of surplus energy in summer which cannot be used and is curtailed. This is a waste of energy. Due to the large amount of equipment needed to achieve self-sufficiency, the climate impact increases compared to a grid connection. Increasing the local production of renewable energy and local storage of electricity in batteries is a valid ambition and is even cost-effective in the future, but only when a connection to the distribution grid is maintained. (Section 7.3.3)

11. Distribution grids and hydrogen imports are important enabling factors

Connection to a hydrogen distribution grid is less costly than supply of hydrogen by other means (*e.g.* via trucks). The development of different methods for hydrogen storage and distribution may affect this, but is highly uncertain. A fine-meshed distribution grid to supply low-pressure gaseous hydrogen is the best guarantee to enable hydrogen-based heating solutions. (Section 7.3.2)

Furthermore, this study assumes that a steady supply of affordable, renewable hydrogen is available. This could be ensured by domestic hydrogen production with sufficient storage, or by import of green hydrogen via ships or pipelines. Both the import of green hydrogen and the availability of a hydrogen distribution grid are realistic future scenarios. (Section 4.2)

12. Energy efficiency recommendations are similar for all-electric and hydrogen-based houses

The use of hydrogen for heating does not change the 'no-regret investments' for homeowners. Insulation is cost-effective also for hydrogen-based heating. Low temperature heating systems, if possible at limited cost, are the best type of heat delivery system. Photovoltaics are a profitable investment, also when hydrogen is used or produced. Moreover, many of these investments have payback periods of less than 15 years. Since it will probably take at least 15 years before the use of hydrogen may become commonplace, it makes no sense to wait for hydrogen-based heating before investing in energy efficiency measures. (Sections 7.2.5 & 7.4.3)

13. Many aspects of heating and powering buildings have not yet been sufficiently investigated

An answer to the following question is still lacking:

"How can we heat and power our buildings in a sustainable, equitable way at the lowest societal cost?"

This study is the first step towards understanding how hydrogen might contribute to this question. However, many unknowns remain: the role of gas-fired power plants; the capacity of electrical distribution grids; the feasibility of hydrogen distribution grids; import of green hydrogen; the amount of domestic renewable energy production; the amount of rooftop renewable energy production; renovation rate and future building stock; legislative needs; the role of energy communities and collective heating; tariff structures; etc. To solve these questions, further studies and pilot projects are required. (Section 8.2)

2 Inzichten van deze studie

1. Waterstof is een valabele optie om gebouwen mee te verwarmen

Dit is de hoofdboodschap van deze studie. Onze resultaten geven aan dat de kostverschillen tussen all-electric verwarmen en waterstoftechnologieën eerder klein zullen zijn vanaf 2030-2040. All-electric verwarmen en waterstoftechnologieën kunnen naast elkaar bestaan. Elke aanpak heeft zijn specifieke voor- en nadelen.

De berekeningen uit deze studie zijn ruim onvoldoende om te kunnen concluderen dat waterstof zeker gebruikt moet worden voor verwarming van gebouwen. Echter, de resultaten tonen wel overtuigend aan dat het gebruik van waterstof niet a priori moet worden afgeschreven, zonder het potentieel ervan te kennen.

2. Hernieuwbaar gas zal een rol spelen in gebouwverwarming

Gebouwen met een warmtepomp verbruiken 2 tot 4 keer meer elektriciteit in de winter, wanneer de aanvoer van elektriciteit uit zonne-energie beperkt is. Verschillende studies geven aan dat 17-44% van ons toekomstig elektriciteitsverbruik zal worden geproduceerd in gascentrales. Zelfs in een 'all-electric' scenario zal dus een groot deel van de energie die nodig is om gebouwen te verwarmen, afkomstig zijn van een hernieuwbaar gas zoals groene waterstof. Bovendien stellen deze studies dat minstens 30% van de energievraag van de residentiële sector zal bestaan uit het rechtstreeks verbruiken van een gas voor verwarming. (Sectie 4.5)

3. Warmtepompen zijn de meest efficiënte technologie

Er bestaat geen twijfel dat de hoogste efficiëntie van warmteproductie behaald wordt met een warmtepomp. Het hoge omzettingsrendement kan door geen andere technologie worden geëvenaard. Bijgevolg is de primaire energievraag lager wanneer er een warmtepomp gebruikt wordt voor verwarming. (Figuur 39)

4. Het gebruik van waterstof leidt tot een lagere elektriciteitsvraag

Waterstofketels verbruiken geen stroom voor warmteproductie. Bijgevolg is de stroomvraag van een woning met een ketel lager, zeker in de winter. Bij warmtekrachtkoppeling (WKK) wordt elektriciteit geproduceerd tijdens de warmteproductie, wat leidt tot een zeer lage of zelfs negatieve elektriciteitsvraag. Waterstoftechnologieën veroorzaken dus minder druk op de elektrische infrastructuur en verminderen mogelijk de nood aan bijkomende hernieuwbare elektriciteitsproductie. Daarentegen gebruiken zij de gasinfrastructuur, en vertrouwen op de import of seizoensopslag van groene waterstof. (Figuur 6; Sectie 7.4.4)

5. Waterstof vergemakkelijkt decentrale productie van hernieuwbare energie

De capaciteit van het stroomnet om elektriciteit uit zonne-energie te absorberen, is beperkt. De capaciteit van het gasnet is echter veel groter. Decentrale productie van hernieuwbare energie kan dus op veel grotere schaal dankzij waterstofproductie (via elektrolyse of waterstofpanelen). Dit sluit de productie van elektriciteit uit zonne-energie niet uit, beide kunnen naast elkaar bestaan. Het wordt dankzij waterstof makkelijker om energiepositieve woningen te bekomen. Zelfs een woning die uitsluitend verwarmt met elektriciteit, kan een waterstofproducent worden om het netto energieverbruik te verminderen. (Secties 7.2.5 en 7.4.4)

6. In veel bestaande gebouwen is verwarmen op waterstof de goedkoopste optie

Vanaf 2030 kan verwarmen op waterstof geleidelijk competitief worden. In veel bestaande gebouwen is doorgedreven renovatie niet makkelijk en is een volwaardig warmteafgiftesysteem op lage temperatuur niet beschikbaar. Onze resultaten tonen aan dat er slechts een klein verschil is tussen all-electric verwarmen en verwarmen op waterstof. Wanneer ook de extra kosten voor lage temperatuurverwarming in rekening worden gebracht, leidt verwarming op waterstof duidelijk tot de laagste kost. (Secties 7.2.1 en 7.4.2)

7. Als lage temperatuurverwarming aanwezig is, is all-electric verwarmen de goedkoopste optie

Als lage temperatuurverwarming reeds aanwezig is zonder bijkomende kosten, is verwarmen met uitsluitend een warmtepomp de goedkoopste optie. Dit weliswaar vanuit het lokale standpunt, zonder rekening te houden met de impact op het energiesysteem. Voor nieuwe verkavelingen lijkt het weinig zinvol om te investeren in een uitbreiding van het gasnet. (Sectie 7.5)

8. Hybride verwarming wordt wellicht de meest toegepaste methode van verwarmen

Warmtepomptechnologie is niet in strijd met waterstoftechnologie. Integendeel, beide zijn ideale partners. In vele bestaande gebouwen zal verwarmen op beperkte temperatuur mogelijk zijn (bvb. klassieke radiatoren die overgedimensioneerd zijn). In dergelijke gevallen kan de laagste kost bekomen worden door een warmtepomp te combineren met een waterstofketel. Dit soort ‘hybride warmtepomp’ is bovendien erg flexibel en toekomstbestendig. (Sectie 7.2.1)

De combinatie van WKK met een warmtepomp is financieel voordelig in sommige gevallen, bijvoorbeeld een nieuwbouwwijk met een warmtenet. Deze hybride vorm leidt tot een netto elektriciteitsvraag van bijna nul doorheen het hele jaar, aangezien de WKK de stroom voorziet die verbruikt wordt door de warmtepomp. In het algemeen hebben woningen met een lage warmtevraag baat bij een kleine WKK met een iets grotere warmtepomp, terwijl woningen met een hoge warmtevraag baat hebben bij een grote ketel met een wat kleinere warmtepomp. (Sectie 7.2.3)

9. Warmtekrachtkoppeling (WKK) kan het stroomnet bevoorraden met groene stroom in de winter

WKK-eenheden produceren gelijktijdig warmte en elektriciteit aan een omzettingsefficiëntie van bijna 100%. Terwijl all-electric verwarming veel stroom verbruikt wanneer de warmtevraag hoog is, zullen WKK-eenheden op die momenten net veel stroom produceren. Een woning met een WKK wordt dus een netto producent van elektriciteit in de winter. Als de WKK gevoed wordt met groene waterstof, is hij dus groene stroom aan het injecteren op het net in een periode wanneer er vaak een tekort aan groene stroom dreigt te zijn. De aanwezigheid van WKK’s kan dus de nood aan grotere gascentrales verminderen. (Sectie 7.4.4)

10. Off-gridinstallaties zijn duur en hebben een grotere klimaatimpact

Het is technisch haalbaar om een gebouw los te koppelen van het net en zelfvoorzienend te worden. Dit wordt nog meer mogelijk gemaakt dankzij waterstof. Echter, niet aansluiten op het net leidt tot veel hogere kosten. Bovendien is er een groot surplus aan energie in de zomer dat niet gebruikt kan worden en dus verspild is. Door de grote hoeveelheid apparatuur die nodig is om heel het jaar zelfvoorzienend te kunnen zijn, wordt de klimaatimpact groter dan wanneer er een eenvoudige aansluiting op het net wordt voorzien. Niettemin is het raadzaam om zo veel mogelijk hernieuwbare energie te produceren en om lokaal elektriciteit te bufferen in een batterij. Dit is zelfs financieel rendabel in de toekomst, maar enkel als er ook een aansluiting op het net beschikbaar is. (Sectie 7.3.3)

11. Gasdistributienetten en import van waterstof zijn belangrijke succesfactoren

Aansluiten op een gasnet is minder duur dan het laten leveren van waterstof op andere manieren (bvb. per vrachtwagen). Dit kan veranderen in de toekomst door ontwikkeling van nieuwe technologieën, maar dat is op dit moment hoogst onzeker. Een fijnmazig distributienet dat huizen bevoorraadt met gasvormig waterstof op lage druk is de beste garantie om verwarming op waterstof mogelijk te maken. (Sectie 7.3.2)

Verder gaat deze studie er van uit dat een continue aanvoer van betaalbare hernieuwbare waterstof mogelijk is. Dit kan bereikt worden door binnenlandse waterstofproductie met voldoende opslag, of door groene waterstof te importeren per schip of pijpleiding. Zowel de import van groene waterstof als de beschikbaarheid van een distributienet voor waterstof zijn realistische scenario’s voor de toekomst. (Sectie 4.2)

12. Aanbevelingen op het vlak van energie-efficiëntie blijven gelden voor waterstof

Het gebruik van waterstof voor verwarming doet niets af aan de energie-investeringen die het meest rendabel zijn. Investeren in isolatie is rendabel, ook wanneer er met waterstof verwarmd wordt. Lage temperatuurverwarming is de beste manier om je woning te verwarming, als die optie er is tegen beperkte kost. Fotovoltaïsche panelen zijn een goede investering, ook wanneer er waterstof gebruikt of geproduceerd wordt in een woning. Bovendien hebben dit soort investeringen typisch een terugverdientijd van minder dan 15 jaar. Aangezien het wellicht nog minstens 15 jaar zal duren eer het gebruik van waterstof gemeengoed is, heeft het geen enkele zin te wachten op waterstof om dergelijke investeringen te doen. (Secties 7.2.5 en 7.4.3)

13. Vele aspecten van de verwarming en energiebevoorrading van gebouwen zijn nog te weinig onderzocht

Tot op vandaag ontbreekt een antwoord op deze vraag:

“Hoe kunnen we onze gebouwen verwarmen en van energie voorzien op een duurzame, billijke wijze aan de laagste maatschappelijke kost?”

Deze studie is de eerste stap naar het beter begrijpen van hoe waterstof aan deze kwestie kan bijdragen. Er zijn echter nog vele onbekenden: de rol van gascentrales; de capaciteit van het elektrische distributienet; de haalbaarheid van distributienetten op waterstof; import van groene waterstof; de hoeveelheid binnenlandse hernieuwbare energieproductie; de hoeveelheid hernieuwbare energieproductie op daken van gebouwen; de renovatiegraad en het toekomstige woningpatrimonium; nood aan wetgeving; de rol van energiegemeenschappen en collectieve verwarming; tariefstructuren; etc. Om deze vragen op te lossen, is er nood aan bijkomend onderzoek en pilootprojecten. (Sectie 8.2)

3 Recommendations for policy makers

The results of the BatHyBuild project indicate that there are several interesting options for powering and heating of buildings, depending on the energy demand profile of the building and a number of boundary conditions (possibility of low temperature heating, presence of a gas grid *etc*.). Even if all-electric solutions are, on the level of a single building, more energy efficient than gas/hydrogen based solutions, the cost and the stability of total electrical system has to be considered as well.

Assuming that hydrogen will be available in large quantities from 2030 onwards via both import and domestic production, supported by the current scenarios for a widespread European hydrogen backbone that will supply the hydrogen, we see several interesting options for hydrogen in residential applications and by extension in other types of buildings.

Starting from the results of the BatHyBuild study, we can formulate a number of recommendations towards our policy makers:

1. Develop a long term vision for heating and powering buildings in 2050.

An integral but realistic vision on the desired situation in 2050 should be put forward.

"Heat plans"[2] have been developed for Flanders, in which the heat demand for different cities and communities has been mapped and the potential sustainable heat sources are identified. A detailed analysis starting from these plans, of how the heat demand can be met in the different cities and what solution is preferrable, can lead to a long term blueprint of required technologies.

On the transition path towards this long term blueprint, strategic decisions are required *e.g.* on the destination and use of grid infrastructure. If gas grids are discarded, we lose the option of utilizing renewable gases even if they turn out to be useful.

Spill-over from other sectors will have an influence on this long term strategy, *e.g.* the use of large volumes of hydrogen in industry can enable its use of hydrogen in buildings. This depends on overall energy policy and industrial policy.

Clear and sustainable decisions on tax schemes and tariff structures are required, such that homeowners are motivated to invest in future-proof heating systems.

A tax shift should be worked out from electricity to fossil energy. Both fossil gas and fossil electricity should be taxed rather than renewable energy, *i.e.* not the energy vector, but its climate impact should be taxed. Europe will lead the way here with its expected review of the energy taxation directive in the course of 2021 .

2. Do not discard hydrogen a priori.

Nearly all studies indicate that gas will still represent a substantial share in the final residential energy use (cfr. paragraph 4.5). There is a discrepancy with the common debate on heating houses

[2] https://www.gemeentevoordetoekomst.be/artikel/vlaanderen-zet-groene-warmte-op-de-kaart

where often heat pumps and district heating (with waste heat) are seen as the only possible solutions. We call on our policymakers to act according to the results of these studies, and investigate if and how we could use renewable gases in buildings, at the lowest societal cost.

For those locations, such as densely populated historical city centres, where all-electric solutions are not straightforward and waste heat is not massively available, it should be investigated what type of renewable gas represents the most interesting option. Different solutions may exist next to each other, *i.e.* local distribution grids with either biogas, synthetic methane and hydrogen dependent on the local situation. For cities and districts close to the future hydrogen backbone, a local hydrogen distribution network can be an interesting solution, while at other locations close to biogas production sites a biogas network can be preferrable.

3. Support research and pilot projects to learn about the opportunities and drawbacks of hydrogen in the built environment.

If we want to be ready for the future energy landscape as a region, we should perform studies and pilots now. This allows us to create a vision based on facts and experience, which is necessary if our region wants to keep up with developments in decades to come.

Pilot projects allow us to study synergies between different technologies. The study shows that hybrid solutions of heat pumps and gas supplied heat devices (boilers or CHP) to cover peak demand can be a very interesting solution. Testing these hybrid systems in a real situation, given local energy supply and grid conditions, is required to find the optimum working regime of such devices.

Pilot projects will allow us also to map real costs, practical boundary conditions, legislative needs, safety issues, *etc*.

Moreover, pilot projects encourage innovation, support the many Flemish companies active in this sector, and ensure that our sector generates skilled professionals and know-how on this topic.

4. Do not focus solely on efficiency, but focus on achieving a renewable, equitable future at the lowest societal cost.

The use of hydrogen in buildings should be assessed as part of a complete energy system, not only on the level of a single house. It should be investigated which is the overall best solution, *i.e.* is it preferrable to supply heat pumps (in winter) with centrally produced electricity from hydrogen-powered gas turbines, or is it more advantageous to use decentralized hydrogen units for heating?

Efficiency is important but should be considered in a bigger picture, it is a cost optimisation issue rather than a pure energy issue. If green hydrogen can be imported at low cost, efficiency is less important. In that case, deep electrification will cause a larger impact on our power system than having a diversified system with a share of gas. Conversely, if most of the hydrogen is to be produced by electrolysis within Belgium, the supply of hydrogen will be limited and efficiency does play a large role.

5. Do not focus solely on ideal cases, but focus on real cases.

In the debate on future heating solutions, the focus is mostly on very well insulated new-build houses. Reduction of energy demand of buildings is urgently needed and renovation rate should increase. However, even with an acceleration in building renovation, there will still be a high share of buildings that are not capable of having a low temperature heating system at reasonable cost or due to certain restrictions (*e.g.* cultural heritage).

An assessment should be made of the real expected building stock in 2050 and how these could be heated at the lowest cost for society and for the individuals.

6. Speed up the deployment of renewable energy production.

Whether we opt for deep electrification or for other strategies, we will benefit from large production capacities of renewable energy. Further deployment of solar energy, including dual use of building surfaces (roofs, façades, etc) to maximally capture solar energy, is needed.

In order to avoid overload of the electrical infrastructure when maximizing solar PV capacity, it should be investigated to what extent hydrogen panels and electrolyzers at the residential, distributed level can be a complementary solution.

7. Investigate the systemic benefits of CHP units.

The capacity of our electrical infrastructure can also set limitations to all-electric solutions and expanding the system can lead to very high societal costs. CHP units can – possibly in hybrid solutions with heat pumps – supply part of the required electricity from renewable gas and relieve the electrical system at moments when there is peak demand.

4 Background information and context

4.1 Introduction

In this chapter, we provide some background information required to understand the assumptions and framework that is used in the BatHyBuild calculation model.

In the study, we make a number of assumptions for the year 2050 on the availability of green hydrogen. We assume that a hydrogen network is available, with a constant supply of green hydrogen. This assumption is based on a number of future scenarios that are currently being developed on both national and international level on import of hydrogen and future hydrogen pipeline networks. In paragraphs 4.2 and 4.3 we briefly summarize these scenarios.

The renovation level of buildings, which determines their actual energy consumption, is an important parameter in the study. The expectations for the coming decades regarding this renovation level are discussed in paragraph 4.4.

The future role of gas and electricity in the residential sector have been analysed in many studies; paragraph 4.5 gives a short overview of the main views on this topic.

The different technologies required to produce hydrogen and convert it to power and heat, on the scale which is relevant for residential application, are briefly discussed in paragraph 4.6.

4.2 Import of green hydrogen

It is clear by now that sun and wind will become two of the primary sources of sustainable energy.

However, several studies have already indicated that for Belgium, as is the case for most European countries, the domestic electricity production from local solar and wind capacity will not be sufficient to cover the full demand of energy in a climate neutral society. Besides the electricity demand, an important part of the energy (and feedstock) demand will still be covered by molecules, e.g. for transport, high temperature heating and flexible thermal gas plants.

Import of massive volumes of energy will be required. In several regions in the world, renewable energy is available in much more higher quantities (more wind and sun hours) than in North-Western Europe. Additionally, the availability of the required space to install turbines is a major constraint in our region. It may therefore be more economical and easier to produce part of our renewable energy in regions where the combination of sun, wind and space is abundant.

Large-scale transportation of energy across ultra-long distances will be done in the form of molecules and more specifically as hydrogen or derived molecules such as synthetic ammonia, methane of methanol.

The entire value chain for the import of hydrogen and hydrogen carriers from several locations in the world to Belgium has been mapped in a detailed manner by 'the Hydrogen Import Coalition'[3]. A financial analysis of the full chain has been made, including production of renewable electricity and hydrogen, conversion to different hydrogen carriers, transport by pipeline or by ship and

[3] https://www.waterstofnet.eu/_asset/_public/H2Importcoalitie/Waterstofimportcoalitie.pdf

terminalling, leading to a 'Levelized cost of Hydrogen (LCOH) ' for different production locations for different time horizons (2030-2050).

As an overall conclusion from the import study, it can be stated that the cost of renewable imported energy lies in the range of 80-110 €/MWh by 2030-2035 with a further cost reduction potential down to 70-100 €/MWh or lower by 2050.

The range of magnitude for the levelized cost of hydrogen as deduced from the import study, has been used as input in the BathyBuild model for 2030-2050 as presented in chapter 6.

4.3 Hydrogen pipeline infrastructure

When large scale import of hydrogen and centralised production at the sea coast (from offshore energy) will be developed, transport of hydrogen from these production sites or terminals to the main areas of consumption will be required.
For this purpose, recently a EU hydrogen backbone has been presented by a number of EU TSOs.[4]

A large part of this backbone will be built reusing retrofitted natural gas pipelines.
For Belgium, Fluxys has proposed a trajectory for a local hydrogen backbone, as shown in Figure 1.

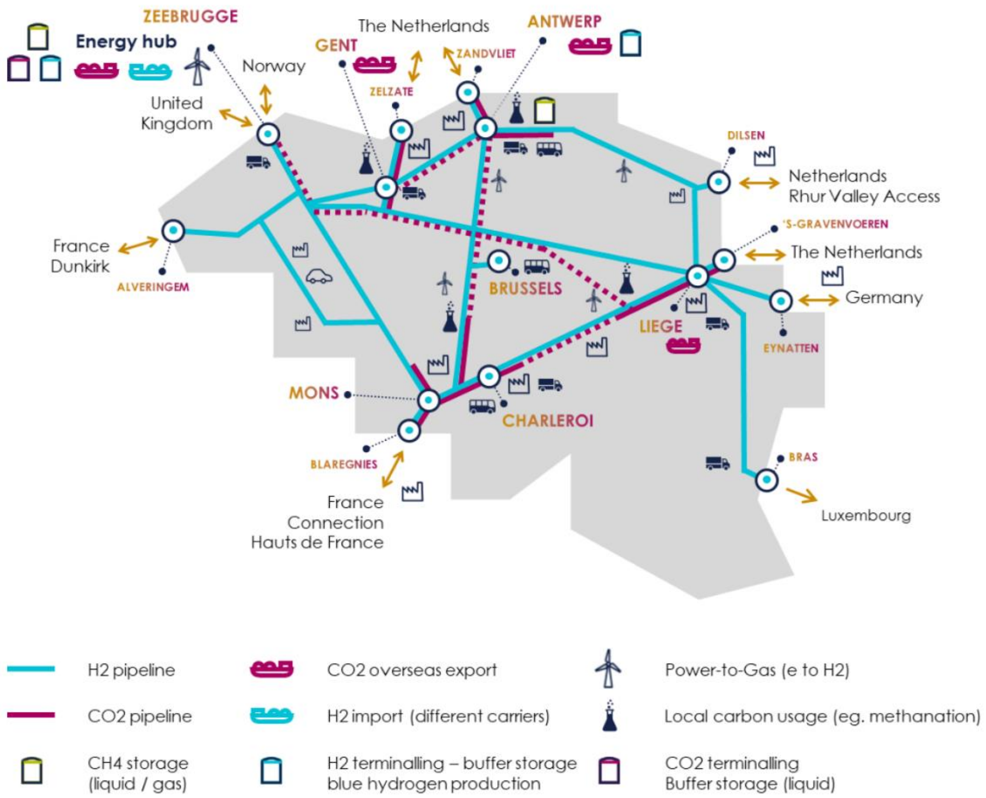

Figure 1: Fluxys' long-term vision for the H_2/ CO_2 backbone in Belgium

This H_2 backbone will not be finalised before 2030. As a first priority, this backbone is focused on connecting the industrial clusters. Further coupling to a fine-mazed distribution grid is not yet planned, but can be a next step which can open the opportunity to the availability of low cost hydrogen in certain locations in Belgium, also for energy supply to buildings. Experience from other European countries has shown that existing polyethylene piping used for gas distribution grids is suited for transporting hydrogen. In Belgium, we have a very high degree of connection to the gas grid[5] and moreover, the majority of our gas pipelines are indeed made of polyethylene.

4.4 Renovation level of buildings

Before determining the ideal technology for heating a building, one should minimize its energy consumption. For new-build houses, this is a relatively easy task. One can assume that houses built in the next decades will have a low heating demand. However, most of the houses which have to be heated in 2050, already exist today. When also counting the embodied energy of the building materials, the climate impact of a house may be smaller when renovating instead of demolishing, even if the annual heat demand is slightly higher as result.

The non-electrical energy use of households was 8 718 kWh/capita in 1990 and was still 6 630 kWh/capita in 2019.[6] When correcting for households with electrical heating, the average non-electrical energy use was 7 367 kWh/capita in 2019. This translates into an average non-electrical energy demand of 17 018 kWh per household.

By 2050, the Flemish government aims for all of the Flemish buildings to reach an energy label of at least A.[7] This corresponds roughly with E60, or 7000 - 12000 kWh annual heat demand for a typical house.[8] Today, merely 4% of Flemish houses reach energy label A, while 57% is still at an energy label of D-F. To achieve our target by 2050, an annual renovation rate of the existing building stock of over 3% is required every year until 2050. The actual rate of renovations is just 2.5%. Many of these renovations do not reach an A-label. At this rate, at least one quarter of Flemish houses will not reach energy label A by 2050, potentially much more.

4.5 The role of gas and electricity in the residential sector in 2050

Many words have been spent on the topic of hydrogen. Even more so on the topic of using hydrogen to any extent in the residential sector. Conversely, studies investigating this application are scarce. Here, we discuss some Belgian, Flemish and Dutch studies on the electricity sector and the residential sector in 2040-2050.

The Federaal Planbureau has developed a model to assess the role of hydrogen in the Belgian energy system in 2050.[9] They compare a scenario with a clear focus on deep direct electrification, while another scenario ('diversified energy supply') leaves more room for additional energy vectors. In the diversified scenario, about 80% of the houses which have a heat pump opt for the hybrid solution, working in tandem with a gas-based appliance. In both scenarios, 31-33% of electricity is

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[5] Fluvius, Visie 2050: de Vlaamse energienetten van de toekomst, 2020.

[6] De Vlaamse Energiebalans. https://www.energiesparen.be/energiestatistieken

[7] Vlaamse Langetermijnrenovatiestrategie voor gebouwen. https://www.energiesparen.be/vlaamse-langetermijnrenovatiestrategie-voor-gebouwen-2050

[8] Average of 55 kWh/m^2 - S. Verbruggen, M. Delghust, A. Janssens (2019), Onderzoek naar de relatie tussen het e-peil, het berekende energiegebruik en het werkelijke energiegebruik, UGent.

[9] Federaal Planbureau, Fuel for the Future. More molecules or deep electrification of Belgium's energy system by 2050, October 2020.

generated by gas turbines fed with hydrogen. In both scenarios, up to half of the electricity demand is for power-to-gas applications (both for flexibility and end use hydrogen needs). Furthermore, the import of hydrogen is deemed to be significant (providing over 80% of hydrogen demand) if its price reaches 50 €/MWh.

According to the latest study of Energyville,[10] 17% of annual electricity demand would be produced using gas turbines and fossil fuels in 2040, while import from neighbouring countries increases to a share of 23%. In the residential sector, gas is expected to make up 42% of final energy demand in 2045. Even in the 'high renewables' scenario, gas still provides 30% of final residential energy demand. The study assumes that no CO_2 emissions are associated with the use of gas as an energy vector. However, it is not specified what type of gas would fulfil the role played by natural gas today.

In an analysis of Elia,[11] gas-fired power plants will provide between 27-44% of electricity generation in 2040. They assume a heat pump penetration of 20-45% in 2040, about half of which are hybrid installations. Hydrogen was not mentioned, and combined heat and power generation was only considered for large-scale electricity production.

A recent Dutch study[12] found that DSOs and TSO will have to invest 102 € billion to reinforce their electrical grids in the coming decades. The annual costs will increase from 2.8 € billion to 5.6 € billion for electrical grids, while they will reduce from 1.2 € billion to 0.7 € billion for gas grids by 2050. However, both electricity and gas customers will see grid fees increase with 54-98% and 9-37% respectively, due to a diminishing number of gas consumers. The implications of switching to hydrogen were not explicitly assessed.

The capacity of Flemish distribution grids to bear the loads of the future (renewable generation, electrification) is still under investigation in the Bregilab project.[13] There has been a study to assess the potential for absorbing solar electricity, however.[14] The study assumes a global peak injection limit on the Belgian distribution grid of 6 GW. This equates to merely 1.5 kW per connection point. At a high penetration of 30 GWp solar PV on residential rooftops, the injection limit is then only 0.2 kW/kWp, leading to curtailment of peak production even when including a battery (at 1.5 kWh battery capacity per kWp installed solar PV). The authors claim that by discharging the batteries to the grid at night, they are ready for charging during the day, which minimizes costs of grid reinforcement and limits curtailment to 20% of the produced electricity. The study did not consider heating demand of buildings, the impact of heat pumps, or hydrogen.

The existing studies either casually assume that 'some type of gas' is still used in the residential and electricity sectors, or they do not engage with the topic. When it comes to distribution grids, the capacity and costs of the electrical grid to manage future peak loads nor the ability of the gas grid to carry hydrogen has been convincingly assessed. This finding is in stark contrast with the common discussions found in the media and online, where the use of hydrogen in the residential sector is often discarded a priori. This may or may not turn out to be a good policy. In any case, the assumption today is not based on facts and studies.

[10] Energyville, Belgian Long Term Electricity System Scenarios, September 2020.
[11] Elia, Electricity scenarios for Belgium towards 2050, November 2017.
[12] PwC, De energietransitie en de financiële impact voor netbeheerders, April 2021.
[13] https://vito.be/nl/bregilab
[14] Meuris *et al*. (2018). *Prog Photovolt Res Appl*. 27 : 905-917.

4.6 Technological developments and breakthroughs

In the paragraphs below, we briefly list the different technologies that are relevant for the application of hydrogen in buildings, both for the production of hydrogen, for the storage of hydrogen as for the conversion of hydrogen to power and heat.

4.6.1 Production of hydrogen

Hydrogen can be produced by different techniques: today, most hydrogen is produced from natural gas with **steam methane reforming**, which is a CO_2 emitting process. This production technique can in principle be converted to a low carbon production method if carbon capture and storage (CCS) applied. SMR and carbon capture are typically large scale industrial processes.

For the production of green hydrogen (=low carbon AND renewable), **water electrolysis** powered by renewable electricity is the most applied technique.
Due to the ambitious plans for hydrogen roll-out in Europe, developments in electrolyser technology are strongly accelerating, with the focus on large systems (MW-GW scale), material cost decrease and efficiency increase.

Electrolyser installations (AEL, PEMEL technology)[15] up to a few MW scale are already operational. Projects of >= 100 MW are under development. This scaling up will lead to the availability of low cost hydrogen, if low cost electricity is available and if hydrogen is produced centrally in large installations. There is however limited focus on small scale electrolysers to be used for local hydrogen production (kW scale) in the built environment, such that low cost systems will not be soon available in this market segment. This may also lead to the choice for larger electrolysers to be used on district level.

Other techniques are hydrogen production from biological origin (e.g. gasification of biomass and biowaste), from direct solar water splitting using solar thermal heat or direct sunlight (photonic energy), or from pyrolysis processes for hydrogen production from biomass/biogas with solid carbon as side product.

Direct solar water splitting by photonic energy i.e. " hydrogen panels"[16] is a promising technology which is particularly suited for use in the built environment since these panels can be installed on houses and buildings similarly to PV panels.

4.6.2 Storage of hydrogen

The volume of the (gaseous) hydrogen storage is defined by the hydrogen pressure; the higher the pressure the more compact the storage. However, higher pressures require a more expensive compressor and higher cost pressure vessels/containers and require a number of safety precautions. Low cost, compact and safe storage of hydrogen is one of the bottlenecks for residential application of hydrogen. Solutions on district level, where the compressor unit and the storage containers can be shared with a large group of users are therefore more realistic than hydrogen storage for a single house. Typical storage pressure for stationary applications are 80 bar (large tanks for level of a district) or 200-300 bar for more compact storage on the level of a single house.

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[15] AEL: Alkaline electrolysis, PEMEL: Proton exchange membrane electrolysis, SOEL: Solid oxide electrolysis
[16] KU Leuven development (www.solhyd.org)

An alternative solution could be to bind hydrogen molecules in solid or liquid compounds, from which they can easily extracted at the time of use. This circumvents the use of a compressor and allows to store more hydrogen per volume unit.

Metal hydrides are a well-known alternative that can absorb hydrogen molecules. They are commercially available for small quantities, see e.g. [17] but are not yet widely used for larger scale storage. Some residential applications are being developed based on this storage principle[18].

Other solutions as clathrates and liquid organic hydrogen carriers are still in the R&D phase, but might contribute to more practical and lower cost storage of hydrogen in the future.[19]

Further breakthroughs in low cost and compact storage of hydrogen are essential for solutions with local storage of hydrogen. Hydrogen solutions coupled to a hydrogen distribution grid, where the storage is partly done in the grid itself and in larger centralised storage, as is the case for natural gas today, do not suffer from this problem.

4.6.3 Conversion of hydrogen to power & heat

Different technologies are available or are in development for the production of heat and power from hydrogen.

A **hydrogen gas boiler** that operates on 100% hydrogen -to be used for central heating- has been developed by a few companies (e.g. Remeha and Bekaert heating). A hydrogen boiler functions in the same way as a natural gas boiler and is expected to be only slightly more expensive. Technically, they are also very similar but a number of components such as the flame detector and the burner have to be replaced to enable functioning on hydrogen. Hydrogen burns with a much higher flame speed, which increases the flame temperature locally and can generate high levels of NO_x; a burner redesign is required to keep the flame at a lower temperature (e.g. by influencing the mixing of air and hydrogen) and minimise NO_x formation.

Combined Heat Power (CHP) units operating on hydrogen are available. They can be based on either combustion of hydrogen or on fuel cell technology. In our region E. Van Wingen has an **ICE-based CHP** available with 100 kW electrical power. **Fuel cell** based micro-CHPs (order of 10s of kW) are offered by several suppliers, such as Viessmann and Elugie. Today these fuel cell solutions are mostly connected to the natural gas grid and extract the hydrogen from the natural gas (cracking) before feeding it into the fuel cell. These CHPs are very energy efficient if electrical and thermal efficiency are added; the ratio between electrical and thermal output varies with the specific technology (combustion versus PEM fuel cell versus SOFC fuel cell).

The above mentioned hydrogen solutions can be linked to an air source heating pump, in a **"hybrid heat pump" set-up**. Such a hybrid heat pump can be a solution if a low temperature heating system is no option in a (mostly older) building; the boiler or CHP can be switched on in colder periods of the year to assist the heat pump.

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[17]https://www.pragma-industries.com/hydrogen-storage/
[18] https://www.gknpm.com/globalassets/downloads/powder-metallurgy/2018/gkn-metal-hydride-based-hydrogen-storage.pdf/
[19] Preuster *et al.* (2017). Annu. Rev. Chem. Biomol. Eng. 8 : 445-471;
Andersson & Grönkvist (2019). Int. J. Hydrogen Energy 44 : 11901-11919;
https://moonshotflanders.be/mot4-arclath

Systems that are combining the production of hydrogen with the conversion of hydrogen into power and heat (“**all-in-one**”) are also developed; the Solenco Power box is an example developed in Belgium.

5 Literature study and pilot projects

5.1 Studies on the use of hydrogen in buildings

Several studies have already analysed the possibilities for the use of hydrogen in buildings. Especially in the Netherlands, where a strong focus exists to abandon the use of natural gas and realise a fast transition to a new energy carrier, a number of analyses has been done. Also in the UK, an ambitious long term planning for conversion of the natural gas grid towards hydrogen has been proposed.

A list of different studies is given in the Appendix, section 10.1.

Main conclusions of the studies:

- Hydrogen will play a very limited role in the built environment until 2030, because the high demand for low carbon hydrogen in the industry will be the first priority. On short term hydrogen in buildings will remain expensive due to the lack of infrastructure for distribution and the high investment costs. After 2030, upscaling of hydrogen supply for the industry will lead the availability of low cost H_2 for other applications.
- An important element is the reuse of the gas network, with which infrastructure / total costs can be limited compared to heat networks and heat pumps.
- Where all-electric or heat networks are not possible (think of older detached buildings in the countryside), hybrid heat pumps are an option. These hybrid heat pumps are fed with green gas and / or hydrogen.
- In older buildings, in cities with an existing gas network, solutions such as a hydrogen boiler or CHP can be a solution, if hydrogen is available below a certain price. Conversion of a house to a low temperature heating system (heat pump of heating net) might be more expensive.
- In new buildings, the hydrogen price must be much lower (<3 €/kg) to be competitive with a heat pump.
- Hydrogen can be used for better integration into the total energy system; all-electric solutions may require peak power or large-scale energy storage. Hydrogen in existing gas infrastructure provides flexible energy supply and storage in a cost-effective way.
- No low-CO_2 solution is close to competitive with natural gas (H_2 price of < 1 € kg required).

5.2 Pilot projects

Several pilot projects have been set up, mostly in the Netherlands. The main purpose of the pilot projects is to demonstrate the technology, to learn about the optimal way of using it e.g. in combination with other technologies such as heat pumps or heating grids and to develop the regulatory framework (safety, financial aspects..). In the table below an overview of a number of realised and projects is given.

Two main principles can be distinguished: either the hydrogen is produced centrally and distributed via a gas distribution grid (cfr. the current natural gas model) or the hydrogen is used as a local storage ("H_2-home battery") for local electricity production from PV.

“central” PRODUCTION of H_2, VIA local distribution grid		
PROJECT	**SETUP**	**RESULTS/STATUS**
Project Ameland (NL)	• Local production of H2 from PV. • H2 pre-mixed with methane to concentration of max 20% H2 and injected in small decoupled part of the gas grid. • Mix of methane and H2 used in appartment complex during years (2007-2011). Standard heating appliances have been used.	• Conclusion of the project is that admixing of 20% of H2 is no problem for the users, the pipeline infrastructure and the appliances.
Project Rozenburg (NL)	• Local production of H2 from PV and from the grid. • Transport of the H2 via dedicated gas pipeline of Stedin to the boiler house of an apartment complex. Phase 1 (2013-2018) : H2 is locally converted to synthetic methane, that is burnt in existing boilers. Phase 2 (2018-2023): use of pure H2, for which a dedicated H2 boiler is used	Technical feasibility demonstrated of the full system and individual components. Operational characteristics have been studied and it has been shown that the produced methane is compatible with the NL gas grid. https://www.dnvgl.com/publications/power-to-gas-project-in-rozenburg-the-netherlands-39020
Project Waterstofwijk Hoogeveen (NL), locatie Nijstad-Oost	• Construction of 100 new build houses connected to a local H2 distribution grid, each house with its H2 boiler for heating. ○ Phase 1: trucked-in H2 (2021) ○ Phase 2: locally produced H2 (electrolysis, from RE) (2023) ○ Phase 3: H2 from pipeline (H2-backbone) (2027) • Conversion of 427 existing houses to a similar solution.	Not yet in realisation phase. Starts in 2021. Purpose of the demonstration: proof of technical feasibility, legislation, public acceptance… Funding: Programma Aardgasvrije Wijken of RVO https://research.hanze.nl/ws/portalfiles/portal/34882351/HANZE_20_0635_Publieksvriendelijke_versie_Waterstofwijk_Gewijzigde_Herdruk.pdf
Stad aan ’t Haringvliet (NL)	• Conversion of 600 existing older buildings with H2 boilers. In 2025 they should be disconnected from natural gas supply.	Not yet in realisation phase.
“DECENTRAL” PRODUCTION of H2 (from local PV) , WITH LOCAL STORAGE NEAR BUILDING		
Waterstofhuis Goeree-Overflakkee	• One family house with own PV installation on the roof. Local H2 production and storage. H2 production and conversion to	Operational since 2019.

	power/heat is done with the Solenco Power box. The H2 is stored in gas cilinders. This project fits in a larger project in Goeree-Overflakkee, where the aim is to convert 250 houses to H2 within 5 years.	
ROLECS Leuven (BE)	House with H_2 panels. Aim was to install a H_2 boiler and have local H_2 storage, but the permitting did not succeed for this.	1 panel operational since 2019. https://solhyd.org/nl/projecten/rolecs/
Off-grid House Brütten, near Zürich (CH)	• House for 8 families, completely self-sufficient (off-grid), with PV, batteries, electrolyser, fuel cell, heating pump and H2 & heat storage. http://www.proton-motor.com/energieautarkes-mehrfamilienhaus/?lang=de	Operational since 2016. Grid independency has been demonstrated. Especially in Dec and Jan electricity production from H2 is required, since PV is not supplying sufficient energy.
Offgrid family house Göthenborg (S)	• Family house, self-sufficient with PV, alkaline electrolyser, batteries and 300 bar storage. • Scaling up to apartment complex (172 units) in Vårgårda Municipality of Sweden was planned, but the project was stopped because it appeared not to be profitable	https://www.linkedin.com/pulse/true-pioneer-goes-off-grid-michael-jensen/ https://www.tellerreport.com/news/2020-09-03-attentional-hydrogen-project-in-v%C3%A5rg%C3%A5rda-stopped.S19rpYBRXD.html

The (planned) project of Hoogeveen, where a new-build district (Nijstad Oost) and an existing district (Erflanden) will be heated with hydrogen boilers supplied by a local hydrogen grid, has been analysed in detail[20], with comparison of the hydrogen solution with alternative solutions such as heating grids or all-electric solutions.

The conclusion of this analysis is that the total energy costs per year for a hydrogen solution are lower than for the all-electric case, especially in a district with existing houses and an existing gas grid.

The main contributions for the higher cost of the all-electric case in an existing district are the installation cost of the heat pump and required heat buffer for hot water, the required removal of an unused gas network and the insulation costs to enable low temperature heating. Regarding the total system cost, it is argued that an all-electric solution in the Netherlands (from reference[21]) will lead to a total cost of 45 bn€ and 31 bn€ in a molecule scenario (green gas and hydrogen). However, the mentioned molecule scenario in this reference starts from a blue hydrogen assumption.

[20] https://www.researchgate.net/publication/350353695_Indicative_Social_cost_benefit_analysis_Hydrogen_heating_MKBA_Hydrogen_City_Hoogeveen_the_Netherlands

[21] (Berenschot 2019), Bert den Ouden, 2019. Waterstof in de gebouwde omgeving presentatie voor H2 platform 13 december 2019), https://opwegmetwaterstof.nl/wp-content/uploads/2019/12/Berenschot_gebouwde-omgeving.pdf

6 The BatHyBuild model

6.1 Approach and setup of the model

The BatHyBuild model is a bottom-up model, which considers the local context of a house or neighbourhood (Figure 2). The system boundaries are at the end of the street. Within the system, all costs and energy flows are calculated. When a grid is present, we assume it can supply an infinite amount of green energy carriers at a certain assumed cost. Thus, energy carriers flowing into and out of this local system, contribute to the cost and energy balance.

For every calculation, certain parameters can be chosen:

- Context and energy demand
    - Context: new-build / renovation
    - Energy demand: electricity, heating and hot water
- Grid infrastructure
    - Distribution grids: electricity grid, gas grid
    - Microgrid: district heating, gas grid, electricity grid
- Technologies
    - Renewable energy: solar PV / hydrogen panels
    - Energy conversion: heat pump / cogeneration / boiler / electrolysis
    - Energy storage: thermal / battery / gas storage
- Scenarios
    - Time horizon: 2025 / 2030 / 2050
    - Energy prices: optimistic / base case / pessimistic
    - Electricity price: fixed / dynamic
    - Technology development: optimistic / base case / pessimistic

An energy balance is then calculated for every hour of the year (Figure 3). The energy balance takes into account limiting boundary conditions such as the maximum power of the appliances and the maximum energy level of the energy storage. The COP of the heat pump is calculated based on the estimated temperature level of the water and the outside air temperature. A distinction is made between water for central heating and sanitary hot water. Both are assumed to be higher when annual heat demand is higher.[22] Furthermore, the model contains some priority rules. For instance, a heat pump is always prioritized over other appliances. An electrolyzer will only use excess or very low cost electricity to produce hydrogen. A thermal buffer will be charged by the heat pump when excess solar electricity is available or when prices are very low.

[22] For the sake of simplicity, the annual energy demand for sanitary hot water is kept constant for all cases, cfr Table 1.

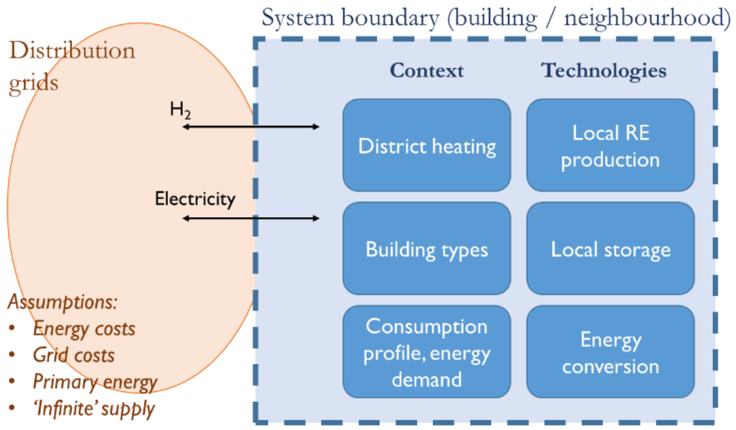


Figure 2: Schematic overview of the scope of the BatHyBuild model.

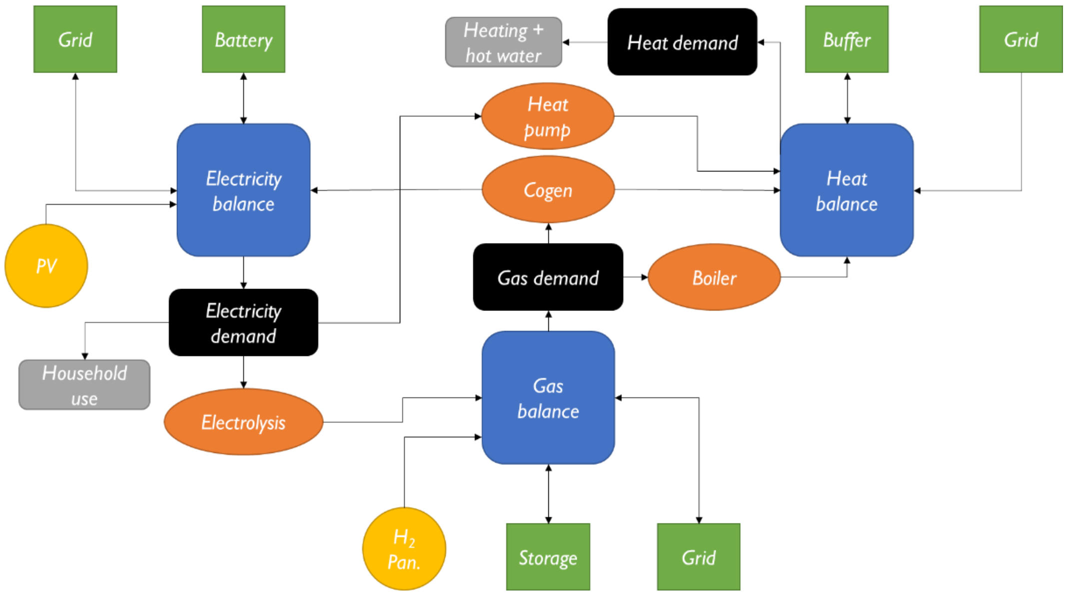


Figure 3: Schematic overview of the BatHyBuild model logic. Three energy balances are calculated (heat, electricity, gas), each with relevant inputs, outputs and buffers.

Based on the energy balance, the hourly demand for grid electricity and grid hydrogen is obtained (Figure 4). Together with the chosen configuration and appliances, a discounted cost calculation is then made over a 20 year period. The cost estimate takes into account CAPEX, OPEX and replacement costs of appliances and grids, energy costs and grid fees. At the end of the 20 year period, a correction is made for the residual net present value of the infrastructure and appliances.

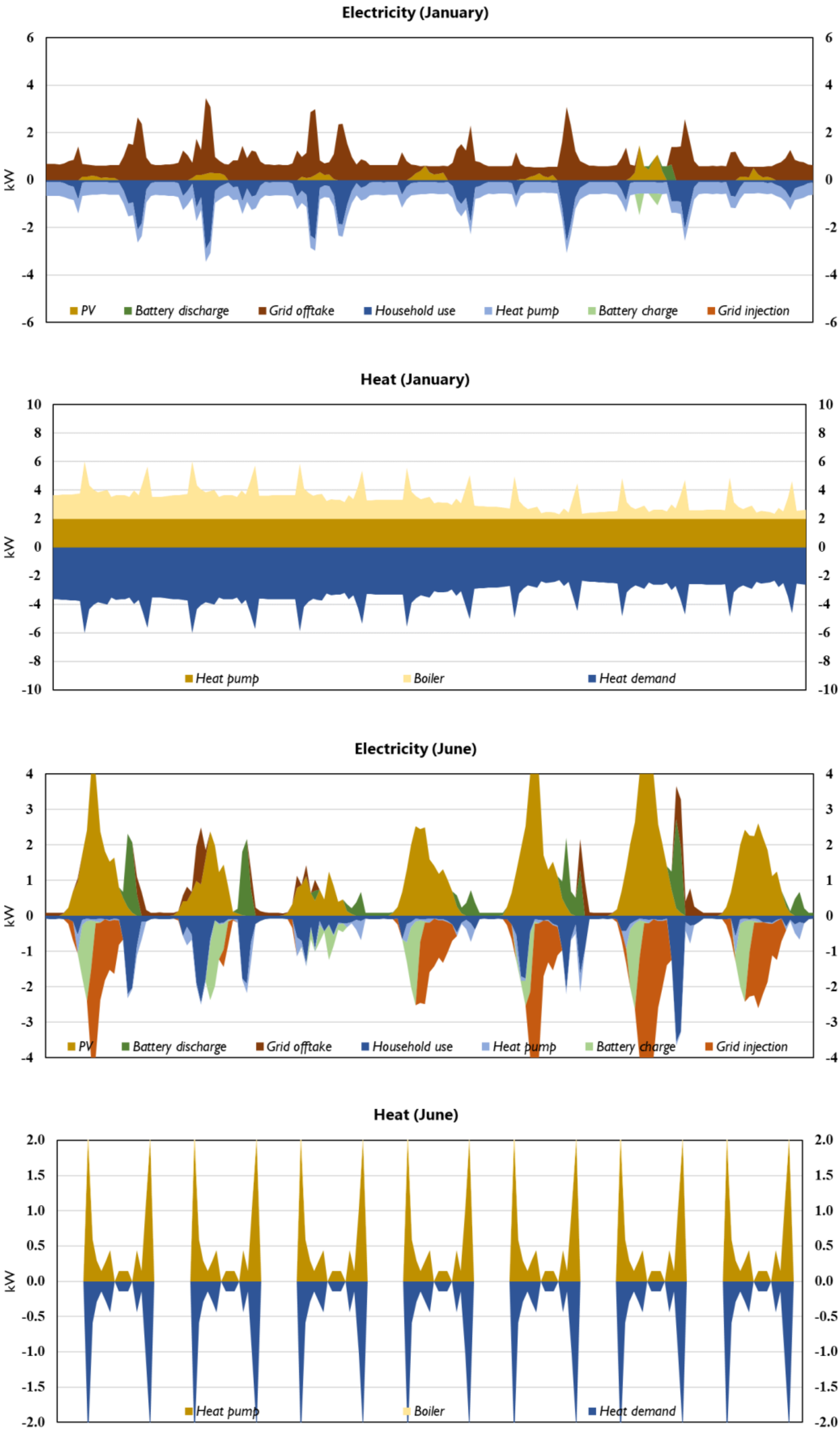


Figure 4: Example of model output. Hourly energy balances for one week in January and one week in June. (Base case, 2050. 13 MWh heat demand, 5 kWp PV, 5 kWh battery, 2 kW heat pump, 15 kW hydrogen boiler).

Some key performance indicators are calculated, which are used throughout this report. We define those KPI's here.

Energy cost

The energy cost is the **sum of all energy-related costs payable by a household**. It includes costs such as the discounted CAPEX of appliances, OPEX, VAT, electricity and hydrogen costs, grid fees and single cost of connecting to the grid (in case of a new-build house). However, **renovation costs are not included**. The cost of insulation, installation of low-temperature heating, purchase of an induction cooking set, adaptations to the hydraulic or sanitary installation, are all not included in this cost.

(Local) system cost

The local system cost is the **sum of all bare energy-related costs of the local system**. It also includes the discounted CAPEX of appliances, OPEX, electricity and hydrogen costs. It includes the real cost of building and maintaining a grid infrastructure. However, it does not include VAT or distribution grid fees. It also does not include renovation costs or costs related to balancing of the electricity grid. Furthermore, the model assumes that existing and new-build electricity grids are always capable of handling the peak loads. Thus, the model does not consider (the cost of) reinforcements of the electricity grid.

Winter electricity demand

This is the **net amount of grid electricity consumed during the 6 coldest months of the year** (October – March). It is the sum of all offtake and injection during that period. This includes e.g. the household electricity use, production of electricity by solar PV and cogeneration units, consumption of electricity by heat pumps and electrolyzers.

Net primary energy demand

This is the **net amount of primary renewable energy required annually to supply a household with the desired energy carriers** (electricity and hydrogen). It is based on the offtake and injection of electricity and hydrogen to their respective grids. Note that we assume all electricity and hydrogen to be renewable. 28% of electricity demand is assumed to be produced in (renewable) gas turbines. 100% of hydrogen demand is assumed to be produced via electrolysis.[23]

6.2 Assumptions

The BatHyBuild model is a simplified model which relies on assumptions for its calculations. Different assumptions will yield different outcomes, and the accuracy of the results depends entirely on the accuracy of the assumptions and input data.

The following general assumptions are valid for all cases and results:

- A gas distribution grid is present which is able to carry hydrogen.
- The grids may supply an infinite amount of hydrogen and electricity, without impacting the energy cost.

[23] These numbers may be a subject of discussion. However, we found relatively little impact of changing the primary energy factors. Thus, we did not attempt to make a comprehensive calculation, which should be the topic of other, top-down studies.

- All of the energy carriers (electricity, hydrogen) are 100% renewable. Blended networks are not considered.
- All technologies are available at any power rating, from 0.5 kW upwards.
- When collective heating is modeled, all of the households are identical. Districts and apartment complexes are assumed to consist of 50 houses or flats, respectively. To reduce the simultaneity of demand peaks, the consumption profiles are somewhat flattened.

Unless stated otherwise, all results shown refer to the base case:

Table 1: Base case model assumptions.

Time horizon	2050
Energy prices	Base case, fixed
Technological development	Base case
Household electricity demand	3.5 MWh/year
Sanitary hot water demand[24]	3 MWh/year
Electricity grid	Distribution grid present
Gas grid	Distribution grid present (not in all-electric cases)
Local renewable energy production	Not included
Inflation	2 %
WACC	1.5 %
VAT	21 %

The technical and cost parameters can be found in the appendix (section 10.2). Based on these ranges, optimistic and pessimistic scenarios were built. In the results shown below, the results of these scenarios are indicated with error bars. Below we explain the selection of some of the parameters:

- One of the components of electricity grid fees is a capacity tariff, which is charged based on the single largest peak of hourly electricity demand. Our implementation of the capacity tariff differs somewhat from the foreseen Flemish mechanism.
- The distribution & grid fees have been assumed to be similar to what is valid today. The distribution grid fees for electricity are lower than today's tariff. However, when also taking into account the capacity tariff, an average household will have similar electricity costs in the BatHyBuild model and in reality in 2021. Drastic tax shifts from one energy carrier to another might change the results and conclusions as is further discussed in paragraph 7.4.2.
- For the hydrogen cost, assumed prices for 2030-2050 are based on estimations of future large scale availability of hydrogen, *e.g.* by import as has been discussed in paragraph 4.2.

[24] Note that this figure is included in the total annual heat demand specified in the next paragraphs. Thus, an annual heat demand of 5 MWh corresponds with a space heating demand of only 2 MWh.

7 Results

7.1 Overview analysed cases

Below, we discuss some different cases households may be faced with. For each case, we will discuss the different heating options under base case assumptions for 2050 (vide supra).

Note that local production of renewable electricity or hydrogen is not included in these examples, because it complicates the interpretation of the results. However, as we explain later, it is typically a good idea to opt for local renewable energy production whenever possible (sections 7.2.5 and 7.3.4). Table 2 provides an overview of the use cases which are discussed in the next sections.

Table 2: Selection of the dataset of modeled scenarios. These cases are considered in section 0. Numbers indicate the annual heat demand for each case.

	Basic insulation	**Moderate insulation**	**Thorough insulation**
Renovation *-Gas grid available*	20 MWh Gas boiler	13 MWh -Heat pump -Gas boiler -Heat pump + boiler -Heat pump + fuel cell	9 MWh -Heat pump -Gas boiler -Heat pump + boiler -Fuel cell -CHP-engine -Heat pump + fuel cell
New-build *-Existing neighborhood: gas grid available* *-New neighborhood: no gas grid available*		9 MWh -Heat pump -Gas boiler -Heat pump + fuel cell	5 MWh -Heat pump -Gas boiler -Heat pump + boiler -Fuel cell -CHP-engine -Heat pump + fuel cell
Collective appliances: district heating or apartments *- Single gas grid connection possible*		9 MWh -Heat pump -Gas boiler -Heat pump + fuel cell -Heat pump + CHP-engine	5 MWh -Heat pump -Gas boiler -Heat pump + boiler -Fuel cell -CHP-engine -Heat pump + fuel cell -Heat pump + CHP-engine

7.2 Illustrative case studies & results

7.2.1 Renovation of an existing house

Here, we assume an average existing house which is insulated to reduce its energy consumption. Three types of renovation are compared: minor interventions (20 MWh annual heat demand); moderate insulation (13 MWh annual heat demand); thorough insulation (9 MWh annual heat demand). The costs of insulation and renovation are not modeled and are not included in the results. We also do not make explicit assumptions about the availability of low temperature heating. All-electric heating is modeled for any heat demand of 13 MWh or lower. In practice, low temperature heating will not always be possible for real cases.

Of all the different heating options, all electric (heat pump only) results in the lowest annual energy costs (Figure 5). However, one can see that the configurations with a heat pump, a boiler or a combination ('hybrid heat pump') all have comparable costs, especially when taking into account the broad uncertainty range.

When the house is heated with a CHP, the energy cost is considerably higher. However, when a small fuel cell is combined with a heat pump, the resulting cost is only slightly higher than other options. The reasons for these cost differences are explained in section 7.3.1.

All-electric solutions cause a winter electricity demand which is at least twice that of solutions without heat pump. The CHP solutions result in a negative winter electricity demand (Figure 6). For the fuel cell case, a very large amount (around 6 MWh) of surplus electricity is injected into the grid. Hybrid solutions present an interesting compromise between winter electricity demand and affordability.

Certain practical considerations are not directly considered in this study, but are important decision factors nonetheless. For example, is the local electricity grid capable of handling the peak loads? Is there enough space available for the heat pump units? For the hydrogen applications, hydrogen safety is an important aspect to be further investigated.

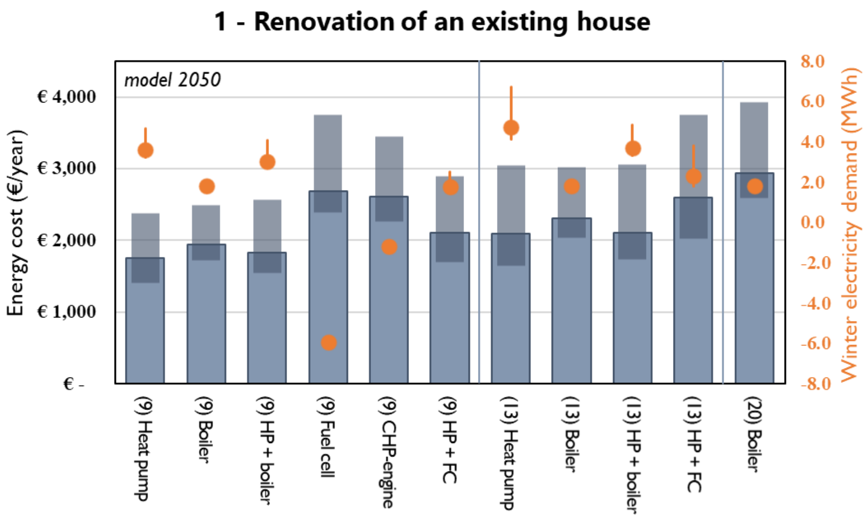


Figure 5: Annual energy cost and winter electricity demand for the different heating options for three degrees of renovation: Limited renovation with 20 MWh annual heat demand, moderate renovation with 13 MWh annual heat demand and thorough renovation with 9 MWh heat demand. Calculated for the year 2050. Error bars indicate optimistic and pessimistic scenario results. Energy costs do not include insulation or renovation costs.

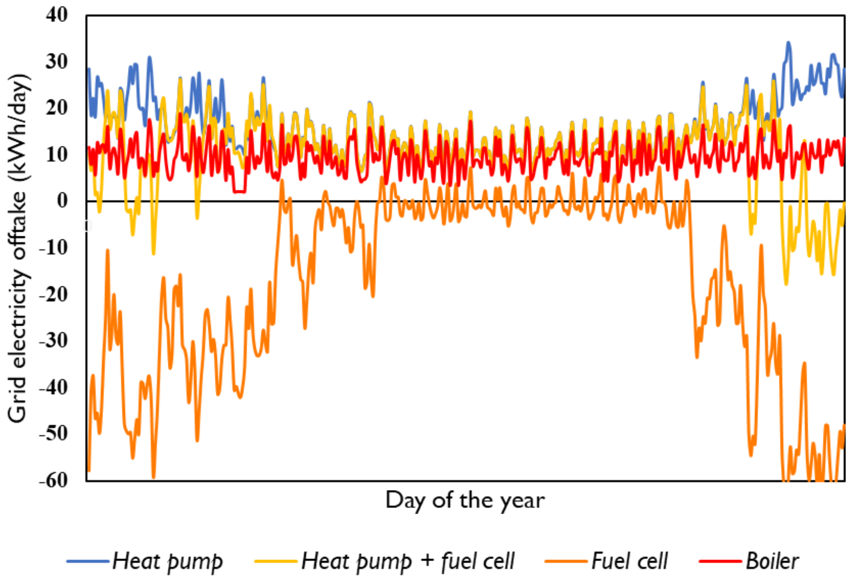


Figure 6: Daily grid electricity demand for a house with 9 MWh heat demand. Four different heating options are compared (base case, 2050). Negative electricity demand indicates net injection of electricity.

When the total cost over a 20 year period is plotted, one gets an idea about the 'renovation budget': the amount of money which can be spent on more drastic renovation without a higher total cost (Figure 7). For example, the least drastic renovation with 20 MWh heat demand provided by a boiler, is ca. € 25 000 more expensive than the lowest-cost option. One could argue that this budget would be better spent on insulation rather than on hydrogen and electricity.

On the other hand, the solutions with a hydrogen boiler (with or without additional heat pump) are between 0 – 6400 € more costly than all-electric solutions. This budget is not enough to install a new central heating system. Thus, if low temperature heating is not available, solutions including a hydrogen boiler are the optimal choice.

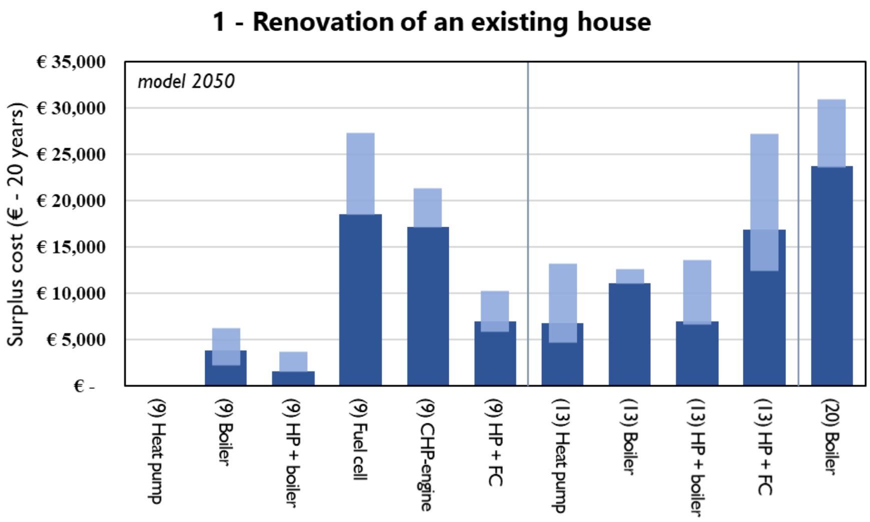


Figure 7: Surplus energy costs compared to the lowest cost solution (9 MWh annual demand - heat pump) calculated over 20 years for the different heating options for three degrees of renovation. Calculated for the year 2050. Error bars indicate optimistic and pessimistic scenario results.

In conclusion, all-electric heating using a heat pump is the least-cost option, when low temperature heating is available. When low temperature heating is not possible, a hybrid heat pump (supported by a boiler) is the better choice. Including a boiler also reduces the winter energy demand. CHP units result in higher energy costs, but these may be minimized in combination with a heat pump. Finally, the annual heat demand of existing houses should be reduced to significantly less than 20 MWh to minimize total cost.

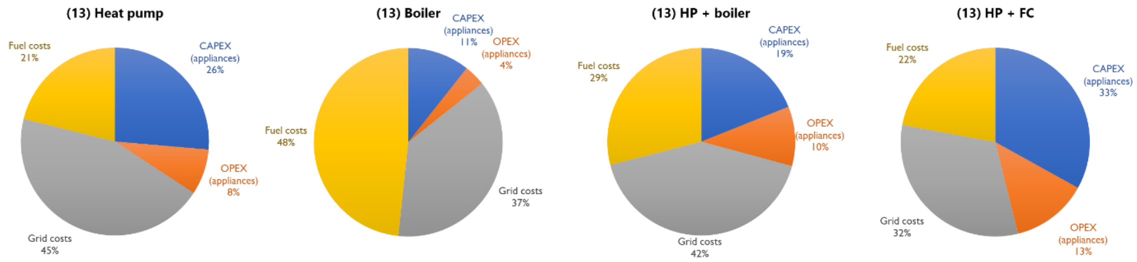


Figure 8: Division of the total energy costs for the different heating options for the case of moderate renovation (13 MWh annual heat demand). Energy costs do not include insulation or renovation costs.

7.2.2 New-build house

For new-build houses, we assume annual heat demand of either 5 or 9 MWh. In both cases, an all-electric solution with heat pump yields the lowest cost (Figure 9). Solutions including a boiler are at a slightly higher cost, yet with lower winter electricity demand. It is remarkable that all in all, hydrogen boilers are a valid alternative to heat pumps even for modern houses with very low heat demand. Cogeneration units result in a (moderately) higher energy cost, but with a lower or even negative winter electricity demand.

When looking at the local system cost (according to the definition given earlier), the differences are somewhat more pronounced (Figure 10). For new districts, the requirement for a gas grid infrastructure has a significant impact on the system cost of solutions with hydrogen. Here, the case for all-electric heating is very clear.

In conclusion, for new-build houses in new neighborhoods, all-electric solutions are clearly advantageous over hydrogen-based alternatives. In existing neighborhoods where gas infrastructure is already available, heat pumps are still the least-cost option. However, hydrogen boilers or cogeneration units are a valid alternative and should be investigated for their system-level benefits.

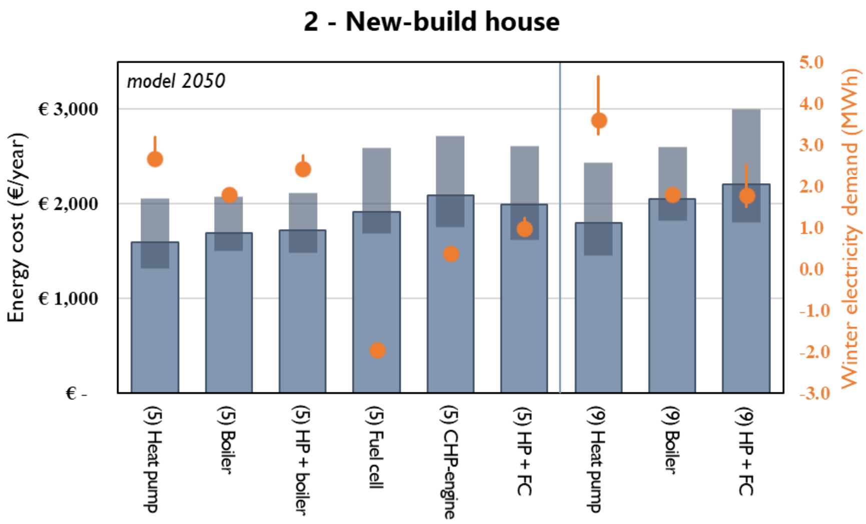


Figure 9: Annual energy cost and winter electricity demand for the different heating options for new-build houses with two degrees of insulation: thorough insulation (5 MWh annual heat demand), moderate insulation (9 MWh annual heat demand). Calculated for the year 2050. Error bars indicate optimistic and pessimistic scenario results. Energy costs do not include insulation or construction costs.

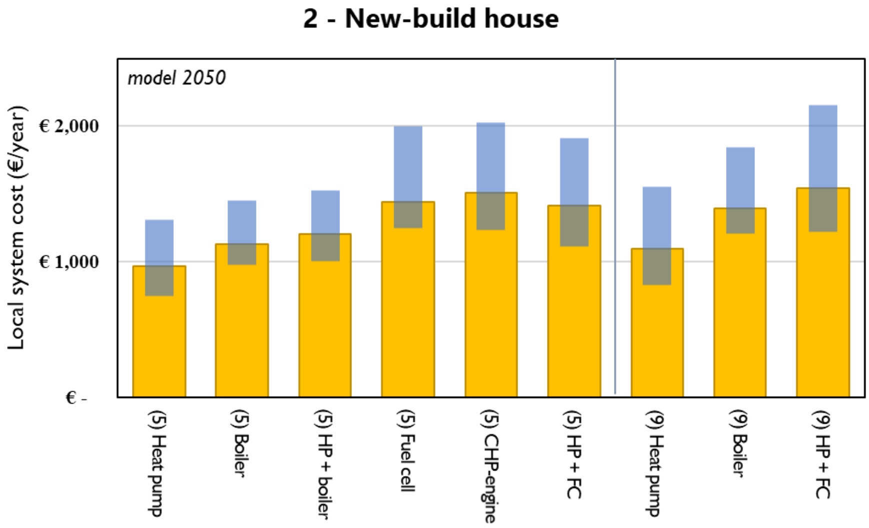


Figure 10: Annual local system cost for the different heating options for new-build houses in a new-build district with two degrees of insulation: thorough insulation (5 MWh annual heat demand), moderate insulation (9 MWh annual heat demand). Calculated for the year 2050. Error bars indicate optimistic and pessimistic scenario results. System costs do not include insulation or construction costs, nor supralocal costs such as grid balancing.

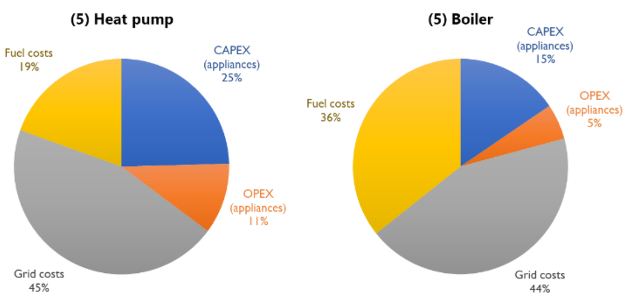


Figure 11: Division of the total energy costs for the different heating options for 5 MWh annual heat demand).

7.2.3 New-build neighborhood with district heating network

A new-build neighborhood was assumed, with 50 houses having either 5 or 9 MWh annual heat demand. The neighborhood is equipped with district heating, fed solely by centralized appliances (note that the case of using residual industrial heat is not considered here). There isn't a gas grid in the streets, but one central connection to the national grid can be made to supply centralized appliances with hydrogen. This case has the benefit of limiting the use of hydrogen to one, well-controlled space at reduced safety risk.

All-electric solutions with heat pumps are the least-cost option (Figure 12). Hybrid solutions also incorporating a boiler are a good alternative. The use of a centralized fuel cell is a valid option, especially when combined with a heat pump, which results in a minimal reliance on the electricity grid (Figure 13). CHP-engines are also possible, at a slightly higher cost. In general, the cost difference between various options is less pronounced when district-level heating is chosen.

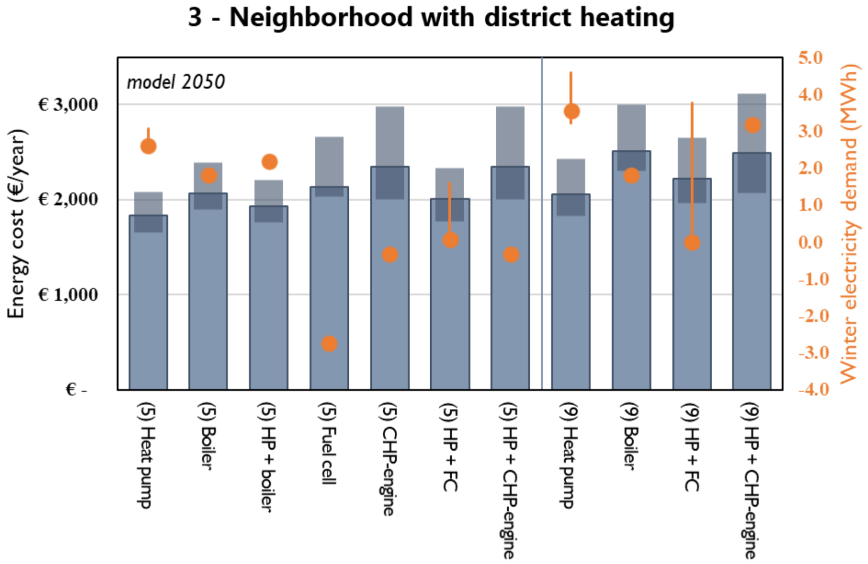


Figure 12: Annual energy cost and winter electricity demand for the different heating options for a district heating network with two degrees of insulation: thorough insulation (5 MWh annual heat demand), moderate insulation (9 MWh annual heat demand). Calculated for the year 2050. Error bars indicate optimistic and pessimistic scenario results. Energy costs do not include insulation or construction costs.

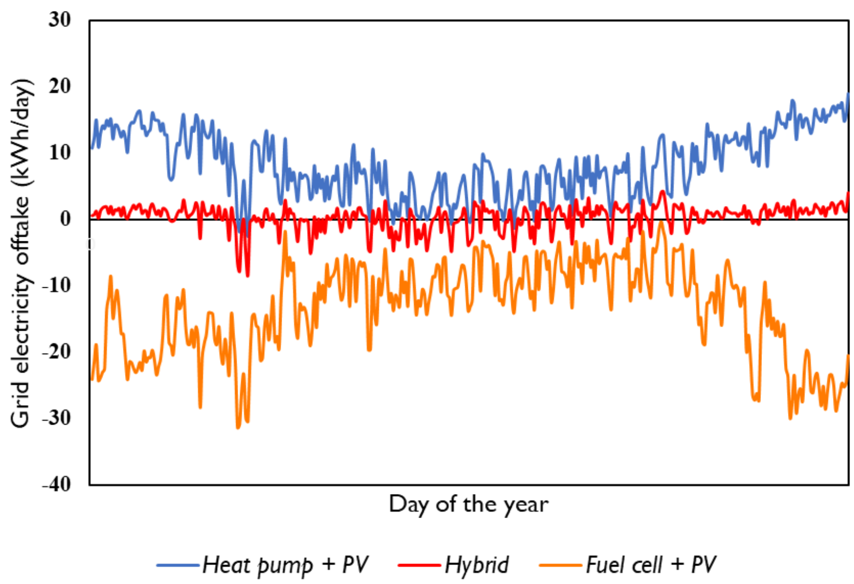


Figure 13: Daily grid electricity demand for a district with a heating network with 5 MWh heat demand. Three different heating options are compared, each including PV and batteries (base case, 2050). 'Hybrid' refers to the combination of a heat pump and fuel cell, also with PV and batteries. Negative electricity demand indicates net injection of electricity. Note: the results shown in Figure 12 do not include renewable energy production. Here, renewable electricity production is included to balance the energy demand and illustrate the possibility of near-zero reliance on the electricity grid.

7.2.4 Apartment complex

An apartment complex is considered, with 50 dwellings each having 5 MWh annual heat demand. Heat is generated by centralized appliances. The relative outcomes of the different solutions are comparable with a district heating neighborhood, albeit at lower absolute costs (Figure 14). All-electric is the least-cost option. Hybrid solutions combining a heat pump with a boiler or fuel cell are also possible at comparable cost. Under the assumptions of the model, the results were nearly identical for new-build apartment complexes and for retrofitting of existing buildings.

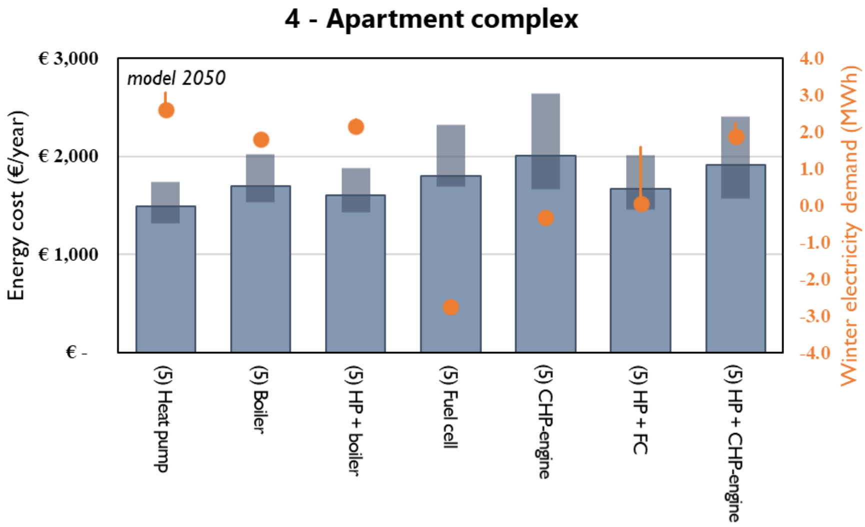


Figure 14: Annual energy cost and winter electricity demand for the different heating options for an apartment complex with 5 MWh annual heat demand per household. Calculated for the year 2050. Error bars indicate optimistic and pessimistic scenario results. Energy costs do not include insulation or construction costs.

7.2.5 Local production of renewable hydrogen

In all results shown until now in this section, local production of renewable hydrogen and/or electricity was not taken into account. Here, we look at the impact of local production of renewable hydrogen. Here, we consider a wide set of cases, each with electricity production from 5 kWp PV and a 5 kWh battery per house (Table 3).

In the case of hydrogen panels, 20 panels were added to the installation. In the case of electrolysis, a total of 10 kWp of photovoltaics were assumed with an electrolysis unit of 2 kW per household. For centralized systems, the photovoltaics were still assumed to be installed on the rooftops of the individual houses. For a total of 500 kWp photovoltaics, a single electrolysis unit of 100 kW was assumed. Importantly, the model only allows solar electricity to be used for feeding the electrolyzer. This means surplus electricity from cogeneration units is always injected into the grid and never used to produce hydrogen. For a discussion on electrolysis in the case of dynamic electricity prices, see section 7.4.2. In all cases, hydrogen was assumed to be consumed either immediately, or injected into the gas grid. Cases with local hydrogen storage are discussed in section 7.3.2.

In cases with hydrogen panels, about 8 MWh hydrogen is produced annually along with 4 MWh of solar electricity. For the cases with electrolysis, ca. 3 MWh of solar hydrogen is produced annually, also with a net amount of 4 MWh solar electricity.[25] Without local storage, a hydrogen auto-consumption of 20-50% is achieved for electrolysis and 10-30% for hydrogen panels. Since more hydrogen is produced in the case of hydrogen panels (which is possible without excessive loads on the electricity grid), the relative amount of auto-consumption is lower.

Table 3: Specifications of renewable energy installations in different cases throughout this report.

	Individual appliances	Collective appliances (50 households)
Base case	No renewable energy	No renewable energy
Only PV	5 kWp PV 5 kWh battery	5 kWp PV (per household) 200 kWh battery (collective)
Electrolysis	10 kWp PV 5 kWh battery 2 kW electrolyzer	10 kWp PV (per household) 200 kWh battery (collective) 100 kW electrolyzer (collective)
Hydrogen panels	5 kWp PV 5 kWh battery 20 hydrogen panels	5 kWp PV (per household) 200 kWh battery (collective) 20 hydrogen panels (per household)

The results show that in all cases, the energy cost is lower when hydrogen panels are installed (Figure 15). Of course these data rest on the important assumption that hydrogen panel technology has sufficiently matured by 2050. Also, these cases all consider installations of 20 panels. We expect that the cost efficiency of hydrogen panel installations will be less for installations of < 10 panels. Conversely, larger roofs may host larger installations with comparatively increased returns. Note that there is no competition with conventional solar photovoltaics: the cases assume that both solar technologies are combined. Hydrogen panels are not cost-effective in the specific case of high CAPEX and low energy prices.

[25] The financial optimum is at a PV:electrolysis ratio of 5:1. As a result, the electrolyzer has a power rating of 2 kW when the maximum PV size is constrained to 10 kWp. Less hydrogen is then produced than in the hydrogen panel case.

Data on electrolysis show a more diffuse picture. In all but a few cases, individual electrolyzers are not cost efficient (Figure 16). These results are however highly dependent on electricity prices and tariff structures. This is elaborated in section 7.3.4. Larger electrolysis units boast significant cost benefits. As a result, collective electrolysis installations may in some cases be cost efficient (Figure 17). Note that these are the results of a generalized model. Individual installations may be optimized by tuning the dimensioning of solar capacity (and orientation), battery size and electrolyzer size. Moreover, larger installations at MW size (connected with many more households) would return a completely different picture. With optimistic CAPEX assumptions and pessimistic energy prices, all hydrogen production methods are profitable. Note also that solar PV is a profitable investment in all cases (Figure 18).

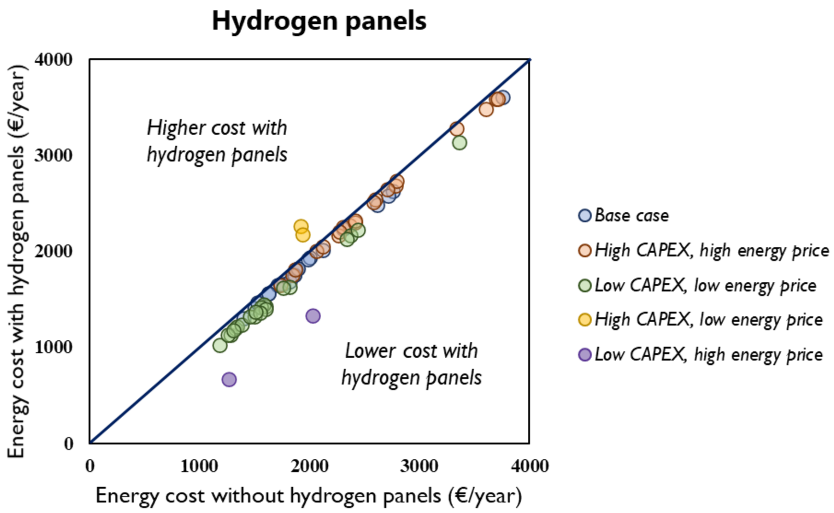


Figure 15: Energy cost with and without hydrogen panels, for a wide range of modeled cases. For each case, the base case, optimistic scenario (low CAPEX, low energy prices) and pessimistic scenario (high CAPEX, high energy price) is shown. Two additional scenarios were calculated for two cases: high CAPEX, low energy prices and low CAPEX, high energy prices. Data points below the line indicate that hydrogen panels are profitable in that case.

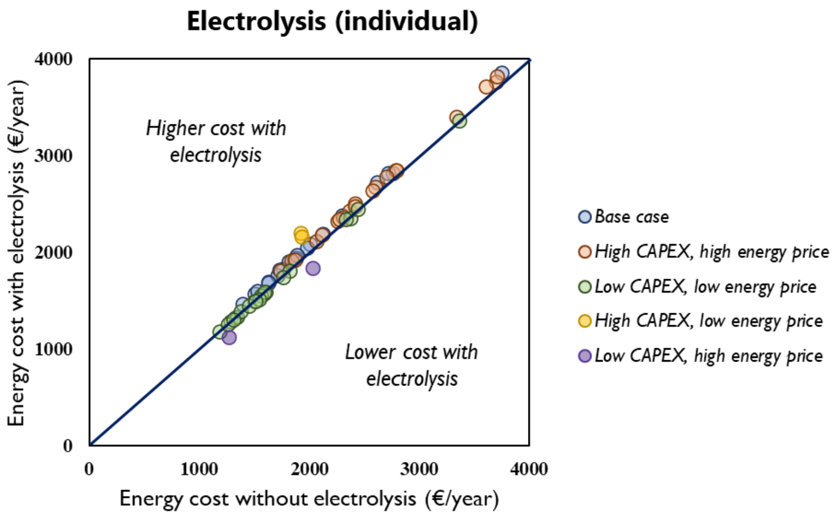


Figure 16: Energy cost with and without electrolysis (at household level), for a wide range of modeled cases. For each case, the base case, optimistic scenario (low CAPEX, low energy prices) and pessimistic scenario (high CAPEX, high energy price) is shown. Two additional scenarios were calculated for two cases: high CAPEX, low energy prices and low CAPEX, high energy prices. Data points below the line indicate that electrolysis is profitable in that case.

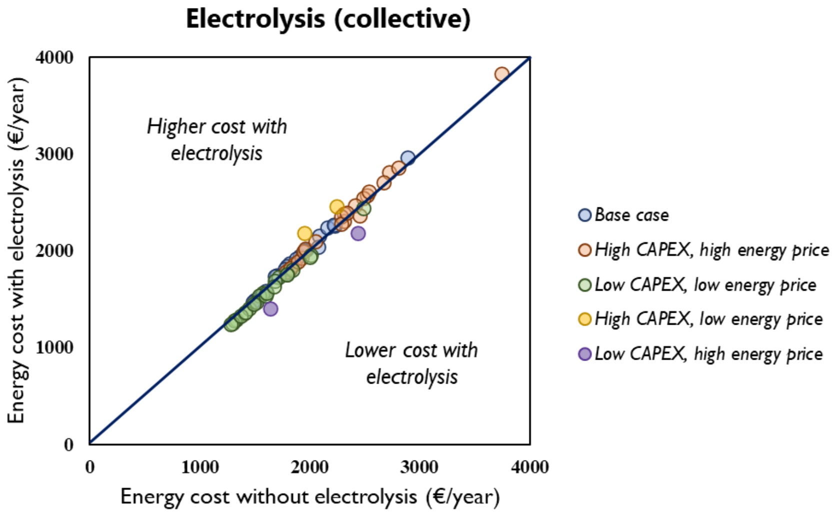


Figure 17: Energy cost with and without electrolysis (centralized), for a wide range of modeled cases. For each case, the base case, optimistic scenario (low CAPEX, low energy prices) and pessimistic scenario (high CAPEX, high energy price) is shown. Two additional scenarios were calculated for two cases: high CAPEX, low energy prices and low CAPEX, high energy prices. Data points below the line indicate that electrolysis is profitable in that case.

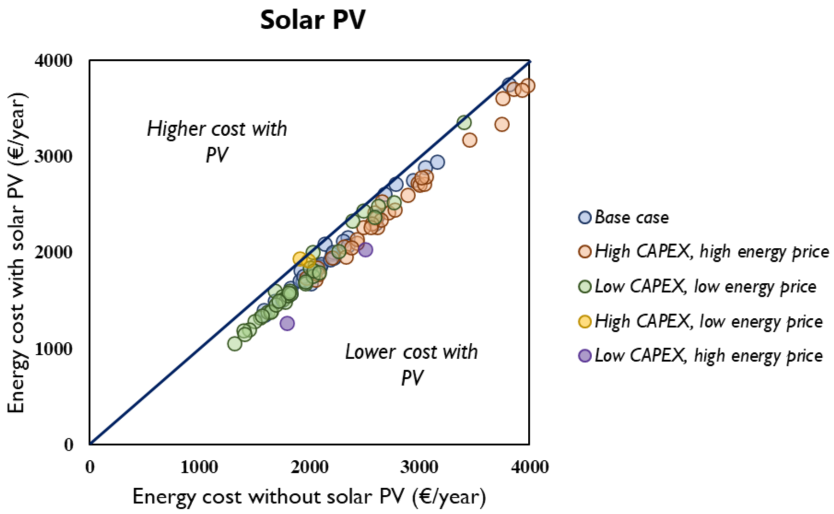


Figure 18: Energy cost with and without solar PV, for a wide range of modeled cases. For each case, the base case, optimistic scenario (low CAPEX, low energy prices) and pessimistic scenario (high CAPEX, high energy price) is shown. Two additional scenarios were calculated for two cases: high CAPEX, low energy prices and low CAPEX, high energy prices. Data points below the line indicate that PV is profitable in that case.

7.3 Detailed analysis of cases

7.3.1 Cogeneration technologies

In previous sections, we saw that cogeneration technologies typically incur the highest costs. We shall investigate the case of a new-build house with 5 MWh annual heat demand. Figure 19 and Figure 20 show that solutions with a fuel cell or CHP engine have higher CAPEX compared to both a heat pump and a boiler. However, the largest impact is caused by fuel costs (electricity and hydrogen). Both cogeneration technologies consume large amounts of hydrogen to produce electricity. However, the value of the generated electricity is insufficient to compensate the higher hydrogen costs (Figure 21). This is especially the case for fuel cells. CHP engines produce relatively more heat and less electricity, which results in lower cost of heat production in the base case.

Given the large sensitivity to fuel costs, one would expect different outcomes in different scenarios. Surprisingly, dynamic electricity prices do not have a large effect on the relative cost of cogeneration technologies (cfr. section 7.4.2). There are several reasons for this. First, injecting electricity into the grid is rarely a profitable business model even with dynamic prices. Thus, high autoconsumption is still key. Second, at 5 MWh annual heat demand the total value of the produced electricity is too small to compensate for the difference in CAPEX. Third, in the examined case the electricity consumption of the heat pump is relatively small compared to household electricity consumption, which is constant for all cases. However, at higher annual heat demand, larger cogeneration units are required which exacerbates the CAPEX difference.

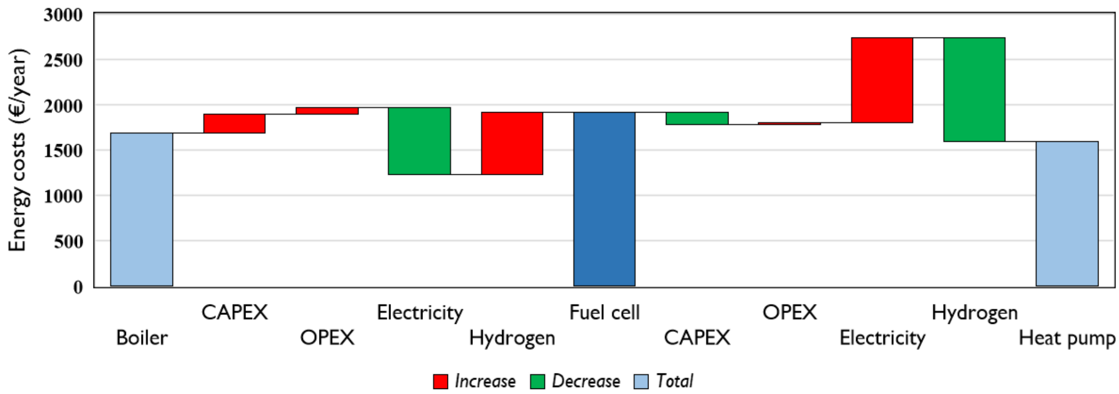


Figure 19: Waterfall graph of of energy cost of three different heating options (boiler, fuel cell or heat pump), for a house with 5 MWh heat demand in 2050. Increase and decrease of specific costs is indicated, as one shifts from one heating solution to the other (left to right).

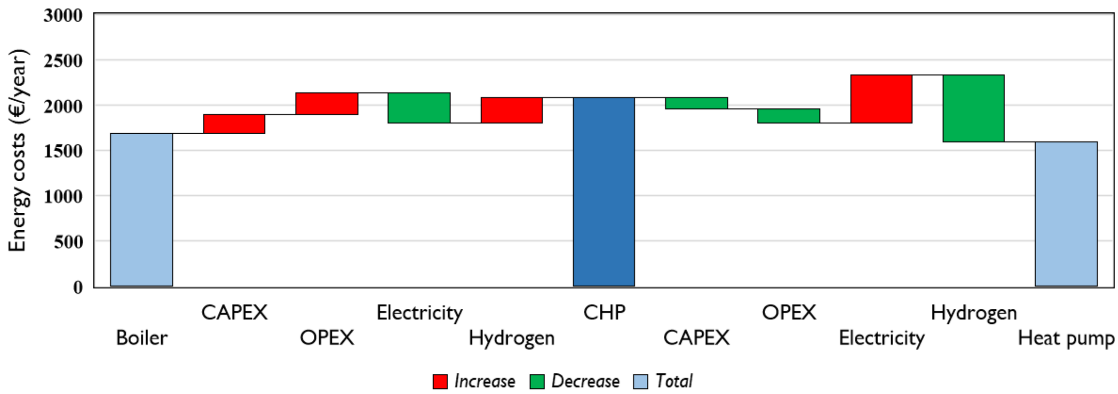


Figure 20: Waterfall graph of of energy cost of three different heating options (boiler, CHP engine or heat pump), for a house with 5 MWh heat demand in 2050. Increase and decrease of specific costs is indicated, as one shifts from one heating solution to the other (left to right).

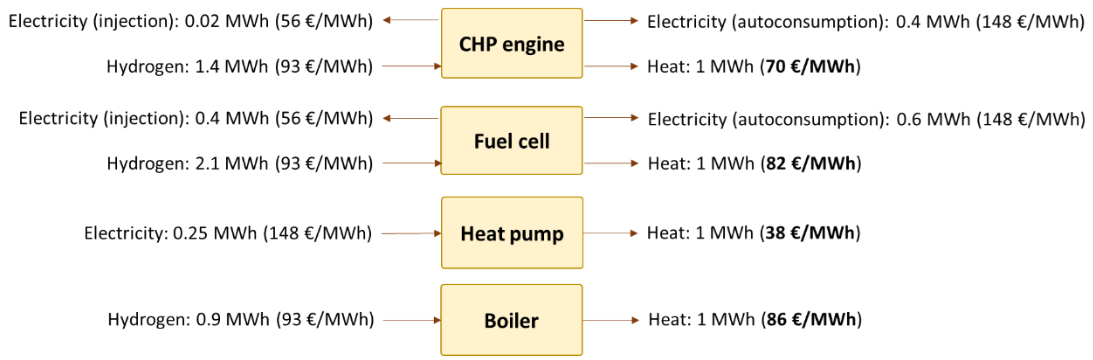


Figure 21: Net cost of heat production for four different heating solutions, 2050. Input and output of energy carriers to produce 1 MWh of heat is indicated. For cogeneration units, the auto-consumption (and the resulting cost of heat) will depend on the specific case. CAPEX and OPEX are not included in these numbers.

Figure 22 shows the cost contributions for a house heated with either a fuel cell or a CHP engine. The sum of hydrogen and electricity costs is equal for both cases. The fuel cell has a higher investment cost, while the CHP engine has higher replacement costs and higher OPEX. As a result, the fuel cell option has a lower overall cost. For cases with higher annual heat demand (9 MWh and more), the CHP engine outperforms the fuel cell (Figure 5). As heat demand increases, the relative cost of heat becomes a dominant factor, which is lower for the CHP engine. For hybrid heating however, the fuel cell outperforms the CHP engine. In those cases, the electricity produced by the fuel cell is used directly by the heat pump. Thus, auto-consumption increases and the relative cost of heat becomes lowest for the fuel cell case.

The benefits of cogeneration do become clear when the cost ratio between gas and electricity changes. When hydrogen cost is lower than the average cost of electricity, cogeneration becomes profitable. This is discussed in section 7.4.2. Finally, it is important to acknowledge the systemic benefits of cogeneration (see section 7.4.4). These units will drastically reduce electricity demand in winter, or may even inject electricity into the grid in cold periods. When green hydrogen is used as the fuel, the injected hydrogen is also green. Since these decentralized units are nearby electricity consumers, they may reduce the stress on distribution grids. Furthermore, the conversion efficiency approaches 100% since both heat and electricity are utilized. These benefits should be weighed against the alternative scenario, in which centralized gas turbines provide much of the electricity demand in winter. These gas turbines would be fed with the same hydrogen gas, to provide electricity for electrified heat production.

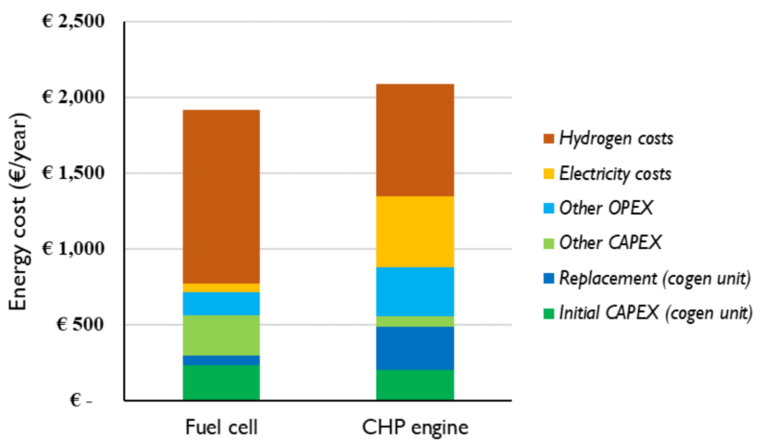


Figure 22: Components of the energy cost of a house with 5 MWh heat demand, heated with a fuel cell or a CHP engine.

7.3.2 Local storage of hydrogen

In all the cases considered previously, the gas distribution grid serves not only to connect different households in the neighborhood, but also provides a connection to national grid infrastructure, supplying hydrogen or absorbing excess local hydrogen production. Here, we will investigate cases with local storage of hydrogen (while still maintaining a grid connection), to allow local buffering of the produced hydrogen and increase auto-consumption.

Consider a new-build house with 5 MWh annual heat demand, equipped with a hydrogen boiler and solar PV, connected to a hydrogen grid. If hydrogen panels are installed on such a building, the net hydrogen demand becomes negative. On an annual basis, 6.5 MWh of hydrogen is injected into the grid, while 3.1 MWh of hydrogen is taken from the grid. The auto-consumption of the produced hydrogen amounts to 18%. This is the amount of produced hydrogen which is used instantaneously. The cost of the produced hydrogen is lower than the price of grid hydrogen, so the total energy cost is reduced. When 1.3 MWh of local compressed[26] hydrogen storage is added, the cost increases significantly. The household is now self-sufficient for hydrogen.[27] Auto-consumption increases to 57%, the rest is injected into the grid. Nonetheless, the reduction in grid hydrogen costs is very limited, since there are almost no grid fees on gas (under current circumstances!). Thus, there is limited incentive to auto-consume one's own hydrogen production. Moreover, the electricity consumption slightly increases to operate the compressor. Despite this negative result, note that the surplus cost of local storage is not exuberant (ca. € 500/year). Future changes in tariff schemes may swing the benefit to local storage, for example if high grid fees render auto-consumption more interesting.

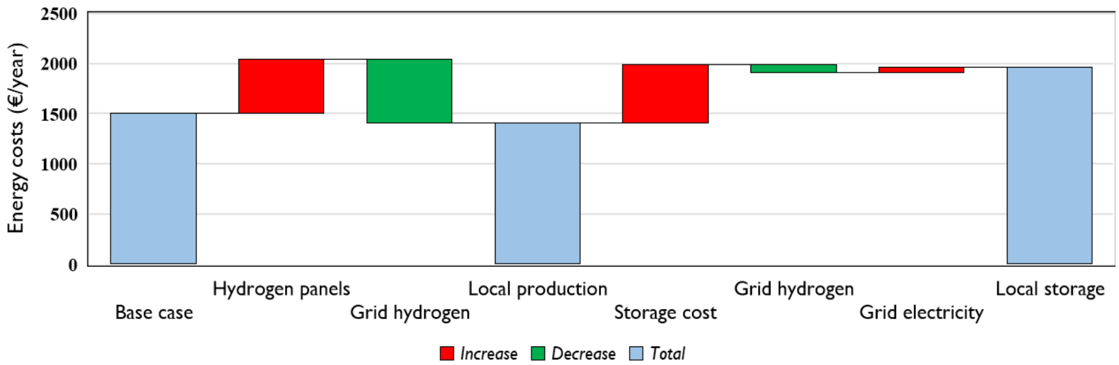


Figure 23: Waterfall graph of of energy cost of three different cases without local hydrogen production, with local hydrogen production via hydrogen panels, and with local production and storage of hydrogen. Increase and decrease of specific costs is indicated, as one shifts from one case to the other (left to right).

An alternative case may be considered, where the same household does not produce any hydrogen locally. In the base case, all of its hydrogen requirements are taken from the grid. In absence of a grid, we could imagine that hydrogen is brought to the house much like fuel oil today. To minimize costs, this would not be done in a compressed state, but via a chemical carrier (*e.g.* LOHC or clathrate)[28]. The resulting energy cost depends almost entirely on the cost per MWh of the supplied

[26] The case here considers compression to 200 bar, which occupies a compressed gas volume of ca. 2.2 m^3. If storage at 30 bar is chosen, compression costs can be much lower, but the cost of the storage vessels will be higher and they will occupy more space. Compressed gas volume would increase to ca. 14.5 m^3.

[27] For more cases targeting self-sufficiency, see section 7.3.3.

[28] The results are similar for collective installations supplied with tube trailers. This technology is already available today. It is not known which approach would be best on the long term.

hydrogen source. If it is sold at 80 €/MWh (similar to the total cost of grid hydrogen in the base case), the energy cost increases only slightly due to the cost of the tank. It is more likely, however, that the price will be more elevated. At 120 €/MWh, the energy cost is still acceptable. Note that this example has a very limited heat demand of 5 MWh/year, and that the storage cost may be underestimated (*e.g.* systems to release hydrogen from chemical carriers are not explicitly included in the cost). Every such extra cost will further improve the competitiveness of alternatives, such as all-electric.

In conclusion, local storage will most likely increase costs compared to a case with a hydrogen distribution grid. Unless tariff structures change drastically, local storage will not be cost-effective when a hydrogen grid is available. In absence of a hydrogen grid, the cost of local hydrogen storage or delivery of hydrogen carriers could possibly be kept within acceptable limits, if the energy demand of the building is not too high.

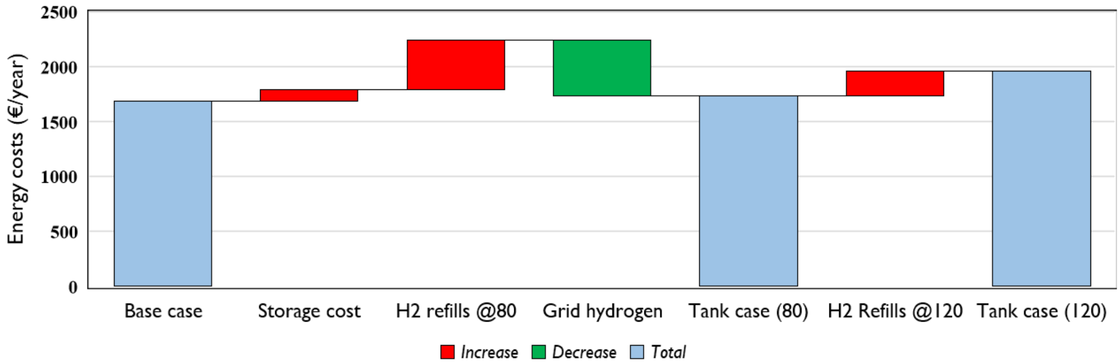


Figure 24: Waterfall graph of of energy cost of three different cases with a hydrogen grid, with supply of hydrogen to a stationary tank at a cost of 80 €/MWh, and with supply of hydrogen to a stationary tank at a cost of 120 €/MWh. Increase and decrease of specific costs is indicated, as one shifts from one case to the other (left to right).

7.3.3 Off-grid houses

Many see hydrogen as a means to disconnect their household from the electricity grid. By producing hydrogen and electricity locally, a building may become self-sufficient and even disconnect from the gas grid as well. We investigate this presumption here.

First, let us consider an energy conscient household with an electricity demand of only 2 MWh/year and annual heat demand of 5 MWh/year. These are very low energy demands. Providing even such a dwelling with its own energy needs throughout the year without utilizing hydrogen is very difficult indeed. Without intensive optimization, the BatHyBuild model ends up at a battery capacity of 100 kWh, fed by an array of 14 kWp solar PV. Needless to say, an enormous surplus of electricity is produced in summer which is curtailed. 8 MWh of solar electricity is left unused, which is even more than the annual energy consumption of the household itself. This is financially and ecologically suboptimal.

Using hydrogen, one could reduce the solar PV capacity to 10 kWp. In times of excess production, electricity is stored in a small battery of 5 kWh and converted to hydrogen in a 3 kW electrolyzer, connected to 1.7 MWh of compressed hydrogen storage (ca. 50 kg, requiring 3 m^3 volume at 200 bar). This configuration results in much less lost energy and lower overall cost. It is, however, still a complex and costly option. When hydrogen panels are installed, a PV capacity of 4 kWp suffices. Even then, electricity curtailment still occurs, and energy costs are comparable. If an electricity grid would be available, an all-electric solution would be nearly four times less expensive. We also looked at the case where an individual decides to disconnect from the electricity grid and connects only to a hydrogen grid instead. This is also more expensive than the situation with a connection to the electricity grid.

Table 4: Technical parameters and performance metrics of off-grid cases, with 2 MWh electricity demand and 5 MWh heat demand. Five cases are compared: off-grid all-electric, off-grid including electrolysis and a fuel cell, off-grid including hydrogen panels and a fuel cell, conventional all-electric, and a house with no connection to the electricity grid, but connected to the gas grid only.

2 MWh electricity 5 MWh heat	**Off-grid All-electric**	**Off-grid Hydrogen (1)**	**Off-grid Hydrogen (2)**	**Electricity grid All-electric**	**Gas grid only Hydrogen**
Solar PV (kWp)	14	10	4	5	2
Heat pump (kW)	12	3	3	3	3
Fuel cell (kW)		1	1		1.5
Electrolysis (kW)		3			
Hydrogen panels (#)			8		
Thermal storage (kWh)	100	100	100	30	30
Battery storage (kWh)	100	5	10	5	10
Gas storage (kWh)		1690	1690		
Electricity shortage (kWh/year)	77	21	42	0	9
Electricity curtailment (kWh/year)	8183	1935	726	0	406
Energy cost (€/year)	3833	2552	2496	1102	1597

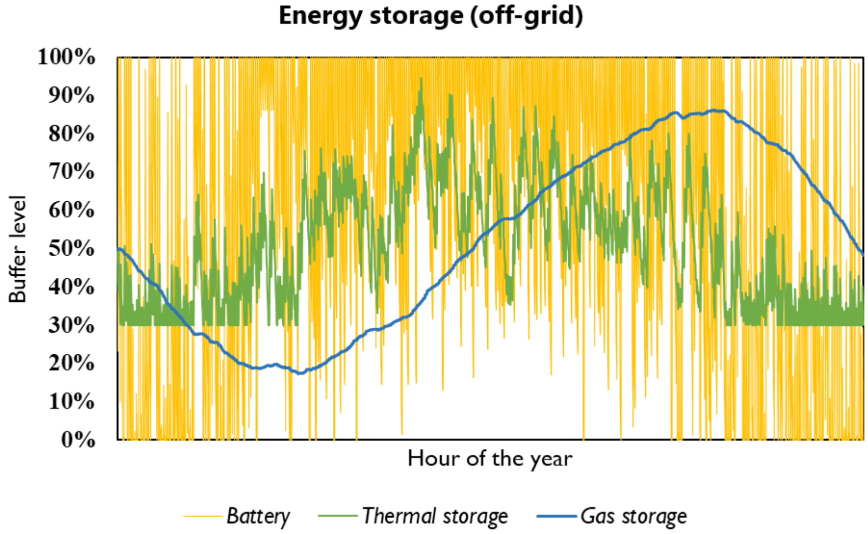


Figure 25: Levels of energy storage buffers throughout the year, for an off-grid house equipped with an electrolyzer. (2 MWh electricity demand, 5 MWh heat demand. See Table 4 for detailed description).

All these effects are exacerbated in a 'normal' household. With an electricity demand of 3.5 MWh/year and heat demand of 9 MWh/year, the financial, energetic and ecologic discrepancies are even worse. In conclusion, it is technically feasible to obtain an off-grid situation, and hydrogen makes it easier to span the winter season. However, our results show that connecting to the national grid infrastructure results in much lower costs.

In addition, non-financial parameters such as energy security, sufficient space for energy storage and safety are important. Given the already higher cost of off-grid approaches, we may conclude that true off-grid houses will always be a very small niche in a highly connected country such as Belgium.

Table 5: Technical parameters and performance metrics of off-grid cases, with 3.5 MWh electricity demand and **9 MWh** heat demand. Five cases are compared: off-grid all-electric, off-grid including electrolysis and a fuel cell, off-grid including hydrogen panels and a fuel cell, conventional all-electric, and a house with no connection to the electricity grid, but connected to the gas grid only.

3.5 MWh electricity 9 MWh heat	**Off-grid All-electric**	**Off-grid Hydrogen (1)**	**Off-grid hydrogen (2)**	**Electricity grid All-electric**	**Gas grid only Hydrogen**
Solar PV (kWp)	30	18	6	10	3
Heat pump (kW)	12	3	3	4	2.5
Fuel cell (kW)		1.8	2		2.5
Electrolysis (kW)		6.5			
Hydrogen panels (#)			18		
Thermal storage (kWh)	100	100	100	30	30
Battery storage (kWh)	120	10	15	5	10
Gas storage (kWh)		3380	3380		
Electricity shortage (kWh/year)	221	25	33	0	19
Electricity curtailment (kWh/year)	18 999	2 895	2 506	0	921
Energy cost (€/year)	4792	3894	3504	1469	2142

7.3.4 On-site renewable energy production

In the base case for 2050, solar PV produces electricity at a cost of ca. 50 €/MWh. Thus, it has reached cost parity with grid electricity. Even when all of the electricity is injected into the grid, the installation of PV is still profitable. This brings up the question: why not cover the entire roof surface area with solar PV?

On a regional level, Flanders has a rooftop area of about 250 km^2 (not taking into account surfaces suited for BIPV[29]). At a projected power conversion efficiency of ca. 30%, such an area would roughly correspond with 75 GWp of solar PV, while the injection capacity of the distribution grid (for the whole of Belgium) is estimated at only 6 GW.[30] Even if not all building surfaces will receive peak solar irradiation at the same time, it is clear that the total potential of solar electricity production largely surpasses the absorption capacity of the electrical grid.

[29] Building Integrated Photovoltaics

[30] Meuris *et al*. (2018). *Prog Photovolt Res Appl*. 27 : 905-917.

On the other hand, Flanders' rooftop area could produce more than 1000 kton hydrogen per year, without impacting the electricity grid. This is more than the current industrial hydrogen production capacity. Figure 26 shows the impact on the distribution grid of increasing renewable energy production via different strategies. When an electrolyzer with a certain power rating is included, the maximal peak is reduced accordingly.[31] Hydrogen panels have no impact on the electricity grid at all. Clearly, rooftop hydrogen production is an opportunity to be investigated, next to a maximal roll-out of rooftop electricity production.

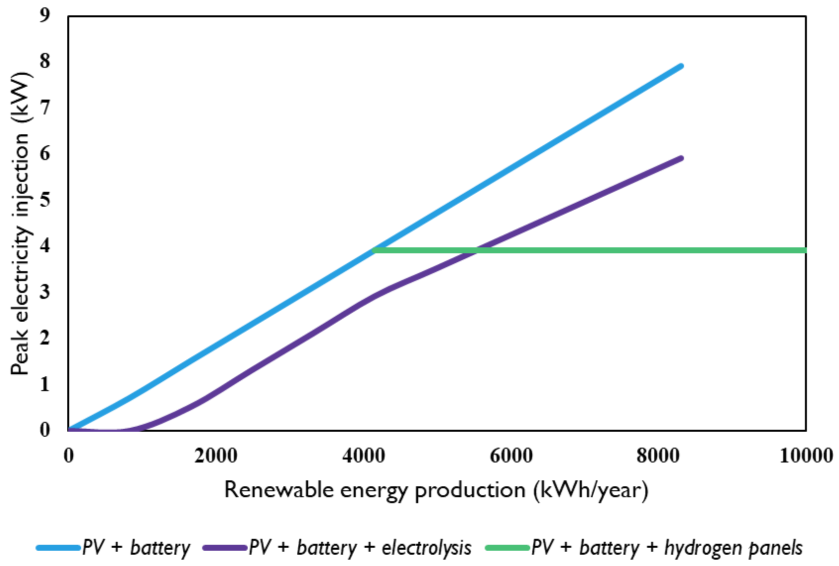


Figure 26: Peak of electricity injection into the electrical grid, as more renewable energy is produced by increasing the generation capacity. Three cases are compared: an increasing amount of PV with increasing battery capacity, an increasing amount of PV with increasing amount of battery and electrolysis power, fixed PV with battery and an increasing amount of hydrogen panels.

In several scenarios local hydrogen production is cost effective even at very low auto-consumption (Figure 27). Indeed, this could change the way we think about consumers and prosumers. An all-electric household could become a hydrogen producer. In the base case scenario, adding hydrogen panels to an all-electric building has no impact on the net energy cost, but it results in an energy-positive building. For a household with a hydrogen boiler, there is a net positive effect on energy cost, since in this case there is some auto-consumption of the hydrogen. In the extreme case of optimistic technology assumptions and pessimistic energy prices, the profitability of local hydrogen production is very clear. Conversely, with pessimistic technology assumptions and low energy prices, local hydrogen production is not cost effective even with auto-consumption.

[31] In the cases of Figure 26, 1 kW electrolysis power is included for 1-5 kWp solar PV power, while a 1:5 ratio of electrolysis power and solar PV power is maintained at higher installed PV capacity (*i.e.* up to 2 kW electrolysis capacity, at 10 kWp solar PV). If one would like to further reduce the peak electricity injection, an electrolyzer with a higher power rating may be chosen.

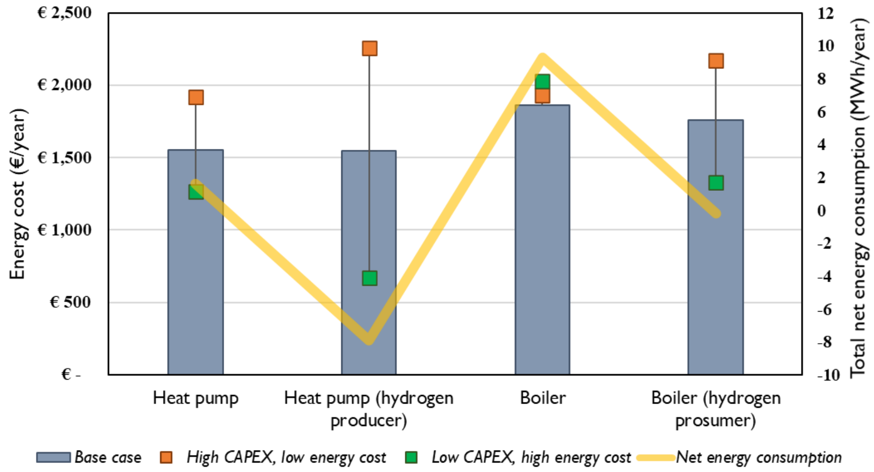


Figure 27: Energy cost for a house with 5 MWh annual heat demand and with or without local hydrogen production via hydrogen panels. Cases with heat pump and boiler are compared. Error bars show alternative scenarios. Yellow curve shows the resulting net final energy consumption.

7.4 Detailed analysis of boundary conditions

7.4.1 Feasibility of hydrogen in 2025 & 2030

In all of the above cases, we examine the projected situation in 2050. Here, we assess the feasibility of using hydrogen in the coming decade. In the short term, the cost of green hydrogen will be higher and the technologies will be less developed than in 2050. (see section 10.2) For 2025, we assume that hydrogen is delivered by truck at the doorstep of the considered house, at a high cost of 270 €/MWh. In 2030, we assume a context where a hydrogen distribution grid is available, and the energy cost of hydrogen is 89 €/MWh.

We will revisit some of the cases which had the least energy costs in 2050. For a renovated house with 9 MWh heating demand, a significant cost gap emerges between an all-electric house and one that is heated with a hydrogen boiler in 2025 (Figure 28). However, the difference in winter electricity demand also increases, since a nominal COP of 3.5 is assumed in this case[32]. As a result, the winter electricity demand is nearly 3 times higher for an all-electric solution. Remarkably, the hybrid heat pump presents an affordable alternative. In 2030, the cost differences between all three options are minimal.

[32] Compared to 4.5 in 2030 and 5 in 2050.

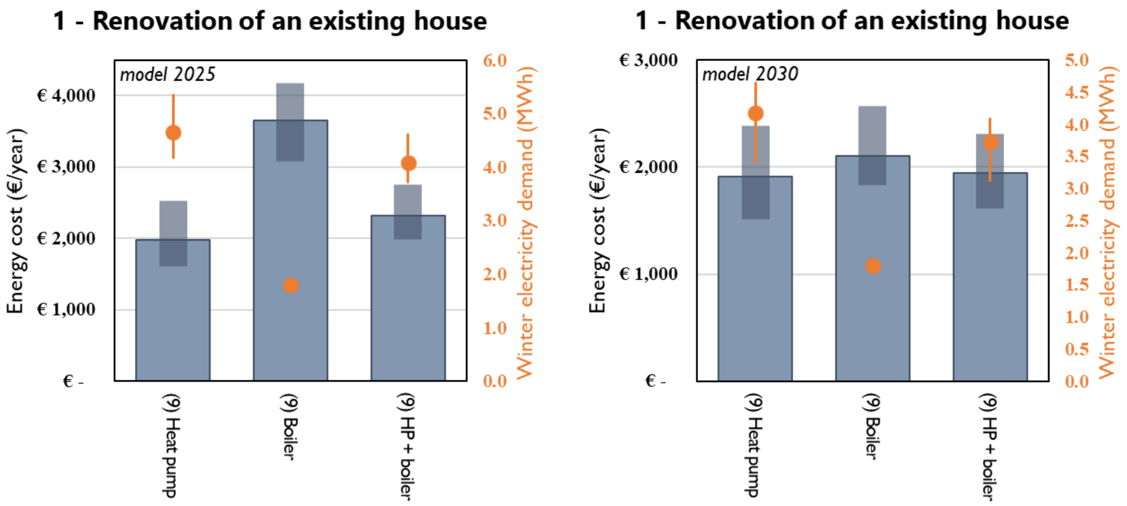


Figure 28: Annual energy cost and winter electricity demand for different heating options for a renovated house with 9 MWh annual heat demand, in 2025 (left) and 2030 (right). Error bars indicate optimistic and pessimistic scenario results. Energy costs do not include insulation or renovation costs. The 2025 scenario assumes that no hydrogen grid is present.

For a new-build house with a very low heat demand of 5 MWh, the differences between all-electric and a hydrogen boiler become smaller (Figure 29). Fuel cell technology is less competitive, predominantly due to its high CAPEX in the short term. Nonetheless, fuel cells still lead to a net injection of electricity in winter time with its associated benefits.

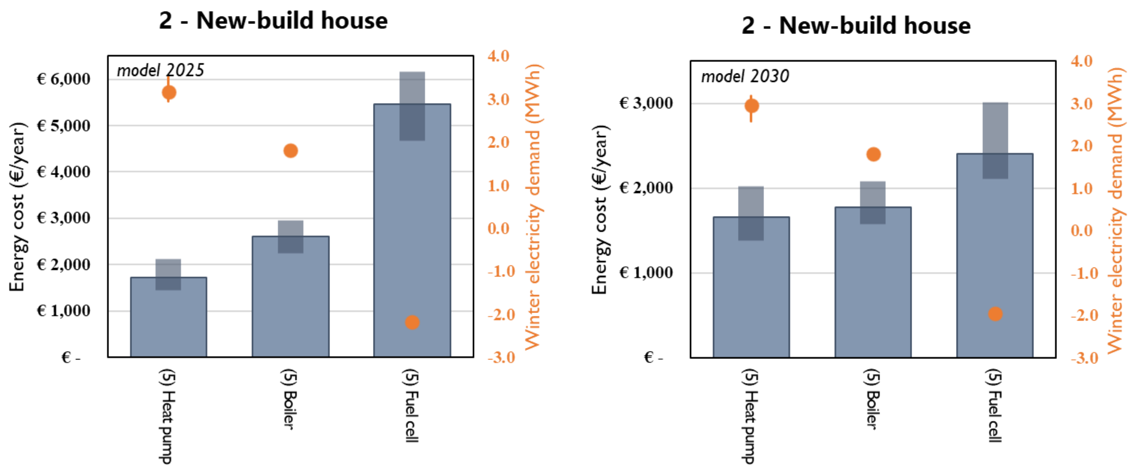


Figure 29: Annual energy cost and winter electricity demand for different heating options for a new-build house with 5 MWh annual heat demand, in 2025 (left) and 2030 (right). Error bars indicate optimistic and pessimistic scenario results. Energy costs do not include insulation or renovation costs. The 2025 scenario assumes that no hydrogen grid is present.

Perhaps the biggest hurdle to the deployment of hydrogen solutions within the next 10 years, is the absence of hydrogen distribution grids. As we discussed in section 7.3.2, hydrogen may be delivered to the end user by other means. It remains to be seen at what cost this will be possible. Moreover, this section assumes no additional costs for early adopter households while in reality one may expect a premium to be paid initially.

In conclusion, hydrogen is unlikely to play any significant role in buildings in the coming years. This may change in the medium term. Several of the hydrogen use cases which are viable in 2050, are also expected to be viable from 2030 onwards. This depends on several assumptions and boundary conditions: the availability and affordability of green hydrogen which will be driven by other developments such as the large scale application of hydrogen in industry and transport; the presence of an infrastructure for delivery of hydrogen; the actual cost of installing and operating hydrogen appliances when this is not yet standard practice.

7.4.2 Energy costs & grid tariffs

In all cases considered above, a fixed energy price was assumed throughout the year. That is, at every point in time the energy cost as well as the grid tariffs of hydrogen and electricity are fixed. In reality, prices fluctuate and these fluctuations will increasingly be felt also by individual consumers. To simulate the **effect of price fluctuations**, we modulated the energy component of the electricity cost throughout the year. In one scenario, the historic Belpex data were taken for 2018. However, the height of the upward and downward peaks was increased to exaggerate the effect of dynamic prices. In another scenario (‘custom’) the prices were modulated based on outside temperature (lower = higher prices) and solar irradiation (higher = lower prices). In all scenarios, the average electricity cost was equal to 60 €/MWh. The model incorporates some control logic, such as switching on the heat pump preferably when prices are low, while a cogeneration unit will switch on when prices are high.

Figure 31 and Figure 32 show that dynamic electricity prices have a very limited effect on the model outcome. As one may expect, an all-electric heating solution experiences higher costs when electricity prices are increased in winter, while a cogeneration solution experiences lower costs in this case. However, the household electricity use (at 3.5 MWh per year) seems to be the dominant factor rather than the heating-related electricity. Moreover, heat can be stored in a thermal buffer at relatively low cost. Thus, smart appliances are able to avoid or profit from temporary spikes in electricity costs.

In conclusion, dynamic electricity prices do not seem to undermine the conclusions of this report. We must stress that we conducted only a superficial investigation of this effect. More reliable future electricity prices, as well as more profound optimization procedures should allow for a better understanding of its impact.

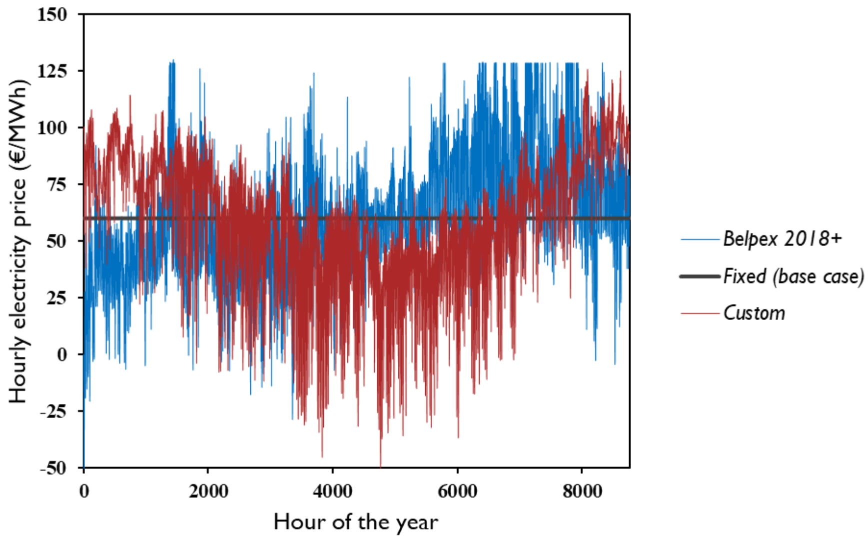


Figure 30: Hourly electricity prices throughout the year for three different scenarios: base case (fixed price), Belpex 2018+ (modulated historic data) and Custom (modeled according to irradiation and outside temperature). These price profiles were used in the calculations for the results of this section.

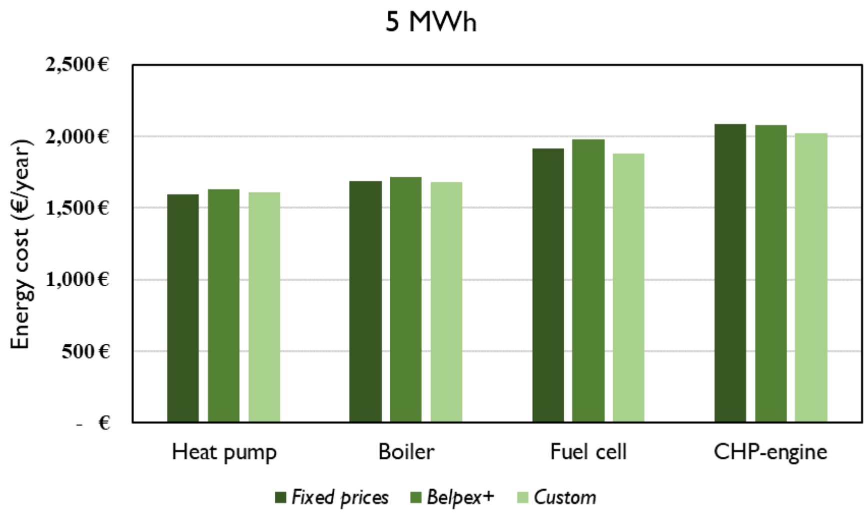


Figure 31: Energy cost (2050, base case) for four different heating options, for a new-build house with 5 MWh annual heat demand. Three scenarios are compared, with fixed and dynamic electricity prices.

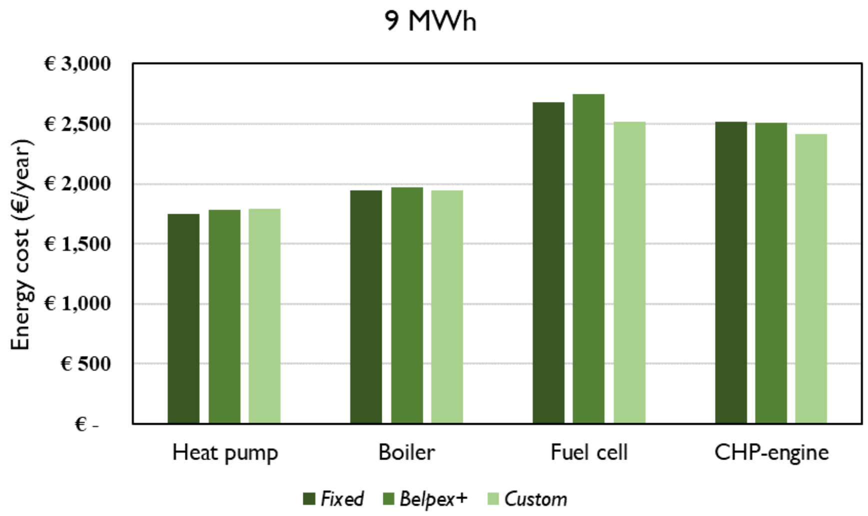


Figure 32: Energy cost (2050, base case) for four different heating options, for a renovated house with 9 MWh annual heat demand. Three scenarios are compared, with fixed and dynamic electricity prices.

We now present a **sensitivity analysis on hydrogen and electricity prices**. To this end, we investigate a renovated house with an annual heat demand of 9 MWh, in 2050. Three cases were considered: a heat pump, a hydrogen boiler and a fuel cell. For each case, different scenarios were calculated (technology development, variable prices), to obtain a best case and worst case result. We based the outcome on the system cost, which means it is not impacted by grid tariff schemes. Figure 33 presents the results. For each combination of hydrogen and electricity costs, the lowest-cost option is shown. Only when the given option is better than all others in all scenarios, it is assigned one of the zones. The zone named ‘hydrogen’ is one in which it is unclear whether a boiler or a fuel cell is better, but both of them outperform the heat pump. The zone named ‘uncertain’ indicates a region where different model assumptions will yield different outcomes (heat pump, boiler or fuel cell).

Only at unrealistically low hydrogen prices (< 10 €/MWh) will hydrogen appliances outperform a heat pump under all circumstances. At high electricity costs, the fuel cell becomes a better option because of the value of injected electricity. At low electricity costs, the boiler is the preferred option. At high hydrogen prices (especially when electricity prices are low), the heat pump is the least-cost option. At intermediate hydrogen prices (10-70 €/MWh), a large zone of uncertainty exists where technological performance and CAPEX may swing the advantage to any of the different solutions.

Importantly, the system costs do not include the cost of renovation, such as the installation of a low-temperature heating system. In a second analysis, we added a surplus renovation cost of € 10 000 to the heat pump case, corresponding with € 500 extra cost per year. This corresponds with a case where low-temperature heating is not yet available. Now, hydrogen solutions have the lowest system cost at any hydrogen cost below 60 €/MWh (Figure 34). Even at a hydrogen cost of 100 €/MWh and zero electricity cost, the heat pump solution is not a clear winner. Note that hybrid solutions were not considered in this analysis. If one can use a hybrid heat pump to avoid the surplus costs of construction works but is still able to benefit from the efficiency of a heat pump, this is likely to be the best option. As one may expect, low electricity prices benefit heat pumps while low hydrogen prices benefit boilers and fuel cells. Yet we conclude that the relative costs of hydrogen and electricity are not the only determinants of the system cost. The cost and performance of the technologies, as well as the additional renovation costs, are at least as important.

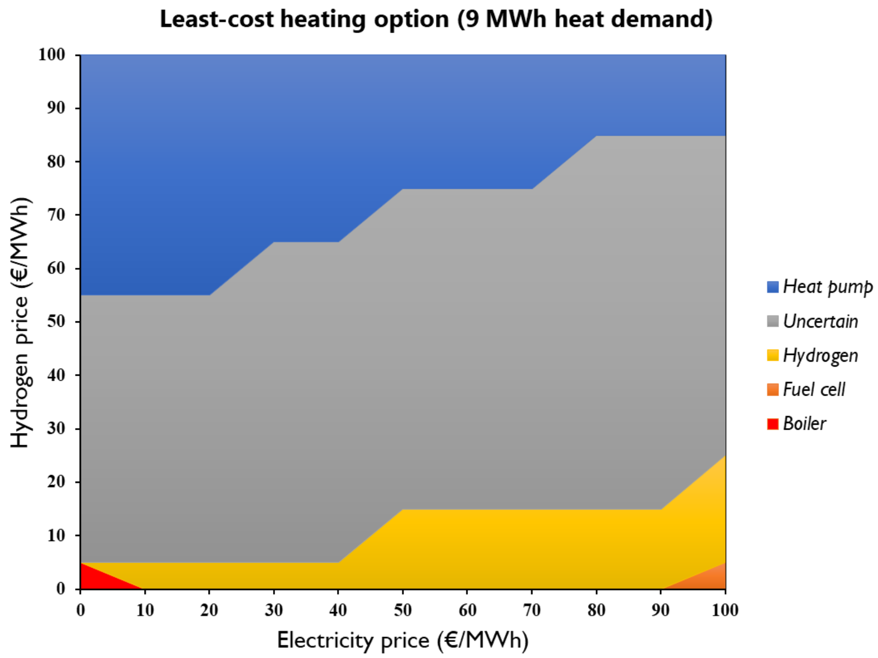


Figure 33: Diagram indicating the lowest-cost heating option for every given combination of hydrogen and electricity price. A renovated house with 9 MWh heat demand is used as the reference case. The lowest-cost option is the one which yields the lowest cost under all circumstances (optimistic to pessimistic scenarios). If no single solution is obtained, a grey color ('Uncertain' – either heat pump or other solution may be lowest cost) or a yellow color ('Hydrogen' – either fuel cell or boiler may be lowest cost) is used.

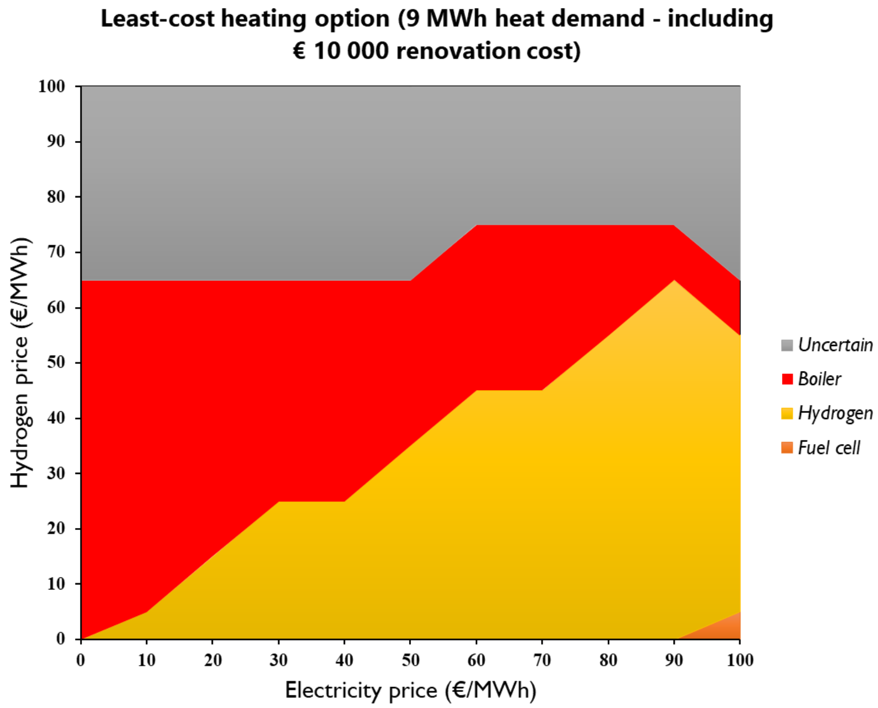


Figure 34: Diagram indicating the lowest-cost heating option for every given combination of hydrogen and electricity price. A renovated house with 9 MWh heat demand is used as the reference case. We assume that no low-temperature heating system is available. Therefore, a cost of € 10 000 was added to the heat pump solution. The lowest-cost option is the one which yields the lowest cost under all circumstances (optimistic to pessimistic scenarios).

Finally, we consider the **impact of tariff schemes**. Today, grid fees payable on electricity are relatively high. This is partly due to the cost of maintaining and balancing our electrical energy system, partly because of other taxes and costs of the energy transition. It is uncertain how these tariff schemes will look in the future. Some promote a tax shift to promote renewable energy and account for the societal costs of fossil energy. Note that neither electricity, nor gas is fully renewable or fossil. Thus, a tax shift should focus on the primary energy source rather than the energy carrier.

The relative impact of grid costs could be seen in Figure 8 and Figure 11. Here, we show the relative share of electrical grid costs and gas grid costs for different cases. Figure 35 shows that grid fees, especially for electricity, can make up a large portion of the total energy cost. However, we also note that even if grid fees would be abolished, the relative cost differences between different cases remain the same. Thus, the conclusions of the BatHyBuild study will hold even if electricity grid fees would be reduced. The reason is the following: even in the boiler scenario, having only household electricity use, electricity grid fees are high. This shows that household electricity use is the dominant cause of electricity costs. If fees on gas usage would increase in the future, the relative costs of different scenarios might be significantly impacted.

In conclusion, tariff schemes may have a large impact on the optimal choice for a household as they make up a large part of total household energy costs. Moreover, they impact the relative benefit of local energy storage and production. Therefore, a clear view on tariff structures for decades to come is essential for individuals and companies to make informed decisions. Furthermore, it is important for tariff schemes to reflect the true costs incurred by the consumed energy carrier, to align the interests of society and of the individual. Fees on hydrogen gas should be related to the costs of the gas infrastructure, while costs of electricity should be based on the cost of the electricity infrastructure.

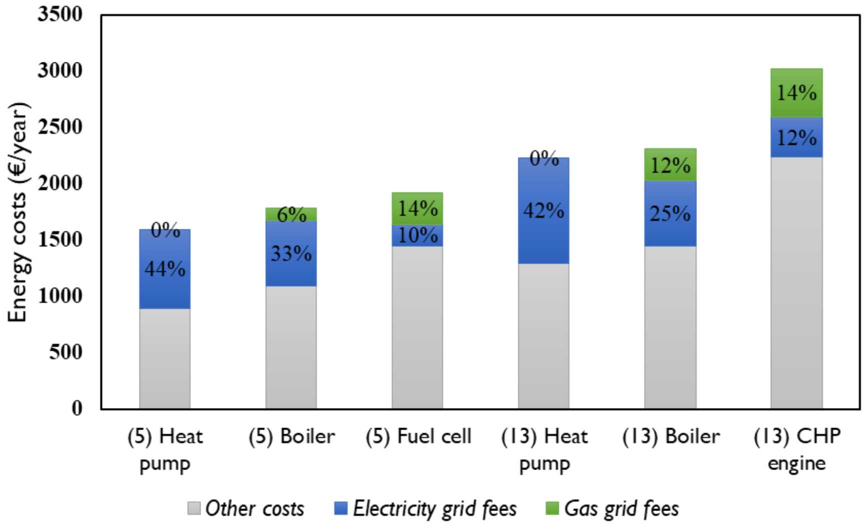


Figure 35: Energy cost of different heating solutions for two cases: a new-build house with 5 MWh annual heat demand and a renovated house with 13 MWh annual heat demand. The share of the grid costs of hydrogen and electricity in the total energy cost is indicated.

7.4.3 Energy demand

Regardless of the technology that is used, higher heat demand generally results in higher energy costs (Figure 36). This is also the case when local electricity and/or hydrogen production is available. Figure 37 shows the cost difference between a poorly insulated house (20 MWh/year) and more energy efficient houses, over a timescale of 20 years. With cost differences in excess of € 20 000, it is clear that proper insulation is and will remain a no-regret investment. As energy demands decrease, there are diminishing returns. The financial optimum will depend on the local situation and will not always be a drastic renovation down to passive house levels.

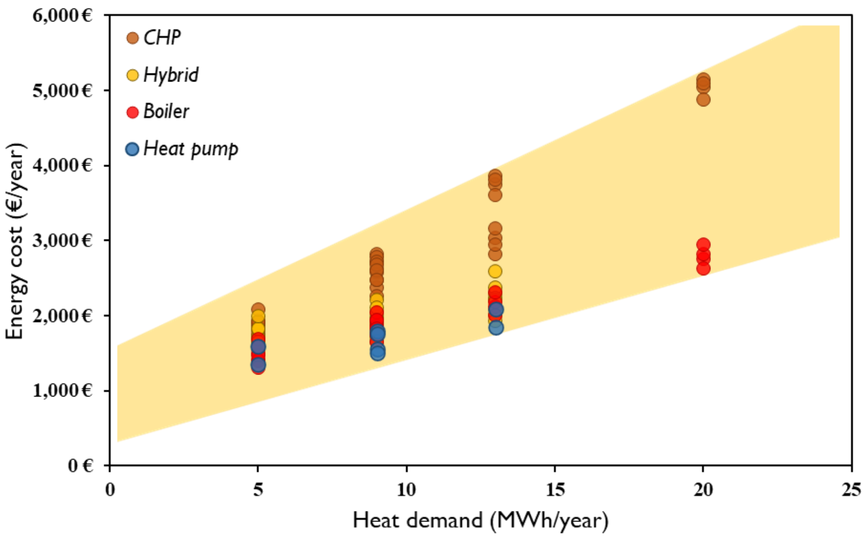


Figure 36: Energy cost for a variety of cases (both with and without renewable energy production) plotted against the heat demand of those cases. Colors indicate the chosen heating solution. Only base case results are shown.

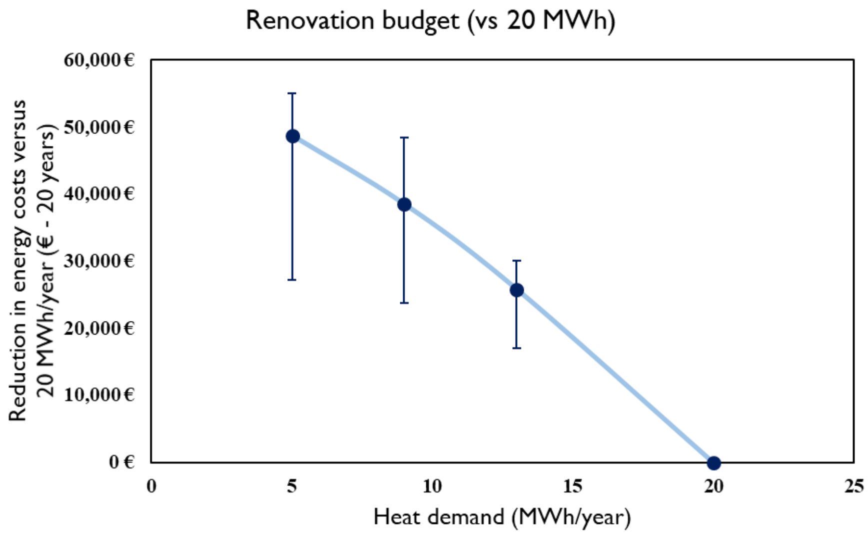


Figure 37: Reduction in energy cost relative to a case with 20 MWh heat demand. This cost difference can be considered to be the available renovation budget. Error bars indicate the spread of the calculations (taking into account different heating solutions, and optimistic/pessimistic scenarios).

7.4.4 System-level considerations

This study assesses the potential of hydrogen in buildings via a bottom-up analysis. The local context may be approached in three ways:

- Assessing the energy cost for the individual consumer. This cost includes VAT, grid fees, etc.
- Assessing the 'local system costs'. These are the total bare costs of the system under investigation. It calculates the real grid and energy costs, but does not take into account effects on a larger scale, such as grid balancing.
- Assessing the 'global system costs'. This would take into account all societal costs in a top-down manner. This approach is not the scope of the BatHyBuild study, but will briefly be discussed in this section.

Figure 38 illustrates the close relationship between the local system costs and the costs paid by the individual consumer. Thus, most of our results and conclusions hold both for the individual energy costs and the local system costs. Exceptions are possible, such as when a new gas grid would have to be built (Section 7.2.2). Here, the system costs go up significantly while the additional CAPEX is not felt by the consumer.

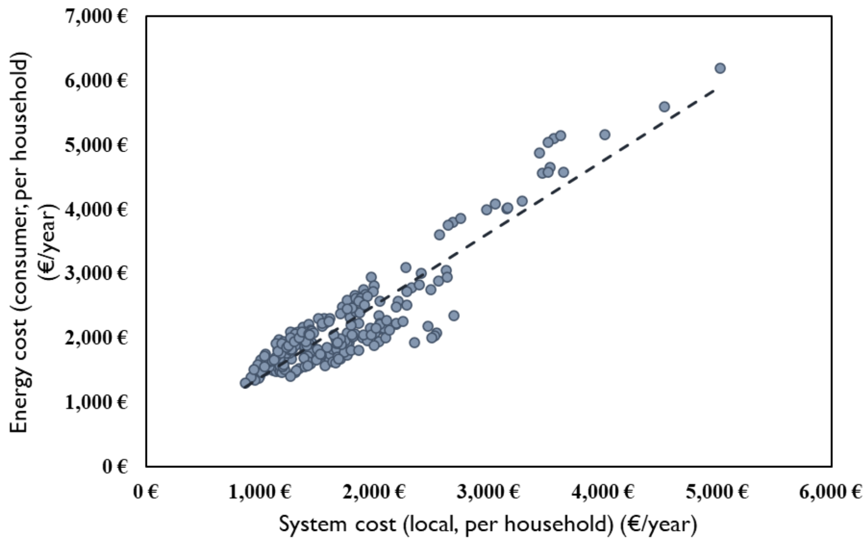


Figure 38: Energy cost and system cost, plotted for a wide variety of modeled cases. Trendline indicated by dashed curve.

This study does not have the ambition to calculate the global cost of future energy systems. The model does not allow it, and furthermore one would have to build many scenarios with different assumptions. Our model simply assumes that there is an infinite supply of both renewable electricity and renewable hydrogen at a certain cost. In reality, we may lack sufficient amounts of green hydrogen or we may face renewable electricity shortages in winter. Moreover, the grid infrastructure should be able to handle the chosen configurations. Thus, from an energy system perspective, we cannot say what is the preferred technology for each situation at this point.

We can, however, look at some key performance indicators which tell us something about the impact on the energy system. Here, we will consider:

- *Net annual primary energy consumption* : this metric relates to the total amount of renewable energy which has to be generated to provide a household with energy for one year. If it is high, it means large amounts of energy have to be imported or produced within the country.
- *Winter net electricity demand* : this metric indicates the amount of electricity which has to be supplied to a household during the 6 coldest months of the year. If it is high, large amounts of renewable electricity have to be produced either directly e.g. via wind turbines, or indirectly through turbines fed with renewable gas.
- *Peak electricity grid load* : this metric indicates the largest load caused on the electrical grid by the household (injection peak or offtake peak), throughout the year. If it is high, the distribution grid may not be able to handle the power flow.

Figure 39 illustrates the common knowledge that 'all-electric solutions are more efficient'. Annual primary energy demand is lower than equivalent solutions based on hydrogen. It is also clear that heat pumps cause the largest winter electricity demand. As a household requires more heat, both the primary energy demand and the winter electricity demand increase. For heat pumps, both metrics are positively correlated, while there is a negative correlation for cogeneration technologies. CHP units produce electricity when producing heat, which is mostly during winter. Depending on the metric which should be minimized, one can select a different technology (Table 6).

It becomes more complex when renewable energy is added to the picture (Figure 40). In this case, even negative primary energy demand is possible by adding hydrogen panels to already low-energy buildings. Consequently, it is possible to end up in the bottom left quadrant, having both negative primary energy demand and negative winter electricity demand. Note that in the data shown, all-electric solutions always have a positive primary energy demand since only the installation of solar PV is considered in those cases. Of course, primary energy could become negative for those buildings too, by simply adding more solar PV. This would then cause a larger stress on the electricity grid, as discussed in section 7.3.4.

The impact of heat pumps on the peak electrical load is, however, small (Figure 41). As heat demand increases, the peak load caused by the heat pump increases accordingly. However, peaks caused by household appliances, electric vehicles and PV are likely to be more significant. At a COP of 4, even a thermal peak of 10 kW will cause only 2.5 kW of electricity demand. The occurrence of such peaks can be minimized by insulation and thermal buffering.

Table 6: Decision matrix for different scenarios at energy **system** level.

<table>
<tr><th colspan="2"></th><th colspan="2">Domestic renewable electricity production</th></tr>
<tr><th colspan="2"></th><th>High</th><th>Low</th></tr>
<tr><th rowspan="2">Import of green hydrogen</th><th>High</th><td>Unclear

(both are possible from an energy system perspective)</td><td>Hydrogen-based preferable

(minimization of (winter) electricity consumption)</td></tr>
<tr><th>Low</th><td>Unclear

(direct electrification versus domestic hydrogen production)</td><td>All-electric preferable

(minimization of primary energy consumption)</td></tr>
</table>

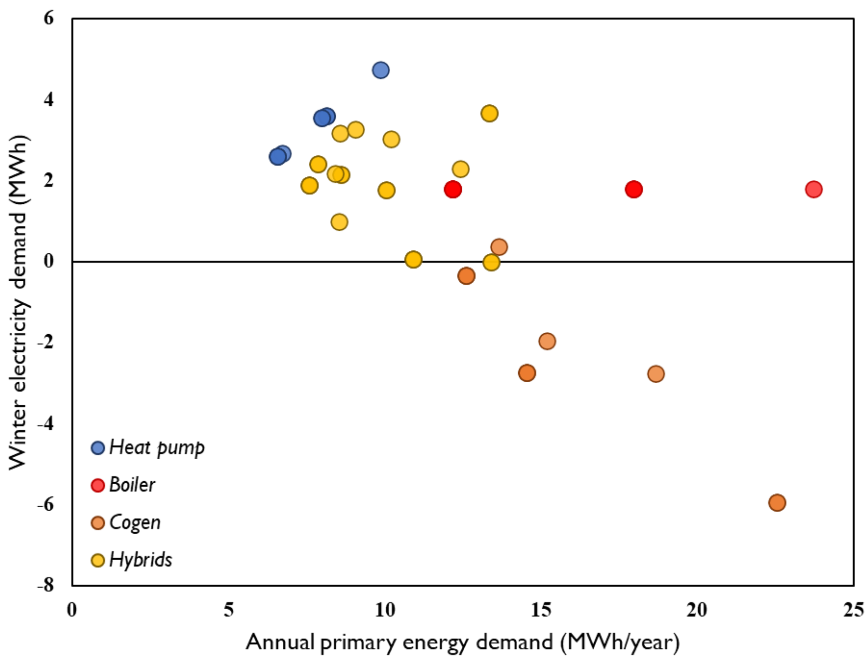


Figure 39: Winter electricity demand and annual primary energy demand, plotted for a variety of cases with different heating solutions (2050, base case, annual heat demand of 5, 9 or 13 MWh).

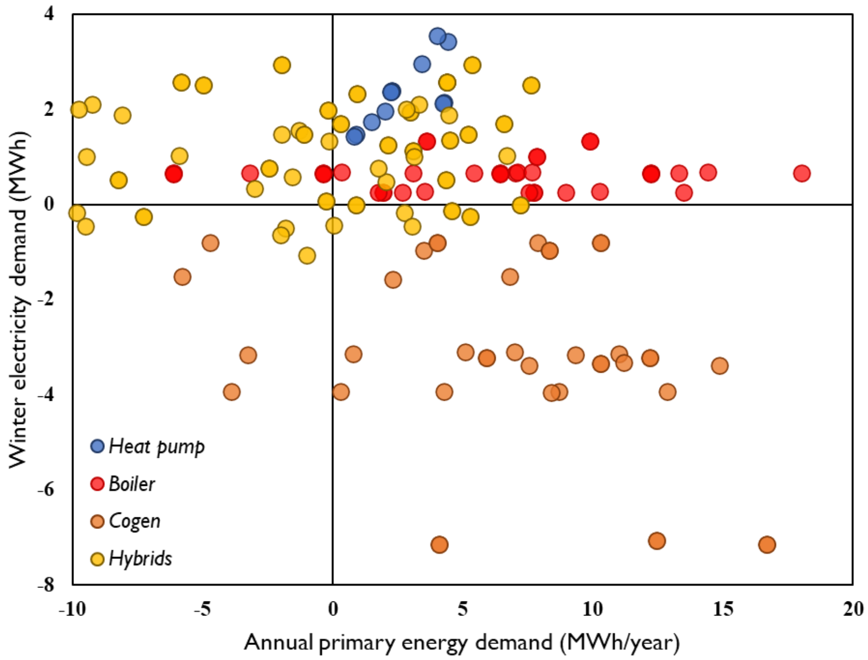


Figure 40: Winter electricity demand and annual primary energy demand, plotted for a variety of cases with different heating solutions including renewable energy production (2050, base case, annual heat demand of 5, 9 or 13 MWh). Renewable energy production from PV, electrolysis and hydrogen panels are all considered (Table 3).

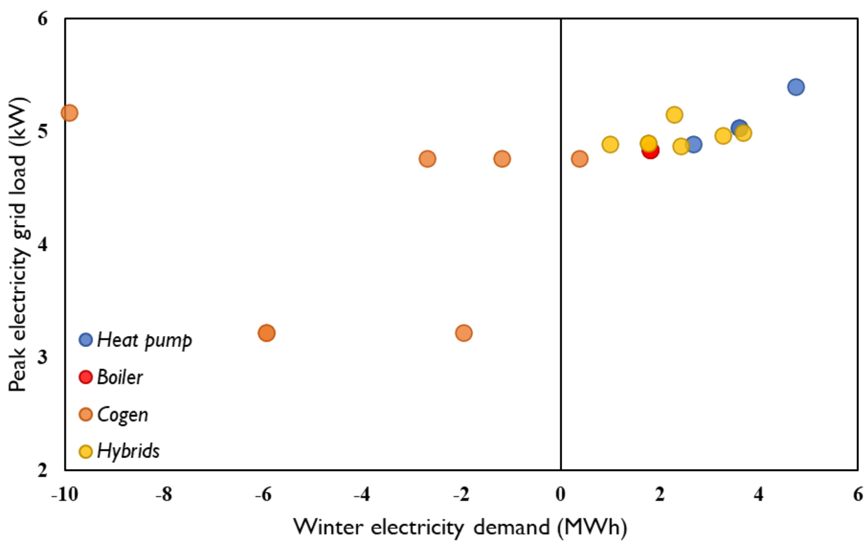


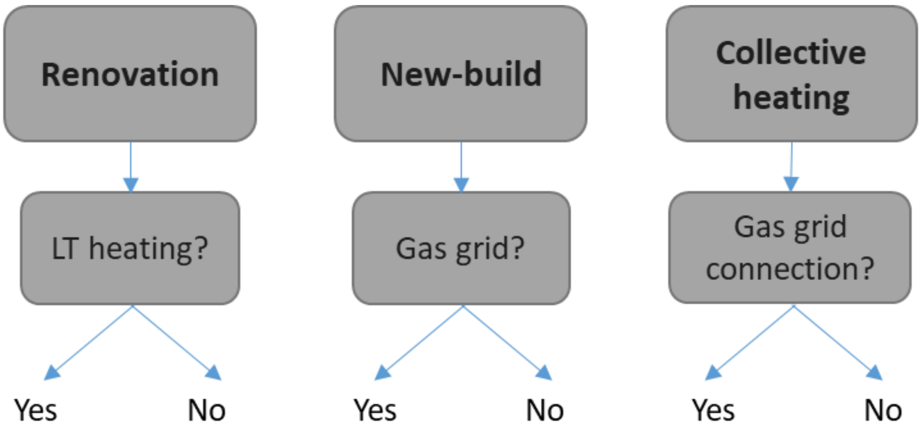
Figure 41: Peak load on the electricity grid and winter electricity demand, plotted for various cases without renewable energy production (2050, base case, annual heat demand of 5, 9 or 13 MWh).

7.5 Decision tree

Based on all the previous sections, it is possible to distill a decision tree (Figure 42). As we have made abundantly clear, our model does not take into account energy system level considerations, such as the management of the electrical grid or supply of green hydrogen. Therefore, we can only provide a decision tree from the individual's perspective, solely aiming at minimal energy costs. This decision tree is then valid for the base case (2050) under the assumptions of the BatHyBuild model.

Furthermore, the decision tree does not take into account all possible heating options, such as biomass boilers. It only serves to summarize the energy cost results of this study.

In most of the presented cases, all-electric heating is the least-cost option. A hydrogen boiler is often a good alternative, at slightly higher cost. When low-temperature heating is not possible, a hybrid solution (boiler + heat pump) is a clear winner. While this is only one of the 6 alternative cases, this case may turn out to represent the majority of our building stock in 2050. Fuel cells and CHP engines are especially interesting in cases with collective heating, and in combination with a heat pump. Finally, solar PV is always a good investment in 2050. Local hydrogen production (section 7.2.5) is often also profitable, but has to be examined case by case.



1st choice	Heat pump	Hybrid (HP + boiler)	Heat pump	Heat pump	Heat pump	Heat pump
2nd choice	Boiler[33]	Boiler	Boiler		Hybrid (HP + boiler or HP + CHP)	
Renewable energy	Solar PV: always profitable Electrolysis and/or hydrogen panels: case-dependent					

Figure 42: Decision tree targeting minimal household energy costs for different cases (2050). This figure summarizes the conclusions concerning the energy costs of the cases analyzed in this study. It does not take into account societal costs or systemic effects.

[33] This case may be a suitable 2nd choice *e.g.* when space limitations or other practical considerations prohibit the use of a heat pump.

8 Discussion

8.1 Limitations of the study

The intention of this study was to make a first bottom-up assessment of the use of hydrogen technologies. For the sake of simplicity, many boundary conditions were not explicitly modelled and various assumptions were made. Future studies should take these into account. Below is a list of limitations of the current model.

- We consider the Flemish context, with its associated tariff structures and consumption profiles.
- We followed a generalized approach. Specific contexts (*e.g.* historic buildings, specific environments such as city centers) will yield different outcomes.
- No full-fledged hydraulic calculations are performed. While water temperature was taken into account to some extent, this was not sufficient to cover this aspect in full.
- There is a large uncertainty on the assumptions for 2050. By considering a range of assumptions, the sensitivity to this uncertainty was assessed (and visualized in the results of the previous paragraphs).
- Tariff structures and dynamic electricity prices may have a large impact on certain scenarios. These aspects were not comprehensively assessed or optimized.
- The model assumes an infinite supply of 100% renewable energy carriers. In reality, the widespread adoption of a certain technology will have an impact on the availability of renewable, affordable energy carriers.
- The systemic effects (*e.g.* grid balancing) of the different technologies were not taken into account.
- Collective energy systems (cohousing, energy communities, district heating) should be assessed more carefully in dedicated models.
- Not all existing technologies were assessed. For example: soil-water heat pumps, air-air heat pumps, biomass boilers, solar thermal collectors, industrial waste heat, …
- Insulation and costs of renovation were not explicitly modeled.
- The embodied energy[34] of technologies and infrastructure was not taken into account. In certain cases, this will have a large impact on the net overall impact.
- The results could be impacted by drastic technology breakthroughs, *e.g.* in hydrogen storage or renewable energy production.
- Charging of electric vehicles and vehicle-to-grid applications were not taken into account.
- Space cooling was not taken into account. In a changing climate, this may become a large share of residential energy demand.

8.2 Recommendations for further analysis

To better understand the role of hydrogen in the residential sector, additional research is needed. Three types of future assessments would help map the potential and drawbacks of hydrogen for the built environment.

[34] Energy required to produce the appliances and infrastructure

Pilot projects

The application of hydrogen in real-life contexts is necessary to understand practical boundary conditions, safety aspects, real incurred costs, and legislative and permitting requirements. Moreover, it allows a technological evaluation of different types of technologies. It would give professionals the opportunity to gain practical experience with hydrogen gas and companies to come up with innovative solutions. Last but not least, these projects are important to assess the social acceptance and understand the concerns the local population might have.

Specific locations could be targeted for pilot projects with a clear added value of hydrogen, for example: historic city centers, district heating sites where the industrial activity is ceased, locations with poor electrical infrastructure, locations close to hydrogen-related activities, …

Top-down studies

We lack proper geographic and time-resolved assessments of the capacity of the distribution grid to handle load peaks and injection peaks. The utilization of the gas distribution grid for pure hydrogen gas is to be assessed.

A true systemic analysis of future energy scenarios should be performed, taking into account the role hydrogen could play. These should consider the extent of renewable electricity production, hydrogen production and hydrogen import in the future. These should look at decentralized CHP units versus centralized gas turbines. And these studies should take into account the real building stock in 2050, with its associated energy demand and heating options.

Bottom-up studies

There is also still room for bottom-up studies. When complete neighborhoods are considered, what is the interplay between different consumers, prosumers and producers? Heterogeneous districts with different types of actors will yield a certain collective energy demand pattern. What is the impact of allowing hydrogen boilers and CHP units, versus the case with only electrified heating? Finally, how could energy communities be beneficial to maximize local energy production and consumption, and what is the benefit of district heating versus separate appliances? Such bottom-up studies could also take into account the real costs of renovation and insulation.

9 General conclusions

The BatHyBuild study sets out to investigate the potential application of hydrogen technologies following a bottom-up approach. By modeling the energy management of a household or a set of households, we gained insight into the cost and energy performance of different heating solutions.

This study rests on some important starting points: 100% green energy, import of affordable hydrogen, and hydrogen distribution grids. If all these preconditions are met, there is a very clear case for using hydrogen in buildings. If they are not all met or if the future is uncertain, it should be further investigated what benefits hydrogen could provide.

Clearly, if green hydrogen is not commonplace, the use of hydrogen gas does not contribute to the transition towards renewable energy. For this reason and others, hydrogen will not play a big role in buildings before 2030. From 2030 onwards, green hydrogen may be available in larger volumes due to scaling up of industrial and transport applications and might become a cost-effective option in the build environment.

From a cost perspective, the use of a hydrogen boiler (ideally in combination with a heat pump) is beneficial when low temperature heating is not available or when all-electric heating is not possible for other reasons. When low temperature heating is available, all-electric heating yields the lowest energy cost.

From an energetic perspective, the use of heat pumps leads to a lower primary energy demand but a higher electricity demand. The use of CHP units in buildings is particularly interesting, since they may become net producer of electricity. Finally, local renewable energy production may be significantly increased by producing hydrogen, without impacting the electrical grid.

In general, we demonstrate that hydrogen technologies may hold several benefits for individuals, grid operators and the energy system. The use of hydrogen in buildings should therefore not be discarded, but assessed in more detail.

We do not pretend to have said the last word about hydrogen in buildings with this study. Many aspects are under-investigated, and many simplifications have been made. But we hope to open up the discussion about the topic and wish to stimulate further investigations which could support or contradict the insights of this report.

As a follow-up of this study, testing of hydrogen concepts and especially hybrid electric-hydrogen solutions in real life situations and pilot projects are recommended. Such projects will lead to insights and experience with respect to practical boundary conditions, safety aspects, real incurred costs, and legislative and permitting requirements. Additionally it will offer the local players that are active in this field, the opportunity to develop and showcase their technology and stimulate further innovative solutions.

10 Appendices

10.1 Literature list

nr	Country	Year	Title & link	Author
1	NL	2020	Waterstof in de gebouwde omgeving	Stedin
2	NL	2020	Waterstof als optie voor een klimaatneutrale warmtevoorziening in de bestaande bouw	TNO
3	NL	2018	Warm aanbevolen: CO2-arme warmte in de gebouwde omgeving	RLI
4	NL	2020	Klimaatneutrale energiescenario's 2050	Berenschot
5	UK	2017	H21 Leeds City Gate project	Northern gas networks
6	Global	2020	Path to hydrogen competitiveness	Hydrogen Council
7	Global	2019	The future of Hydrogen	IEA
8	EU	2019	Gas for climate, the optimal role for gas in a net-zero emissions energy system	Navigant
9	EU	2020	Gas for climate, a path to 2050	Navigant
10	EU	2020	European Carbon Neutrality: The Importance of Gas	DNV-GL
11	NL	2020	Scenario's voor klimaatneutraal energiesysteem	TNO
12	NL	2021	Waterstofwijk, Plan voor Waterstof in Hoogeveen link to public report link to detailed technical report	Consortium Hoogeveen
13	NL	2021	Waterstof in de gebouwde omgeving, thematiek link to waterstoflab	Waterstoflab
14	UK	2020	Exploring the evidence on potential issues associated with trialling hydrogen heating in communities link to report	Hy4heat

10.2 Overview of input data

Energy vectors

		2025	2030	2050
Electricity				
Energy cost	*€/MWh*	30-90	30-90	30-90
Capacity tariff	*€/kW*	50	50	50
Distribution grid fee	*€/MWh*	40	40	40
Transmission grid fee	*€/MWh*	48	48	48
Injection cost	*€/MWh*	4	4	4
Primary energy factor[35]	*MWh/MWh*	1.52	1.47	1.41
Hydrogen				
Energy cost	*€/MWh$_{LHV}$*	219-320	71-130	59-112
Grid fee	*€/MWh$_{LHV}$*	22.5	22.5	22.5
Injection cost	*€/MWh$_{LHV}$*	1.9	1.9	1.9
Primary energy factor[36]	*MWh/MWh$_{LHV}$*	1.83	1.70	1.57

Water temperature

Central heating water	30-50 °C
Sanitary hot water	46-55 °C

Technology parameters[37]

Solar PV		**2050**
CAPEX	*€/kWp*	360-790
OPEX	*€/(kWp.year)*	0
Replacement cost inverter	*€/kWp*	200
Lifetime inverter	*years*	15-30
Lifetime panels	*year*	25-30
Performance factor	*kWh/kWp*	830

Hydrogen panels		**2050**
Hydrogen production	*kg/(panel.year)*	9-14
CAPEX	*€/panel*	250-400
Lifetime	*years*	25-30

[35] 100% renewable electricity is assumed in all scenarios. A factor of 1 is assumed for direct renewable electricity production. 28% of electricity is assumed to be generated in renewable gas turbines at 64% efficiency.
[36] All hydrogen is assumed to be produced by electrolysis directly from renewable electricity.
[37] For confidentiality reasons, not all parameters are shown for all technologies.

Heat pumps (individual)		2025	2030	2050
Nominal COP[38]	-	3-4	3.5-5.5	3.5-6
CAPEX[39]	*€/kW$_{th}$*	800-1500	800-1500	800-1500
OPEX	*€/year*	80-150	80-150	80-150
Lifetime	*years*	15	15	15

Heat pumps (collective)		2050
Nominal COP	-	3.5-6
CAPEX	*€/kW$_{th}$*	400
OPEX	*€/year*	800-1500
Lifetime	*years*	15

PEM fuel cell (individual)		2025	2030	2050
Thermal efficiency	$kW_{th}/kW_{g,LHV}$	40-47%		
Electrical efficiency	$kW_e/kW_{g,LHV}$	45-50%		
CAPEX	*€/kW$_e$*		3200-5000	1500-4000
OPEX	*€/(kW$_e$.year)*		50-100	50-80
Replacement cost stacks	*€/kW$_e$*		400-875	300-800
Lifetime stacks	*years*		15	15
Lifetime system	*years*		30	30

PEM fuel cell (collective)		2050
Thermal efficiency	$kW_{th}/kW_{g,LHV}$	36-41%
Electrical efficiency	$kW_e/kW_{g,LHV}$	47-56%
CAPEX	*€/kW$_e$*	600-1500
OPEX	*€/(kW$_e$.year)*	30
Replacement cost stacks	*€/kW$_e$*	200-600
Lifetime stacks	*years*	15
Lifetime system	*years*	30

ICE CHP (individual)		2050
Thermal efficiency	$kW_{th}/kW_{g,LHV}$	62%
Electrical efficiency	$kW_e/kW_{g,LHV}$	25%
CAPEX	*€/kW$_e$*	1500-4000
OPEX	*€/(kW$_e$.year)*	150-300
Replacement cost	*€/kW$_e$*	1125-3000
Replacement interval	*years*	10-15
Lifetime system	*years*	20-30

[38] This value is modulated throughout the year based on outside temperature. Typically, the resulting SCOP is lower than this value.
[39] For all technologies involved, the CAPEX increases when the installation becomes very small, due to a larger impact of the installation cost.

ICE CHP (collective)		2050
Thermal efficiency	*$kW_{th}/kW_{g,LHV}$*	55%
Electrical efficiency	*$kW_e/kW_{g,LHV}$*	35%
CAPEX	*€/kW_e*	600-3000
OPEX	*€/(kW_e.year)*	100
Replacement cost	*€/kW_e*	450-2250
Replacement interval	*years*	10-15
Lifetime system	*years*	20-30

Hydrogen boiler (individual)		2025	2030	2050
Efficiency	*$\%_{LHV}$*	109%	109%	109%
CAPEX	*€*	3000	3000	3000
OPEX	*€/year*	65-150	65-150	65-150
Lifetime	*years*	15	15	15

Electrolysis (individual)		2050
Efficiency	*$\%_{LHV}$*	59-68%
CAPEX	*€/kW_e*	800-2000
OPEX	*€/(kW_e.year)*	31
Replacement cost stacks	*€/kW_e*	350
Lifetime stacks	*years*	10
Lifetime system	*years*	20

Electrolysis (collective)		2050
Efficiency	*$\%_{LHV}$*	63-72%
CAPEX	*€/kW_e*	600-1000
OPEX	*€/(kW_e.year)*	8-13
Replacement cost stacks	*€/kW_e*	116-225
Lifetime stacks	*years*	8-15
Lifetime system	*years*	30

Thermal buffer (individual)		2025	2030	2050
Heat losses	*%/h*		0.20%	
CAPEX	*€/kWh*		50	
Lifetime system	*years*		15	

Thermal buffer (collective)		2025	2030	2050
Heat losses	*%/h*		0.05%	
CAPEX	*€/kWh*		10	
Lifetime system	*years*		15	

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