



Potential Sources of Flexibility for the Belgian Electricity System

Joannes Laveyne

Doctoral dissertation submitted to obtain the academic degree of
Doctor of Electromechanical Engineering

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Acknowledgments

In your hands is a special work, or at least a work with a special backstory. Perhaps not many acknowledgements open with these words, and to the uninformed reader this may seem a doctoral dissertation like many others. It is however the path that led to this PhD which is somewhat uncommon. But before diving into that story, I would first like to extend my gratitude to the people who meant a lot to me during this special journey.

First of all, there is of course probably the best thing that ever happened to me, my boyfriend Koen. Thank you, Koen, for always being there for me, during both the good moments and the moments of stress and deadlines. Thanks for taking me on holiday against my will, knowing full well that I would actually enjoy being away from everything for a while. Thanks for giving me space to make the most of my creative moments, even if they don't always adhere to 9-to-5 hours. We have put off a lot of things until "the little book is done", and I look forward to starting the next chapter of our relationship with you.

And Koen, as you can clearly see: if I say I'm going to finish something, I'm going to finish it. No need to remind me every year.

This work would also not have been possible without my loving parents. During the childhood of me and my brothers, our family certainly didn't have it easy. Nevertheless, you gave it your everything to be able to provide as much as possible, and a good education took precedence in this. I think we can say your hard work paid off.

From my father, I also received the broad interest in technology (and probably also the habit of starting many projects at the same time). Dad, you were already experimenting with renewable energy long before it was called renewable. A homemade thermal solar panel, or a yellowed booklet on how to build your own small wind turbine with little more than some wood, old car parts and a good set of hands. Perhaps it was meant to be like this. Mom, dad, thanks for everything.

Even if you write a PhD alone, it would not be possible without the support of colleagues. In this regard, I would first of all like to thank technician Vincent

and administrative assistant Marilyn. Although you were not directly involved in this dissertation, you are colleagues you enjoy going to work for. A chat, a laugh in between. You are the foundation on which the lab is built.

Thanks also to Brecht, with whom I once bet a crate of Duvel on who would finish his PhD first, but which has been so long since, I'm sure he's already forgotten about it. Thanks for all the technical discussions and insights, chats and attending some legendary conferences together.

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Thanks also to all other colleagues, both in our office and outside, those who are still working there and those who have left us in the meantime. The lab wouldn't be the same without you. Thanks also to all my former colleagues of Power-Link, the former energy knowledge platform of Ghent University where my career started. And thank you to Kevin, my former business partner. Even if we lost contact since, I still consider you one of the best friends I've ever had.

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Finally, I also want to thank my thesis jury, with each one of the esteemed members an important and well-respected expert in their specific field of expertise and an influential voice in the ongoing debate about the energy transition. Thank you for taking the time in your busy schedules to read and improve this work, especially if this subject is somewhat outside your zone of academic comfort.

About that backstory...

When I started working at Ghent University in 2009 (I had to look it up), I didn't even have a master's degree yet. Combining things, in this case working and studying, seemed like a good idea even back then. And as is often the case with scientific projects, a project assistant was urgently needed, and I found myself at the right time at the right place.

It became the beginning of a varied career at Power-Link, an interdisciplinary knowledge centre for what was then called clean tech, bridging academia and industry. I worked there on innovative technologies that were then just on the verge of their industrial breakthrough, such as solar panels, and technologies that 15 years later are *still* just on the verge of their industrial breakthrough, like hydrogen or small wind turbines.

In 2011, now with a master's degree in Electrical Energy Engineering on my wall, the then director of Power-Link, Prof. Greet Van Eetvelde, convinced me to start a PhD. I was given the freedom to determine the subject relatively freely. I chose to do research on digitising electricity measurements and how to process and manage this digital data. The interface between electrical energy and digital communication was and still is my passion. Moreover, it was then already clear that our conventional power grid would have to digitise at a rapid pace to cope with increasing electrification.

This soon became extra apparent when the software and algorithms I was developing also attracted a lot of industrial interest. After having to answer apologetically for the umpteenth time to questions from companies "where they could buy this" or "what this should cost", I decided to start a spin-off company, Argus Technologies, in 2012. After all, how hard could it be to combine research and entrepreneurship?

Turns out it's hard. Quite hard.

The just over six years in which I, together with co-founder Kevin Gaytant, ran the spin-off and built it into a small but innovative SME remain the most intense, but also most instructive years of my career up until now. Presenting a concept at a scientific conference is one thing, but effectively turning it into something you can generate sustainable income from is another. Besides running the company, you also have to further refine the technology, establish customer relationships and attract investment capital. We had the incredible advantage of being able to count on the support of UGent TechTransfer, which advises and assists researchers with entrepreneurial plans. Jeroen De Maeyer and Patrick Vankwikelberge were a mainstay during that period, as was colleague Dorine Gevaert.

When the spin-off was sold to an investment firm in 2018, I refocused on scientific research. However, the power grid had not sat idly by, but had already been firmly digitised during that period - including by companies like my spin-off. In other words, my original line of research had already been put into practice. I started working as a scientific collaborator on temporary projects, such as on energy synergies on business parks or small wind turbines (something that continues to haunt me to this day). Gradually, I also started writing and getting my own project applications approved, a matter of using my fundraising and project coordination skills developed as an entrepreneur but now for academic purposes. All these focused on large-scale sources of flexibility for the electrical energy system. Amongst others, I landed a project with a unique consortium of other Flemish knowledge institutions and industrial partners which stood at the cradle of the roll-out of local energy communities in Flanders. Together with my newfound *compagnons de route* Sam Hamels en Marten Ovaere we embarked on several projects concerning residential electrical flexibility. And in between, I carried out academic consultancy for industry and governments.

The advantage of working on different projects is you get to taste many research subjects and disciplines, and many of these projects have had tangible impacts on technology and policy developments. The downside is it's hard to dig deep scientifically. One of the main challenges of this PhD was therefore creating a scientifically sound synthesis of the many different and diverse subtopics I worked on during the years. And finding the time to publish about them and to actually write the dissertation itself. While not perfect, I hope this work has succeeded in this. And above all, I hope it contains useful and innovative insights and take-aways, both for the academic or the casual reader.

Nederlandstalige samenvatting

In de afgelopen vijf decennia heeft de wereld een buitengewone toename van het energieverbruik gekend. Onder invloed van de bevolkingsgroei, de industrialiserende economieën en het stijgende welvaartsniveau is het jaarlijkse verbruik van primaire energie meer dan vervijfvoudigd, van ongeveer 30.000 TWh in 1950 tot 159.000 TWh in 2022. 84% van dit energieverbruik wordt gegenereerd door fossiele brandstoffen zoals kolen, olie en gas. De gevolgen hiervan zijn duidelijk zichtbaar in de concentratie van koolstofdioxide in de atmosfeer, de belangrijkste drijvende kracht achter klimaatverandering.

Om de uitdaging van klimaatverandering aan te gaan, is de overgang naar energiebronnen met netto nul koolstofuitstoot essentieel. Elektriciteit speelt hierbij een sleutelrol. Hoewel het zelf geen energiebron is, is het zowel een efficiënte drager van energie als gemakkelijk om te zetten in andere vormen van nuttige finale energie, zoals warmte of beweging.

Om deze elektriciteit op een duurzame manier op te wekken, is er behoefte aan schone energiebronnen. Waterkracht en kernenergie zijn lange tijd een steunpilaar geweest bij de opwekking van emissiearme elektriciteit en hebben een stabiel aandeel van respectievelijk 15% en 10% in de wereldwijde elektriciteitsmix. In de afgelopen twee decennia zijn zonne- en windenergie echter naar voren gekomen als dominante groeifactoren in de opwekking van duurzame elektriciteit. Als gevolg van aanzienlijke kostenverlagingen en schaafeffecten in de productie wekken wind- en zonne-energie nu meer dan 12% van de wereldwijde elektriciteit op en het ziet ernaar uit dat hun aandeel het komende decennium zal verdubbelen of verdrievoudigen.

Nergens is dit duidelijker dan in de Europese Unie. In 2023 leverden deze twee bronnen 713 TWh, of meer dan 27% van de jaarlijkse elektriciteitsproductie van de EU-27. In 2002 leverden ze nauwelijks 2%. Terwijl de jaarlijkse productie van wind- en zonne-energie in de EU-27 de elektriciteitsproductie van kolengestookte elektriciteitscentrales (447 TWh) in 2019 al overtreft, overtreffen ze vanaf 2022 ook de productie van gasgestookte elektriciteitscentrales (557 TWh) en kernenergie (613 TWh).

Hoewel deze ontwikkeling positief is vanuit klimaat oogpunt, gaat de integratie van grote hoeveelheden intermitterende hernieuwbare energie in het bestaande elektriciteitsnet gepaard met een aantal uitdagingen. Het

beschrijven van deze uitdagingen en het evalueren van mogelijke mitigerende opties is het onderwerp van dit proefschrift.

Historisch gezien was het elektrische energiesysteem gebaseerd op grote, gecentraliseerde elektriciteitscentrales die een continue hoeveelheid basislastvermogen, zogenaamde *baseload*, produceerden, waarbij flexibele fossiele centrales en waterkracht zorgden voor de dagelijkse belastingsschommelingen. In België en Frankrijk zijn of waren deze basislastcentrales vooral kerncentrales. In feite is het elektrische systeem in deze landen mee geëvolueerd met de nucleaire technologie, waarbij het elektrische transportnet is gebouwd en uitgebreid om deze grote basislastcentrales te kunnen herbergen. Omdat de intermittentie van het elektriciteitsverbruik niet overeenkwam met de continue basislastproductie van de kerncentrales, werden er ook andere investeringen gedaan, zoals de bouw van pompcentrales om energie op te slaan. Het energiebeleid was er ook op gericht om een meer continu elektriciteitsverbruik (financieel) te stimuleren.

Met de instroom van hernieuwbare energie op het net is dit historische paradigma van een op basislast gericht energiesysteem snel aan het veranderen. Windenergie en zonne-energie zijn de goedkoopste nieuwe bronnen van koolstofarme energieproductie geworden, maar hun energieoutput is niet-regelbaar, althans niet naar boven. Hun output is afhankelijk van de beschikbaarheid van zon en wind. Door hun lage productiekosten trekken ze echter grote investeringsbedragen aan. Er wordt aangetoond dat, op basis van de huidige groei van zowel de geïnstalleerde capaciteit van wind en zon als de verwachte groei van het elektriciteitsverbruik, zon en wind in 2030 in staat zullen zijn om ten minste één uur per dag te voorzien in het totale Belgische elektriciteitsverbruik, ondanks het feit dat ze slechts ongeveer een derde van de totale jaarlijkse elektriciteitsopwekking voor hun rekening nemen. In de zomer en het middenseizoen zullen ze deze stroom zelfs nog meer uren tot het grootste deel van de dag kunnen leveren.

In welke volgorde bronnen van elektriciteitsproductie aangewend worden is echter niet gebaseerd op hun technische beschikbaarheid, maar op de groothandelsmarkten voor elektriciteit. De twee belangrijkste soorten groothandelsmarkten zijn de langetermijnmarkt (futures) en de day-aheadmarkt (spot). Op de termijnmarkt wordt elektriciteit verhandeld met een leveringsdatum die weken, maanden of zelfs jaren vooruit ligt. Op de gelijknamige day-aheadmarkt wordt elektriciteit verhandeld voor levering de

volgende dag. De day-aheadmarkt is een openbaar verhandelde markt, waarop de uurprijs voor elektriciteit voor elke dag wordt gepubliceerd. Dit proefschrift toont aan dat dit leidt tot prijsconvergentie tussen de futures- en de spotmarkt, omdat er anders arbitrage tussen de markten zou optreden.

Terwijl de meeste elektriciteit, vooral door basislastgeneratoren, wordt verhandeld op de langetermijnmarkten, fungeert de spotmarkt in feite als de prijsbenchmark. Hier heeft het stijgende aandeel van hernieuwbare energie een drukkend effect op de gemiddelde spotmarktprijs, vooral overdag door het stijgende aandeel van zonne-energie. De spotmarkt maakt gebruik van marginale prijzen, dat is de prijs om één bijkomende eenheid van energie te produceren, om een rangorde van steeds hoger geprijsde opwekkers op te stellen totdat de vraag- en productieprijscurven elkaar kruisen. Aangezien de meeste producenten van hernieuwbare energie geen brandstofkosten hebben, zijn hun marginale kosten op korte termijn laag tot nul.

Het drukkende effect van hernieuwbare energie op de spotprijzen stimuleert elektriciteitsverbruikers om een groter deel van hun verbruik op de spotmarkt te kopen in plaats van op de termijnmarkt. Dit geldt vooral als ze hun verbruiksprofiel kunnen aanpassen aan het intermitterende gedrag van hernieuwbare energiebronnen, en zo optimaal kunnen profiteren van de perioden met lage elektriciteitsprijzen en tegelijkertijd de blootstelling aan perioden met hoge prijzen kunnen beperken.

Deze ontwikkelingen leiden tot een paradigmaverschuiving in de manier waarop elektriciteit wordt geproduceerd, verhandeld en verbruikt. In plaats van het historische concept van grote elektriciteitscentrales die het basislastverbruik leveren en weersonafhankelijke, stuurbare (piek)centrales die het intermitterende verbruik volgen, gaan we naar een systeem waarbij intermitterende hernieuwbare energiebronnen de bulkbelasting leveren en stuurbare centrales de restbelasting, dat is de belasting die niet door hernieuwbare energiebronnen kan worden gedekt. Er is daarom een toenemende behoefte aan flexibiliteit in het elektriciteitssysteem.

"Flexibiliteit" wordt in dit proefschrift gedefinieerd als de "grootschalige vermindering of toename van zowel het verbruik als de productie van elektriciteit gedurende langere perioden, of het verschuiven er van gedurende een of meerdere dagen". Zo wordt een onderscheid gemaakt met "technische flexibiliteit", die voornamelijk wordt gebruikt voor de stabiliteit op korte termijn van het elektriciteitsnet, bijvoorbeeld via ondersteunende diensten, en van "seizoensopslag", wat het grootschalig en langdurig opslaan van energie betreft.

De hierboven beschreven overgang brengt meerdere uitdagingen met zich mee. Met de huidige productie infrastructuur en elektriciteitsnet kan deze restbelasting grotendeels worden geleverd met door fossiele brandstoffen gestookte centrales, zoals gasturbines in gecombineerde dan wel open cyclus (CCGT, resp. OCGT). Hoewel de koolstofemissies van deze centrales onder het Europese emissiehandelssysteem vallen en als zodanig andere emissies elders compenseren, wordt in dit proefschrift aangetoond dat dit niet noodzakelijkerwijs waar is. Door de dynamiek in het emissiehandelssysteem zullen deze emissies waarschijnlijk slechts gedeeltelijk worden gecompenseerd. Om het aantal met fossiele brandstoffen gestookte elektriciteitscentrales te minimaliseren of zelfs te vermijden, moet de hoeveelheid restbelasting daarom worden geminimaliseerd en moet de rest worden opgewekt door bronnen met een lage of gecompenseerde koolstofuitstoot. Dit vereist een grote mate van flexibiliteit in zowel het opwekkings- als het verbruiksprofiel van elektriciteit.

In dit proefschrift wordt o.a. onderzocht of kerncentrales kunnen bijdragen aan deze flexibiliteit van aan de opwekkingszijde. In tegenstelling tot wat vaak wordt gedacht, zijn kerncentrales niet onbekwaam om flexibel te werken. Op bepaalde parameters, zoals *ramp rate*, doen ze het zelfs beter dan andere thermische centrales die conventioneel worden ingezet om flexibiliteit te bieden, waaronder CCGT- en OCGT-centrales.

Bij de beoordeling van hun economische aspecten blijkt echter dat flexibele opwekking de financiële basis van kerncentrales beïnvloedt en hun winstgevendheid vermindert of zelfs tenietdoet. Nucleaire opwekking wordt gekenmerkt door hoge vaste kosten, die vaak tot 75% of meer van de totale elektriciteitsproductiekosten uitmaken, onafhankelijk van de hoeveelheid geproduceerde elektriciteit. Een verlaging van de productie van een kerncentrale verhoogt daarom de relatieve kosten van een eenheid geproduceerde elektriciteit.

Bovendien lopen kerncentrales, door het drukkende effect van hernieuwbare energiebronnen op de spotprijzen, het risico hun blootstelling aan de spotmarkt te vergroten omdat klanten met langetermijncontracten gestimuleerd worden om (een deel van) hun verbruik op de spotmarkt in te kopen. Dit verhoogt de onzekerheid over de toekomstige winstgevendheid en leidt tot opportuniteitskosten voor de exploitanten van kerncentrales en investeerders. Hierdoor lijken conventionele kerncentrales geen waarschijnlijke rol te spelen als toekomstige leverancier van grootschalige flexibiliteit aan het systeem.

Een soortgelijke analyse wordt ook uitgevoerd voor kleine modulaire reactoren (Small Modular Reactors - SMR), een nieuwe en opkomende methode voor het opwekken van kernenergie. SMR's zijn bedoeld om de kapitaalkosten van kernenergie te verlagen door kleinere reactoren te bouwen, waarbij de meeste onderdelen gestandaardiseerd zijn en in een fabriek worden gebouwd, en vervolgens worden getransporteerd en geassembleerd op de bouwplaats. Dit proefschrift toont aan dat, hoewel kleiner bouwen leidt tot negatieve schaafeffecten, waardoor de kosten per eenheid geproduceerde energie stijgen, leereffecten door meer te bouwen kunnen leiden tot kostenbesparingen. Omdat SMR's echter dezelfde kostenstructuur hebben als conventionele kerncentrales, met vooral vaste kosten, kan echter worden verwacht dat ook zij te lijden hebben onder onzekere vooruitzichten wat betreft toekomstige winstgevendheid.

Een andere optie voor flexibiliteit aan de aanbodzijde die in dit proefschrift onderzocht wordt zijn thermische centrales die waterstof als brandstof gebruiken, bijvoorbeeld door bestaande aardgasgestookte centrales achteraf uit te rusten. Dit heeft het voordeel dat de hoge mate van flexibiliteit en de OPEX-gedreven kostenstructuur van CCGT- en vooral OCGT-centrales behouden blijft, terwijl de koolstofemissies van het gebruik van aardgas als brandstof worden vermeden. Een analyse van de literatuur en gesprekken met de industrie tonen aan dat het achteraf aanpassen van bestaande aardgasgestookte centrales een haalbare technologische optie is, vooral voor recente en toekomstige installaties. Deze worden meestal "waterstofklaar" gebouwd, wat betekent dat ze tot 30% waterstof per volume kunnen stoken met slechts kleine wijzigingen, en tot 50% met meer ingrijpende aanpassingen. De benodigde CAPEX voor deze wijzigingen is beperkt, respectievelijk ongeveer 1-2% en 2,4-3,6% van de CAPEX voor een nieuwe gasgestookte elektriciteitscentrale. Volledige waterstofomzetting is technisch ook mogelijk, maar vereist uitgebreidere aanpassingen aan de centrale. Maar zelfs als rekening wordt gehouden met de noodzaak van de toevoeging van katalytische reductie van stikstofoxiden, worden de vereiste investeringen geschat op minder dan 10% van de totale kosten van een nieuwe centrale.

Hoewel het achteraf aanpassen van aardgasgestookte elektriciteitscentrales om duurzame brandstoffen zoals waterstof te verbranden een aantrekkelijke optie lijkt, gezien zowel de technologie als de investering, hangt het af van de beschikbaarheid van duurzame waterstof en methoden om het op te slaan en naar de elektriciteitscentrale te transporteren. Hoewel er verschillende routes mogelijk zijn, vormen de hoge energievereisten voor de productie van

duurzame waterstof en de lage volumetrische energiedichtheid verschillende uitdagingen, waardoor het onwaarschijnlijk is dat waterstof kan worden gebruikt als belangrijkste energiebron voor grootschalige elektriciteitsopwekking. Het heeft echter wel potentieel als reservebrandstof, bedoeld voor gebruik in (omgebouwde) O/CCGT's om back-upvermogen te leveren tijdens perioden van lage productie van hernieuwbare energie.

Deze dissertatie onderzoekt ook of elektrolytische waterstofproductie kan worden gebruikt om flexibiliteit aan de verbruikerskant te bieden. De meeste elektrolyzers hebben een groot dynamisch vermogensbereik, waardoor het mogelijk is om hun output te moduleren volgens de intermitterende productie van hernieuwbare energie. Aangezien er een groeiende behoefte is aan koolstofarme waterstof, niet alleen als energiedrager maar vooral als duurzame grondstof voor de chemische en staalindustrie, lijkt flexibele elektrolytische waterstofproductie veelbelovend.

Er wordt echter aangetoond dat elektrolytische waterstofproductie om zowel technische als economische redenen niet geschikt is voor grootschalige flexibiliteit. Slijtage van de meeste typen elektrolyzers blijft constant, onafhankelijk van de belastingsfactor. Bovendien, als de gemiddelde belastingsfactor afneemt, moet de capaciteit van de elektrolyser toenemen om de productievolumes constant te houden. Dit leidt tot hogere CAPEX-vereisten, met negatieve gevolgen voor de kosten van waterstofproductie. In een typische Europese omgeving wordt verwacht dat elektrolyzers een hoge belastingsfactor moeten bereiken, vaak meer dan 6000 equivalente vollasturen per jaar, om waterstof tegen concurrerende kosten te produceren. Daarom kan worden geconcludeerd dat waterstofproductie eerder een basislastproces is dan een flexibel proces.

Een andere opkomende vorm van flexibiliteit aan de consumentenkant is de zogenaamde residentiële flexibiliteit, een term die Demand Side Management (DSM) en Demand Side Reduction (DSR) omvat met residentiële activa zoals warmtepompen (HP) en elektrische voertuigen (EV). Tot nu toe waren DSM en DSR grotendeels het exclusieve domein van grote industriële elektriciteitsverbruikers. Met de toenemende elektrificatie van verwarming en personenvervoer zal de rol van deze residentiële flexibiliteit zich echter ook uitbreiden met DSR.

In dit proefschrift worden uitgebreide definities van flexibiliteit voorgesteld voor gebruik in woontoepassingen. De concepten van impliciete en expliciete flexibiliteit, zoals toegepast bij grootschalige industriële flexibiliteit, zijn

minder duidelijk wanneer ze gebruikt worden bij residentiële flexibiliteit. De technologische waardeketen is daar complexer, er zijn vaak meerdere actoren bij betrokken en de processen die inkomsten genereren zijn minder rechtlijnig. Deze dissertatie stelt daarom voor om deze definities aan te vullen door de technische aspecten van waar de signalen die de residentiële activa aansturen worden gegenereerd los te koppelen van de rationale waarom en hoe de signalen werden gegenereerd en welke partij rechtstreeks voordeel haalt uit de flexibiliteitsactivering.

Voor impliciete flexibiliteit impliceert dit dat het optimalisatiedoel erin bestaat de totale kosten van het elektriciteitsverbruik rechtstreeks te verminderen, bv. door het verbruik te verschuiven naar uren met een lagere elektriciteitsprijs. Deze optimalisatie kan worden geautomatiseerd en/of op afstand worden uitgevoerd, waarbij alleen de stuursignalen naar de deelnemende activa van het huishouden worden gestuurd, zolang de deelnemers een eenvoudige methode hebben om (tijdelijk) af te zien van de optimalisatie en dit onbeperkt kunnen doen.

Voor expliciete flexibiliteit is het doel van de optimalisatie om inkomsten te genereren met een dienst die extern aan de deelnemende huishoudens wordt geleverd, bijv. ondersteunende diensten, waarbij deze inkomsten achteraf worden verdeeld. Deze optimalisatie gebeurt op afstand, met signalen die naar de deelnemende activa van het huishouden worden gestuurd, en de voorwaarden voor opt-out worden vastgelegd in een overeenkomst tussen het deelnemende huishouden en de aanbieder van de flexibiliteitsdienst.

Er wordt ook voorgesteld om een derde vorm van flexibiliteit toe te voegen, namelijk (semi-)passieve flexibiliteit. Dit is een vorm van residentiële flexibiliteit die geen of slechts een enkele interactie met de eindgebruiker vereist. Het is een passieve optimalisatie die het voordeel heeft dat ze eenvoudig in te stellen is, maar die niet altijd gegarandeerd het beste effect heeft omdat de optimalisatie geen rekening houdt met werkelijke (gemeten) parameters. Een voorbeeld is het instellen van de verwarming van de warmwatertank tijdens de middag, omdat de groothandelsprijzen voor elektriciteit meestal het laagst zijn tijdens de middag, of omdat dit meestal samenvalt met de piekproductie van geïnstalleerde zon-PV.

Een andere vorm van deze semi-passieve flexibiliteit is het installeren van zon-PV-panelen in een specifieke oriëntatie, zodat ze beter aansluiten bij het typische dagelijkse elektriciteitsverbruik, dat 's ochtends begint en 's avonds piekt. Een typische opstelling van PV-panelen op het zuiden heeft een

piekopbrengst tijdens de middag en is 's avonds vaak al gedaald tot nul. Er wordt onderzocht of het verdelen van de panelen over twee verschillende georiënteerde arrays, bijvoorbeeld een oostelijke en een westelijke, dit productieprofiel beter op elkaar afstemt.

Hiertoe wordt een methodologie gepresenteerd voor het berekenen van de opbrengst en de productiecurve van willekeurig georiënteerde PV-systemen op basis van een beperkt aantal vereiste parameters en met behulp van een anisotroop *all-sky* model dat beter geschikt is voor West-Europese omstandigheden dan het gangbare isotrope model, en worden simulaties op basis van echte residentiële belastingsprofielen en netwerkparameters gebruikt om deze aanname realistisch en nauwkeurig te valideren.

Er wordt aangetoond dat de injectiepiek 's middags kan worden "afgevlakt" door een unitaire opstelling van PV-panelen in twee verschillende oriëntaties op te splitsen. Er is echter slechts een klein effect op het begin en einde van de energieproductie in respectievelijk de ochtend en avond, alleen enigszins merkbaar tijdens de wintermaanden. Hoewel de gesplitste oriëntatie de injectiepiek kan verlagen, verlaagt het ook de totale opbrengst van de PV-panelen, wat mogelijk leidt tot een suboptimale oplossing.

Impliciete en expliciete residentiële flexibiliteit laten een groter potentieel zien voor het afstemmen van het energieverbruik op de productie, waarbij perioden met lage prijzen optimaal worden benut. Residentiële flexibiliteit kent echter een aantal specifieke uitdagingen die tot nu toe onopgelost zijn gebleven. Gezien de beperkte impact van individuele residentiële elektriciteitsverbruikers, moeten grote aantallen worden samengevoegd. Vergeleken met industriële toepassingen verhoogt dit de initiële installatiekosten en de complexiteit van het beheer, terwijl de opbrengstmarge per individuele installatie zeer klein is. Met residentiële flexibiliteit blijft dit echter zeer problematisch, aangezien er een grote diversiteit is in zowel types en merken van activa, als niveaus en methodes om hun stroomverbruik te controleren. Dit betekent dat flexibiliteitsleveranciers vaak moeten vertrouwen op sturingsalgoritmen op maat, afhankelijk van het type installatie en het merk, wat het uitbouwen van een rendabele business case sterk bemoeilijkt.

Deze dissertatie laat zien dat de enige duidelijke manier om dit probleem aan te pakken is door meer interoperabiliteit en digitale communicatie via Application Programming Interfaces (API's). Dit zijn geautomatiseerde interfaces die een gedocumenteerd protocol gebruiken en over bestaande fysieke interfaces zoals Ethernet of WiFi lopen. Om de acceptatie te

vergroten hoeven noch het protocol noch de interface zelf uniform gestandaardiseerd te zijn, maar moeten de lay-out en het datamodel open en gedocumenteerd zijn om de interoperabiliteit te vergroten. Dit betekent dat fabrikanten van bijvoorbeeld warmtepompen of elektrische voertuigen methoden kunnen implementeren om hun apparaten te laten praten met andere apparaten van andere fabrikanten, en zelfs om reeds bestaande apparaten te ondersteunen in retrofit-toepassingen.

Tot slot wordt de behoefte aan duidelijke prijssignalen voor residentiële activa besproken. De elektriciteitsprijs op groothandelsmarkten is een signaal met informatie over de beschikbaarheid van productie en de behoefte aan meer verbruik. Deze informatie moet optimaal naar residentiële consumenten stromen om hun elektriciteitsverbruik flexibel te kunnen maken.

Dit prijssignaal moet ook de eigenaars van residentiële zon-PV-installaties bereiken. Producenten van hernieuwbare energie hebben te lijden onder lage groothandelsprijzen in een fenomeen dat prijskannibalisatie wordt genoemd, waarbij de toenemende instroom van goedkope hernieuwbare energie leidt tot een daling van de hoge marktprijzen. In België wordt dit gedeeltelijk veroorzaakt door het grote aantal residentiële fotovoltaïsche installaties die niet op de hoogte zijn van de groothandelsprijzen voor elektriciteit en dus ook niet van het door de consumenten gevraagde productievolume. Omdat deze installaties niet op de hoogte zijn van de groothandelsprijs voor elektriciteit en niet gecontroleerd kunnen worden door bijvoorbeeld elektriciteitsleveranciers of netwerkbeheerders, hebben ze een steeds grotere impact op zowel de energiemarkt als de stabiliteit van het elektriciteitssysteem. In de toekomst zullen deze installaties bewust moeten worden gemaakt van de markt- en netwerkomstandigheden om vernietiging van de sociale welvaart en een stijging van de netwerkkosten te voorkomen.

English summary

Over the past five decades, the world has experienced an extraordinary increase in energy consumption. Driven by population growth, industrialising economies and increasing welfare levels, yearly primary energy consumption has risen more than fivefold, from around 30.000 TWh in 1950 to 159.000 TWh in 2022. 84% of this energy consumption is generated by fossil fuels such as coal, oil and gas. The effects of this are clearly visible in the concentration of atmospheric carbon emissions, the main driver behind climate change.

To address the challenge of climate change, the transition to energy sources without unabated carbon emissions is essential. Electricity plays a key role here. While not an energy source itself, it is both an efficient carrier of energy and is easily converted into other forms of useful energy, such as heat or motion.

To generate this electricity in a sustainable way, there is a need for clean energy sources. Hydropower and nuclear power have long been a mainstay in the generation of low-emission electricity, holding a steady 15% and 10% share in the global electricity mix respectively. However, in the past two decades, solar energy and wind power have emerged as a dominating growth factor in the generation of sustainable electricity. Driven by substantial cost reductions and scale effects, wind and solar now generate over 12% of the global electricity, and are set to double or triple their share the coming decade.

Nowhere has this been more apparent than in the European Union. In 2023, these two sources provided 713 TWh, or more than 27% of the yearly electricity production of the EU-27. In 2002, they provided barely 2%. While yearly wind and solar output in the EU-27 already surpassed the electricity generation of coal-fired power plants (447 TWh) in 2019, as of 2022 they also outproduce the gas-fired power plants (557 TWh) and nuclear generation (613 TWh).

While this evolution is positive from a climate point of view, integrating large quantities of intermittent renewable energy into the existing electricity grid comes with its own set of challenges. Describing these challenges and evaluating possible mitigating options is the subject of this dissertation.

Historically, the electrical energy system was based on large, centralised power plants producing a continuous amount of baseload power, with flexible fossil-fired plants and hydropower taking care of the daily load variations. In Belgium and France, noticeably, these baseload plants are or were nuclear power plants. In fact, the electrical system in these countries co-evolved with nuclear technology, with the electrical transport grid built and expanded to accommodate these large baseload plants. Because the intermittency of the electricity consumption did not match with the continuous baseload generation of the nuclear power plants, other investments were undertaken as well, e.g. the construction of pumped hydro storage. Energy policy was also aimed at (financially) stimulating a more continuous electricity consumption.

With the influx of renewable energy on the grid, this historical paradigm of a baseload-centred energy system is changing rapidly. Wind and solar have become the cheapest new sources of low-carbon energy production, but their energy output is non-dispatchable, at least not upwards. Their output is dependent on the availability of sun and wind. However, due to their low production cost they are attracting large amounts of investment. It is shown that, based on current growth of both installed capacities of wind, solar and expected growth of electricity consumption, in 2030 solar and wind will be able to provide the total Belgian electricity consumption for at least one hour each day, despite only making up around one third of the total yearly electricity generation. In the summer and middle seasons, they will be able to provide this power for even more hours to most of the day.

The dispatch of electricity generators is however not based on their technical availability, but by wholesale electricity markets. The two main types of wholesale markets are the long term, or futures, market and the day-ahead, or spot, market. On the futures market, electricity is traded with a delivery date weeks, months or even years in advance. On the eponymous day-ahead market, electricity is traded for delivery the next day. The day-ahead market is a publicly traded market, publishing the hourly electricity price for each day. It is shown that this leads to price convergence between the futures and the spot market, as otherwise arbitrage between markets would appear.

While most electricity, especially by baseload generators, is traded on the long-term markets, the spot market effectively functions as the price benchmark. Here, the increasing share of renewable energy has a depressing effect on the average spot market price, especially during daytime hours due to the increasing share of solar energy. The spot market uses marginal pricing

to establish a merit order of increasingly higher priced generators until demand and production price curves intersect. As most renewable energy generators have zero fuel cost, their short-run marginal cost is low to zero.

The depressing effect on spot pricing caused by renewable energy provides incentive to electricity consumers to procure larger parts of their consumption on the spot market instead of the futures market. This especially holds true if they can adapt their consumption profile to the intermittent behaviour of renewable energy sources, and by doing so optimally capture the periods of low electricity prices while mitigating exposure to periods of high prices.

These evolutions lead to a paradigm shift on how electricity is produced, traded and consumed. Instead of the historical concept of large power plants providing the baseload consumption and dispatchable (peak) plants following the intermittent consumption, we are moving to a system where intermittent renewables provide the bulk load, and dispatchable plants deliver the residual load, which is the load which cannot be covered by renewables. There is therefore an increasing need for flexibility in the power system.

"Flexibility" in this dissertation is defined as the "large-scale reduction or increase in both consumption or production of electricity over extended periods of time, or shifting of it over one or more days". It is thus distinguished from "technical flexibility", which is mainly used for short-term stability of the power grid, for example through ancillary services, and from "seasonal storage", which is the large-scale, long-term storage of energy.

The transition described above presents multiple challenges. With the current infrastructure and installed power base, delivering this residual load largely falls to fossil-fuel fired power plants such as Closed or Open Cycle Gas Turbines (CCGT, OCGT resp.). While the carbon emissions of these plants fall under the European Emission Trading System and as such offset other emissions elsewhere, it is shown in this dissertation that this does not necessarily hold true. Due to dynamics in the Emission Trading System, it is likely that these emissions will only be partially compensated. To minimise or even avoid fossil-fuel fired power plants, the amount of residual load should therefore be minimised, and the remainder generated by low-carbon emission sources. This requires large amounts of flexibility in both the generation and consumption profiles of electricity.

It is investigated if nuclear plants can contribute to this flexibility from the generation side. Contrary to popular belief, nuclear power plants are not incapable of flexible operation. On certain metrics such as ramp rate they even fare better than other thermal plants conventionally dispatched to provide flexibility, including CCGT and OCGT.

However, when assessing their economical aspects, it is shown that flexible generation impacts the financial baseline of nuclear power plants and decreases or even negates their profitability. Nuclear generation is characterised by its large fixed cost, often taking up to 75% or more of the total electricity production cost, independent of the amount of electricity produced. Lowering the output of a nuclear power plant therefore increases the relative cost of a unit of produced electricity.

Furthermore, due to the depressing effect of renewables on spot pricing, nuclear power plants are at risk of increasing their exposure to the spot market because customers engaged in long term contracts are incentivised to procure (part of) their consumption on the spot market. This increases the uncertainty of future profitability and leads to opportunity costs to nuclear power plant operators and investors, incentivising them to rather redirect capital and human resources to other forms of generation offering a lower risk and better outlook on profitability.

This analysis is also performed for Small Modular Reactors (SMR), a new and upcoming method of generating nuclear power. SMRs intend to lower the overnight capital cost of nuclear energy by building smaller reactors, with most of the components standardised and built in a factory, then transported and assembled on the building site. It is shown that, although building smaller leads to negative scale effects, increasing the cost per unit of energy produced, learning effects by building more could lead to cost savings. However, because SMRs share the same cost-structure as conventional nuclear plants, it can be expected that they too suffer from uncertain outlook on future profitability.

Another supply-side flexibility option assessed are hydrogen fuelled thermal power plants, e.g. by retrofitting existing natural gas fired plants. This has the benefit of retaining the high degree of flexibility and the OPEX driven cost-structure of CCGT and especially OCGT, while avoiding the carbon emissions of using natural gas as a fuel. An analysis of literature and interviews with the industry shows that retrofitting existing natural gas fired power plants is a valid technological option, especially on recent and future installations. These tend to be built “hydrogen ready”, meaning they can fire up to 30%

hydrogen by volume with only minor changes needed, and up to 50% with more significant modifications. The CAPEX required for these changes is limited, around 1-2% and 2,4-3,6% of the CAPEX for a new gas fired power plant, respectively. Full hydrogen conversion is technically also possible, requiring more extensive modifications to the plant. However, even taking the need for the addition of catalytic reduction of nitrogen oxides into account, the required investments are estimated to be less than 10% of the overnight cost of a new plant.

While retrofitting natural gas fired power plants to combust sustainable fuels like hydrogen seems an attractive option considering both technology and investment, it does rely on the availability of sustainable hydrogen and methods to store and transport it to the power plant. While there are several possible pathways, the high energy requirements of producing sustainable hydrogen and the low volumetric energy density present several challenges, making it unlikely to be used as a main energy source for large-scale electricity generation. However, it does show potential as a reserve fuel, intended to be used in (retrofitted) O/CCGTs to provide back-up power during periods of low renewable energy production.

It is also investigated if electrolytic hydrogen production can be used to provide flexibility from the consumer side. Most electrolyzers have a wide dynamic power range, making it possible to modulate their output following the intermittent production of renewable energy. As there is a growing need for low-carbon hydrogen, not only as an energy carrier but most importantly as a sustainable feedstock for chemical and steelmaking industries, flexible electrolytic hydrogen production looks like a promising fit.

It is however shown that electrolytic hydrogen production is not suitable for large scale flexibility, for both technical and economical reasons. Wear and tear of most types of electrolyzers stays constant, independent of load factor. Additionally, if the average load factor decreases, the capacity of the electrolyser must increase to keep production volumes constant. This leads to increased CAPEX requirements, negatively impacting the hydrogen production cost. In a typical European setting it is expected that electrolyzers must reach high load factors, often more than 6000 equivalent full load hours per year, to produce hydrogen at competitive cost. It can therefore be concluded that hydrogen production is more a baseload process than it is a flexible one.

Another upcoming form of flexibility on the consumer side is so called residential flexibility, a term encompassing Demand Side Management

(DSM) and Demand Side Response (DSR) with residential assets such as Heat Pumps (HP) and Electric Vehicles (EV). Up until now, DSM and DSR have been largely the exclusive domain of large industrial electricity consumers. However, with the increasing electrification of heating and passenger transport, the role of this residential flexibility will also expand to DSM and DSR.

This dissertation proposes augmented definitions of flexibility to be used in residential applications. The concepts of implicit and explicit flexibility, as applied in large-scale industrial flexibility, are less apparent when used with residential flexibility. The technological value chain is more complex there, often with several actors involved and with less straightforward revenue generating processes. It is therefore proposed to augment these definitions by the decoupling of the technical aspects of where the signals controlling the residential assets are generated from the rationale why and how the signals were generated is proposed and which party the flexibility activation directly benefits.

For implicit flexibility, this then implies the optimisation goal is to reduce the total electricity consumption cost directly, e.g. by shifting consumption to hours of lower electricity price. This optimisation can be automated and/or done remotely, with only the control signals being sent to the participating assets of the household, as long as the participants have a straightforward method to (temporarily) opt out of the optimisation and can do this unlimited times.

For explicit flexibility, the optimisation goal is to generate revenue with a service provided externally to the participating households, e.g. ancillary services, with this revenue being distributed ex-post. This optimisation is done remotely, with signals sent to the participating assets of the household, and opt-out conditions are defined in an agreement between the participating household and the flexibility service provider.

It is also proposed to add a third form of flexibility, (semi-)passive flexibility. This is a form of residential flexibility which requires no, or only singular, interaction with the end-user. It is a passive optimisation which has the benefit of being uncomplicated to setup, but is not guaranteed to always have the best effect as the optimisation does not take actual (measured) parameters into account. An example is setting the heating of the domestic hot water tank to occur during noon, because wholesale electricity prices generally tend to be lowest during noon, or because this generally coincides with the peak production of installed solar PV.

Another form of this semi-passive flexibility is installing solar PV panels in a specific orientation, so it more aligns with the typical daily electricity consumption behaviour, which starts in the morning and peaks in the evening. A typical south-facing array of PV panels has a peak output during the noon and has often dropped already to zero in the evening. It is investigated if splitting the panels over two different orientated arrays, e.g. one east and one west, better aligns this production profile.

To this end, a methodology for calculating the yield and production curve of arbitrarily oriented PV systems based on a limited number of required parameters and using an anisotropic-all-sky model better suited for Western-European conditions than the prevalent isotropic model is presented, and simulations based on real residential load profiles and grid parameters are used to provide a realistic and accurate validation of this assumption.

It is shown that, by splitting a unitary array of PV panels in two different orientations, the injection peak at noon can be “flattened” out. However, there is just a minor effect on the start and end of energy production in the morning and evening respectively, only somewhat noticeable during winter months. While the split orientation can lower the injection peak, it also lowers the total yield of the PV panels, possibly leading to a suboptimal solution.

Implicit and explicit residential flexibility show a larger potential for aligning energy consumption with production, optimally capturing periods of low prices. Residential flexibility, however, has a number of specific challenges that have so far remained unresolved. Given the limited impact of individual residential electric consumers, large numbers need to be aggregated. Compared to industrial applications, this increases the up-front installation cost and management complexity, while the yield margin per individual installation is very small. With residential flexibility, this however remains very problematic, as there is a wide diversity in both types and brands of assets, and levels and methods to control their power consumption. This implies that flexibility providers often must rely on bespoke control methods depending on the type of asset and brand, hindering any form of profitable business case.

This dissertation shows that the only clear path to tackling this issue is by increased interoperability and digital communication through Application Programming Interfaces (API). These are automated interfaces using a described protocol and running over existing physical interfaces, e.g., Ethernet or WiFi. To increase adoption, neither the protocol nor the interface

itself needs to be uniformly standardised, but their layout and data model should be open and documented to increase interoperability. This means that it becomes possible for manufacturers of, e.g., heat pumps or electric vehicles to implement methods of allowing their devices to talk to other devices from other manufacturers, and even to support already existing devices in retrofit applications.

Finally, the need for clear price signals for residential assets is discussed. The electricity price on wholesale markets is a signal carrying information about the availability of production and the need for more consumption. This information needs to optimally flow to residential consumers to be able to make their electricity consumption flexible.

This pricing signal must also reach owners of residential solar PV installations. Renewable energy generators suffer from low wholesale prices in a phenomenon called price cannibalisation, where the increasing influx of low-cost renewable energy leads to declining capture rate of high market prices. In Belgium, this is in part driven by the large amount of residential solar PV installations unaware of wholesale electricity pricing and thus the volume of generation requested by consumers. Because these installations are unaware of the wholesale electricity price and cannot be controlled by e.g. electricity suppliers or network operators, they have an increasingly large impact on both the energy market and the stability of the electricity system. Going forward, these installations will need to be made aware of market and grid conditions in order to prevent destruction of social welfare and an increase of grid costs.

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List of acronyms

API	Application Programming Interface
BACS	Building Automation Control System
BR1	Belgian Reactor 1
BWR	Boiling Water Reactor
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CEN	Comité Européen de Normalisation
CENELEC	Comité Européen de Normalisation Electrotechnique
CF	Capacity Factor
CP-1	Chicago Pile 1
CP-4	Chicago Pile 4
DER	Distributed Energy Resource
DLE	Dry Low Emissions
DSM	Demand Side Management
DSR	Demand Side Response
EDF	Electricité De France
EV	Electric Vehicle
FBR	Fast Breeder Reactor
FOAK	First Of A Kind
GM	Generale Maatschappij
GRC	Gas Cooled Reactor
GW	Gigawatt
HBES	Home Building Electricity System

HEMS	Home Energy Management System
HP	Heat Pump
HTGR	High Temperature Gas-cooled Reactor
HTR	High Temperature Reactor
IAEA	International Atomic Energy Agency
INES	International Nuclear Event Scale
IoT	Internet of Things
IPP	Independent Power Producers
LCOE	Levelised Cost Of Energy
LNG	Liquified Natural Gas
LTO	Long Term Operation
LWR	Light Water Reactor
MPPT	Maximum Power Point Tracking
MSR	Molten Salt Reactor
MW	Megawatt
NECP	National Energy and Climate Plan
NPP	Nuclear Power Plant
O&M	Operations & Maintenance
OCGT	Open Cycle Gas Turbine
OPEX	Operational Expenditure
OTC	Over The Counter
PCI	Pellet Cladding Interaction
PV	Photovoltaic
PURPA	Public Utility Regulatory Policies Act
PWR	Pressurised Water Reactor

SAREF	Smart Applications REference
SCC	Stress Corrosion Cracking
SCR	Selective Catalytic Reduction
SFR	Sodium Fast Reactor
SMR	Small Modular Reactor
SOE	Solid-Oxide Electrolysis
TYNDP	Ten Year Network Development Plan
UNGG	Uranium Naturel Graphite Gaz
WACC	Weighted Average Cost of Capital
WENRA	Western European Nuclear Regulators' Association
WLE	Wet Low Emission

1 Introduction

1.1 Context of this research

Over the past five decades, the world has experienced an extraordinary increase in energy consumption. Yearly primary energy¹ consumption has risen more than fivefold, from around 30.000 TWh in 1950 to 159.000 TWh in 2022.

The rise of energy consumption is closely tied to industrialisation and the increasing global welfare of people. Industrialisation transforms economies from primarily agricultural-based to manufacturing-based, requiring more energy to power factories, machines, and transportation systems. As countries industrialise, they also become wealthier, leading to higher levels of energy consumption as people can afford more appliances, electronic devices, and transportation.

Fossil fuels, such as coal, oil, and gas, have been the primary energy source powering this (r)evolution, accounting for approximately 84% of global primary energy consumption in 2022. Fossil fuels are however a source of greenhouse gas emissions and the major contributor to their rising net-surplus in the atmosphere, the main driver behind climate change. Burning fossil fuels releases carbon dioxide and other greenhouse gases into the atmosphere, trapping heat and leading to a warming planet. Fossil fuel combustion also releases other pollutants, such as sulphur dioxide and nitrogen oxides, which can lead to respiratory problems, heart disease, and other health issues. Furthermore, they are finite resources, and their extraction and processing can have significant environmental impacts, including habitat destruction and water pollution.

To address these challenges, many countries have or are adopting stringent climate, environmental and energy policies. The European Union has pledged to become net-zero by 2050, meaning all energy use must come from low-carbon sources and any residual emissions of greenhouse gasses must be abated. This pledge is based on a bifurcated approach. Firstly, increasing the electrification of final energy use reduces the reliance on fossil fuels and associated emissions of greenhouse gasses and other pollutants. This has a

¹ The energy contained in raw, unprocessed fuels such as coal, oil but also wind or solar irradiation.

significant impact on sectors relying primarily on fossil fuels, such as (residential) heating and transportation. Many industrial processes using fossil fuels as the primary energy source will have to become electrified as well.

This electrification of households, transportation and industrial processes will drastically lower the consumption of (primary) energy, as most of the electric equivalents to fossil-fuelled processes or technologies have significant higher energetic efficiency. E.g. where a petrol-powered engine only converts around 23% of the energy contained in the fuel to useful motive power, an electric motor converts more than 93% of the electricity into motion. Likewise, where a gas-fired boiler converts around 98% of the natural gas input to useful heat, heat pumps convert up to 4 times their electrical input into heat by extracting additional energy from the environment. In general, up to two thirds of the worldwide consumed primary energy is converted into waste heat, which is discarded into the atmosphere.

While electrification will lead to a decrease of total primary energy consumption, there will be a sharp increase in the consumption of electricity as processes and energy consumption shift from fossil fuels to electricity. To reach its 2050 goals, Europe will need to double or even triple its current production of electricity, *while also* producing it entirely from low-carbon sources.

The second measure policy makers are therefore implementing is promoting and expanding low-carbon electricity production such as nuclear power or renewable energy. During the last two decades, renewable energy has become very cost-effective and accessible, and its use has grown significantly. According to the IEA, in 2021 renewable energy held a share of 14% of global primary energy, and 30% of global electricity production.

This shift is even more pronounced in Europe. In 2022, renewable energy (including hydro and biomass) accounted for 38% of electricity generation in the 27 countries making up the European Union (EU-27), a three-fold increase since 2003. Most of this growth is attributed to solar and wind energy. Combined, these two sources provided 623 TWh, or more than 22% of the yearly electricity production. In 2002, they provided barely 2%.

While yearly wind and solar output in the EU-27 already surpassed the electricity generation of coal-fired power plants (447 TWh) in 2019, as of 2022 they also outproduce the gas-fired power plants (557 TWh) and nuclear

generation (613 TWh). With the current market outlook, electricity production from solar and wind energy are on a path to double or even triple by 2030.

This evolution puts significant strain on the current organisation of the European electricity system. Specifically, there is a growing need for large-scale flexibility in the system, to balance both increasingly intermittent power production and increasingly “peaky” power consumption. The analysis of these challenges, potential solutions and an outlook on the future of the system are the subject of this doctoral dissertation. The main research question can be formulated as: “what are potential sources of flexibility in the (Belgian) electrical energy system?”

1.2 Research question

Consider the illustrative representation of the typical daily total load profile of the Belgian electricity system in Figure 1, subfigure (a). This profile can be divided into three distinct segments:

- a nighttime segment with low and generally stable load,
- a daytime segment with load ramping up in the morning and stabilising during the day,
- an evening segment marked with a high peak load, before settling back to the nighttime segment.

While Figure 1, for stylistic reasons, has unitless axes, in 2023 the typical peak load on the Belgian electricity system during the evening segment is around 12GW, with nighttime load being 6GW and daytime load in between, depending on the season.

This typical load curve used to be supplied by a stack of power generation plants of diverse technologies. Nuclear, but in earlier times also coal-fired plants, provided the *baseload*, the amount of power that, at any given time, was consumed by the system. These types of plants were therefore called baseload generators or baseload plants. Belgium used to have 6GW of nuclear generation, for a long period of time coinciding with this ever-present minimum load on the system.

The variable part of the load was provided by several types of fossil-fired plants. The load in the daytime segment, with its predictable ramp-up in the morning, was often provided by Combined Cycle Gas Turbine (CCGT) plants, combining a natural gas fuelled turbine with a steam turbine to achieve

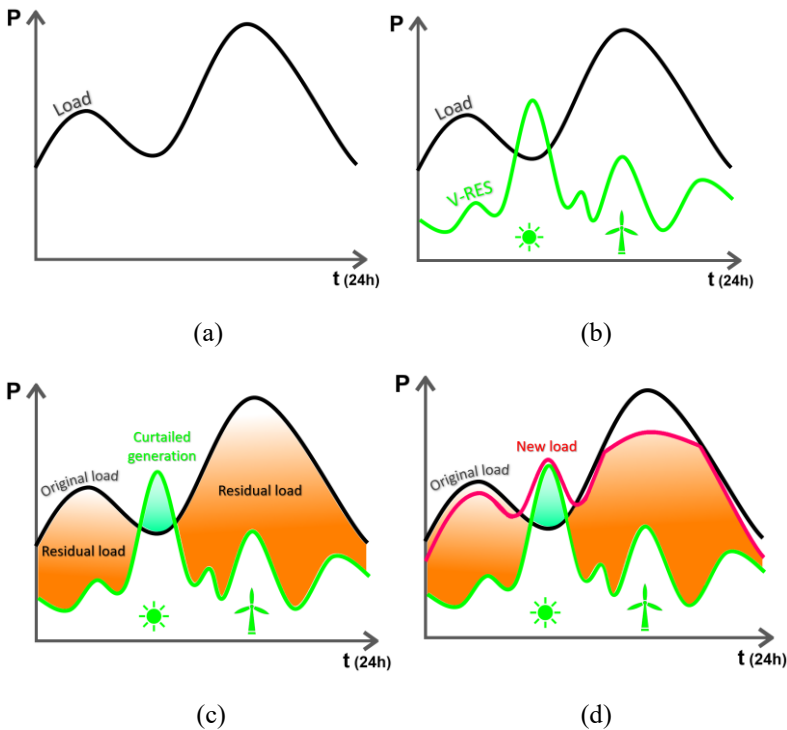


Figure 1: Stylised representation of daily load on the Belgian electricity system (a), superimposed with an illustrative generation profile of intermittent renewable energy (b), indicating the residual load and generation which needs to be curtailed (c) and finally a potential new load profile reducing both residual load and curtailment peaks.

greater efficiency, albeit at lower ramp times. The evening peak was often provided by Open Cycle Gas Turbines (OCGT), being able to rapidly respond to peak loads and having the ability to start and stop quite fast.

As of the turn of the 21st century, renewable energy generation started to come into play as well. At first, they were regarded as “fuel savers”, as during times of high wind speeds and/or solar irradiance, they could substitute a part of the flexible power generation, allowing fossil-fired power plants to burn less fuel.

With the industrial scale-up of modern renewable energy, its cost has however fallen drastically. Wind energy has seen a cost decrease of more than 50%, prices for solar generation have even been slashed by ten. Accordingly, their share in the total load generation has increased

significantly, from close to zero at the turn of the century to more than 20% in 2022. Given current policies and economic trends, this share will most likely triple by 2030.

This large influx of low-cost, intermittent renewable energy, depicted in Figure 1, subfigure (b), has eroded the conventional model of baseload. Instead, we are entering a new paradigm, the one of *residual* load. In this new model, renewable energy provides the *bulk* of the power generated, albeit through a non-dispatchable generation profile which does not necessarily match the load profile. The gaps left between the bulk power and the total load are the residual load, which must be covered by other, dispatchable power generators as shown in Figure 1, subfigure (c).

The rapid increase in renewable power generation has given rise to an increasing mismatch between power generation and consumption. With conventional technology, the most straightforward way to reliably provide the residual load and mitigate this mismatch is through fossil-fired power plants, mainly CCGT and OCGT. However, given the issue of climate change, this is far from an ideal solution and can only be accepted as a temporary stopgap solution.

Going forward, new and innovative ways to keep the European electrical system in balance in a climate-friendly way will have to be developed and deployed. This will entail a large amount of flexibility in the consumption of electricity, both on an industrial and residential scale. By shifting consumption away from periods of high peak demand, and towards periods of high renewable energy generation, a new load profile can be constructed which reduces the mismatch between production and consumption (Figure 1, subfigure (d)).

Exploring possible ways to provide this large-scale flexibility is the core research question of this dissertation. In this context, “flexibility” means the shifting or the increase/reduction of large amounts of electrical energy consumption or production (hundreds of MWs to GWs) for extended periods of time (minutes to hours). This is in contrast to “technical” flexibility, which mostly entails short-term (seconds to minutes) variations in power consumption meant to provide supporting services to the grid, e.g. to maintain or restore grid frequency to its nominal setpoint. Because of the different scales of both time and energy, the challenges of providing the flexibility required to change the load curve can be expected to be of a different magnitude.

1.3 Approach

There are many technological solutions with the potential to mitigate the issue of generation-consumption mismatch, as outlined in section 1.2 Research question, through flexibility. In this dissertation, a selection of technologies was made based on their applicability in Belgium and an identified research gap. This resulted in three broad types of technologies which were reviewed for their ability to provide large-scale flexibility:

- *Nuclear power*, selected because of its established presence and industrial history in Belgium, and the existing availability of nuclear generation assets. Furthermore, the flexibility potential of nuclear generation is often not investigated in studies of the future Belgian electricity system, e.g. the Elia Adequacy & Flexibility studies. [1]
- *Hydrogen*, both its electrolytic *production* and its use as a zero-carbon fuel for *flexible power plants*. There is a sizeable consumption of hydrogen in Belgium, mainly as a feedstock for its large chemical industry, and this is expected to increase, e.g. the production of so-called green steel. In the future, the production of this hydrogen will have to become low carbon, with electrolytic production currently being the most feasible way. It is therefore worthwhile to investigate if this production can be made flexible. Additionally, there are many existing natural gas fired power plants in Belgium, currently providing the bulk of large-scale flexibility to the power system. Hydrogen is considered a potential zero-carbon fuel for this type of assets. Investigating the future reuse of these assets could yield valuable insights.
- *Residential flexibility*, both in the production of electricity with rooftop solar PV installations and in the consumption of electricity by residential customers. Due to the ongoing electrification of building heating and road transport, the electricity consumption of households is expected to increase significantly. Correspondingly, the uptake of heat pumps and electric vehicles, arguably the most evident technologies to address these challenges, has a large potential for flexibility. The investigation into this type of flexibility is a developing but promising field of research.

Not all technologies could be withheld. E.g. increasing the electrical interconnection between member states of the European Union holds the potential to level out big parts of the intermittency of renewable energy production, by connecting large-scale solar energy production in the south of

Europe with wind power around the North Sea and large hydroelectric reservoirs in central and northern Europe. However, this research trail is already significantly explored in existing literature and studies, and implementation of this potential is, to an extent, already being realised. [1]

The same is arguably true for the use of utility-scale batteries, which can introduce a tremendous amount of short-term flexibility to the system. But with a power capacity of 5 to 8 GW of large-scale batteries, as of 2024, being planned in Belgium to provide this flexibility, this potential is already established.

The rest of this dissertation is structured as follows. In order to investigate potential future evolutions of the electrical energy system, it is worthwhile to consider its historical context. Exploring how this system was conceived and how it evolved over the years provides valuable insight into the drivers and barriers of future changes. In the first chapters of this dissertation, the historical construction and operation of the electrical power system is explored, focussing on the Europe and Belgium.

Historically, the electrical energy system in these regions was based on large, centralised power plants producing a continuous amount of baseload power, with flexible fossil-fired plants and hydropower taking care of the daily load variations. In Belgium and France, noticeably, these baseload plants are or were nuclear power plants. In fact, their electrical system co-evolved with nuclear technology, with both countries showing a remarkably intertwined history which is still reflected in the current electrical energy system. The first chapter investigates how nuclear power production developed historically, how it influenced the organisation of the electrical energy system and why it floundered after a period of intense growth.

In line with the research question, it is then analysed how nuclear plants, existing or new build, can be used to provide flexibility to the electrical system. While often conceived as purely baseload generators, many nuclear reactors exhibit a large technical potential for flexible operation. The technical specifics of several technologies are explored and compared.

While the potential for flexibility is there, nuclear power plants almost always run as a baseload generator, save for a few reactors operating in very specific circumstances (mainly France). It is investigated what barriers there are for flexible operation, and if these can be overcome.

Next to conventional nuclear power plants, the flexibility potential of small modular reactors is investigated as well. Small modular reactors are a new

and upcoming technology for nuclear energy production, comprising smaller size reactors based on conventional or innovative nuclear concepts. They intend to complement or replace large, conventional reactors, and offer the potential to truly unlock nuclear flexibility. In this dissertation, these aspects are assessed in the same techno-economic manner as used for the conventional reactors previously.

Besides from the generators' side, electrical flexibility can also be provided from the consumers' side. In the next chapters, it is investigated if and how this flexibility can contribute to the electrical system.

While a lot of research on industrial flexibility has already been performed, the state of the art mostly focuses on technical flexibility, e.g. to provide support for maintaining grid frequency. The research question of this dissertation entails energy flexibility, e.g. being able to shift consumption over time, and requires a different approach, focusing on types of energy consumption exhibiting potential for energy and power flexibility.

Concerning industrial flexibility, the case of electrolytic hydrogen production is singled out. Hydrogen is an important feedstock for the chemical industry and can be used as an energy carrier as well. Up until now, almost all hydrogen production is derived from fossil fuel. Decarbonising this process is possible through electrolytic production of hydrogen, producing the chemical element from water and electricity. This is however a very energy-intensive process, but also provides opportunities for flexibility.

Next to industrial flexibility, there is also a large and growing reservoir of residential flexibility. During the energy crisis year of 2022, household electricity consumption was down more than 12% than average. This shows the significant *technical* potential of demand side flexibility among residential consumers. With the increasing electrification of building heating and passenger transport, the role of this residential flexibility will increase significantly, and should arguably do so without impacting user comfort. Distributed, residential flexibility, however, has a number of specific challenges that have so far remained unresolved. Given the limited impact of individual residential electric consumers, large numbers need to be aggregated. Compared to industrial applications, this increases the up-front installation cost and management complexity, while the yield margin per individual installation is very small. This dissertation investigates these technical barriers and proposes potential solutions.

Our electrical energy system is not only governed by the laws of Kirchoff, but also by complex economic and regulatory processes. The wholesale power market determines which power generators get dispatched when and for how long. The revenues generated on this market dictate the long-term investments made in power generation assets. This economic model, as well, dates from the time before renewable energy was introduced into the electrical system. And just like the technical organisation of this system, the economic model as well is changing in response to the wider energy transition.

Our wholesale electricity markets are structured around the concept that a low price signals large availability of (cheap) energy and thus encourages its consumption. Contrary, a high price signal signals scarcity and stimulates conserving power. By enacting on this price signal, social welfare is optimised. Wholesale electricity prices already incorporate a lot of information, e.g. weather predictions or expected fuel prices. This makes it an elegant, transparent signal that is easy for consumers (or their automated assets) to understand and act on. However, this price signal does not yet reach the end-consumer enough, especially to enable residential flexibility. The various challenges of the current market design are discussed, and some concrete recommendations are made of a technological, economic and regulatory nature, and updated in the light of the recent European energy crisis of 2022. We also take a look at the European Emission Trading System as driver for the energy transition and the transition towards flexibility.

In a final chapter, we summarise conclusions from each part of this dissertation and formulate recommendations for the issues identified.

1.4 Innovative aspects

The energy landscape is changing ever faster, driven by technological disruption, economic shifts and the increasing impact of climate change. This holds especially true for Belgium, an industrial and infrastructural hotspot in the middle of Western-Europe.

This dissertation explores possible future avenues for making the Belgian electricity system more flexible in a robust way and does so from a techno-economic perspective, taking both historic elements and recent developments into account. To the authors knowledge, this presents a unique exercise, at least in recent literature.

This dissertation contains specific elements raising the current state of the art of literature. Section 2.14 *Conclusion: nuclear power as baseload generation* contains a comprehensive analysis of 704 nuclear reactor construction projects worldwide, in order to identify the potential construction cost and time of new nuclear reactors. In section 3.2 *Small Modular Reactors*, the potential deployment of these innovative methods of nuclear energy generation are investigated from a techno-economical viewpoint. In section 4.2 *Hydrogen power plants*, state-of-the-art insight from manufacturers and technology providers were used to assess the viability of hydrogen-fired power plants to provide flexible zero-emission power.

A large part of this dissertation revolves around the residential electricity consumer as a source of flexibility. This is a very innovative field of research which is still in its infancy but developing strongly. With the rising uptake of electric vehicles, heat pumps, home batteries and building further upon the already established technology of solar photovoltaic, new scientific insights but also technological innovations and market developments seem to pop up almost daily. This dissertation increases the state of the art on several levels. First, the technical insights of three projects which I authored or co-authored the proposal and helped implement in practice, all involving residential flexibility, has been incorporated in this dissertation text. These projects were the “REScoopVPP” project, which received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No 893240 “REScoopVPP” (Smart Building Ecosystem for Energy Communities) and which explored methods to enable residential flexibility from a community standpoint, and the “FlexSys” and “InterFlex” projects, funded by the Energy Transition Fund (ETF) of the Belgian federal government, managed by the FPS Economy, SMEs, Self-employed and Energy, which investigated the use of heat pumps, electric vehicles and home batteries to provide electrical flexibility to the grid.

Electrical flexibility has already been demonstrated on an industrial scale. However, these concepts do not translate one-to-one onto residential flexibility, which has a vastly different and more complex value chain and its specific set of hurdles and barriers which need to be addressed. In section 5.1 *Types of flexibility*, this dissertation proposes new definitions for concepts from industrial flexibility, but tailored towards their application on residential assets.

A more theoretical, yet practical applicable innovation is described in section 5.2 *Impact of solar panel orientation on production profile*, where an improved simulation model of a solar panel installation is described and applied to simulate the impact on a residential distribution grid. An adapted version of an anisotropic-all-sky model is proposed instead of the more straightforward isotropic model commonly used in literature, raising the quality of solar panel yield simulations for Belgian conditions.

This dissertation is supported by several peer-reviewed publications. In *“Impact of solar panel orientation on the integration of solar energy in low-voltage distribution grids”*, the model described above is developed and demonstrated [2]. In *“Development of a cloud-based renewable energy monitoring platform”* the first setup of distributed residential energy monitoring and control are described [3]. In *“Increasing economic benefits by load-shifting of electrical heat pumps”*, the techno-economic potential of shifting electricity demand from heat pumps by employing (existing) thermal buffers is demonstrated [4]. *“Potential of domestically provided ancillary services to the electrical grid”* provided a first insight into the potential of residential flexibility, several years before the research field reached its current state [5]. Finally, *“Addressing the challenges of a nuclear phase-out with energy synergies on business parks”* and *“Combining high shares of renewable energy with nuclear power generation on the Belgian energy system”* describe the techno-economic challenges and opportunities of combining high shares of renewable energy with nuclear energy production and its impact on the need for flexibility [6] [7].

Insights from this dissertation have also been incorporated in Belgian consolidated legislation. In November 2021, the “Wet houdende fiscale en sociale vergroening van de mobiliteit” art. 13 modified “Titel II, hoofdstuk II, afdeling IV, onderafdeling 3, onderdeel A, van het Wetboek van de inkomstenbelastingen 1992” to add art. 64quater, mandating home charging stations for electric vehicles to possess an open and accessible Application Programming Interface (API) in order for their installation to be tax deductible. This API must allow Home Energy Management Systems (HEMS), third-party service providers or private individuals to receive feedback of the charging process, and to be able to control at least the charging power and charging duration. The text of the legislation has been written into law verbatim, based on the insights of section 5.3 *Flexibility by residential assets*, specifically 5.3.3 *Interoperability*, after federal policy makers inquired about ways to stimulate manufacturers to adapt interoperability in their products, making it easier to control their energy consumption in a flexible manner.

Similarly, the Flemish regional government adopted similar requirements in order for home battery system to be eligible for a subsidy.

2 Nuclear power as baseload electricity generation

2.1 Introduction

For decades, nuclear power was the only large-scale source of low-carbon electricity available next to hydropower, generating up to 25% of global electricity consumption. Even more, it reached this level in the span of less than two decades, creating a small energy transition of its own. However, despite the rapid scale-up and industrial optimism about the technology in the 1960s and 1970s, the share of nuclear power remained fairly constant during the following decades. Even the surging interest in low-carbon power in the 21st century did not rekindle any significant growth of nuclear electricity generation.

Nuclear power defined the electricity system of many countries, especially Belgium and France. Before the advent of nuclear power plants, electricity generation and distribution were a regional or even local affair, with many small-scale, fossil-fuelled power plants being built close to locations with high electricity demands. The construction of nuclear power plants was however an enormous industrial project, transforming the way electricity was generated, consumed and distributed but also shaping how the sector was regulated for the decades to come.

In this chapter, the technical and institutional drivers behind the development of electricity generation by nuclear power are analysed. It is explored why it was able to grow so quickly but also just as quickly to flounder. This is done through a historical analysis of selected nuclear programmes in Europe and the US. All these programmes have strong interlinks to each other, mainly on a technological level, but also show contradictions on an institutional level. The US programme ultimately enjoyed only moderate success, while in Europe, Belgium and France reached one of the world's top shares of nuclear power in the energy mix. Based on the analysis of these programmes, the future challenges and opportunities for nuclear power are discussed, and policy recommendations are formulated.

2.2 Nuclear power: from discovery to application

The discovery and application of sustained energy production by nuclear chain reactions can be traced back to the combined work of different scientists in Europe and the US in the late 1920s and 1930s. The discovery of nuclear fission of uranium by German physicists Otto Hahn and Fritz Strassmann in 1938 was a catalyst, proving previous theories about chain reactions proposed by Hungarian physicist Leo Szilard. The work on applications utilising nuclear chain reactions developed quickly thereafter, spurred on by the potential for military applications during World War II (WWII). Belgium played a pivotal role in these efforts, as it was then in the possession of vast quantities of uranium ore of extremely high quality.

After the war, attention shifted to harnessing nuclear power for civil applications such as power generation. Many countries initiated domestic programs to design and construct nuclear power reactors. Belgium, again, played a prominent role as it had the industry to build a complete nuclear value chain, from uranium ore to electricity transformation and distribution. Although the plan to build Belgian-designed reactors proved too ambitious, the country contributed significant efforts to other nuclear programmes.

The Belgian electricity generation sector has long been dominated by nuclear energy. During the last decade of the former century and the first one of this century, Belgium generated over 60% of its domestic electricity from no less than 7 nuclear reactors. It might seem odd how a tiny nation as Belgium was able to build up a nuclear industry at several levels on par with frontrunners such as France, the United Kingdom or the United States. It was the providence of the former Belgian industrial bloc controlled by the *Generale Maatschappij van België* (GM) (Frans: *Société Générale de Belgique*), recognising the business opportunity in an intricate string of historical events and coincidences, and using it to become a nuclear industrial powerhouse [8].

Even before WWII, Belgium was already heavily industrialised, forming the worldwide centre of the steel industry and related heavy industries. The linchpin in this industrialisation was the GM, a holding company even older than Belgium itself. The GM owned and operated a vertically integrated industrial conglomerate. It was in possession of the business of resource extraction through subsidiaries such as *Union Minière* (now: *Umicore*) and several, now defunct, coal mining companies. It controlled the metallurgical

sector with *Arbed* (now part of *ArcelorMittal*) and *Cockerill*. The produced metals were used by its *Compagnie Générale de Chemins de Fer* (now: *CFE*) and *La Brugeoise et Nivelles* (now part of *Bombardier*) enterprises for railway laying throughout Europe and manufacturing locomotives and other rolling stock respectively. The now partially dismantled *Ateliers de Constructions Électriques de Charleroi* (ACEC) was a leading manufacturer of electrical machines. The GM had a *de facto* monopoly on shipping lines to and trading with Africa and Asia through *Compagnie Maritime Belge* (CMB). At its height in the first half of the 20th century, the GM owned more than 800 Belgian companies and was in control of over 40% of the Belgian economy. The GM was dubbed *a state within a state*, exerting a large influence on political matters as well [9] [10].

At that time, Belgium was in possession of the vast and resource rich colony of Congo. Naturally, the GM had vested interests in this overseas territory as well through local ventures such as *Union Minière du Haut Katanga*. Working for the latter, a British geologist searching for copper discovered a rich radium and uranium ore deposit near the town of Shinkolobwe in 1915. From 1921 and onwards, a mine was established. The uranium ore was of an exceptional quality, containing up to 65% uranium oxide by weight. By comparison, regular ore at the time contained no more than 5% uranium oxide, current commercial deposits yield around 0,5%. Rather surprisingly, uranium had no known industrial uses at the time and the mine was mainly worked for radium, with the uranium ore simply discarded as waste. The ore containing the highest amount of radium was shipped to the Belgian *Union Minière* site of Olen, where it was isolated from the uranium contents. There as well, the uranium contents were of no interest and were simply piled as waste on the Olen site [11] [12].

The discovery of nuclear fission of uranium by German physicists Otto Hahn and Fritz Strassmann in 1938 quickly turned things around. While fission was theorised before, no atomic element was known that demonstrated the ability to undergo fission when bombarded with neutrons, and thus the theory was not accepted. This changed with the discovery Hahn and Strassmann made, and the news quickly spread throughout the scientific community. The discovery saw the previously formulated theory of Hungarian scientist Leó Szilárd about nuclear chain reactions, and the tremendous amount of energy they released, confirmed. Szilárd urged his fellow physicists not to publish on this topic, fearing the misuse of the concept by an increasingly assertive Nazi Germany. Nevertheless, in 1939 a French group of scientists lead by Frédéric Joliot-Curie submitted three

patents describing the practical uses of nuclear chain reactions. One of these documents, called *Perfectionnement aux charges explosives*, is regarded as the very first patent on nuclear weapons [13] [14].

Overnight, the uranium stockpiles of *Union Minière* suddenly became a coveted asset. Already in 1939, Frédéric Joliot-Curie signed an agreement with *Union Minière du Haut Katanga* executive Edgar Sengier to jointly investigate and exploit *all* potential uses of the uranium ore. Unknown to Joliot-Curie however, Sengier already had a secret meeting with the British Government to supply uranium for their clandestine atom bomb project, cryptically called *Tube Alloys*. Yet, both agreements were short-lived. With the onset of WWII in September of the same year, both Joliot-Curie and Sengier fled to New York. Fearing the pending invasion of Belgium by Nazi Germany *Union Minière* undertook the vast task of shipping an unknown quantity of the uranium stockpiles at their Olen factory and half of the stockpiles at Shinkolobwe, totalling over 1.500 tons, to the United States. Only small quantities were delivered to France (Joliot-Curie) and the UK (*Tube Alloys*) [12] [15].

With scientists such as Enrico Fermi, Albert Einstein and the emigrated Leó Szilárd in their ranks, the Americans were already keenly aware of the dreadful military applications of a uranium-based nuclear chain reaction. Szilárd appealed the Belgian ambassador in New York to draft a letter to then U.S. President Franklin D. Roosevelt, warning about the ramifications should Nazi Germany be able to unlock the power of the nuclear chain reaction. This prompted the president to establish the *Advisory Committee on Uranium* to evaluate the potential threat of nuclear weapons and to draft a plan of action for the United States. The committee acknowledged that, while still only a theory, “an atomic bomb would possess a destructive capability far greater than anything mankind had ever witnessed.” It advised the president to acquire 46 tonnes of uranium oxide and 4 tonnes of graphite so US scientists could validate the theory in secrecy. This was the start of what, as of 2020, is still the second most complex and expensive experiment in the human history: the *Manhattan project*² [16] [17].

Unlike the French and the British, the Americans were initially not aware of the Belgian access to high-quality uranium oxide. It was only when the

² As of 2020, the Manhattan project shares the second place with the experimental ITER fusion reactor, both coming in at a cost of around €25 billion (adjusted for inflation). Only the International Space Station topples this number with an estimated cost of €150 billion.

Manhattan project came under steam that the Americans quickly ran out of a domestic uranium supply. The US military sent out aides to solicit mining companies to procure uranium ore. When one of these aides met with expatriated *Union Minière* director Sengier in his New York office to discreetly ask him about the possibility of mining uranium ore, the Belgian industrialist famously leaned back in his chair and answered: “You can have the ore now. It is in New York, a thousand tons of it. I was waiting for your visit.” [12]

The Manhattan project, and in some degree the British *Tube Alloys* counterpart, kick started the development of nuclear technology in the US and UK. After the war, attention shifted from destructive applications to harnessing the power of the atom. A sprawling nuclear research field required ever more uranium, so *Union Minière* and the Belgian government were solicited for the remaining 3.000 tonnes of uranium ore in the Shinkolobwe mine. A memorandum between the three countries was signed, promising Belgium priority access to civil nuclear developments in return for the mining rights [18].

2.3 From military to civil applications

One of the many parts of the Manhattan project was the assembly of the very first artificial nuclear reactor. This was called the Chicago Pile-1 (CP-1), because it was just that: a huge pile of graphite blocks stacked under the viewing stands of the Stagg Field football stadium in Chicago, as the facilities of the Metallurgical Laboratory at the University of Chicago were too small to house it. Built by hastily recruited high-school dropouts under the supervision of Fermi and Szilárd, CP-1 consisted of a cubic assembly of alternatively stacked graphite and uranium blocks, encased within a graphite outer layer. The reactor had no cooling systems nor radiation shielding, as it was meant to operate at very low power levels [13] [19] [20].

By stacking uranium very dense, the neutrons uranium naturally emits are absorbed by the surrounding uranium. If a neutron hits the nucleus of a uranium atom, this atom can undergo nuclear fission, leading to the release of even more neutrons and thermal energy. These released neutrons could then force other uranium atoms to undergo fission themselves. If done correctly, this would lead to the sustained nuclear chain reaction the physicists sought to demonstrate. The pile had a neutron counter inside, so the increase of neutron activity could be measured. This neutron counter was

also wired to an emergency system, which would rapidly drop control rods back into the reactor if the chain reaction went out of control [21].

Because they used unenriched natural uranium, no less than 41 tonnes of uranium oxide and 5 tonnes of uranium metal were required. Holes were drilled in the graphite blocks through which control rods, which could absorb neutrons without undergoing fission themselves and thus control the rate, could be inserted. The pile was assembled between 16 November and the 1st of December of 1942.

The next morning, Fermi, Szilárd and their colleagues gathered to witness the first demonstration of a sustained nuclear chain reaction. At 09:54, the experiment began with the controlled removal of the first control rod. Very slowly, other control rods were removed as well. About one-and-a-half hours later, the safety control rods automatically reinserted themselves due to the trip level of the neutron detector being set too low, thereby resetting the experiment. Fermi ordered CP-1 to be secured, as he announced it was lunch time [20].

Work resumed from the start at 14:00. At 15:25, based on the readings of neutron activity, Fermi declared the CP-1 to have achieved *criticality*, demonstrating the world's first artificially induced sustained nuclear chain reaction. The reactor ran for several minutes, reaching a peak thermal power of 0.5W, before safety systems again kicked in and the reactor was shut down [21].

While the goal of CP-1 was to demonstrate the nuclear chain reaction required to build atomic weapons, harvesting the emitted thermal energy for peaceful, civilian applications was always in the back of many nuclear physicist's mind at the time. During and after the war, several other prototype reactors were built. The Chicago Pile-4 (CP-4), while of a totally different design than CP-1 and not even built in Chicago, Illinois but in Arco, Idaho, was the first nuclear reactor to have its thermal energy harvested for electrical generation. At 13:50 on December 20, 1951, CP-4 powered four 200-Watt light bulbs, becoming the first reactor to produce electricity. This was achieved by connecting a heat exchanger to the cooling mechanism of the reactor, turning water into steam, which then powered a steam turbine with a small electrical generator attached. This became a staple for almost all other electricity producing reactors afterwards [22].

While CP-4, later renamed Experimental Breeder Reactor I, was not intended for energy production, it demonstrated the feasibility of nuclear-powered

electricity generation. The reactor was eventually able to generate 200kW of electrical power from 1.4MW of thermal energy, before suffering a partial melt-down in 1955 [22] [23].

The year following the CP-4 powered light bulbs, work began on the BORAX series of test reactors. While the BORAX-I and BORAX-II reactors were literally built to blow themselves up, to quite literally test the fall-out of a destructive reactor incident, BORAX-III was built purposefully to generate electricity. It was also the first grid-connected reactor, providing up to 2MW of electrical power to the city of Arco [24].

Parallel with these civilian research projects, the United States Navy was building their own reactor prototypes to prove that nuclear power could be used for propulsion and electricity generation on military vessels, particularly submarines. In contrast to the more straightforward Boiling Water Reactor (BWR) design of the BORAX, the Navy, together with the Westinghouse manufacturing company, worked on the compact but more complex Pressurised Water Reactor (PWR). The PWR design was later adapted for civilian use by Westinghouse, while industry competitor General Electric commercialised the BWR [22].

2.4 European developments

While the civilian nuclear developments in the immediate post-WWII period were concentrated in the US, several other countries started domestic programmes as well. For example, the (eventual) French program of building pressurised water reactors for nuclear electricity generation is arguably the world's most successful example of the scale-up of nuclear power, both in speed and cost of deployment.

While already at the end of the 1970s most nuclear construction programs worldwide were faltering, there was one nation that soldiered on undeterred. Between 1970 and 2000, France brought 60 reactors online, averaging one reactor every 6 months. Furthermore, these reactors were built mostly on-time and within budget, eventually generating 80% of the French electricity production at a cost competitive to other technologies. The French deployment of nuclear power reactors is arguably the most successful nuclear scale-up in the industrialised world [25] [26].

For a time however, the outlook of the French nuclear program looked quite bleak. The initial attempt at a civil nuclear program were marred by financial troubles, political turmoil, institutional clashes and safety issues. These

turbulent times lasted from the start of the French nuclear program in 1946 all the way to 1968, when large-scale civil unrest led to a political turning point in the history of the Fifth Republic. This makes it even more fascinating how the French were able to kick-start their impressive nuclear scale-up just 2 years later [27].

This section performs a critical evaluation of the French nuclear program, analysing how the country was able to implement a successful nuclear scale-up and what aspects are relevant in today's radically changed and fast-moving energy landscape. This requires a comprehensive investigation of the technical, social and political background of the French nuclear program. We explore how standardisation, series-building and wide-scale political and governmental support alone were not enough to enable the programs' success, as the preceding French designed graphite-moderated reactor also enjoyed these benefits but failed on an industrial scale.

Instead, the success hinged on the very limited number of actors involved. The government and the public were merely bystanders of what essentially was a technocratic decision-making process controlled solely by the involved nuclear parties. This severely simplified virtually all aspects of the construction program. As France had only a single, nationalised electrical utility company, EDF, this single-buyer situation allowed EDF to dictate the terms of sale to the supplier. Its giant corps of skilled engineers and technical managers enabled EDF to take full control of the construction process, implementing rigorous cost control and efficiency gains. As the sole electrical utility in France, EDF had the market power to set the electricity price in a way which always guaranteed the profitability of the nuclear program, eliminating any risk premium on the investment. Safety regulation was drafted by the parties involved in the nuclear construction process and tailored to the ongoing developments [28].

Even with these institutional benefits however, the French nuclear program began to slow down during the 1980s. Realising the projected growth in electricity consumption had been overestimated, the need for additional reactors dwindled. Furthermore, even the rigorous cost-control implemented by EDF could not prevent a cost increase for each new batch of commissioned reactors. Sales on the tight and competitive international market were not sufficient to keep the French nuclear industry under steam. Domestic research programs for new reactor designs did not deliver or found no commercial uptake. During the 1990s, the once sprawling French nuclear

industry diminished to the role of caretaker, focused on keeping existing plants online.

In general, the French civil nuclear program can be divided into three distinct periods. The first period comprises the early nuclear developments starting after the end of the Second World War, the rising influence of the military nuclear program in the 1950s and the political and institutional clashes about the French long-term nuclear strategy. These clashes were mainly about the choice of reactor design. President de Gaulle refused national electrical utility EDF to use American pressurised water reactors, giving preference to domestically developed graphite-moderated alternatives. These reactors however proved inadequate as power producing generators, as they were actually designed to produce the plutonium needed for the French nuclear weapons. The deficient performance, rising constructions costs and a string of safety incidents almost drove EDF to despair. Eventually the electric utility, interestingly with Belgian support, was able to demonstrate the superior qualities of the American Westinghouse PWR design.

The second period starts around 1969 and is characterised by EDF taking control of the nuclear program. They implemented an ambitious plan calling for the construction of dozens of nuclear reactors around France. A single reactor design, the Westinghouse PWR, was selected to increase the learning effects. EDF used its vast human resource capital of skilled engineers and managers to take full ownership of the construction process, minimising dependency risks on suppliers and internalising the learning effects and efficiency gains. This led to the heydays of the French nuclear production program in the 1980s, with new reactors coming online almost every month. When later on the nuclear program still had to cope with rising construction prices and the realisation that projected electricity consumption was overestimated set in, the program experienced a cooldown.

The third period starts with the construction of *Civaux 2* in 1991, the last contemporary reactor built on French soil. This period is marked by the European power sector shaken up by deregulation and unbundling, slashing up established vertically integrated utilities and eroding the power of monopolists. Faced with overcapacity on the European electricity market and competition with new and fast-evolving technologies such as gas turbines and renewable energy, the business case for new nuclear reactors dims. The French nuclear industry fades from a construction powerhouse to the role of caretaker of aging assets.

The French nuclear program is intertwined with the developments in Belgium at several levels. Its roots can be traced back to the scientific developments of Frédéric Joliot-Curie, and his deal with *Union Minière du Haut Katanga* executive Edgar Sengier to jointly investigate and exploit *all* potential uses of the uranium ore procured from the Shinkolobwe mine in the Belgian Congo. As previously discussed, the outbreak of the second World War foiled these plans, and Sengier quickly shipped most of the uranium ore to the United States [8].

Unlike other European nuclear physicists, Joliot-Curie did not flee the continent. His colleagues smuggled his research notes and papers to safety in the United Kingdom, but Joliot-Curie himself joined the French resistance, taking part in covert operations against the Nazi occupiers (his speciality apparently being the manufacturing of Molotov cocktails). He played an important role in the Liberation of Paris, leading to the Germans surrendering the city on August 24, 1944, and the reestablishment of French military control by Charles de Gaulle.

Almost exactly one year later, on the day the bombs fell in Hiroshima and Nagasaki, the world was shockingly introduced to the power of the atom. Joliot-Curie lamented what happened on that fateful 9th of August, 1945, afraid the dreadful show of force would strike fear in the hearts of man and eclipse the potential of peaceful applications of nuclear power. Despite holding several patents on the construction of atom bombs, the French physicist vehemently opposed nuclear weapons.

In October 1945, Charles de Gaulle appointed Joliot-Curie as France's first High Commissioner for Atomic Energy, and he became head of the newly created *Commissariat à l'Énergie Atomique* (Atomic Energy Commission, CEA). He used this position to successfully lobby against France pursuing the development of nuclear weapons, and instead focus on peaceful applications of nuclear power. The nascent Fourth Republic agreed to this, although it was more out of practical necessity. The country's industrial apparatus was still in shambles and political instability impeded a quick economic recovery. France at the time could simply not afford a nuclear weapons program [29].

The CEA set the goal of building a 100MW power reactor within the timeframe of 10 years. This was a somewhat ambitious goal, as the French industry was in a terrible state, the government had a constant lack of funds and the country had little to no uranium readily available. Luckily, French physicists who fled the country during WWII and found employment in the Allied nuclear weapons programs, were allowed by their host nations to

return home. There they joined the CEA. The financial compensation they had received for their services rendered for their former host nation even formed the main budget of the CEA for several years.

While France had little to no uranium readily available, mineralogists knew uranium ore was present in large parts of France and its overseas areas. Joliot-Curie hired dozens of ex-resistance fighters, who had a good knowledge of the terrain in their respective regions, as prospectors. Already in 1948, a minable deposit was found in the Limousin region, two years later the first uranium ore was mined. Because of the dirigiste economic policy implemented by De Gaulle, in which the state plays a strong directive role in projects deemed of national interest, dozens of mines would quickly follow.

Lacking the technological means and funds to build advanced light-water reactor designs like the United States were doing, Bertrand Goldschmidt and Lew Kowarski proposed to build a less complex heavy-water³ reactor (then still called a 'pile'). The two French physicists had built a similar pile for the Canadian nuclear weapons program during the war. This approach had the benefit that it could run on the natural uranium coming from the mines, as France did not have the means to build the complex systems needed for uranium enrichment [30].

Work on the reactor started in 1947 and just one year later the *Zoé*, as it was nicknamed (*Zéro de puissance*, *Oxyde d'uranium*, *Eau lourde*), achieved criticality. *Zoé* was meant to study nuclear reactions, reactor design and to produce radioactive elements for other research fields. In 1949, continuing the research he performed in Canada, Goldschmidt succeeded in isolating plutonium – a key element to produce nuclear weapons [31].

That same year, the Soviets detonated their first atomic bomb. This came as a shock to most Western nations, as they only expected the Soviets to be able to build these weapons in the next decade. The nascent Cold War immediately reached a new height and led to anti-communist sentiment in the public opinion. Together with other pacifist scientists, artists and authors, Joliot-Curie drafted the *Stockholm Appeal* calling for the international outlawing of nuclear weapons.

³ Heavy water is water containing deuterium in stead of hydrogen. Deuterium is an isotope of hydrogen, possessing one additional neutron. This makes it a less potent neutron moderator than regular "light water". A reactor using heavy water can therefore run on unenriched uranium, whereas light-water reactors require enriched uranium to function.

Joliot-Curie was however a firm believer in the communist ideals and a prominent member of the French Communist Party. When, following the *Appeal*, he publicly declared that he and his fellow scientists “would never use any shred of their knowledge against the Soviet Union”, the French government quickly removed Joliot-Curie from all institutional functions. With him and several other pacifist scientists purged, the French nuclear program quickly took a turn towards military applications [32].

While a heavy-water reactor was less complex to build than a light-water reactor, heavy water was expensive and difficult to find. Zoé was as such not a scalable solution. For its production-fleet, the CEA opted for a graphite moderated, Gas Cooled Reactor (GRC), similar to what the British were building.

A GCR essentially consists out of a large, long block of graphite, with cylindrical holes drilled through it along its horizontal axis. Canisters filled with natural uranium are placed in the holes. Natural uranium emits low levels of high-speed neutrons, that normally do not interact with the uranium itself. The graphite functions as a moderator, slowing the neutrons down and increasing the chance that they collide with a uranium atom. When this happens, the atom undergoes fission, releasing energy in the form of heat and another free neutron. This neutron can then collide with other uranium atoms, leading to a chain reaction.

At regular intervals, new fuel canisters are added to the reactor, pushing the older canisters deeper in the cylindrical holes until they fall out of the backside of the reactor into a cooling pool. A non-flammable gas like CO₂ or helium, is blown through the cylindrical holes to absorb the heat of the reactor. This hot gas is then channelled through a heat-exchanger, transferring the heat to water and turning it into steam. This steam eventually drives a turbine and generator, producing electricity.

A GCR is a quite simple design, requiring no advanced technological or industrial means beside the ability to produce highly refined graphite. It runs on natural uranium, removing the need to build complex uranium enrichment facilities or to import enriched uranium from other countries. It was therefore seen by the CEA as the perfect technology to implement in France. A side-effect of a GCR is however that it transmutes part of the uranium fuel into plutonium, a difficult to handle radioactive element.

In 1952, State Finance Secretary Félix Gaillard introduced the first five-year plan for the development of nuclear energy. It instructed the CEA to build up

to three experimental UNGG (*Uranium Naturel Graphite Gaz*) reactors by 1956. In secret, preparations were also started on a nuclear weapons project which would use the plutonium produced by the UNGG reactors. This project was enacted in 1954 and would remain unknown to the public until De Gaulle announced its existence in 1958 [33].

In 1956, the first UNGG reactor, simply called *G1* achieved criticality. This reactor did not live up to the goal the CEA had set itself in 1946, namely building a 100MW power reactor within the timeframe of 10 years. *G1* had a thermal power of only 40MW and did not produce any useful energy, instead being optimised for the production of plutonium.

In line with the dirigiste economic policy of France, the French government instructed the electrical utility *Électricité de France* (EDF), a state-owned monopolist, to work together with the CEA on harnessing the power of the UNGG for electricity generation. The following two reactors, *G2* and *G3*, which went online in respectively 1958 and 1959, were the first electricity producing French reactors. Each had an electrical power of 40MW.

After the experimental G-series of reactors, construction of the following industrial-size UNGGs was entrusted to EDF, with the CEA taking up a supervisory role. This was the start of an institutional conflict between EDF and the CEA, as EDF tried to optimise the design for cost effectiveness and maximum power generation, with the CEA constantly opposing any design changes as this would decrease the yield of plutonium production.

The G-series UNGG reactors and the transition to its scaled-up industrial-size versions quickly revealed the drawbacks of the design. Owing to the use of natural uranium, they had a relative low efficiency and produced large volumes of nuclear waste. It was also discovered that with rising power output, controlling the reactor became increasingly difficult. The largest size a UNGG could practically be scaled up to was limited to 540MW. Despite the relative simplicity of their design, this also implied that many reactors and large nuclear waste processing facilities would have to be built, making the design uneconomic.

Inside EDF, engineers and executives were becoming more convinced of the merits of the American light-water PWR design, which by then several surrounding countries (including Belgium) were considering for adoption. While this design was more complex and expensive, a PWR could be scaled up in size far beyond the limits of the UNGG, and as such fewer units would have to be built. And while the natural uranium fuel of the UNGG was cheap,

handling of the large volumes of produced radioactive waste was complex, dangerous, and expensive. The Windscale fire, in which a British *Magnox* reactor, similar in design to the UNGG, caught fire and burned for days, and several smaller incidents in French UNGG reactors, also raised questions about the stability and safety of the design.

The PWR however required enriched uranium, which France was unable to produce by itself. Due to the war-time Manhattan project, still the most expensive research program to date, the United States were the sole source of this nuclear fuel. Many French politicians had a deep-rooted distrust of the “Anglo-Saxons,” as De Gaulle liked to call the English-speaking peoples, and did not want to become dependent on the United States for their energy supply – let alone their nuclear weapons.

Instead, France initially setup and participated in collaborations with the UK, Italy and Germany to jointly develop a European uranium enrichment cycle. However, as the UNGG reactor design progressed, these collaborations were abandoned by France in 1955 resulting in their collapse. The French government felt the advanced UNGG project, which did not require enriched uranium, gave it a strategic advantage over other European nations which France could exploit [34].

France had however not given up on enriched uranium. In 1957, the CEA activated the *EL3*, a heavy-water research reactor using enriched uranium. This fuel was provided by the United States, which had just enacted the *Atoms for Peace* program (see supra).

While the clandestine project to develop plutonium-based fission bombs was progressing well, it was already clear that two-stage thermonuclear weapons⁴ would be required for France’s nuclear deterrence to be credible. To keep these weapons compact enough for long-range delivery vehicles, the primary stage would require highly enriched uranium. Furthermore, De Gaulle had ordered the development of nuclear-powered submarines (*Sous-marin Nucléaire Lanceur d’Engins*, SNLE), which required the compactness and safety of an enriched-uranium fuelled PWR.

⁴ Two-stage thermonuclear weapons, commonly called “hydrogen bombs”, use the power of a small nuclear fission bomb (the “primary”) to make a second stage, containing a plutonium spark plug and deuterium fuel, to undergo an uncontrolled nuclear fusion reaction. This greatly increases the destructive yield of the weapon while keeping its size quite compact.

With the French nation prospering economically again, in large part due to the *Marshall Plan*, in 1958 the decision was made to build a uranium enrichment facility. The primary intent was to produce weapons-grade uranium for use in the military thermonuclear weapons and nuclear propulsion projects, but it would soon have civil applications as well.

By 1958 the drawbacks of CEA's UNGG reactor were becoming undeniable. Although it preferred the more complex but robust American PWR design, EDF, by government decree, was confined to the French-designed reactor and the uncomfortable collaboration with the CEA. However, that same year a group of pragmatic private enterprises decided to establish a company that would shape the course of France's, Europe's and even the world's civil nuclear future. That company was called *Framatome* and would eventually lead to a nuclear renaissance in France.

2.5 Belgian nuclear ambitions

Meanwhile in Belgium, the Belgian industrial apparatus survived the second World War pretty much unscathed. This was mainly due to direct intervention of the GM during the war, while the Belgian government was exiled to London. In their absence, the GM executives that remained behind formed a shadow government, effectively commandeering the Belgian war time economy. Alexander Galopin, a director of the GM and executive of *Union Minière*, instituted the eponymous *Galopin doctrine*. He posited that, because of the British naval blockade, Belgium became dependent on Germany or German controlled territories for food and other essential supplies. To be able to pay for this, the Belgian economy would need to keep producing goods and sell them to Nazi Germany. The doctrine was also prompted in an effort to protect the interests of the GM. Galopin correctly assumed that the Germans would not harm industrial assets that were producing goods to their advantage. This course of action was and remains highly debated. While the doctrine forbade the production of military ordnance, Belgian factories did produce parts required for many military equipment. *Union Minière* also sold the remaining 1.000 tons of uranium oxide at the Olen stockpiles to German companies and promised shipments of new ore from Shinkolobwe whenever it became possible again. *Union Minière* executives would later assert they were unaware of the military potential of uranium, a dubious claim seeing the earlier agreements between Sengier and the French and British [18] [35].

With most of their assets surviving the war intact, the GM realised they had all relevant industries to develop nuclear power generation in their portfolio

of businesses: from uranium mining over steelmaking facilities to produce reactor vessels to the production of electrical generators and auxiliary equipment. Additionally, the GM had already developed an interest in electrical power generation during the interbellum, seeing how rolling stock became increasingly electrified. They strongly felt nuclear power was the future for Belgium, and conveyed that feeling to the post-war Belgian government as well. The memorandum promising Belgium access to Allied nuclear technology would become the springboard for a whole new industrial age. Or so was assumed.

The hopes to share in the spoils of Allied nuclear developments however soon vaporised when the United States passed the Atomic Energy Act of 1946 which, while declassifying many of the nuclear technology and knowledge to US companies, also forbade sharing it with other countries. As compensation for the memorandum being rendered moot, Belgium was allowed to levy taxes on the export of uranium to the United States and would receive processed uranium fuel for three civilian reactors [36].

The Belgian ambitions toward nuclear power however, remained undeterred, and the domestic development of nuclear reactors was attempted. The taxes on uranium exports were used to establish and fund several Belgian nuclear research agencies, including the *Studiecentrum voor Kernenergie* (SCK•CEN) in 1952, which would later on become central to the nuclear advancements in Belgium.

The 1950's was characterised by unbridled nuclear optimism in the media and public opinion of the Western world. It was assumed nuclear reactors would provide such an abundant supply of clean, cheap energy that in 1954 it prompted Lewis Straus, then secretary of the United States Atomic Energy Commission, to predict electricity would soon become "*too cheap to meter*" [37].

The impact of nuclear accidents and the issue of radioactive waste were at the time not yet clearly understood or plainly ignored, as indicated by the press coverage minimising the impact of the Windscale fire of 1957. In this incident, a British air-cooled plutonium-producing reactor caught fire, burning for three days and releasing radioactive fallout over the UK and large parts of Europe. It is now classified as a level 5 incident on the International Nuclear Event Scale (INES) of 7 levels, together with the later *Three Miles Island* incident in 1979 [38].

The optimism in the media and public opinion about nuclear energy was however not shared by the American electrical utility companies. Nuclear energy was seen as “experimental” and “uneconomical”, especially compared to the established technology of coal-fired power stations and its steady supply of domestically produced coal fuel. Reactor producers Westinghouse and General Electric failed to convince any utility company to shoulder the investment of the first commercial nuclear power station. This presented an existential threat to nuclear technology, as military funding alone was not sufficient to keep the costly research programmes and fuel production economically, shared between military and civil applications, viable. Industrial revenue had to be found [39].

Faced with reluctant utility companies, Westinghouse and General Electric saw no other option than to bear the brunt of financing the first commercial nuclear power stations themselves. General Electric offered the New Jersey incumbent utility *Jersey Central Light and Power* to build a first commercial BWR power plant, the 636 MW *Oyster Creek Nuclear Generator Station*, for a fixed price of 68 million dollar. This proposal gathered attention everywhere, as a nuclear power station at this price level (\$107/kW) was competitive with fossil-fired power plants.

General Electric knew that it could not build *Oyster Creek* for 68 million dollars, but the project was seen as a demonstrator to convince utilities of the economic viability of nuclear power. The nuclear industry reasoned that, once enough orders were placed, learning rates and scale effects would bring the cost of nuclear reactors down to economic viable levels.

15 years after *Oyster Creek* was completed, nuclear construction costs had however risen to more than \$3.000/kW. *Oyster Creek* was eventually sold for 10 million dollars, before being shut down. It is estimated General Electric and Westinghouse combined lost about 1 billion dollars on these demonstrator projects [39].

Oyster Creek, as a commercial demonstrator for the first generation of commercial BWRs, shows some analogies to the present-day *Olkiluoto* NPP, which is a commercial demonstrator for the third generation EPR reactor built by EDF/Areva. Meant to be the first commercial application of the PWR, EDF agreed in 2005 to build the reactor for a fixed price of 3 billion euros, with its entry into service scheduled for 2010. As of writing (2022), *Olkiluoto* is still under construction and costs have ballooned to more than 11 billion euros. Like General Electric did with *Oyster Creek* in 1969, EDF expects the

costs of further units to drop due to positive learning rates and scale effects of increased reactor production [40].

At the time, General Electric and Westinghouse felt comfortable taking a leap of faith with the demonstrator projects due to a number of reasons. Because nuclear technology was seen as indispensable for the US military, there was a large degree of regulatory capture in the United States Atomic Energy Commission and its successor agency the Nuclear Regulatory Commission. Deploying civil applications of nuclear power would allow to pass on part of the costs of the nuclear research and fuel-production programs, which until the 1950s only had academic or military applications, to the general public. This regulatory capture resulted in a lenient approach to permitting requests and safety regulations, e.g. the *Price–Anderson Nuclear Industries Indemnity Act* which limited the liability of the nuclear industry in the case of a nuclear incident. This situation of regulatory capture would last until the Three Mile Island accident in 1979⁵ [41].

Arguably the biggest driver was however the forecast of an enormous rise in electricity consumption both in the United States and the world, and the believe that there was no alternative other than nuclear power to provide this. During the 1950s, electricity consumption in the US increased up to 7% year over year. Furthermore, government planners assumed a fixed relationship between electricity consumption and GDP growth. The potential market size was therefore seen as virtually unlimited. In reality, later technological improvements would decouple this relationship. Inflation and rising electricity costs would also contribute to depress the electricity consumption [42] [43].

2.6 Atoms for Peace – start of international collaboration

With initially limited interest in commercial nuclear power stations in the domestic market, the United States government decided to change course on international cooperation. During an address to the United Nations assembly in 1952, President Eisenhower introduced the *Atoms for Peace* program, intended to aid friendly nations in developing civil nuclear power.

⁵ On March 28, 1979, a combination of design flaws, mechanical failures and insufficient training of the operators lead to a partial meltdown of a reactor in the Three Miles Island NPP in Pennsylvania, United States. The incident released radioactive gasses and coolant into the environment.

The real goal however was the stimulation of overseas business for US nuclear companies, who by then had a head start in the development of nuclear technology of almost a decade. Westinghouse Electric Company, which had converted their PWR design built with military funding for the first nuclear submarine, into the first commercial, reliable and, by the standards at the time, safe nuclear reactor design intended for power generation, was set to profit the most from the program [25] [26].

Many aspects of the civil nuclear technology chain however had a so-called dual-use: next to power generation they could also be used to produce fissile material required for nuclear weapons production. The United States therefore kept tight control over what parts of the designs and fuel cycle could be shared with other countries, only giving participating countries limited insight in the technical details and blueprints of the reactor design. The construction of the reactors and the supply of nuclear fuel was only allowed to be done by US companies. As a result, Allied nations such as France or the UK showed little interest in the Atoms for Peace program. Their secret nuclear weapons programmes required full control over the nuclear production chain.

By 1956, it dawned Belgium that, despite full financial support of the government and the GM, designing and building a full-scale power producing reactor was too big a challenge for such a small country. While they succeeded in building and commissioning an experimental reactor, the Belgian Reactor 1 (BR1), at the SCK•CEN site in Mol, it was clear that setting up the full nuclear supply chain required to build and operate power producing reactors would depend on international cooperation. While disappointed, the GM assumed their companies would still be the supplier of the main materials and components in this supply chain or build them under license.

In 1956, the Belgian government drafted the first ever energy plan for Belgium. Like in the US, government planners envisioned a 7% yearly growth of electricity demand for the next two decades, with growth in electricity consumption tightly coupled to GDP growth. At the time, electricity in Belgium was produced by oil- or coal-fired power plants. The Suez-crisis⁶ of the same year led to a surge in fossil fuel prices. This kindled the dream of

⁶ In 1957, Egypt nationalised the foreign-owned Suez Canal Company, seizing control over the Canal. In response, Israel, the UK and France launched a military operation to regain control. The Canal was closed for 6 months, leading to economic disruption in Europe.

nuclear-powered energy-autarky. It was assumed that more domestic electricity production would shield Belgium from crises on the international energy markets. Politicians acted on this momentum by ordering an investigation in to building four 'large power reactors', the first time the Belgian government officially took position on the topic of nuclear power. Then minister of Economic Affairs Jean Rey added explicitly that this would only be possible with the involvement of private partners [44].

The Belgian government petitioned the American *Atoms for Peace* initiative, additionally ordering a nuclear reactor solely to power the *World Exposition Fair* to be held at Brussels in 1958. This was exemplary of the unwavering belief in nuclear power at the time. It prompted baron Paul Kronacker, a prominent industrialist and benefactor of nuclear research at the time, to state that "the future of Belgium would depend solely on the speed and ingenuity by which nuclear power would be employed." [45]

The World Expo of 1958 was never powered by a nuclear reactor. ACEC, the engineering subsidiary of GM, did receive the coveted licence on the Westinghouse PWR in 1957, but in order to comply to the *Atoms for Peace* program requirements, the GM had to allow Westinghouse to acquire a large part of the shares in ACEC. This signalled the start of a declining Belgian industrial involvement in the nuclear production chain.

By the 1960s, the business profile of the GM started shifting. Their Belgian coal mining activities started to become unprofitable, with hard coal increasingly being displaced by liquid fuels in both heat and power generation. Confronted with newer, more efficient steel mills in the rebuilt post-WWII Europe, the steel sector underwent a major reorganisation. The activities of rail laying and production of rolling stock declined significantly due to the rise of the automobile. Civil unrest in the Congo disrupted their activities in the former colony.

A weakened GM also started to lose control over their nuclear industrial chain. The partial yielding of ownership of ACEC to Westinghouse would later be followed by a complete take-over by the American conglomerate. The strategic important activity of nuclear fuel production performed by the GM subsidiary '*Métallurgique et Mécanique Nucléaire*' (later: FBFC International) eventually shared the same fate. The activities of electrical power generation and energy distribution were becoming the new core of the GM conglomerate.

2.7 A nuclear war between French institutions

The American *Atoms for Peace* program, enacted in 1958, encouraged the export of the US PWR and BWR reactor designs to nations which entertained friendly diplomatic relations to Washington. It required US companies to keep tight control over the technological details of the reactor design. It did however not specify what a *US company* actually was. That same year, French industrial giants Schneider and Merlin Génin, together with Belgian industrialist Édouard Empain, decided to form a company together with Westinghouse, the US producer of PWRs, called *Framatome (Franco-Américaine de Constructions Atomiques)*. By having a company that was both American and French, the founders aimed to satisfy the sensitivities of both the US and French governments.

The main motivation for the formation of Framatome was the decision of EDF to build a NPP in the Chooz commune, close to the French-Belgian border. As EDF was having troubles scaling up the UNNG design, Framatome instead offered to EDF the proposal of building a PWR. This was approved, but due to the government decree Framatome had to build the facility turn-key by themselves. This propelled the company from an engineering firm into a full-blown industrial contractor.

Work on *Chooz A* started in 1960. Framatome built a scaled-up version of the original Westinghouse PWR design, having a maximum power output of 305MW. Peculiarly, the reactor was built inside a mountain, 150m below ground. Chooz A achieved criticality in 1967.

The involvement of wealthy Belgian industrialist Empain in Framatome is noteworthy. Empain was the majority owner of ACEC, the Belgian electrotechnical company that would later build several PWRs in Belgium under a Westinghouse license (see *infra*). Belgium had already settled on the Westinghouse design, and as such had a lead on the French when it came to the PWR design. Chooz A would give ACEC the practical experience of building a PWR, as groundbreaking for the first Belgian reactors was still years away.

The French-Belgium collaboration was not limited to the construction of Chooz A, but also extended to its operation. The *Société d'Energie Nucléaire franco-belge des Ardennes* (SENA), jointly controlled by France and Belgium, was created to manage and run the power plant. After the successful

demonstration of Chooz A, this cooperation would later also build the Belgian Tihange NPP. The PWR at Tihange would be three times as powerful as the one in Chooz, establishing the scale benefits of this design [46].

While EDF explored the enriched-uranium fuelled PWR design, the CEA went full in on the natural-uranium fuelled GCR. It started a series of developments on advanced, high-temperature GCRs and breeder reactors. The latter were seen by the CEA as a solution to many of the UNNGs' problems. Like the UNNG, breeder reactors run on natural uranium. But where the UNNG does not even extract 1% of the energy in the uranium before the fuel becomes nuclear waste, breeder reactors can "breed" almost all of the natural uranium fuel into fissile material (plutonium). This virtually eliminated the production of nuclear waste. And unlike the UNNG, breeder reactors could be scaled up to higher power levels. The drawbacks of breeder reactors is their technological complexity, even compared to PWRs, potential safety issues and a high price tag.

During the 1960's, tensions between EDF and the CEA climaxed. With rising construction costs and a string of safety and reliability incidents, EDF grew increasingly frustrated with the UNNG reactors. The success of the PWR design in Chooz and abroad demonstrated painfully clear that the American design did not suffer the same issues affecting the UNNG. The PEON-commission (Production d'Électricité d'Origine Nucléaire), a government body created in 1955 to determine France's civil nuclear strategy, recommended the decision on further reactor construction should be made on economic grounds. Yet, De Gaulle would not budge, and ordered EDF to keep on building reactors of the French design.

The bomb finally burst in November 1968, when EDF found no contractors willing anymore to take responsibility for UNGG construction. De Gaulle had to come to terms and gave up his resistance against foreign reactor designs. This would prove to be De Gaulle's last act in the nation's energy policy, as the president had grown immensely unpopular with the French and, amid civil unrest following the May 1968 protests, was forced to step down the next year.

In November 1969 de Gaulle's successor, Georges Pompidou, officially abandoned the UNGG design and ordered EDF to switch to light-water reactors. Officially, the main reasons were economically of nature. The American PWR and BWR designs were already starting to become in use across the globe, and this scale-up allowed the United States to produce and sell enriched nuclear fuel at relative low cost. However, a month before the

decision a UNGG reactor in the *Saint-Laurent-des-Eaux* NPP suffered a partial meltdown. Although it did not receive much media coverage at the time, the incident is still the most serious nuclear incident to occur on French soil (INES level 4), and also played a part in the final decision to abandon the French design.

The nuclear war between the CEA and EDF had come to an end [47].

2.8 Industrial concentration in Belgium

The first energy distribution grids in Belgium were natural gas networks, the first one dating from 1819 in Brussels. During the 19th century, larger cities such as Antwerp, but even smaller ones like Ninove, followed the Brussels lead. Gas was produced by heating cokes in specialised “gas factories”. Each city had its own gas factory, with the produced gas colloquially called “city gas”. City gas contained up to 50% hydrogen. The gas distribution grids were limited to the city borders and mainly used for public lighting, later on for home cooking purposes as well. To manage the production and distribution of gas, each city founded their own municipal company.

By the end of the 19th century, the second Industrial Revolution brought about rapid developments of electrical technology. The Belgian inventor Zenobé Gramme contributed directly to these innovations with his Gramme generator in 1869, one of the first practical methods to generate direct current (DC) power. In 1880, the city of Brussels installed electrical arc lighting on the Charles Rogier Square, supplied by three gasoline powered Gramme generators. Five years later, a somewhat larger project allowed the storefronts in the busy Nieuwstraat to be lit by electrical lighting.

All these first applications of electrical energy generated the power on-site. In 1898 the first true electrical power station was built, to supply the industrial area south of Brussels with three-phase alternating current (AC). By that time, the benefits of electrical machines compared to the older steam technology were obvious, and many cities followed suit. Small companies formed to build and operate the electrical production and distribution infrastructure. These companies were mainly a cooperation between several local industrial partners, municipalities or both.

The municipal gas companies feared this novel type of competition, and successfully obtained an injunction stipulating that only they had the right to subterranean energy infrastructure on public grounds, effectively forbidding

the laying of electrical cables below ground. The electrical companies however switched to air cables suspended on utility poles.

Like the gas distribution networks, the first electrical grids were relatively small, centred around one power plant and only supplying a city or part of it. In this early period, the GM was already involved in electrical companies such as *Société d'Électricité de l'Escaut* (S.E.E.), mainly due to the electrification of tramways and later railways.

During the First World War (WWI), the Belgian industry and infrastructure suffered heavy damage. After the war, gas companies gave up their resistance to electrical infrastructure and turned to the production and distribution of electricity as well. This led to a sprawling growth of electrical infrastructure, with each city having one or multiple electrical companies. To tackle the challenge of rapidly electrifying the industry, companies started cooperation or outright merged. Because of the large capital requirements, banks such as Bank of Brussel entered as shareholders. The S.E.E. transformed into Interescout and built the first large scale power plant of 500MW in Schelle. At the advent of WWII, up to 92% of the Belgian municipalities were electrified, a world record at the time.

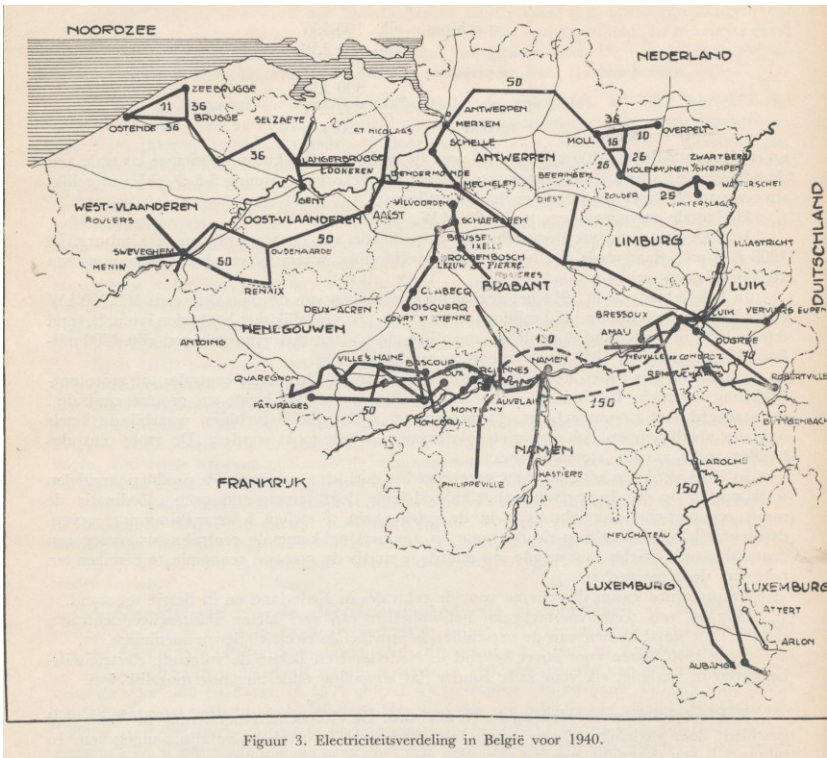
However, there was no integrated transport grid yet. Electrical energy distribution was organised around one or several power plants near a large city or industrial area. If power plants were coupled into a shared grid, these were all part of a common owner, often municipalities. One exception was the Meuse valley in the Walloon region which, for the time, had a quite integrated grid due to the presence of heavy industry. Remarkably, there was no standardised voltage level for transmission at the time, with most lines operating at 50kV, some at 150kV, but many others at 36, 26 or even 10kV.

With the organisation around NPPs taking form (cfr. infra), the GM started construction of a better integrated transport grid. The connection between the proposed sites for NPPs, mainly Doel (Antwerpen) and Tihange (Liège), and the envisioned pumped hydro station of Coo was to form the backbone of the future high-voltage grid. At first, this backbone was routed from Doel over station Mercator (Antwerp) to station Bruegel (Brussel), continuing to Courcelles (Charleroi) and finally following the Meuse valley to Tihange. Two connections with the Netherlands were made, with the primary one at Doel and a second one at Maasbracht. Conversely, France was interconnected over Avelgem and Lonny. The backbones were operated at 380kV.

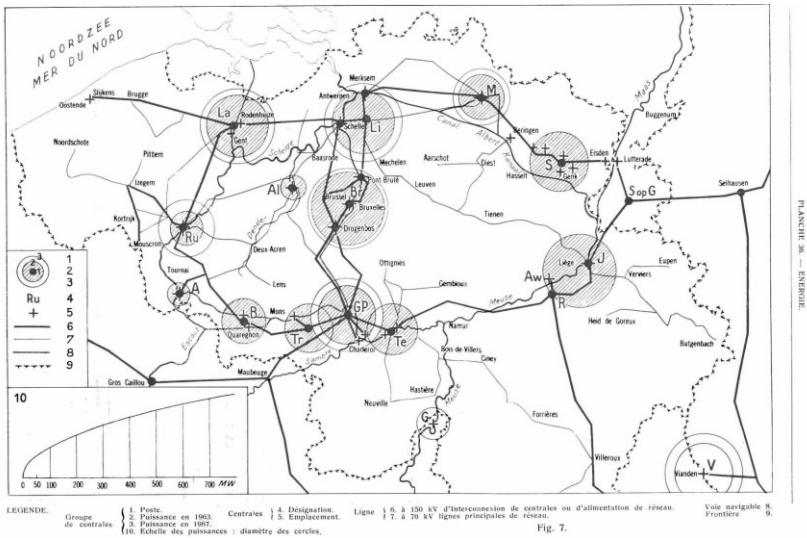
This initial backbone did not have a sufficient back-up capacity to guarantee full power flow between the sites if the connection went down. It was, as such, not able to operate in N-1 conditions, relying on the 150kV regional grid to take over if the single 380kV would fail. Therefore, a second 380kV was later added, routed from Doel to Massenhoven (Antwerpen), Van Eyck (Maaseik) and Tihange. Figure 2 shows a composite figure of the historical evolution of the Belgian transport grid.

Historically, the Belgian transport grid has been designed as a top-down-architecture, centred around large power plants delivering electricity to downstream consumers. Because of the ongoing transition towards an internationally more connected and more decentralised system, it keeps evolving. Recent additions cover the extension and reinforcement of the branches towards the North Sea and France to support offshore wind energy and interconnection with the United Kingdom. Meanwhile, the existing backbones have been upgraded to ensure the entire system is implemented with a 3x2GW capacity.

2 - Nuclear power as baseload electricity generation - 38



(a)



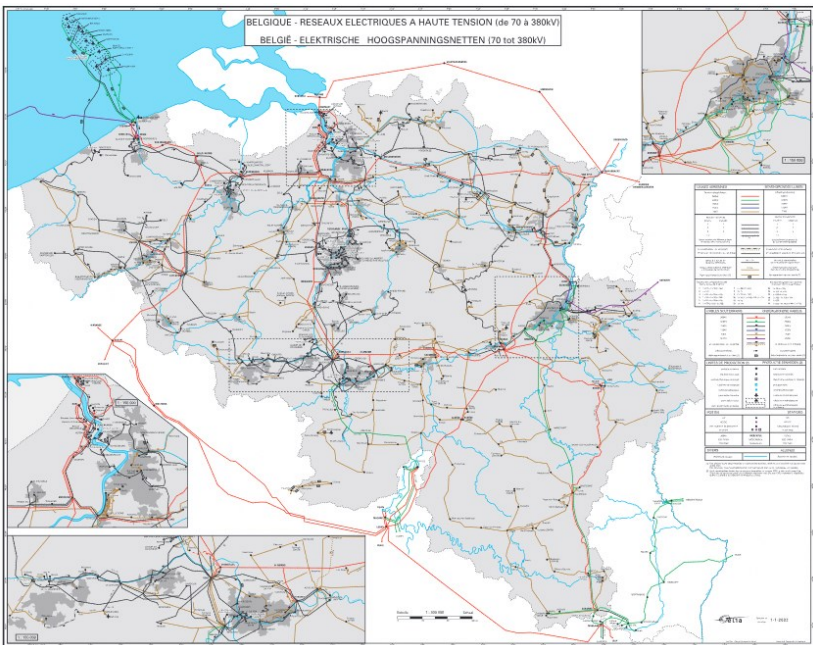
(b)

2 - Nuclear power as baseload electricity generation - 39

Réseau belge 380 kV 4 août 1982



(c)



(d)

Figure 2: Evolution of the Belgian electrical transport grid a) after WWII b) 1963, before the nuclear power plants c) 1982, after finishing the nuclear power plants d) current (2024). Compiled from various sources. [175] [176]

2.9 Belgian nuclear plans take form

Following the call of the Belgian government 'to investigate the building of large power reactors' in the 1950s, the Belgian electricity producers jointly founded the 'Syndicate for the study of high-power atomic power plants', Synatom. This established the dominance of the private sector, effectively the GM, on the deployment of nuclear power in Belgium, suppressing the government and the general public to the role of bystander. A 'permanent contact body' between the industry and the government was formed by the 'commission Boereboom', named after its president and chief of staff of the Ministry of Public Works. This commission could, effectively, only take note of the decisions and initiatives taken by the industry and, although deemed 'permanent', only existed for 9 months.

The indifference of politicians and the general public towards one of the most important energy policy decisions of the century might appear strange by current standards. Several explanations have been proposed. One is the unflinching belief in limitless economic growth, stemming from a post-WWII reconstruction background, and the belief that only nuclear power could support this. This was made tangible by the rapid expansion of petrochemical activities around the port of Antwerp, and the fear that this job growth might be hindered if nuclear power was not introduced soon [44] [48].

As was usual during the 1960s, planners assumed a steady growth of electricity consumption and a fixed relationship between electricity consumption and GDP growth. Based on their own estimates of electricity consumption growth, Synatom initially proposed to build 7 nuclear power plants in Belgium. One at Doel, near the port of Antwerp, another in Tihange, three others along the North Sea coast. After finalising the siting studies, only Zeebrugge was withheld as the sole coastal location, although additional studies for the construction of nuclear power plants on artificial islands were started. Doel and Tihange were selected as well. Synatom decided on these sites autonomously, without any involvement of policy makers or societal interest groups.

Construction of the first Belgian power reactor, Doel 1, started in 1969. Remarkably, groundbreaking at the site started even before the building permit was applied for. The construction of Tihange 1 started under similar circumstances. This was indicative of the position the electricity producers assumed themselves, and of the passivity of the policy makers at the time [44].

By the 1970s, public opinion however started to take form. While the oil crisis of 1973 strengthened the belief of the electricity producers in nuclear power even more, the publication of the 'Limits to Growth' report by the Club of Rome the year before also started to question the assumption of limitless economic growth [49].

If the growth rate projected by Synatom was sustained, this would require up to 40GW of installed electricity generation capacity by the year 2000. As the size of a nuclear power plant was limited to a few GW, this would imply dozens of nuclear power stations all around Belgium.

While in the US and other nations, the public opinion on nuclear power started to become more critical due to significant cost overruns (see below), the public debate on nuclear power in Belgium however erupted due to more domestic reasons. In 1974, EBES applied for a permit to build a nuclear power station in Zeebrugge. This application was initially treated as a minor administrative affair, until a city councilman got wind of it. The town of Zeebrugge was by then under heavy pressure by the expansion of the sprawling Port of Zeebrugge and related industrial activities. Alarmed by the possibility of yet another huge industrial installation so close to a residential area, townspeople started an organised protest. This protest spread rapidly in the province of West-Flanders and forced the Zeebrugge city council to reject the application out of "reasons of ecological origin and threats to touristic appeal" [44] [50].

The protests led to the first parliamentary debate on nuclear power in Belgium, in October 1974, however only after the plans for additional reactors on the already licensed sites of Doel and Tihange were approved. The debates were limited to discussions about the siting of nuclear power plants, the concept of and perceived need for nuclear power were never questioned [51].

In 1975, several hundred academics of different Belgian universities⁷ published an open letter, warning for the foreign involvement (Westinghouse) in critical energy infrastructure and requesting the government to enact a temporary moratorium on new nuclear installations until more scientific clarity on unsolved issues such as nuclear waste was

⁷ Ghent University played a leading role in this warning about the issues with nuclear power, with science philosophers such as Etienne Vermeersch and nuclear experts as Gilbert Eggermont spearheading the protest.

available. This was the first time the issue of waste disposal was considered, even as the first reactors had already reached criticality.

In an effort to depoliticise the debate and remove the nuclear industry from its role as both judge and judged party, the government of prime minister Leo Tindemans assembled a multidisciplinary expert group called '*De Raad der Wijzen*'. This group was to compile a report on all pros and cons of nuclear energy in Belgium, but was however requested not to speak about the desirability or need for nuclear power as "this was a political issue" [52].

The end report published by '*De Raad der Wijzen*' avoided taking up a position in the debate, but gave arguments that could be used both in favour and against more nuclear power plants. In the meantime, the debate about nuclear power had cooled down, and a feeling that all important decisions had already been taken anyway set in. Furthermore, the economic recession of the 1970s awoke society from the dreams of limitless economic growth, prompting the government to adopt a more precarious stance against the "unbridled spending of the nuclear industry" [8].

2.10 Onset of decline

Spurred by the expectation of immense growth in electricity consumption, lenient government regulation and the introduction of fixed-price turn-key NPPs by Westinghouse and General Electric during the 1960s, United States electric utility companies would order a record number of 259 nuclear reactors. Although most of these plants suffered construction delays and cost overruns, this was masked by the successful demonstration of the first commercial NPPs. By the end of the 1960s it became clear that construction costs of NPPs tended to increase with each plant built. The nuclear industry assumed this was because yet not enough projects were commissioned, and still expected to eventually reap the benefits of scaling up production and deployment of nuclear reactors. The outbreak of the 1970s energy crisis⁸ strengthened their believe in future growth, as nuclear energy was positioned as the only method to decrease dependence on foreign energy imports. The US situation and beliefs were widely reflected in Europe as well, as was discussed in the previous paragraph [53].

⁸ At the start of the 1970s, many Western nations faced shortages of petroleum products, leading to elevated prices. The crisis was exacerbated in 1973 when, during the Yom Kippur War, the Organization of Arab Petroleum Exporting Countries proclaimed an oil embargo to the West.

During the 1970s energy crisis, many local markets saw a decline in the consumption of both energy and goods. The high energy prices drew investments of energy-intensive companies away from production expansion towards energy-efficiency measures, decoupling the relationship between energy use and production output. Electricity consumption stagnated, even when later on production output rose again [42].

The depression of electricity consumption and the fear of a looming recession following the energy crisis made electric utility companies reluctant to invest in large, costly nuclear power plants which took up to a decade or more to build.

Furthermore, in 1978 the United States Congress passed the *Public Utility Regulatory Policies Act* (PURPA). The main goal of PURPA was the conservation of electrical and fossil energy, increasing the efficiency in facilities and resources used by utility companies and the construction of smaller scale, distributed generation such as co-generation, small-scale hydropower and solar energy. In order to get utilities to invest in efficiency gains and in these new and often innovative technologies, PURPA partially deregulated the electricity market. Utilities now had to allow so-called Independent Power Producers (IPP) access to their electrical grids so they could produce and sell electricity to customers. By allowing competition, incumbent utilities would be forced to increase their efficiency and lower their costs, something which would eventually be reflected in the electricity tariffs.

In the ten years before PURPA was passed, on average 10 reactors started construction each year. In 1978, when PURPA was passed, only one new nuclear reactor started construction. It was also to be the last, up until 2013 (see section 2.13 *Nuclear reactor construction time*).

While it is often assumed that the Three Miles Island nuclear incident in 1979, and the resulting public backlash towards nuclear energy, was responsible for the decline of the (US) nuclear industry, in reality the downturn had already set in years before. E.g. the orderbook for new nuclear reactors in the US, which in 1973 still contained 41 orders, had dropped to zero by 1978. Five months before the Three Miles Island incident, *Business Week* warned that “*the lights are going out for the U.S. nuclear industry*” and that “*as in the U.S., nuclear power in Europe and Japan is facing the most serious crisis in its 30-year history*” [54].

Three Miles Island resulted in major public backlash against the lacking safety culture in the US nuclear industry at the time and prompted investigation into regulatory capture of the US Nuclear Regulatory Commission. It was however not the main driver of the decline of the US nuclear industry. Of the 51 US reactor order cancellations that happened before the later *Chernobyl* incident, 41 of those were already cancelled before *Three Miles Island* happened. The rising costs of nuclear reactor production, the recently introduced competitive pressure in the electricity market and the realisation that the projected increase in electricity consumption was severely overestimated, were the primary drivers leading to the decline of the nuclear construction industry. From the peak of 259 US nuclear reactors ordered, eventually only 112 would ever be built. By 2020, 40 of them were already retired permanently due to unfavourable economics [55].

2.11 The French exception

After the debacle with the UNCG reactors, France radically changed its approach on nuclear energy and shifted from domestic reactor designs to the American PWR. This had profound consequences, both domestically and abroad. Since that decision in 1970, the French nuclear industry has significantly influenced both industrial and economic landscapes by constructing nuclear capacities totalling 62,000 MW domestically and 6,000 MW internationally. This accounts for 22% of global nuclear capacity outside the former Soviet bloc. France has excelled in developing technologies across the entire nuclear fuel cycle, from uranium mining to fuel reprocessing, and has been a pioneer in the development of second-generation reactors, notably the Fast Breeder Reactor (FBR), especially before the cancellation of nuclear programs in OECD countries during the 1980s. [27]

A key factor to this success has been the ability to control both construction times and costs. French investment costs in nuclear technology have been significantly lower than those in other industrialised nations, with a notably smaller increase in costs during the regulatory, industrial, and technological learning phase. This effective cost management, coupled with relatively stable construction times, contrasts sharply with the experiences of other countries like the USA, where costs and construction times escalated dramatically [56].

As discussed previously, the ascent of the French nuclear industry came from a relatively modest industrial base, particularly in comparison to its American and German counterparts. The initial institutional and technological framework suffered due to poor performance and misaligned goals, but after

1970 France's nuclear industry thrived by making judicious industrial and technological decisions at critical junctures. These included the adoption of dominant American technology and avoiding the pitfalls of a dominant relationship with suppliers.

This adoption of American technology was crucial given the potential for "nationalist" goals to overshadow industrial and commercial pragmatism, a trend observed in other French technological endeavours of the 1960s. EDF and other related industrial firms chose to align with the prevailing technological trends in the American industry, particularly in reactor technology, thereby sidestepping the limitations of the domestically developed UNCG reactor technology.

In contrast for example, the British nuclear industry remained hampered by the technological nationalism which had characterised the first French nuclear programme and led to the premature adoption of the Advanced Gas-cooled Reactor (AGR) and the rejection of Light Water Reactors (LWRs) favoured by utility companies and manufacturers, further disadvantaging the industry.

However, France's move away from the domestically developed UNCG reactor didn't mark the end of technological nationalism. A series of compromises led to the "Frenchification" of the Pressurized Water Reactor (PWR) in a collaborative effort between CEA (French Alternative Energies and Atomic Energy Commission), Framatome (now Areva), and EDF. This was partly motivated by a desire to escape American governmental control over the export of reactors under American licenses. This period also saw the commitment to build the SuperPhenix Fast Breeder Reactor prototype, despite a gloomy outlook for the international nuclear market. These strategic decisions, driven by national interests, did not impose significant costs on manufacturers or EDF, which demonstrated a willingness to support "national technology".

The effectiveness and industrial prowess of France's nuclear sector are largely attributed to its ability to standardise the design of large reactors and alternators, facilitated by bulk orders. This standardisation was made possible by two main factors: regulatory consistency and a concentrated industrial landscape.

Firstly, the close relationship between the nuclear industry's promoters, such as the CEA and the Ministry of Industry, and the safety regulators led to a flexible approach to regulation. This approach ensured the stability of safety

standards across different reactor series, in stark contrast to countries like the USA, Germany, and Japan, where frequent changes in safety regulations hampered the learning process and led to costly modifications to reactors already under construction.

Secondly, the existence of a single reactor supplier and a large electrical operator with significant engineering capabilities, such as EDF, allowed for the successful execution of major reactor series through significant contracts. EDF, acting as its own industrial architect, was pivotal in managing the integration between the nuclear and electrical aspects of the power stations. Although EDF's design involvement was limited due to Framatome's reliance on foreign licenses, EDF played a crucial role in quality assurance, equipment verification, and the management of construction sites.

The scenario was quite different in other major industrialised nations, where the electricity sector was fragmented, and multiple reactor suppliers existed. This fragmentation hindered the standardization of reactor designs and the oversight of construction, leading to a lack of incentive for efficient project management, especially in the face of continual regulatory changes [57].

The French experience underscores the significance of a centralised industrial structure and a strong relationship between the producer and the user in the successful deployment of nuclear reactor technology. The French approach to nuclear technology, characterised by centralisation, stable regulation, industrial planning, and coordinated industrial relations, aligned well with the country's political system of “dirigence” and “national champions” such as EDF.

The critical role of EDF in the French nuclear reactor construction program is underscored by its emphasis on standardization and efficient construction timelines, elements that have been pivotal to its technical success. Like the GM, EDF is sometimes described as a “state within a state” due to its significant influence and autonomy. According to then President of EDF, Marcel Boiteux, factors contributing to EDF's success include the large scale of its ordering program, the implementation of standardised designs, the utility's direct oversight of the construction process, and its stringent control over quality and costs, which reportedly extended to minute details like the quality of food at construction sites [58].

Standardisation, particularly for something as intricate and impactful as nuclear reactors, necessitates ongoing, focused effort and a conducive institutional framework, complete with independent entities and a strong

dedication to the cause. Boiteux highlights the disciplined approach within EDF and Framatome, where any new or innovative ideas were deferred to future projects to maintain consistency in the current series.

EDF's strategy to directly engineer and oversee construction projects, leveraging its vast pool of skilled engineers, has been instrumental in achieving shorter construction times and controlling cost increases for its initial series of nuclear reactors. However, a shift in EDF's commitment to standardization, particularly with the introduction of new reactor designs and a slowdown in the nuclear program post-1981, signaled a departure from this successful model, leading to prolonged construction periods and escalating costs towards the program's conclusion.

An ex-post analysis of the construction cost of the French nuclear reactor programme, based on government data which was only released after 2001, provides an approximation of the true cost of the French nuclear reactor program and is shown in Figure 3. It indicates a substantial increase in the real investment costs for the construction of PWRs in France during this period. Initially, from 1974 to 1984, the specific investment costs rose approximately 5% per annum, from around 4.200 FF/kW (French Francs, adjusted for inflation) to 7.000 FF/kW. This escalation continued from 1984 to 1990, with costs increasing to about 10.000 FF/kW, marking a 6% annual increase. For the later N4 reactor series, which featured an entirely French design, the costs surged by another 45%, reaching about 1.500 FF/kW [59].

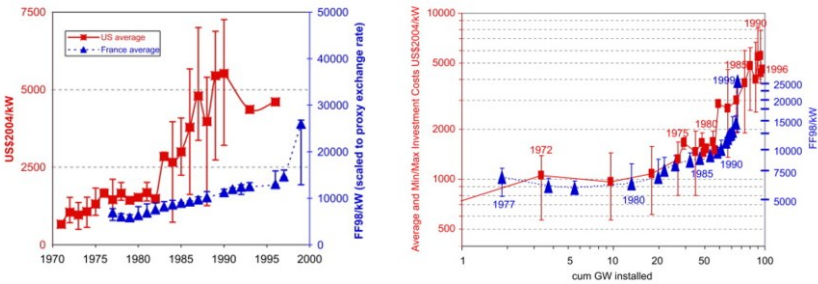


Figure 3 (a): Comparison of French (FF98/kW) and US (US\$94/kW) nuclear construction costs, average and min/max per reactor completion year – Grubler, A, *The costs of the French nuclear scale-up: A case of negative learning by doing*, 2010 and Koomey, J, Hultman, NE, *A reactor-level analysis of busbar costs for US nuclear plants, 1970–2005*, 2007; (b) Average and min/max reactor construction costs per year of completion date for US and France versus cumulative capacity completed – Grubler, A, *The costs of the French nuclear scale-up: A case of negative learning by doing*, 2010

This cost analysis, despite its inherent uncertainties, highlights a significant trend of escalating costs, particularly emphasised in the construction of the later N4 reactors. The variation in costs among different reactors was notable, with the most expensive reactor costing over four times more than the least expensive. However, when extreme cases are excluded, and an average is taken across reactor generations, the cost escalation appears more moderate yet still significant, roughly doubling from the earliest to the later reactors.

This escalation in construction costs is attributed not merely to extended construction times but also to several deliberate decisions and changes in the program. Key factors include deviations from standardised designs, particularly the “Frenchification” of the reactors, and the ambitious introduction of a new, entirely French design in the N4 reactors. These changes aimed at improving reactor economics, increasing domestic component use, and achieving technological leadership, but they also led to significant cost increases.

The analysis suggests that while safety enhancements were part of the design changes, they were not the primary drivers of cost escalation. Instead, the focus on larger scale, domestic manufacturing, and technological innovation were more influential in driving up costs. This substantial real cost increase, despite a favourable institutional environment for nuclear power in France, underscores the complexity and financial challenges associated with nuclear reactor construction and design evolution.

2.12 Technological challengers appear

It was not only escalation of cost and complexity which slowed the growth of nuclear power from the 1980s on, but also competition from other technologies. Until the 1970s, large thermal power plants, whatever their fuel source, all used the Rankine thermodynamic cycle. In this cycle, a fuel source is converted into thermal energy, heating water in a boiler. This produces steam, which then powers a steam turbine. A generator attached to the turbine axle generates electrical power, which is fed into the grid through transformers.

This meant that the basic design of most thermal power plants was very similar. The largest differences lay in the method of converting the fuel into thermal energy. Until the 1960s, Belgian power plants mostly used hard coal,

which was burned in a furnace under and around the boiler. In older power plants, small chunks of coal were burned on moving grates under the boiler. In later power plants, this was replaced by a furnace in which pulverised coal was blown into and combusted with a controllable amount of air, leading to a more efficient operation [60] [61].

Because of the declining coal mining activities in Belgium at the beginning of the 1960s, other fuel sources were sought. Next to the shift to nuclear, as discussed previously, additional power plants burning fuel oil or natural gas were built. Some existing coal plants were converted to accept these fuels as well. All these plants, nuclear or fossil, relied on the Rankine cycle to produce electrical power.

At the end of the 1970s, the introduction of the large-scale gas turbine, followed by combined-cycle power plants at the start of the 1980s, led to a technological disruption in the energy sector [62].

Gas turbines use the Brayton thermodynamic cycle, with air as the working medium. In this cycle, controlled amounts of pressurised air and a gaseous combustible fuel are mixed and burned, with the expanding heat wave channelled into a turbine. Here, the thermal energy of the combustion is directly converted into mechanical energy, making the turbine spin. This turbine drives both an electrical generator as the intake air compressor.

Gas turbines are rather compact installations and eschew the complex and heat-losing plumbing and boilers of fuel-burning power plants based on the Rankine cycle, leading to significantly lower installation and maintenance costs.

Gas turbines were used for electrical power production before the 1970s, but these were mostly refurbished aeroplane engines, limited in power to a few MWs. Their efficiency was significantly lower than that of a conventional thermal power plant. They were (and still are) reserved for back-up purposes, owing to their low cost and fast ramp-up times [63].

To increase the efficiency of the Brayton cycle, combustion pressure and temperature of the working fluid (air) must be increased. For a long time, materials able to withstand these conditions for extended periods of time were not available. During the 1960s and 1970s, advancements in metallurgy and material science led to metal alloys able to withstand pressures up to 30 bar and temperatures up to 1200°C. This made the production of high-power, high-efficiency gas turbines a possibility [61] [64].

The introduction of the gas turbine caused a paradigm shift within the power industry. Just as the rising cost and complexity of building nuclear power stations became apparent, and oil-fired power stations were troubled in the aftermath of the 1973 oil crisis, an uncomplicated, low-cost technology entered the market. A gas turbine power plant could be built in under 2 years, did not require a large upfront investment and was not subject to complex permitting rules.

Gas turbines have the additional benefit of being able to run on many fuels, as long as it can be gasified. An operator could run their gas turbine on natural gas, diesel, fuel-oil, even petroleum distillates, as market conditions evolved. Furthermore, they could be started and stopped as electricity demand varied. All this gave gas turbines a very compelling business case.

The introduction of combined-cycle power plants in the 1980s established the new reference for building new power stations for the coming decades. In the combined cycle, the hot exhaust gasses from the Brayton-cycle gas turbine heat water into steam, powering a Rankine-cycle steam turbine attached to the same axle as the gas turbine. By utilising the waste heat of the gas turbine to drive an additional steam turbine, the efficiency of a combined-cycle power plant could be improved tremendously, up to 60%. This made combined-cycle power plants an economically interesting choice even for baseload power generation [63].

To reduce material stress and fatigue, a steam turbine must be brought up to operating temperature more gently than a gas turbine. Combined-cycle power plants therefore have slower ramp-up times than gas turbines, but higher than those of Rankine-cycle plants. Combined-cycle plants can however be built with a so-called bypass, allowing the operator to use both the gas and the steam turbine, or only the gas turbine by directing its exhaust gasses directly to the environment, bypassing the steam generator. If only the gas turbine is used, this is an OCGT. If both the gas and steam turbine are used, this is a CCGT.

These technological and economic innovations happened against the backdrop of significant natural gas reserves being discovered. The discoveries in the North-Sea region especially would have a large impact on the European industry. The Gullfaks oil and gas field was discovered in 1978. The Snorre, Oseberg and the gigantic Troll gas field were discovered in 1979. During the first half of the 1980s, 6 other large fields would be discovered [65].

During the 1970s and 1980s, large natural gas infrastructures such as drilling rigs and transportation pipelines were being deployed in Western Europe. Because of its beneficial position along the North Sea, Belgium played a pivotal role with the commissioning of the Zeepipe, connecting Belgium to the Norwegian natural gas field *Sleipnir*.

The availability of a secure and economical source of natural gas, coupled with the technological advantages natural gas fired power plants had over traditional coal-fired stations and their economical advantages in terms of investment and operating costs cemented natural O/CCGTs as the standard for new power plants. They were also seen as a good match to complement nuclear baseload production. As most nuclear plants were not built for load-following, another source of flexibility was required. Nuclear plants produce virtually the same electrical output 24/7, while electricity consumption changes during the day and year. Energy storage and demand flexibility was therefore required. In Belgium, this was partially solved by the construction of the Coe pumped hydro storage, by incentivising electrical accumulation heating (which produces and stores heat during the night for release during the following day) and other measures. The flexibility O/CCGTs could provide constituted an additional complement to the inflexible operated nuclear power plants.

The introduction of O/CCGTs also started to change the strategic business perception of power generation. For the first time, the beliefs that economies of scale, dictating that bigger and bigger power plants would lead to lower and lower costs were challenged. Furthermore, the lower investment costs and project risks of O/CCGTs meant that building power plants was no longer the prerogative of state-controlled or state-sanctioned monopolists. Many of the first private players to later appear on the electricity market would do so with a natural gas fired power plant. This would eventually lead to a winddown of the incumbent monopolists and drastically change the electricity market, as will be discussed in the chapter on wholesale electricity markets.

2.13 Nuclear reactor construction time

The data of 704 nuclear reactor construction projects worldwide, as present in the Power Reactor Information System form IAEA, were analysed to gain insights in the evolution of construction time between the advent of nuclear power reactors at the end of the 1950s and today. [66]

To exclude prototype and research reactors, only reactors with a net power generating capacity of 300MWe or more were withheld. This yielded 593 unique reactor construction projects. These were then ranked by date of first grid connection and grouped by decade. Every group includes the starting year of that decade. The last group also includes the current decade, as the number of reactors completed from 2020 to the date of writing (2024) is too limited to plot as a complete decade group.

Due to a first analysis resulting in large discrepancies between construction times in different regions of the world, the data were further split into different regional groups showing a correlation between the different countries but a distinct trend between other regions. Figure 4 displays the processed data.

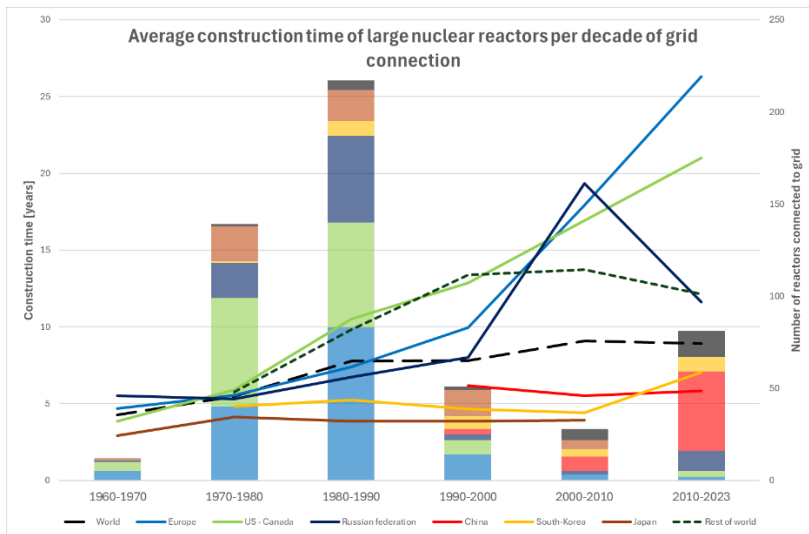


Figure 4: Average construction time (line) and number of large nuclear reactors (bar) per region and decade of grid connection, processed data from [66].

A first conclusion is that, as of the golden age of nuclear grid connections in the 1980s, global average construction time of large power reactors (300MWe or more) shows an increase of only 15%, from 7.76 years to 8.9 years. This despite the wildly varying number of reactors built and connected during the decades.

The underlying data, however, show large discrepancies between the different selected regions. In the US-Canada region, construction times have increased more than threefold. From groundbreaking to grid connection,

building a new power reactor in North America now takes, on average, 21 years. These numbers are one-upped by Europe, where it now takes more than a quarter of a century to get a new reactor to deliver electrons to the grid. This stands in stark contrast with the 1980s, when average construction times were just above 7 years.

There are three reasons global average construction times have remained relatively stable. One is the consistent performance of Japan and South Korea in constructing reactors on time. A second one is the recovery of the nuclear construction capabilities of the Russian Federation, which were severely impacted following the dissolution of the Soviet Union. But arguably the main reason is the emergence of China as a dominant nuclear energy force, embarking on an ambitious construction program reminiscent of France during the 1970s but this time keeping construction times under control.

The correlation between the number of reactors built and construction time seems weak, certainly not causal. For example, during the 1980s, Europe connected more than double the number of reactors (83) to the grid than it did a decade before (40), yet construction times increased 33%. Likewise in North America, the number of reactors connected to the grid remained relatively constant between the 1970s (59) and 1980s (50), yet construction times almost doubled to 10,5 years. Conversely, China completed 14 times more reactors during the last decade than it did in the 1990s, yet construction times remained almost unchanged. The same goes for Japan, who kept the gold medal of shortest construction times despite the wildly varying amounts of reactors built during several decades. South-Korea, on the other hand, sees a 60% increase in construction times, despite doubling the amount of reactors connected to the grid.

While it is sometimes claimed building more reactors will lead to shorter repeat construction times due to learning effects, there seems to be no unambiguous empirical evidence to support this. Likewise for costs, evidence from the French and US nuclear reactor construction programs have shown an increase of construction cost with the number of reactors built (see section 2.11 *The French exception*).

While a full analysis of the reasons behind these *negative* learning effects is outside the scope of this dissertation, arguably they seem less connected to a reactor being a *nuclear* asset than it being a *complex* asset. Other complex construction projects, e.g. transportation or energy infrastructure, but even Olympic swimming pools, have also shown an increase in average construction times in those regions where nuclear construction projects tend

to take more time. This suggests similar underlying reasons, e.g. the availability and cost of skilled construction labourers and cost of construction materials [67].

2.14 Conclusion: nuclear power as baseload generation

In this chapter, the historical role of nuclear power and its role in shaping the current electrical energy system were discussed. The advent of nuclear power reactors marked a significant evolution in the way electrical systems were structured and operated, primarily because these reactors were large, centralised sources of electricity. This centralisation shaped the development of the electrical grid, which was designed to distribute power from these large, centralised points of generation to downstream consumers spread across vast areas.

As discussed in section 1.2 *Research question*, the main drivers behind the energy transition are Distributed Energy Resources (DERs). Initially, DERs were small scale CHP installations having limited impact on the electricity system as a whole. However, due to significant cost decline of these technologies, in 2023 wind energy and solar PV have come to provide more than 27% of total European electricity generation. With the current growth rate, these technologies are projected to achieve at least a 50% share by 2030 [68] [69].

The stellar rise of wind and solar, which are mostly distributed in nature, is upending the conventional organisation of the electrical grid. Energy fluxes on the grid are becoming bidirectional, and even if DERs are installed centralised, e.g. concentrated in an off-shore windfarm, it is often on places without existing infrastructure. This requires the electrical grid to adapt and expand. While wind and solar PV have become the cheapest new sources of electricity generation, they do cause costs in the rest of the system.

Comparing system costs is however nuanced and not straightforward. The existing grid infrastructure, as discussed, was designed and built to accommodate large, centralised power plants and also came with a significant cost. These were amortised over many years, with investments recouped through long-term use. As there is a transition towards a more decentralised energy system, characterised by DERs like solar PV and wind, new and substantial investments are again required to upgrade and adapt the existing grid. Therefore, any comparison of system costs needs to

acknowledge these fundamental differences in infrastructure requirements and investment timelines between the traditional centralised system and the emerging decentralised model.

While the uptake of nuclear power exhibited a fast ramp-up during the late 1970s, it was shown how its growth encountered various challenges over time, leading to a stagnation in the construction of new nuclear plants in many parts of the world. The high capital costs associated with building and operating nuclear power plants, the complexity of nuclear technology, leading to increasingly long lead times and the overestimation of future electricity consumption which never materialised were the main drivers for the decline of new NPP construction. At the same time there was a trend towards deregulating the energy market in many Western countries, lowering the investment appetite of complex projects with long lead times. Additionally, advances in gas turbine design, high availability of cheap, natural gas and a at the time negligible concern about climate impact positioned O/CCGT power plants as a lower-cost and more flexible option for new power plant construction. Rising public concerns over safety and the disposal of nuclear waste also detracted to the willingness to embark on new nuclear projects.

Despite the stagnation of new NPP construction, as of 2023 nuclear power remains the largest source of low-carbon electricity generation after hydropower, both globally (10%) as in Europe (22%). With a projected increase in electricity consumption due to electrification, and stringent climate goals requiring this electricity to be low-carbon, technologically nuclear power remains an attractive option. Several hurdles, especially in Europe and the US, however remain.

Arguably, one of the biggest issues facing new NPP construction is cost, accordingly leading to a high LCOE uncompetitive with other power producing technologies. This cost is heavily dependent on financing costs, as NPPs are CAPEX-driven projects. Depending on the Weighted Average Cost of Capital (WACC), financing costs of a new NPP alone can take up to 60% of the total expenditures of the construction project, depicted in Figure 5. This high WACC is caused by the high hurdle rate financiers expect, driven by cost overruns and construction delays of previous construction projects [70].

A hurdle rate is the minimum rate of return a project or investment must achieve to be considered worthwhile, or *bankable*, by an investor providing the financing. In Europe and the US, construction of new NPPs are often announced with optimistically short construction times and costs. Once the

project is underway, both construction time and costs tend to creep or even inflate. E.g., all EPR construction projects in Europe have seen their construction time and costs more than double.

Investors take this risk into account by increasing their expected hurdle rate. Increased construction time leads to opportunity costs (the money could have been invested somewhere else) which must be priced in.

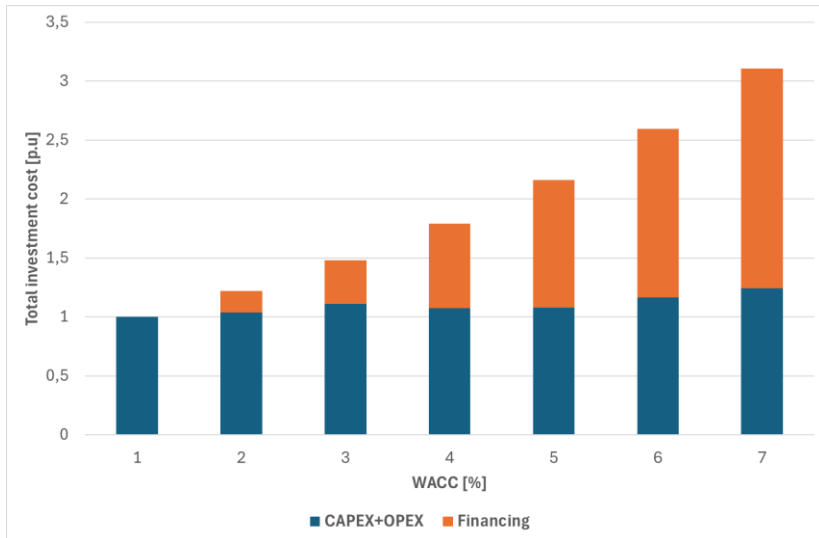


Figure 5: Total cost of a new NPP for different WACC, assuming a 10 year construction period, with WACC = 1 as reference, adapted from [71]

The reasons for construction time overruns are complex, and a full analysis is outside the scope of this dissertation. However, a part of it can be attributed to design decisions by reactor manufacturers. E.g. the decision by EDF to design the EPR with state-of-the-art safety measures like double containment walls with one liner has proven to increase cost and complexity. Westinghouse designed their AP-1000 to be modular, with many parts being manufactured in a central factory and then shipped to and assembled on site. This did not yield the expected cost savings, but drove the construction cost up.

Other reasons are outside the reactor manufacturers control. E.g. lack of a sufficiently large and technically skilled workforce is a common complaint of construction and manufacturing industry as a whole. Likewise, new NPPs suffer long and complex permitting processes. Safety regulations are not standardised, not even in Europe.

In order for new NPPs to be constructed economically, nuclear safety regulation should become more aligned. Their construction in Europe is significantly affected by the diverse national nuclear safety regulations across different countries. While the European Union (EU) has established a framework to ensure nuclear safety through directives such as the Nuclear Safety Directive (2009/71/Euratom), amended in 2014 (2014/87/Euratom), the implementation of these directives is carried out at the national level. The directives aim to enhance nuclear safety by incorporating lessons learned from incidents like the Fukushima accident and by aligning with international standards from organisations like the Western European Nuclear Regulators Association (WENRA) and the International Atomic Energy Agency (IAEA). They mandate rigorous safety assessments, significant enhancements for older reactors, and increased transparency and public information dissemination [72] [73].

Despite these EU-wide directives, the actual application and enforcement of nuclear safety regulations can vary significantly from one EU member state to another. Each country is responsible for submitting national reports on the implementation of these directives, which illustrate the approaches taken at the national level. These reports reveal the diversity in how nuclear safety is managed and regulated across the EU, reflecting differences in national priorities, technical standards, and regulatory practices. These differences are one of the reasons for the significant budget overruns of the Hinkley Point C project in the UK, with the French EPR design being build there requiring over 7,000 adaptations to comply with the British safety regulations.

Whatever the reasons for the overruns, arguably more candour by the nuclear industry about the realistically expected construction costs and times of new NPPs is required. These are essential to optimally align economic and energy policy with NPP construction timeframes. Even more importantly, if construction times are projected to be extensive but realistic, suitable financing instruments can be developed. For example, special long-term and public obligations such as the French “Livret A” could reduce the cost of financing and lower the total cost of the plant [74].

Another possibility is the Mankala financing model, a distinctive approach used in Finland. Under this model, a group of investors, usually energy intensive companies, form a non-profit limited liability company for the common purpose of constructing a nuclear power plant. Each investor is responsible for covering a portion of the company's costs in proportion to

their ownership stake. In return, they are entitled to a proportionate share of the electricity produced, essentially at cost price.

This setup provides a unique way to secure a stable and predictable supply of electricity. It is however, not without its obligations and risks for the participating companies. They are required, and not just entitled, to purchase the electricity produced, even if the production cost exceeds market prices, potentially leading to losses. Despite these risks, the Mankala model has been successfully utilised in Finland for decades [75].

Finally, the construction of new nuclear power plants in Europe by a united approach, rather than each country using their own national champions and subcontractors, could offer significant advantages in terms of efficiency, cost-effectiveness, and environmental impact. This approach would help avoid the situation where every new nuclear power plant becomes a First of a Kind (FOAK) project, which typically faces higher costs, longer timelines, and greater risks due to the unique challenges and learning curves associated with each project.

A united European approach to nuclear power plant construction could leverage shared expertise, resources, and best practices across member states, leading to the standardisation of nuclear reactor designs and construction methodologies. This standardisation could reduce the costs associated with the design and construction phases of nuclear power plants, as well as streamline regulatory approval processes. By avoiding the “FOAK syndrome”, where each project is essentially starting from scratch, economies of scale can be realised, and the overall efficiency of nuclear power plant construction can be improved.

In order to avoid costly new build, it could also be an option to keep existing NPPs online. However, nuclear power plant life extensions or Long Term Operation (LTO), comes with its own challenges. Nuclear power plant operators mainly sell their produced energy on the long-term market, through contracts that last several years and usually have a fixed price. They often conclude these contracts directly with large industrial consumers (so-called Over The Counter or OTC contracts). This is more extensively discussed in section 6 *Wholesale markets as driver for flexibility*.

The economic challenge of an LTO is the operational cost structure of fully depreciated NPPs, which consists of up to 75% fixed costs, mainly personnel, equipment and financial costs. As such, the production cost is strongly linked to inflation and (consumption) price indices. This is in contrast to fossil fired

power plants such as O/CCGTs, which are mainly dependent on fossil fuel prices [76].

Long-term fixed-price contracts thus fit well with the cost structure of a nuclear power plant, which is characterised by fixed costs and a negligible fuel cost. Depending on the type and age of the nuclear power plant, this fuel cost, including provision for waste treatment, is between 5% and 15% of the total production cost. An operator therefore wants their NPP to run as many equivalent full-load hours as possible. At the same time, this type of contract also fits well with the requirements of many industrial customers, who appreciate the certainty of weather-independent power at a fixed price.

Although the majority of electricity has so far been traded on the long-term market, it is the short-term market that sets the price. In this market, also known as the day-ahead or spot market, electricity is traded for next-day delivery. The spot market is public and publishes for each hour of the day the price at which electricity is quoted at that time. The average price of long-term contracts, including OTCs, follows the average price of the spot market, as can be seen in Figure 6, which shows 6 years of data compiled from the EPEX spot and EEX futures market, the dominant electricity wholesale market platform in Europe. Should the spot market be structurally cheaper, consumers would be less inclined to enter into long-term contracts and would mainly buy on the spot market. Conversely, if the price of long-term contracts were structurally cheaper than the spot market, power generators would lose money because they could increase their prices. In practice, therefore, price convergence occurs, albeit with some delay due to the maturity of long-term contracts.

2 - Nuclear power as baseload electricity generation - 60

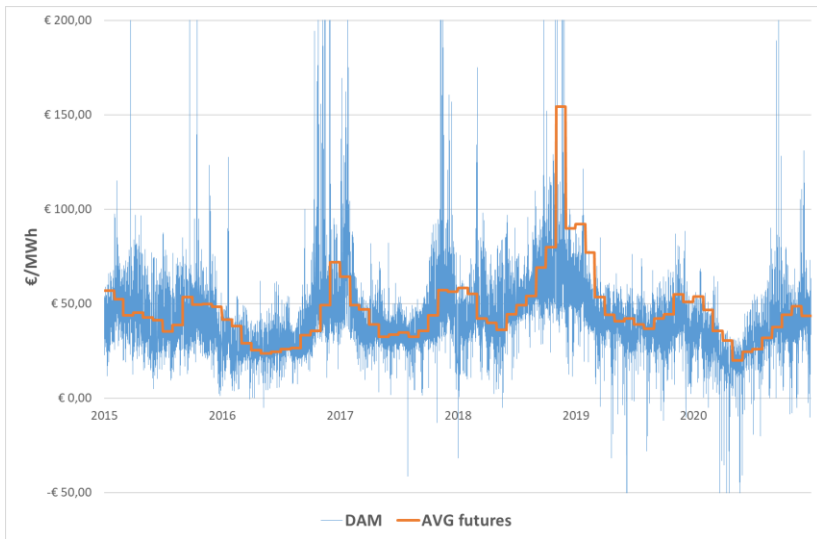


Figure 6: historic comparison of spot prices on the EPEX DAM and average contract prices on the EEX futures market

With the increasing amount of renewable energy, there is also increasing price volatility in the short-term market. Instead of baseload consumption, this incentivises industries to make their electricity consumption more flexible. This can be realised by e.g. battery parks or exploiting buffers in an industrial process. By making these interventions, industries can yield savings on their energy costs compared to a long-term fixed-price contract.

Not all industrial processes can of course be made flexible, and a large chunk of industry will continue to have a baseload consumption profile suitable for long term contracts with a NPP. But because nuclear energy production is a high CAPEX, high fixed cost operation, an increasing exposure to the spot market could lead to decreasing revenues, up to a point where the fixed income from long term contracts no longer suffices to operate profitable. The operator could increase the price of long term contracts, but this creates the risk of losing even more long term contracts to the spot market.

Additionally, the increasing amount of renewable energy has a price depressing effect on wholesale electricity prices. At the same time, the cost of nuclear power, including that from existing plants through LTO, is rising. E.g., the cost of electricity produced by the most recent Belgian NPPs, Doel 4 and Tihange 3, has been calculated by the federal energy regulator CREG to be €35/MWh in 2022, indicating a comfortable operational margin compared

2 - Nuclear power as baseload electricity generation - 61

to the average wholesale prices of around €45/MWh during previous years [77].

As part of the LTO of those NPPs, extending their operational lifetime with 10 years up to 2035, the Belgian federal government requested analyst firm Lazard for an update of this cost estimate, including the impact of the required investments and a 6% profit margin for NPP operator Engie. The primary results, pending an update based on actual bids received by the operator, indicated that a strike price of €81/MWh would be required [78].

A similar issue has arisen in France, where the strike price to economically operate existing NPPs under LTO has been calculated to be about €71/MWh [79].

The increasing amount of variable renewable electricity in the mix therefore increases the uncertainty about future profitable operation of NPPs, even in a LTO scenario. Even in 2030, the renewable capacity installed in Belgium is projected to be able to provide most of the national electricity consumption for one to several hours a day, for each day in the year, despite only providing 35% of the total yearly electricity consumption [80].

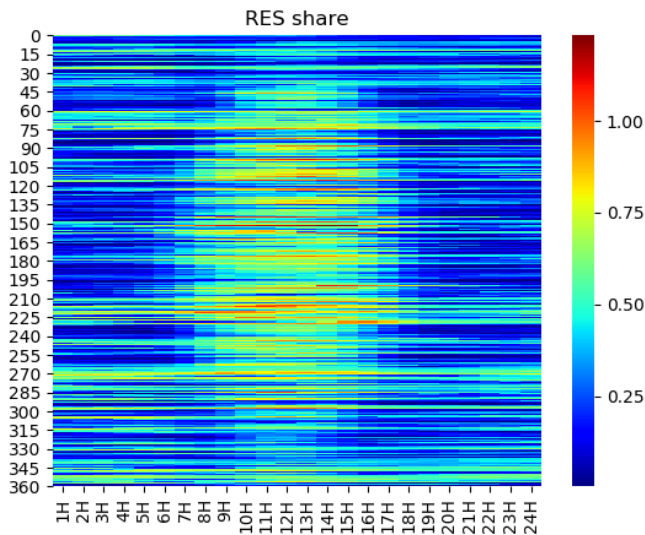


Figure 7: Heatmap of projected uncurtailed RES production in total Belgian system load of 2030 [7].

The projected hourly production of renewable energy compared to the total electricity consumption in Belgium in 2030 is depicted as a heatmap in Figure

7, with the X-axis showing the hour of the day (with 0 being midnight) and the Y-axis showing the day of the year (with 0 being January 1). This graph has been constructed using the projected electricity consumption from the ENTSOE-E Ten Year Network Development Plan (TYNDP) 2020 report, and the expected renewable energy capacities from the Belgian National Energy and Climate Plan (NECP) [81] [80].

Figure 7 assumes no curtailment of the installed renewable energy capacities which, in practice, might not be the case (see section 6.1 *Power plant dispatching*), and should only be used as a comparison between projected maximal renewable energy output and consumption. It is however indicative of the changing energy and energy market landscape in Belgium and Europe the coming years.

In its Impact Assessment of the 2040-2050 climate goals, published in February 2024, the European Commission concluded that the total installed capacity of nuclear power plants in the European Union might decrease from the current 94GW to 71GW in 2040, to remain stable thereafter. Achieving net zero emissions, according to the Commission's projections, will mainly be dependent from renewable energy, which is projected to make up 89% of the mix by 2050, breakthrough innovations in storage technology and the ambitious expansion of electricity grids to link variable generation, consumption and storage of electricity. It adds that, with increased commitment to nuclear newbuild, installed capacity could remain roughly constant, at the expense of a small decrease in renewable energy [82].

3 Flexibility by nuclear power plants

3.1 Conventional nuclear reactors

3.1.1 Technical potential

Contrary to popular belief, nuclear power plants are not incapable of flexible operation. On certain metrics such as ramp rate they even fare better than other thermal plants conventionally dispatched to provide flexibility, including CCGT and OCGT. Flexible operation of NPPs is however subject to specific technical constraints, adding complexity to reactor operation. In this section, these constraints are investigated.

Historically NPPs were built as pure baseload power plants meant to always operate at or very close to their rated power, maintenance and refuelling periods notwithstanding. This simplified safe reactor operations and reduced wear and tear on the fuel assemblies and components such as valves and pumps. Additionally, there was no need for the NPP to ramp its power production down or up as in these early days nuclear power only provided a fraction of the total electricity generation.

The original Westinghouse PWR design was however always intended to provide flexibility, owing to its original design goal as the steam power plant on military vessels. Reactor power output could be modulated by inserting or retracting the control rods to specific positions inside the reactor core. As discussed previously, inside a nuclear reactor a ^{235}U atom in the fuel captures a neutron and undergoes fission, releasing energy and two to three new neutrons. One or more of these neutrons will be absorbed by another ^{235}U atom, continuing the fission chain reaction. In order to control the rate of fission, control rods, made from a material which absorbs neutrons but does not undergo fission itself, can be placed between the uranium fuel rods. These control rods are inserted from the top of the reactor. The deeper they are inserted, the more free neutrons they absorb and thus the more they decrease the reactivity and power output of the reactor.

While this method seems simple enough, it comes with some challenges. The main issue is posed by uneven axial power distribution in the reactor core. For practical reasons, the control rods are always inserted from the top of the reactor. This means the top part of the fuel rods is always first to undergo a decrease in reactivity. Furthermore, fresh coolant is delivered to the core from the bottom, heating up as it rises to the top. As the temperature of the

water increases, it expands and its density decreases. This also means the neutron moderation effect of the water decreases, decreasing the reactivity in the top part of the core even more. This leads to a temperature and power gradient between the top and lower part of the reactor, which increases mechanical stress on the fuel assembly (especially the cladding) [83].

As a solution to this problem, the uneven axial power distribution can be mitigated by the controlled adding of a neutron absorbing agent to the coolant, effectively turning the coolant into a 'fluid control rod'. The adding of this so called 'neutron poison', in most cases boric acid, is already standard practice in most PWRs in order to control reactivity decrease of the fuel during the fuel cycle. As fresh fuel is delivered, its reactivity is still very high and needs to be moderated by the boric acid. During operation, as the fuel is burned up and the reactivity of the reactor decreases, the concentration of boric acid is decreased as well. By changing the concentration of the boric acid in the coolant, the reactivity and thus power output of the reactor can be controlled. As the boric acid in the coolant is more or less evenly distributed, the uneven axial power distribution problem can be mitigated. The downside is the relatively slow speed of changing the boric acid concentration and an important volume of waste effluents (generated by the boron) that needs to be managed.

Both methods of controlling the reactor power must also take the issue of xenon oscillations into account. Xenon-135 is the strongest known neutron absorber. In a reactor, ^{135}Xe is created by the decay of Iodine-135, which in turn is created by the decay of Tellurium-135. ^{135}Te is a waste product from the main fission reaction, created proportionally to the power output of the reactor. It takes only 19 seconds for ^{135}Te to decay to ^{135}I , but around 6,6 hours for ^{135}I to decay to ^{135}Xe . As such, there is a significant time delay between the power output of the reactor changing and the change in ^{135}Xe neutron concentration.

If ^{135}Xe captures a free neutron it transforms into ^{136}Xe , which has no significant neutron absorbing properties. This process is called 'burning off' the Xenon. The burn rate of ^{135}Xe is proportionally to *actual* reactor power, while, due to the time lag of the decay process, the production rate of ^{135}Xe is proportional to *average* reactor power.

During normal, steady-state operation, the production and burning of ^{135}Xe in the reactor are in equilibrium. When the power of the reactor is however decreased, the burning rate of the ^{135}Xe decreases while the production rate of this strong neutron moderator remains (temporarily) unaffected. The

resulting buildup of ^{135}Xe increasingly inhibits the reactivity and thus the power output of the reactor for several hours. If left unchecked, ^{135}Xe concentrations can reach a level where the reactor effectively shuts down, a situation known as ‘falling into the xenon pit’.

^{135}Xe decays naturally into Caesium-135 after 9,2 hours. As this happens, the ^{135}Xe concentration decreases and reactor power output automatically increases again. Likewise, if reactor power output is increased, the burn rate of ^{135}Xe increases while the production rate lags behind. This leads to an increase of reactivity and thus reactor power.

Xenon oscillations pose significant safety and operational issues but can be prevented by proper planning of the change in reactor power. Most PWRs, after reaching the desired power setpoint, will observe a *hold period* of several hours, making sure the window of xenon oscillations has closed before transitioning to a new setpoint. Despite boasting impressive ramp rates, these hold times are a significant drawback when considering the flexible operation of NPPs.

Another handicap of NPPs is that reactors using the boron regulation method cannot provide flexibility when the end of the fuel cycle is nearing. As discussed above, the reactivity of the fuel drops as it is consumed during the fuel cycle. At the end of the fuel cycle, the reactivity has dropped so low that increasing the boron concentration could stall the chain reaction. When this point in the fuel cycle is reached, no further modulation of reactor power is possible anymore. The exact moment differs by reactor design and fuel assembly type but is generally somewhere between the 80-90% mark of the fuel cycle. A typical fuel cycle lasts 12 to 18 months, so modulation of this type is not possible during the final one or two months.

From 1970 and onwards, both French and German reactors started modifying their power output on a daily basis. The first French *CPO* PWRs already used the boron regulation method to regulate oscillations, the so called “*Mode A*”, later expanded to “*Mode A flexible*” when the safe operation of the former was validated. In this mode control rods work in concert with the boron regulation. The main goal was to provide frequency regulation and grid stabilisation reserve, and the reactors only modulated their power output by modest percentages [84].

As the share of nuclear power in the French electricity mix increased rapidly, increasing demands for flexibility arose. NPPs were expected to perform *load following*, where they adapt their power output to daily or even seasonal

changes in electricity demand. French reactors built during the 1980s would therefore support “*Mode G*”, a novel method of controlling reactor power output by the use of so-called *grey rods*. Grey rods were specialised control rods which had a lower neutron absorption rate than the typical control rods (nicknamed *black rods*). This allowed fine-grained tuning of the power output, and also avoided most of the uneven axial power distribution problem. Reactors utilising Mode G had superior ramp rates (up to 5% of the rated power per minute), had the possibility of a fast return to full power, and could theoretically achieve any desired power setpoint. Boron was only used for regulation, minimising the waste effluent. The downside of Mode G was a significant increase in control complexity.

Table 1: Sample range of flexibility capabilities of various generating units in the French generator fleet

<i>Generating unit type</i>	<i>Maximum power [MW]</i>	<i>Minimum power [MW]</i>	<i>Ramp rate [MW/min]</i>	<i>Frequency control for a 50 mHz deviation (MW)</i>
<i>Nuclear</i>	900/1300	300/400	30	25/34
<i>Coal</i>	600	280	6	15
<i>Combined Cycle Gas Turbine</i>	400	200	7	40
<i>Open Cycle Gas Turbine</i>	70	40	22	0
<i>Hydro</i>	250	0	7	5

French NPPs built from the 1990s on used an even improved control method called “*Mode X*” which effectively avoided the chance on xenon oscillations and could be used during the whole fuel cycle. Mode X could also eliminate the need for additional boron regulation and associated waste effluents by sacrificing the possibility of a fast return to full power. An overview of the flexibility capabilities of different generator types in the French electricity generation fleet is presented in Table 1.

In contrast to the evolving flexibility features of the French reactors, German built PWRs like the Siemens *Konvoi* design incorporated a large flexibility potential already in their design phase. This was based on specialised control rods, meant to regulate reactor reactivity (the “D-bank”), working in tandem with the normal control rods (“L-bank”) and a boron regulation system. Contrary to the French reactors, where reactor modulation was largely controlled manually, the German design employed an advanced automated control system taking in data from reactivity sensors inside the reactor core, even including moving probes. This allowed the control system to minimise

or prevent the uneven axial power distribution problem. Furthermore, all components of the coolant systems were designed for frequent reactor output power modulation. This gave the German PWRs a distinctive potential for flexibility. They were able to reach virtually any setpoint between 0% and 100% of their rated thermal power P_r , with ramp rates up to 60% P_r per minute. They could be shutdown, even disconnected from the grid, and started back up reaching full power only a few hours later. The amount of modulation cycles, in which power could be reduced and then brought to 100% again was, for all practical purposes, unlimited [85] [86].

In 1991, several large European utilities and nuclear engineering firms came together to standardise the requirements for newly built NPPs across Europe. This resulted in the European Utility Requirements document which, among other things such as plant layout, materials, components and safety assessment methodology, regulated the minimum required flexibility a new NPP should have. [87] [88]

According to the European Utility Requirements, a NPP:

- must be able of continuous operation between 50% and 100% of its rated power;
- must be able to cycle between 100% of rated power and its minimum power limit (cfr supra at least 50% of rated power or less) back to 100% at least
 - o 2 times per day,
 - o 5 times per week,
 - o cumulative 200 times per year;
- provide a ramp rate of:
 - o at least 3% of rated power per minute upwards and downwards if the load variation is planned,
 - o at least 20% of rated power per minute downwards during emergency load variations;
- load-following operations should be achieved without adjusting the boron concentration during the power variation manoeuvre;
- the unit must be able to contribute to grid frequency stabilisation and to grid restoration;
- must provide the option of increasing the ramp rate up to 10% of rated power per minute if required by the grid operator.

New NPP designs, such as the Areva EPR and Westinghouse AP1000, comply to and often exceed these minimum requirements. Some existing NPPs are already in compliance, while others have been upgraded throughout the

years to be compliant as well. These existing NPPs however require an individual license from the regulator validating the specific capabilities of the reactor and of the implemented control procedures [89].

From 2010 and onwards, load-following procedures were adopted in the Belgian NPPs as well. D4 and T3 are allowed to perform a so-called *extended modulation*, decreasing power output to 50% of nominal power at a ramp rate of 1% of nominal power per minute, for a period (or hold time) of minimal 2h to a maximum of 72h. This can be repeated every 72h but can only be performed 30 times during a single fuel cycle of 18 months. The other Belgian reactors can perform a *restricted modulation*, with reactor output decreasing to 75% of nominal power at the same ramp rate, for a period of minimal 2 to a maximum of 6h. Restricted modulation can only be performed up to 5 times per fuel cycle. Furthermore, the load-following action must be planned at least day-ahead, giving the NPP operator time to execute the proper procedures (verifying the state of the effluent waste tanks, personnel briefing etc.). Due to these limitations, flexibility of the Belgian NPPs is rather limited and reserved for extraordinary market circumstances.

While the manuals of present-day nuclear reactors, including the Belgian ones, boast significant flexibility potential, most NPPs operate in a baseload mode providing 100% of their rated power output for most of the year. France is one of the few exceptions, with around a dozen of their 56 reactors performing daily load-following. In fact, several countries like Germany and Sweden stopped providing load-following with NPPs.

3.1.2 Economical and logistical challenges

There are several reasons why NPP operators are reluctant to provide regular reactor power output modulation. The issue of xenon oscillations has been extensively discussed above and has been shown to be manageable. However, unless specified equipment and control systems, like the French *Mode X*, are implemented, safety procedures impose strict limitations on the ramp speed, hold time and repeatability of the modulation. This limits the economic appeal of reactor modulation, as increasing Variable Renewable Energy Sources (VRES) production results in the market valuing faster forms of flexibility increasingly more.

Other limitations on flexibility, not contained in the reactors' manual, are the concerns about fuel reliability. Nuclear fuel rods are made of fuel pellets contained within the *cladding* or outer shell of the rod. When a fresh fuel rod

is used for the first time, the fuel pellets fracture into smaller fragments. This is caused by the high radial temperature gradient and associated mechanical stress in the pellet as the fission reaction mainly takes place on the outside of the pellet and the inside of pellet stays up to 450°C cooler. These fissures lead to the production of corrosive fission gasses, which the cladding must be able to handle.

The fuel pellets contain uranium, while the cladding is made of a zirconium alloy. These two metals have different thermal expansion coefficients meaning they expand and contract due to heat on different speeds. When power output of the reactor is changed rapidly, this can cause Pellet-Cladding-Interactions (PCI), where the uranium pellets push strongly on the cladding. Additionally, the significant temperature variations caused by changing the power output of the reactor lead to increased fissures of the fuel pellets, increasing the production of corrosive fission gasses.

This effect, combined with the PCI, put significant strain on the cladding and can lead to Stress Corrosion Cracking (SCC), resulting in failure of the fuel rod. While PCI and SSC related fuel failures have been rare, its prevention is an additional restraint on the flexibility that can be provided by NPPs.

The two most important factors limiting the use of NPPs as flexible power plants are however not technical, but logistical and economical of nature.

When new fuel is inserted into a reactor, its reactivity is still very high. As the fuel is “burnt up” during the operation of the reactor, its reactivity decreases. When it hits a lower threshold, the fuel is considered “spent” and must be replaced.

Replacement of nuclear fuel is a complex and time-consuming process. The operator must calculate the exact specifications of the new fuel to order. These must be verified and licensed by the nuclear safety regulator before the order can be placed with the fuel producer. The producer then builds the fuel according to the requested specifications. Because of the safety regulations on fissile materials, transporting the fuel to the plant requires careful planning and coordination between the fuel producer, the NPP operator, the transport companies, the regulator, and the safety authorities. The entire process of ordering new fuel and getting it delivered can take around 18 to 24 months.

When the fuel is replaced, the reactor must be taken offline. Fuel cycles are designed to coincide with the scheduled maintenance requirements of NPPs, which take around 1 to 2 months to complete. This maintenance must also

be planned ahead, as the NPP will not be producing electricity during this period and this maintenance often involves external work crews which have to be planned in (and are shared with other NPPs).

Under constant reactor power output, the fuel burnup rate follows a predetermined trajectory and planning the fuel replacement and reactor maintenance is quite trivial. Decreasing the reactor power output (increasing the amount of modulation) however decreases the amount of energy extracted from the fuel assemblies and thus lowers the burnup rate. The more reactor power output is modulated, the longer time it will take for the fuel to be finally “burned up”.

NPP operators must therefore take the modulation of the reactor into account when calculating the specifications of the fuel and planning the refuelling and maintenance date. This presents the NPP operators with a logistical challenge, shown schematically in Figure 8. [80]

	Low number of modulations planned	High number of modulations planned
Low number of modulations achieved	OK	Fuel depleted before end of fuel cycle
High number of modulations achieved	Fuel left at end of fuel cycle	OK

Figure 8: Economic and logistic challenges of reactor modulation

Consider a NPP operator foreseeing 30 reactor modulations of 6 hours each, to 50% of the rated reactor power. It takes these assumptions into account when ordering the fuel and planning the refuelling date.

When, during the new fuel cycle *more* than these 30 modulations are performed, at the planned refuelling moment the fuel will be more reactive than anticipated. This can lead to safety and handling issues of the “spent” fuel, and is uneconomical use of the fuel.

If, during the new fuel cycle *less* than these 30 modulations are performed, the fuel will be burnt up before the planned refuelling date. The NPP will have

a forced outage before the planned date, leading to economic losses and logistical issues.

These challenges are exacerbated when using staggered fuel replacement, where at the end of a fuel cycle only part of the fuel is replenished. This is commonplace in many reactors, including the Belgian ones, where only 1/3rd of the fuel is replaced at the end of every 18-month cycle of D4 and T123, and 1/4th for the 12-month cycle of D123. Because the total energy content of the whole fuel assembly must remain within regulatory specifications, the new fuel rods need to be built according to the expected energy content at the time of refuelling.

This implies that the NPP operator must make an estimation of the amount and type of reactor modulations that would be financially beneficial to their business years beforehand (when calculating the fuel specifications). This also requires making long-term assumptions of the electricity market. This is increasingly more difficult as the volatility of this market increases year after year. Additionally, even if the market circumstances change, the NPP operator must perform the amount and type of modulations previously planned or risk disrupt the planned outage and maintenance dates.

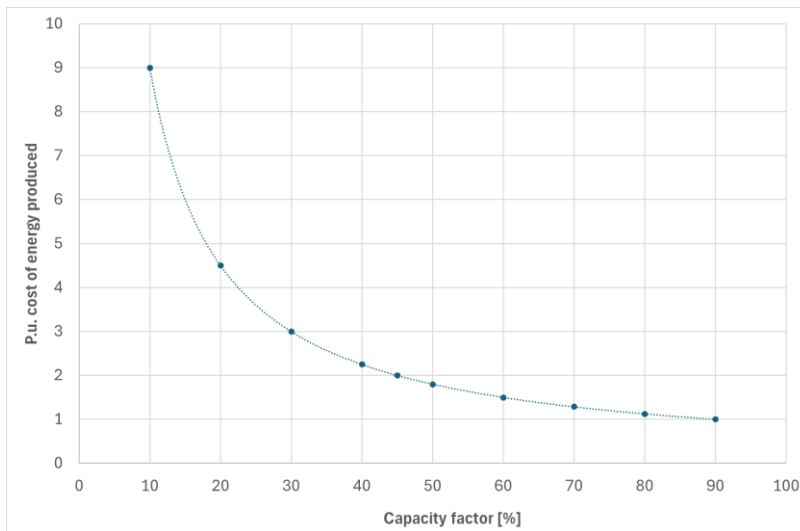


Figure 9: Per unit cost of energy produced by a nuclear power plant in relation to capacity factor (CF of 90% = 1 p.u. cost)

Next to the logistical challenges of reactor modulation, load-following also has an impact on the operational cost of a NPP. Because the NPP operating

cost can be regarded as a fixed cost per running hour independent of the NPP output, decreasing the output through modulation increases the cost of each produced unit of electricity by the same factor. This quadratic relationship between fixed operating costs and energy production cost is shown in Figure 9, with a capacity factor of 90% representing an energy production cost of 1. A 10% drop in capacity factor already leads to a production cost increase of 12,5%, a 20% drop to 28,5% etc. E.g. it has been calculated that the 61GW strong French nuclear fleet, which historically has a relative low capacity factor of 70%, yearly forgoes between 7,9 and 12,2 billion euro of revenue in comparison with a fleet maintaining a typical capacity factor of 90% [90].

Load-following is therefore regarded by NPP operators as well as the International Atomic Energy Agency as economically undesirable, and to be reserved if no other options are available [83].

3.2 Small Modular Reactors

As a response to the growing complexity of building large conventional nuclear power plants, and the associated delays and cost overruns as detailed in the previous sections, several initiatives within the broader nuclear industry were started to move into the other direction: building smaller. Smaller reactors reduce the total cost footprint of each individual unit by lowering the overnight cost and associated risk premium on the capital required to finance the reactor. Furthermore, if sufficiently small, these reactors could be built *modular*, meaning they could be assembled on-site out of standardised components built on a factory line. Factory-produced modular parts of SMRs and micro-reactors can lower the levelised capital and operation and maintenance (O&M) costs of the reactor. This could enable scale-effects and corresponding cost reductions like seen in the field of renewable energy. Designs of smaller reactors based around this concept of modularity are colloquially called Small Modular Reactors (SMR) [91] [92].

Smaller reactors also offer other benefits. Distributing the energy generation load over many small reactors, as opposed to one large reactor, reduces the risk of power outage in the case of a reactor unexpectedly going offline. SMRs can operate with longer fuel cycles and have shorter refuelling times. As smaller reactors operate at lower thermal power, the time for post-shutdown decay heat to dissipate is much lower than their large reactor counterparts. This leads to an increase in capacity factor and reduces the time other power plants need to carry the load when an SMR is taken offline for refuelling or maintenance. SMRs also benefit from enhanced safety due

to lower thermal power and passive safety systems like natural circulation of coolant [93] [94].

As of 2023, more than 80 SMR designs are being developed globally. Sometimes by existing nuclear conglomerates like EDF, but often by rather small start-up companies experimenting with non-conventional designs. However, only a few designs have already received a safety license, and no prototypes have been built yet. The general assumption is that by the end of this decade, several prototypes will be demonstrated operationally.

It should be noted that SMRs differ from *small reactors*, which already exist in the form of naval reactors or floating power barges. These are generally bespoke designs, and lack the *modular* design aimed to enable mass-production of the reactor components.

There are several ways to categorise SMR designs. One is according to (electrical) power output, which can range from only a few MWs up to 400MW. The designs at the low end of this category are often called *microreactors*, while those at the upper end resemble conventional reactors designed around modularity.

A second categorisation, which will be used in this text going further, is on the basis of reactor coolant (and moderation) type, as depicted in Figure 10. Here, three broad categories can be distinguished:

- *Water* reactors
- *Molten salt* reactors
- *Gas cooled* reactors

In general, most designs in the *water reactor* category are colloquially called *Generation III/III+* designs, meaning they build further upon the designs of conventional water-moderated, uranium-fuelled power reactors, although miniaturised and with modularity in mind. Of all SMR designs, these are currently the most advanced in their development, with at least one design already receiving an operating license in the US and aiming for a first operational plant by the end of this decade.

SMR designs in the other categories entail so called *Generation IV* designs, using radically different types of reactor coolant and neutron moderators. They are based on newly developed technologies, or existing technologies which saw little further development once the water-moderated, uranium-fuelled reactors established themselves as the dominant technology during the 1970s.

By virtue of their distinctive design, Generation IV SMRs promise innovative properties, such as complete passive safety, the ability to produce (almost) no nuclear waste and to reach much higher coolant temperatures (>700°C), making their waste heat useful for application in industrial processes. However, they are also the least advanced designs, currently existing only as theoretical concepts.

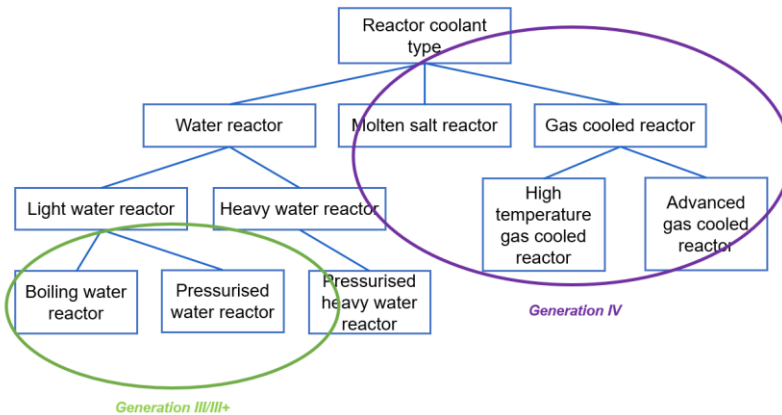


Figure 10: Classification of Small Modular Reactor designs by reactor coolant type

3.2.1 Water reactors

Designs in this category can be divided into reactors using conventional light water as coolant and moderator, and reactors using heavy water respectively. As developments of heavy water SMRs are, as far as could be established, limited to theoretical concepts, we only consider light water reactors in the following.

Conventional light water reactors make up more than 95% of the current global fleet of power reactors. As such, it comes as no surprise that all Gen III/III+ SMR designs are based on this tried-and-true technology. These designs also benefit from being able to use the existing fuel production and waste processing chains. Their operational safety aspects are similar to existing reactors, facilitating the obtaining of safety licences from nuclear regulators. These properties allow light water based SMRs to more easily integrate in the current landscape of the nuclear industry.

Light water reactors can be divided further into two different types. The most prevalent one, accounting for more than 80% of all light water SMR designs being worked on, is the conventional PWR. Again, this is correlated to the fleet of conventional power reactors, of which more than 70% are also of

PWR design. Furthermore, there is ample prior art on small PWRs, as this reactor type was originally developed for naval propulsion and power production. Hundreds of small PWRs have already been built, powering ships and submarines all over the world.

Most of the SMRs of the PWR type are scaled down versions of existing large-scale reactors, although the scale factor is often only around 2 to 3. E.g the Rolls-Royce SMR, currently in a licensing stage, has a rated electrical output of 470MW, placing it into the power range of conventional PWRs. The EDF NuWard design, expected to enter demonstration phase by 2030, has a rated output of 340MW.

Other designs focus more on smaller sizes, like the NuScale 77MW design (up until 2023: 55MW). The design goal is to offset potential negative scale effects by almost complete series manufacturing, thereby decreasing the total cost per MW. A typical power plant would then consist of several of these mini-reactors, allowing greater operational flexibility as well. Reactors could be turned on or off depending on grid load, or refuelling of a reactor could take place without taking the whole plant offline.

The NuScale SMR is currently one of the designs most advanced in its development process, having already received a license to operate from the U.S. Nuclear Regulatory Commission (albeit for the previous, 55MW design), with a demonstration plant expected to go online before the end of this decade. This date is however still in flux, and has been postponed multiple times from its original deadline of 2023. The cost of power sold to achieve economic break-even operations has meanwhile risen from 58\$/MWh to 119\$/MWh, further indicating the complexity of developing and constructing new reactors.

3.2.2 Molten-salt reactors

The history of molten-salt reactor (MSR) technology traces back to the mid-20th century, to pioneering work in the 1950s at the Oak Ridge National Laboratory in the United States. This research culminated in the design and construction of the Molten-Salt Reactor Experiment (MSRE) in the 1960s. The MSRE, operational from 1965 to 1969, demonstrated the feasibility of using a liquid fluoride salt mixture as both fuel and coolant. This experiment showcased several potential advantages of MSRs, such as inherent safety features and the ability to utilise thorium fuel. Despite these achievements, MSR research experienced a shift in focus as funding was redirected towards traditional solid-fuel reactor technologies, leading to a temporary slowdown

in MSR development. With the advent of SMR, this technology gained renewed interest.

MSRs have several advantages compared to conventional PWRs. One notable benefit lies in safety. MSRs operate at lower pressures and come equipped with intrinsic safety features. The liquid state of the fuel allows for natural cooling and expansion, thwarting any meltdown scenarios which PWRs are susceptible to. This inherently safer design reduces the chances of catastrophic accidents, fostering a sense of security in their operation.

Another advantage lies in fuel efficiency. MSRs hold the potential to extract more energy from their fuel, rendering them notably more efficient than their PWR counterparts. Furthermore, MSRs exhibit adaptability in fuel sources, including the utilisation of thorium. This alternative fuel choice proves advantageous due to its greater abundance compared to uranium, coupled with the ability to transmute thorium into fissile material, thus expanding fuel availability.

MSRs also address environmental concerns through reduced waste generation. Their unique design produces fewer long-lived radioactive waste materials, thanks to continuous online fuel reprocessing that eliminates a significant portion of problematic fission byproducts.

A unique aspect of MSR is their ability to make use of the high thermal inertia of their coolant, enabling short-term energy storage (hours) and increasing their ability to integrate with intermittent, renewable energy systems.

3.2.3 High-temperature and advanced gas-cooled reactors

High-temperature gas-cooled reactors (HTGRs) and advanced gas-cooled reactors (AGRs) offer a set of distinct advantages over conventional PWRs, analogous to MSRs. One key benefit lies in their inherent safety features. HTGRs and AGRs operate at higher temperatures compared to PWRs, which inherently reduces the risk of coolant boiling and the potential for core damage during accidents. This feature, combined with the use of graphite as a moderator and helium as a coolant, results in a design that is exceptionally stable even at elevated temperatures, minimising the likelihood of catastrophic meltdowns and ensuring the preservation of core integrity.

A second advantage stems from the fuel utilisation capabilities of HTGRs and AGRs. These reactors exhibit a remarkable ability to extract more energy from the same amount of fuel due to their high operating temperatures. The

increased thermal efficiency leads to greater electricity production for a given amount of nuclear fuel, making HTGRs and AGRs more fuel-efficient compared to PWRs. Additionally, the design flexibility of HTGRs allows them to employ a diverse range of fuel types, including fertile thorium and reprocessed spent fuel, contributing to enhanced resource utilisation and reduced long-term radioactive waste.

One of the aspects distinguishing gas reactors from MSRs is their ability to rapidly modulate their power output, allowing them to balance intermittent renewable energy generation. Also, the higher temperature of their coolant allows industrial use of their waste heat.

3.3 Economics of Small Modular Reactors

Modularisation of nuclear reactor construction is not new. The French nuclear construction program was characterised by a, for the time, high degree of modularisation. For example, at one time the Framatome metalworks in La Creusot was constructing 26 reactor pressure vessels in a row [95].

Modularisation of reactors has also been used more recently. The Westinghouse AP1000, a conventional PWR with a rated electrical output of 1 to 1.4GW, is a highly modular design aimed at lowering its capital cost and installation time. Not only does the reactor pressure vessel, large parts of its (emergency) cooling system and its control and instrumentation system arrive prebuilt at the construction site, even parts of the structural elements housing the components are built in a Westinghouse factory and then shipped to the installation site to be assembled.

In 2009, work began on constructing two 1.2GW AP1000 units at the Vogtle Electric Generating Plant in Georgia, United States. The project was budgeted at 14 billion dollars, with the commissioning date expected to be late 2016. Construction of the first of these two reactors was eventually completed in 2023, with the total project costs having ballooned to 30 billion dollars.

Likewise, in 2012, construction began of two 1.1GW AP1000 units on the V.C. Summer Nuclear Generating Station of South Carolina, United States. The project was budgeted at 9.8 billion dollars with an estimated commission of the plant in 2017. However, by 2017 construction had not yet reached 50% and it was estimated the project would require additional funding of 15

billion dollar in order to reach completion. Construction was eventually stopped, and the project given up.

In both cases, much of the delay and cost overruns were linked to the subpar quality of the delivered modular parts, requiring extensive reworks on site. E.g., on the Vogtle site, a temporary factory was setup to reweld the parts received from the main Westinghouse production factory, incurring severe additional costs and delays.

The cases mentioned above do not necessarily demonstrate that modularity cannot be more cost-effective than conventional reactor construction. It does, however, show that positive learning effects are required before modular series construction can achieve cost benefits. This is especially the case for SMR, as reducing the scale of a reactor, or any industrial project in general, leads to negative scale effects, as conversely sizing up the size leads to positive scale effects.

In order to achieve meaningful learning rates and to lower capital expenditure costs, the total number of projects and thus the installation base must increase. The installation base to achieve cost parity with conventional nuclear can be estimated by using a one-factor learning concept often employed in nuclear power economics [96]:

$$\left(\frac{s}{s_0}\right)^\alpha = \left(\frac{X}{X_0}\right)^{-LR}$$

with

s	the average size of SMR projects
s_0	standard size of conventional nuclear projects
α	the scale effect
X	total install base
X_0	initial install base
LR	learning rate

Assuming a typical SMR project size of 0,3GW compared to a conventional reactor size of 1GW, a learning rate of 10% and a scale effect of 0,6, $\frac{X}{X_0}$ becomes 1.411. On a current global install base of 390GW of conventional reactors, this means an additional 160GW of SMR, or 533 projects, should be built in order to achieve cost parity.

As to date no SMRs have been built, the above calculation remains a crude estimation, but is however useful to indicate the scale required for SMR to

reach cost-parity to conventional nuclear generation. It will require an additional level of deployment to go below that level.

Learning rates and scale effects are heuristic concepts from production theory, based on observations of realised production or construction projects and generalised by interpolation or curve fitting missing data points. The parameters used in the estimation above are based on general rule of thumbs used by the IEAA and also found in textbooks on nuclear power economics. [96] [97]

These “rule-of-thumb” estimates are based on observations of conventional nuclear projects and, as such, do not lend themselves particularly well to extrapolation of novel reactor concepts. The literature however offers an array of theoretical frameworks for the calculation of production costs and the examination of factors influencing the cost dynamics of emergent technologies. Steigerwald et al. provide an overview of some broadly adopted, foundational methodology for projecting the construction expenditures associated with reactor technologies. A primary point of divergence among these methodologies is their respective approaches to incorporating the scaling factor [98] [99].

However, as most SMRs are based on existing technologies, it is possible to estimate these parameters based on a thorough technical analysis of preceding designs and realisations. This is quite straightforward for light water reactors (Gen III/III+), as these technologies are the current mainstay of the global nuclear fleet. For Gen IV SMR, there is a larger data gap, requiring looking into the early development stages of these concepts. Often reactors of these types were already developed or being worked on historically, but they failed to reach commercial application because of the water-moderated, uranium-fuelled reactor types established themselves as the dominant technology on the global market.

The methodology developed by Steigerwald et al. allows an estimation of future CAPEX and OPEX costs of the different SMR technologies. By running Monte Carlo simulations, varying these input parameters and the expected load factor in their respective uncertainty intervals, a LCOE can be calculated, resulting in the overview shown in Figure 11 [99].

3 - Flexibility by nuclear power plants - 80

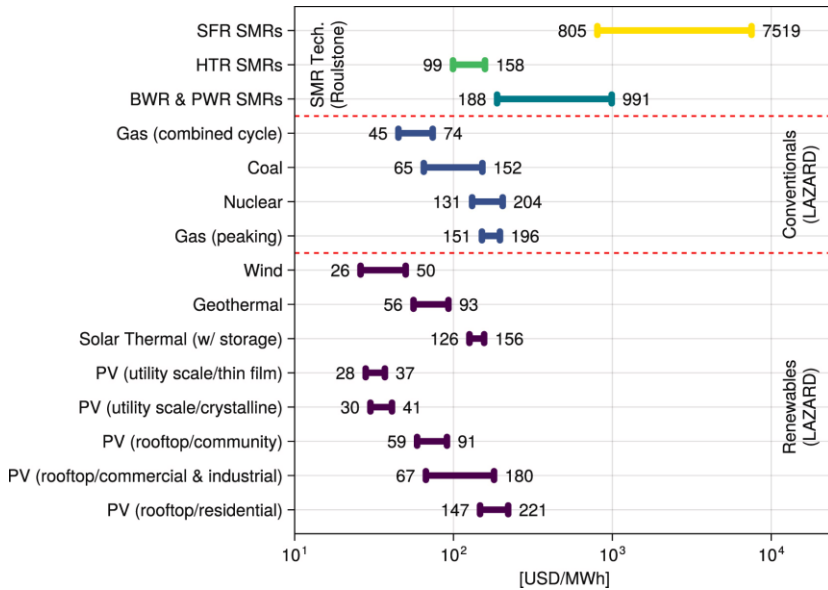


Figure 11: LCOE comparison of Sodium Fast Reactors (SFR), High Temperature Reactors (HTR) and BWR and PWR SMR with other generation. Interquartile range shown for SMRs. Steigerwarld et al. [99]. LCOE of other technologies based on Lazard [100].

Technological analysis of these different SMR types shows that to achieve or surpass cost parity with conventional nuclear, negative scale effects should be lower and learning rates higher than current estimates, even those given by SMR manufacturers. In the context of PWR concepts, it is observed that the initially decreasing trend in manufacturer-stipulated construction costs per MW correlates with a reduction in reactor capacity. Interestingly, for the high-temperature Gen IV reactors, per MW costs are lower than PWRs. This phenomenon is noteworthy as PWRs rely on technologies well-established within higher-capacity conventional reactors. In the domain of sodium fast reactors, the recorded costs are maximal [99].

Another economic aspect is the deployment size. Consider renewable energy production. In 2022, electricity production from solar (203 TWh) and wind energy (420 TWh) reached a new height. With a combined generation of 623TWh, these sources provided more than 22% of the yearly EU-27 electricity production. While wind and solar output already surpassed that of coal-fired power plants in 2019 (447 TWh), they now also outproduce the gas-fired power plants (557 TWh) and the nuclear power plants (613 TWh) in the European Union. Reaching this share in the total electricity output

happened mostly in the past 15 years, with solar and wind providing just 3% in 2007 [101].

Given an average yearly load factor of 85%, it would require a capacity of 84GW of SMR to be installed to match the same output as the currently deployed renewables. Expressed in individual installations, given an average capacity of 200MW per unit this would amount to 418 SMRs. If given the same timespan of 15 years to reach this target, this calls for 28 SMR deployments per year across Europe. For Belgium, with a share of 3,1% of the total EU-27 electricity consumption, this would amount to 13 SMR installations, or one every 14 months.

Currently, there are 2 SMR projects planned in the EU-27. In 2021 a contract with SMR manufacturer NuScale was signed calling for the commissioning of six 77MW VOYGR-6 SMR by 2028 in Romania, for a combined capacity of 462MW [102]. In 2021 twelve of the same units were ordered in Poland, with the 924MW plant to be commissioned in 2029 [103]. This would amount to a lead-time of 8 years between signing the order and the commissioning. It is however difficult to estimate reliable lead-times from these FOAK projects. The contract for the very first NuScale plant, a 12-unit project in Utah, was signed in 2014 with a commissioning date of 2024. As of 2022, citing cost overruns the project has been scaled back to 6 units and a commissioning date of 2030 [104].

The required need for uranium fuel could also be an issue. As described in the previous paragraphs, all SMR designs currently “close to market” are small or miniaturised PWRs using the common uranium fuel cycle. This implies similar or worse fuel consumption per produced unit of energy as regular PWRs [105]. A 1GW PWR running at an average 85% load factor consumes around 27 tonnes of uranium fuel per year [106]. The fuel requirements for 84GW of SMR, sufficient to produce the same yearly electricity output as wind and solar in 2022, would require around 2.259 tonnes of additional uranium fuel per year, more than doubling the current EU-27 consumption of 2,197 tonnes per year [107].

Scaling up the production of nuclear fuel is therefore critical in enabling a large uptake of SMR. For the past ten years, domestic production of nuclear fuel production in the EU-27 has been relatively constant. As of 2023, only five EU-27 countries have production facilities to produce nuclear fuel: Germany, Spain, France, Romania, Sweden. Furthermore, 31% of the fuel consumed by nuclear power plants in the EU-27 is delivered by Russian state companies. [107] While uranium is, at the time of writing, not part of the

European trade embargo imposed on Russia after the 2022 invasion of Ukraine, European utilities are looking to replace Russian fuel, if possible by fuel produced by European facilities.

Uranium fuel is produced by enriching natural uranium. No significant deposits of natural uranium is present (anymore) in European soil, so the resource must be imported. Niger (24%), Kazakhstan (23%) and Russia (20%) are the biggest suppliers of natural uranium to the EU-27. [107] This presents an additional challenge to the European nuclear fuel industry: while having to ramp up fuel production to replace the imports of Russian-made fuel, they also must do so while reducing a fairly large dependence (20%) of Russian natural uranium.

The primary source of natural uranium is the ore uraninite, U_3O_8 , which can be found in several regions across the earth. The largest producers of natural uranium are Kazakhstan (41%), Canada (13%) and Australia (12%), together accounting for 66% of worldwide production. At the current rate of consumption, the known uranium reserves are predicted to be sufficient for at least 120 years. [108] Seawater is estimated to contain up to ten times the amount of uranium found on land and could in the future be a mineable resource as well, provided economic and scalable techniques of extracting the dissolved uranium can be developed [109].

As natural uranium contains only 0.71% of the fissile isotope U_{235} and PWRs require concentrations of 3-5% fissile material in their fuel, it must be enriched to produce nuclear fuel. Nuclear enrichment involves processing the natural uranium into a gaseous form of uranium hexafluoride (UF_6), which is then sent into a cascade of gas centrifuges. Each centrifuge separates a small portion of the U_{235} isotope, forwarding a slightly more enriched gas to the next centrifuge until the concentration of fissile material required for nuclear fuel is reached.

To produce 1 kg of nuclear fuel, around 10 kg of natural uranium is required. 9 kg of depleted uranium hexafluoride remains. This metal has little industrial purposes. Most of the European production is exported to the main fuel producer, Russia, for storage or reprocessing.

Scaling up the production of uranium fuel is not only very capital-intensive, due to non-proliferation measures it is also regulatory very complex. Additionally, new facilities for waste produced during the production of uranium fuel will need to be set up.

3.4 Conclusion: flexibility by nuclear power plants

In this chapter it was investigated if and how nuclear power plants can contribute to large scale flexibility of the power system. An analysis of the technical characteristics of conventional PWRs was performed, revealing that, in contrast to what is sometimes assumed, nuclear reactors have a considerable technical potential for flexible operation. While initially designed as baseload power providers to operate continuously near full capacity, by design most reactors include provisions for power output modulation through various means. E.g. the German *Konvoi* reactors were specifically designed with flexibility in mind, employing specialized control rods (the "D-bank") in conjunction with standard control rods ("L-bank") and a boron regulation system. An advanced automated control system, informed by reactivity sensors and moving probes within the reactor core, manages this flexibility, effectively addressing the challenge of uneven axial power distribution and allowing for significant operational adaptability. These reactors can modulate power output extensively, achieving any power level between 0% and 100% of their rated capacity with ramp rates up to 60% per minute, and can be rapidly shutdown and restarted.

In response to growing flexibility demands, particularly in France as nuclear power's share in the electricity mix expanded, other novel operational modes were developed. The introduction of 'Mode G', for instance, utilised specialized grey control rods to allow fine-tuned power adjustments, achieving superior ramp rates and operational flexibility. This mode reduced the reliance on boron for power regulation, minimizing waste while increasing operational complexity.

Reactor flexibility levels were standardised by major European utilities and nuclear engineering firms in 1991. This EUR-requirements set minimum flexibility standards for new NPPs, dictating that they should be able to operate continuously between 50% and 100% of rated power, handle multiple power cycling per day and week, provide specific ramp rates for planned and emergency load variations, contribute to grid frequency stabilization and restoration, and offer the option for increased ramp rates as required by grid operators.

New reactor designs like the Areva EPR and Westinghouse AP1000 comply with or exceed these standards, and some existing NPPs have been upgraded to meet these requirements, albeit needing individual licensing for their

specific capabilities. In Belgium, from 2010, NPPs adopted load-following procedures with defined limits on modulation frequency and depth, indicating a cautious approach to flexible operation, mainly reserved for exceptional market conditions.

The ability of NPPs to adjust their power output does face some constraints like xenon oscillations, which can be mitigated with careful planning. Furthermore, towards the end of a fuel cycle, the reduced reactivity of the fuel limits the potential for power modulation, especially in reactors employing boron for power regulation. This constraint typically affects reactor flexibility in the final months of the 12 to 18-month fuel cycle.

Further technical concerns relate to fuel reliability. The integrity of fuel rods can be compromised by pellet-cladding interactions and stress corrosion cracking, caused by rapid changes in reactor power output and the resulting mechanical stresses and temperature variations. These issues place additional restrictions on the extent to which NPPs can safely modulate their power output.

Despite the technical capabilities for flexibility documented in reactor manuals and demonstrated by the French nuclear fleet's routine load-following, most NPPs traditionally operate in a baseload mode, delivering constant power output throughout the year. The shift away from load-following in countries like Germany and Sweden reflects a broader trend of limiting the flexible operation of NPPs, possibly due to operational complexity, economic considerations, and evolving energy market dynamics.

Economically, load-following operations increase the operational costs of NPPs due to the fixed nature of many of their operating expenses. Given that the operating expenses of NPPs are essentially fixed costs per running hour regardless of their output, reducing the output via modulation results in a proportional increase in the cost for each unit of electricity produced. A decrease in capacity factor by 10% can already result in a 12.5% rise in production costs, while a 20% reduction can lead to an increase of 28.5%, and so forth.

Additionally, the process of replacing nuclear fuel is complex and lengthy, requiring meticulous coordination among multiple parties and adherence to stringent safety regulations, often taking 18 to 24 months from ordering to delivery. This process, along with the need to take reactors offline for refuelling and maintenance, complicates the planning of fuel cycles and maintenance schedules, especially because power output modulation must

already be factored in when ordering the fuel. When the pre-scheduled amount of modulation is not reached, the reactor fuel is either too reactive at refueling time, or depleted beforehand. This especially holds true for Belgium, which, in contrast to France, lacks integration into a larger nuclear ecosystem.

Given these complexities, load-following is viewed by NPP operators and international bodies like the IAEA as economically undesirable, to be considered only when no alternatives are available. This situation underlines the multifaceted challenges NPPs face in adopting flexible operations, balancing technical feasibility with logistical and economic viability. It is therefore unlikely that NPPs will become large sources of flexibility for the power system.

The above analysis was also performed for Small Modular Reactors. Due to their smaller size and reduced footprint, they are considered as an attractive option compared to conventional, large-scale reactors. As most current SMRs are considered Generation III/III+ designs, building on traditional water-moderated, uranium-fuelled reactors but with a focus on miniaturisation and modularity, they share the same technical potential for flexibility as conventional larger reactors. However, it is shown that SMRs also have a very comparable cost-structure, mainly driven by fixed costs such as investment and fixed O&M costs. While it logistically may be less complex to provide large-scale flexibility with SMRs, their economic base-line will be similarly impacted, making it unlikely future operators will be using them to provide large-scale flexibility to the power system.

4 Hydrogen as a flexibility vector

4.1 Flexibility by hydrogen production

Hydrogen is the most abundant chemical element in the universe, constituting around 75% of all normal matter. Due to its simple atomic structure, with the most common isotope (^1H) consisting only out of one proton and one electron, it is also the lightest and smallest atom, earning it the first place in the periodic table of elements.

On Earth, naturally occurring hydrogen is almost always part of a molecular compound, ranging from water (H_2O) over methane (CH_4) to even table sugar ($\text{C}_{12}\text{H}_{22}\text{O}_{11}$). The discovery of discrete hydrogen is contributed to the English natural philosopher Henry Cavendish, who discovered that the reaction of acids and metals resulted in the creation of salts and 'inflammable air', which produced water when burned.

Due to its simplistic structure, hydrogen readily forms stable structural bonds with other chemical elements and is therefore a fundamental component of many biological and industrial processes. Especially their combination with carbon, the so-called *hydrocarbons*, play an essential role as a combustible energy carrier and as a precursor to chemical aromatics – the building blocks of many synthetic materials.

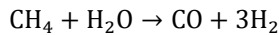
Elemental hydrogen is also combined with nitrogen to form ammonia, essential in the production of fertiliser and as a precursor to many other chemical compounds. Hydrogen sees widespread use in the petrochemical industry to refine crude fuel, and as a reducing agent in the metallurgical industry.

Worldwide industrial consumption of pure hydrogen amounts to about 74 Mton per year, with a further consumption of 42 Mton of hydrogen mixed with other elements. 96% of this hydrogen is produced from fossil fuels, by splitting hydrogen and carbon. In almost all cases, this carbon is eventually released in the atmosphere. The direct CO_2 emissions of hydrogen production amount to around 830 Mton per year, or 2% of the global total.

In Belgium, around 600 kton of industrial hydrogen is consumed yearly. This is mainly used to produce fertiliser, but other applications such as foodstuffs and petroleum refining take up a fair share as well.

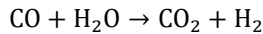
Hydrogen in Belgium is produced by the following methods (in descending order).

- Steam methane reforming (SMR) is the mixing of methane (CH₄) and high-temperature steam under high pressure and exposing this mixture to a nickel catalyst. The result is a synthetic gas or syngas consisting of dihydrogen (H₂) and carbon-monoxide (CO). In a second step, H₂ production can be increased by exposing the



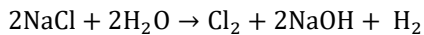
produced CO together with medium-temperature steam to an iron oxide catalyst. This mixture then undergoes a water-gas shift reaction, whereby the oxygen from the steam oxidises the carbon-monoxide to CO₂.

This process is exothermic, providing some of the heat for the syngas production step. The main source of heat is however the burning of a part of the methane feedstock. Combined with the resulting CO₂ after the water-gas shift reaction, SMR produces 5,45



ton of CO₂ per ton of H₂. The resulting H₂ is relatively impure, with up to 15% of the volume contaminated by carbon. Over 90% of domestic H₂ is produced by SMR, often as the feedstock for ammonia production in the Haber-Bosch process, which is quite tolerant to contaminated H₂ feedstock.

- Chlor-alkali electrolysis is the process of chemically splitting an



aqueous sodium chloride solution (brine) into chlorine (Cl₂) and sodium hydroxide (NaOH, caustic soda) with hydrogen as a byproduct, by running an electric current through the solution.

It belongs to the family of alkaline water electrolysis processes which, depending on the solution, can also yield other products such as potassium hydroxide (KOH).

In Belgium, only chlor-alkali electrolysis is performed on an industrial scale. The chlorine is mainly used as a precursor for the production of chlorinated plastics. Around 32 kton of H₂ is formed

as a byproduct per year, which is used for other chemical processes or burned together with methane in gas turbines.

The power input for this process is electricity, with around 51 kWh energy required to produce 1 kg of H₂.

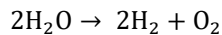
- Dehydrogenation of alkanes into olefins is the transformation of simple, stable hydrocarbons such as ethane (C₂H₆) or propane (C₃H₈) into reactive olefins such as ethylene (C₂H₄) or propene (C₃H₆) by cleaving of some of the hydrogen molecules. The olefins are the main product of this process and are used as building blocks for many synthetic compounds such as plastics. Hydrogen is the byproduct, and often contaminated with olefins requiring its purification through pressure swing adsorption if it is to be used in other chemical processes. Alternatively, it can be burned with methane or part of the feedstock in heat recuperators. Dehydrogenation processes are endothermic, requiring the reactants to be heated to around 500°C while exposing them to catalysts.

There are additional sources of H₂ production in Belgium, e.g. as the byproduct of electroplating, but these are negligible quantities.

Note that none of the processes listed above have the production of hydrogen as their main objective. H₂ is produced as an in-situ precursor for the synthesis of other elements such as ammonia, or as a byproduct that is often discarded.

Dedicated hydrogen production is practically non-existent, even at the global level, the main reason being that (excess) H₂ from fossil sources is so cheap and abundant. Industrial, fossil H₂ costs around €1-2/kg (2020 prices).

Dedicated production of hydrogen from non-fossil sources is possible through a variety of methods, particularly by electrolysis. All water electrolysis electrically decompose water into its elements.



The process is carbon free, provided the required electricity is generated from carbon-free sources. Each method has some different characteristics, mainly concerning the efficiency which is expressed as the amount of electrical energy required to produce hydrogen compared to the specific energy of hydrogen of 39.4 kWh/kg. A 100% efficient electrolyser would consume 39.4 kWh of electrical energy to produce 1 kg of H₂.

The main electrolysis processes are listed below.

- Alkaline water electrolysis has already been briefly touched upon in the discussion of chlor-alkali electrolysis. It is the oldest and most-used method of water electrolysis, with installations sizing up to multiple hundred MWs. If H₂ is the desired end product, an aqueous solution of 25% KOH is used.

It has a relatively high efficiency of 60-80%, requiring around 51 kWh of energy to produce 1 kg of H₂. The purity of the hydrogen ranges around 99.7-99.9%.

The main downside of alkaline water electrolysis is waste management of the corrosive solution, from which the KOH compounds must be recovered. Additionally, alkaline water electrolysis is inefficient at high current densities, meaning the electrolyser cannot operate at low load. This limits the potential of load-following dynamic energy production or energy prices.

- Proton Exchange Membrane (PEM) electrolysis tries to address some of the limitations of alkaline water electrolysis. It uses demineralised water, producing only extremely pure (99.9999% by volume) hydrogen and oxygen. It operates at high current densities, making it a good candidate for flexible load-following operation. While its theoretical efficiency ranges up to 90%, its practical efficiency of 60-70 could be improved. PEM electrolysis requires 55 kWh to produce 1 kg of H₂.

Despite being in development since the 1970s, many technical challenges remain unsolved. PEM electrolyzers carry a high investment cost, among other things by their platinum electrodes. They do not scale well, with the largest units ranging only in the few MWs. Their durability remains an issue.

Due to these reasons, PEM electrolyzers are currently only seen in lab settings, where they produce chemically clean hydrogen for use in lab processes or fuel cells.

- Solid Oxide Electrolysis (SOE) is a promising technology currently in development. In essence, it is a solid oxide fuel cell that runs in regenerative mode, producing hydrogen and oxygen from distilled water. Distinct from other electrolysis processes, the electrolyte is 'solid' in the form of steam (produced from heating water) being absorbed into a porous ceramic cathode. When a voltage is applied, the steam is split into hydrogen, collected at the cathode, and oxygen, connected at the anode.

SOE has the potential of exceptional efficiencies up to 90%, requiring only 44 kWh to produce 1 kg of H₂. The downsides are the required operating temperatures of 500-850°C, requiring high-heat-resistant materials, and the limited load-following flexibility. Longevity of the fuel cell is currently still an issue.

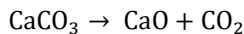
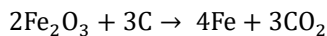
There are many additional methods to produce non-fossil hydrogen, such as biological routes as dark fermentation (using bacteria) or photolysis (assisted by solar irradiation), but as these are still in very experimental stages they will not be discussed here.

As hydrogen plays such an essential role in industrial applications, while for all practical purposes being completely generated from fossil fuels, it is a main target for decarbonisation by producing it instead from low-carbon electricity through electrolysis of water. Several issues need to be tackled.

With existing electrolysis processes, generating the *current* domestic industrial hydrogen consumption would require around 33 TWh of electricity, more than one third of the total Belgian electricity consumption. Even if the highly efficient SOE process would become usable at large scale, the amount of additionally required electricity surpasses the availability of renewable sources.

This number rises even more when looking at decarbonising other industries which are currently not using hydrogen in their processes. One example is steelmaking, which traditionally has a large presence in Belgium's industrial landscape. The ArcelorMittal steelmaking plant in Ghent produces around 5 Mton of steel each year. The required crude iron is procured by reducing naturally oxidised iron (Fe₂O₃) ore with coke fuel in a blast furnace.

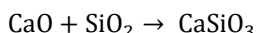
Additionally, a flux agent, usually limestone (CaCO₃), is added to remove silica



impurities (SiO₂) from the iron ore.

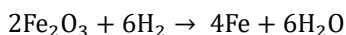
The heat from the burning coke decomposes silica into reactive calcium oxide and carbon dioxide, with the calcium then fixating the silica into easily removable calcium silicate.

As evident from the above reactions, CO₂ is produced in both steps of the



reducing process. Steelmaking amounts for around 4% of global greenhouse gas emissions, with the ArcelorMittal plant of Ghent with 9.6 Mton CO₂ equivalents accounting for 8% of the total Belgian emissions.

Crude iron production can be made emissions-free by directly reducing the iron ore with hydrogen.



This produces sponge iron, which can be melted along with scrap metal in electric arc furnaces, making the total process carbon-free. Additionally, the produced water can be reused for hydrogen production through electrolysis. Directly reducing iron with hydrogen is currently in the demonstration phase.

Directly reducing iron with hydrogen requires 51 kg of H₂ per ton of steel. In order to produce the same 5 Mton steel the current ArcelorMittal plant yields yearly, 255 kton of H₂ would be required. This amounts to an additional 13 TWh of required electrical energy per year. To put this into perspective: this is around the same expected yearly energy produced by all Belgian offshore wind farms by 2030.

Steelmaking is just one of many industrial processes which can be, partly or fully, decarbonised with hydrogen. The potential for domestically generated fossil-free hydrogen falls short of being able to decarbonise the whole Belgian industry, so a prioritisation of hydrogen applications could be beneficial.

Hydrogen produced through electrolysis is only as carbon free as the electricity required for it. Renewable energy is often seen as the major producer of low-carbon electricity for electrolysis, with some even suggesting to produce hydrogen from renewable energy 'surpluses', e.g. when wholesale prices become negative.

Electrolysis is however by economical means a baseload process. While alkaline electrolyzers have some and PEM electrolyzers a large potential for

load-following, e.g. modulating the production setpoint and thus the energy consumption according to electricity prices or availability, this is economically nefarious for electrolyzers dedicated to hydrogen production.

The investment cost or capital expenditure (CAPEX) of an electrolyzer is dependent on its maximum production capacity. Operating below this capacity means running below the economic optimum concerning CAPEX write-off. While flexible operation might yield additional revenue streams, this is mostly limited to participation in the electricity reserve markets (e.g. ancillary services markets) and not the wholesale electricity market. In this case, the impact on the capacity factor, which is the amount of equivalent full-load hours during one year, is fairly limited.

The situation is somewhat different for in-situ electrolyzers, most of which currently produce chlorine as the main feedstock ingredient for upstream processes, as they might have buffering possibilities to make up for the mismatch between the feedstock consumption of the process and production by the electrolyzer. Electrolyzers dedicated to the production of hydrogen as a commodity however need to maximise their production output in order to not be driven out of the market.

In order to stay competitive, the operator of a dedicated hydrogen electrolyzer will therefore be incentivised to maximise their Capacity Factor (CF), running at full load as much as possible. This contradicts with the variability of renewable energy, and especially with the claim of 'running on renewable energy surpluses'. Instead, dedicated electrolyzers run the risk of creating additional baseload consumption on an already constrained energy system.

When modelling several electrolysis scenarios, this need for a high number of running hours becomes transparent. Although real cost data are hard to obtain, an expert elicitation study puts the 2020 CAPEX costs between 800 and 1300 €/kW for alkaline, and between 1000 and 1950 €/kW for PEM systems. By 2030, these costs are estimated in the same report to be only slightly lower, ranging 700 to 1000 €/kW and 850 to 1650 €/kW for alkaline and PEM, respectively [110]. This tracks with another study analysing the investment costs of electrolysis from the past 30 years which, by projecting the learning rates and scale effects, arrives at an estimated cost of 790 to 910 €/kW and a wide 400 to 960 Euro/kW, for alkaline and PEM technology, respectively [111].

Next to CAPEX considerations, there is also a desire to maximise the CF from the side of operational expenses (OPEX). The wear-and-tear of electrolyzers, especially concerning the membrane, is independent of production output. This means that an electrolyser running at low output is wearing down equally as fast as while running at maximum output.

A second caveat is electricity cost. As around 51 kWh is required to produce 1 kg of H₂, at average electricity wholesale prices of +/- €60/MWh 1 kg of H₂ has an *electricity cost* of €3. Current fossil-based hydrogen has a *production cost* of €1-2/kg. Taking the low-end values for electrolyser CAPEX and high-end values for efficiency into account, it would require more than 7000 annual operating hours for an electrolyser to reach a levelised cost of hydrogen which is in the same ballpark as the cost of fossil-derived hydrogen [112].

Table 2: Electrolytic hydrogen production costs according to various scenarios, adapted from [112].

CAPEX [€/kw]	2000	800	800	800	800
Annual operating hours	7000	2000	1000	500	7000
Electricity cost [€/MWh]	70	70	140	0	60
Electrolyser efficiency [%]	60	80	80	80	80
Hydrogen production cost [€/kg]	7,0	6,1	12,2	10,5	3,7

ENTSO-E's TYNDP scenarios consider an annual average of 1800 hours of cheap wholesale electricity prices in 2030 [113]. Elia's most recent *Adequacy & Flexibility* study estimates this closer to 500 – 1200 hours, even with a declining trend in later years [1]. This illustrates that the availability of low-cost electricity to produce hydrogen through electrolysis will not only be tight, but also that producing it exclusively with low-cost electricity will make the produced hydrogen prohibitively expensive.

This is even more the case when considering hydrogen production from "surplus" electricity, as indicated by negative wholesale electricity prices. Currently, these negative prices are limited to a few dozens of hours annually. It is however debatable if this amount will increase with a rising share of intermittent renewable energy production. The main drivers behind negative wholesale electricity prices are a combination of fixed green energy

support mechanisms, distributed RES (mainly residential PV) not participating in the energy market and inflexible thermal power plants.

Fixed green energy support mechanisms, e.g. green certificates awarded for every produced MWh of renewable electricity, are increasingly phased out and expected not to play any significant role anymore in 2030 and beyond, being replaced by other support measures (if required) like contracts-for-difference. In order to allocate the hosting capacity for new PV installations, these will increasingly have to respond to market signals (e.g. to avoid congestion). Additionally, as the business case for inflexible thermal generation is diminishing, more flexible power plants will replace them. This implies that electricity generators, even RES, might want to stop producing once the wholesale electricity price reaches their marginal cost, avoiding the generation of “surplus” electricity and the appearance of negative wholesale prices.

In order to produce electrolytic hydrogen at a levelised cost comparable to hydrogen today (which is mainly derived from fossil fuels), the electricity input will have to satisfy two conditions:

- A constant (“baseload”) supply profile
- A constant low-cost profile

If these conditions are not met, electrolyzers will likely increase the baseload consumption of electricity, or unlikely to be cost-competitive with current methods of hydrogen production.

Arguably, carbon levies on fossil fuels and/or fossil-based hydrogen can rectify this situation. This can make electrolytic hydrogen production cost-competitive to fossil-derived hydrogen, but only by virtue of increasing the cost of the latter. Additionally, it ignores the fact that domestic electrolyzers will have to compete on a global market with foreign low-carbon hydrogen production. Already in 2020, it is possible to produce hydrogen from electrolysis at €1/kg in areas such as Saudi Arabia or Morocco, which have regions with high availability of both solar irradiation and wind [114]. While long-distance hydrogen transport is currently not yet feasible, the transport of derived chemicals and feedstock such as ammonia or synthetic methane is. The economic ramifications of a shift towards the import of these feedstocks, as compared to domestic production, are however beyond the scope of this dissertation.

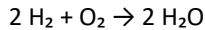
4.2 Hydrogen power plants

4.2.1 Hydrogen as combustible fuel

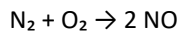
Hydrogen is a combustible fuel. In optimal circumstances, it burns very cleanly and produces only water vapour as waste products. In fact, hydrogen has historically been used as a combustible fuel in several applications. Before the advent of natural gas (methane) distribution networks, many cities in Europe and the US used so-called *town gas* (US) or *city gas* (Europe). This gas was produced by local gasworks, facilities that converted coal, oil, or other carbonaceous materials into a gas mixture suitable for distribution to homes, businesses, and streetlights. The most common type of city gas was produced by heating coal in the absence of air, a process known as "destructive distillation" or "carbonisation." This process released volatile components from the coal, including gases like hydrogen, methane, and carbon monoxide, as well as various hydrocarbons. The resulting gas mixture was then cleaned and purified before being distributed to local consumers through a network of gas pipes. City gas could contain up to 50% hydrogen by volume. It often also contained large amounts of carbon monoxide and volatile organic compounds, making the gas and its combustion products toxic. With the discovery of large natural gas fields in both Europe and the US, city gas was phased out in favour of natural gas, consisting of only methane and some trace elements.

Another combustible application is the use of hydrogen as a rocket fuel. Liquefied hydrogen is mixed with liquefied oxygen and ignited in the combustion chamber of a rocket engine, with the exhaust of the resulting high-temperature, fast-expanding combustion products providing thrust for the vehicle. Hydrogen has the benefit of having a high energy content per unit of mass, giving hydrogen-fuelled rocket engines a high specific impulse. Specific impulse can be seen as the efficiency, or the "gas mileage", of a rocket engine. Hydrogen however has a low energy density, meaning a low energy content per unit of volume, requiring it to be highly compressed and/or cooled cryogenically in order to keep the size of the fuel tanks practical. This also means the fuel tanks and piping must be constructed to withstand these pressures and temperatures, adding mass to the rocket and (partially) offsetting the benefit of a higher specific impulse. For this reason, only a few rocket families used hydrogen as their main fuel (Space Shuttle, Delta IV, Ariane, ...), with most others opting for RP-1 (a refined form of kerosene) or other combustible fuels like hydrazine.

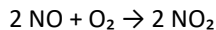
When hydrogen (H₂) is burned in the presence of oxygen (O₂) from the air, the main reaction is:



This reaction produces water vapor (H₂O) as the primary combustion product, which theoretically makes hydrogen a clean-burning fuel in terms of greenhouse gas emissions. However, the high temperatures generated during combustion can cause some of the nitrogen (N₂) present in the air to react with oxygen (O₂) to form nitrogen oxides (NO_x). This happens through a series of reactions involving nitrogen and oxygen atoms from the air, with nitrogen gas (N₂) first reacting with oxygen gas (O₂) to form nitric oxide (NO)



This nitric oxide can then react with additional oxygen gas (O₂) to form nitrogen dioxide (NO₂).



These nitrogen oxides are harmful pollutants as they contribute to the formation of smog, acid rain, and other environmental and health problems. NO_x emissions are regulated in many regions due to their negative impacts on air quality, human health and fragile ecosystems.

Every combustion using air as oxidiser and reaching a sufficiently high temperature (1,371°C) can produce NO_x emissions. Natural gas, for example, has an adiabatic flame temperature in the vicinity of that of hydrogen (1,937°C vs. 2,182°C). But NO_x production can be inhibited by carefully controlling the combustion process, so it takes places at more or less constant and reduced temperature. In natural gas burning turbines, such as in O/CCGTs, a technique called Dry Low Emissions (DLE) are used to limit the amount of NO_x produced.

One of the main benefits of using hydrogen as a combustible fuel in rocket engines is also its main drawback in using it in gas turbines: its high flame speed. Flame speed is the rate at which a flame front advances through a combustible mixture of fuel and oxidiser. With 1.7 m/s, hydrogen has a significant higher flame speed than methane, at only 0.4 m/s. Furthermore, due to its low molecular weight, hydrogen also has a high reactivity and low flame stability. This also increases the sensitivity to flame stretch. Flame stretch is a phenomenon that occurs when a flame front, which is the boundary between the unburned and burned portions of a combustible

mixture, is subjected to varying flow velocities or turbulence in its environment. As the flame front interacts with these flow variations, it can become elongated or compressed, affecting its shape, propagation speed, and overall behaviour. Contrary to methane, the combustion of hydrogen in a turbine is much more erratic and unpredictable, with alternating regions of low and extremely high combustion temperatures. The latter is one of the main reasons for the increased NO_x emissions [115] [116].

It should be noted that the first generations of gas turbines also suffered from significant NO_x emissions. During the three decades following the widespread introduction of O/CCGTs, turbine manufacturers developed several techniques to lower these harmful emissions. For some time, Wet Low Emissions (WLE) was used, whereby water is injected into the gas turbine to lower the flame temperature and stabilise combustion. While this worked, it also reduced turbine efficiency.

The current state-of-the-art DLE techniques are based on research into advanced turbine design and operation. In DLE systems, fuel and air are premixed in a lean mixture before combustion. Lean mixtures contain a lower fuel-to-air ratio than stoichiometric (chemically balanced) mixtures, which can help reduce the peak flame temperature and thus mitigate NO_x formation. DLE systems use advanced combustion chamber designs that promote efficient mixing of fuel and air while minimising hotspots. This design helps maintain uniform temperature distribution and reduces the likelihood of high-temperature zones where NO_x formation is likely to occur. Some DLE systems employ staged combustion, where the combustion process is divided into multiple stages. In each stage, different amounts of fuel are injected to achieve efficient and controlled combustion, further lowering peak temperatures.

The concept of using hydrogen as a combustion fuel in power plants is relatively new. This means further research into DLE technology tailored to hydrogen is required in order to achieve efficient and reliable low-NO_x hydrogen turbines. Next to existing aspects of DLE, the design of advanced fuel injectors that disperse hydrogen uniformly and efficiently is a field of interest. E.g. to compensate for the high flame temperature and low stability of hydrogen combustion, micromix burners have shown high potential. Micromix burners are a type of combustion technology designed to achieve efficient and low-emission combustion processes in various applications, including industrial furnaces, gas turbines, boilers, and more. These burners are characterised by their ability to provide thorough mixing of fuel and air

on a very small scale, resulting in improved combustion performance and reduced emissions. Other potential technologies include catalytic combustion or advanced turbine cooling concepts.

Recent research has also indicated that the current methods used for measuring NO_x in exhaust gasses of gas turbines might inflate NO_x emissions in high-hydrogen systems by as much as 40%. Continuous NO_x analysers at power plants measure volumetric stack concentrations of pollutants, and not their actual mass production rates. The latter is derived by using a standardised sample analysis process, in which exhaust samples are dried, measured and the measurement value then corrected by a fuel-dependent factor. While this factor is well established for standard fuels such as natural gas, it can be shown that the factors used for hydrogen and hydrogen-methane blends as fuel indicate a higher volumetric concentration for the same mass concentration, indicating a new approach to NO_x emissions monitoring for power plants using hydrogen might be needed [117].

4.2.2 Retrofitting existing power plants

As the share of renewable energy continues to expand, conventional generation will see reduced running hours due to merit order effects. Dispatchable, weather-independent power plants, so called *firm power plants*, will however remain to play a crucial role to ensure security of supply and generate electricity during periods of low renewable energy production. Firm power plants with a high CAPEX/MW but low OPEX/MWh, e.g. nuclear, however require a high number of running hours to recuperate their costs in the market. Conversely, power plants with a lower CAPEX/MW but a higher OPEX/MWh are economically better suited to provide this firm back-up capacity. These can recuperate their costs with a lower amount of running hours provided these hours are marked by a high wholesale electricity price, which should be the case during tight security of supply conditions. The downside is that low CAPEX/MW, high OPEX/MWh technologies are currently mainly fossil-fueled, with the cost for fuel and emission allowances driving the OPEX/MWh.

Hydrogen as combustible fuel opens up perspectives to (re)use O/CCGT power plants as an emissions-free alternative to the use of natural gas. O/CCGTs have superior characteristics over other technologies to provide flexibility to the system:

- High power, often multiple 100MWs
- Fast and dynamic power ramping

- Fast start-up (in case of OCGT)
- Lower CAPEX/MW compared to other firm technologies, as discussed above.

The latter argument is especially true if we reuse existing, natural gas fuelled O/CCGT power plants, most of which will be written off, and so do not require any significant CAPEX anymore, by the time green hydrogen production ramps up to high volumes. The current Belgian O/CCGT fleet totals to more than 4GW, with an additional 1.5GW of smaller gas-fired plants. It is estimated that another 4GW of O/CCGTs will be built by 2030. This implies a large potential for later hydrogen refits [118].

CAPEX rates are estimated at 830€/kW for a new CCGT in 2030, and 435€/kW for a new OCGT [1]. Data from the CRM auction held by the federal government indicate this can be lower, up to 620€/kW if not starting from a greenfield but rather a new development on an already existing site [119]. For retrofits on existing power plants these costs can even be lower, but it depends on several technical factors. In the previous paragraph, we already touched upon the potential and challenges of using hydrogen as combustible fuel. As of 2023, limited blending of hydrogen by volume with natural gas is already performed at some natural gas fuelled power plants, especially ones with smaller gas turbine size (<100MW). With a volumetric ratio of 30% hydrogen, no significant changes are required to the turbine design. The CAPEX cost is estimated at 3.5-6€/kW.

To achieve a volumetric ratio of 30% hydrogen, modifications to the turbine are required in order to account for the changed flame characteristics, as discussed in the previous paragraphs. Additionally, the fuel piping needs to be modified so it can safely transport hydrogen. Gaskets will require replacing to account for the smaller molecular size of hydrogen. The CAPEX cost is estimated at 8-15€/kW. Fuel blends with up to 30% hydrogen are already used in several (smaller) power plants.

Increasing the volumetric ratio to 60% requires more significant changes. The turbine must be upgraded to account for the higher ratio of hydrogen. Piping needs to be replaced. A new fuel mixer is needed. As the density and amount of water vapour in the exhaust gasses changes, modifications to the Heat Recovery Steam Generator (HRSG) might be required. Selective Catalytic Reduction (SCR) of the exhaust gasses might be needed to keep NOx emissions within the regulatory boundaries. CAPEX is estimated at 20-30€/kW.

To achieve full hydrogen operation, a new gas turbine burner design is required (e.g. a micromix burner discussed in previous paragraphs) and the HRSG must be replaced. CAPEX is estimated at 25-55€/kW.

Table 3 shows an overview of the different hydrogen blending ranges, their estimated CAPEX impact and technical modifications which need to be made.

Table 3: Overview of CCGT retrofit changes required for hydrogen-fuelled operations, based on industry assumptions (Siemens, Engie)

Hydrogen range [%vol]	0-15	15-30	30-60	60-100
Retrofit CAPEX estimation [€/kW]	3,5-6	8-15	20-30	25-55
No changes required	Combustor Piping Turbine blades Fuel mixing HRSG SCR	Turbine blades Fuel mixing HRSG SCR		
Modifications required	Gaskets Instrumentation Control system	Combustor Piping Instrumentation Control system	Instrumentation Control system Turbine blades Fuel mixing HRSG	Instrumentation Control system Turbine blades HRSG
Replacement required		Gaskets	Gaskets Combustor Piping	Gaskets Combustor Piping Fuel mixing
Additional installation required			SCR	SCR
Overall assessment	No significant modifications	Minor modifications	Significant modifications	Major modifications

The CAPEX estimates for volumetric ratios higher than 30% hydrogen are based on industry best estimates, as no O/CCGT power plants could be found operating commercially at ratios of 40% hydrogen or more. High power turbine burners allowing 100% hydrogen fuel also have yet to reach commercial introduction. However, even if these estimates are only ballpark figures, it does give a sense of scale to the amount of required CAPEX for retrofitting an existing CCGT. Even using worst estimates, the estimation is limited to 10% of the CAPEX of a new plant, indicating a hydrogen retrofit should be an economic possibility.

4.2.3 Hydrogen logistics

Of all gaseous combustible fuels, hydrogen has a very high energy density by mass of approximately 142 MJ/kg, making it very suitable for energy-intensive applications requiring low mass or mechanical inertia like rockets. Natural gas, by comparison, contains only 56 MJ/kg. At Standard Temperature and Pressure (STP), hydrogen however has an extremely low density, containing just 0.0899 kg/m³. By comparison, natural gas has a density of 0.657 kg/m³. This has a significant impact on the volumetric energy density, with hydrogen containing 10.8 MJ/m³ and natural gas 37 MJ/m³ (lower heating value, STP). In fact, the volumetric energy density of hydrogen is the lowest of all common gaseous or liquid fuels.

The low volumetric energy density of hydrogen poses significant logistical challenges in transporting and storing the fuel. Typically, gaseous fuels are compressed or cooled to a liquid to increase their volumetric energy density, making transportation more efficient. Natural gas becomes a liquid at a temperature of -168 °C, increasing its volumetric energy density to around 20.8 GJ/m³. This is called Liquefied Natural Gas (LNG). The benefit of LNG is that little to no compression is required, allowing the liquid to be handled at atmospheric pressures. This simplifies transportation infrastructure such as LNG carriers, as they do not have to be equipped with the weight of high-pressure containment vessels, instead only requiring thermal insulation.

Hydrogen can only be liquified by cooling as its critical point (the point above which it cannot be liquefied, no matter how much pressure is applied) is at a temperature of -239.95 °C and a pressure of 1.3 MPa. This means that above this temperature, no amount of pressure will liquefy hydrogen, it must be cooled. To be able to liquify hydrogen at standard pressure, it must be cooled to a cryogenic -252.87 °C and kept at that temperature. If the container is not insulated perfectly, warming hydrogen will continuously escape into the atmosphere (the so-called *boil-off*). Reaching these temperatures is only possible with expansive and energy-intensive cryogenic cooling. Even then, liquified hydrogen only reaches a volumetric energy density of 8.9 GJ/m³, under half that of natural gas.

A more energy efficient way to increase the volumetric energy density of hydrogen is by compressing it. A pressure of 18 - 22MPa is standard practice to transport hydrogen in so-called tube trailers. However, at this pressure hydrogen only carries 1.8 GJ/m³. This is quite low, even compared to Compressed Natural Gas, a non-liquified form of gas storage at a pressure of 45 MPa. CNG contains 9 GJ/m³, roughly equivalent to liquified hydrogen.

To give an idea of the logistical challenges of running a power plant on hydrogen, let us consider a large LNG tanker with a capacity of 160,000 m³ LNG. With a density of 475 kg/m³ and using a lower heating value of 55.5 MJ/kg, this ship carries around 1.172 GWh of natural gas.

Given an 800 MW CCGT running at 65% efficiency, this power plant consumes 29.5 GWh of natural gas per day. Ignoring conversion losses, this means the CCGT can run 39.7 days on the contents of the LNG carrier.

Considering a liquid hydrogen carrier with the same capacity of 160,000 m³. Taking a density of 70.85 kg/m³ and a lower heating value of 120 MJ/kg, this equates to approximately 378 GWh, or around one third the energy contents of the LNG carrier. Considering the same efficiency, the CCGT can run for 12.8 days on this volume of gas.

Substituting natural gas for hydrogen would require a threefold increase in carrier shipments if the gas were to be imported, assuming liquid hydrogen carriers equal the size of LNG carriers can be built. But the challenges do not end with the import and transportation infrastructure. Typically, natural gas is stored at standard temperatures and pressures of 8 to 28 MPa, reaching a density of 67 to 228 kg/m³ and a volumetric energy density of 1 to 3.5 MWh/m³.

Due to reasons of material properties and costs, large amounts of gaseous hydrogen are usually not stored at pressures exceeding 10 MPa in aboveground vessels and 20 MPa in underground storages [120]. With restricted storage pressures, so are the achievable hydrogen storage densities also limited: at 10 MPa and 20 °C, the density of hydrogen gas is approximately 7.8 kg/m³, translating to an energy density of around 0.25 MWh/m³.

The significant challenges associated with hydrogen transport and storage make it an unwieldy fuel, and probably unlikely to be used as a main energy source for large-scale electricity generation. However, it does show potential as a reserve fuel, intended to be used in (retrofitted) O/CCGTs to provide back-up power during periods of low renewable energy production. During these periods wholesale electricity prices will be high, providing an offset to the costly logistics.

It should be noted that there are other methods of mitigating the logistical challenges of transporting and storing hydrogen. Hydrogen can be hydrogenated with organic molecules such as toluene, creating a dense and stable molecule suitable for transportation and storage. Hydrogen can be

adsorbed in porous carbon-based materials, metal-organic frameworks, porous polymeric materials or zeolites with similar results. Or it can be chemically bonded with other molecules, creating formic acid, ammonia or methanol which can be safely transported and used directly as an energy source or feedstock for the chemical industry. All these options, however, come with other drawbacks, especially concerning the energy required for the conversion processes [121]. A full evaluation is beyond the scope of this dissertation.

4.3 Conclusions: hydrogen as a flexibility vector

In this chapter, the electrolytic production of hydrogen and its use as a flexible energy carrier has been analysed. Hydrogen is an element with many industrial uses, but currently more than 96% of it is produced from fossil fuel.

Hydrogen can be produced electrolytically, by splitting water molecules into hydrogen and oxygen using electricity, a process called electrolysis. The wide dynamic power range of most electrolyzers allows for the modulation of their output in alignment with the fluctuating production of renewable energy sources. Given the increasing demand for low-carbon hydrogen in industries such as chemicals and steelmaking, the concept of flexible electrolytic hydrogen production appeared promising.

However, the findings suggest that electrolytic hydrogen production faces limitations as a large-scale flexibility solution due to both technical and economic factors. The consistent wear and tear on electrolyzers regardless of load factor, coupled with the need for increased capacity to maintain production volumes at lower average load factors, escalates capital expenditure and, by extension, the cost of hydrogen production. In a typical European context, achieving competitive hydrogen production costs necessitates high load factors, often exceeding 6000 equivalent full load hours annually, positioning hydrogen production more as a baseload rather than a flexible process.

Hydrogen can also be used as a sustainable combustible fuel. This opens potential avenues for flexible power generation in thermal power plants, particularly by retrofitting existing natural gas-fired plants. This offers the advantage of maintaining operational flexibility of CCGT and OCGT, while eliminating the carbon emissions should they have run with natural gas as fuel.

This chapter validated the technological viability of retrofitting modern installations to be 'hydrogen-ready'. Such plants can accommodate hydrogen blends up to 30% with minimal modifications and up to 50% with more extensive alterations, with the capital expenditure for these adaptations being relatively modest.

Despite the technological appeal and low investment requirement for converting natural gas power plants to hydrogen, the overall feasibility hinges on the sustainable production, storage, and transportation of hydrogen. The challenges associated with the high energy input required for sustainable hydrogen production and its low volumetric energy density render it an improbable primary energy source for extensive electricity generation. However, its utility as a reserve fuel in retrofitted gas turbines, providing backup during low renewable energy output, highlights its potential contribution to the energy mix.

5 The residential consumer as a source of flexibility

The effects of climate change on the daily lives of people in Belgium and abroad have become undeniable, underlining the need to accelerate the fossil fuel phase-out. As discussed in the introduction, this energy transition requires the large-scale electrification of our energy consumption, powered by sustainable, renewable energy sources.

In recent decades, Belgium has taken important steps in this area such as pioneering offshore wind energy and expediting the installation of PV panels, especially rooftop solar. This has however also brought its own share of challenges, such as increased chance of congestion on the distribution grid and, increasingly, large price swings on wholesale electricity markets during the summer because of residential PV systems not participating in the market.

The shift towards electrification will also have other impacts. There are 6 million passenger cars in Belgium, and 84% of homes are heated with boilers using natural gas or heating oil. If these are all to become electric, the grid will be faced with challenges that have never been seen before.

As the intermittency in electricity production increases, so should flexibility increase in residual production and, most importantly, electricity consumption. In the context of electricity consumption, DSR and DSM are commonly used. DSR focuses on the immediate response of electricity consumers to price signals, while DSM encompasses a broader perspective that includes long-term energy efficiency measures as well.

In the following sections, some potential sources of residential flexibility are investigated. It is analysed if solar PV panel orientation can provide “passive” flexibility by adding heterogeneity to the energy injection profile, and what the potential and barriers for providing “active” flexibility with residential assets such as heat pumps and electric vehicles are.

5.1 Types of flexibility

Literature defines implicit flexibility as flexibility which is not forced upon a participant or participating asset, but rather *suggested*, e.g. through a price signal which may or may not entice the participant to decrease (or increase) their consumption. For the end-user, this form of flexibility is the least

intrusive, as they might or might not react on the implicit signals depending on other boundary conditions. Participation, and as such the volume of activated flexibility, is therefore uncertain.

Explicit flexibility on the other hand is the direct activation of flexibility, e.g. an increase or decrease in consumption, by a contracted participant. This activation is controlled by an explicit signal containing the activation conditions such as volume, power and duration of the flexibility which must be delivered, and is in line with a (contractual) agreement both the participant and the activation requesting party have engaged in.

While the concepts of implicit and explicit flexibility are quite clear in theory, and can often be applied this way in large-scale industrial flexibility, the concepts are less apparent when used with residential flexibility. The technological value chain is more complex there, often with several actors involved and with less straightforward revenue generating processes. E.g. can a control signal to deactivate a heat pump during high electricity prices, generated on the centralised cloud of a flexibility service provider the end-user has contracted to lower their energy bills, still considered implicit flexibility? Or what about a flexibility service provider sending this signal because they need to activate contracted volume on the reserve markets, but with the end-user temporarily opting out due to personal reasons (e.g. they are ill and require higher indoor climate comfort)?

This dissertation proposes an augmentation of the current definitions regarding the forms of flexibility. Specifically, the decoupling of the *technical* aspects of *where* the signals controlling the residential assets are generated from the rationale *why* and *how* the signals were generated is proposed and *which* party the flexibility activation directly benefits.

As will be discussed in section 5.3 *Flexibility by residential assets*, there is currently no definite way how residential flexibility can be organised on the technical level, nor is there currently a view on pending regulation to expedite this. Residential flexibility is characterised by a wide diversity of assets having a flexibility potential, but also possessing wildly different characteristics and dynamics (e.g. heat pumps, electric vehicles, home batteries, etc.). Furthermore, a single household will typically contain assets from different manufacturers, each implementing their own way of letting the asset be controlled externally (if it is allowed). Due to their low individual impact on revenue generation by flexible operation, installing complex control systems on the assets is financially not viable.

The most likely option(s) to prevail in the future seems to be digitally connected assets, using an API and a local/cloud-based/hybrid control system. This control system can be provided by the manufacturer of the asset, by a third party or be part of a local home automation system. Arguably it will be (at least partly) cloud based for better maintainability of the software and to interface it with market price signals.

This implies that generation of the control signals, independent of the type of flexibility, will likely originate from this cloud and, as such, from outside of the household. Concerning implicit flexibility, where, in an industrial process, the process or business operator would make control decisions over their process based on the availability of market price signals in residential flexibility it can be expected that end-users delegate this responsibility to a (remote) third party. This party generates and sends the control signals to the assets, which are expected to carry them out. According to the theoretical definitions discussed above, this would make it explicit flexibility. However, it arguably remains implicit flexibility, yet automated and controlled remotely.

To further delineate this concept, the type and place of the generated benefit can be considered as well. In the example above, the optimisation performed by the third-party is in the direct benefit of the end-user. E.g., the remote party takes in the state of the different assets in the household assigned to provide flexibility, takes in the actual values of the digital meter (consumption/injection) and considers the current wholesale electricity prices to make an optimal scheduling of the assets so the electricity cost is minimised (also taking capacity tariffs, if applicable, into account. This results in a lower total cost of the electricity consumption of the household, which is directly apparent on their (e.g. monthly) bills without the intervention of a third party.

An example of explicit flexibility could be identical in the way *where* the control signals are generated, but differ from *why* they are generated and *who* is the directly benefitting party. Consider an aggregator having an active contract to supply activation volume to the ancillary services market, e.g. automatic frequency restoration. When requested by the TSO, this aggregator, or a contracted third party, can generate the control signals in much the same way as with implicit flexibility, e.g. taking the status of the different flexibility providing assets in the household into account. However, activation of these assets now does not necessarily impact the electricity consumption cost of the household, or could even impact it negatively (e.g.

reducing PV output or increasing consumption). The aggregator generates revenue from the activation of the volume, and then compensates the participants for their activation and/or additional costs incurred by splitting and sharing a part of this generated revenue. The generation of the control signals therefor must also optimise for total cost, including this external revenue.

In order to augment and adapt the existing definitions of flexibility to the residential level, the following characteristics are proposed.

For implicit flexibility:

- The optimisation goal is to reduce the total electricity consumption cost directly, e.g. by shifting consumption to hours of lower electricity price.
- The optimisation can be automated and/or done remotely, with only the control signals being sent to the participating assets of the household.
- The participants have a straightforward method to (temporarily) opt out of the optimisation and can do this an unlimited number of times.

For explicit flexibility:

- The optimisation goal is to generate revenue with a service provided externally to the participating households, e.g. ancillary services, with this revenue being distributed ex-post.
- The optimisation is done remotely, with signals sent to the participating assets of the household.
- The opt-out conditions are defined in an agreement between the participating household and the flexibility service provider.

Note that, using the same technical control chain and value chain, implicit and explicit flexibility can be provided interchangeably. E.g., a household could subscribe to the implicit optimisation services of a third party but also enrol in an explicit flexibility program of the same provider. While not actively exercising explicit flexibility, implicit flexibility is provided in the time in between.

Additionally, the definition of a new form of electrical flexibility is proposed: (semi-)passive flexibility. This is a form of residential flexibility which requires no, or only singular, interaction with the end-user. It is a passive optimisation which has the benefit of being uncomplicated to setup, but is not guaranteed to always have the best effect as the optimisation does not take actual

(measured) parameters into account. An example is setting the heating of the domestic hot water tank to occur during noon, because wholesale electricity prices generally tend to be lowest during noon, or because this generally coincides with the peak production of installed solar PV. Actual prices or PV generation might however differ from day to day, thereby leading to optimisation failure on some days. However, the average optimisation result is positive, with the occasional losses being a trade-off for the simplicity of this method. Figure 12 displays a summary of the proposed flexibility definitions with some examples.

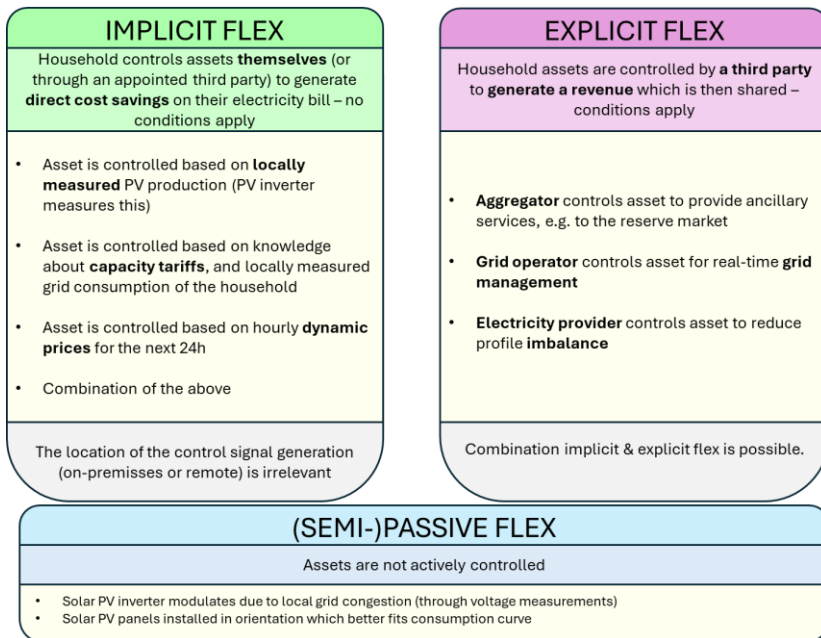


Figure 12: Comparison of proposed definitions of residential flexibility

Note that, in the future, a household might employ different forms of flexibility which could be in conflict. If (European) policy makers decide to view “flexibility” as a different product than “electricity provision”, households could engage in multiple contracts at once: a retail electricity supply contract, an electricity injection contract, and an electricity flexibility contract. While retailers could be using price signals to elicit implicit flexibility with their customers and thereby reduce their profile balancing costs, the customer could have contracted their EV or heat pump to a flexibility service provider which actually benefits from suppliers’ imbalance as they can then

sell their aggregated flexibility volume on the imbalance market. It remains to be seen how this complexity will play out in the future.

5.2 Impact of solar panel orientation on production profile

Solar PV has undoubtedly become the main driver behind the transition to renewable energy. This especially holds true for Belgium. From a modest installed capacity of 112MW in 2008, over the years this has grown to 9,9GW at the end of 2023 [122].

A large share of solar energy in the electricity mix comes with its own problems. Most of the installations are not-responsive to the grid or the wider electricity system. Because of their concentration, they all have similar yield curves. These two issues have given rise to the infamous “duck curve”, where high solar injection at noon depresses wholesale electricity prices and pushes other electricity producers out of the market.

A possible solution that does not rely on possibly expensive hardware or software upgrades can be investigated. It has already been shown that different horizontal and vertical orientations of PV panels can benefit the electricity system as a whole by increasing the coincidence between PV production and electricity consumption [123].

Indeed, by varying the orientation the typical PV production peak at noon can be flattened, and power production can be shifted towards the morning and early evening, better matching the typical residential consumption profile. This is a form of passive flexibility, as defined in section 5.1 *Types of flexibility*.

The effect of different orientations of the panels of the PV installation on the energy production curve and the accompanying impact on the distribution grid has however not been intensively studied for its impact in Belgium. One of the issues is that the prevalent irradiation models for PV yield calculation do not account for specifics of Belgian weather.

In this section, a methodology for calculating the yield and production curve of arbitrarily oriented PV systems based on a limited number of required parameters and using an anisotropic-all-sky model better suited for Western-European conditions than the prevalent isotropic model is presented, and

simulations based on real residential load profiles and grid parameters are used to provide a realistic and accurate validation of this research objective.

However, the methodology is valid for any arbitrarily chosen location where irradiation data are available.

The output of a PV system is dependent on the amount of solar irradiance received by the active surface of the PV panels, with the irradiance having a direct (beam) and a diffuse component [124]. The intensity of the direct beam radiation is highly dependent on the incident angle θ , which is the angle of the sunbeam on the surface of a PV panel to the normal of that surface. This geometric relationship can be described in terms of several angles [125], as shown in Figure 13 adapted from [126].

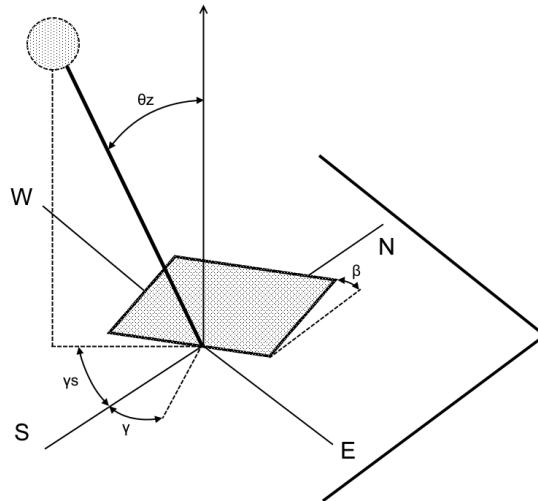


Figure 13: Direction of beam radiation and its associated angles

- β Tilt angle of the surface of the PV panel to the horizontal
- θ_z Zenith angle, the angle between the vertical and the sunbeam
- γ Surface azimuth angle, the angle between the south and the normal of the PV panel surface as projected on the horizontal plane, with east of south being negative and west of south being positive
- γ_s Solar azimuth angle, similarly to γ the angle between the south and the sunbeam as projected on the horizontal plane

Simple trigonometry allows us to calculate the incident angle θ as

$$\cos \theta = \cos \theta_z \cdot \cos \beta + \sin \theta_z \cdot \sin \beta \cdot \cos (\gamma_s - \gamma) \quad (1)$$

To calculate the intensity of the diffuse irradiation on the PV panel this dissertation uses an adapted version of the anisotropic-all-sky model proposed in [126] called 'all-sky distribution', instead of the more straightforward isotropic model commonly used in literature. Isotropic models provide accurate calculations of diffuse radiation on tilted surfaces under overcast skies, but tend to underestimate during clear skies. Conversely, models assuming anisotropic distribution perform well under clear skies but overestimate under overcast skies. Because Belgium has both clouded and clear sky situations throughout the year, the all-sky distribution used in this dissertation combines both isotropic and anisotropic assumptions for maximum accuracy.

The total irradiation on the tilted surface is calculated by summing the intensity of the beam irradiation and diffuse irradiation:

$$G_t = \frac{(G_h - G_{dh})}{\cos \theta_z} \cdot \cos \theta + G_{dh} \cdot \left[\frac{1 + \cos \beta}{2} \right] \cdot \left[1 + F \cdot \sin^3 \frac{\beta}{2} \right] \cdot [1 + F \cdot \cos^2 \theta \cdot \sin^3 \theta_z] \quad (2)$$

with

$$F = 1 - \left(\frac{G_{dh}}{G_h} \right)^2 \quad (3)$$

and

G_t	Total irradiation on the tilted surface of the PV panel in W/m^2
G_h	Total irradiation on a horizontal surface
G_{dh}	Total diffuse irradiation on a horizontal surface

The last two terms in the equation represent the anisotropic distribution. During overcast skies, when most of the total irradiation is in the form of the diffuse component, parameter F becomes zero making the model revert to the isotropic distribution. When diffuse radiation is present, the model tends to the isotropic variant.

With total irradiance G_t known, the power output of a PV panel with known power rating and efficiency can be calculated. In this dissertation a modified version of the PV model developed by [127] as described in [128] is used, in which the power output is only dependent on G_t and PV module temperature T_{mod} :

$$P_{DC}(G_t, T_{mod}) = P_{STC} \cdot \frac{G_t}{G_{STC}} \cdot \eta_{rel}(G', T') \cdot \eta_{sys} \quad (4)$$

with

P_{DC}	Power output of the PV panel under conditions G_t and T_{mod}
P_{STC}	Power output of the PV panel at Standard Test Conditions (STC)
G_{STC}	Irradiation at STC, typically 1000 W/m ²
η_{rel}	Instantaneous relative efficiency
η_{sys}	System efficiency
G', T'	Irradiance and temperature normalised to STC values according to

$$G' = \frac{G_t}{G_{STC}} \quad (5)$$

and

$$T' = T_{mod} - T_{mod_STC} \quad (6)$$

Parameter η_{rel} normalises the efficiency of the PV panel, which is measured under STC, to the instantaneous values of irradiance and temperature, taking the temperature dependence of the PV panel into account. This instantaneous relative efficiency is given by

$$\eta_{rel}(G', T') = 1 + k_1 \cdot \ln G' + k_2 \cdot (\ln G')^2 + T' \cdot (k_3 + k_4 \cdot \ln G' + k_5 \cdot (\ln G')^2) + k_6 \cdot T'^2 \quad (7)$$

The coefficients k_1 to k_6 are determined empirically. In [128] measurements taken from 16 different crystalline silicon (c-Si) modules at the JRC Ispra test site in Italy are described. These will be used here.

Module temperature T_{mod} can be estimated from the ambient temperature T_{amb} and G_t by:

$$T_{\text{mod}} = T_{\text{amb}} + c_t \cdot G_t \quad (8)$$

Parameter c_t describes the self-heating of the module by the incident irradiation and is determined by the mounting system of the PV panel. Roof integrated systems heat up faster ($c_t = 0.056 \text{ Km}^2/\text{W}$) than free-standing installations ($c_t = 0.02 \text{ Km}^2/\text{W}$) [129].

Wind speed and wind direction are not included in the calculation of T_{mod} , as it is generally accepted that this makes calculations overly complex without significantly improving model accuracy [127].

Finally, η_{sys} describes additional system losses such as nameplate deviation (-5%), module mismatch (-1.5%), ohmic cable losses (-1.5%) and soiling (-1%), confirming by operational experience by both the author of this dissertation and [129]. These losses are assumed static. Also, the PV modules are assumed to be used with a continuous Maximum Power Point Tracking (MPPT) inverter.

The Royal Meteorological Institute (RMI) of Belgium provided a dataset containing three years' values of 10 min averages of parameters G_h , G_{dh} , θ_z and γ_s , as well as T_{amb} , as measured on a central location in Flanders.

PV inverters combine two complex power-electronic stages into one device which is placed between the PV panels and the main grid. The first stage traditionally consists of a dc-dc boost converter which controls the voltage applied to the PV panels so that they operate on or near their Maximum Power Point (MPP). The second stage is a switch-mode inverter that transforms the direct current generated by the PV panels into alternating current suitable for injection in the main grid, normally at unity power factor (PF). The combined efficiency is calculated as:

$$\eta_{\text{inv}} = \frac{P_{\text{AC}}}{P_{\text{DC}}} \quad (9)$$

with P_{AC} the power that is injected into the grid:

$$P_{\text{AC}} = P_{\text{DC}} - P_{\text{loss}} \quad (10)$$

The power losses P_{loss} in an inverter consist of both a static and a dynamic part. The static part is essentially the power consumed by the control logic and auxiliaries such as communication (Ethernet, display, etc.). The dynamic consists of the losses over the semiconductor switches, magnetic components, wiring and capacitor losses, which are dependent on the current and thus power flowing through them.

In datasheets and literature, the Euro-efficiency value is often conveniently used as an approximation of the total inverter losses of a traditional installation used in Europe [130]. This is described as:

$$\eta_{eur} = 0.03 \cdot \eta_{5\%} + 0.06 \cdot \eta_{10\%} + 0.13 \cdot \eta_{20\%} + 0.10 \cdot \eta_{30\%} + 0.48 \cdot \eta_{50\%} + 0.2 \cdot \eta_{100\%} \quad (11)$$

This assumes that the inverter will work for 20% of the time at maximum power, 48% of the time at half of its maximum power etc. In this dissertation we evaluate the power output of a PV system however at different angles and azimuths, possibly leading to vastly different power regimes imposed on the inverter than in the traditional case. In [131], a simple mathematical model that describes the efficiency curve of any solar inverter under variable load is presented:

$$\eta(P_{\text{DC},\text{pu}}) = A + B \cdot P_{\text{DC},\text{pu}} + \frac{C}{P_{\text{DC},\text{pu}}} \quad (12)$$

And

$$P_{\text{DC},\text{pu}} = \frac{P_{\text{DC}}}{P_{\text{inv}}} \quad (13)$$

with P_{inv} being the rated power of the inverter and the coefficients A, B and C being parameters that represent the efficiency of the inverter at certain points along the inverter efficiency curve. The authors of [131] suggest taking the efficiencies at respectively $P_{\text{DC},\text{pu}}=0.1$, 0.2 and 1 because these represent the bending points and end point in the efficiency curve of a typical PV inverter. With $\eta(P_{\text{DC},\text{pu}})$ at these points known from the datasheet, solving a system of linear equations yields parameters A, B and C. These can then be used to calculate the inverter efficiency under each occurring load. In this dissertation we also added an additional static loss of -1.5% due to nameplate deviation of the inverter.

The combined PV and inverter model allow to simulate realistic AC energy production profiles for any arbitrary orientation of the PV system, based on the RMI provided solar measurements. This model and the input data are added to a realistic LV feeder network to investigate the impact of different orientations on the power quality and efficiency of the grid. A complete description of this model and its assumptions can be found in [2].

5.2.1 Total PV production

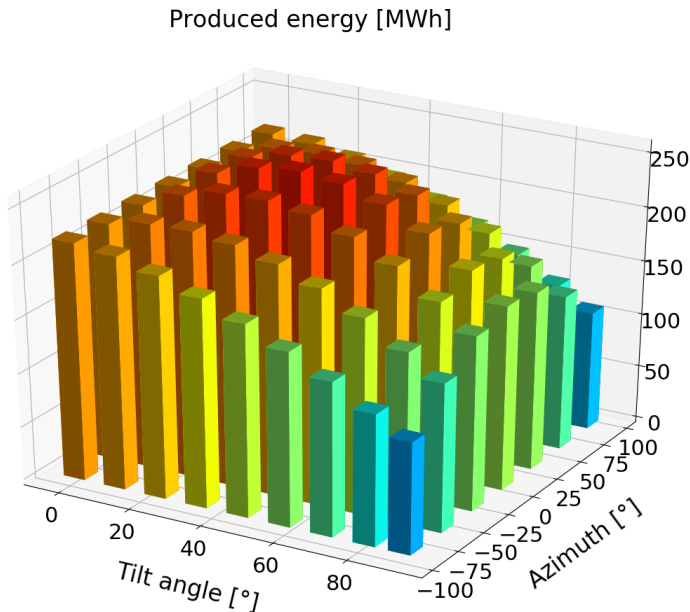


Figure 14: Yearly combined PV output for all tilt and azimuth angles

Figure 14 displays the total PV production. This is the yearly output energy of all PV systems in the simulated feeder combined. The [34.5:0] ([tilt angle:azimuth]) simulation yields the greatest output of 256 MWh per year, while [90:-90] and [90:90] score 110 MWh and 105 MWh respectively. This is to be expected, since the optimal orientation of a PV system at the latitude of Belgium is considered to be [35:0].

Notice that lowering the tilt angle of the PV panels in general only slightly decreases the output of the PV system, while increasing the tilt angle leads to rapidly dropping yields once the optimal orientation has been passed. This again is due to the specific geographical coordinates of Belgium, and will change with different latitudes. It also shows that deviating from optimal

angles can have a severe effect on PV yield. E.g., deviating from [34.5:0] to [11.5:-30] leads to a drop in yearly production output of 7.6%.

5.2.2 Curtailed PV production

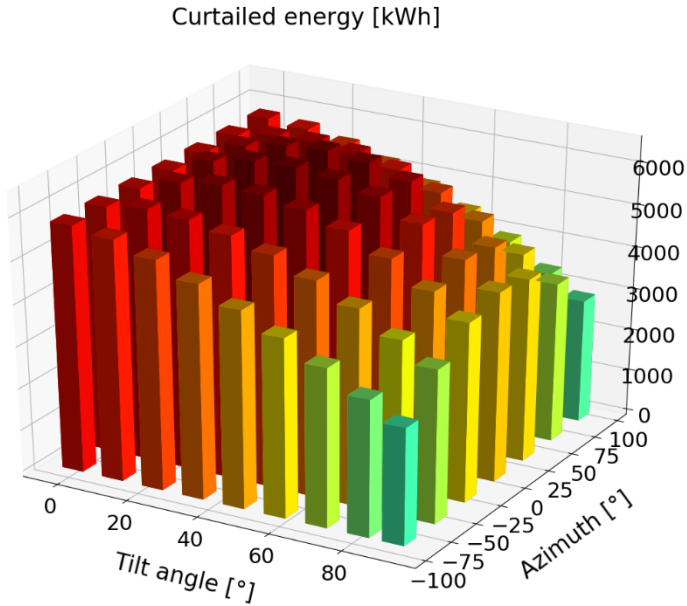


Figure 15: Yearly curtailed PV output for all tilt and azimuth angles

Figure 15 displays the amount of curtailed PV production. This quantifies the total amount of PV production that is curtailed, and thus lost, across the feeder due to overvoltage conditions experienced by the solar inverters. In other words, it is the additional energy that could have been generated if no overvoltages were to happen. If the inverter experiences an overvoltage condition, it disconnects from the grid until the overvoltage condition has ended.

The profile of curtailed PV energy is similar to that of the produced PV energy. Indeed, as PV production is increased, so do the chances of overvoltage conditions increase because the grid has to absorb more PV production, leading to a voltage rise.

The maximum PV production curtailed is again at the [34.5:0] orientation, where 6.4MWh of production is lost. The least PV production is lost at the [90:90] orientation, where 2.9MWh of production is curtailed.

5.2.3 Time shifting of PV yield curves

The developed model also allows for the plotting of daily PV yield curves. This is useful to compare the flexibility by heterogeneity in different PV panel orientations can bring to the injection profile on the electrical grid. Two 1kW systems are compared:

- One system with its array completely oriented south,
- One system split in two 500W arrays, facing completely east and west respectively.

The inclination of both arrays are kept at 35°. Daily yield curves for several seasons are compared.

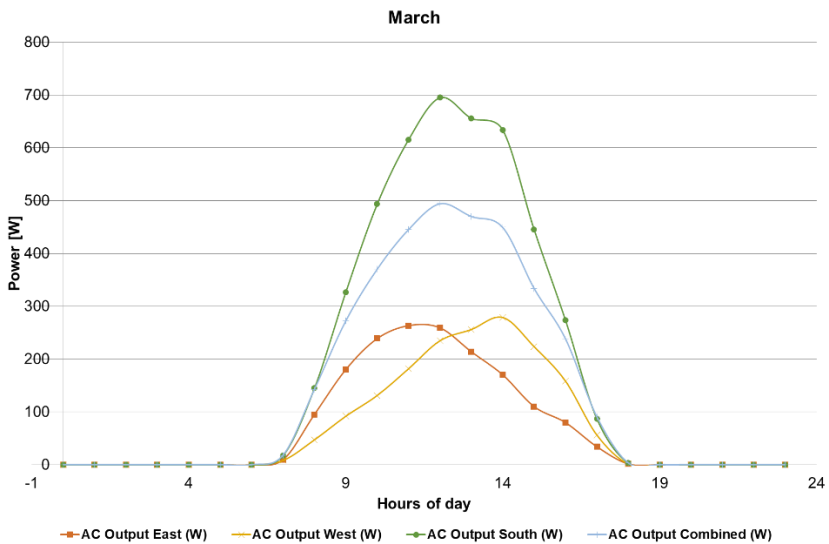


Figure 16: PV yield curves for unitary, South-facing array and split, East-West facing array during an average day in March

Figure 16 shows that, for early spring, there is no noticeable time shift in the combined (east + west) yield of the split oriented array. A yield increase is present from 8h, with a similar slope as the unitary array. Similarly, the downward slope analog and drops to zero at around 18h. Note that the maximum combined output is however lower than the unitary array, verifying the findings earlier.

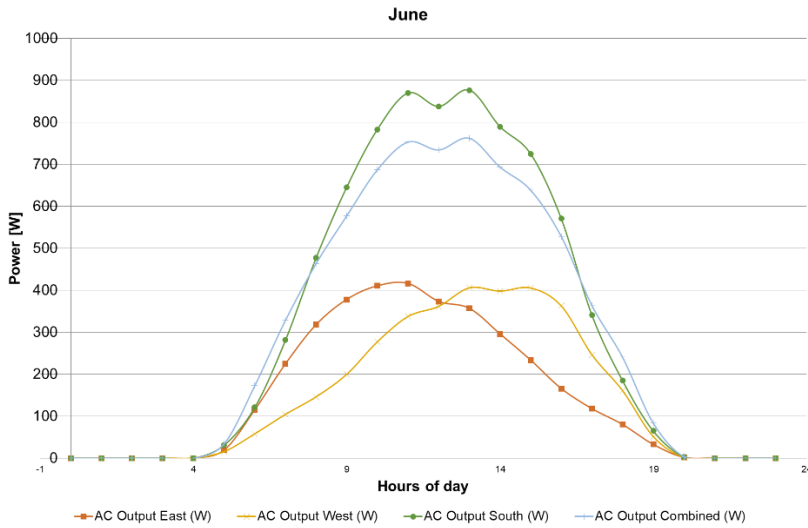


Figure 17: PV yield curves for unitary, South-facing array and split, East-West facing array during an average day in June

During a summer day, depicted in Figure 17, the yield curve of the split array shows a small but noticeable time shift. Both arrays “wake” up at the same time, but the split array yield has a slightly higher slope than the unitary array. However, the effect is negligible. The maximum output is, again, lower for the split array than for the unitary array.

For a winter day, shown in Figure 17, the results are similar but opposite as the summer day. The unitary array “awakes” somewhat earlier than the split array, and also shows a steeper slope than the split array. Similarly, the split array yield drops earlier than the unitary array in the afternoon. The maximum yield of the unitary array is remarkably higher than the one of the split array.

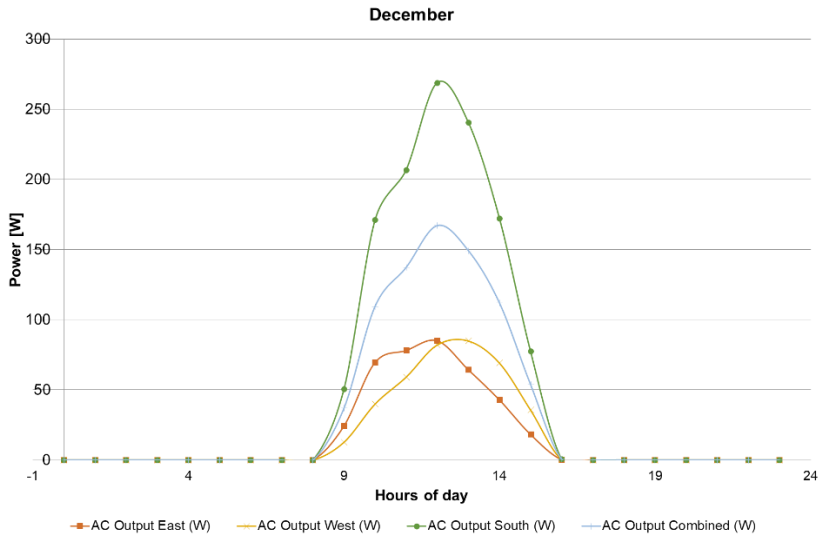


Figure 18: PV yield curves for unitary, South-facing array and split, East-West facing array during an average day in December

As such, it can be concluded that different orientations of PV panel arrays has a negligible impact on the spread or time shifting of the PV yield curve. Any flexibility coming from solar PV installations must therefore be “explicit”, e.g. by controlling yield or MPPT setpoints.

5.3 Flexibility by residential assets

With the increasing share of intermittent renewable energy production in the total electricity mix, the energy production profile has become more erratic as well. Storage, effectively levelling peaks in production and consumption, is one option, but currently technically infeasible for large volumes of energy. Another option is aligning consumption more with production, via DSM and DSR.

DSM emerged in industry following the oil crises of 1973 and 1979, as an offshoot of increasing industrial energy efficiency. DSM is the practice of reducing electricity usage, particularly during peak hours, by shifting consumption to off-peak periods. This approach aimed to avoid the operation of costlier oil-based power plants, thereby reducing electricity production expenses and overall costs for consumers.

In contemporary usage, the terms DSM and DSR have been expanded to encompass the provision of ancillary services by consumers to the TSO and

the balancing of variable electricity production from renewable energy sources. Ancillary services, also known as system services, are essential for maintaining grid frequency and voltage within acceptable levels and are sourced by the TSO. Since the TSO does not possess any flexible assets to provide these services, it relies on grid users, including both consumers and producers, to contribute flexibility.

While the primary incentive for DSM remains economically driven, such as through variable electricity pricing or remuneration for ancillary services, an environmental dimension has been added. The provision of ancillary services by loads helps reduce the need for fossil fuel-based power plants to provide such services, thereby lowering CO₂ emissions. In contrast to the 1970s, where peak electricity prices were to be avoided due to the use of oil peaking plants during periods of soaring oil prices, the consumption of low marginal cost RES electricity is now incentivised due to the existence of price valleys.

Until now, DSM and DSR have been largely the exclusive domain of large industrial electricity consumers. However, the recent energy crisis has shown the potential for at least DSM is also present in residential energy consumption. In 2022, Belgian household electricity consumption was down more than 12% than average. This validates the significant potential of demand side flexibility among residential consumers, and that (wholesale) pricing plays an important signalling role in this.

With the increasing electrification of heating and passenger transport, the role of this residential flexibility will also expand do DSR. The batteries of electric vehicles and the thermal inertia of homes heated by heat pumps present powerful opportunities for smart energy use.

5.3.1 Current evolutions

The electrification of heating within residential, transportation, and industrial sectors is experiencing a notable acceleration. Legislative bodies are enacting measures to foster electrification while concurrently diminishing reliance on fossil fuel-derived solutions within these domains. The widespread integration of heat pumps is emerging as a cornerstone in the transition towards sustainable energy, contributing significantly to the realization of carbon neutrality, aligning with the objectives stipulated by the European Green Deal. It further underscores the imperative of prioritising investments in renewable energy sources and energy efficiency measures to diminish Europe's dependency on fossil fuel imports and advocates for a twofold increase in the current rate of heat pump installations in homes.

In the year 2022, heat pump sales within Europe achieved a landmark, with transactions exceeding 3 million units. This significant milestone represents a 38% augmentation in sales compared to the figures recorded in. As delineated by the European Heat Pump Association (EHPA), the demand for heat pumps, designated for heating and sanitary water applications, has witnessed substantial expansion across all Member States. Remarkably, sales in certain nations, such as Belgium, have escalated by over 60%. This surge is largely attributable to the phased introduction of prohibitions against fossil fuel-based heating apparatus in new constructions (and potentially in existing structures, as suggested in Germany and the Netherlands). Nonetheless, in absolute terms, the annual sales volume of heat pumps remains inferior when contrasted with, for instance, the annual installations of gas boilers.

Flexible demand-side management has long been a reality in industry, making an increasingly important contribution to grid stability and security of supply. Distributed, residential flexibility, however, has a number of specific challenges that have so far remained unresolved. Given the limited impact of individual residential electric consumers, large numbers need to be aggregated. Compared to industrial applications, this increases the up-front installation cost and management complexity, while the yield margin per individual installation is very small. Reducing the complexity and installation cost of residential flexibility is therefore a key concern.

Likewise, the electrification of the transportation sector is accelerating, especially concerning personal automobiles. The forthcoming prohibition by the European Union on the sale of new gasoline and diesel vehicles (excluding those powered by e-fuels) from 2035 is anticipated to markedly accelerate the uptake of electric vehicles (EVs) throughout Europe. Notably, in the Nordic countries, EVs constitute about 40% or more of total vehicle sales. In the Central Western European region, the penetration rate of EVs (encompassing both battery EVs and plug-in hybrid EVs) in the market oscillates between 20% and 40%. Various national policies have been enacted to foster the adoption of EVs, accompanied by the substantial rollout of public charging infrastructure to facilitate this transition. In Belgium, tax policies related to company vehicles are poised to significantly drive the widespread adoption of EVs on Belgian thoroughfares in the forthcoming period.

This electrification is expected to have a high impact on the Belgian electricity system. TSO Elia expects new EV and HP will add up to 20TWh of electrical energy consumption by 2035 [1].

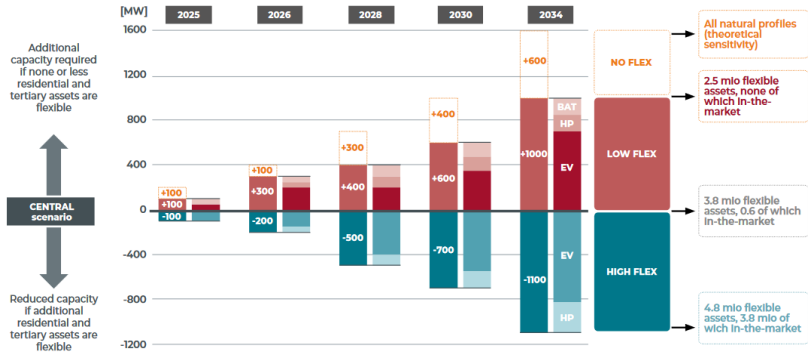


Figure 19: Impact of flexibility on new capacity additions in the Belgian system (Elia)

More importantly is the impact on additional capacity needs if that electricity consumption is not made flexible. Figure 19 shows the influence of flexibility sensitivities on the adequacy calculations of Elia, with a particular emphasis on delineating the roles of EV, HPs and residential battery storage systems under scenarios of high and low flexibility. In the context of low flexibility sensitivity, the allocation among EVs, HPs, and batteries corresponds to 70% for EVs, with HPs and residential batteries each contributing 15%. Conversely, in scenarios characterised by high flexibility sensitivity, the distribution is more concentrated between EVs and HPs, with respective contributions of 80% and 20%, as the input from batteries is marginal in comparison to the base scenario projected for 2034.

It is important to note that this is based on the assumption that by 2034, flexible consumption will be fully integrated into the market.

The analyses by Elia reveal that by 2034, heightened flexibility penetration could diminish the required additional flexible generation capacity by an aggregate of 1,100 MW. In contrast, if only a limited degree of flexibility is actualised, the required additional capacity is anticipated to escalate by 1,000 MW by 2034. The significance of this impact intensifies over time due to the annual growth of EVs and HPs installed, resulting in an exponential augmentation of assets.

The willingness of the people to participate in DSM or DSR with household assets is, in any case, there. In the FlexSys project, two surveys were

organised to map the potential of flexibility with residential assets. One survey was held on 1,514 cooperants of energy provider Ecopower, while another was held on 1,256 participants from the general public. The participants were polled, if offered to them, how likely they would be to enroll in a flexibility program.

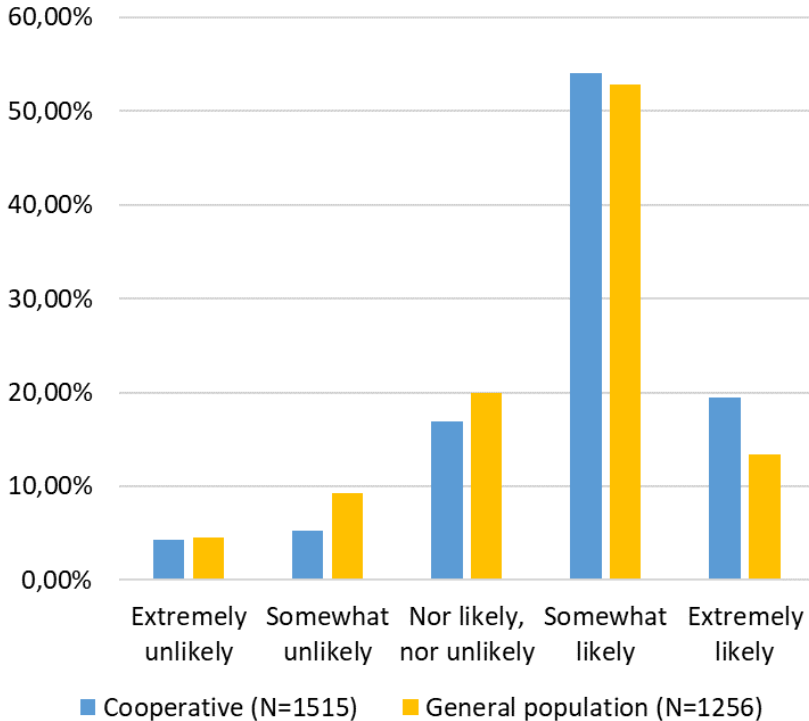


Figure 20: Willingness of households to participate in flexibility schemes (FlexSys project)

The results indicate that most of participants were inclined to very inclined to participate.

5.3.2 Technical challenges

The analysis from Elia underscores the criticality of making additional loads as flexible as possible to mitigate the necessity for expanded capacity. However, unlocking the flexibility of assets is intricate and cannot be realised instantaneously, particularly against the backdrop of the rapidly evolving electrification landscape. Meticulous planning and strategic foresight are imperative, and retrofitting existing infrastructure to exploit its flexibility

potential poses more challenges than ensuring that newly installed assets are inherently equipped with 'smart' capabilities from the onset.

An industrial process is predictable and controllable, and so is its contribution to flexible demand management. With residential flexibility, however, user behaviour plays an important role. Identifying and dealing with the individual needs and preferences of end-users, who use the devices that will provide residential flexibility, is a second important aspect.

Because of the decentralised and aggregated nature of residential flexibility, financial and administrative flows are also considerably more complex than in industrial deployment, and current regulations are not always appropriate. Clearing and removing these barriers is a third area of work.

Finally, for both residential flexibility and the energy transition to succeed, a certain critical mass of participation must be achieved. It is important for the uptake of flexibility that this participation is socially inclusive. The energy transition therefore also presents an opportunity to close socio-economic rifts in society.

The installation of heat pumps and home chargers for electric vehicles, while limited in yearly volume, has already been going on for quite some time and will only pick up in pace in the coming years. Most of these devices offer limited to no means of controlling their energy consumption, save from, for example, programming their thermostatic clock or plugging in the electric vehicle. Devices who do offer some power steering options mainly expose this functionality through either proprietary interfaces, or interfaces not fit for the purpose of extended flexibility.

Many heat pumps employ the SGR interface to steer their power consumption. As shown above, the SGR interface is a unidirectional interface, accepting input commands but providing no feedback if the device actually complies with the request and what the impact on its operation is. Furthermore, the interface does not allow fine-grained control of the device, providing only three degrees of freedom roughly described as *normal operation*, *block* and *increase consumption*. This is a limit of the physical implementation of the SGR interface, carried out as two potential-free input contacts (also called *dry contacts*).

Potential-free contacts are a staple in (industrial) control logic as they ensure galvanic isolation with the controlling device switching the contacts. This means the controlling device can be on another potential as the target device, be powered from another power source and prevents any incidental

problems like overvoltage to affect the target device and vice versa. In fact, other auxiliary input contacts of heat pumps are implemented in the same way.

Connecting to these potential-free contacts however requires (partially) disassembling the heat pump to expose the physical contacts, then attaching a suited controlling device (in most cases a device with relay outputs is required), providing this device with power and then reassembling the heat pump again. The order of how the input contacts are connected must also be carefully checked, as some brands (e.g. Mitsubishi) flip the order in comparison to the SGR specification. Some manufacturers, e.g. Daikin, require the purchase of an extension board providing the SGR inputs, but only on some models.

The seemingly outdated nature of SGR stems from its original purpose: alleviating distribution grid congestion by means of *ripple-control* relays. Ripple control is a widely employed method of load control, using high-frequency command signals superimposed on the 50Hz mains power. A specially tuned receiver reacts to the high-frequency commands and switches a relay accordingly. Ripple-control is commonly used by network operators to turn public lighting on or off, or to signal the start and end of peak and silent hours. With the increasing share of residential PV installations leading to congestion of some parts of the distribution network, network operators started experimenting with ripple-control to send curtailment messages to PV inverters if local grid congestion was detected. In some countries, like Germany, this led to a requirement for PV inverters to react to these curtailments, lowering their power production and alleviating the grid congestion. The same method could also be used for a complimentary action: *increasing* consumption when high levels of PV injection, and thus low electricity prices, were available. Heat pump manufacturers active in Germany started implementing support for ripple-control receivers, soon leading to the *de facto* standard of SGR.

Other manufacturers, e.g. Stiebel-Eltron, provide a more extended control interface in the form of the Modbus protocol delivered over RS-485. This enables two-way digital communication with the heat pump, allowing for more fine-grained control (e.g. controlling setpoints) and feedback of the operation of the heat pump to the controlling device. As both the Modbus protocol and RS-485 are standardised, this gives some more options in controlling devices, as support for these interfaces is better established than SGR. Like SGR, however, RS-485 is an interface with its roots in (industrial)

control logic, requiring some knowledge of proper wiring and most often also access to the internal logic board of the heat pump. Furthermore, some manufacturers, e.g. Nibe, implement a proprietary version of this protocol, making available, standardised control devices incompatible with the heat pump.

The situation with EV home chargers is somewhat similar to heat pumps. The charging speed of an EV can theoretically be controlled through the IEC 61851 protocol. Compatible charging plugs, e.g. the ubiquitous IEC 62196 Type 2 connector, have a dedicated connection called the *control pilot* signal indicating if the car is connected to a compatible charging station. The charging station can then superimpose a high-frequency PWM signal onto the control pilot signal, with the duty cycle of the PWM signal indicating the amount of power the onboard EV charger can request from the charging station. Theoretically, this allows for the charging station to control the charging speed and the power drawn from the grid.

The support for IEC 61851 however varies wildly between both EV and charging station manufacturers. Some EVs ignore the PWM control signal, leaving the charging speed to be completely controlled by the on-board charging controller. Some charging stations do not provide a (dynamic) PWM signal, defaulting to a fixed (maximum) power draw. And charging stations which do offer a dynamic PWM control signal often have limited ways for an external HEMS to influence this signal. This implies that both the EV and the charging station must be specifically selected in order for IEC 61851 to work correctly.

These and more practical experiences learned during the retrofit-focussed REScoopVPP project serves as an indication of the technical hurdles a user can potentially face when upgrading existing assets to support extended flexibility. Users need some advanced technical skills in order to make their existing assets flexible, or hire a technician to do it for them. The cost of the latter can however be higher than the potential financial gains of several years of flexible operation of the asset.

These issues severely limit the potential uptake and scale-up of residential flexibility with existing assets. Furthermore, there is currently little indication manufacturers of heat pumps and EVs are moving towards more straightforward methods of allowing HEMS to control the energy consumption of their devices. This can become a serious issue, as a large take-up of these assets is expected in the coming years.

5.3.3 Interoperability

When looking into newer generations of residential energy assets like heat pumps and EVs, it is clear that manufacturers are dedicating more time and effort to integrate more accessible digital interfaces based on existing and standardised data protocols like TCP/IP. These protocols however only define the communication network layer, but not the application layer. The former describes how messages should be transmitted, the latter determines what the messages should actually contain. In practice, this means newer assets can easily be connected to the home network and/or the internet, but sending and receiving data and commands to/from them is still not possible for third parties like EMS integrators.

This lack of interoperability has different causes:

- No established, already well-supported (de facto) standard specification for data exchange between smart energy devices
- No regulatory framework demanding interoperability
- No inclination towards interoperability because of commercial interests (“walled garden” approach)

On the topic of standardisation of data models, some work has been carried out into developing and promoting a standardised framework. In Europe, two initiatives are prevalent.

SAREF (Smart Appliances REference) is a standardised ontology, or data model, developed by the European Telecommunications Standards Institute (ETSI). It provides a common framework for describing and representing the functionalities and properties of smart appliances and devices used in the context of the Internet of Things (IoT). It defines a set of generic concepts and properties that can be used to describe various types of smart appliances, including household appliances, energy management systems, environmental sensors, and more. SAREF aims to enable interoperability among different smart devices and systems by providing a consistent and standardised way to describe their capabilities, features, and behavior.

SAREF4EE (Smart Appliances REference ontology for Energy Efficiency) is an extension of the SAREF ontology specifically focused on energy-related aspects. It provides additional concepts and properties to describe the energy efficiency features and capabilities of smart appliances and devices. SAREF4EE enables more detailed and standardised representation of energy-related information, such as energy consumption, energy efficiency classes, power management capabilities, and energy-saving modes.

The goal of SAREF4EE is to support energy efficiency initiatives and enable the development of smart grid and demand-response applications. By incorporating energy-related information into the standardised SAREF framework, SAREF4EE facilitates the integration of smart appliances and devices into energy management systems, allowing for optimised energy consumption, demand response, and overall improved energy efficiency in various domains, including residential and commercial settings.

A competing standard series is BS EN 50491-12 “General requirements for Home and Building Electronic Systems (HBES) and Building Automation and Control Systems (BACS) smart grid application specification”, also called the *Open European Smart Energy standard S2*. This standard is being developed by CEN-CENELEC, which is the joint technical organization formed by the merger of two European standardisation bodies: the European Committee for Standardization (CEN) and the European Committee for Electrotechnical Standardization (CENELEC). Like SAREF, it describes the fundamental aspects of semantic interoperability for the data interface and the related data exchange between a HEMS and its users. It provides a technology independent set of data models and interaction patterns in order to enable smart assets to integrate into the HEMS.

Both standardisation initiatives seem to suffer from what is called “design by committee”, a decision-making process or approach in which a group of stakeholders collectively contributes to the design or development of a product, system, or solution. It involves a collaborative effort where the different stakeholders, often from different backgrounds or organizations, have input and influence over the design process.

This process often leads to scope creep, as the collaborative effort tries to incorporate the use-cases of all stakeholders, resulting in a complex standard which ultimately sees little real-world adoption.

SAREF has seen some adoption, mainly within EEBUS. This is an European industry initiative driven by various companies and organizations in the energy, heating, and home automation sectors. EEBUS focuses on establishing a standardised communication and information exchange protocol for energy management in smart homes and buildings. However, EEBUS itself has a limited market share and its virtually non-existent outside the EU.

BS EN 50491-12 has not yet seen any formal implementation, although the KNX foundation is investigating if it can be implemented in the KNX system.

Like EEBUS, KNX is an European industry initiative mainly driven by the building automation sector. KNX is widely used in large-scale building automation, but has little implementation beyond this owing to the cost of the hardware and software licensing.

A different approach is being taken by the Matter home automation standard, formerly known as Project CHIP (Connected Home over IP). This is a communication protocol developed collaboratively by several large technology companies, including Apple, Google, Amazon, and the Zigbee Alliance. It aims to establish a unified and interoperable framework for smart home devices, enabling seamless connectivity and interaction among different devices and platforms.

Matter operates on the TCP/IP protocol and leverages existing networking technologies to facilitate communication between devices. It is designed to provide a secure, reliable, and scalable solution for home automation. Like SAREF and BS EN 50491-12, it defines common data models and protocols to ensure interoperability among diverse devices, regardless of their manufacturers. This interoperability enables users to control and manage their smart home devices using a single unified interface, reducing fragmentation and enhancing user experience.

The approach of Matter differs from SAREF and BS EN 50491-12 in that it is being developed by a core group of technology companies. Other companies are able to join the Matter standard as adopters, implementing the standard in their products and services, and submitting requests for additional use cases. This results in a more lightweight standard, growing organically as adoption rises.

While Matter is currently focused on home automation, ever more energy-based use cases are being added. The consortium already consists out of several manufacturers of heat pumps and EV chargers. It has also opened up to the open-source community, enabling open-source platforms to support the standard.

5.4 Requirement for clear flexibility signals

We are all familiar with the concept of price as a signal of availability. Our wholesale electricity markets are structured around the concept that a low price signals large availability of (cheap) energy and thus encourages its consumption. Contrary, a high price signal signals scarcity and stimulates

conserving power. By enacting on this price signal, social welfare is optimised.

Wholesale electricity prices already incorporate a lot of information, e.g. weather predictions or expected fuel prices. This makes it an elegant, transparent signal that is easy for consumers (or their automated assets) to understand and act on.

The wholesale electricity price however does not integrate many other cost factors or profit opportunities. Think of capacity tariffs or grid congestion taxes on the local distribution or transmission grid, portfolio balancing fees (or earnings) incurred by the energy community or (their) electricity provider, a direct CO₂ emissions price, etc. Furthermore, price signals such as the wholesale price currently do not penetrate the market deep enough to reach (enough) end-users, reducing the efficiency of the market.

Even if these signals reach end-users, they risk being too complex or incoherent for optimal decision making (e.g. in the form of manual action or selecting the right schedule for EV charging, HP operation etc.). Do they maximise consumption during times of low wholesale prices? What will the impact on their capacity tariff be? Do low prices necessarily imply a low CO₂ intensity of the electricity consumed?

Part of the challenge relates to the fact that the properties of some of the potential signals (which may or may not be aggregated into a single signal) can still change significantly in the future, due to the continuous evolution of the electricity system. Two crucial signals to which this applies are wholesale prices and CO₂ intensities. The profile characteristics of these signals (i.e. their dynamics in terms of hourly fluctuations, including how many hours in a row they stay low or high, etc.) are important to take into account when developing real-world residential flexibility.

5.5 Conclusions on residential flexibility

In conclusion, this investigation has underscored the significance of semi-passive flexibility by examining the strategic orientation of photovoltaic (PV) panels. Traditional south-facing configurations, which reach maximum output at midday, were re-assessed in this research in favour of an east-west bifurcation, aiming to synchronise solar energy production with the diurnal patterns of electricity consumption, which escalate in the morning and attain their zenith in the evening. Employing an anisotropic-all-sky model, which is

more apt for Western European climates compared to the traditional isotropic model, and conducting simulations informed by real residential consumption patterns and existing grid frameworks, this study corroborated its initial theory.

The empirical results of this research confirm that a dual-orientation of PV arrays can indeed temper the midday peak of power generation. However, the effect on augmenting energy production during the early and late hours is modest, with a slight intensification observed in the winter months. It is pertinent to note, though, that while this methodology curtails peak power injection, it concurrently reduces the total energy output, which could deem it an ineffectual strategy.

Moreover, this dissertation explored the capacity of residential flexibility—both implicit and explicit—in harmonising energy utilisation with production, thus exploiting intervals of diminished energy costs. Despite its promise, residential flexibility encounters formidable obstacles, chiefly due to the heterogeneity and complex control mechanisms of domestic appliances, alongside the substantial expenditure and complexity inherent in aggregating a multitude of minor-scale consumers.

This scholarly work highlights the indispensable nature of enhanced interoperability and digital interconnectivity, achievable through the utilisation of Application Programming Interfaces (APIs). Such advancement, by championing open and well-documented frameworks and data models, would enable devices across various manufacturers to communicate effectively, thereby augmenting compatibility and facilitating retrofit applications.

Furthermore, the discourse elucidates the essentiality of transparent pricing signals to residential entities, especially in the context of solar PV installations. The issue of price cannibalisation, intensified by residential solar PV proprietors' limited comprehension of wholesale electricity market dynamics, accentuates the necessity for these systems to be responsive to market and grid exigencies. Aligning solar PV operations with these factors is vital to ameliorate the potential detriments to market equilibriums and grid-related expenditures, thus preserving social welfare and guaranteeing the proficient functioning of the electric power infrastructure.

Regulators should avoid imposing a single data standard or communication protocol, but rather commit to enforcing interoperability between different

standards, products and services and allowing third parties to access and integrate the standard within their products and services.

This can be realised by requiring manufacturers to document their API and to make this documentation publicly available. Third parties can then use this documentation to make their device or proprietary standard interoperable with the other device or standard, and vice versa. Policy makers and regulators have some leverage available due to the subsidies and tax breaks they award to clean energy devices and services. They can couple these benefits to the availability of public documentation and openness of the data protocol.

6 Wholesale markets as driver for flexibility

6.1 Power plant dispatching

It might be assumed the electricity system is only governed by the physical laws of Kirchoff. Engineers try to guide the flow of electrons through cables, transformers and phase shifting transformers and generally succeed in this quite well. The generation and consumption of these electrons, however, is governed by idiosyncratic concoctions dreamed up by economists. Concepts arcane to the engineer, such as wholesale markets, marginal pricing and social welfare, determine how much electricity flows over the engineering marvel which is the electrical grid and in what direction.

Electricity is traded in wholesale markets, often employing marginal pricing in a *pay-as-cleared* method. This means that the price is set by the last unit of production selected by the market to meet demand, and that only this price is valid for all market participants. Although they have different physical properties, the same method is used with other commodities - such as grain, rice, minerals, metals, oil, coal and gas.

The current way in which the price of electricity is determined is a result of the liberalisation of the energy market, which began in 1996. That liberalisation aimed to achieve a European energy system that was to be "more reliable, cheaper and more competitive" than the historical system, where each country was an "island" in Europe, dominated by monopolistic energy companies. Being able to trade electricity freely within Europe was a crucial requirement for European integration of the energy system. Yet it would eventually take 12 years and three packages of directives before the European electricity market was truly a reality.

In the electricity market, electricity is traded as a commodity between sellers and buyers. The producers, which are the companies that produce electricity with their power plants, are the sellers. The suppliers are the buyers, buying electricity on behalf of their customers (the final consumers) and supplying it to them. Together, they form the supply and demand sides of the electricity market, respectively. The organisation of the wholesale market is depicted in Figure 21.

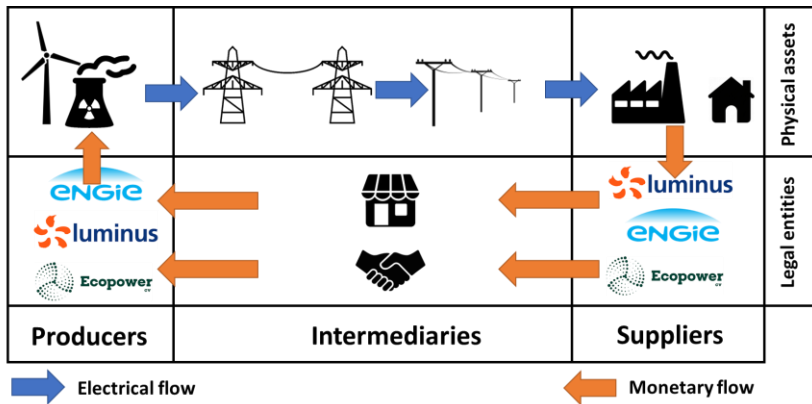


Figure 21: Organisation of the wholesale electricity market

Although the roles of producer and supplier are (mandatory) split, they can still belong to the same business group. For instance, Engie is both a producer and a supplier of electricity. Nevertheless, this does not mean that as a customer with supplier Engie you will necessarily be supplied with electricity that was generated by producer Engie. Indeed, supplier Engie has to agree on a price with producer Engie, and may as well resort to a cheaper producer if it presents itself on the market.

Some large consumers may also be their own supplier. Energy-intensive companies, for instance, may well often buy electricity directly from a producer on the market.

There are two ways in which producers (supply) and suppliers (demand) can find each other on the market. The first are so-called Over The Counter (OTC) contracts. These are bilateral contracts in which a producer and a supplier agree directly between each other on a quantity, price and time for the supply of electricity. Pricing is completely free, and depends only on what the two parties agree between themselves. About two-thirds of all electricity is traded through these direct agreements.

The second way electricity can be traded is through electronic exchange platforms. This is very similar to stock exchanges. Here, the producer puts an offer in the market, the supplier a demand, the exchange platform tries to match them. Transactions happen anonymously, only the price and quantity of electricity traded is published. In these types of agreements, the exchange platform sets the rules of the game. Using the exchange platform is voluntary, but the agreements concluded there are binding for the

participating parties. In Europe, EPEX, which includes the Belgian power exchange Belpex, is the largest exchange platform for electricity.

In what follows, we focus on the rules used by the power exchanges to determine the price of electricity. Although only one third of all electricity is traded via these exchange platforms, in practice they also set the price for bilateral OTC contracts, and thus of the entire electricity market. This is an inevitable consequence of the public nature of the exchange platforms. If a supplier sees that the electricity price on the exchange platform is lower than what it has negotiated bilaterally with a producer (in an OTC contract), it will exert pressure to lower the price. Conversely, a producer who notices that the price on the exchange platform is higher than the one he has agreed (in an OTC contract) with a supplier will want to increase his price. In other words, price convergence occurs.

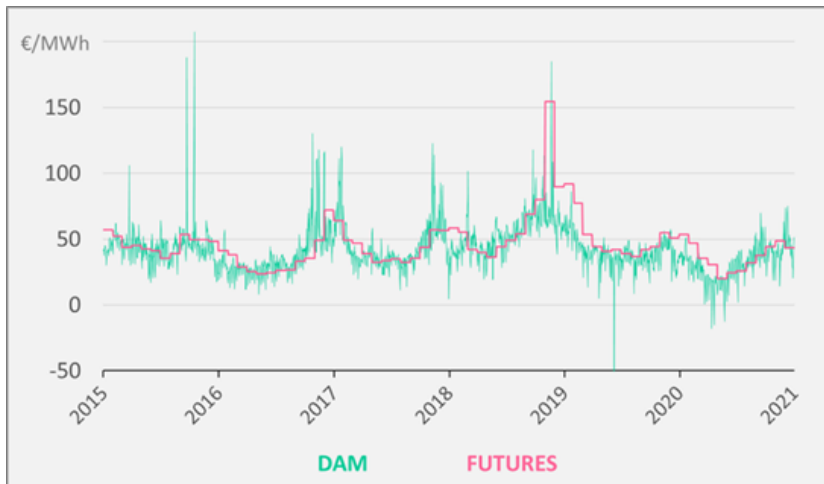


Figure 22: Comparison of average spot prices and futures prices on the EPEX wholesale electricity market

The rules of play of the exchange platforms can be called rather special, and are at the root of the perceived complexity of the electricity market. According to these rules, the exchange platform receives offers from producers to sell electricity all day long, and requests from suppliers to buy electricity. However, the price producers put on their offers is not the full cost of production of the electricity offered. It is the marginal cost. This marginal cost mainly includes the fuel cost to produce the offered amount of electricity multiplied by the plant efficiency (the amount of units of fuel required to produce a unit of electricity).

Using marginal costs has several benefits. Historically, only generators who were already producing in order to fulfil long-term or bilateral OTC contracts traded on the exchanges. Any additional, unused capacity was offered on the exchange. As their fixed costs were already recovered by the long-term contracts, the only cost of producing another, or *marginal* unit of energy is their fuel cost and, if applicable, some small Operational & Maintenance (O&M) costs. Today, this is still the case, although recent years have seen generators which only sell their energy on the exchange.

As the exchange is public, using marginal pricing also obscures the total production costs of generators, which could be viewed as sensitive. Additionally, as both the fuel price of e.g. of natural gas or coal is also publicly known, and moreover the same for all producers, as well as the approximate efficiencies of different types of power plants, inflating the production cost would immediately stand out. Using marginal cost therefore leads to transparent and fair pricing. This can be seen as an emergent property of efficient markets. [132]

This phenomenon of inflated prices was (and is) realistic because after the liberalisation of the energy market, almost all generation capacity was owned by the former monopolistic energy companies. Even today in Belgium, one party still owns three quarters of all thermal power plants. These companies were thus able to cover the real production cost price, since there were no competitors who could prove that it could also be done cheaper. The Don Corleone syndrome was also lurking: their dominance allows these giants to make the market an offer they cannot refuse.

The marginal cost, however, does not cover the full production cost of the quantity of electricity offered. Producers also have fixed costs, such as the capital depreciation of their investment in the power plant. This is certainly the case for producers with a low or even absent fuel cost, such as nuclear or renewable energy. Should they receive only the marginal cost they would not come out of the cost. There would therefore be no reason for these producers to participate in the exchange platform.

However, the design of the exchange platform offers a solution here too. The rules dictate that the exchange makes a so-called closing or clearing once a day. Here, the platform ranks all offers to produce electricity according to increasing cost price, and all requests to purchase electricity according to decreasing cost price. This is called the supply curve and the demand curve, respectively. At a certain point, supply and demand intersect. This point is called the market price.

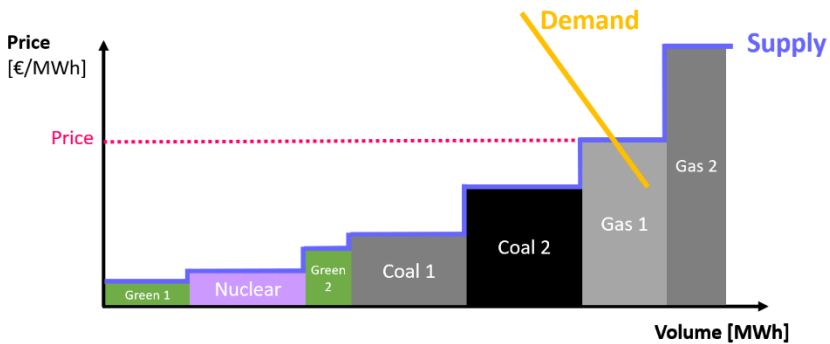


Figure 23: Traditional merit order curve

The rules of the exchange platform dictate that all producers receive this market price, even if they offered electricity at a lower price. In contrast, producers who asked for a higher price see their offer rejected: they will not be able to sell electricity. This rule has the effect that producers with a low marginal cost can recover their fixed costs because they receive a market price higher than their marginal cost. Moreover, it motivates generators to make an offer at the lowest possible price. After all, if the price of their offer at clearing were found to be above the market price, it would be rejected and they would not be able to sell any electricity at all. So there is downward price pressure.

There is also a positive effect on the supplier side. Suppliers who offered a higher than market price now only have to pay the (lower) market price, and can pass on these savings to their customers. At the same time, suppliers are motivated to offer a sufficiently high price. Indeed, if the price at which they wanted to buy electricity were lower than the market price when the market clears, their demand would be rejected. This would mean that they could not buy electricity and their customers would therefore be in the dark. So this is where upward price pressure arises.

This interplay of upward and downward price pressure ensures that electricity is sold to suppliers as cheaply as possible, but also not so cheaply that producers can no longer make a profit. Moreover, it encourages producers to invest in generation units with a (very) low marginal cost, as this allows them to achieve larger margins relative to the market price. Given the low to no fuel cost, the only generation units with a (very) low marginal cost are renewable energy or nuclear. So there is also a clear climate gain.

The introduction of exchange platforms resulted in a decade of relatively stable and low electricity prices, benefiting industry and society. Moreover, it helped fuel the investment boom in renewable energy. But it also discourages investments in conventional power plants, which have high marginal production costs. Moreover, various governments saw an opportunity to amend low electricity prices with all kinds of taxes and surcharges, so the price paid by the end customer did not always reflect the positive effect of the power exchange.

The system of a single market price determined during market clearing is called pay-as-cleared. The market price is determined by the producer's supply located at the intersection of the supply and demand curve. This supply is therefore the most expensive unit of production that was just selected, as the more expensive offers are rejected. This unit of production is called the marginal unit. Thus, the price at which the producer offered this marginal unit determines the market price.

Because the market ranks all production offers from low to high price, the production units with low marginal cost, such as nuclear or renewable energy, are rarely the marginal unit. Indeed, these are at the very front of the ranking. As a result, the marginal unit is quasi always a generation unit with higher marginal costs. In practice, this means a power plant that has to buy fuel to produce electricity, as marginal cost largely includes the cost of fuel.

A gas power plant turns out to be the marginal unit more than half the time. Moreover, this gas power plant does not even have to be located in its own country: due to the European unification of the electricity market and the interconnection of energy networks, the price is determined on a European scale. The fact that gas plants are so often the marginal unit is the reason for the strong link between the electricity price and the gas price.

Having a fossil plant determine the market price is beneficial for social welfare. The higher marginal cost of those power plants, because of their fuel cost, keeps lower marginal cost but higher fixed cost producers (renewables, nuclear) profitable. It also encourages investment in those units with lower marginal cost, which is also socially desirable.

However, the pay-as-cleared system becomes problematic when the fuel cost becomes abnormally high due to external causes. This has been the case during the European energy crisis of 2022, when gas prices rose from €25/MWh to more than €200/MWh. Since a gas power plant is almost always

the marginal unit, and therefore determines the price on the electricity market, the electricity price therefore rises along with the gas price.

In addition to the standard long- and short-term markets, there are some markets for electricity that are not used in the case of other commodities. These are necessary because of electricity's unique technical properties. There is the "very short term market", also known as the intraday market, where small surpluses or deficits that appear just hours before the effective delivery can still be sold or bought. There are also balancing markets where market participants compete with each other to keep the balance between supply and demand as cheaply as possible at any given moment in *real time*. These will not be discussed in this text.

All of the abovementioned markets are increasingly integrated across the many national borders in Europe, generating large welfare gains for all Europeans, since cheaper production can be sold in more expensive regions. According to ACER³, the welfare gains from market coupling have already amounted to approximately €34 billion per year over the past decade.

However, not all markets are as well-integrated already. In particular, much work remains to be done to better integrate the long-term market, to increase the number of market players and thereby increase liquidity. This could significantly smoothen the process of buying and selling electricity up to five years (or more) into the future, thereby strengthening and stabilising investment incentives in generation capacity

6.2 Peak loading pricing

Wholesale electricity markets, of which the exchanges are part of, are structured around the economic concept of peak-load pricing. In literature, primarily North-American literature, wholesale electricity pricing is often compared to other sectors using peak-load pricing, such as airplane tickets or hotel rooms. A synonym of peak-load pricing however is congestion pricing, and for many West-European readers this provides a more intuitive approach to understanding the goals behind the pricing structure of the wholesale electricity markets. [132]

Congestion pricing is a system of charging users of public goods that are subject to peak demand, e.g. leading to congestion, differentiated prices. According to the underlying economic theory, the objective of congestion pricing is to use the price signal to make users conscious of the costs that they impose upon the system when consuming during the peak demand. By

raising the prices during peak times, the redistribution of the demand in space or in time is encouraged, leading to a more efficient use of the system. In the case of public goods, this has a net benefit on social welfare.

Just as a congestion charge is used to spread public road use in time and space to avoid the inefficient investment in additional lanes only useful during peak times, peak-load pricing facilitates the efficient decisions regarding generator investment, generator dispatch and pricing of generation services.

Just as a city planner is occupied by the question of how many lanes to build, an electricity system planner is occupied by the question of how much (and which) electrical generation capacity should be built to satisfy demand in the most optimal way.

The answer to this question was provided at the start of the second golden age of European electrification following WWII, by French economist Marcel Boiteux and his theory of marginal-cost based electricity pricing. Boiteux would later on become the director of French energy giant EDF. [133]

As electricity can be seen as an essential, public good, this implies the central planner must maximise the social welfare. In wholesale electricity market terms, this means maximising the net surplus of consumption. This is elaborated upon further.

The consumption, or demand for electricity, is time dependent and *somewhat* elastic. Concerning the former, demand for electricity is lower during the night, and higher during the day. Demand also has a recurring peak during the morning, when factories and coffeemakers alike are turned on, and in the evening, when meals are prepared and fridges opened to get a cold one.

Concerning demand flexibility, at least a portion of electricity users are sensitive to the electricity price, that is, they decrease demand when prices are high and increase demand when prices are low. As of writing, this is mainly limited to industrial consumers who buy electricity directly on the wholesale market or have a so-called *pass-through* contract with their supplier. It is however expected that, with the introduction of digital meters all around Europe, these pass-through contracts reflecting real-time wholesale electricity pricing, will be adopted by residential consumers as well. The Clean Energy Package introduced provisions entitling all final customers who have a smart meter installed to conclude a dynamic

electricity price contract with at least one supplier in their market and with every supplier that has more than 200,000 final customers. [134]

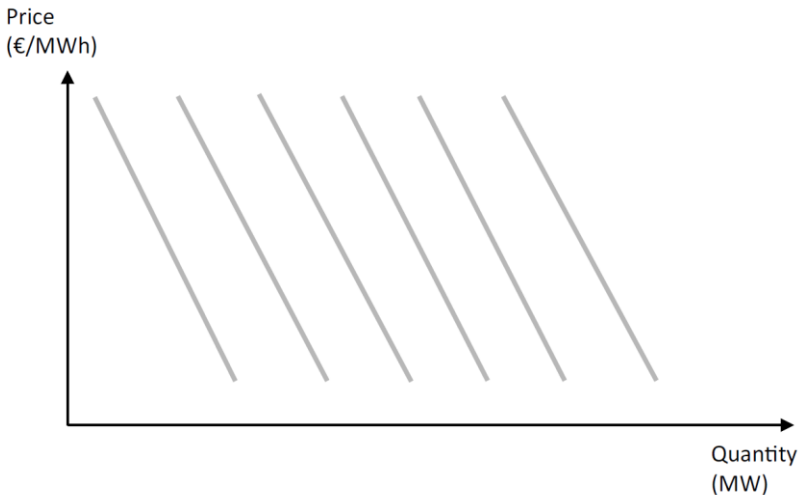


Figure 24: Inverse demand curves (source: [135])

Demand in function of price can be represented by *inverse demand curves*, plotting demand on the horizontal and price on the vertical axis. The inverse demand curve shows that a certain demand can have a certain elasticity. If electricity prices are high, some consumers will lower their consumption, while the opposite is true if prices are low. As demand fluctuates during the day, there are multiple demand curves. On the current wholesale market, demand (and supply) is fixed for every hour of a given day, leading to 24 downward sloping, time-dependent inverse demand curves as depicted Figure 24.

The downward slope of the inverse demand curve represents the decreasing consumer surplus, that is, the utility ('benefit' or 'pleasure'), of increasing consumption. A family during a winter evening might be consuming 2 kWh of electricity for heating, 1 kWh to keep the lights on, 1 kWh to watch television and 1 kWh to keep their refrigerator running.

While they use 5 kWh of electricity, the utility they derive can be different for every consumed kWh. They would obviously value their electrical consumption for heating the most, e.g. at the subjective price of 0.5€/kWh. That is, they derive a utility, a 'pleasure' or a consumer surplus they value at 0.5€/kWh from these 2 kWh.

The 1 kWh of electricity consumption for lighting might be valued somewhat lower at 0.4€/kWh, meaning the family derives more utility from heating than from lighting. The 1 kWh consumed by watching television might be valued even lower at 0.3€/kWh, as the family might switch to playing a board game or, good heavens, read a book. Finally, the last 1 kWh used by the refrigerator might be valued at just 0.2€/kWh, as its consumption can be shifted by an hour without impacting the quality of the stored food.

The total consumer surplus in this example accounts to:

$$2 \cdot 0.5 + 0.4 + 0.3 + 0.2 = 1.9\text{€}$$

Each additional unit of consumption results in a *marginal consumer surplus*, that is, an additional utility derived from consuming an additional quantity of electricity. The above example clearly shows this marginal surplus is decreasing with additional consumption, with the electrical consumption of the fridge only valued at 0.2 €/kWh.

The surpluses discussed up until now are the *gross* surpluses. By subtracting the cost of producing the quantity of consumed energy, we arrive at the *net* surplus. This net surplus is thus the economic value derived from consuming a quantity of electricity minus the cost of producing this quantity.

Assuming the cost of producing energy is €0,1/kWh, the total net surplus of our example amounts to

$$1,9 - 5 \cdot 0.1 = 1.4\text{€}$$

Likewise, there exists a *marginal net surplus*, which is the additional net surplus created by consuming an additional quantity of electricity. In our example, the electrical consumption of the fridge has a net marginal surplus of 0.1 €/kWh.

Consuming energy is generally a short-term decision. Our example family can quite easily decide to increase or decrease their consumption, based on the short-term net surplus or utility they want to derive.

The objective of the benevolent system planner is to maximise the total short-term net surplus. This means that, in an optimal system, every unit of electricity that yields a positive net surplus is produced and consumed, as each of this unit generates a utility which is higher than the cost of its

production. At the same time, units of electricity that generate a negative net surplus must be avoided, as these generate a utility which is lower than the cost of its production and result in a suboptimal system.

Notice the importance of the marginal surplus as a signal to indicate whether the system is in this optimal equilibrium between consumption and generation. As long as the net marginal surplus is higher than zero, consumers derive additional utility from consuming an additional unit of electricity. When the net marginal surplus reaches zero, the system is in optimal equilibrium. Consuming more would yield no net benefit, or might even result in a negative net surplus.

The same logic applies to the suppliers' side. If there is a net marginal surplus to be achieved by consuming an additional unit of electricity, suppliers will produce this unit as it can be reasonably expected consumers will want to achieve this additional benefit by buying this electricity. The suppliers will stop producing additional units of electricity if the net marginal surplus reaches zero, as it can be expected that no consumer will want to incur negative utility.

A system is at the optimal state if demand and production are in equilibrium. In this situation, the marginal net surplus is zero and the marginal surplus is equal to the price of producing the energy, which is the *marginal cost*.

6.3 On- and off-peak

Just as with congestion charging, where the city planner wants the amount of lanes optimally used, the electricity system planner wants its system to be *on-peak*. That is, the committed generation capacity must be optimally utilised. If generation capacity is committed but not used, this implies a sub-optimal system with unused, spare capacity. This situation is called *off-peak*.

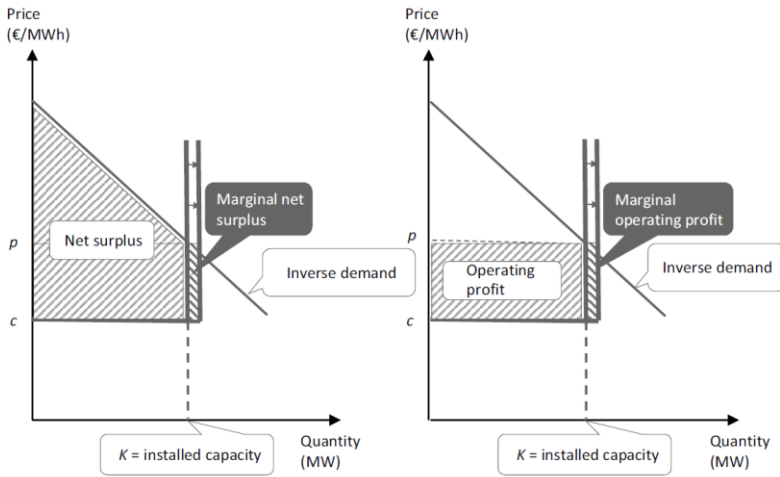


Figure 25: Short-term net surplus and marginal short-term net surplus (left), and operating profit and marginal operating profit (right) for any on-peak hour source: [135]

Due to technical constraints, generation capacity is divided into discrete quantities. When an electrical generation plant is turned on, it can produce electricity up to its maximum capacity K . If consumption Q exceeds this capacity K , an additional plant must be turned on to meet the demand.

The cost structure of these power plants broadly consists out of a variable cost per produced unit of energy c , and a fixed cost tied to the maximum capacity r . In a conventional power plant, the variable cost c is the cost of the units of fuel burned to produce a unit of electricity, and is expressed in €/MWh. In most renewable energy systems, this cost is essentially zero. The capacity cost r consists of fixed costs, such as the amortisation of the invested capital to build the plant, staff costs etc., and dependent on the maximum capacity of the plant K .

Observe that in an off-peak system, that is a system where generation capacity exceeds demand, the cost of producing an additional, or marginal, quantity of electricity is equal to the variable cost c . Because consumers want to achieve every positive net surplus, in an off-peak system demand will adjust to c .

If for some exogenous reason, e.g. the evening peak in electricity consumption, demand increases up to the maximum capacity K , the system becomes on-peak. When the system is on-peak, the price becomes equal to the value of the last additional unit of consumed energy. As the maximum

generating capacity K is reached, no additional unit of consumption can be generated anymore. This has some profound implications, which are discussed in the following paragraphs.

Up until now, the reasoning has focused on costs. However, a power plant owner also wants to achieve a reasonable profit for the (financial) risk they undertake to build and operate the plant. This profit margin is added on top of the costs, forming a *price*. From a consumer perspective, this has no impact on the presented reasoning, as this *price* is the *cost* they incur from buying the electricity, and the price is expected to always cover the cost of producing this electricity.

When demand Q exceeds the generating capacity K , the price shows a curious behaviour. As there now is scarcity, consumers will vie for the last available unit of electricity and be willing to pay higher prices. In an on-peak system, price adjusts to capacity K . This is illustrated in Figure 25.

If an on-peak system only had one generation plant, the price of electricity could become very high. In reality, however, there are multiple generation plants. This means that the price will rise to the capacity cost of the next generation plant which needs to be activated to supply the increase in demand beyond K . As demand rises, increasingly more, increasingly more fuel cost-intensive generation plants are switched on. This collection of plants is called the *merit order*. The last generation plant to be activated in order to supply demand is said to be *on the margin*, and is known as the *marginal unit*.

As total generation capacity is divided into discrete intervals, with the interval size equal to the maximum generation capacity of the respective power plant, this also reflects in the price. As discussed above, in an off-peak system, that is a system where demand is lower than the committed generation capacity, the price will be equal to the variable cost c of the currently active power plant, and demand adjusts to this price. If the system becomes on-peak, that is if demand equals the maximum committed generation capacity, the price rises to cover the capacity cost of the next power plant which needs to be turned on. After this power plant is turned on, the system generally becomes off-peak again, with prices reflecting the variable cost of this marginal plant. Reiteratively, demand now adjusts to the price, leading the system to become on-peak again.

The innate tendency of the system to become on-peak, and thus optimise the social welfare, is one of the key qualities of using this wholesale market

design based on marginal pricing. When on-peak, no available generation capacity is wasted. Additionally, on-peak demand adjusts to the price, preventing the next, more expensive generation plant from being turned on unless consumers are willing to pay for its capacity cost.

6.4 Price cannibalisation

The system of on- and off-peak pricing works particularly well on markets where the merit order contains generators with high short-run marginal cost, e.g. fossil-fuel fired power plants. However, the rising share of renewable energy, with its low to zero marginal cost, is presenting the current market organisation with challenges. These are exemplified by the rising number of hours with negative prices. Where in 2015 the EPEX spot market, where electricity for Belgium is traded wholesale, logged the first 2 hours with negative prices, in 2023 this had already risen to 222 [136] [137].

As the market price indicates the balance between supply and demand, negative prices are a sign of an oversupply of electricity production. Or a shortage of electricity consumption. The phenomenon currently mainly occurs during hours with lots of sun and wind and reduced consumption, typically on weekends, indicating renewable energy is the main driver.

A negative price means that a generator is willing to pay a consumer money to consume its electricity. Negative prices can only exist provided the producer still generates some margin somewhere. Otherwise, they would simply produce less energy. The energy production of solar panels, wind turbines but also, as discussed in section 3 *Flexibility by nuclear power plants*, nuclear power plants can be adjusted downwards relatively easily.

A second potential cause for negative pricing is that producing less imposes additional costs on the energy producer, and they are therefore willing to pay to avoid those costs. A final possibility is that the producer is simply unaware of the negative prices, and so keeps on producing even though the market signals an overabundance.

Until now, in Belgium negative energy prices are derived from a combination of these factors. A major driver is the historical subsidy systems for certain wind turbines, where the producer is awarded a fixed fee per MWh of electricity produced, regardless of whether that produced electricity is useful or not. In Belgium, for example, there are four offshore wind farms that receive this type of subsidy, with the support varying between €90 and €107 per MWh. This means the producers only have an incentive to shut down

their turbines when the electricity price approaches the -90 and -107 €/MWh limit, respectively [138].

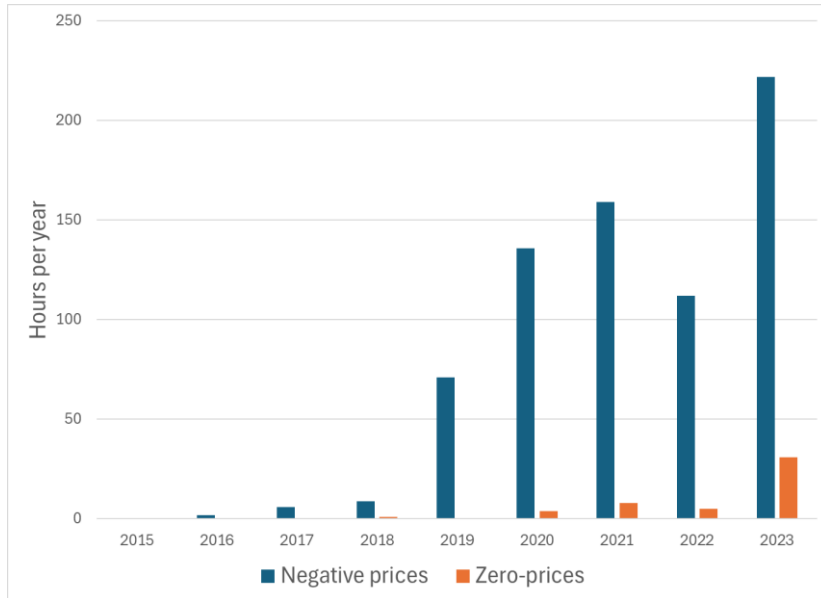


Figure 26: Yearly amount of hours with negative or zero-price on the EPEX spot market

This subsidy system seems rather misguided, but fits into the zeitgeist of the first developments of industrial wind power in the late 2000s. It was difficult to forecast then how fast renewable energy would grow, and the possibility of negative prices were still an academic curiosity. These subsidy systems are limited in time, and for Belgium will start to expire from 2030 onwards.

The five other Belgian offshore wind farms, as well as those to be built in the future, are also under a different subsidy system where support is limited or non-existent during periods of negative prices. Moreover, these parks have to pay back subsidies when energy prices increase a certain limit set for each park. This earned the government €190 million last year. Production subsidies for Flemish onshore wind turbines have not been granted since 2023 [139].

The second main driver for negative prices is the large share of residential PV installations that are unresponsive to market signals, either because they are under a net-metering regime or because they receive a fixed injection fee

from their supplier. This is further explored in section 5.4 *Requirement for clear flexibility signals*.

Owners of these installations keep injecting energy into the grid, even when market prices are negative. Their supplier is contractually obliged to deposit this energy onto the market, thereby incurring a cost which they contractually cannot charge to the owner of the solar PV installation. While an individual solar panel owner has hardly any impact on the energy market, in Belgium in 2023, there is already an installed capacity of 10GW of solar, half of which belong to residential owners. Compared to a system peak load of 10GW, this arguably has a sizeable impact.

A third driver of negative prices is producers for whom producing less involves a greater cost than paying consumers to use their energy. Typically, these are nuclear power plants and hydropower plants. As discussed in section 3 *Flexibility by nuclear power plants*, most nuclear power plants can indeed reduce their output, called "modulating". However, this is a complex process that requires some preparation, and has a logistical and economic impact on the plant's operation. Moreover, there are limitations on the speed and depth with which nuclear power plants can be tuned, as well as the timing. For instance, it is not possible in the first months after and last months before the time the nuclear fuel is replaced. As a result, nuclear plant operators prefer not to modulate, and are willing to offer a negative price to avoid it.

Another scenario concerns conventional (dam) or run-of-river hydropower plants. The main task of most reservoirs and dams is to regulate the water level in front or behind the dam, e.g. to protect areas from flooding or to create a water buffer for irrigation or industry. Discharging water usually has to be done through the turbine to extract kinetic energy from the water, in order to limit the speed of the outflowing water [140].

As this water management takes precedence over energy production, hydropower often contributes to negative prices. For instance, hydro power plants in the French Alps contributed to the creation of negative prices during the Easter holidays of 2024, because space had to be made in their reservoirs for upcoming meltwater [141].

Negative energy prices can be considered a form of market inefficiency because the production and consumption of energy are not optimally allocated, resulting in a loss of social welfare. However, it arguably is a temporary situation, and it can be expected periods with negative energy

prices will diminish in the future. Volumetric subsidies for renewable energy are expiring, removing the incentive for operators to produce at negative energy prices. Net metering regimes and fixed-price injection contracts are being phased out, and replaced with real-time digital meters and dynamic injection tariffs. Moreover, suppliers will increasingly expect their solar panel customers to limit or stop their injection in the event of negative prices. This can be done by connecting a smart controller to the solar panel inverters. In other words, the best remedy against negative energy prices is negative energy prices, as discussed in section 5.3 *Flexibility by residential assets*.

In contrast, we are moving towards a future with more and more hours where the energy price is exactly zero euros. This is already visible on the EPEX spot market. Whereas the first hour with a zero-price occurred in 2010, in 2023 this had risen to 31 hours. At these moments, producers do reduce their production because they can no longer avoid the negative prices they would otherwise have to pay.

With the increasing amount of renewable energy, so do hours with zero-price increase. This has a depressing effect on wholesale electricity prices, which has been predicted and is increasingly becoming a reality [142].

Price is an indicator of the relationship between supply and demand. In wind and solar power production, there is a large simultaneity factor, so maximum production often happens at the same time. At those times, renewables flood the market and the price falls sharply, below the production price. As a result, the capture price also falls.

The capture price is calculated as the average market price weighted of the hourly production. This metric encapsulates the principle that the financial returns of renewable energy projects are contingent upon their generation profiles, thereby potentially diverging from the prevailing wholesale market prices.

This presents energy producers with a challenge. Due to the abundance of renewable energy, the price at which it can be sold falls below production cost. This phenomenon is called *price cannibalisation*.

Price cannibalisation presents a challenge to future profitability and investments not only in renewable energy, but also in other forms of low marginal cost electricity production. E.g. operators of NPP typically sell most of their energy production in advance, at a predetermined price. This revenue not only covers the fixed costs of plant operation, but also generates

a margin. The cost of producing any additional, marginal unit of production is as such virtually zero.

Decreasing wholesale market prices however give consumers more incentive to buy a larger share of their energy on the spot market, rather than through bilateral long-term contracts. If consumers enter into long-term contracts at all, there is pressure to do so at prices that reflect those on the wholesale market more directly. This increases the exposure of generators to the wholesale market, undermining their baseline profitability.

Tackling the challenges of price cannibalisation is subject of a currently ongoing academic debate, which largely falls outside the scope of this work. However, as price cannibalisation is caused by low prices, and low prices are caused by production of electricity outmatching the demand, bringing demand more in line with production is one potential solution to the issue.

By incentivising consumers to adjust their energy usage to align with periods of high renewable production, demand can be more synchronised with supply, mitigating the mismatch that leads to market price drops. For example, during times of peak wind or solar generation, consumers can be encouraged to shift their energy-intensive activities, thus absorbing excess production. This not only helps to maintain a more stable price for electricity but also increases the profitability of low marginal cost generators, which often are also low carbon, and incentivises future investments.

6.5 Conclusions on the role of wholesale markets for flexibility

This chapter delved into the economic background of the wholesale electricity market in order to analyse how flexible assets can be integrated, how the market signals a need for activation of this asset, and how flexibility, especially from the consumer side, is increasingly essential in order for the future of our power system. This analysis was performed in order to both underpin the other chapters with the necessary economic insights, but also to determine how large-scale flexibility is required for the future of the power system.

First, the organisation of the wholesale electricity markets was analysed. Although most of the electricity is traded on long term contracts, often bilateral between producer and consumer, it was shown how the short-term spot market, used through exchanges, actually determines the wholesale

price. As this exchange is public, the price of long-term contracts converges to that of the spot market, because otherwise arbitrage would be possible.

The spot market, organised through power exchanges, was then further analysed. This market uses marginal pricing and pay-as-cleared as key concepts. The benefits of marginal pricing, creating a fair and transparent way of dispatching the individual power generators, were discussed, as was the benefit of pay-as-cleared, allowing generators to recoup more than just their marginal costs.

The concept of marginal costs were then further substantiated by exploring the key concept of peak-load pricing, and how this contributes to optimising total welfare. Peak-load pricing ensures consumers have an incentive to decrease their consumption in order to prevent an increase in the power price, caused by the otherwise required activation of a more expensive generator in the merit order. At the same time, it also incentivises them to maximise their consumption to fully load the marginal generator, thereby maximising its output and profitability.

While the dispatch system described above traditionally worked well with conventional merit orders, containing high marginal cost units such as fossil-fuel fired power plants, it was shown that this does not necessarily holds true when the energy market becomes dominated by low marginal cost units such as renewables and nuclear. In fact, this can lead to market inefficiencies, as demonstrated by the rising hours of negative prices on the Belgian electricity wholesale markets.

Even when market-distorting instruments such as volumetric production subsidies are taken out of the equation, the rising share of renewable energy exerts a depressing effect on the wholesale electricity price. This is mainly focussed in a rising number of hours with low to zero prices, as renewable energy tends to have high simultaneous output, thereby flooding the market with supply. This leads to a decreasing capture rate, which is the amount of normal or high market prices the renewable generators can capture, and eventually to price cannibalisation, whereby renewable energy undermines its own economic baseline. It is shown, however, that this not only affects renewable energy, but also other low marginal cost generators such as nuclear power, as it might increase their exposure to the short-term spot market at the expense of long term contracts. This was similarly discussed in section 2 *Nuclear power as baseload electricity generation*.

While price cannibalisation is a multi-faceted challenge, one of the main causes is a mismatch between supply (electricity generation) and demand (electricity consumption), with a high influx of renewable energy generation being concentrated into a concentrated number of hours, with energy demand following a different load curve. It can therefore be concluded that flexibility is key in order to mitigate or even prevent price cannibalisation, as flexibility has the potential to bring consumption more in line with production, thereby preventing the wholesale electricity price from bottoming out in periods of high renewable energy production, and increasing the capture rate of low marginal costs generators.

7 ETS as a driver of the energy transition

7.1 Introduction

This chapter serves as a background study into the European Union Emissions Trading System (ETS), and how its dynamics influence the future application of and investment decisions in certain types of flexible power production, specifically nuclear power and hydrogen-refits of existing natural gas fired power plants. Its conclusions are incorporated into sections 2 *Nuclear power as baseload electricity generation* and 4.2 *Hydrogen power plants*.

The ETS is a cap-and-trade style instrument to regulate and limit GHG emissions. It was implemented by the European Commission in 2005 in response to the legally binding GHG reduction targets of the 1997 Kyoto protocol and has since been one of the pillars of European climate policy. The ETS covers all electricity and heat generating installations of 20MW and more, as well as the bulk of the energy-intensive sectors such as (but not limited to) oil refineries, steel and cement production and petrochemical processing, in the 27 EU member states and Iceland, Norway and Liechtenstein. As of 2012, aviation emissions of flights within the European Economic Area (EEA) are included as well. All combined, around 50% of total EU GHG emissions are subject to the ETS, which makes it the worldwide largest system of its kind. [143] As the EC's chief negotiator at the United Nations Framework Convention on Climate Change, Belgian economist and climate expert prof. Jos Delbeke played a key role in establishing the ETS.

A GHG cap-and-trade mechanism differs from a GHG taxation system ('carbon tax') as it sets a limit (the cap) to the amount of (future) emissions and allows participants to trade their emissions rights through a market-based approach. This has a number of benefits compared to a carbon tax, mainly the certainty about quantity (the maximum quantity of GHG emissions for the period of time is known, allowing predictable (policy) planning) and utility maximisation (assuming the endogenous EUA price formation reflects utility and is equal for all participants).

In the EU ETS, the total cap is divided into yearly emission allowances (EAs), which are allocated to each member state according to their National Allocation Plan (NAP). The EAs are then auctioned off on the emissions trading

market or allocated freely to installations and businesses at risk of relocating their activities to non-ETS countries, preventing to so-called 'carbon leakage'.

The yearly EA allowance comes with a linear reduction factor (LRF), which decreases the amount of EAs available to businesses and thus gradually increases scarcity. This allows businesses subject to ETS time to implement emission reducing policies and supports the allowance price as the need for EAs consequently starts dropping.

At the end of each year, every installation or business subject to ETS must surrender one EA for each ton of CO_{2e} emitted during that year. Surrendered EAs are then destroyed. Businesses with excess EAs, e.g. due to emission mitigating efforts, can sell these to other participants in need of more EAs, e.g. business which have expanded their activities. This requirement to decrease emissions somewhere in the system to allow an increase of emissions elsewhere is sometimes called the 'waterbed effect': in order to have an outwards bulge of the bed one needs to push inwards elsewhere, but the amount of water in the bed stays the same [144].

Excess EAs can also be 'banked', that is, kept for later use. Conversely, 'borrowing' from later periods is allowed as well.

ETS is divided in 'phases' lasting several years. After each phase, evaluation and adjustment, e.g. of the LRF, is possible. As of 2021 the ETS is in Phase IV, which sees the LRF increased from 1.74% to 2.2%.

Despite businesses subject to ETS reducing their GHG emissions by 35% up until 2019 [145], the mechanism has not been without its fair share of shortcomings. These are mainly caused by an overly optimistic expectation of economic growth when setting the initial cap in 2005. The worldwide financial crisis of 2008 and the following European debt crisis led to reduced consumption, and thus reduced production and associated need for EAs, which lingered on for many years after. Additionally, member states were very generous in the allocation of free EAs, mainly citing concerns about the national economy or employment rate if businesses had to finance all their emissions independently.

As ETS is a market-based mechanism, the allowance price is subject to supply and demand mechanics. If demand is low, so is the price. This was painfully demonstrated during the financial crisis, when zero demand led to a zero AU cost. Even in the following years, the price fluctuated below the €10/ton mark, a far cry from the €20-25 believed to be needed for a functioning carbon market, [146].

7.2 The green paradox

One of the main apparent deficiencies of the ETS is the lack of a so-called *price floor*. By design, price forming in the ETS is completely endogenous, preventing the introduction of a price floor. In 2015, the EC therefore decided to introduce the Market Stability Reserve (MSR).

The MSR introduced the concept of the Total Number of Allowances in Circulation (TNAC):

$$TNAC = Supply - (Demand + allowances in the MSR)$$

The idea of the MSR is that if the TNAC exceeds a certain threshold, set at 833 million EAs), 12% of the TNAC will be removed from the market and placed in the MSR. In practical terms, this means that if the total number of EAs banked by ETS participants is too high, the auctioning of next year's EAs will be reduced by 12% of the TNAC.

This mechanism aimed to create artificial scarcity, propping up the price. The scarcity is however only temporary: the AUs kept in the MSR are to be released back into the market when demand is higher again and the TNAC drops below 400 million EAs. In practice, this would be done by increasing the yearly auction volume by 100 million EAs per year.

Note that the MSR mechanism itself has no direct influence on the total number of EAs and thus no direct impact on the total emissions in the ETS. It merely shifts the supply of EAs in time. The 'waterbed' stays intact.

This so called 'backloading' of EAs back into the market was however found to be calculated in by ETS participants, and as such the MSR failed to have a significant impact on the EA price. In response, the EC adapted the MSR mechanism in 2018.

First, if the intake of EAs in the MSR is triggered, the 12% of TNAC share was increased to 24% until 2023. Second, starting from 2023, if the number of EAs held in the MSR exceeds the level of EAs auctioned the previous year, all EAs in the MSR above this level will be destroyed.

In practical terms, this means that the artificial scarcity creation by the MSR is temporarily accelerated and potentially made permanent. The MSR now has a direct impact on the total number of EAs in ETS, as EAs will be destroyed if demand stays low. The waterbed is now 'leaking',

As of 2021, the TNAC amounts to 1,579 million EAs, firmly above the limit of 833 million triggering intake into the MSR. As a result, during the following year 379 million EAs will be placed into the MSR, which up until then already contained 1.925 million EAs [147].

Up until June 2020, 360 million EAs were auctioned, with the total volume of 2019 being 588 million. This is significantly down from pre-MSR yearly auction volumes which were around the 900 million mark [148].

Hypothetically if this were 2023, around 725 million EAs in the MSR could be destroyed, reducing the total emission cap of the ETS equivalently with 725 Mton CO_{2e}. The real number is however hard to quantify, as it depends on economic developments and policy implementations up to and beyond 2023. Additionally, the EA allocation volumes were realigned in 2020 due to the UK leaving the EU, making extrapolation irrelevant [149].

From a climate standpoint, the ETS ‘waterbed leakage’ is beneficial, as it is an endogenously created lowering of the total emission cap. The MSR is a completely automated mechanism, requiring no political or policy maker intervention. However, it requires the TNAC to remain above 833 million EAs to sustain the leakage. This could be supported by emission demand reducing climate policy, but the MSR might have unforeseen consequences as to that regard.

To map the impact of demand reducing policy, we construct a generalised model of the ETS to investigate two time periods t_1 , being the moment a policy maker announces a climate mitigating policy, and t_2 , the moment the policy is enacted.

In the ETS market, EA demand d is subject to price p , which we will call the endogenous demand function $f(p)$. As EAs are eventually surrendered in exchange for emission e , we use the latter notation to represent demand as well. $E = e_1 + e_2$ represents the total demand, and thus emissions of the two periods considered.

Emissions e are also affected exogenously by the demand reducing policy, of which the effect is represented by the coefficient α . For a given time period t , emissions are therefore:

$$e_t = f_t(p_t) + \alpha_t \quad (14)$$

Emissions must be covered by EAs, which in turn must be provided by the exogenous supply (free allocation + auctioning) of EAs \bar{s}_t .

If ETS participants have been allocated more EAs in t_1 then they will surrender, they are allowed carry over (bank) the excess EAs to t_2 . Note that not all participants are per se *consumers* of the EAs they hold. As with any traded commodity, arbitrage is possible as well.

The aggregate banking over all participants is represented by b . If b exceeds the exogenous set limit \bar{b} , the MSR intake is triggered and the supply s_2 is reduced by δb .

In t_1 , oversupply of the initial EA allocation is added to the bank. As supply and demand must eventually be balanced in the ETS, demand in t_2 is provided by the carried over aggregate bank and the allocation s_2 . This leads to the following set of equations.

$$e_1 + b = \bar{s}_1 \tag{16}$$

$$e_2 = \bar{s}_2 + b \quad \text{if } b \leq \bar{b} \tag{17}$$

$$e_2 = \bar{s}_2 - \delta b + b \quad \text{if } b > \bar{b} \tag{18}$$

As we are considering the impact of the MSR, we assume $b > \bar{b}$. The aggregate emissions over both periods E can then be written as

$$\begin{aligned} E &= e_1 + e_2 \\ &= \bar{s}_1 + \bar{s}_2 - \delta b \end{aligned} \tag{22}$$

This mechanism by which aggregate emissions decrease proportionally with banking is at the core of the MSR. Banking reduces the demand in t_1 , which leads to a decreased supply in t_2 . Note, as initial supply s_1 is fixed, that the decrease in total emissions is only dependent on the demand in t_1 .

$$dE = -\delta db = \delta de_1 \tag{23}$$

Now assume the policy maker introduces a demand reducing policy, e.g. a phase-out of fossil-fired plants, effective in t_1 . With $\alpha_1 < 0$ demand e_1 is reduced, which due to (19) leads to an increase in banking b . Assuming the conditions in (21) are met, this leads to a lower supply $\bar{s}_2 - \delta b$ in t_2 , and thus lower aggregate emissions E . The waterbed is leaking, the demand reducing policy is effective.

Assume however that the policy maker introduces a demand reducing policy in t_1 , but only taking effect in t_2 . As $\alpha_2 < 0$, ETS participants expect a lower

demand for EAs in t_2 , and as a result will bank less. Consumers, e.g. industrial facilities, might also be incentivised to consume more EAs before the policy enters into effect. This increase in demand is effectively taken from the banked EAs that would otherwise flow into the MSR and be destroyed.

This leads to what is called the 'Green Paradox': a well-intended emission reducing policy, e.g. announcing the closure of a coal-fired plant some time in the future, can actually lead to an increase in aggregate emissions [150]. As the expected decrease of EA demand results in lower banking and as such lower rate of EA destruction in the MSR, net emissions increase compared to the case where no reduction of demand in later period t_2 occurred.

This finding illustrates that the timing of policy announcement and implementation is imperative for the effectiveness of the policy. A policy announced and enacted early on would translate early emission reductions (almost) fully to aggregate emission reduction. Conversely, announcing a policy early on but only enacting it in the future leads to a decrease in the

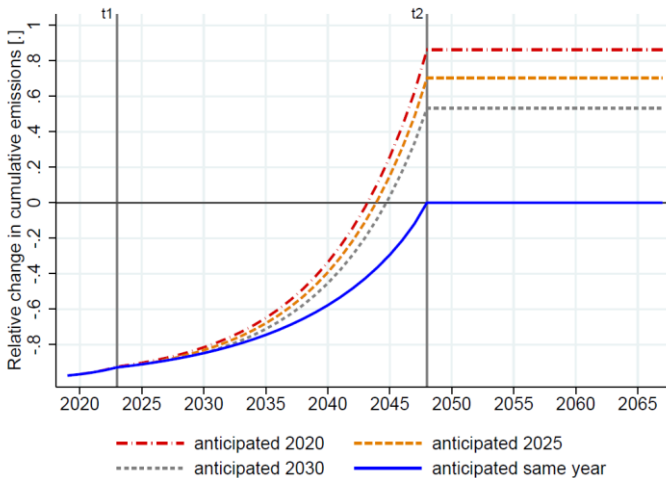


Figure 27: Plot from [151] showing the effects on cumulative emissions of a demand-reducing policy that reduces demand by one million EUAs (1 MtCO₂) in the "reduction year" t , with the policy anticipated in year $s \leq t$.

reduction or even an increase of the aggregate emission. The effect is roughly cubic, as shown in Figure 28. If a demand reducing policy is announced and enacted in 2020, it will lead to almost full translation into aggregate emission reduction. If the policy is only enacted between 2035 and 2040, the effect is halved. It becomes zero by 2045, and completely reversed by 2048. [151]

‘Surprise policies’, announced and enacted at the same time, also have a profound impact on aggregate emission reduction but, similar to announced policies, the effect diminishes how later on the policy is announced and implemented. This is due to lower inflow of EAs in the MSR as time progresses and supply gets tighter. Additionally, surprise policies or policies enacted on short-term might negatively impact society and industry, as adjustment requires time.

Note that next to the Green Paradox discussed above, a ‘Grey Paradox’ is theoretically possible as well: an announced *heightening* of emissions some time in the future might actually lead to *decreased* aggregate emissions. Take, as a purely random example, the announced replacement of low-carbon nuclear energy with fossil-fired gas plants. Anticipating higher allowance prices and/or tighter EA supply, future gas plant operators might start banking EAs before the new gas plants are put into operation. This increased banking leads to increased chance of inflow in the MSR being destroyed, and thus leading to lower aggregate emissions.

ETS adjustments might mitigate or even prevent paradoxes. The most straight-forward solution is to match any announced demand-reducing policy with an equivalent decrease of future EA allocation, effectively reducing the total emission cap. The EC has up until now been quite wary of such interventionist measures, as they are politically sensitive. This has not prevented individual countries, like Germany, from already planning to withhold future allocation of their assigned national EAs in line with the emissions of their coal phase-out [152]. This leads to its own paradox, however. As EAs are traded EU-wide, this measure reduces the TNAC and thus the amount of EAs destroyed by the MSR [153].

One could argue that exogenous methods such as decreasing the total emission cap are not very efficient. It is a politically sensitive measure, requiring time-consuming negotiations and conciliation, a process not really adapted to the rapid economic and technological changes in today’s society.

It is also worth noting that the discrete intake and backloading triggers defined in the MSR can lead to unique price transients. As long as $b \leq \bar{b}$, there is no destruction of EAs in the MSR in t_2 . When b crosses the threshold \bar{b} , destruction jumps to δd . This leads to a set of multiple metastable market equilibriums, where the expectations of ETS participants do not necessarily line up with those of the policy maker, or even of their fellow ETS participants. This can lead to coordination mismatch and decreasing utility maximisation. [151]

Making matters worse, b and TNAC are only determined once a year and many months ex-post, when ETS participants have submitted their filings and the EC has verified them [154]. This leads to additional lag between the moment scarcity arises or disappears, and the moment the MSR enacts.

Reviewing other cap-and-trade systems indicates a price collar is often used as an endogenous market stability mechanism [155]. Price collars define (soft) price floors and price ceilings. E.g., the Regional Greenhouse Gas Initiative (RGGI), implemented across nine north-eastern US states, uses a Cost Containment Reserve (CCR) which appears similar to the MSR, but is price-focused instead of quantity-based. If the price floor is reached, allowances are loaded into the CCR and backloaded to the market if the price ceiling is reached, thereby reducing price volatility. However, as both the price floor and ceiling are exogenously set, this remains a sensitive political issue. Additionally, price transients are just traded in for quantitative transients, leading to the same type of issues.

Alternatively, the allowance supply could be made subject to the EA price, comparable to the California-Quebec Western Climate Initiative (WCI) cap-and-trade system. The WCI is quite extraordinary, as it covers almost all GHG producing sectors except for agriculture but (already) includes automotive and heating fuels, and is quite short-lived (8 years). Price signals are communicated in real-time through the market, and as such represent (expected) changes in scarcity much closer than the TNAC [156]. By using a predefined, transparent supply function the EA price should behave more apparent and stable, which is a benefit for a cap-and-trade system covering almost all commodities. WCI has however demonstrated prices consistently at the price floor, occasionally rising to the price ceiling, but seldom intermediate. This has been attributed to high ex-ante uncertainty of WCI participants on the total emissions cap and the expected willingness of policy makers to intervene in the price setting if prices remain high, which is assumed to be likely as the abatement cost curve is quite inflexible (e.g. switching to a more efficient vehicle). [157] This might prove interesting for the anticipated expansion of ETS into automotive and heating fuels [158].

In July 2021 however, the EC pressed ahead and proposed a one-off downwards adjustment of the EU-wide ETS cap to -61% compared to 2005, down from the current number of 43% [159].

7.3 Waterbed sealing

As discussed above, EA destruction in the MSR (waterbed leakage) has a direct effect on the aggregate emission cap. However, for the waterbed to remain leaking the condition stated in (21) must be met.

In the previous sections, we discussed the impact of policy (announcement) timing on the aggregate emission cap. This is called the indirect effect. In general, the indirect effect opposes the direct effect through the green paradox and is strongest if the announced policy takes effect at a time when the TNAC has decreased below 833 Mton CO_{2e} and no more EAs are destroyed.

The timing of this ‘waterbed sealing’, or the condition stated in (21) to become false, introduces an additional degree of freedom. Evidently, the later the year the waterbed is sealed the larger the effect of EA destruction is, but also the stronger the impact of the indirect effect is.

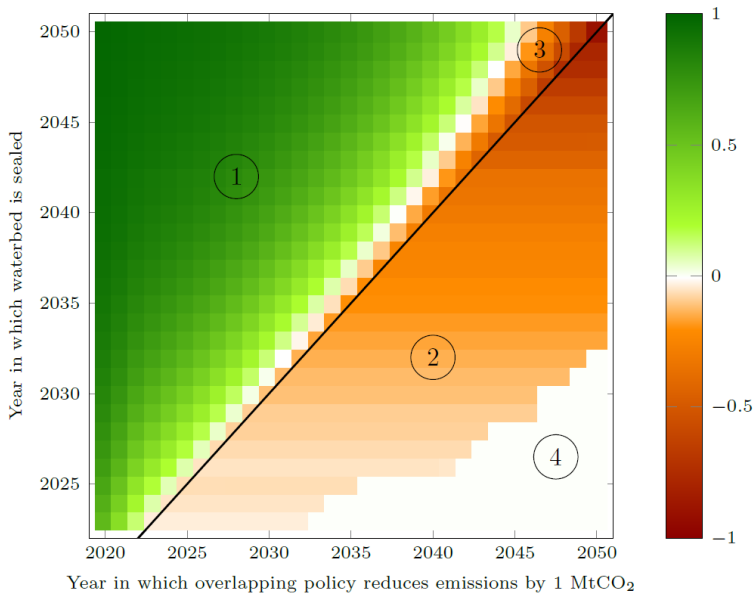


Figure 29: Plot from [160] indicating waterbed leakage as a function of the year the overlapping policy or shock takes place (horizontal axis) and the year the waterbed is sealed (vertical axis).

Bruninx and Ovaere summarise the effect of both degrees of freedom graphically [160]. Figure 29 depicts waterbed leakage for a policy announced in 2020 under the current ETS, depending on the year the policy is enacted (horizontal axis) and the year the waterbed is sealed (vertical axis). Waterbed leakage is defined as $\frac{dE}{\delta ab'}$, meaning if the leakage equals 1 a policy to decrease (increase) emissions with 1 Mton CO_{2e} decreases (increases) aggregate emissions with 1 Mton CO_{2e}. Conversely, if leakage equals -1 a policy to decrease (increase) emissions with 1 Mton CO_{2e} increases (decreases) aggregate emissions with 1 Mton CO_{2e} and the policy is said to backfire.

Four regions can be identified in the graph. In the first region, upper left part of the figure, the direct effect is dominating because the announced policy is implemented before the indirect effect becomes positive and before the waterbed is sealed. In this region, emission reducing policies contribute positively to aggregate emission reduction.

The later the year the policy is enacted, the lesser the direct effect becomes, and the more the (inverse) indirect effect increases. The black line represents the tipping point, where the direct effect equals zero. To the lower right of this line is region 2, where the green (grey) paradox is situated. An emission reducing policy backfires, increasing the aggregate emissions. Note that the indirect effect increases with the time between policy announcement and enactment, which is in line with section 7.2 The green paradox, but remains the same after the waterbed has sealed.

In region 3, in the upper right corner, the indirect effect dominates the direct effect (if present), even to the extreme (-1). Region 4 depicts the situation where the TNAC is zero, and no more banking can be performed.

The timing of waterbed sealing has a similar impact on aggregate emissions as the timing of policy announcement. The waterbed seals if the TNAC drops below the limit of 833 Mton CO_{2e}, after which the MSR stops taking in EAs. The TNAC is dependent on EA demand, of which the future evolution is however hard to assess. It is not only dependent on (announced) policy, but also on causes beyond control of the policy maker, such as the state of the European economy, shifting customer demands or unforeseen demand shocks. Take, for example, the Covid-19 pandemic. This led to an unforeseen large drop in EA demand, resulting in an almost one-to-one translation between temporary emission reduction and aggregate emission reduction [160].

EA demand is also dependent on the shape of the abatement cost curve: if it will cost more (less) to reduce emissions in the future, emitters will be more (less) incentivised to start with emission reduction now and bank allowances for later. The slope of the cost curve is partially dependent on future technological advances, e.g. the expectation that a future technology will be able to economically avoid or sequester emissions. In general, however, the cost curve has been found to be steep, especially in the short term [161].

Announced policy such as the EC-proposed one-off downwards adjustment of the ETS total emission cap also have an influence. If this policy comes to pass, ETS participants will expect a tighter future EA supply and a higher emission cost, leading to increased emission reduction now and higher banking levels. Note that this also mitigates the paradox effect.

Wrapping up, we can conclude that EA destruction in the MSR is positive from a climate standpoint, but discards the certainty of the emission cap. This could lead to less efficient policy making, as the exact impact of the policy is now dependent on factors outside the policy maker's control. If the time between policy announcement and enactment is short and the waterbed remains leaking for a long time, the policy is highly efficient (possibly even beyond expectation). If the intermediate time is however long and/or the waterbed is sealed in between, the policy can back-fire and actually increase aggregate emissions.

Note that, even though aggregate emissions can increase due to policy back-firing, the total emissions will never exceed the exogenously set cap ($\delta = 0$). Basic ETS waterbed functionality remains intact.

In that light, the downwards adjustment of the cap can be seen as a no-regret measure. Although, as we will discuss in the next section, it could have peculiar implications on Belgian energy policy.

8 Conclusions and further research

8.1 Conclusions

Our electricity system is shifting from the historical model based on large power plants providing *base* load generation, to one dominated by intermittent renewable energy providing *bulk* load, leaving the question of how to provide the *residual* load generation in a sustainable way. The large influx of renewable energy is changing the way we produce, trade and consume electricity. Going forward, flexibility in both production and consumption of electricity will be of increasing importance.

The goal of this research was to evaluate several options to provide this flexibility to the Belgian electricity system more in a robust way, performing this analysis from a techno-economic perspective and taking both historic elements and recent developments into account. The research focussed on technologies which have a high degree of applicability towards the Belgian electricity system. Nuclear was selected due to its historic presence in Belgium. Hydrogen was selected because of the large demand for this molecule as feedstock, with electrolytic production currently being the straightforward production method, and for its possible use as a zero-carbon fuel for flexible power plants. Residential flexibility, both in the electricity production by rooftop solar and in residential energy consumption, was selected due to the high penetration of rooftop solar in Belgium and the oncoming electrification of building heating through heat pumps and mobility through electric vehicles.

A summary of this section is displayed in Table 5, for each technology indicating the technical and economic aspects deemed most significant, together with general remarks toward their application as a large scale flexibility provider.

		Conventional nuclear	SMR	Electrolytic hydrogen	Hydrogen fuelled plants	Residential PV generation	Residential consumption
Technical aspects	Demand side potential	N/A	N/A	High	N/A	N/A	High
	Generation side potential	High	High	N/A	High	Medium	N/A
	Technological uncertainty	Low	High	Low	Low	Low	Medium
Economic aspects	Investment cost	High	Medium	Medium	Low	Low	Medium
	Operational costs	Low	Low	Medium	High	Low	Medium
	Economic uncertainty	High	High	Medium	Medium	Low	Medium
Main remarks	Main issues	Decreasing running hours negatively impact profitability and endanger future investments	Many of the economic challenges of conventional nuclear remain. Negative scale effects increase levelised cost . Technology still under development .	Large dynamic operation might negatively impact levelised hydrogen production cost .	Complex storage logistics . Expected limited supply chain.	Low impact of different orientations on production profile (unless for extreme angles). Decrease in yield when changing orientation from optimal.	Complex aggregation of assets due to lack of interoperability and size of asset pool required. User behaviour can be a limiting factor.
	Main opportunities	Low-carbon, proven technology . Existing assets.	Lower overnight cost (per plant) might be more attractive than conventional nuclear .	High expected demand for electrolytic hydrogen.	Low CAPEX. Relatively easy to retrofit existing natural gas power plants.	With decreasing panel cost , benefit of changing production profile might outweigh yield decrease.	Large expected increase in electric vehicles and heat pumps.

Table 4: Summary of technical and economic aspects of each reviewed flexibility option, with general remarks towards their applicability (N/A: Not Applicable)

The investigation into whether nuclear plants can contribute to the generation side's flexibility provided insights not well covered in the existing research on electrical flexibility. Contrary to the prevailing notion, it was shown that nuclear power plants technically do possess the capability for flexible operation, potentially even surpassing other thermal plants, such as CCGT and OCGT, in certain metrics like ramp rate. However, the economic evaluation revealed that engaging in flexible generation adversely affects the financial performance of nuclear power plants, potentially eroding or nullifying their profitability. The economic challenge stems from the substantial fixed costs associated with nuclear generation, which constitute 75% or more of the total cost of electricity production, regardless of the volume of electricity produced. Consequently, reducing the output of a nuclear power plant elevates the relative cost per unit of electricity generated. It was shown that a 10% drop in capacity factor already leads to a production cost increase of 12,5%, a 20% drop to 28,5% etc. Nuclear power plant operators are therefore reluctant towards flexible operation.

Moreover, the economic operation of nuclear power plants already faces increasing uncertainties. Nuclear power plant operators contract most of

their production on the long-term (futures) market. The influx of renewable energy sources, however, creates growing price volatility on the spot (day-ahead) market, with increasingly longer periods of very low to even negative prices. This creates an incentive for energy consumers to shift their procurement of energy (at least partially) from the long-term market to the spot market, especially if they can also introduce flexibility in their energy consumption, potentially further underlining the economic baseline of nuclear power plants.

While conventional nuclear power plants are technically able to provide large scale generation flexibility, the significant negative economic implications and uncertainties on (profitable) power plant operation severely inhibits their role as a flexibility provider. This makes it an unlikely source of large-scale flexibility.

Small Modular Reactors (SMR), a new and upcoming method of generating nuclear power, intent to tackle some of the economic issues conventional nuclear power plants face. They aim to decrease the upfront capital costs by utilising smaller, standardised components manufactured in factories and assembled onsite, leading to a lower operating cost. Similar to conventional nuclear power, the techno-economic aspects of SMRs as a flexibility provider were analysed.

Technically, SMRs can be divided into several categories. In this dissertation, a division based on reactor coolant was selected, leading to three distinct categories: water-based reactors, molten-salt reactors and gas-cooled reactors. The analysis mainly focussed on water-based reactors, as they are most close to market introduction due to their design being based on well-established conventional reactors.

SMRs using water as reactor coolant retain much of the technical flexibility potential of conventional reactors, as they are in essence a scaled-down version of it. However, it was shown that the smaller scale of SMRs introduces negative scale effects, increasing the relative capacity cost (€/kW) of this technology compared to conventional reactors. This can be offset by mass production, assuming this will lead to a positive learning rate outweighing the negative scale effect.

Water-based SMRs not only retain many of the technical characteristics of conventional, large-scale reactors, their cost structure is comparable as well. They are characterised by a large upfront investment (CAPEX) and relatively low operational cost (OPEX). This also implies they carry over the same cost

issues when operating in a flexible way, with a result in power input leading to a higher relative cost of the energy produced, mirroring the challenges faced by conventional nuclear power plants.

As a second technology option to provide large-scale flexibility, the feasibility of hydrogen-fuelled thermal power plants was assessed, particularly by retrofitting existing natural gas-fired plants, was assessed. This strategy offers the advantage of maintaining operational flexibility akin to CCGT and OCGT while eliminating carbon emissions associated with natural gas combustion. It also has high applicability in Belgium, where natural gas-fired plants are currently one of the largest existing providers of flexible generation. The research, supported by a review of literature and industry consultations, validated the technological viability of retrofitting modern installations to be 'hydrogen-ready'. Such plants can accommodate hydrogen blends up to 30% with minimal modifications and up to 50% with more extensive alterations, with the capital expenditure for these adaptations being relatively modest. Even hydrogen-only combustion is possible, however requiring more extensive upgrades or even replacement of turbine components.

Despite the technological appeal and low investment requirement for converting natural gas power plants to hydrogen, the overall feasibility hinges on the sustainable production, storage, and transportation of hydrogen. The challenges associated with the high energy input required for sustainable hydrogen production and its low volumetric energy density render it an improbable primary energy source for extensive electricity generation. However, it shows high utility as a reserve fuel, providing backup during (extended) periods of low renewable energy output. The low CAPEX, high OPEX cost structure gives this technology a considerable economic advantage as a large-scale flexibility provider.

Next to hydrogen as a fuel for flexibility from the generation side, the viability of electrolytic hydrogen production as a demand-side flexibility mechanism was assessed. The wide dynamic power range of most electrolyzers allows for the modulation of their output in alignment with the fluctuating production of renewable energy sources. Given the increasing demand for low-carbon hydrogen in industries such as chemicals and steelmaking, the concept of flexible electrolytic hydrogen production appeared promising. However, the findings of this research suggest that electrolytic hydrogen production faces limitations as a large-scale flexibility solution due to both technical and economic factors. The consistent wear and tear on electrolyzers regardless of load factor, coupled with the need for increased

capacity to maintain production volumes at lower average load factors, escalates capital expenditure and, by extension, the cost of hydrogen production. In a typical European context, achieving competitive hydrogen production costs necessitates high load factors, often exceeding 6000 equivalent full load hours annually. Although some flexibility is possible, e.g. to provide ancillary services to the grid, economically electrolytic hydrogen production can be regarded more as a baseload rather than a large-scale flexible process.

As a final option, the provision of flexibility by residential customers was investigated, both from a generation and consumption perspective.

Considering the generation side, the exploration of semi-passive flexibility through the strategic orientation of solar PV panels has been studied. The conventional south-facing orientation of PV panels, with power output typically peaking at noon and diminishing by evening, was re-evaluated in favour of a split orientation, with arrays facing east and west, to better match daily electricity consumption patterns which increase in the morning and peak in the evening. Utilising an anisotropic-all-sky model, better suited for Western-European climates than the conventional isotropic model, alongside simulations grounded in actual residential load profiles and grid parameters, it was shown that this split orientation of PV arrays can indeed mitigate the noon peak in power injection. Nonetheless, the impact on extending production times in the morning and evening remains marginal, becoming somewhat more pronounced during winter months. While this approach can reduce peak injection, it also diminishes the overall energy yield, potentially rendering it an economically less efficient solution. However, due to the significantly decreased prices of solar PV panels the previous years, this may still offer potential to provide flexibility to the system.

From the consumption side, the potential of shifting or adapting the residential electricity consumption in order to provide flexibility to the system was investigated. It was shown that residential electricity consumption holds a very large technical potential for flexibility when taking the expected future adoption rate of heat pumps and electric vehicles into account. Despite this potential, residential flexibility faces significant challenges, particularly due to the diverse nature and control mechanisms of household appliances, compounded by the high costs and complexity associated with aggregating numerous small-scale consumers. This is not only implies the technical implementation of residential flexibility, but also

the development by flexibility providers of transparent and easy-to-understand value propositions towards end customers.

From a technical perspective, the pivotal role of increased interoperability and digital communication, facilitated through Application Programming Interfaces (APIs), was found to be essential in overcoming these barriers. By promoting open and documented layouts and data models, manufacturers can enable their devices to interact with those from other brands, enhancing compatibility and supporting retrofit applications.

From the economic side, the dissertation addresses the crucial aspect of clear price signalling to residential assets, particularly concerning solar PV installations. The phenomenon of price cannibalisation, exacerbated by the lack of awareness among residential solar PV owners about wholesale electricity pricing, underscores the need for these installations to be attuned to market and grid conditions. This alignment is imperative to mitigate the adverse effects on market stability and grid costs, thereby safeguarding social welfare and ensuring the efficient operation of the electricity system.

8.2 Further research

In this dissertation, three distinct groups of technologies were evaluated for their potential to provide flexibility to the electrical grid. The technologies were selected due to their applicability to the Belgian energy system, and an identified research gap.

The selection of these technologies is by no means an exhaustive, nor a definitive list. Some technologies were omitted because they are already well researched (e.g. increasing the electrical interconnection with other countries). Others were not included because their development is still in an early phase, with many uncertainty around their technical and economic potential.

The energy transition continues to accelerate, driven by ever-faster technological evolutions and changing economic conditions. It is quite possible that the conclusions of this work will seem dated after only a few years, perhaps even earlier. The recommendations for further research should therefore also be seen in that light.

A first recommendation may be further and quantitative investigation of the potential of residential flexibility to contribute to the security of supply of the electrical energy system. During the last two years of this dissertation, the FlexSys project has set up pilot sites consisting of measurement and control

gateways in participating family homes to engage in data collection. Setting up these pilots turned out to be quite challenging, so useful data collection could only start late and did not arrive in time to be included in this dissertation. That data is now coming in and can provide valuable insights into both the technical and (user behaviour-adjusted) realistic potential contribution of residential flexibility to the security of supply. A clear knowledge gap was identified here during the research, both in academic literature and operational studies. Further quantification of these contributions is therefore recommended.

Another rapidly developing aspect is the contribution of nuclear power in general, and SMRs in particular, to the flexibility of our electric power system. Many of the technical aspects of SMRs are still crystallising, and it remains to be seen whether the assumptions used in this work will materialise. Specifically, it seems interesting to investigate the economic case for SMRs in relation to other forms of flexibility, such as large-scale battery storage and DSM. In literature, this evaluation is mainly done from a central planner scenario with perfect foresight. This may give a distorted picture given that these technologies will eventually operate, at least in Europe, in a competitive and liberalised energy system. As SMRs are effectively built, more and more operational technical and economic data of them will also become available.

A third research avenue to be recommended is that of simplifying the integration and dispatch of residential flexibility. As raised in this work, there are currently too many technical barriers to overcome in order to roll out residential flexibility at scale. Some of these barriers are *hard* technical, such as the problem of making different systems, e.g. HP and EV, work together seamlessly. Further technological research and the drafting of regulatory cues regarding interoperability are therefore needed.

Dispatching residential flexibility also has strong limitations at present. Implicit flexibility now follows the wholesale market price signal. This is simple and transparent, but comes with limitations. For instance, the DAM price signal goes only one day far into the future, while optimal charging of e.g. EV batteries in function of user behaviour sometimes has to be planned days in advance. The wholesale market price signal also does not contain real-time information, e.g. on the current system imbalance. Explicit flexibility can take this into account, but the way residential flexibility needs to be explicitly dispatched now is technically very complex. A recommendation could be to explore the generation of a single real-time implicit price signal that combines

all available technical and market information. Such a signal would have the advantage of (technical) simplicity and transparency to the end user.

Finally, there are some multidisciplinary research recommendations. An increasingly intermittent energy system requires more flexibility, but this flexibility also requires suitable contracts and settlement procedures. On the one hand, there is a case to be made for aiming for quasi-real time contracts, examining how they should be designed to be as transparent and have as little overhead as possible. On the other hand, an intermittent system also increases the need for stable long-term contracts. Parts of industry, but also the general population, benefit from stability and predictability of (part of) the energy price, e.g. to ease investment scheduling or to hedge price variations. Research on this can also contribute to the research track above.

Another interdisciplinary research avenue is to further analyse the reasons for construction cost and time overruns for nuclear reactors, and whether this will turn out differently for SMRs. This research could draw on historical analysis of other large-scale construction projects to see if correlations can be found there. And with several countries announcing the construction of new nuclear projects, new data points also become available to test assumptions about construction times and costs against.

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